REDACTED

REVISED DIRECT TESTIMONY

OF

RICHARD J. ZURASKI

Senior Economist

Illinois Commerce Commission

Energy Division—Policy Section

Commonwealth Edison Company	:	**00-0259**
	:	
Petition for expedited approval of implementation of a market-based alternative tariff, to become effective on or before May 1, 2000, pursuant to Article IX and Section 16-112 of the Public Utilities Act	:	
	:	
Central Illinois Public Service Company	:	**00-0395**
Union Electric Company	:	
	:	
Petition for approval of revisions to market value tariff, Rider MV	:	
	:	
Illinois Power Company	:	**00-0461**
	:	
Proposed new Rider MVI and : revisions to Rider TC	:	

September 5, 2000

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Section 1: Introduction

I. Witness Qualifications

Q. State your name and business address.

A. Richard J. Zuraski, Illinois Commerce Commission, 527 East Capitol Avenue, P.O. Box 19280, Springfield, Illinois, 62794-9280.

Q. By whom are you employed and in what capacity?

A. I am employed as a Senior Economist in the Illinois Commerce Commission's Energy Division—Policy Section.

Q. What are your responsibilities within the Energy Division—Policy Section?

A. I provide economic analyses and advise the Commission and other staff members on issues involving the gas and electric utility industries. I review tariff filings and make recommendations to the Commission concerning those filings. I provide testimony in Commission proceedings. In selected cases, I sometimes act as an assistant to the Commission or to hearing examiners.

Q. State your educational background.

A. I graduated from the University of Maryland with a Bachelor of Arts degree in Economics. I obtained a Masters of Arts degree in Economics from Washington University in

St. Louis. I completed other work toward a doctorate in economics from Washington University, but have not completed all requirements for that degree.

Q. Describe your professional experience.

A. Since December 1997, I have been a Senior Economist in the Policy Program of the Commission's Energy Division. I held the same position from February 1990 to December 1997, in the Commission's Office of Policy and Planning (prior to its incorporation into the Energy Division). Before that, I held positions in the Commission's Least-Cost Planning Program and Conservation Program. While employed by the Commission, I have testified in numerous docketed proceedings before the Commission. Prior to coming to the Commission in November 1987, I was a graduate student at Washington University, where I taught various courses in economics to undergraduate students in the Washington University night school and summer school.

II. Purpose of Testimony

Q. What is the subject matter of your testimony?

A. This testimony concerns three independent proposals by Commonwealth Edison Company ("ComEd"), Illinois Power Company ("IP"), and Ameren Central Illinois Public Service Company and Ameren Union Electric Company ("Ameren"), respectively, to institute "market index" mechanisms for computing "market values," which would be in lieu of the default determinations of "market values" produced each year by a Neutral Fact Finder ("NFF"), under Section 16-112 of the Public Utilities Act ("Act").

Q. How is the remainder of your testimony organized?

A. In this first introductory section, I next provide some background on the nature of the delivery services option for purchasing electric services on an unbundled basis, the Power Purchase Option ("PPO"), and the customer transition charge ("CTC") which is paid by delivery service and PPO customers under the Illinois Public Utilities Act ("Act"). Then, I comment on the importance of the so-called "market value" ("MV") in the computation of PPOs and CTCs. Then, I briefly describe the nature of the Commission's authority to modify a utility's proposal to implement a non-NFF alternative mechanism for computing market values.

In the second major section, I assess the various features of the three specific proposals before the Commission and, in some instances, I recommend modifications.

I am also sponsoring 15 Schedules, in Staff Exhibit 3.1.

In places, my testimony is identical or nearly so with the testimony that I presented in April 2000 in the ComEd-only docket, which has been consolidated within the current proceeding. Many of the concepts discussed in my April 2000 testimony are true for all three utilities and repeating them in a more general context, herein, ensures that the testimony can be cited in the record for all three dockets. In places, my April 2000 recommendations for the ComEd docket have changed, as a consequence of further analysis and consideration.

III. Background on Delivery Services, the PPO, and CTCs

Q. Please describe the restructuring of the electric utility industry that has taken place in Illinois since 1997.

A. The Electric Service Customer Choice and Rate Relief Law of 1997, which became effective in December of 1997, created Article 16 of the Act. That article required each electric utility in the State to file tariff sheets with the Commission that would enable retail customers located in the electric utility's service area to receive electric power and energy from suppliers other than the electric utility. That is, rather than purchase the gamut of traditional utility services from the utility as a single "bundled" package, customers would be able to purchase "delivery services" from the utility on an unbundled basis and purchase the power output of generators from other third-parties, such as other utilities, power marketers or generating companies. Among participants in ICC delivery service proceedings, these third-party entities, who are eligible to market power at retail in Illinois, have come to be known collectively as "retail electric suppliers" ("RESs"). This term includes, but is not limited to, Alternative Retail Electric Suppliers ("ARES") as that term is defined in the Act. Through the restructuring described above, delivery services remain regulated, but the business of supplying power at retail may be subject to a greater degree of competitive forces, as utilities and RESs vie for the patronage of consumers.

Q. Does the Act provide utilities with any special protections against these competitive forces?

A. Yes. The Act did not subject utilities to the rigors of a potentially competitive marketplace without a transition period. During this transition period, utilities that have embedded costs of generation that are higher than what the market will bear are afforded opportunities to recover what might otherwise have been "stranded" costs through a nonbypassable "customer transition charge" ("CTC"). The CTC is applied to customers that switch from bundled service to delivery service, whether the customer receives power and energy from a RES or from the utility on an unbundled basis through the so-called Power Purchase Option ("PPO").

Q. What is the PPO?

A. The PPO is, in essence, a bundled service that a utility is required by the Act to offer to non-residential customers if the utility chooses to impose a CTC. However, while the utility, under the PPO, continues to provide the entire panoply of traditional utility services as a single bundled package, the utility's PPO <u>charges</u> are unbundled into (a) a PPO administrative fee component, (b) a delivery services component, (c) a CTC component, and (d) a power and energy component. The charge(s) for the power and energy component are to be based on the same market values used in the computation of the CTC.

IV. The Importance of Market Values

Q. What is the role of Market Value ("MV") in the CTC?

A. The Act specifies a basic formula for computing the CTC, which I simplify as follows:

$$\mathbf{CTC = BR - DSR - MV - mf}, \quad \text{where}$$

BR is the customer's or customer class' average bundled rate,

DSR is the customer's or customer class' average delivery services rate

MV is the market value (as adjusted for the load characteristics for the customer or customer class); and

mf is a "mitigation factor" applicable to the customer or customer class.

Hence, the MV is one of the components in the basic formula for computing the CTC. Although a specific rationale was not given in the Act for this formula, a clearly reasonable interpretation of the formula is that the CTC affords the utility an opportunity to continue recovering (during the transition period) the cost of generation resources included in the regulated bundled rate (i.e., BR - DSR) net of the price that the utility theoretically can obtain in the market for the output of its generation resources (i.e., MV) and also net of the so-called mitigation factor. The mitigation factor is defined in the Act and is described below.

Q. What is the *mitigation factor*?

A. One might loosely refer to the **mf** as a "stretch factor," in that the utility must achieve cost savings of at least **mf** in order to at least fully recover the potentially stranded costs associated with restructuring. It varies somewhat by customer class and increases somewhat as the transition period progresses. However, the mitigation factor is not subject to any regulatory examination by the ICC or any periodic reconciliation process, so utilities can significantly over-recover or under-recover their potentially stranded costs, depending upon how effectively utilities manage their costs and unearth and develop new revenue sources.

Q. What happens if the above CTC formula results in a negative number?

A. If the above formula results in a negative number, then the CTC is set to zero. In other words, utilities are permitted to recover otherwise stranded <u>costs</u>, but are not required to return any stranded benefits after they are allowed to enter the marketplace as an unregulated competitor.

Q. What does a delivery services customer pay for electric services?

A. The delivery services customer pays to the utility the applicable set of delivery services rates ("DSRs") and the applicable CTCs, if any. The customer also pays to a RES a negotiated price for power and energy. If the MV used in the CTC formula is representative of actual prices being paid for power and energy in the retail market, then the amount that any given customer pays to the RES might be expected to be somewhere in the neighborhood of MV. However, the actual price of power and energy paid by any given customer is an unregulated contractual matter between buyer and seller and is not directly tied to the inputs into the CTCs. Hence, the MVs should only be considered a proxy or estimate of the actual market price, **P**, facing a typical customer, subject to some degree of error:

$$\mathbf{MV = P + error.}$$

Here, a positive **error** represents the MVs in the CTC being overestimated, while a negative **error** represents the MVs being underestimated.

Q. How does the total bill of the delivery services customer compare to the bundled rate?

A. Again using a simple model, and assuming that the CTC is positive, the delivery services customer pays the following:

Delivery Service Customer's Total Bill

$$\mathbf{= DSR + CTC + P}$$

$$= \mathbf{DSR + (BR - DSR - MV - mf) + P}$$

$$= \mathbf{DSR + (BR - DSR - (P + error) - mf) + P}$$

$$= \mathbf{BR - mf - error.}$$

Hence, the delivery services customer would pay a total amount equal to the bundled rate minus the mitigation factor minus the error in the MV estimate of the applicable market prices. As long as the **error** in the market value estimate that is used in the CTC is positive (or, if negative, at least not as great in magnitude as the mitigation factor), then the customer will be able to save by switching to delivery services at market price, **P**.

Q. If the MV is sufficiently under-estimated, what happens to the customer's total bill?

A. If **MV** is underestimated enough, such that **-error - mf > 0**, then the customer's total bill would be greater under delivery services than under the traditional bundled service arrangement.[1] Presumably, few, if any, customers would choose to pay more for basically the same commodity. Hence, a sufficiently underestimated MV will prevent customers from switching to a RES. Thus, even though a RES may be able to supply electricity to a retail customer at a rate that is less than the true market value of power and energy and less than the utility's own embedded generation costs, an underestimated MV in the CTC can prevent a RES from showing a customer any savings relative to the bundled rate. Basically the same problem can prevent a RES from showing a customer any savings relative to the PPO, as well.

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[1] For example, suppose the **mf** is 0.73 cents per kwh and the **error** is -0.94 cents per kwh (the negative sign indicating that the market prices have been ***under***-estimated. In that case, **-error - mf** = - (-)0.94 - .73 = +0.94 - 0.73 = 0.21 cents per kwh. Hence, the Delivery Service Customer's Total Bill in this hypothetical example would be higher than the bundled rate by 0.21 cents per kwh.

Q. Do customers and RESs always benefit when, all else constant, the MV rises?

A. No, not all customers benefit from a rise in MV. On the one hand, a prospective delivery service customer is apt to prefer an over-estimated market value, since this leads to a decrease in the CTC without affecting the actual market price that the customer pays to a RES. Overestimated MVs also mean that a RES, all else constant, would be in a better position to offer savings to any given customer, relative to the bundled rate or the PPO. In contrast, sufficiently **under-estimated** MVs could render it impossible for some or all RESs to bring savings to customers, as suggested by footnote 1. Hence, one could argue that overestimating MVs could stimulate more competitive entry, while underestimating MVs could retard the development of competitive entry, during the transition period.

On the other hand, if a particular customer's cheapest option is **not** to be a delivery services customer, but rather is to be a **PPO** customer, then the customer does not necessarily benefit from an increase in the CTC's MVs. To see this, one must first understand what a PPO customer pays for electric service.

Q. What does a PPO customer pay for electric services?

A. The PPO customer pays to the utility the applicable PPO administrative fee ("Fee"), the applicable set of delivery services rates (DSRs), the applicable transition charges (CTCs) and the applicable MVs (the same MVs used to compute the CTC). Hence, unlike the delivery services customer that purchases power and energy from a RES, the customer taking the PPO faces the same MVs as positive charges for power and energy that are included in the customer's CTC as credits.

Q. If the PPO customer faces the same MV as both a positive charge and a credit, does the MV merely "cancel" in the customer's total bill?

A. Again using a simple model, the MVs, as well as the DSRs, cancel. That is, under our simplified formula, the PPO customer pays:

$$\mathbf{PPO\ Total\ Bill}\Big|_{CTC>0}$$

$$= \mathbf{Fee + DSR + MV + CTC}$$

$$= \mathbf{Fee + DSR + MV + (BR - DSR - MV - mf)}$$

$$= \mathbf{Fee + BR - mf}$$

Hence, the MV appears to be irrelevant to the calculation of a PPO total bill. However, one must remember that the above formula is a simplified view of the rate structure. A more detailed accounting would show that the DSR as a positive charge may consist of several different components, but, as a credit within the CTC, the DSR has been reduced to a single number. Similarly, while the MV as a positive charge in the PPO may consist of several different MVs that vary between on-peak and off-peak, summer and winter (or even more finely disaggregated time periods), as a credit within the CTC, these MVs have been reduced to a single number. Because of these factors, the simple equation above should be viewed as an abstraction. However, the simple equation nevertheless shows the tendency (particularly for the average customers within each of the rate classes) of the MVs to cancel as the MVs essentially are both added and subtracted in the customer's total PPO bill.

Q. What happens to the PPO when the CTC is zero?

A. The Act does not appear to require utilities to provide the PPO unless the customer is paying CTCs. Nevertheless, there are differences between the Illinois electric utilities in the exact provisions for initiating or terminating PPO service when the CTC is zero. Simply stated, ComEd permits individual customers to take the PPO even if the customer's transition charge is zero, while IP and Ameren do not permit this to occur. As shown below, if the transition charge is zero, the PPO total bill will ***tend*** to be higher than the bundled rate. However, in some instances, this will not be the case.

Q. How does the PPO Total Bill with a CTC of zero compare to the PPO with a positive CTC?

A. Since we are concerned with market value in this case, assume that the difference between the two CTCs is due to differences in market value assumptions. Using the simple model of the CTC, from page 5 above, the fact that a CTC is zero implies that the CTC formula results in a number less than or equal to zero:

$$\mathbf{0 \geq BR - DSR - MV - mf = CTC}$$

$$\mathbf{DSR + MV \geq BR - mf.}$$

Adding the PPO **Fee** on both sides of the last inequality preserves the inequality and helps to show the relationship between the PPO with a zero CTC and a PPO with a positive CTC:

$$\mathbf{PPO\ Total\ Bill}\,\Big|_{CTC=0} \mathbf{= Fee + DSR + MV}$$

$$\geq$$

$$\mathbf{Fee + BR - mf = PPO\ Total\ Bill}\,\Big|_{CTC>0}$$

Hence, in the simple model of the PPO, the PPO customer does not necessarily benefit from an increase in the MV.

Q. How can a zero CTC be interpreted?

A. Neglecting the mitigation factor (or assuming that the CTC formula would have been less than **-mf**) and assuming that the "market value" used in the CTC is a reasonably accurate measure of the actual prices of power and energy prevailing in the market, a zero CTC implies that the average customer in the class is already getting a bargain relative to the market. That is, rewriting the inequality in my last answer, without the mitigation factor:

$$\mathbf{BR} \ \leq \ \mathbf{DSR + MV} \qquad \textit{(neglecting the mf).}$$

Hence, for some customers for whom the CTC is zero, the best value may be the bundled rate. However, for these same customers, the PPO may constitute an even <u>better</u> deal as long as the MV is sufficiently underestimated that a positive CTC remains. In that instance, the PPO can be used to generate a savings approximately equal to the mitigation factor (net of the PPO administrative **Fee**).

Q. Are there any other reasons why a customer may not be able to save by switching to delivery services and taking service from a RES when the MV is either accurate or over-estimated relative to actual market prices and a positive CTC is in place?

A. Yes. There is no reason to expect all RESs to be equally endowed with resources, to have the same abilities to manage quantity and price risks, to have comparable aggregations of loads, or, more generally speaking, to have the same costs. Hence, <u>some</u> RESs will be unable to recover their costs, even if those costs fall below the utility's embedded generation costs, since the RES's costs must also fall below the MV to remain competitive with the utility's PPO or bundled rates. Furthermore, by the time that a RES knows that a customer is switching to delivery services, once-accurate averages of market prices may be obsolete and under-estimates of the more current state of affairs. Also, there is no reason to expect that all customers will impose the same per unit cost on RESs. The CTC's MVs may be differentiated by class in order to capture some of these differences, but there is no guarantee that all customers can be profitably served, even if the CTC's MVs are reasonably good estimates of the average market prices prevailing in the market during some relatively relevant time period(s). There is no single set of prices that has an undeniable claim on being the rightful "Market Value." Finally, there are several costs of doing business as a RES that may not exist for the utility and may not be included in either the MV credit or the delivery services credit within the CTC. Such costs may include the cost of purchasing energy imbalance service from the utility as transmission provider, the cost of dealing with the utility's complex business practices, and additional marketing costs.

V. <u>The Commission's Authority to Modify a Utility's Proposed Market Index or to Create a Market Index That is Uniform Across All Utilities</u>

Q. Under what authority may the Commission approve an index mechanism for computing market values?

A. Section 16-112 (a) states that:

> The market value to be used in the calculation of transition charges as defined in Section 16-102 shall be determined in accordance with either (i) a tariff that has

> been filed by the electric utility with the Commission pursuant to Article IX of this Act and that provides for a determination of the market value for electric power and energy as a function of an exchange traded or other market traded index, options or futures contract or contracts applicable to the market in which the utility sells, and the customers in its service area buy, electric power and energy, or (ii) in the event no such tariff has been placed into effect for the electric utility, or in the event such tariff does not establish market values for each of the years specified in the neutral fact-finder process described in subsections (b) through (h) of this Section, a tariff incorporating the market values resulting from the neutral fact-finder process set forth in subsections (b) through (h) of this Section.

Thus, the Commission may approve a market index tariff, but, in the absence of such a tariff, the default is to rely upon the NFF process for the derivation of the market values to be used in the calculation of transition charges.

Q. Does the Commission have authority to modify a utility's proposal to replace the NFF with an alternative method?

A. With respect to such alternative methods for computing market values, Section 16-112(m) states that:

> The Commission may approve or reject, or propose modifications to, any tariff providing for the determination of market value that has been proposed by an electric utility pursuant to subsection (a) of this Section, but shall not have the power to otherwise order the electric utility to implement a modified tariff or to place into effect any tariff for the determination of market value other than one incorporating the neutral fact-finder procedure set forth in this Section. Provided, however, that if each electric utility serving at least 300,000 customers has placed into effect a tariff that provides for a determination of market value as a function of an exchange traded or other market traded index, options or futures contract or contracts, then the Commission can require any other electric utilities to file such a tariff, and can terminate the neutral fact-finder procedure for the periods covered by such tariffs.

Hence, the Commission apparently has the authority to modify a proposed market index methodology for computing market values, but utilities can reject the Commission's modifications and rely instead on the NFF market values for purposes of computing transition charges.

Q. **May the Commission create a single market index template that would be virtually uniform across all Illinois electric utilities that are empowered to and choose to impose transition charges?**

A. Yes. However, the Commission cannot force any utility to accept a uniform market index tariff. Hence, the end result could be that some utilities accept while other utilities reject the uniform market index, choosing to retain the NFF-based market values, instead. Such an end result may entail more variation between utilities than the adoption of closely-related but otherwise utility-specific market index tariffs.

Q. **Do you recommend a uniform market index for all three utilities?**

A. No. If all my recommendations were accepted, the Commission would approve three separate market indexes that are extremely similar in some respects but not in all respects. Any market index mechanism has to accomplish the same basic tasks in order to generate a set of market values. The utilities' proposed indexes approach some of these tasks in a virtually identical fashion and some of these tasks in significantly different ways. The approach I took toward such differences is explained in response to the next question.

Q. **Why shouldn't all three market indexes be identical?**

A. First, there may be differences in the actual market prices relevant to the three utilities, which justify some inter-utility differences in the market indexes. However, most of the differences in the utilities' index proposals cannot be explained by underlying differences in the markets. Rather, these other differences in the proposals reflect the utilities' preferences for how their indexes and their related rates and riders should be structured. Due to the fact that the utility has the option of rejecting the Commission's modifications, I believe it is prudent to "prioritize" and resist the urge to make relatively unimportant changes or changes that do not unambiguously improve upon the index. Thus, when it is not clear whether one utility's method is significantly better than the other two utilities' methods, as long as the methods seem reasonable, I recommend that the Commission accept each utility's unique proposal. However, in other instances, where changes to a utility's proposal are highly advisable, I generally strive toward a uniform approach.

Section 2: Assessment of the Proposals for Market Index Alternatives to the NFF

I. Use of Market Index Approach

A. Overall Policy Considerations

Q. Should the Commission prefer the adoption of a market index or the retention of the Neutral Fact Finder process for computing market values.

A. If the Commission had the ultimate authority to impose a market index approach on a utility, I would definitely argue that a market index approach would be preferable. First, it is my understanding that the NFF process is very expensive. Second, there is significant testimony in this docket already that the NFF process is producing outdated results that under-estimate contemporary levels of market prices. Third, I believe it is preferable to divorce the observation and estimation of "market value" as much as possible from the Illinois service territories within which these market value estimations will be applied in transition charges (I shall return to this third point in just a moment).

However, since utilities, under the Act, are given the right to refuse the Commission's modifications to a market index proposed by the utility, the Commission is always vulnerable to "buyer's remorse." There is a good deal of uncertainty surrounding the market, and the utility, as a constant buyer and seller of electricity, is probably in a better position to gauge the marketplace than the Commission. If the utility accepts the Commission's modifications (if any) to a proposed market index, it may be reasonable to assume that the utility expects the index to be less than the NFF's MVs, producing higher transition charges, thus helping the utility retain its market share or otherwise over-recover transition charges. Notwithstanding this concern, I recommend that the Commission adopt market indexes for the three utility companies in this docket. For one thing, so far, the proposed indexes generally seem to produce higher MVs than the NFF's reports.

Q. Why do you believe that it is preferable to divorce the observation and estimation of "market value" as much as possible from the Illinois service territories within which these market value estimations will be applied in transition charges?

A. If observations of retail prices within a utility's service territory are utilized to compute transition charges, there will tend to be a downward spiral over time in the observed market values that would contribute to retarding the development of competition throughout the transition period. In effect, the Neutral Fact Finder process cannot observe Illinois retail prices without changing them. To better visualize this effect, consider a world in which the market prices that exist in period 1 are observed and used to compute the MV for period 2; prices in period 2 are observed and used to compute the MV for period 3; etc. A simplified example is shown in the following table:

	Prices, P, offered by Alternative Suppliers in time period, t									MV(t+1)
t	a	b	c	d	e	f	g	h	i	= Avg(P,t)
1	20.00	21.00	22.00	23.00	24.00	25.00	26.00	27.00	28.00	**24.00**
2	20.00	21.00	22.00	23.00	24.00					**22.00**
3	20.00	21.00	22.00							**21.00**
4	20.00	21.00								**20.50**
5	20.00									**20.00**

In the simplified hypothetical example shown in the table, above, for a given customer class, suppose the utility's bundled rate includes a power and energy component of at least $28, while there are suppliers willing to offer the same product to customers within the same customer class at prices (a-i) ranging from $20 to $28. A range of prices rather than a single market clearing price might be due to several factors, including varying credit risks, varying levels of marketing competence, varying levels of brand-name acceptance.

Assuming the absence of any transition charges, retail consumers might very well decide to do business with these alternative suppliers. To simplify matters, suppose the NFF observes a symmetrical distribution of the a-i market prices in period 1 and therefore computes an official "market value" of $24 (the average of the a-i observed prices). Since $24 is less than the utility's power and energy component of the utility's bundled rate, the utility is eligible for transition charges under the Act. However, once the transition charge is introduced, the higher half of the alternative suppliers' offers may no longer be low enough to entice consumers away from the utility's PPO offering or the bundled rate. Hence, in period 2, only the lower half of the original offers would be observed by the NFF, even if the original cost structure of the industry remained unchanged. The average of the period 2 observed contracts would be $22, which is lower than the original average of $24. Once again, assuming something like the average of the period 2 observed prices is used by a NFF to compute the next transition charge, then the period 3 transition charge would rise and render an even greater share of the original offers unattractive to customers.

Further iterations over time would continue to crowd out more deals and would lead to observations of even lower market values, eventually settling upon a tighter distribution of prices at the lower end of the original distribution, even if the original cost structure of the industry remained unchanged.

At least two things could help to counteract the effect of this downward spiral in the MV and upward spiral in the transition charge. First, the cost structure of the industry could face a downward trend rapid enough so that alternative suppliers could keep up with the rising transition charge by lowering their costs and their power and energy charges to consumers, while still making a profit and providing the customer with savings over the regulated rates. Second, the increasing mitigation factor would help to counteract the effect of the fall in observed market values in the local market. This second factor may be particularly relevant to the residential customer classes, when they become eligible for delivery services, since the utility will not be obligated to provide such customers with a PPO, which includes the same mitigation factor as other delivery service options. Finally, it should be recalled that differences between the structure of bundled rates and delivery service rates can also present opportunities for some customers, even if the unbundled power and energy is sold to the delivery service customer at a price above the NFF's market value. All else constant, though, the NFF approach of tying the utility's transition charge to the prices observed in the utility's retail marketplace should tend to crowd out otherwise viable unbundled deals.

To avoid generating such a downward bias in market values and upward bias in transition charges over the course of the transition period, I recommend adopting an index that divorces the observation and estimation of "market value" as much as possible from the Illinois service territories within which market value estimations will be applied in transition charges.

B. Broad Outline of the Three Utilities' Market Index Approaches

Q. Please describe the very broad outlines of the three proposals before the Commission in this consolidated docket.

A. All three proposals rely on timely observation of **forward** markets (months-ahead sales) as the foundation for deriving on-peak prices. All three proposals rely on historical **spot** market data (day-ahead sales) as the foundation for deriving off-peak prices.

Two of the proposals (Ameren's and ComEd's) provide for two market value computations per year: (A) one based on a 12-month "Applicable Period A" beginning in June, and (B) the other based on a 9-month "Applicable Period B" beginning in September. New delivery service customers either get the Applicable Period A or the Applicable Period B market values, depending on when they switch to delivery services during the year.[2] Veteran

[2] Summer-time switchers get the Applicable Period A values, while those customers switching from September through May initially get the Applicable Period B values.

delivery service customers all receive new Applicable Period A market values and CTCs, once per year, each June.

In contrast, IP would compute 12 sets of market values and CTCs per year (one each month). However, each of these monthly computations would provide values that are applied for a 12-month period into the future. All new and veteran IP customers would receive market values and CTCs for a 12-month period, starting on the customer's delivery services anniversary date of each year. For example, a customer that switches to delivery services in May 2001 would receive a new MV/CTC calculation each May.

II. Concerns *re* methodology for Setting Peak MVs

Q. Please describe the data that the companies propose to utilize for on-peak prices.

A. The companies propose to utilize timely observations of forward market activity, including direct observations of prices on the Altrade and Bloomberg PowerMatch electronic trading platforms. In addition to these sources, IP also proposes to use indirect observations of surveyed forward prices, reported in Power Market's Week. Each of these data sources includes price data from several different geographic markets. ComEd proposes to use prices for the "Into-ComEd" market, while Ameren and IP both propose to use prices for the "Into-Cinergy" market. Ameren and IP would then adjust the Cinergy prices with some form of "basis" adjustment. In this context, the "basis" is the difference between the price for power in one geographic market versus another. While Ameren and IP used different basis "models," they both rely on historical spot market price data for day-ahead on-peak power sales and they are both based upon the untested hypothesis that the relationship between **spot** prices in two different geographical markets is a good predictor of the relationship between **forward** prices in two different geographical markets. Staff witness Christ has examined this hypothesis and discusses it in his testimony in this consolidated case. Staff witness Christ also makes recommendations for the computation of basis differentials.

Q. Do you agree with the utilities' proposal to use recent forward market activity as the basic source of on-peak price data?

A. Yes. Data options other than forward market data include historical spot market data and futures market data. Historical spot market prices will reflect whatever conditions may have existed at the time, including extremes in weather or other events that elevated or depressed prices, whereas forward market prices will tend to reflect "normalized" expectations for the future period over which the MVs and CTCs will be in place. Futures prices would also reflect normalized expectations for the future period, but presently, there is virtually no activity in the most relevant electric power futures markets, including the Cinergy, Entergy, and PJM contracts traded on NYMEX.

A. Selection of Base Index

i. Into Cinergy v. Into ComEd

Q. Do you have any opinion about whether the utilities should use Into-Cinergy or Into-ComEd as the starting point for deriving on-peak prices?

A. Yes. Due to the correlation between markets as well as the greater liquidity of Cinergy versus ComEd, I argue below that ComEd's market index should be modified to use Into-Cinergy as the starting point for deriving on-peak prices, similar to the approach proposed by IP and Ameren.

ii. Correlation of markets

Q. Why shouldn't IP and Ameren use Into-IP data and Into-Ameren data, respectively, to derive their on-peak market values?

A. While there are published surveys of **spot** market prices more geographically relevant to these utilities, there may not be any sources of significant forward price data specifically for Into-Illinois Power or Into-Ameren (or Into-Lower MAIN). For example, these markets are not listed on the Altrade or Bloomberg PowerMatch electronic trading platforms from which the utilities seek to acquire forward market price data. Very few forward market trades for Into-Illinois Power, Into-Ameren, or Into-Lower MAIN are seen in Power Markets Week Daily Price Report database. Hence, if using forward market prices is important, an available proxy for both Into-Illinois Power and Into-Ameren must be relied upon. Into-Cinergy is apt to be a reasonable proxy because it is in the Midwest, relatively close to the Lower MAIN region within which Illinois Power and Ameren are located, and the spot market prices between Cinergy and Lower MAIN are highly correlated.

Schedule 1, attached, shows how Cinergy, ComEd, and MAIN day-ahead spot prices have tended to move together over the last two and a half years. Schedule 2 is the same comparison, but focuses on the non-summer months. Schedule 3 is a comparison of on-peak