State of Illinois

Illinois Commerce Commission

CENTRAL ILLINOIS PUBLIC SERVICE COMPANY and UNION ELECTRIC COMPANY Petition for approval of tariff sheets implementing revised Market Value Index methodology.	)	Docket No. 02-0656
COMMONWEALTH EDISON COMPANY Proposed revision of Rider PPO (Power Purchase Option – Market Index), Rate CTC (Customer Transition Charge) and Rider ISS (Interim Supply Services), and to establish Rider CTC – MY (Customer Transition Charge – Multi-Year Experimental) (Tariffs filed on October 1, 2002)	)	Docket No. 02-0671
ILLINOIS POWER COMPANY Proposed establishment of Rider MVI II, Market Value Index II. (Tariff filed October 1, 2002)	)	Docket No. 02-0672
ILLINOIS POWER COMPANY Proposed revisions to Rider TC (Transition Charge for Customers), Rider PPO (Power Purchase Option Service) and Rider MVI (Market Value Index)	)	Docket No. 02-0834 (Cons.)

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INITIAL BRIEF OF THE ILLINOIS COMMENCE COMMISSION STAFF

STEVEN G. REVETHIS
JOHN C. FEELEY
Office of General Counsel
Illinois Commerce Commission
160 North LaSalle Street
Suite C-800
Chicago, Illinois 60601
(312) 793-2877

Counsel for the Staff of the
Illinois Commerce Commission

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I. Introduction

NOW COMES the Staff of the Illinois Commerce Commission ("Staff"), through its attorneys, and files its Brief in the above-captioned proceeding. This case 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 modify their "market index" mechanisms for computing "market values," in lieu of the default determinations of market values ("MVs") produced each year by a Neutral Fact Finder ("NFF"), under Section 16-112 of the Public Utilities Act ("Act").

A. Statutory Provisions

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, which 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. (Staff Exh. 1.0, pp. 2-3).

The Act did not subject utilities to the rigors of a potentially competitive marketplace without a transition period. During this transition period, utilities that had embedded costs of generation that were higher than what the market will bear are afforded opportunities to recover what might otherwise have been "stranded" costs through a non-bypassable "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"). (Staff Exh. 1.0, p. 3)

Section 16-102 of the Act specifies a basic formula for computing the CTC, which can be stated in simplified terms as:

BR - DSR - MV - mf , 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 determined by Section 16-112), and
"mf" is a "mitigation factor" applicable to the customer or customer class.

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. (emphasis added) 220 ILCS 5/16-112(a).

Thus, the Commission may approve a market index tariff (as described by the text emphasized in the excerpt above), but, in the absence of such a tariff, the default is to rely upon a neutral fact finder process for the derivation of the market values to be used in the calculation of transition charges.

A more detailed account of the CTC, the PPO, and how Section 16-112 market values ("MVs") figure into the rates of delivery services customers can be found in Staff Exh. 1.0, at pages 2-13.

B. History of Market Value Process

1. Previous Market Value Cases Before the Commission

Since no other companies have sought to institute transition charges, the issue of market index tariffs has been relevant to only Ameren, IP, and ComEd. Each of these companies made proposals to institute market index tariffs with their initial delivery service tariff filings in March 1999.[1] The Commission rejected each of these proposals, so market values were provided by an NFF, hired by the Commission. The NFF's market values were in effect when the first set of delivery services customers became eligible for delivery services at the end of 1999.

On March 31, 2000, ComEd filed a revised market index tariff proposal. After an expedited proceeding, the Commission entered an interim order approving, with some revisions, ComEd's proposed market index tariff.[2] This tariff went into effect on May 1, 2000, but provided a transitional period through December 2000, during which customers could choose between the NFF and the new market index tariff-derived market values and transition charges.

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[1] Ameren (Docket No. 99-0121), ComEd (Docket No. 99-0171 and 99-0117), IP (Docket No 99-0140). ComEd's delivery services tariff filing (99-0171) was made 22 days after its market index tariff filing (99-0117) and stayed in a separate docket.

[2] Docket No. 00-0259, Interim Order, April 27, 2000.

On June 1, 2000, Ameren CIPS and Ameren UE filed a petition for approval of revisions to their market value tariff, Rider MV; and, on June 5, 2000, IP filed tariff sheets to place into effect proposed new Rider MVI and revisions to its Rider TC. Both filings replaced the NFF-based market values and transition charges with market index tariff-derived values. The Commission, in conference on July 6, 2000, on its own motion, consolidated the three dockets involving the market index tariff proposals of ComEd (Docket No. 00-0259), Ameren (Docket No. 00-0395), and IP (Docket No. 00-0461). The consolidated dockets went to hearing, and the Commission entered a final order on rehearing on April 11, 2001.

In its order, the Commission approved the replacement of the NFF with market index tariffs for all three utilities, noting "the shortcomings attributed to the use of the NFF process for purposes of determining market values."

> Staff and some other parties have suggested, for example, that the NFF process is a cumbersome, expensive procedure which has produced outdated and inaccurate results that have underestimated market prices.[3]

As a condition for approval, the Commission required certain modifications to the utilities' proposed tariffs, noting

> [T]he ComEd, IP and Ameren MVI proposals should be approved, subject to the conditions and other modifications found appropriate below. The Commission believes that with such modifications, these proposals can be expected to produce more accurate (and for that matter higher) market values than does the NFF, particularly for volatile peak periods in the summer season, and will better facilitate the development of competition during the transition period.[4]

The utilities accepted these modifications and filed compliance filings soon thereafter, so by May/June 2001, Ameren, ComEd, and IP had market index tariffs in effect.

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[3] Docket Nos. 00-0259/00-0395/00-0461 (Cons.), Order on Reopening, April 11, 2001, pp. 154-155.

[4] Docket Nos. 00-0259/00-0395/00-0461 (Cons.), Order on Reopening, April 11, 2001, p. 155.

Nevertheless, the Commission did not approve permanent market index tariffs, reasoning as follows:

> The Commission has reviewed the positions of the parties on this issue. In light of the types of concerns summarized above, the Commission is not prepared at this time to authorize the utilities to permanently put their market value tariffs in place, even as modified by the Commission proposals contained in this order. …
>
> Accordingly, given that the mandatory transition period ends January 1, 2005 and that electric utilities may collect transition charges through December 31, 2006 (unless that collection period is extended to no later than December 31, 2008 pursuant to Section 16-108(f) of the Act), the Commission proposes that the market value tariffs of each utility be modified such that they shall cease to be effective no later than the conclusion of the customer's May, 2004 billing period. If a utility accepts this proposed modification, it is directed to file a new market value tariff on or before October 1, 2002. This filing date will provide sufficient time for the parties and Commission to evaluate such proposals. It will also allow time for such other actions as may be utilized in establishing market values, although reestablishing the NFF process, if it has been discontinued, is not a scenario the Commission wishes to encourage.[5]

In compliance with the Commission's order, ComEd, IP, and Ameren made filings on October 1, 2002. Illinois Power filed supplemental changes on October 31, 2002. Those filings are the focus of the present consolidated proceeding. (Staff Exh. 1.0, pp. 13-16)

2. Procedural History of this Proceeding

On October 1, 2002 Ameren filed a petition pursuant to Section 9-201 of the Act, 220 ILCS 5/9-201, requesting that the Commission issue an Order approving tariff sheets which set forth changes to the Ameren's market index tariff and related tariffs approved in Docket No. 00-0395. The matter was docketed as ICC Docket No. 02-0656. In addition, on a related matter Ameren in a separate filing is seeking to suspend the operation of its transition charge tariff ("TC") and Purchase Power Option Service ("PPOS") tariffs from approximately June, 2003 through May, 2005. That matter was docketed as ICC Docket No. 02-0657.

On October 1, 2002 ComEd filed revisions to its market index tariff and related tariffs. In addition, ComEd proposed a new experimental tariff, Rider CTC-MY - Customer Transition Charges - Multi-Year (Experimental) ("Rider CTC-MY) that is applicable to Rate CTC. (ComEd Supplemental Statement Dated October 1, 2002). On October 16, 2002 the Commission suspended the tariffs. The matter was docketed as ICC Docket No. 02-0671.

On October 1, 2002, Illinois Power Company filed a revised market index tariff with the Commission. On October 16, 2002 the Commission suspended the tariff. The matter was docketed as ICC Docket No. 02-0672.

On October 31, 2002, IP filed additional rate sheets in which it proposed to revise Rider TC, Rider PPO and Rider MVI to be effective December 16, 2002.

On November 7, 2002 the Administrative Law Judge ("ALJ") consolidated ICC Docket Nos. 02-0656, 02-0671 and 02-0672 for purposes of hearing and order. Tr. 9 On December 11, 2002 the Commission suspended the rate sheets filed by IP on October 31, 2002 and consolidated the matter with Docket Nos. 02-0656, 02-0671 and 02-0672. The December 11, 2002 suspension matter was docketed as ICC Docket No. 02-0834.

On November 7, 2002 a status hearing was held at which time the ALJ set a schedule. The schedule set provided for the utilities to file direct testimony on November 18, 2002, Staff and Intervenors to file responsive testimony on December 16, 2002, utilities to file rebuttal testimony on January 10, 2003 and hearings to be held January 15, 16 and 17, 2003. The schedule also provided for a briefing schedule.

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[5] Docket Nos. 00-0259/00-0395/00-0461 (Cons.), Order on Reopening, April 11, 2001, p. 157.

The following witnesses testified for ComEd: Karl A. McDermott, National Economic Research Associates; Cheryl Beach P.E., FTI Consulting; William P. McNeil, ComEd, and Paul R. Crumrine, ComEd.

The following witnesses testified for IP: Brian W. Blackburn, IP; Mark J. Peters, IP; Lisa A. Smith, IP; and Tamara L. Evey, IP.

The following witnesses testified for Ameren: Robert J. Mill, Ameren, and Keith P. Hock, Ameren.

Staff offered the testimony of Richard J. Zuraski and Eric P. Schlaf.

A number of parties filed petitions to intervene, which were granted by the ALJ. Not all parties intervened in all four of the consolidated dockets. The following parties intervened and sponsored witnesses. The retail electric supplier coalition, ("RES Coalition") composed of AmerenEnergy Marketing, Blackhawk Energy Services, L.L.C., Central Illinois Light Company, Constellation NewEnergy, Inc., MidAmerican Energy Company, Nicor Energy L.L.C., and Peoples Energy Services Corporation, sponsored a number of witnesses. Those witnesses were (1) the panel testimony of Phillip R. O'Connor, Ph.D, Constellation NewEnergy, Inc. and Brent Gale, MidAmerican Energy Company; (2) Marc L. Ulrich, Econ One Research, Inc.; (3) the panel testimony of Mario Bohorquez, Constellation NewEnergy, Inc., Rodney Boyle, MidAmerican Energy Company, and Thomas Leigh, AmerenEnergy Marketing; and (4) the panel testimony of Wayne Bollinger, Peoples Energy Services Corporation, Keith Goerss, Central Illinois Light Company, and Richard S. Spilky, Constellation NewEnergy, Inc.

Five other intervening parties sponsored their own witnesses. The Illinois Energy Consortium ("IEC") sponsored David Grace, President of the IEC. The United States Department of Energy ("DOE") sponsored Dr. Dale E. Swan, Exeter Associates, Inc. The Illinois Industrial Energy

Consumers ("IIEC") sponsored Robert R. Stephens, Brubaker & Associates, Inc. The Building Owners and Managers Association ("BOMA") of Chicago sponsored Guy Sharfman, Econ One Research, Inc. Finally, Trizec Properties, Inc. ("Trizec") sponsored Roger W. Turner, GEV Corp.

C. Summary of Positions and Recommendations

Staff recommends that the Commission approve the adjustments that Staff addressed in its testimony. Further, Staff has identified several adjustments proposed by parties that it does not oppose. These recommendations are set forth in the brief that follows.

D. Other

II. Proposed Adjustments

Before addressing each of the adjustments proposed by parties in this case, the Commission should revisit its previous findings with respect to the objective of constructing market index tariffs. Most fundamental is the Commission's interpretation of the Act's phrase, "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." (Section 16-112(a))

In Docket Nos. 00-0259/00-0395/00-0461 (Cons.), the Commission considered testimony and argument on whether the market value should represent wholesale or retail prices, or some combination of the two. In its Order on Reopening, the Commission concluded:

> On the issue of the appropriate market, the Commission believes that the General Assembly intended for the market value, which is determined pursuant to Section 16-112 of the Act, to represent the value of power and energy at the retail level. This is consistent with the Commission's interpretation of the statute as a whole and with the Commission's previous findings related to market value. The Commission's view is that when the definition of transition charges in Section 16-102 of the Act is read along with Section 16-110, which relates to the PPO, and Section 16- 112 of the Act which explains how market value is to be

> determined, it is clear that market value is not intended to reflect the wholesale market value. The Commission notes that the same issue arose previously in the utilities' delivery services proceedings. On this point, the Commission previously found, "[I]t is clear to the Commission that the General Assembly contemplates that the market value may include costs associated with retail marketing costs." (Docket Nos. 99-0120/99-0134, Order at 109-110)
>
> By making an upward adjustment to the market value established by the NFF to reflect retail marketing costs, the Commission indicated its belief that the statute contemplates the use of retail market values rather than wholesale market values. No party has explained why the Commission's previous decision was incorrect or how circumstances here are different than they were slightly over one year ago. The Commission hereby affirms its decision that the market values contemplated by the Act are retail market values.
>
> The purpose of the current proceeding, then, is to obtain a reasonable estimate of retail market value as a function of an exchange traded or other market traded index. Based on the record presented, this process by necessity starts with a market index that is representative of the wholesale market, since that appears to offer the best source of data currently available. To the extent methodologies are presented which provide reasonably accurate quantifications of adjustments to account for differences between the wholesale and retail markets (such as the previously approved line loss, retail marketing cost, and Zuraski load shaping adjustments), the Commission believes such adjustments should then be applied in arriving at retail market values. As previously mentioned, several parties in this case have recommended adjustments to the ComEd, IP and Ameren MVI proposals for that purpose. Each such proposed adjustment is addressed separately below. (Order on Reopening, Docket Nos. 00-0259/00-0395/00-0461 (Cons.), April 11, 2001, p. 164)

Again, in this docket, parties have presented testimony attempting to explain what the General Assembly really meant to say when it used the phrase "market value … applicable to the market in which the utility sells, and the customers in its service area buy, electric power and energy." For instance, ComEd witness McDermott asserted:

> By definition, the market value should be a forward looking concept and should represent the value of the power and energy freed up from removing customers from the ComEd system. Any other definition would allow new entrants to unfairly take advantage of investments made under a different regulatory regime. Clearly, such a pricing policy would contradict the stated goal of Section 16-101A(c) of the Act. (p. 5)

It is not clear to whose definition Dr. McDermott is referring. In any event, it is one not found in either the Commission's April 11, 2001 Order on Reopening or the Act. There is no mention of the value of "freed up" power and energy anywhere in the Act, let alone in the context of Section 16-112 market values. In any event, the Staff sees no reason for the Commission to reject its previous finding that "the General Assembly intended for the market value … to represent the value of power and energy at the retail level."

A. Energy Imbalance Adjustment

RES Coalition witnesses Bollinger, et al., argue that the cost associated with the risk of managing energy imbalances is not incorporated into the current MV tariffs. (RES Coalition Exh. 4.0, pp. 7-13) For ComEd, they propose a periodic adjustment that takes into account the difference between the PPO price and energy imbalance charges applied to the difference between ComEd-forecasted usage and actual usage. In an example, the witnesses computed an adder of $3.95/MWh for the summer 2001, June, July, and August time period.

ComEd witness McNeil disagreed with the RES panel. (ComEd Exh. 4.0, pp. 7-10) He argued that the panel's analysis ignores the ability of RESs to update their scheduling up to 20 minutes before the delivery hour using short-term forecasts. He also notes that for 6,379 hours out of 8,760, imbalance energy was actually lower cost than the PPO energy price. Further, the highest energy imbalance prices are generally predictable based on expected high temperatures; therefore the RESs can manage the risk during those short periods by paying close attention to their short-term forecasts and scheduling appropriately. He also opines that the current ComEd methodology (the price-shaping process) accounts for the risk of energy imbalances. Finally, he notes that the Commission has previously determined that energy imbalance costs are a delivery service, not a supply service, and the associated adders and discounts should be reflected in ComEd's delivery service CTC credit.

Staff does not agree with all of Mr. McNeil's arguments. In general, the OATT energy imbalance tariff is designed to deter imbalances. As such, it poses the risk of additional costs for RESs and/or their customers. Nevertheless, the Commission has previously ruled that energy imbalance costs are a delivery services cost. Thus, a credit for energy imbalance costs should already be included in the CTC. It should not also be included in the market value credit.

B. Capacity Backed Adjustment

IP and Ameren both proposed new or additional capacity charge components within their MV formulas. For ComEd, the issue of capacity cost adjustments is addressed in Section C below "Inclusion of "Placeholder" for Potential RTO-Imposed Costs or Market Changes (e.g. Capacity adjustment)."

1. Illinois Power

IP proposed to remove a 0.061 cents per kWh component, currently embedded in its MV calculations, and add a new set of per MW-month capacity charges. Assuming a 100% load factor, the current 0.061 cents per kWh is equivalent to an annualized value of $5,343.60 per MW-year. Assuming a 50% load factor, 0.061 cents per kWh is equivalent to an annualized value of $2,671.80 per MW-year.

IP's initial proposal was for a set of 12 monthly capacity charges, which summed to $9 per MW year. However, in rebuttal testimony, IP amended this proposal to a set of 12 monthly capacity charges, which sum to $12 per MW year. In support of these charges, IP witness Peters noted that the revised capacity charges, along with other revisions to its initial proposal, were the result of negotiations with other parties to this proceeding (RES Coalition and IEC). From IP's standpoint, the revised charges are part of a compromise on "the total value determination." The changes are included in a memorandum of understanding ("MOU") sponsored by IP witness Blackburn. (IP Exh. 1.9)

RES Coalition witnesses Bohorquez, et al., also supported this change. (RES Coalition Exh. 3.0, pp. 10-11) Like Mr. Peter's mention of a "total value determination," the RES Coalition witnesses stressed that their support of the capacity charge proposal was contingent upon the adoption of other components of the MOU, specifically the "floating adder" proposal to be discussed later.

As noted by Staff witness Zuraski, Staff expects that IP's proposal would lead to a modest increase in MVs and a corresponding decrease in transition charges. (Staff Exh. 1.0, p. 23) Hence, Staff recommends the Commission accept the proposal.

2. Ameren

Ameren proposed to add a new factor, "$CAP," in the equations for MVs. It would be multiplied by the class' peak hour consumption for the year and divided by annual consumption. In its initial filing and testimony, Ameren did not give a specific value or formula for the $CAP. In rebuttal testimony, Ameren proposed a charge of $205.15 per MW-day (from Ameren's OATT Schedule 4A), further stating that:

> In contrast to the currently proposed tariff filing, the rate will be applied on a daily basis only during the summer months. The summer months are defined in Rider MVI. The application of this charge only during the summer months is consistent with both Ameren's experience in the Illinois market and with the assumptions and methodology that were used to calculate the value. (Ameren Exh. 3.0, p. 4)

Staff witness Zuraski did not support Ameren's proposal, noting that "If Ameren's petition to suspend Riders CTC and PPO is ultimately approved, these additional charges will not benefit Ameren's delivery services customers over at least the next two annual Applicable Period As."

Furthermore, he found no justification for including an ***additional*** capacity charge component to Ameren's MV. (Tr. 492-493) Ameren has not shown that the current capacity charge component is deficient. Thus, Ameren has not shown how the additional capacity charge component is just and reasonable. IIEC witness Stevens also argued against the additional capacity charge. (IIEC Exh. 1.0, pp. 12-17; Tr. 646-647)

For the above reasons, Staff recommends that the Commission reject Ameren's proposed additional capacity charge adder.

C. Inclusion of "Placeholder" for Potential RTO-Imposed Costs or Market Changes (e.g. Capacity adjustment)

RES Coalition witnesses Bohorquez, et al., recommended that IP and ComEd include a "placeholder" in their tariffs for changes that may come about when the utilities become integrated into RTOs. (RES Coalition Exh. 3.0, pp. 22-25) The witnesses prepared a partial list of such potential changes, including: transmission rate changes, capacity requirements affecting capacity costs, congestion management changes affecting hedging costs, possible elimination of the Chicago Hub, and imbalance tariff changes, to name a few.

In response, ComEd witness McNeil seemed to indicate support for this concept, unless it involved setting actual numbers at this time:

> However, if the Direct Panel Testimony's use of the term "placeholder" is in reference to placing a statement in the filing noting that this issue will be further reviewed if the open access transmission rules change in the future due to the implementation of an RTO, then I would not object to the inclusion of such a statement. (ComEd Exh. 4.0, p. 20)

In Staff's opinion, a "placeholder" in the tariff may not be particularly useful. However, it would be appropriate for the Commission to instruct the utilities to file revisions to their MV and/or CTC tariffs whenever there are relevant and material changes in the underlying markets.

D. Odd Lot Adjustment

RES witnesses Bollinger, et al, argue that there is a difference in the shape of retail load versus a wholesale block shape, and that the necessity to acquire power in "odd lots" imposes costs on RESs that are not accounted for under the current MV methodologies employed by the utilities. (RES Coalition Exh. 4.0, pp. 13-15)

BOMA witness Sharfman and IEC witness Grace provided additional rationale for the existence of these odd lot costs:

> Odd lot premiums occur in term markets because power is generally bought and sold in 50 MW blocks. Fewer transactions occur for power volumes below this amount. As a result, there is less liquidity, which results in higher bid-offer spreads. Since the majority of retail customers have power demands well below 50 MWs, alternative retail electric suppliers will many times procure power in the wholesale market at amounts less than the 50 MW standard block. As a result, they are susceptible to incur these premiums. Odd lot premiums are a pure supply cost and therefore should be incorporated into the supply price for electric power and energy. (Sharfman, BOMA Exh. 1.0, p. 17)
>
> The MVI must systematically reflect the costs of purchasing power in less-than-contract lots because very few individual Illinois customers are able to use full contract commitments to serve their own loads without modification due to size and load patterns. (Grace , IEC Exh. 1.0, p. 8)

In quantifying these additional costs, RES Witnesses Bollinger, et al, stated:

> Historically, a variable schedule for "odd lots" has an average premium above a block schedule of 20% for the on-peak period and 30% for the off-peak period (as defined by NERC.) Approximately 5-10% of CILCO's load fell into the variable "odd lot" category. This would result in an upward adjustment to the current MVECs by approximately $.55/MWH.

ComEd witness McNeil, however, finds no evidence to support the existence of 20% and 30% premiums for odd-lot purchases. Rather, he seems to speculate that the premiums observed by the RES panel would merely reflect their higher use of power when market prices are higher. In other words, he argues that the higher cost of serving odd lots is already included in the Company's hourly price-shaping/load-weighting methodologies, which "disaggregate the customer's annual usage into 8,760 'odd lots' and apply the real time price shape against the cost of each 'odd lot.'" Mr. McNeil's comparison (ComEd Exh. 4.0, table on p. 12) does little to support his argument, since the table compares (a) the cost computed for each of the ComEd classes (with both load-weighting and price-shaping) to (b) the cost of a flat load over 8760 (with no load-weighting and no price-shaping). A better comparison would have been between (a) the load-weighted and price-shaped cost and (b) the load-weighted but not price-shaped cost.

Clearly there are two competing theories. However, in weighing the evidence presented, Staff is inclined to accept the proposal by Bollinger, et al., for an off lot premium. Staff recommends that the Commission accept their computed value of $0.55 per MWH for this adjustment.

E. Customer Churn Adjustment

RES Coalition witnesses Bollinger, et al., indicate that RESs often absorb the risk of "customer churn," while ComEd's PPO tariff eliminates this risk:

> Many contracts likely submitted offer customers the ability to exit their contracts early for various reasons. The risk associated with customer churn is not reflected in the RES Prices. ComEd's tariff requires a customer to remain on PPO until the following May billing period, thus eliminating any risk from customer churn. (RES Coalition Exh. 4.0, p. 42)

The witnesses do not appear to be asking for an adjustment associated with the risk of customer churn. Hence, Staff sees no basis for the Commission to order a customer churn adjustment to MVs.

F. Residual Error Term Adjustment

RES Coalition witnesses O'Connor and Gale argue that the MV tariffs represent a "model" of reality, and all models are imperfect and prone toward some error.

> For every model, there is a "*residual*," that is some portion of the modeled reality that remains unexplained by the model. The unexplained residual related to any given model may be attributable to any number of factors, such as inadequate,

> faulty or missing data. It can also be due to incorrect elements of the model that fail to capture the actual interplay between variables under real conditions and the subsequent failure to identify and incorporate important features of the actual phenomena being simulated into the model. (RES Coalition Exh. 1.0, p. 5)

They further argue that the current MV models produce residuals that do not have an expected value of zero. In other words, the models are biased. More specifically, they produce estimates of MV that are biased downward.

> The RES Coalition, through a multi-method approach, has identified a residual relative to the MVI currently in place of over two-fifths or approximately 15 mils or 1.5¢/kWh relative to the actual value of power and energy for retail service. This is the extent to which the current MVI under-prices the Market Value of Energy Charge ("MVEC") in relation to the observed market value of energy in ComEd's retail service market. The technical and structural modifications to the MVI proposed by the RES Coalition would reduce the unexplained residual to roughly one-third or 8 mils per kWh ($0.008/kWh or $8/MWh). This remaining unexplained residual can be accounted for by an adder to the MVI calculation. (RES Coalition Exh. 1.0, p. 6)

The "residual" difference between the "observed market value of energy in ComEd's retail service market" and the "current MVI" referenced by the RES witnesses O'Connor and Gale appear to be based, at least in part, on the exhibits of RES Coalition witness Ulrich.[6] The residual of "approximately 15 mils or 1.5¢/kWh" is equal to the simple average of the nineteen "Differences" between the RES contract prices observed by Dr. Ulrich and ComEd's most recent Period A MVs for various of the non-residential classes (nine classes for the "RES MVI – ComEd MVI" calculations found in Exhibits D and ten classes for the "RES NFF – ComEd NFF" calculations found in Exhibit E).

Dr. Ulrich's NFF and MVI studies are discussed elsewhere in this brief. As noted on page 46, as far as Staff is concerned, the Ulrich study shows that (for reasons that remain unclear), some

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[6] For instance, O'Connor and Gale state, "***Dr. Ulrich's study showed differences between prices that could be derived from RES contracts that would be the type reviewed in a NFF process and prices in the current MVI*** on the order of

customers in the ComEd service territory are paying RESs more for electric power and energy than the MVs embedded in the most recent Applicable Period A filings by ComEd. Staff has no opinion as to whether this justifies any particular adjustment to the MV formulas.

G. Retail Margin Adjustment

ComEd witness McNeil argued that retail margin costs should not be included in the determination of Section 16-112 MVs, noting:

> Factors that have been labeled retail margin, customer acquisition costs, retail electric power and energy sales and marketing costs, or retail marketing administrative costs relate to a RES's potential costs of doing business and have nothing to do with the market value of freed-up electric power and energy. I do not believe such factors are appropriate to consider in determining market values. We also do not have a way to estimate such costs in any reasonable way. (ComEd Exh. 3.0, p. 12).

Several witnesses disagreed with Mr. McNeil, but failed to include a specific adjustment for retail margin. (see Sharfman, BOMA Exh. 1.0, p. 14; Grace, IEC Exh. 1.0, p. 7) Given the lack of any concrete proposal, Staff finds no basis to recommend the adoption of a specific retail margin adjustment.

H. Avoided Administrative (and related) cost Adjustment

IEC witness Grace testified that

> The MVI must systematically reflect the full costs of administration of customer services, enrollment, and marketing that are avoided by the utility when a customer takes supply from an independent supplier. (IEC Exh. 1.0, p. 8)

Furthermore, BOMA witness Sharfman refuted Mr. McNeil's testimony that marketing administrative costs should not be included as part of the MVEC calculation. (BOMA Exh. 1.0, p. 14).

25% to 77%, strongly indicating that the approximate nearly 40% average under-pricing of the MVI values contended by

However, as ComEd witness Crumrine notes in regard to Mr. Grace's testimony:

> He offers no quantification of the costs avoided and an extremely low-level of guidance and detail regarding the exact costs he claims ComEd avoids. (ComEd Exh. 6.0, p. 30)

Staff believes that the purpose of this proceeding is to determine the value of power and energy sold at retail, and not to determine specific costs avoided by the incumbent utilities when customers switch to delivery services. However, if such costs are incurred by RESs in providing retail power and energy, it would be reasonable to assume that these costs are embedded in retail power and energy prices. Furthermore, they might not be included in the current MV computation because those computations are based on wholesale price observations. Hence, Staff has no fundamental objection to the inclusion of an administrative cost adjustment in the MV tariffs. However, Staff has no independent basis upon which to estimate such costs. Thus, given the lack of any concrete proposals on the record, Staff finds no basis for the adoption of an administrative cost adjustment.

I. Retail uplift adjustment

BOMA witness Sharfman opined that:

> The supply component is comprised of the MVECs, which should recover the cost of buying power in the market as well as additional costs associated with supplying retail load that are not part of delivery services. These additional costs, often referred to as retail uplifts, include costs associated with business operations and risks of serving retail load that are not recovered in Rate RCDS and Rider TS. (BOMA Exh. 1.0, p. 13)

Later in his testimony, Mr. Sharfman stated his belief "that the parties who can best value these uplifts are the alternative retail electric suppliers in Illinois who have to incur these costs when serving retail customers." (p. 24) There was never a specific proposal for a retail uplift adjustment.

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the RES Coalition is well founded." (RES Coalition Exh. 1.0, p. 8, emphasis added)

Given the lack of any concrete proposal, Staff finds no basis to recommend the adoption of a specific retail uplift adjustment.

J. Avoided PPO cost Adjustment

As noted above in relation to the "Avoided Administrative (and related) cost Adjustment" (Section H., page 17), Staff believes that the purpose of this proceeding is to determine the value of power and energy sold at retail, and not to determine specific costs avoided by the incumbent utilities when customers switch to delivery services. RESs do not incur avoided PPO costs and, as such, it seems unlikely that they would be embedded in retail rates for power and energy.

K. Load following Adjustments

BOMA witness Sharfman testified that:

> It's possible to purchase firm LD power in the forward market, but not in the real time market. Suppliers engaged in intra-day scheduling or load following through real time trading can't purchase firm LD power. To deliver power to an end user in ComEd's service territory ComEd requires either a firm LD contract or a source designation. Since Firm LD power is not available in the real time market, a trader may have to pay a premium for source designation. This premium, along with other costs associated with load following, is not built into the current method to calculate the MVECs and is not part of any of ComEd's proposed technical changes. (BOMA Exh. 1.0, p. 15)

IEC witness Grace similarly testified that:

> The MVI must systematically be modified to reflect the costs avoided by the incumbent utility for load following services. (IEC Exh. 1.0, p. 8)

However, these witnesses did not present any specific recommendations for load following adjustments. Given the lack of any concrete proposal, Staff finds no basis to recommend the adoption of a specific load following adjustment. In any event, it appears as if the issue of load following may be closely akin to the issue of odd lots. As discussed elsewhere in this brief (on page 14), Staff recommends that the Commission adopt an odd lot adjustment of $0.55 per MWH.

L. Proper method for allocating sales and marketing expenses

RES Coalition witnesses Bollinger, et al., criticize the method in which ComEd allocates sales and marketing expenses between the various customer classes (i.e., proportional to the number of customers in each class). (RES Coalition Exh. 4.0, pp. 21-29) They claim that the current method is inaccurate for the following reasons:

First, it is inconsistent with ComEd's own sales and marketing efforts, by implying that residential customers would receive "over 90% of ComEd's sales and marketing efforts." Second, the Commission has clearly intended for the sales and marketing adjustment to reflect RES' efforts and no RES is even registered to serve residential customers, let alone actively marketing to those customers. RESs are most actively marketing to customers over 400 kW, yet ComEd's method results in a sales and marketing adjustment of 0 cents per kWh for these large customers. Third, it belies common sense to believe that classes consuming most of the kWhs should receive such a small allocation, resulting in counter-intuitive sales and marketing adjustments of 0 cents per kWh. Fourth, they argue that ComEd's cost allocation method is inappropriate because it is inconsistent with the requirements of Section 16-112(k) of the Act, in that the allocation of these expenses do not take into account the daily, monthly, annual, or any other relevant characteristic of the customer's demands upon the electric utility's system. They argue that ComEd's method of allocating sales and marketing expenses is based solely (and inappropriately) on the number of customers in each RCDS class.

RES Coalition witnesses Bollinger, et al., also note that, going forward, the sales and marketing adjustment should not be based on the utility's own sales and marketing expenses, since:

> ComEd, as an integrated distribution company ("IDC"), is not supposed to be engaged in the marketing of generation services. Therefore, it would be more accurate to determine a sales and marketing expense adjustment to the MVI

> based on the actual costs incurred by the RES community. (RES Coalition Exh. 4.0, p. 29)

Nevertheless, because the Commission has ordered the use of ComEd's sales and marketing expenses as a proxy, Bollinger, et al., propose a second-best alternative, namely allocating the Company's expenses on the basis of class energy use, resulting in a uniform adjustment of 0.026 cents per kWh. (RES Coalition Exh. 4.0, p. 28) Staff recommends that the Commission adopt this proposal, which is well supported in the record.

M. Off-Peak Issues

1. Adjusting of zeros and negative values in the PJM Hourly Price Data

Both Ameren and ComEd proposed a modification to their price-shaping methodologies for hours during which the PJM West price is zero or negative. They proposed to replace the zero and negative values with the average of that month's off-peak PJM West price. RES Coalition witnesses Bollinger, et al., criticized these proposals, but agreed that zero and negative hourly prices should be replaced. In particular, they argued that the zero and negative values should be replaced with the average values of the closest two positive prices, chronologically, on either side of the zero or negative prices. (RES Coalition Exh. 4.0, pp. 30-39) Summarizing, they stated:

> The RES Coalition's Method is more accurate because it substitutes a more realistic positive hourly price value during periods of time in which prices are very low. It is preferred because it does not overstate of the off-peak PJM hourly values resulting in a decline in the off-peak scalars (which in turn causes the MVI to decline more than a technical adjustment of this nature should). The RES Coalition Method produces reasonable and realistic results, and therefore should be adopted. (RES Coalition Exh. 4.0, p. 39)

Staff witness Zuraski provided some support for the RES Coalition's recommendation, stating:

> I would not be opposed if, instead of the average of all off-peak hourly prices in the month, [Ameren and ComEd] would use the midpoint of (a) the first prior positive hourly price, and (b) the next subsequent positive hourly price, on either

> side of the negative or zero price(s). … However, I do not expect this change to have a very significant effect. From my own experimentation with the alternative, neither an increase nor a decrease in the market value is guaranteed by these changes.

ComEd witness Crumrine acquiesced to this position, stating:

> ComEd believes Mr. Zuraski's proposal is another reasonable approach, and would be willing to accept Mr. Zuraski's proposal if the Commission believes that such proposal is preferable to ComEd's. (ComEd Exh 6.0, p. 38)

Ameren witness Hock also acquiesced, stating:

> Ameren would be willing to adopt the RES Coalition methodology for treating zeros and negative values in the PJM price shape. I believe that the RES Coalition's proposed methodology is the same as that which Staff witness Zuraski says would be acceptable. (Ameren Exh. 3.0, p. 8)

Based on the record evidence, the Staff recommends that the Commission mandate that ComEd and Ameren adopt the RES Coalition proposal for treating zero and negative PJM West hourly prices.

2. Other

Staff has no other off-peak adjustment issues to raise.

N. Basis Adjustment

1. Illiquidity Adjustment

RES Coalition witnesses Bohorquez, et al., argue that RESs are subject to greater liquidity risk associated with wholesale power and energy purchases at the ComEd, IP, and Ameren markets relative to the Cinergy hub. (RES Coalition Exh. 3.0, pp. 18-22) They further argue that difference in liquidity risk manifests itself in the spot prices from which the utilities derive the basis differentials used in the MV tariffs. Specifically, the witnesses argue that bid-ask spreads are greater in the Illinois markets than they are in the Cinergy market and buyers are likely to pay a price near the higher "ask" side of the spread in an illiquid market. Hence, the computation of basis differential should include an illiquidity adjustment, which they compute to be $0.88 per MWH. They recommend that this adjustment be recalculated with each "snapshot period."

ComEd witness McNeil disagreed with the RES Coalition witnesses, noting:

> First, there is no justification for using the "bid-ask" spread to calculate basis adjustments. The ask price is by definition a price that buyers thought was too high to pay and the bid price is too low for sellers. … I would also note that the data sources relied upon in the table at line 460 of the Panel testimony are highly questionable and problematic. (ComEd Exh. 4.0, pp. 18-19)

In Staff's view, the testimony and evidence on this issue is not conducive to a ***confident*** decision for or against an illiquidity adjustment. Both sides of the issue are supported in the record. After weighing the evidence, though, Staff recommends that the Commission adopt the RES proposal for an illiquidity adjustment. However, rather than recompute the adjustment periodically, Staff would recommend a static adjustment of $0.88 per MWH, based on the analysis provided by RES Coalition witnesses Bohorquez, et al.

2. Other

Staff has no other basis adjustment issues to raise at this time.

O. RES Coalition Proposal to Synchronize Price Shape Data from the PJM Market with Load Shape Data

RES Coalition witnesses Bollinger, et al., argue that the price shaping/load weighting methodologies currently in use fail to adequately account for the way in which

> "Prices tend to be lower than average during shoulder on-peak hours and higher than average during the more peaked on-peak hours." Order, ICC Docket Nos. 00-0259/0395/0461 at 98. (RES Coalition Exh. 4.0, p. 16, quoting a Commission order)

They argue that the current method fails because:

> [T]he load shape data comes from the ComEd market and the price data comes from the PJM West market. These two markets are not "in sync." … ComEd's MVI methodology fails to recognize the reality that while there is a heat wave in Chicago and demand is spiking, it could be chilly week with lower demand and

> thus lower power prices in western Pennsylvania. (RES Coalition Exh. 4.0, pp. 17-18)

To better synchronize the data and correct the price shaping/load weighting adjustment, the RES witnesses suggest that the utilities "organize the actual demand hours for each 1x16 period across each respective month with the PJM West relative price such that the greatest usage is multiplied by the greatest price." (RES Coalition Exh. 4.0, p. 19) Furthermore, the witnesses clarified that this process be done for each customer class, separately. (Tr. 332)

ComEd witness McNeil criticized the proposal as

> nothing more than an outright mathematical manipulation of data solely for the purpose of generating a higher result. … There is nothing I can think of which would make the inputs to the methodology more "out of sync" than their proposal. (ComEd Exh. 4.0, p. 17)

While agreeing in principle with the idea that there can be a problem with the synchronization of the PJM price data and the Illinois utilities' load data being, Staff cannot support the particular remedy sponsored by the RES Coalition. It is not well supported and it implicitly assumes that each customer class in Illinois somehow has its own weather. As presented, this is not a wholly credible theory.

On the other hand, a lack of synchronization in the data would tend to reduce market values. To address this issue, Staff recommends that the utilities continue to perform the same price shaping process, but with multiple years worth of hourly price and load data, as proposed by the three utilities. However, instead of averaging the yearly results of the price shaping/load weighting process (as proposed by the utilities), Staff recommends that each utility select the yearly results that maximize the load weighted average market value for each class.

P. Other

Staff has no other proposed adjustments to include in this section of its brief.

III. Floating MVI Adder Proposal

A. To which utilities, if any, should a floating MVI adder apply

There are several potential problems with the MVI adder proposal, as described in the parties' Memorandum of Understanding ("MOU"). These concerns are set forth below.

The method for calculating the proposed adder is different from the method prescribed by the Act, and for this reason the proposal would appear to be in contravention of the statute. Section 16-102 of the Act defines the term "transition charge" and sets out several elements that are to make up the calculation. Included in these is the following:

> "(3) less the market value for the electric power and energy that the electric utility would have used to supply all of such customers' electric power and energy requirements, as a tariffed service, based on the usage identified in paragraph (1), with such market value determined in accordance with Section 16-112 of this Act." 220 ILCS 5/16-102.

Section 16-112, in turn, provides detailed guidance on making the market value determination. As previously quoted (see page 2), Section 16-112(a) provides two alternative methods for making the market value calculation: through tariffs, which are to rely on exchange-traded or market-traded index, option, or futures contracts applicable to the relevant market area, or through the neutral fact-finder process.

The parties' proposed adder would appear to not follow either of the two approaches contained in Section 16-112. The proposal would instead replace the statutorily prescribed elements with the parties' own methodology, which relies on reports of customer switching activity. Because the proposal would substitute a different, non-statutory, scheme for making the market value calculation, the proposal appears to conflict with the provisions of the Act. Here, the legislature has specifically set out the components that are to be used in making the market value calculation; using a different set to make the calculation is inconsistent with the statutory requirements. Indeed, Section 16-112(m) appears to specifically limit the Commission's authority to adopt alternative methods of making the market value calculation. Section 16-112(m) states:

> "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." 220 ILCS 16-112(m).

Administrative agencies cannot act in ways that are contrary to their governing statutes. "This court has consistently held that, inasmuch as an administrative agency is a creature of statute, any power or authority claimed by it must find its source within the provisions of the statute by which it is created." Bio-Medical Laboratories, Inc. v. Trainor, 68 Ill. 2d 540, 551, 370 N.E.2d 223, 228 (1977); see also Business and Professional People for the Public Interest v. Illinois Commerce Comm'n, 136 Ill. 2d 192, 243, 555 N.E.2d 693, 716 (1989) ("an agency only has the authorization given to it by the legislature through the statutes"). An administrative agency has no general or common law power, and an agency must instead find within its governing legislation the authority it seeks to assert. City of Chicago v. Fair Employment Practices Comm'n, 65 Ill. 2d 108, 112-13, 357 N.E.2d 1154, 1155 (1976). The Commerce Commission, "because it is a creature of the legislature, derives its power and authority solely from the statute creating it, and its acts or orders which are beyond the purview of the statute are void." City of Chicago v. Illinois Commerce Comm'n, 79 Ill. 2d 213, 217-18, 402 N.E.2d 595, 597-98 (1979). An administrative agency's authority is limited by the provisions of the agency's governing statutes, and an agency has no more power than is conferred on it by the legislature. Any calculation of market value under article XVI must be made in conformity with the methods prescribed in Section 16-112.

Arguably, by relying on observations of customer switching activity rather than market prices, it is not immediately clear how the proposed adder reconciles with the statutory requirements. However, Staff believes that the lack of customers switching to delivery services, in light of positive transition charges, can be evidence that the MV credit embedded in those transition charges is too low (i.e., that it under-estimates the retail price at which retail customers can be served). In other words, if there is no customer switching, then clearly RESs are unable to make a profit and provide any savings to customers, at the current level of the transition charge. Hence, customer switching might be an appropriate foundation for an adjustment to the index upon which Section 16-112 market values are based.

Notwithstanding any legal objections to the MOU, the methodology for estimating market values has some appeal. First, the fact that the marketers would be willing to sign affidavits describing their marketing efforts is a strong indication that they are prepared to actively solicit customers in the IP service area. Since only about three suppliers have acquired customers in the IP market (Tr. 217), virtually any proposal that results in more marketing activity could result in customer benefits. Second, the notion that the actions of market participants could shed light on the proper valuation of market values may be worth considering. If market prices of a desired accuracy cannot be obtained through methods relying on the observations of wholesale trading activity, then perhaps the accuracy of market values could be enhanced by observing the activities of retail market participants in response to results of the calculations using more traditional methods.

On the other hand, it must be noted that one result of implementation of the MOU likely will to be cause transition to equal zero for some unknown number of customers, which would render those customers ineligible for the PPO. If RESs were to pick up the customers that lose their PPO eligibility, then the loss of PPO eligibility would be balanced by an increase in competitive activity. However, there is no guarantee that this will occur or that customers will benefit, as IIEC witness Stephens pointed out. (IIEC Exh. 1.0, pp. 10-11) There may be other barriers that could be deterring RESs from marketing in the IP service area other than the existence of transition charges. For example, IIEC witness Stephens noted that the MOU is limited in scope to transition charges and does not address such problems as market concentration among RESs. (Tr. 648) If other barriers that may be hindering the attractiveness of the IP market cannot be overcome, then the effect of the MOU may simply be to move customers from PPO service, where savings can be obtained, back to bundled service. This would not be an acceptable trade-off.

B. Beginning value

C. Incremental changes

D. Limits on floating MVI adder

E. Determining Level of Marketing Activity

There is a fundamental problem with the MVI adder proposal, as described in the parties' Memorandum of Understanding. The role that the proposal seeks to assign to Staff in which the Commission relinquishes to Staff the authority to make the market value adder determination cannot be squared with other requirements of the Act.

Section 16-101 of the Act requires that all tariffs and rates be formulated under the requirements of the Act, unless a provision in article XVI specifies otherwise. Section 16-112, quoted above, requires that the market value figure be set either through "a tariff that has been filed by the electric utility with the Commission pursuant to Article IX of this Act" or through the neutral fact-finder process described further in section 16-112. The parties' Memorandum of Understanding assigns to Staff a different and much larger role than is contemplated by either of the two statutory methods for making the calculation, however, for it gives to Staff the authority to make final determinations that cannot be reviewed or considered by the Commission. As noted above, an administrative agency may not act in ways that are contrary to its enabling statutes, and therefore the validity of this aspect of the parties' proposal must also be questioned.

One might argue, however, that the proposed adder is like a tariff and that the Commission, by approving the proposal, would in effect be delegating its tariff-approval powers to Staff. Whether a delegation of power in those circumstances would be proper is open to question, as the following cases suggest.

In Board of Trustees, Prairie State College v. Illinois Educational Labor Relations Board, 173 Ill. App. 3d 395, 527 N.E.2d 538 (1988), a college that had been charged with an unfair labor practice contended, among other things, that the charge was invalid because it had been signed by the labor board's executive director rather than by the board members themselves; the college argued that the director lacked the authority to issue complaints of unfair labor practices. The appellate court rejected the college's argument, concluding that the board had properly delegated its charging authority to its executive director. The court explained:

> "The test for determining whether an administrative agency may delegate a particular function to a subordinate employee is whether the power exercised by the subordinate employee 'is so important, requiring the exercise of judgment on matters of policy, as to preclude the likelihood that the legislature would have been willing to have the particular power exercised by anyone other than the ultimate authority within the agency.' (1 F. Cooper, State Administrative Law, at 92 (1965).) In conformity with this principle, the supreme court has held that absent statutory provisions to the contrary, administrative agencies may delegate to hearing officers their power to hear evidence in contested cases. Starkey v. Civil Service Comm'n (1983), 97 Ill. 2d 91, 454 N.E.2d 265; Homefinders, Inc. v. City of Evanston (1976), 65 Ill. 2d 115, 357 N.E.2d 785." Board of Trustees, 173 Ill. App. 3d at 414, 527 N.E.2d at 551.

The court went on to examine the language of the labor board's governing statutes, which gave the board the authority to hire necessary personnel, and the court observed that the statutory provisions "reflect[] a legislative intent that the Board have the power to delegate functions which do not result in the final adjudication of substantive rights to such of its subordinate employees as it sees fit." Board of Trustees, 173 Ill. App. 3d at 415, 527 N.E.2d at 551. The court concluded that the board's executive director possessed the requisite authority to sign and issue unfair labor practice charges, and the court therefore rejected the community college's argument that the charge was invalid because it had not been signed by the labor board itself. The court drew the line at decisions that either finally adjudicate substantive rights or that otherwise have an important impact on public policy: actions or decisions that fall short of those thresholds may be delegated, while those that result in final adjudications or otherwise have an important impact on public policy may not be delegated. The court did not believe that issuance of the charge represented a final adjudication or had an important public policy impact. Although the court did not define "final adjudication" or attempt to distinguish that concept from administrative review, it is clear that the focus should be on finality within the agency itself, for the contention being made is that the agency has improperly delegated its authority to subordinate officers or employees.

The appellate court applied a somewhat different analysis in Hoardwood, Inc. v. Department of Public Aid, 175 Ill. App. 3d 432, 529 N.E.2d 1009 (1988). In that case the court concluded that the executive director of the Department of Public Aid had properly delegated to the agency's deputy director the authority to render final decisions in cases involving Medicaid participation and reimbursement. The service provider challenged an adverse decision, arguing that the order was invalid because it had been signed by the agency's deputy director rather than by the executive director. The appellate court rejected that argument, concluding that the executive director could authorize the deputy to perform the task. In reaching that result, the court considered the language of the operative statute and the strong public policy favoring efficient administrative operations. The court concluded:

> "While it may have been preferable for the legislature to expressly use the language of 'Director or his designee,' as we find in the Nursing Home Reform Act of 1979 (Ill. Rev. Stat. 1985, ch. 111½, par. 4151-110) (but which has applicability only to the Director of Public Health, and not the Director of Public Aid), the absence of this explicit language does not indicate a contrary intent. Moreover, the consequences of literally applying the plain meaning of the term Director under the facts of this case could be detrimental to the efficient operation of the State Medicaid plan. An application of that nature appears to be contrary to the perceived intent of the drafters in promulgating the statute. Accordingly, we conclude that the execution of the final administrative decision by the Executive Deputy Director was not improper." Hoardwood, 175 Ill. App. 3d at 436, 529 N.E.2d at 1012.

Applying these considerations to the parties' Memorandum of Understanding leads one to conclude that the proposal, if put into effect, would constitute an improper delegation of authority by the Commission. Under the proposal, Staff's periodic calculation of the adder would be a final adjudication of substantive rights, for that decision would determine, with finality within the Commission, the amount of this particular component of power rates; the proposal does not assign any role in this process to the members of the Commission. Such a delegation of authority to Staff would be inconsistent with the principle expressed in Board of Trustees, which precludes delegation of the authority to make final adjudications or other decisions that have an important impact on public policy. And although the Hoardwood court permitted a subordinate--the deputy executive director--to render a final agency decision, decision-making authority in that case was still concentrated in what may be described as the office of the executive director, and was not being shared with others outside that circle. It is more difficult to justify delegation to Commission staff in the absence of express statutory authorization for that action. It may be noted that the Illinois Commercial Transportation Law, unlike the Public Utilities Act, contains a provision authorizing the

Commission to delegate decision-making authority to Staff. See 625 ILCS 5/18c--1203(1) (authorizing Commission to delegate decision-making power in certain types of cases to Staff).

Finally, IP proposed a vague alternative in which docketed proceedings would be initiated by IP to determine whether the adder was appropriate for a set time period. Given the lack of detail of this IP alternative Staff at this time is unable to comment but reserves the right to address the alternative should any party address it with more specificity in its initial brief.

F. Other

The Staff has no other issues to raise within this section of its brief.

IV. Multi-year option issues

ComEd proposes experimental Rider CTC-MY, which allows customers to select a two-year transition charge, rather than a single-year transition charge. Only customers with individual transition charge calculations would be eligible to compete in the lottery for the limited number of slots available in the experiment.

According to ComEd witness Crumrine, ComEd is offering Rider CTC-MY in response to concerns raised by market participants about variations in yearly transition charges (ComEd Exh. 5.0, p. 20). The major benefit of this proposal, as Mr. Crumrine notes, is price certainty (Ibid.). Customers taking service under Rider CTC-MY would not be subject to fluctuations in the transition charge portion of their electric bills for the duration of the fixed-year transition charge and thus could fairly accurately estimate their total electric bills for the duration of their period of service under Rider CTC-MY.

The proposal has two disadvantages. First, customers taking service under Rider CTC-MY would lose supply options that are available to other customers. Rider CTC-MY customers would give up their rights to receive service under the Power Purchase Option. Rider CTC-MY customers that are placed on Rider ISS would be prohibited from returning to bundled service. Rather, Rider ISS customers that come to that service after a term on Rider CTC-MY must either choose Rider CTC-MY or Rate HEP, a market-based rate that contains provisions that ComEd has proposed be modified by the Commission. (Tr. 799-800) Second, ComEd proposes to limit the availability of the service to a total of 500 MW. It is unclear to Staff how ComEd's proposed methodology for auctioning the available slots for service under the proposed Rider would work in practice. The auction must be conducted in such a way as not to give preferences to any customer group or supplier.

The proposed experimental program apparently has widespread support among customers and suppliers, so none of these drawbacks should doom the proposal. Thus, Staff recommends the Commission should approve the proposal on an experimental basis, but with two additional provisions. First, as explained in Section V.D of this brief, all customers over 400 kW should be permitted to receive an individual transition charge calculation. These customers should also be eligible to compete in the lottery to obtain an opportunity to receive a multi-year transition charge. Second, Staff recommends that the Commission order ComEd to provide regular reports on the supply options and the suppliers chosen by each of the customers taking service under Rider MV CTC. This information will assist the Commission in assessing the success of the experimental program.

A. Availability of multi year contracts

Staff takes no position.

B. Length of multi year contracts

Staff takes no position.

C. Adjustments of multi year TC for changes in delivery service rates and mitigation factors

Changes to delivery service rates and mitigation factors have always been taken into account in the CTC calculations. Staff does not believe this should be an issue.

D. Market value adder based on length of contract

Trizec wtness Turner's testified that:

> ComEd's proposed Rider CTC-MY does not provide any reduction in CTC charges to reflect the fact that ComEd will be relieved of the responsibility of providing electricity to these customers for a long period. … ComEd should provide a further reduction in CTCs to those customers who commit to a multi-year CTC and its requirement to not purchase electricity from ComEd under either its bundled rates or PPO-MI tariff for the period of the multi-year CTC. This CTC reduction should be "progressive" with greater reductions being given to customers that elect CTCs that are determined for greater periods of time. (Trizec Exh. 1.0, pp. 9-10)

On cross examination, Mr.Turner stated that (1) he had not quantified the magnitude of his proposed adjustment, (2) he had not determined how it should be computed, and (3) he had not quantified the extent to which the 'CTC reduction should be "progressive" with greater reductions being given to customers that elect CTCs that are determined for greater periods of time.' (Tr. 516-517)

Without a specific proposal in the record, Staff sees no basis for the Commission to order a market value adder (or CTC reduction) based on length of contract.

E. Limitation on load eligible for multi year TC contracts

Only customers with individual transition charge calculations can vie for service under Rider CTC-MY. Staff recommends that the customers eligible for individual transition charge calculations should be expanded to include all customers with a demand greater than 400 kW (see Section V.D.).

The customers with demand between 400 kW and 1,000 kWh should be permitted to compete in the multi-year transition charge lottery.

F. Implications of RES default during multi year TC contract

As discussed above, ComEd proposes that customers leaving service under Rider CTC-MY that subsequently take service under Rider ISS would not be permitted to revert to bundled service after a full term of service under Rider ISS. This provision is potentially troublesome, since Rate HEP, the only alternative for a Rider CTC-MY customer other than RES supply, is a market-based service that might not be attractive service for all customers. Nevertheless, Staff does not oppose this provision, and the reports that Staff recommends that ComEd provide to the Commission should show whether an unduly large number of customers are being forced onto Rate HEP.

IP offered to permit multi-year transition charges customers to take service under Rider ISS in the case of RES default (Tr. 198-199; 258-259). Under IP's plan, such customers would pay the standard Rider ISS rate, plus an additional ten percent. Further, Rider ISS who do not choose an IP bundled rate or select a new RES would be placed at IP's discretion on an IP bundled tariff or Rider ISS for the remainder of the multi-year term. Customers placed on Rider ISS for the balance of their multi-year term apparently would be prohibited from taking service from a RES (Tr. 259-260)

Staff does not object to customers being placed on Rider ISS if their RES defaults. However, Staff is not convinced that an adder of 10 percent above the standard Rider ISS rate would be appropriate. Moreover, Staff is not convinced that IP should have the ability to determine whether a customer should remain on Rider ISS or be placed on a bundled tariff for the remainder of the multi-year term. Staff recommends that multi-year customers placed on Rider ISS receive service under that tariff's existing terms and conditions. If IP wishes to modify Rider ISS to accommodate multi-year transition charge customers, IP should file a tariff more fully describing the parameters of its proposal.

G. Other

The Staff has no other issues to raise within this section of its brief.

V. Time Period and TC Administration Issues

A. Frequency of MV/TC calculations

Several arguments were advanced against changing method of calculating market values. ComEd witness Crumrine noted that it was unclear whether calculating market values on a quarterly basis would provide any improvement over the current Period A / Period B methodology because RESs apparently do not necessarily purchase power during snapshot periods. (ComEd Exh. 6.0, p. 41) Mr. Crumrine also noted that market values calculated on a quarterly basis would not necessarily be more accurate than market values calculated under the Period A / Period B scheme. Mr. Crumrine stated that changing moving to quarterly estimation of market values could lead to customer confusion. (Ibid. p. 42) Under cross-examination, Staff witness Zuraski and IIEC witness Stephens made similar points. (Tr. 645; Tr. 491)

The argument for moving to quarterly snapshots is that, under the current system, customers have very little time after market value data is released to decide whether to take delivery services. (RES Coalition Exh. 4.0, p. 53) Moving to a quarterly snapshot methodology presumably would give customers more time to consider their supply options. However, the proposal to move up the market value release date to February 1st would provide many of the same benefits, without the drawback of potential added customer confusion. Thus, Staff does not support the quarterly snapshot proposal.

B. Moving data collection period for Applicable Period A to January

Moving up the data collection period for Period A from February-March to January and releasing the results of the data gathering by February 1st would provide customers additional time to compare the guaranteed savings associated with PPO service to any offers that are received from RESs. The drawback to moving the data collection period to an earlier date is that an earlier snapshot period may be more likely to be in error than a later snapshot period. Notwithstanding this potential drawback of the proposal, the potentially large benefits of giving customers more time to consider their options probably will outweigh the drawbacks of a potentially larger error between projected and actual market values that would occur with an earlier collection period. Staff therefore supports ComEd's plan to move the data collection period for Period A to January, with a release date of February 1st. However, Staff's support of this plan should not be construed as acceptance of ComEd's proposal to restrict the Period A enrollment period to the period between February 1st and March 31st. Staff opposes that proposal (see item IV.C.)

C. Decision Window for PPO Customers

ComEd proposes to restrict the enrollment period for Period A PPO to the period between February 1st and March 31st. ComEd's proposal is offered in conjunction with its proposal to release market value information on February 1st, rather than on April 1st. As discussed above, Staff does not oppose that proposal.

The proposal to limit the Period A PPO enrollment period to a specific two-month period unnecessarily restricts the amount of time customers would have to decide whether to take Period A PPO at the earliest possible date. Currently, customers may enroll for the Period A PPO essentially any time up to within 30 days of the end of the three-month (June-August) summer period.

ComEd portrays its proposal as a means to prevent "gaming" strategies by Retail Electric Suppliers that result from the RES' ability to rely on the PPO as a supply source (ComEd Exh. 3.0, p. 10). Under these strategies, RESs determine whether it is cheaper to supply their customers through the PPO (either by using their authority as agents to enroll their customers onto the PPO or through the Section 16-110(b) PPO Assignment provisions) or from power purchased on the wholesale market. Such strategies, according to ComEd, are unfair to ComEd because they impose costs on ComEd (p. 10). However, ComEd did not quantify any costs that it might incur as a consequence of the RESs potentially relying on the ComEd-supplied PPO as a supply source. (ICC Staff Exh. 2.0, p. 4)

ComEd acknowledges that RES' reliance on the PPO as a potential supply source does not increase the prices that ComEd will pay for the power and energy it purchases from its affiliated supplier, because those prices are fixed until the expiration Power Purchase Agreement ("PPA") in 2005. (Tr. 594-595) Under the PPA, ComEd does not have to pay reservation or "take-or-pay" fees for the right to purchase power from its affiliate (Ibid.). It pays only for the power it purchases. Thus, ComEd's power procurement costs do not increase even though RESs may rely on ComEd to supply power through the PPO.

Staff agrees that the ComEd proposal has the benefit of guaranteeing that all customers eligible for the PPO have 59 or 60 days after the release of market value data to determine whether to take the PPO at the beginning of the Period A period. For the customers that currently have less than 60 days to evaluate their supply options, ComEd's plan is an improvement. However, this benefit (which is not applicable to all customers, since many customers have over 30 days to evaluate their options) comes at the cost of taking away the perhaps larger customer benefit of being able to sign up for the Period A PPO until June or July. The proposal could deprive those customers who decided to enroll for the PPO during the sign-up period to the assure themselves of savings of the opportunity to take advantage of RES deals that might be forthcoming between March 1st and the beginning of Period A. It may also deprive some customers of the opportunity to obtain savings by starting Period A during June or July. (BOMA Exh. 1.0, p. 27) Customers should not have to sacrifice these benefits to obtain another, possibly smaller benefit. A better plan would be to simply move up the release date of the market value data to February 1st without unduly restricting the Period A PPO enrollment period.

D. *Customer Eligibility for individual TC calculation*

A surprisingly large percentage of customers cannot save money by taking PPO service. According to data provided in ComEd Exhibit Attachment PRC – R1, between 14% and 85% of smaller-use customers in ComEd delivery services rate classes 1-6 would not save money by signing up for the PPO. Increasing the number of customers that receive individual transition charge calculations would enable more customers to obtain mitigation factor benefits by signing up for the PPO. (RES Coalition Exh. 4.0, p. 56; BOMA Exh 1.0, p. 27; Tr. 693 and 706) Providing additional customers could also have the benefit of a higher level of accuracy than transition charges derived from class data because the individual transition charge is directly related to a customer's actual load shape, reducing the need for a specific customer to subsidize other customers through the class methodology. (RES Coalition Exh. 4.0, p. 56)

While Section 16-108 of the Act only requires ComEd to provide a limited number of customers with individually calculated transition charges, ComEd has proposed to provide the 1,300 customers with a demand greater than 1 MW with custom transition charges. The cost of this effort, as shown in an attachment to ComEd witness's Crumrine's direct testimony, is estimated to be $172,3000, with ongoing annual costs of $61,300 (see the chart labeled "Cost Summary", Attachment PRC – R1, page 2 of 2). This attachment also shows the cost of providing individually calculated transition charges to additional groups of customers. For the 5,100 customers with a peak demand greater than 400 kW, ComEd estimates an initial cost of $638,300, with an ongoing annual cost of $240,300. The total costs or providing individual transition calculations for the smaller group are significantly smaller for the 1,900 customers with a peak demand exceeding 800 kW. For this group of customers, ComEd estimates an initial cost of $237,500, with an ongoing annual cost of $89,500. These costs apparently already include the costs that ComEd would incur to provide individually calculated transition charges to customers in the 1 to 3 MW group.

Representatives of both the RES Coalition and customers groups recommended that ComEd should provide customers with a peak demand greater than 400 kW with individual transition charge calculations. (BOMA Exh. 1,0, p. 27; RES Coalition Ex. 4.0, pp. 57-58) ComEd customers with a demand exceeding 400 kW have interval meters, which BOMA witness Sharfman testified would provide ComEd with the proper data needed to calculate individual transition charges without risk or considerable added expense. (BOMA Exh. 1.0, p. 27) ComEd stated that their objection to this proposal is primarily administrative in nature. (Tr. 709) Staff recognizes the benefits of increasing the number of customers eligible for individual transition charge calculations and supports these recommendations. However, how ComEd could recover the administrative costs of making custom transition charges available to a larger group of customers is an unanswered question.

E. Customer Aggregation for individual TC calculation

The RES Coalition recommends that the Commission modify ComEd's tariffs to permit customers to aggregate load to attain the class size minimum required to obtain customer-specific transition charges. (RES Coalition Exh. 4.0, p. 59) The benefits of this proposal are that additional customers would receive individual transition charge calculations and the promotion of aggregation-related services (Ibid.). In response, ComEd witness Crumrine noted that this proposal would result in additional administrative costs for ComEd and would allow customers to choose between a transition charge derived from the aggregation methodology or the customer class to which the customers belong. (ComEd Exh 6.0, p. 43)

The very existence of the proposal highlights how the current method used to estimate transition charges results in a lack of savings opportunities for some customers. There is a need for consideration of policies that expand customer savings opportunities. One step in this direction would be to adopt the proposal to require ComEd to provide individual transition charges to a demand greater than 400 kW. After that initial step is taken, it would be worthwhile to enlarge the number of customers qualifying for individual transition charges through the adoption of the aggregation proposal.

F. Other

ComEd proposes to restrict the availability of the Period B PPO to bundled customers. These customers may only start a Period B PPO during the monthly billing periods extending from September through May. Staff witness Schlaf and BOMA witness Sharfman both recommended against adoption of this proposal. (ICC Staff Exh. 2.0, p. 6; BOMA Exh. 1.0, p. 27) Staff witness Schlaf testified that the proposal would only benefit ComEd's generating affiliate without any corresponding customer benefit. Mr. Sharfman stated that limiting the availability of the Period B PPO would limit customer choices without harming ComEd. (BOMA Exh. 1.0, p. 27)

Staff recommends that this proposal not be adopted until at least 2005, when ComEd's Power Purchase Agreement with its generating affiliate expires. Under these contracts, ComEd pays a fixed amount for the amount it purchases from its generating affiliate, without any reservation or take-or-pay costs. Thus, allowing customers other than bundled customers taking delivery services for the first time does not impose costs on ComEd. Staff notes, however, that it would not be averse to considering prior to 2005 less-restrictive proposals that might address any problems that ComEd believes are associated with current Period B eligibility provisions.

VI. Other Issues

A. Multi year price shaping

Ameren and ComEd currently compute a price shaping adjustment, using 8760 hours (one year) of PJM West hourly prices, along with 8760 hours of load data for each customer class. These companies now propose to use multiple years of PJM West and load data in this price shaping adjustment. ComEd proposes to use the most recent three calendar years' worth of hourly data, while Ameren proposes to use all data since January 1999. The shaping of the most recent monthly or yearly forward prices (for on-peak and off-peak forward contracts) would be performed separately for each year's worth of PJM and load data, leading to values for (1) summer, (2) non-summer, (3) summer-peak, (4) summer-offpeak, (5) winter-peak, (6) winter-offpeak, and (7) the total load-weighted market value. Thus, for ComEd, for example, there would be three price shaped values for each of these seven aggregated time periods. The simple average of the three values for each of the aggregated time periods would comprise the final price-shaped value. Ameren would follow the same procedure, except with more years of hourly PJM price and load data. In addition, when applying the price shaping adjustment, both ComEd and Ameren propose to replace non-positive PJM hourly prices with the average of all the positive off-peak PJM prices in the month.

As for IP, it currently uses a different price shaping adjustment, which was originally approved by the Commission in Docket Nos. 99-0120 and 99-0134, consolidated. In essence, the IP methodology shapes only on-peak prices, while the ComEd/Ameren methodology shapes both on-peak and off-peak prices. In the current docket, IP proposes to retain this basic methodology, but, to "utilize multiple prior years" for the development of the adjustment.[7]

Staff witness Zuraski stated that he had no preference for or against the multi-year price shaping proposals. He only pointed out that while this change would have increased market values had it been in effect during the last computation of ComEd and Ameren's Applicable Period A market values, there is no reason to expect that the proposal will continue to systematically increase market values. As noted in the section on synchronization (on page 23), instead of averaging the yearly results of the multi-year price shaping/load weighting process, Staff recommends that the utility select the yearly results that maximize the load weighted average market value for each class. Staff believes this is a better means of addressing the potential lack of synchronization between the PJM price data and the Illinois load data, discussed by RES Coalition witnesses Bollinger, et al. (RES Coalition Exh. 4.0, pp. 16-19)

B. Price and Data Availability – Monitoring and Reporting Requirements

RES Coalition witnesses Bohorquez, et al., approve of the proposed switch to using forward market data as the source of off-peak prices. However, they note that the forward markets for off-peak forwards are relatively thin. Hence, they propose that the utilities be required to continuously monitor and report the availability of these data. Furthermore, if the data becomes insufficient, the witnesses recommend that the utilities conduct a "competitive auction" for off-peak power delivered into their service territories as a substitute method of gathering off-peak price information for the MV tariffs. (RES Coalition Exh. 3.0, pp. 15-18) They also recommend the continued monitoring and reporting of on-peak forward market data availability. Should these data become insufficient,

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[7] See IP's October 30, 2002 filing, Supplemental Statement, p. 2, under '"Zuraski" Price Shaping Adjustment.'

the witnesses again recommend that the utilities conduct a "competitive auction" for on-peak power delivered into their service territories as a substitute method of gathering on-peak price information for the MV tariffs.

On cross examination, the witnesses admitted that they had no real plan for how the competitive auctions would work and Staff wonders why such an *ad hoc* auction would be a more liquid source of data than an already well-established marketplace, such as the Intercontinental Exchange. The witnesses seem to ignore the obstacles and costs confronting a party wishing to conduct such an auction.

Furthermore, the RES Coalition may be rather cavalierly assuming that this Commission has the authority to authorize an electric utility to conduct a competitive auction for the purpose of deriving Section 16-112 market values. Section 16-102 of the Act requires transition charges to be based on Section 16-112 market values. However, Section 16-112 says nothing about an utility-moderated auction. In addition, Section 16-103(c) of the Act, which discusses (among other things) certain sales of power and energy at "***Market based prices***," declares that "Market based prices as referred to herein shall mean, for electric power and energy, either (i) those prices for electric power and energy determined as provided in Section 16-112, or (ii) the electric utility's cost of obtaining the electric power and energy at wholesale through a competitive bidding or other arms-length acquisition process." Methods (i) and (ii) appear to be meant to be mutually exclusive, meaning that a competitive auction at which the electric utility obtains electric power and energy at wholesale could not form a proper basis for developing Section 16-112 MVs.

For all the above reasons, the Staff recommends that the Commission refrain from ordering the utilities to conduct competitive auctions for the purpose of computing Section 16-112 MVs.

However, the Staff has no objection to the RES Coalition's recommendation that utilities continue to provide periodic reports on the availability of on-peak forward market data

C. Dr. Ulrich's MVI Study

RES Coalition witness Ulrich presented a comparison of ComEd's most recent Period A MVs to a set of MVs implied by review of RES contracts with Illinois retail customers entered into between February 25, 2002 and March 22, 2002 (basically the same period of the most recent Period A snapshots of on-peak forward prices required by the current ComEd tariff). (RES Coalition Exh. 2.0) As summarized by RES Coalition witnesses Bollinger, et al., the comparison shows "the price differences between ComEd's MVECs and the RES contracts range from 25% to 77%. (*See* Direct Testimony of Dr. Ulrich, Attachment D.) " (RES Coalition Exh. 4.0. p. 40, citing Ulrich, RES Coalition Exh. 2.0, Attachment D)

According to Bollinger, et al., the study supports the position that:

> [T]here is a significant variance between actual market prices and ComEd's MVECs. Therefore, the adjustments put forth by the RES Coalition are appropriate. (RES Coalition Exh. 4.0, p. 45)

After examining Dr. Ulrich's electronic workpapers (an Excel spreadsheet), ComEd witness Beach attempted to rebut the legitimacy and significance of the Ulrich study. (ComEd Exh. 2.0, pp. 11-17) Most of her criticism focused on alleged discrepancies in Dr. Ulrich's claims about the time period over which the contracts were entered. However, on cross examination, it became clear that Ms. Beach's observations were erroneous and based on confusion over Excel's date functions. She also computed some suspicious-looking load factors using data contained in Dr. Ulrich's workpapers. However, on cross-examination, the relevance of this observation was brought into doubt.

Nevertheless, it is unclear what the Commission should make of the Ulrich MVI Study (as well as his NFF Study, described in the next section). At face value, his studies suggest that retail customers are paying significantly more for power and energy than they are receiving in transition charge credits. Why are they doing that? Why not just take the PPO and pay the lower MV embedded in the PPO, or why not remain on the bundled rate? ComEd witness McNeil offered an explanation:

> I conclude, based on the timing and description of the contract data described in the testimony and used in the analysis, that RESs, at a time when power prices were rapidly declining to an all time low, locked customers into contracts with higher prices than the lower prices for power that were available in the market. … This strategy may well have been profitable for the RESs, although very unpopular with customers. (ComEd Exh. 4.0, p. 24)

Hence, Mr. McNeil seems to implicitly assume that, had these contracts studied by Dr. Ulrich been entered into evenly throughout the ComEd period A snapshot period, they would have averaged closer to the final Period A market values filed by ComEd. He also seems to implicitly assume that they were concentrated in an earlier part of the February 25- March 22 snapshot period, and that market prices were relatively higher in the earlier part relative to the later part of the snapshot period. However, Staff does not believe that the record supports any of these assumptions.

As far as Staff is concerned, the Ulrich study shows that (for reasons that remain unclear), some customers in the ComEd service territory are paying RESs more for electric power and energy than the MVs embedded in the most recent Applicable Period A filings by ComEd. Staff has no opinion about whether this justifies any particular adjustment to the MV formulas.

D. Dr. Ulrich's NFF Study

In addition to his so-called MVI Study (discussed above on page 45) RES Coalition witness Ulrich also presented a comparison of ComEd's most recent Period A MVs to a set of MVs implied by review of RES contracts with Illinois retail customers entered into before September 15, 2001 for service rendered anytime after May 15, 2002. (RES Coalition Exh. 2.0) Staff's opinion of Dr. Ulrich's NFF Study mirrors Staff's opinion of his MVI Study. However, Staff has no opinion about whether the study justifies any particular adjustment to the MV formulas.

E. Mr. Sharfman's RPI Study

BOMA witness Sharfman presented a study based upon his consulting firm's Retail Power Index ("RPI"). The study culminates in the computation of a so-called "retail power spread" of $0.98 per MWH. According to Mr. Sharfman:

> The spread illustrates how much money a supplier has left to recover the costs of ancillary services and other costs associated with serving retail load (excluding regulated utility charges, such as distribution, transmission, and CTC) after it purchased wholesale power in the market, while still being able to offer a value proposition for a retail customer. According to BOMA Exhibit 1.3, the $0.98 per MWh retail power spread for the ComEd region means that after a retail electric supplier purchased wholesale power in the market, it would have to recover the costs of ancillary services, and all other costs associated with serving a retail customer, for less than $0.98 in order to compete with the ComEd bundled rate. (BOMA Exh. 1.0, pp. 8-9)
>
> The $0.98 retail power spread for ComEd indicates that there is only a minor difference between wholesale prices and the retail price to beat in ComEd's territory. This minor difference implies that ComEd customers are already paying wholesale prices for retail power. As a result, the spread implies that consumers may not receive any added benefit from retail competition. (BOMA Exh. 1.0, pp. 9-10)

This qualitative conclusion is not much of a news flash. As should be apparent to all who examine the transition charge formula embedded in the Act, it is designed to provide consumers with a relatively small savings opportunity, approximately equal to the "mitigation factor." In essence, Mr. Sharfman "retail power spread" sounds like it should parallel the mitigation factor. Notwithstanding some differences in data and methods of computation, Mr. Sharfman derives his retail power spread ("RPS") as:

$$\mathbf{RPS = BR - DSR - CTC - MV}$$

= BR - DSR - BR+DSR+MV+mf - MV

= mf[8]

Still, his retail power spread is quite a bit smaller than the actual mitigation factor for the small commercial classes that his study considers. For instance, the mitigation factor for the 0-25kw class was $7.43/MWH for the June 2002-December 2002 period and $9.29/MWH for January 2003 to May 2003 period. So why is Mr. Sharfman's parallel computation only $0.98/MWH, even though Mr. Sharfman appears ***not*** to include an energy loss adjustment to his wholesale prices, which, if anything, would bias the analysis toward showing a larger "retail power spread." The record is unclear on this point. Even without such confusion, it would be far from clear how the Commission should translate Mr. Sharfman's study into a proposal for improving the MV tariffs.

F. Reinstitution of the NFF process

Staff recommends that the Commission order whatever changes that it believes are appropriate. If one or more of the utilities decide that they cannot live with the changes, then the Commission will have no choice but to reintroduce the NFF process.

G. Other

Staff has no other issues to raise at this time.

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[8] In these equations, "**BR**" is the bundled rate, "**DSR**" is the delivery services rate, "**MV**" is the market value, and "**mf**" is the "mitigation factor." However, here they are not necessarily identical to the concepts defined in the Act.

VII. Conclusion

For the foregoing reasons, the Staff of the Illinois Commerce Commission respectfully requests that the Commission accept Staff's recommendations.

Respectfully submitted,

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STEVEN G. REVETHIS
JOHN C. FEELEY
Office of General Counsel
Illinois Commerce Commission
160 North LaSalle Street
Suite C-800
Chicago, Illinois 60601
(312) 793-2877

Counsel for the Staff of the
Illinois Commerce Commission

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