STATE OF ILLINOIS

ILLINOIS COMMERCE COMMISSION

Commonwealth Edison Company	)	
	)	
Proposal to implement a competitive	)	Docket No. 05-0159
procurement process by establishing	)	
Rider CPP, Rider PPO-MVM,	)	
Rider TS-CPP and revising	)	
Rider PPO-MI.	)	

DIRECT TESTIMONY OF ROBERT M. FAGAN ON BEHALF OF THE CITIZENS UTILITY BOARD AND THE COOK COUNTY STATE'S ATTORNEY'S OFFICE

CUB-CCSAO EXHIBIT 1.0

June 8, 2005

DIRECT TESTIMONY OF
ROBERT M. FAGAN

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DOCKET NO. 05-0159
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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Robert M. Fagan. I am a Senior Associate at Synapse Energy Economics, Inc., 22 Pearl Street, Cambridge, Massachusetts, 02139.

Q. ON WHOSE BEHALF DID YOU PREPARE THIS PREFILED TESTIMONY?

A. I prepared this testimony on behalf of the Citizens Utility Board and the Office of the Cook County State's Attorney.

Q. PLEASE SUMMARIZE YOUR PROFESSIONAL EXPERIENCE AND EDUCATIONAL BACKGROUND.

A. I am an energy economics analyst and mechanical engineer with 19 years of experience in the energy industry. My work has focused primarily on electric power industry issues, especially economic and technical analysis of competitive electricity markets development, electric power transmission pricing structures, and assessment and implementation of demand-side resource alternatives. Prior to joining Synapse Energy Economics in December 2004, I was employed at Tabors Caramanis & Associates for eight years and Charles River Associates for four years. I hold an M.A. from Boston University in Energy and Environmental Studies and a B.S. from Clarkson University in Mechanical Engineering. Details of my experience are provided in Exhibit 1.1.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE ILLINOIS COMMERCE COMMISSION?

A. No.

Q. HAVE YOU TESTIFIED BEFORE OTHER REGULATORY BODIES OR LEGISLATIVE COMMITTEES ON RELATED WHOLESALE MARKET ISSUES?

A. Yes. I testified before the Texas Public Utilities Commission on stranded cost issues, which encompassed both wholesale and retail market considerations during the transition to a competitive market. I have submitted testimony on Open Access Transmission Tariff issues in Nova Scotia, and I have submitted joint testimony in Maine on transmission capacity reservation needs. I testified on transmission tariff and transmission system code issues in Ontario and Alberta. In all of those jurisdictions, the structure of the impending (Ontario, Nova Scotia) and existing (Texas, Alberta, Maine) competitive wholesale and retail markets was germane to my testimony.

I also testified orally before the Illinois House Electric Utility Oversight Committee on May 3, 2005 on issues similar to those as I address in this testimony.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to examine the wholesale electricity market environment in which the proposed ComEd basic utility service (“BUS”) auctions would take place, recognizing that the foundation for a successful procurement requires a well-functioning, fully competitive wholesale market. I identify the shortcomings of the post-2006-period wholesale market structure in the Northern Illinois ("NI") region of PJM, and I highlight the many price-influencing uncertainties that exist.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. The introductory section includes a brief statement of my qualifications and a purpose statement. I then summarize the major points of my testimony. This follows with a section describing the high generation ownership concentration in Northern Illinois. I next address the immaturity of the Midwest Regional Transmission Organization's ("MISO") spot energy markets, and describe the impact of the PJM-MISO "seam." I then address the current state of FERC's review of market-based rate authority applications. Lastly, I describe the role of the PJM and MISO RTO in mitigation of the exercise of market power and recommend strengthening the mitigation policies of each.

II. SUMMARY

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. First, I show that generation capacity and energy supply concentration in the Northern Illinois region in post-2006 coupled with the pending expiration of the existing ComEd-Exelon contracts for BUS supply will result in the ability of Northern Illinois generation suppliers to exercise market power at times, leading to wholesale market prices that do not reflect competitive market outcomes.

I describe how the inescapable fact of the underlying generation ownership concentration will influence the pricing strategies of all auction participants, regardless of how many suppliers participate in the proposed auction. The presence of a concentrated supply market in Northern Illinois will influence the PJM spot prices in the Northern Illinois region, thereby influencing auction participant perceptions of the value of power available for purchase, in turn exerting upward pressure on the BUS procurement auction "offer" prices (or bids made by the participants to supply BUS) and leading to higher auction clearing prices. The ability of Northern Illinois generation to drive up PJM Northern Illinois prices will be present during times in which transmission constraints restrict the ability of non-Northern Illinois suppliers to effectively compete with Northern Illinois-based suppliers.

Second, I describe how the relative immaturity of the MISO spot energy markets and the insufficient scope of capacity and ancillary service structures in MISO result in a high level of uncertainty concerning the competitiveness of the MISO spot energy markets. This in turn impacts the ability of potential auction participants to secure competitively priced supplies from the MISO region for delivery to the Northern Illinois region, reducing the degree of competition available for supplying BUS in the Northern Illinois region.

Third, I show how the "seam" between PJM and MISO presents a barrier to effective trade between the regions, illustrating that the seam runs directly across Illinois, separating the wholesale electric markets in Northern Illinois from those in Southern Illinois, and thereby denying Northern Illinois residents the benefits of a cohesive, integrated wholesale marketplace for electricity purchase by prospective retail suppliers.

Fourth, I describe the highly uncertain state of the criteria to be used by FERC in the post-2006 timeframe to determine if an entity has market power, noting that current rules are expressly “interim” in nature and may change pending the outcome of FERC’s current proceeding on this issue. I explain that existing FERC-granted market-based rate authority for Midwest Generation, and Exelon’s pending application to FERC for such authority are premised on conditions that will not exist in Northern Illinois in post-2006, and therefore such authority or pending authority does not lead to any conclusions about the potential for exercise of market power in Northern Illinois in post-2006.

Fifth, I point out why existing market monitoring and mitigation rules in place in PJM and MISO are insufficient to address the potential exercise of wholesale market power and the resulting increase in prices likely to be seen in the proposed auction.

Lastly, I state here that I support the recommendations made by William Steinhurst in his testimony in this proceeding.

III. NORTHERN ILLINOIS GENERATION OWNERSHIP CONCENTRATION

Q. WHAT ISSUE DO YOU ADDRESS IN THIS SECTION OF YOUR TESTIMONY?

A. I examine the generation ownership concentration in the Northern Illinois region and the potential for the exercise of market power. Using data from a recent Exelon FERC filing, along with transmission import capability information, I compute installed capacity market shares and generation capacity ownership concentration using the Herfindahl-Hirschman Index (HHI). I also review generation energy and capacity ownership concentration indices in the Northern Illinois region based on reports from the PJM Market Monitoring Unit.

Q. WHAT IS GENERATION MARKET POWER?

A. Simply stated, a generation supplier has the ability to exercise generation market power when its actions have the effect of raising prices (in any applicable market, e.g. capacity and energy) above competitive levels for a significant period of time.[1] These actions include some form of physical withholding of supply; or some form of strategic bidding or economic withholding, wherein the offer prices for available supply are raised above marginal costs. In a perfectly competitive market, no supplier has the ability to exercise market power; all suppliers are “price takers” at all

[1] For a broad overview of market power in electricity markets, see, for example, *Horizontal Market Power in Restructured Electricity Markets*, US Department of Energy, Office of Economic, Electricity and Natural Gas Analysis, Office of Policy, March 2000. Also, see *Understanding Competitive Pricing and Market Power in Wholesale Electricity Markets*, PWP-067, Severin Borenstein, University of California Energy Institute, August 1999.

times. However, in a concentrated supply market, there is a greater likelihood that market power can be exercised.

Q. WHY IS THE OWNERSHIP CONCENTRATION RELEVANT?

A. Concentration of generation ownership gives a supplier or a group of suppliers the ability to either physically or economically withhold generation, resulting in clearing prices higher than those expected in a competitive market. This is the exercise of market power. Physical withholding of generation is when a supplier or suppliers reduce the availability of generation to sell or schedule into the physical marketplace, or spot markets. Economic withholding is when a supplier or suppliers increase (above marginal cost) the price at which they are willing to sell into the spot marketplace. In either of these instances, the spot market clearing price will be above the clearing price that would have resulted in a competitive market and the generation owner or owners -- and other spot market suppliers -- will earn greater revenues than they would have earned in a competitive market.

Q. WHAT EFFECT WILL THE POTENTIAL FOR HIGHER SPOT MARKET PRICES HAVE ON THE PROPOSED AUCTION?

A. Clearing prices in the proposed auction logically will be influenced by auction participants' perceptions of spot market prices. Auction "winners" likely will supply at least some fraction of their BUS obligation from the spot market. In the extreme, a "financial" auction participant not willing to secure long-term supplies could elect to supply all BUS obligations from the spot market.

Q. WHAT IS THE HERFINDAHL-HIRSCHMAN INDEX OF CONCENTRATION?

A. The HHI is a broad measure of ownership concentration. Its calculation is based on the weighted market shares[2] of individual companies in a defined market area. The HHI can be used to gauge whether or not a market might be susceptible to market power abuse.

Q. CAN THE HHI BE USED AS A "BRIGHT LINE" TEST FOR MARKET POWER?

A. No. However, the FERC Merger Policy Statement[3], adapted from the Department of Justice / Federal Trade Commission Merger Guidelines[4], uses three threshold levels of HHI to gauge market concentration. A market with an HHI below 1000 is said to be unconcentrated. A market with an HHI between 1000 and 1800 is said to be moderately concentrated. And a market with an HHI above 1800 is said to be highly concentrated.

Q. CAN YOU SUMMARIZE HOW CONCENTRATION RATIOS CAN INDICATE THE POTENTIAL FOR MARKET POWER ABUSE?

A. Yes. I refer to the PJM MMU 2004 State of the Market Report for a good summary statement of this issue:

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[2] The HHI is computed as the sum of the squares of company market shares. Thus, a market with 5 equally sized firms (each with 20% share of the market) has an HHI equal to $(20)^2 + (20)^2 + (20)^2 + (20)^2 + (20)^2 = 2000$. A market with a single supplier has an HHI = 10,000 ($=100^2$). A market with 20 equally-sized firms has an HHI of $(5)^2 \times 20 = 500$.

[3] FERC Order 592, Inquiry Concerning the Commission's Merger Policy Under the Federal Power Act: Policy Statement, December 18, 1996.

> "Concentration ratios are a summary measure of market share, a key element of market structure. High concentration ratios mean that a comparatively small number of sellers dominate a market, while low concentration ratios mean that a larger number of sellers share market sales more equally. Concentration measures must be applied carefully in assessing the competitiveness of markets. Low aggregate market concentration ratios do not establish that a market is competitive, that market participants cannot exercise market power or that concentration is not high in particular geographic market areas. High aggregate market concentration ratios do, however, indicate an increased potential for market participants to exercise market power." (Page 146)

Q. ARE NI REGION ENERGY AND CAPACITY MARKETS HIGHLY CONCENTRATED?

A. Yes. As I will show, both the energy and capacity markets in the Northern Illinois region are generally highly concentrated.

Q. WHAT OUTPUT METRICS CAN BE USED TO MEASURE GENERATION OWNERSHIP CONCENTRATION?

A. Generation ownership concentration can be measured with respect to energy output, installed or unforced generation capacity[5], or ancillary service capability/availability. Historically, measures of generation ownership concentration have usually focused on capacity ownership, using any of several metrics to measure capacity. These metrics include nameplate MW capacity rating, seasonal MW capacity rating (e.g., generation capacity can vary depending on seasonal conditions such as ambient temperature or

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[4] U.S. Department of Justice and the Federal Trade Commission, Horizontal Merger Guidelines, April 2, 1992, revised April 8, 1997.

[5] Installed generation capacity is usually a reference to the nameplate or seasonal capacity (MW) rating of a generator, without accounting for its planned or unplanned outages (when the capacity is not available). Unforced capacity is the term used in PJM, and the metric upon which the PJM Capacity Credit market is based, that recognizes a reduction in average annual capacity of installed generation based on estimates of outage rates.

cooling water availability or temperature), or average MW capacity adjusted for outages. A capacity concentration metric is usually based on a snapshot in time, and often annual or seasonal snapshots are used. However, a capacity concentration metric can be based on the smallest time interval comprising a market. Thus, capacity concentration metrics could be created for monthly capacity markets, a common period for capacity settlement; or even daily capacity markets, such as PJM's capacity credit market. PJM indeed does compute capacity market HHIs for its daily and its monthly and multi-monthly capacity markets.[6]

Generation energy output over any defined interval (MWh) can also be used to define the ownership concentration of energy supply. PJM uses the hourly interval when examining the potential for exercise of market power within load pockets. To examine concentration on an annual basis, the annual MWh output from the supplies of each generation owner can thus form the numerator of the "market share" metric used to compute HHIs, with the total annual MWh output as the denominator. Computing energy market HHIs over a longer time interval will thus weight ownership concentration based on annual capacity factors; i.e., an owner with considerable baseload generation, such as Exelon, will likely provide a greater fraction of the annual energy than its installed capacity share would otherwise indicate. As I show, this is exactly what the PJM MMU found in the energy markets for northern Illinois since the integration of the ComEd territory into PJM on May 1, 2004.

[6] See for example, PJM's 2004 State of the Market Report, Table 4-1, page 147, *PJM Capacity Market HHI: Calendar Year 2004*. The values reported in that table exclude the ComEd region, as during 2004 the ComEd region was under a separate capacity market construct than the rest of PJM.

Lastly, a generation unit's ancillary service capability in each of several categories can be considered, for example spinning reserve or regulation MW capability.

Q. WHAT IS THE OWNERSHIP CONCENTRATION OF INSTALLED GENERATION CAPACITY IN NORTHERN ILLINOIS?

A. Exhibit 1.2 shows installed generation capacity ownership concentration in Northern Illinois. An index of 1800 is the threshold at which a market is said to be "highly concentrated." Based on data provided in Exelon's recent filing to FERC[7], I compute an installed capacity concentration index of 2,015, above the threshold for a "highly concentrated" market.

When imports into the Northern Illinois region are accounted for, Exelon's share of capacity decreases from 37.5% to 32.5%. However, Exelon and Midwest Generation together still account for more than 50% of the installed capacity in the NI region even when taking simultaneous import capacity into account, as shown in Exhibit 1.2.

Q. WHAT DID THE PJM MMU REPORT SHOW FOR INSTALLED CAPACITY AND ENERGY MARKET OWNERSHIP CONCENTRATION IN THE NORTHERN ILLINOIS REGION FOR 2004?

[7] Supplemental Affidavit of William H. Hieronymus, Exelon filing to FERC May 23, 2005, Exhibit EXE-3 and EXE-4.

A. In the 2004 State of the Market report[8], the PJM MMU stated that installed capacity HHIs in the ComEd region during "phase 2" (May through September, prior to AEP's integration)[9] ranged from 2670 to 4065, with an average of 3368 over the five month period from May 1 to September 30, 2004. The report also indicates hourly energy HHIs ranging from from 4005 to 7746, with an average of 5935. The PJM MMU reports a range because they compute HHIs for all capacity market intervals (daily, monthly and multi-monthly) and for all hourly energy market intervals.

Q. WHY DOES YOUR HHI COMPUTATION RESULT IN A LOWER AVERAGE INSTALLED CAPACITY HHI THAN THE PJM MMU RESULTS?

A. My approach is conservative. I assume a best-case scenario in which all generation units are in service and all capacity from those units is available. The PJM MMU computations use actual data accounting for those variables.

Q. HOW DID YOU DETERMINE THE HHI FOR THE NORTHERN ILLINOIS REGION?

A. I collected data on installed capacity ownership using the most recent market-based rate authority filing by Exelon. To determine Exelon's market share of installed capacity considering imports, I used Exelon's estimate of simultaneous import capacity into the Northern Illinois region.

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[8] 2004 State of the Market, PJM Market Monitoring Unit, March 8, 2005. Tables 2-8 and 2-9, Page 55 (ComEd installed capacity and hourly energy market HHI, phase 2).

[9] American Electric Power ("AEP") integrated its transmission system into the PJM RTO on October 1, 2005.

Q. WHAT IS THE IMPORT CAPACITY INTO THE NORTHERN ILLINOIS REGION?

A. The overall connected transmission capability into the ComEd region is greater than the "simultaneous import capacity," or how much energy can actually flow into the region given the operational constraints unique to electric power transmission systems. I understand that that value is not easily determined, varies considerably depending on system conditions, and is not readily agreed to; in this case, I have used the value noted by Exelon's consultant in a 2003 filing to the FERC, i.e., 4,700 MW.[10]

Q. HOW WOULD THE EXERCISE OF MARKET POWER BE MANIFESTED IN NORTHERN ILLINOIS?

A. The exercise of market power is usually manifested through physical or economic withholding of capacity from the market. Physical withholding occurs when an owner or owners declare a plant or some portion of a plant unavailable for operation, outside of the approved planned maintenance period. Unplanned extension of an outage could also be used to withhold capacity or energy from a market. Economic withholding occurs when a supplier or suppliers offer in capacity or energy to a market at prices above marginal costs. Either of these two actions can result in market clearing prices that would be higher than what is expected in a competitive market.

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[10] Affidavit of William H. Hieronymus, Triennial Market Power Study Update, Exelon filing to FERC, November 7, 2003. Page 9.

In Northern Illinois, both the spot market and the forward bilateral markets will be influenced by the exercise of market power. For example, auction participants' perceptions of higher spot market prices will lead to higher bilateral market prices, including those negotiated in advance of the auction, reflecting the expectation that spot prices would be high.

Q. WHAT CONDITIONS WILL EXIST IN THE POST-2006 PERIOD THAT CAN EXACERBATE THE POTENTIAL FOR EXERCISE OF MARKET POWER IN THE NORTHERN ILLINOIS REGION?

A. Currently, Exelon is contracted to supply ComEd's BUS needs through December 2006. When this obligation to supply load terminates, Exelon may be able to sell its capacity and energy at market-based rates.[11] As long as this obligation is in place, the high ownership concentration levels in the Northern Illinois region are less likely to lead to market power abuse in the PJM spot markets, since Exelon's Northern Illinois capacity is committed to serving this load. However, once this capacity becomes "uncommitted," Exelon is free to either sell into the spot market or negotiate bilateral sales to market participants, without any oversight of the ICC or FERC (if market-based rate authority is granted and/or renewed by FERC). The current load obligation serves to mitigate the likely exercise of market power; but once the load obligation terminates, effective mitigation ceases and the pricing outcomes in both the spot and the proposed auction process will be subject to "highly concentrated" market forces.

[11] This will depend on the outcome of the current proceeding before FERC where Exelon has requested a renewal of its market-based rate authority, and of any future proceedings that may be required.

Those prices are likely to be greater than would be expected with a fully competitive wholesale market.

Q. WHAT IS THE IMPACT ON COMPETITION NOW THAT THE NORTHERN ILLINOIS REGION IS PART OF THE PJM RTO?

A. The inclusion of the former ComEd and American Electric Power ("AEP") and Dayton Power and Light control areas into the PJM RTO allows for a greater degree of unit commitment and dispatch efficiency in the region, but it does not change the generic structural concerns associated with high concentration in Northern Illinois. Post-2006, when transmission constraints bind "into" the Northern Illinois region, the ability of non-Northern Illinois generators to effectively compete with Northern Illinois generators is eliminated or at least diminished (considerably so for many generators in PJM who are electrically distant from the Northern Illinois region). Thus, the relevant market will still be a subset of the broader PJM RTO market during these times, and it is at these times that market power can be exercised in the region.

IV. INSUFFICIENT COMPETITIVENESS OF THE PJM AND MISO WHOLESALE MARKETS

Q. WHAT ISSUES ARE ADDRESSED IN THIS SECTION OF YOUR TESTIMONY?

A. I address three issues, each of which affects the extent of wholesale market competitiveness in both the Northern Illinois region (within the PJM RTO) and the Southern Illinois region (within the MISO RTO). First, I address my concern that the PJM wholesale energy and capacity markets in the Northern Illinois region are not fully competitive. Next, I address the relative immaturity of the MISO spot energy markets. Lastly, I address the seam that exists between the PJM and MISO regions and the market consequences arising from the existence of such a seam.

Q. WHAT SIGNIFICANCE DO THESE ISSUES HAVE ON THE WHOLESALE MARKET AND THE PRICING OUTCOMES IN THE PROPOSED BUS AUCTION?

A. These three attributes of the regional wholesale market structure lead to less competitive wholesale market prices, thereby exposing BUS customers to prices arising from the proposed auction that will be higher than would be expected with fully competitive wholesale markets.

Q. PLEASE EXPLAIN YOUR CONCERN THAT THE NORTHERN ILLINOIS ENERGY AND CAPACITY MARKET WILL NOT BE FULLY COMPETITIVE IN POST-2006.

A. The high concentration of generation capacity ownership in the Northern Illinois region and the correspondingly high concentration of energy supply ownership will result in time periods when there will be the potential for exercise of market power. In particular, this will occur any time there are binding transmission constraints in the region that effectively prevent non-Illinois PJM suppliers or MISO-region suppliers from competing against Northern Illinois region generation.

During the summer of 2004, energy supplier ownership concentration in the Northern Illinois region was exceedingly high. As I've noted, in the PJM 2004 State of the Market Report, the results for the ComEd region during "Phase 2" of the year (May through September) indicate hourly energy market HHIs ranging from 4,005 to

7,746, with an average of 5,935.[12] These values illustrate that the energy market was "highly concentrated" at that time.

Currently, and during the summer of 2004, ComEd's default load was supplied under forward contract with Exelon, mitigating the potential exercise of market power in the PJM spot markets. Because Exelon has this load obligation, it has a greatly reduced incentive to see higher prices in the region, as during any period in which Exelon's supply is not sufficient to serve ComEd's default load Exelon must purchase from the market.

However, when the high ownership concentration is combined with the loss of Exelon's obligation to supply ComEd's default load, the result is an incentive for higher spot market prices.

Q. BUT THE CONCENTRATION VALUES YOU CITE WERE PRIOR TO AEP'S INTEGRATION INTO PJM. HASN'T THE AEP INTEGRATION CHANGED THE PICTURE?

A. The integration of AEP has only minimally changed the picture. The concentration values cited for the summer 2004 energy market in Northern Illinois reflect the presence of import capacity, including that associated with the "pathway" that existed across the AEP region between Northern Illinois and the rest of the PJM region. However, the underlying concentration levels remain high in the Northern Illinois region even after the integration of AEP.

Q. ARE THE MISO ELECTRICITY SPOT MARKETS IMMATURE?

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[12] PJM 2004 State of the Market Report, page 55.

A. Yes. The Midwest RTO commenced day-ahead and real-time spot electricity market operations on April 1, 2005. For the first two months, all supplier offers into this market were cost-based.[13] Beginning June 1, 2005, all offers into this market will be market-based. Thus at the time of this filing, there will have been just eight days of operation of MISO spot electricity markets using market-based offers from generation suppliers.

Q. WILL THE MISO SPOT ENERGY MARKETS BE MATURE ENOUGH TO ENSURE COMPETITIVE PRICING OUTCOMES BY THE TIME THE PROPOSED PROCUREMENT AUCTION WOULD BE HELD?

A. No. At the conclusion of this proceeding, which I understand to be in early 2006, it will likely be too soon to confirm that even the fundamental MISO systems and software will function as expected throughout all seasonal load and capacity conditions. For example, the accuracy and stability of the locational marginal price ("LMP") pricing outcomes arising from the complex security-constrained economic dispatch algorithms are not readily confirmable, and the programmatic inputs used by MISO to compute LMPs are updated frequently. This is but one reason that at present, the MISO RTO spot energy markets are too immature to draw any conclusions regarding the extent to which they do or do not, and in post-2006 will or will not, reflect competitive pricing outcomes. There are several additional reasons that uncertainty of pricing outcomes is to be expected.

[13] 108 FERC ¶ 61,163, August 6, 2004, P. 63. MISO Energy Market Tariff Approval in Docket ER04-691.

Q. WHAT ARE THE OTHER REASONS THE MISO MARKET IS TOO IMMATURE TO ENSURE COMPETITIVE PRICING OUTCOMES?

A. There are two additional substantive reasons why the MISO spot markets can not be sufficiently relied upon to produce competitive pricing outcomes: i) centralized dispatch operations at the MISO RTO are brand new and cover a wide geographic scope; and ii) the MISO energy markets lack a complementary ancillary service market structure and a comprehensive, MISO-wide approach to resource adequacy concerns.

Q. PLEASE EXPLAIN WHY THE NEWNESS OF THE MISO CENTRALIZED DISPATCH IS A CONCERN.

A. Unlike PJM, New York, and New England, the Midwest ISO has commenced centralized generation unit commitment and dispatch operations with no prior experience, and is doing so in an environment where 35 control areas remain (PJM, New York and New England are each a single control area). While I understand that the Midwest RTO as an institution has apparently made laudable strides in establishing the systems required to operate spot wholesale electric markets, that does not imply that the pricing outcomes in the early years of operation can be predictably free from concern, nor that bidders in any proposed Illinois BUS auction would expect those spot markets to so operate.

Q. PLEASE EXPLAIN WHY THE LACK OF STRUCTURED ANCILLARY SERVICE MARKETS IS A CONCERN.

A. The Midwest RTO markets lack centralized operating reserve markets, and a capacity market structure, features of the PJM RTO markets. The presence or absence of these ancillary markets impact the pricing outcomes in the energy market, especially the relationship between regulating resources, spinning and near-term non-spinning operating reserves, and the pricing of energy.

Q. WHEN WILL THERE BE STRUCTURED ANCILLARY SERVICE MARKETS IN THE MISO REGION?

A. It is very difficult to say when structured ancillary service markets will be operational in MISO. MISO has just this spring established an ancillary services task force reporting to the markets subcommittee. One startup document states that a regulation market is planned for the end of 2005 and an operating reserves market is planned for the first quarter of 2006.[14] Another document states that the ancillary services task force will sunset when the ancillary service markets are operational in 2007.[15] In other RTO regions, ancillary service markets have undergone considerable change over many years of evolution.[16]

Q. WHAT IS REQUIRED TO ESTABLISH CONFIDENCE THAT THE MISO SPOT MARKETS WILL PRODUCE COMPETITIVE WHOLESALE MARKET PRICING OUTCOMES?

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[14] MISO ancillary services task force presentation, March 15, 2005.

[15] MISO Ancillary Services Task Force Charter Document, dated April 1, 2005, page 1, "Sunset Provisions." Part of meeting materials of April 4, 2005 MISO Market Subcommittee meeting.

[16] PJM, New England, New York, and California have all experienced considerable difficulty in establishing stable and efficient ancillary service market structures.

A. In short, time -- on the order of years. At least two threshold milestones should be met before the MISO spot market pricing outcomes can be considered competitive. First, an independent evaluation of the pricing outcomes of the market over all seasons and the most common load/supply conditions is required. For example, such an evaluation could determine the price-cost markup present in the market as a measure of its competitiveness. Second, given the impact of local ancillary service markets on unit commitment and dispatch, it would be preferable to have at least one year of energy market operation after incorporation of ancillary service features into the MISO markets structure.

Q. WHAT IS THE PJM-MISO SEAM?

A. The PJM-MISO seam consists of the physical transmission interconnections between the two RTOs. This seam spans over one hundred interconnection points with a nominal non-simultaneous transfer capability on the order of at least 60,000 MW.[17] Exhibit 1.3 visually depicts the boundaries of the Midwest RTO and the PJM RTO in the Illinois region, and the thick solid black line shows the complex and discontinuous seam between the RTOs.

Notionally, however, the seam consists of any impediments load or generation may face in trying to buy or sell energy, capacity, or ancillary services across the boundary. These impediments prevent a seamless integration of wholesale energy markets between northern Illinois (PJM region) and southern Illinois (MISO region).

[17] FERC Docket EL02-65-000, Affidavit of Ronald R. Jackups, filed July 9, 2002. An affidavit by Mr. Ronald Jackups of Cinergy, filed on behalf of certain MISO transmission owners, stated that the seam between MISO and PJM (when Illinois Power was still planning on joining PJM) consisted of 139 interconnections totally 72,400 MVA of capacity (paragraph 15, page 3). Illinois Power has since been acquired by Ameren

The impediments include the day-to-day operational hurdles the RTOs must overcome to allow efficient transactions between the regions, and they include the existence of different energy, capacity, and ancillary service market structures between the regions.

Q. HOW DOES THIS SEAM IMPACT ILLINOIS' ELECTRICITY CONSUMERS?

A. Illinois consumers will be impacted by any wholesale market attributes that arise due to the presence of this seam. As shown in Exhibit 1.3, the seam particularly impacts Illinois, as it slices through the state and leaves approximately two-thirds of the consumers on one side (Northern Illinois) and the remaining third on the other side (Southern Illinois). Thus, two-thirds of the customers will be impacted by wholesale market activity in the western portion of PJM, and one-third of the customers will be impacted by wholesale market activities in central MISO.

Q. HOW DID THIS SEAM ARISE?

A. The seam arose due to the RTO choices made by a number of companies, in particular the choices of ComEd, AEP, and Dayton Power and Light to join PJM rather than MISO. If these companies had chosen to join MISO instead of PJM, it has been argued that the electrical seam would have been much smaller between the two

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and is part of MISO. Subtracting out the direct interconnections between Illinois Power and MISO will conservatively leave at least 60,000 MW of nominal interconnection capacity across the seam.

regions.[18] If they had joined MISO, all of Illinois would have been included under the umbrella of a single RTO.

Q. WAS FERC'S APPROVAL OF COMED JOINING THE PJM RTO CONDITIONED ON RESOLUTION OF TRANSACTION ISSUES ACROSS THIS SEAM?

A. Yes. FERC explicitly called for the formation of a "joint and common market" in its order conditionally approving ComEd's joining of PJM.[19] FERC recognized the importance to regional wholesale market development of resolving the problems created by the existence of this seam. Notwithstanding FERC's condition, PJM and MISO currently still have separate energy markets (and separate provisions for ancillary services and capacity requirements). There is no joint and common market.

FERC's call for a joint and common market was and is aimed at allowing free flowing competition between generators on one side of these lines, and load on the other side of these lines and resolving the complex dispatch and commitment issues that effect each RTO due to the presence of transmission line electricity flows created by suppliers and load in the adjacent region (i.e., "loop flows").

The way in which increased wholesale market competition is projected to come about is through greatly improved dispatch coordination mechanisms used by each of the RTOs on a daily basis. If or when these coordination mechanisms are perfected, in theory each RTO can serve as another source of generation (possibly

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[18] Jackups affidavit, paragraphs 15 and 27, for example. See also the "RTO Configuration Letter" from MISO Market Monitor David Patton to MISO CEO James Torgerson, July 10, 2002.

[19] 100 FERC ¶ 61,137 (July 31, 2002), P. 37-41.

less expensive) that can be used to relieve transmission constraints in the neighboring RTO. While the RTOs claim that much progress has been made towards implementing the required data, communications, and modeling capabilities to put this coordination in action, it nonetheless is projected that the earliest a joint and common market would be ready is September 2007.[20] Given the history of initiating complex RTO coordination mechanisms[21], and the unprecedented scale of the seams coordination proposed for this seam, I believe it is unlikely that the joint and common market that FERC predicated ComEd's PJM RTO participation on will be in place at that time. Thus, well after the date of the proposed auction, it is likely that major seams issues will remain unresolved, negatively impacting the competitiveness of the wholesale markets on either side of the seam.

Q. WHAT IS THE IMPACT TO THE WHOLESALE MARKET OF UNRESOLVED SEAMS ISSUES?

A. The main impact is less efficient energy transactions between the two RTO regions, resulting in greater overall production costs for energy than would be required if a single common market was in place, and likely "distorted" LMPs, or deviations from LMPs that would be expected if a common market were functioning and coordination between RTOs was comprehensive. While PJM and MISO will likely eventually resolve the technical issues to ensure such coordination, it may well be 2008 or beyond before such resolution is assured.

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[20] MISO and PJM joint filing to FERC, FERC Order in Dockets No. ER04-375-17 and ER04-375-18, Order Modifying and Accepting Tariff Filing, Paragraph 64, March 3, 2005.

Q. WILL THE NORTHERN AND SOUTHERN ILLINOIS REGION SPOT MARKETS BE LESS COMPETITIVE BECAUSE OF THE EXISTENCE OF THIS SEAM?

A. Yes, considerably so. The presence of the seam prevents dispatch coordination that would give rise to load diversity gains, production cost improvements, increased unit commitment economies, better ancillary service coordination and greater supply competition. All of those features of broader markets result in reduced prices for any consumer depending on market pricing outcomes.

V. FERC MARKET-BASED RATE AUTHORITY

Q. WHAT ISSUES DO YOU ADDRESS IN THIS SECTION OF YOUR TESTIMONY?

A. I examine FERC's current "interim" methods for evaluating whether or not a supplier should be granted wholesale market-based rate authority, or the ability to sell into wholesale electricity markets in the US at whatever price the market will bear.[22] I also describe the current process whereby FERC is evaluating whether it should consider changing its interim analytical approach to considering market-based rate applications from wholesale suppliers.

Q. HOW DOES THIS RELATE TO WHOLESALE MARKET COMPETITIVENESS IN THE NORTHERN ILLINOIS REGION?

[21] FERC initially required PJM and MISO to operate a joint and common market commencing October 1, 2004. It has taken a significant amount of time and resources to come to agreement on a "Joint Operating Agreement", let alone implement the systems required to create a joint and common market.

A. Any supplier in PJM granted market-based rate authority could, legally, exercise market power (to a certain extent). Thus, whether or not a supplier has FERC approval for market-based rate authority is critical to assessing whether or not the Northern Illinois region of the PJM market might be competitive post-2006: if Northern Illinois suppliers with the potential to exercise market power are granted market-based rate authority, then the only remaining obstacle to exercise of market power is the limited ability of the PJM RTO to mitigate such exercise.

The fact that FERC is currently re-evaluating its "interim" rules used to grant or deny market-based rate authority is telling. This uncertainty concerning how federal regulators will evaluate market power in the PJM region post-2006 is another reason for the ICC to reconsider the use of market-based methods to secure BUS supplies post-2006.

Q. HOW DOES THE FERC ADDRESS WHOLESALE MARKET POWER IN US ELECTRICITY MARKETS?

A. FERC evaluates market power in proposed mergers; grants or denies "market-based rate authority" to wholesale market supplier applicants; oversees cost-based rates for wholesale energy transactions; and oversees ISO and RTO market monitoring and mitigation functions.

Q. WHAT MECHANISMS DOES FERC CURRENTLY USE TO REVIEW WHETHER A COMPANY HAS GENERATION MARKET POWER WHEN

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[22] 107 FERC ¶ 61,018, Order on Rehearing and Modifying Interim Generation Market Power Analysis and Mitigation Policy, April 14, 2004. And, 107 FERC ¶ 61,026, Order on Rehearing, July 8, 2004.

DETERMINING IF IT SHOULD GRANT MARKET-BASED RATE AUTHORITY?

A. FERC currently uses two indicative screens to test whether or not an applicant may have the potential to exercise generation market power.[23] Those tests are known as the uncommitted capacity pivotal supplier test, and the uncommitted capacity market share test. Uncommitted capacity refers to a supplier's capacity net of native load obligations. The pivotal supplier test examines whether or not a company's uncommitted capacity is pivotal to serving a region's peak load. It is designed to address the potential exercise of market power during a region's peak period. The market share test examines whether or not a company's market share exceeds 20% in each of four seasons, accounting for planned outages in each of the seasons. It is designed to address more broadly the ability for a company to exercise market power at various times throughout the year. A rebuttable presumption that a company does not have market power is established if a company passes both the pivotal supplier screen and the market share screen in all four seasons. Conversely, a rebuttable presumption is established that a company does have the ability to exercise market power if it fails either the pivotal supplier screen or the market share screen in any of the four seasons.

Q. ARE THESE TESTS DEFINITIVE DETERMINATIONS OF MARKET POWER?

[23] FERC examines three other "prongs" when reviewing a market-based rate application: transmission market power, affiliate abuse or reciprocal dealing, and if an applicant can erect barriers to entry.

A. No. They are designed primarily to screen out those companies that clearly are small and not likely to be pivotal. It is possible that a company that passes both tests could still have the potential to exercise market power.

Q. DOES EXELON CURRENTLY HAVE FERC-APPROVED MARKET-BASED RATE AUTHORITY?

A. Yes. However, FERC is currently examining Exelon's application for retention of that authority. Exelon submitted in September of 2004[24] an update to its "Triennial Market Power Study Update" which was submitted in November of 2003.[25] The November 2003 submission was in compliance with FERC policy that requires an updated market power analysis every three years. Since Exelon submitted that analysis, FERC issued an Order revising its methods for analyzing market power potential, and required Exelon to submit an update to its triennial filing. Exelon's September 2004 application to FERC was deficient, and FERC required Exelon to submit additional materials, which Exelon completed on May 23, 2005. The outcome of that proceeding is pending.

Q. IF FERC APPROVES EXELON'S APPLICATION TO RETAIN ITS MARKET-BASED RATE AUTHORITY, DOES THAT IMPLY THAT THE WHOLESALE MARKETS IN NORTHERN ILLINOIS POST-2006 ARE COMPETITIVE?

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[24] Exelon Filing to FERC, ER97-3954-017 et al., *Filing in Compliance with Orders on Rehearing in FERC Docket No. PL02-8*, September 27, 2004.

[25] Exelon Filing to FERC, ER00-3251-005 et al., *Triennial Market Power Study Update*, November 7, 2003.

A. No. Exelon's current application reflects its contract obligation to supply ComEd default load through 2006. Each of FERC's two indicative screen tests embodied in its analysis of an applicant's potential to exercise market power examines uncommitted capacity, or the generation capacity net of native load and long-term contract commitments. Post-2006, these commitments no longer are in force and Exelon's uncommitted capacity will increase substantially. Also, Exelon's proposed merger with PSEG is pending. If that merger goes forward, Exelon's capacity ownership concentration in PJM will increase considerably.

Q. WHAT MITIGATION OPTIONS EXIST IF A SUPPLIER HAS THE ABILITY TO EXERCISE MARKET POWER?

FERC has indicated that it could apply case-specific mitigation options and that applicant companies can propose mitigation options. FERC's default mitigation option would be for Exelon to sell power at cost-based rates.

Q. DOES MIDWEST GENERATION CURRENTLY HAVE MARKET-BASED RATE AUTHORITY FROM FERC?

A. Yes. FERC approved Midwest Generation's application for market-based rate authority on April 14, 2005.[26]

Q. PLEASE SUMMARIZE THE STATUS OF EXELON AND MIDWEST GENERATION'S MARKET-BASED RATE AUTHORITY AND WHAT IT MEANS FOR NI POST-2006.

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[26] FERC Order Accepting Updated Market Power Analysis, April 14, 2005, Docket No. ER99-3693-001 et al.

A. Midwest Generation currently has market-based rate authority from FERC. Exelon is likely to obtain such authority given the structure of FERC's pivotal supplier and market share indicative screens, which use an "uncommitted" capacity metric based on January 1, 2005 data.[27] However, in both cases the authority granted is premised on conditions that will not be in place in Illinois post-2006. Post 2006, Exelon's obligation to serve a large portion of ComEd load and Midwest Generation's obligation to sell a significant portion of its output to Exelon will no longer be in place. Each of the companies will have an increased level of uncommitted capacity post-2006 compared to the levels examined by FERC in the recent (Midwest Generation) and pending (Exelon) market-based rate authority applications. Also, if Exelon's pending merger with PSEG occurs, Exelon's capacity share in PJM will increase. Lastly, the criteria used by FERC to assess market power are undergoing review and may change.

Q. DOES FERC-GRANTED MARKET-BASED RATE AUTHORITY DEFINITIVELY ESTABLISH WHETHER OR NOT AN APPLICANT HAS THE ABILITY TO EXERCISE MARKET POWER IN NI POST-2006?

A. No. Applicants may need to re-apply if the conditions under which approval was granted change significantly. FERC is also currently examining the method it uses to analyze market power and grant or deny market-based rate authority. The current method, which was approved in the aforementioned FERC Orders in April and July of 2004, is an "interim" solution; and FERC initiated its current examination in a

[27] Exelon FERC filing in Docket No. ER00-3252-007 et al., William H. Hieronymus Affidavit, May 23, 2005, page 2.

companion order to the April 2004 ruling.[28] Thus, the underlying analytical method on which FERC grants or denies market-based rate authority may change (and even under the current interim rules applicants may need to re-apply).

Q. HOW MIGHT THE CURRENT INTERIM RULES CHANGE?

A. One possible option is that FERC may require forward-looking modeling to determine if strategic behaviors result in market price outcomes that exceed certain thresholds. For example, a common indicator of the extent to which market power is being exercised is the increase in prices above marginal cost that exists in a market, referred to as the Lerner Index. A modeling exercise simulating strategic offer behavior by a generator or multiple generators could determine the Lerner Index for a number of scenarios.

Q. WHAT ARE OTHER REASONS WHY FERC MARKET-BASED RATE AUTHORITY FOR EXELON AND MIDWEST GENERATION DOES NOT ESTABLISH THE POTENTIAL FOR MARKET POWER TO BE EXERCISED IN THE REGION?

A. FERC's current methodology allows each of Exelon and Midwest Generation to use the entire "expanded" PJM RTO as the geographic scope of the market into which they sell. This explicitly biases the results of any applicant's market share or degree to which it is pivotal in favor of the applicant, as it greatly increases the total competing generation even though there are times when non-Northern Illinois PJM RTO based generation supplies cannot effectively compete with NI generators in the

[28] *Initiation of Rulemaking Proceeding on Market Based Rates and Notice of Technical Conference*, April 14,

PJM RTO spot markets. The method does not take into account the time period when transmission constraints bind within the PJM RTO region, as I've noted previously in this testimony. Instead, FERC's rules allow the RTO's mitigation policy to act as a check on market power.

Q. DO RTO RULES ALLOW FOR THE EXERCISE OF MARKET POWER?

A. Yes. For example, PJM allows supplier offers above marginal cost for any generator as long as there are no binding transmission constraints or if there are binding constraints and a sufficient number of competing generators available to relieve those constraints. If there are binding transmission constraints and an insufficient number of competing generators are available to relieve those constraints, PJM still allows offer prices up to 110% of marginal cost. MISO rules allow for the exercise of market power unless certain, relatively generous "offer" price thresholds and price impact thresholds are met, as I describe in the following section.

Q. WHAT DOES THIS MEAN?

A. It means that in less than fully competitive markets, it is legal for suppliers to act in a manner that could result in clearing prices higher than the level that would be seen in fully competitive markets.

2004, Docket No. RM04-7-000.

VI. RTO MARKET POWER MITIGATION CONCERNS

Q. PLEASE SUMMARIZE THE SALIENT ASPECTS OF THE MARKET POWER MITIGATION STRUCTURE IN PLACE IN PJM AND MISO.

A. PJM and MISO each have separate market power mitigation protocols in place. PJM's market power mitigation consists primarily of the ability to "offer price cap" generation suppliers to one of four possible levels when local transmission constraints are binding and an insufficient number of suppliers exist to relieve the constraint.[29] A commonly understood offer-cap level is 110% of the incremental operating cost of the resource; alternatively, the level could be equal to a weighted LMP, or an agreed-upon level between the owner and PJM. If a resource is considered "frequently mitigated", or offer-capped for more than 80% of its run hours, then the offer cap consists of incremental costs plus the higher of $40/MWh or an agreed-upon amount between the owner and PJM.

The mitigation protocol in MISO is different from that in PJM. MISO imposes offer-price mitigation only if offer price and market impact thresholds are violated. MISO defines two areas: broadly constrained area (BCA) and narrowly-constrained area (NCA) within which its mitigation protocols apply. Within BCAs, if a transmission constraint is binding, MISO will screen offer prices and if they are below the threshold of 300% of the "reference level" offer price (a marginal cost

[29] Currently, the PJM tariff states "Offer price caps shall be suspended for any transmission limit(s) for any hour in which there are not three or fewer generation suppliers available for re-dispatch under subsection (a) that are jointly pivotal with respect to such transmission limit(s). Notwithstanding the number of jointly pivotal suppliers in any hour, if the Market Monitoring Unit determines that a reasonable level of competition will not exist based on an evaluation of all facts and circumstances, it may propose to the Commission the removal of offer-capping suspensions otherwise authorized by this section."

based metric) or $100/MWh, whichever is lower, then no action is taken. Within NCAs, the threshold is lower; it is tied to the cost of a new peaking unit in the area. At present, for market-based price offerings commencing June 1, 2005 in MISO, the NCA threshold above reference level is approximately $37/MWh.[30]

Q. WHAT ARE THE WEAKNESSES AND LIMITATIONS OF THE PJM MARKET MONITORING AND MITIGATION TOOLS AND CAPABILITIES?

A. Primarily, PJM is limited to offer-capping suppliers at 110% of marginal costs, even if such an offer cap results in a greater return to the supplier than would be expected in a fully competitive market. The ten percent adder is somewhat arbitrary and it has not been definitively shown that a lower level would not result in outcomes more closely approximating fully competitive markets. Also, there is currently uncertainty in whether or not an additional offer capping exemption will be granted for any major constraints in the PJM West region, which consists of the ComEd, AEP, Dayton Power and Light and Allegheny Power areas. This would result in a reduced ability for the PJM market monitor to impose mitigation in the PJM West region when certain transmission constraints are binding. Also, there is uncertainty around the extent to which PJM can use its “no three pivotal suppliers” test to determine if mitigation can be used when certain transmission constraints bind.

[30] MISO email on May 26, 2005 to all participants.

Q. WHAT ARE THE WEAKNESSES AND LIMITATIONS OF THE MISO MARKET MONITORING AND MITIGATION TOOLS AND CAPABILITIES?

A. The ability of the MISO market monitor to impose mitigation is even more limited than the authority of the PJM market monitor. In most of the MISO region, there is no mitigation at all unless the offer prices of a generation supplier exceed either 300% of the “reference level” or $100/MWh, whichever is lower.

Q. WHAT IS THE IMPACT OF HAVING RELATIVELY WEAK AND LIMITED MARKET POWER MITIGATION TOOLS AVAILABLE TO THE PJM AND MISO MARKET MONITORS?

A. The result is a reduced ability to ensure that market price outcomes are competitive.

Q. IN WHAT WAYS SHOULD THE MARKET POWER MITIGATION TOOLS BE STRENGTHENED IN THE PJM AND MISO REGIONS?

A. The best way to address the presence of market power in wholesale markets is to ensure a competitive market structure, which results in a reduced need to impose mitigation solutions. However, absent a fully competitive structure – i.e., a structure with reduced supplier ownership concentration – mitigation that results in market prices that reflect a competitive outcome is required. To achieve this result, the 10% adder used in PJM should be lowered, recognizing that a just and reasonable rate of return to wholesale suppliers could result with mitigation that lowers the cap to values closer to 100% of marginal costs, since capacity markets exist in PJM to provide return to fixed costs associated with generation assets.

In MISO, the imposition of mitigation should be triggered in a manner similar to PJM – e.g., when transmission constraints bind and limit the available of suppliers, offer capping at a level at least equal to PJM's 110% protocol should be required if there are less than four pivotal suppliers. As MISO develops a more uniform approach to resource adequacy, then its mitigation protocol should be adjusted closer to 100% of marginal costs.

Q. PLEASE SUMMARIZE THE MAIN CONCLUSIONS YOU DRAW FROM YOUR EXAMINATION OF WHOLESALE ELECTRICITY MARKETS IN NORTHERN ILLINOIS.

A. High generation ownership concentration levels, coupled with the termination of Exelon's obligation to serve ComEd BUS load, will lead to the potential for exercise of market power in the Northern Illinois region. This wholesale market structure flaw, combined with immature MISO markets and the presence of a market "seam" between the NI and Southern Illinois regions will result in less than fully competitive wholesale markets in Illinois. The proposed ComEd BUS procurement auction can only be successful if the foundation of a fully competitive wholesale market exists. Thus, even if a superior auction mechanism was devised, until the regional wholesale markets are competitive it is likely that resulting prices to consumers will be higher than necessary.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

Northern Illinois Installed Capacity Market Concentration

Without Imports

	Nameplate Capacity (MW)	Capacity Share	Capacity Share Squared	
ExelonGen	11,426	37.5%	1,403	
Midwest Gen	6,539	21.4%	459	
Ameren	540	1.8%	3	
ArcLight	692	2.3%	5	
Calpine	644	2.1%	4	
Constellation	342	1.1%	1	
Dom/Peoples	1728	5.7%	32	
Dominion	1932	6.3%	40	
DTE	356	1.2%	1	
Duke	814	2.7%	7	
Dynegy	1465	4.8%	23	
Exel/Peoples	407	1.3%	2	
MidAmerican	691	2.3%	5	
NRG	732	2.4%	6	
PPL	540	1.8%	3	
Reliant	1275	4.2%	17	
Tenaska	386	1.3%	2	
	30,509	100%	2,015	HHI

With Imports

	Nameplate Capacity (MW)	Capacity Share
ExelonGen	11,426	32.5%
Midwest Gen	6,539	18.6%
Other NI Suppliers	12,544	35.6%
Imports	4,700	13.3%
	35,209	100%

<u>FTC Merger Guidelines - HHI Concentration Index</u>

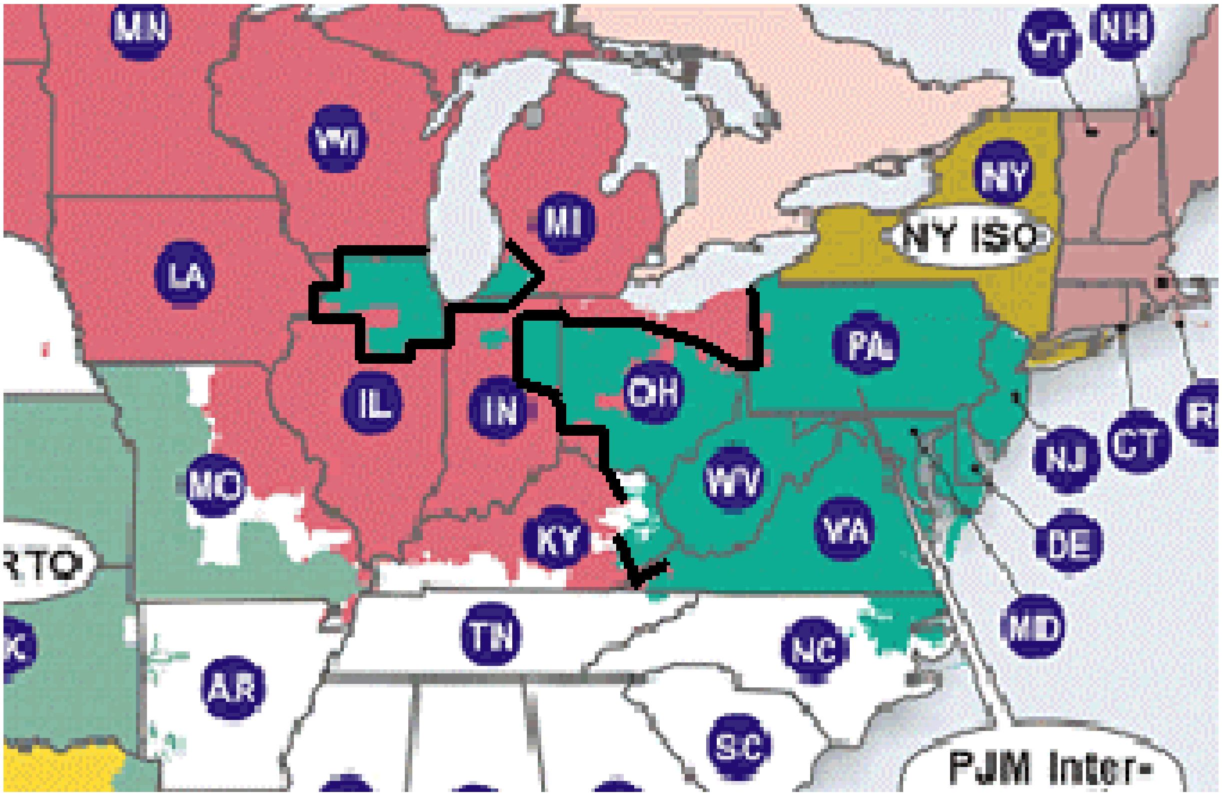
Below 1000	Unconcentrated
1000-1800	Moderately Concentrated
Above 1800	Highly Concentrated

Data Sources:

Supplemental Affidavit of William H. Hieronymus, Exelon Filing to FERC 5/23/05, Exhibit EXE-3, EXE-4 (capacity values).

Affidavit of William H. Hieronymus, Triennial Market Power Study Update, Exelon Filing to FERC, 11/7/2003, page 9 (import capacity).

PJM – MISO Seam



Original Image Source: FERC, "Existing and Proposed RTOs and ISOs, from Platts POWERmap, March 3, 2005

Currently:

- Electrical boundary between the PJM and MISO RTOs.
- Consists of over one hundred electrical interconnections between MISO and PJM companies, at transmission voltage levels.
- Approximately 60,000 MW interconnected capability (contrast: ~3,000 MW connected capability between PJM and the NY ISO)
- Energy transfers across the seam monitored by PJM and MISO RTOs.
- MISO and PJM control their own generation output to ensure no violation of transmission constraints within each of their own regions.

Planned:

- Generation control to be coordinated between MISO and PJM to allow for "cheapest" "redispatch" to prevent transmission constraints from binding.
- Ultimately, a "joint and common market" will result from full-scale coordination.
- This will help to minimize market power concerns by allowing more generation from one region to more closely compete against generation from the adjacent region.