

**2004 STATE OF THE MARKET REPORT**  
**MIDWEST ISO**

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Independent Market Monitor  
for the Midwest ISO

June 2005

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## I. Executive Summary

This report evaluates the state of the Midwest ISO wholesale electricity markets in 2004. The Midwest ISO began operation in February 2002, implementing its open access transmission tariff. Its primary functions since that time, including in 2004, have been the administration of regional transmission service and reliability coordination among formerly independent transmission owners. During 2004, intense preparations continued for the start of day-ahead and real-time locational margin price (“LMP”) energy markets that began April 1, 2005 (“the LMP markets”). Midwest ISO-facilitated operating reserves and other ancillary services markets may be developed later. The LMP energy markets allow the Midwest ISO to efficiently manage transmission congestion and set transparent market-clearing prices at each location on the network.

Because the Midwest ISO did not operate LMP markets during 2004, the focus of this report is on:

- The characteristics and operations of the bilateral markets as they existed in the Midwest ISO region in 2004;
- The existing supply and demand characteristics in the Midwest;
- The Midwest ISO’s provision and coordination of transmission service; and
- The Midwest ISO’s operations as reliability coordinator for the Midwest.

As will be explained herein, many of the issues that confront the Midwest ISO under its administration of its transmission tariff in 2004 will be substantially diminished in importance under the LMP markets.

### ***Supply Conditions in 2004***

The Midwest ISO “footprint” currently contains about 130,000 MW of generating capacity (including only the transmission owners that are members under the current LMP markets). The generator fuel mix in the Midwest ISO is dominated by coal-fired resources, accounting for almost 60 percent of the capability. Most of the recent investment has been in natural gas resources, which currently account for 20 percent of

the capability in the region. The Midwest region relies very little on hydroelectric resources (less than 10 percent of the total capability) relative to other regions.

One important statistic to track as an indication of the adequacy of the resources in the Midwest to meet the demand in the region is the resource margin, which is defined as the percentage by which resources exceed peak load. In 2004, the resource margin in the Midwest ISO area was 26.7 percent. This represents an increase of 2.5 percentage points from 2003, which is due to the fact that slightly more new capacity was added to the system than the increase in load. This level indicates a surplus of generating resources, although the peak demand conditions in 2004 were relatively mild and contributed to the higher resource margin.

We also calculated the resource margin in each of the Midwest ISO sub-regions, dividing the Midwest ISO into four sub-regions: ECAR, MAPP, MAIN (excluding WUMS), and WUMS. The designation of these sub-regions corresponds to major transmission areas in the Midwest ISO. In the four sub-regions, the resource margins range from 23 percent to 30 percent. The resource margin is lowest in WUMS at 23 percent. This represents an increase from 2003, which is primarily due to lower peak loads that occurred in this area in 2004. Low resource margins in WUMS would be of particular concerns because the transmission capability from other regions is limited. In addition, WUMS relies on a relatively large amount of firm imports to satisfy its load. However, the resource margin in 2004 indicates that resources are currently adequate to serve the load in that area.

The resource margins shown above are based on the full capability of the resources in the Midwest ISO area. However, resources are frequently unavailable or derated due to planned or forced outages. The average percent of capacity out of service in 2004 was 11 percent, of which almost two-thirds was the result of planned outages. The outages peaked in the spring and fall months and were the lowest in January and the summer months as expected because suppliers generally scheduled planned maintenance during off-peak periods. The forced outage rates continued to be very low, averaging 4.5 percent according the data from the Midwest ISO's outage scheduling system. However, NERC generation availability data indicates a forced outage rate for the Midwest ISO

area of more than 6 percent, which is closer to historical averages. This indicates that suppliers may not be reporting all of their forced outages. As the Midwest ISO becomes increasingly responsible for generator commitment and dispatch under the LMP markets, it is important that forced outages be fully and accurately reported. Hence, we will continue to monitor this issue and may recommend that the Midwest ISO consider administrative sanctions to enforce its reporting requirements if this pattern continues under the LMP markets.

The final analysis of the supply in the Midwest ISO area is an analysis of market concentration, as measured by the Herfindahl-Hirschman Index (“HHI”). The HHI is calculated by summing the square of each participant’s market share. Economists use this statistic to assess the overall competitive structure of a market, although it cannot be used to draw definitive competitive conclusions for reasons discussed in the report. Our analysis in this area shows:

- The market concentration in WUMS exceeds 2600, indicating that the market in WUMS is highly concentrated. The antitrust agencies generally define markets with HHI levels higher than 1800 to be highly concentrated.
- The market concentration in the other Midwest ISO sub-regions is in the moderately concentrated to un-concentrated range, i.e., less than 1800.
- The overall concentration in the entire Midwest ISO, which is the relevant market when transmission constraints do not isolate sub-regions or local areas, is less than 400.

#### ***Midwest ISO Load Patterns in 2004***

The growth and changes in the pattern of the loads in the Midwest ISO are an important determinant of the outcomes of the bilateral electricity markets and the patterns of congestion that occurred in the Midwest in 2004. Both the peak and average loads are important. The peak loads are those that contribute to the tightest market conditions and

the highest prices. However, the average loads are a more important determinant of the average prices that prevail over the year.

The Midwest ISO system-wide peak was in July, at close to 104,000 MW with a secondary peak in August. While some of the individual control areas in the Midwest ISO experienced peaks in the winter, all of the individual sub-regions have summer peaks. The weather conditions during the summer in 2004 were relatively mild, which contributed to lower peak load conditions. However, average demand in the Midwest ISO area continued to increase at a steady rate, increasing 2.4 percent from 2003 to 2004.

### ***Wholesale Market Prices in 2004***

The Midwest ISO wholesale market for energy was confined to bilateral trading in 2004. We evaluated bilateral energy price survey data and found prices to be closely correlated with input costs and load levels. Prices for coal and oil rose significantly during 2004. In particular, the spot price for coal was more than 60 percent higher in December 2004 than in December 2002. However, natural gas prices, while fluctuating over the course of the year, exhibited only a slight increase. Due primarily to these increases in fuel prices, day-ahead bilateral electricity prices rose by more than 25 percent from 2003.

Our analysis assessing how accurately prices reflected transmission congestion during 2004 continues to indicate that the current bilateral energy prices do not fully or accurately reflect transmission congestion in the Midwest region. This conclusion supports the Midwest ISO's move to LMP markets, which should provide more accurate and transparent price signals. Because these signals direct both short-term generation commitment and dispatch decisions and long-run investment and retirement decisions, the LMP spot markets promise substantial efficiency benefits for the region both in the long run and the short run.

### ***Assessment of Transmission Service***

Our analysis of requests for and approvals of transmission service indicates that approval rates have remained at relatively high levels during 2004. The relatively high approval

rates build on increases in approval rates during 2003. We also examine short-term and long-term approvals separately and we find that transmission service has been adequately available to participants.

We analyze various practices associated with transmission requests and scheduling to identify potential competitive and efficiency concerns. Based on this analysis, we identify three practices that give participants a call option on transmission and restrict its availability to others:

- (1) *Submitting multiple long-term service requests for expiring long-term service to prevent rivals from competing for the service.* The queuing procedures do not prevent a participant from submitting these “self-competing” requests and Order 888 does not allow the Midwest ISO to auction the service on constrained interfaces to ensure it can be acquired by those that value it the highest.
- (2) *Postponing the confirmation of approved transmission service (including failing to confirm the service).* From the time a request is made, the capability is removed from the market so it is unavailable to others. If the request is approved, it remains unavailable to others while the Midwest ISO waits for the participant to confirm it. If it ultimately does not confirm the service, it will have had a free call option on the transmission without making any payment. Depending on the timing of the request, other suppliers may not have the opportunity to utilize the capability once it becomes available again. Hence, although giving participants time after the acceptance of the request to confirm the service provides participants valuable time to arrange power sales, it also introduces the possibility that a participant can make excessive reservations in order to tie up transmission capability. However, our investigation indicates that this has not been a significant problem.
- (3) *Over-designation of network resources.* We find that some customers over-designated network resources in 2004, which reduces the available transmission capability for others. We find that this over-designation substantially reduced the available capability on a number of the Midwest ISO transmission paths. The introduction of LMP markets will eliminate the effect of the over-designations on the utilization of the internal transmission capability because the central dispatch by the LMP markets fully utilizes the physical capability of the system.

The transmission issues related to these three issues have largely been eliminated for the internal Midwest ISO interfaces with the introduction of the LMP markets in April 2005. Nevertheless, it is important to recognize that most of the improvements to the open access tariff that could have been made to address these issues were restricted by the requirements of Order 888 or subsequent Commission decisions. To the extent that the



Commission considers modifications to the open access requirements under Order 888, we would recommend that the Commission consider allowing changes to utilities' open access tariffs that would address these issues. For example, some changes that could be considered include:

- Allowing transmission providers to wait to reduce their ATC until requests are confirmed to address the second issue.
- Restricting the quantity of network resources that can be designated relative to a participant's peak load and requiring all designations, including the transmission provider's own resources, to be made through the OASIS.
- Allowing RTOs to establish a market-based price for their services when the demand exceeds the available supply (e.g., conducting an auction for the capacity).

In a further assessment of transmission service, we also examined the practice of "redirecting" transmission reservations (which allows a re-designation of the original firm source-sink pair to a lower-priority service on an alternative source-sink pair). The practice of redirecting transmission reservations has efficiency benefits, but can also raise concerns if the service is redirected to an affiliate because the transmission revenue is redirected along with the service. While the incentive exists, our analysis does not indicate that it has been a significant problem in 2004.

### ***Midwest ISO Operations***

As the reliability coordinators for the Midwest, the Midwest ISO manages transmission congestion through the NERC Transmissions Line Relief ("TLR") Procedures.<sup>1</sup> Under these procedures, the Midwest ISO monitors real-time flows on flowgates relative to their operating limits. When a flowgate exceeds its limit or is expected to exceed its limit (based on next hour scheduled transmission service, current hour ramping schedules, or other factors), security coordinators will invoke a TLR under these procedures to reduce line loadings.

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<sup>1</sup> See NERC Policy 9 and Appendices 9C1, "Transmission Loading Relief Procedure – Eastern Interconnection"; 9C1B, "Interchange Transaction Reallocation During TLR Levels 3a and 5a"; 9C1C, "Interchange Transaction Curtailments During TLR 3b"; and the "Parallel Flow Calculation Procedure Reference Document".

The TLRs called on Midwest ISO flowgates accounted for more than one-half of all TLRs called in the Eastern Interconnect. This is a considerable share of total TLR events and can be explained by the fact that much of the Eastern Interconnect is operated under LMP or other central markets that redispatch generation to manage congestion rather than using TLR procedures. The report shows the following trends in the TLR activity in 2004.

- Although overall TLR activity was comparable in 2003 and 2004, the Level 5 TLRs that result in curtailment of firm transactions and network service decreased substantially in 2004. This is largely due to outages in WUMS in 2003 that resulted in a large number of Level 5 TLRs.
- The total TLR events in WUMS decreased in 2004 from 2003. However, the WUMS region continued to experience more TLRs than any Midwest ISO region.
  - This is consistent with expectations because WUMS relies heavily on imports and has limited transfer capability from neighboring regions.
  - A large share of the Level 4 TLR events in WUMS reflect the use of American Transmission Company's redispatch process, which does not result in transaction curtailments.
- ECAR experienced a large increase in TLR hours in 2004. A primary cause of this increase was the PJM integration of CE and AEP.
  - When AEP was integrated in October of 2004, generation on the CE system was dispatched at higher levels to replace higher-cost power in eastern PJM. This resulted in increased congestion in Northern Indiana.
  - While this increased congestion in some of the Midwest ISO control areas, imposing costs on market participants as a result of curtailments, it also increased the utilization of the transmission capacity in the Midwest.

Beyond reviewing and summarizing the TLR patterns, we analyzed the TLR events to assess the Midwest ISO's operations as reliability coordinator for the Midwest and evaluate the overall efficiency of the TLR process. Based on these analyses, we conclude that the Midwest ISO's administration of the TLR process as the reliability coordinator for the Midwest was consistent and reliable. Nonetheless, our analysis continues to indicate that the TLR process is a relatively inefficient means to manage transmission congestion, requiring more than three times the quantity of redispatch/curtailment as an LMP market to manage the same congestion.

We also evaluate the Midwest ISO's Available Flowgate Capability ("AFC"). We reviewed hourly AFC calculation results and the short-term transmission service request approval procedures and find that short-term non-firm AFC values do not appear to track real-time flows well. This can lead to underutilization of the transmission system. However, these issues have largely been eliminated through the introduction of LMP markets.

The integration of Commonwealth Edison ("CE") and American Electric Power ("AEP") into PJM in 2004 resulted in changes to regional dispatch patterns. A joint operating agreement between PJM and the Midwest ISO includes protocols to coordinate power flows that affect both systems. When AEP was initially integrated in October, the resulting dispatch changes caused overloads in northern Indiana that the Midwest ISO was having difficulty resolving. This issue was resolved by utilizing the coordination protocols to jointly manage these constraints. The integration also resulted in increased TLR events called by the Midwest ISO. However, activating a TLR is part of the coordination procedure and did not indicate that the integration was harmful. In fact, it reduced the locational price differences between the Midwest and Mid-Atlantic regions.

## **II. Introduction**

This report evaluates the state of the Midwest ISO wholesale electricity markets during 2004. The Midwest ISO wholesale market in 2004 operated as bilateral contract markets while work continued to implement LMP markets. The LMP markets began operating in April 2005. The new markets allow the Midwest ISO to efficiently manage transmission congestion and establish transparent market-clearing prices at each location on the network.

Because the Midwest ISO did not operate LMP markets during 2004, the focus of this report is on the characteristics and operations of the bilateral markets as they existed in the Midwest ISO in 2004. This assessment includes a review and evaluation of existing supply and demand characteristics, transmission service, and certain Midwest ISO operations. As will be explained herein, many of the issues that confront the Midwest ISO under its tariff administration in 2004 will be substantially diminished in importance under the LMP markets.

Section III contains an evaluation of the load and resource balance within the Midwest ISO, including the capacity to import and export power over the primary transmission interconnections in the Midwest. Section IV presents a review and analysis of wholesale electricity prices in the Midwest. Section V contains a summary and assessment of transmission reservation and scheduling patterns during 2004. Finally, section VI is an assessment of the Midwest ISO's current operations, including its management of congestion during 2004.

### III. Characteristics of Midwest Electricity Markets

Understanding the fundamental supply and demand conditions of the Midwest markets is important in assessing the current operations of the Midwest ISO, as well as monitoring the LMP energy markets that began April 2005. In this section, we summarize load and generation within the Midwest ISO region and evaluate the resource balance in light of available transmission capability on the Midwest ISO network.

The Midwest ISO is the independent operator of the regional transmission network comprised of the transmission facilities of the Midwest ISO transmission owners. Transmission-owning members have transferred control of their transmission facilities either as signatories to the FERC-approved Midwest ISO OATT or as participants in Independent Transmission Companies that are members of the Midwest ISO under Appendix I of the Midwest ISO Agreement.

In delineating the Midwest ISO geographic boundaries, we confine our analysis to the Midwest ISO balancing authorities as specified in Exhibit A-1 of the Midwest ISO Market Initiative that are under the Midwest ISO market rules starting April 2005 (hereinafter referred to as “Midwest ISO control areas”). This set of entities, which is different from the set used in our previous Midwest ISO State-of-the-Market reports, is the set of market participants that will participate fully in the LMP markets. In previous years, we used a broader set of entities that included those that we anticipated would be market participants. The status of a number of these participants has been clarified since last year so we are now able to focus on those entities that are participants in the LMP markets.

For our analysis, we divide the Midwest ISO control areas into four sub-regions based on the study areas used in the MAIN Summer Transmission Assessment. These sub-regions are useful in utilizing the transmission assessment results in conjunction with the generation and load statistics in each area. These four sub-regions are:

- (1) ECAR -- the Midwest ISO control areas located in the NERC ECAR region;
- (2) MAPP -- the Midwest ISO control areas located in the NERC MAPP region;

- (3) MAIN -- the Midwest ISO control areas located in the NERC MAIN region, but excluding MAIN utilities located in the Wisconsin-Upper Michigan System (“WUMS”)); and
- (4) WUMS -- the Midwest ISO control areas located in the WUMS region.

There are over 150 distinct owners of generation resources in the Midwest ISO footprint as defined by the set of Midwest ISO control areas. This includes large investor-owned utilities, municipal and cooperative utilities, and independent power producers.

Generation owned by non-transmission owners (e.g., municipal utilities, independent power producers) are included as part of the control area to which their generation is interconnected for purposes of calculating the load and generation statistics in this section.

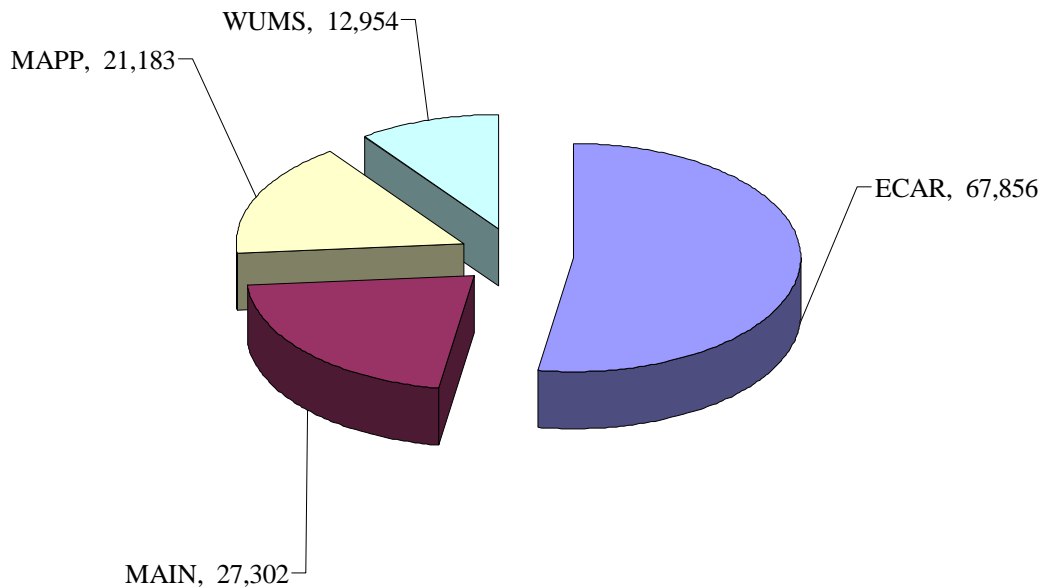
It should be emphasized that these four sub-regions should not be viewed as distinct geographic markets. This is particularly important for the data presented below concerning market concentration in these sub-regions. Therefore, the market concentration in these sub-regions does not allow one to draw reliable competitive conclusions. An accurate market power analysis would require substantially more analysis beyond calculating market shares and concentration statistics.

#### **A. Supply and Demand Balance**

In this subsection, we evaluate the supply and demand balance by identifying loads, generating resources, and firm transfers within the four Midwest ISO sub-regions and the entire Midwest ISO footprint. This provides the data for calculating each sub-region’s “resource margin,” the margin by which firm resources exceed annual peak demand. We find that resources in the Midwest ISO are generally adequate, although limited transfer capability in the WUMS sub-region raises some concerns. Our calculations are generally more conservative than those used for reserve margins by the NERC sub-regions. We use summer capacity (generally lower than nameplate capacity), because the region as a whole experiences peak loads during the summer months. This approach provides a better picture of the generation that will actually be available to serve the Midwest

markets and affect electricity prices in the region. Figure 1 shows the distribution of generating capacity within the four Midwest ISO sub-regions.

**Figure 1: Geographic Distribution of Regional Generation Capacity**



The generating resources within the Midwest ISO footprint totaled approximately 129,300 MW in 2004, compared to 124,900 MW in the same area in 2003. The ECAR sub-region is the largest, with more than one-half of the total generation in the Midwest ISO.

The peak load in each sub-region must be satisfied by a combination of generating resources within the region or imports. Hence, to calculate the resource margin for a sub-region, we take the ratio of the generation and net firm imports to the peak load for each region. Table 1 summarizes this analysis, showing each sub-region's generation, net firm imports, peak load, and the resource margin that these values produce.

**Table 1: Summary of Generation and Resource Margins  
2004**

	Generating Capacity	Net Firm Imports	Load	Resource Margin
ECAR	67,856	548	54,792	24.8%
MAIN	27,302	(505)	20,493	30.8%
MAPP	21,183	2,320	18,076	30.0%
WUMS	12,954	1,275	11,559	23.1%
MISO	129,295	3,638	104,920	26.7%

*Note :* Peak loads used to calculate the Resource Margin were derived from Midwest ISO data. This was supplemented, when necessary, by data from Platts. Net Firm Imports were based on data from the 2004 NERC Summer Assessment and the 2004 Main Summer Assessment.

The resource margins presented here are broad indicators of adequacy of the resources in these areas, which can be useful for identifying potential areas of concern. In our analysis, Generating Capacity and Net Firm Imports do not reflect demand-side resources. To the extent demand-side resources have been deployed during peak periods, they would be reflected in lower peak demand (resulting in a higher resource margin). To the extent demand-side resources were available but not deployed during peak periods, the resource margins may be slightly underestimated because the peak load will be higher.

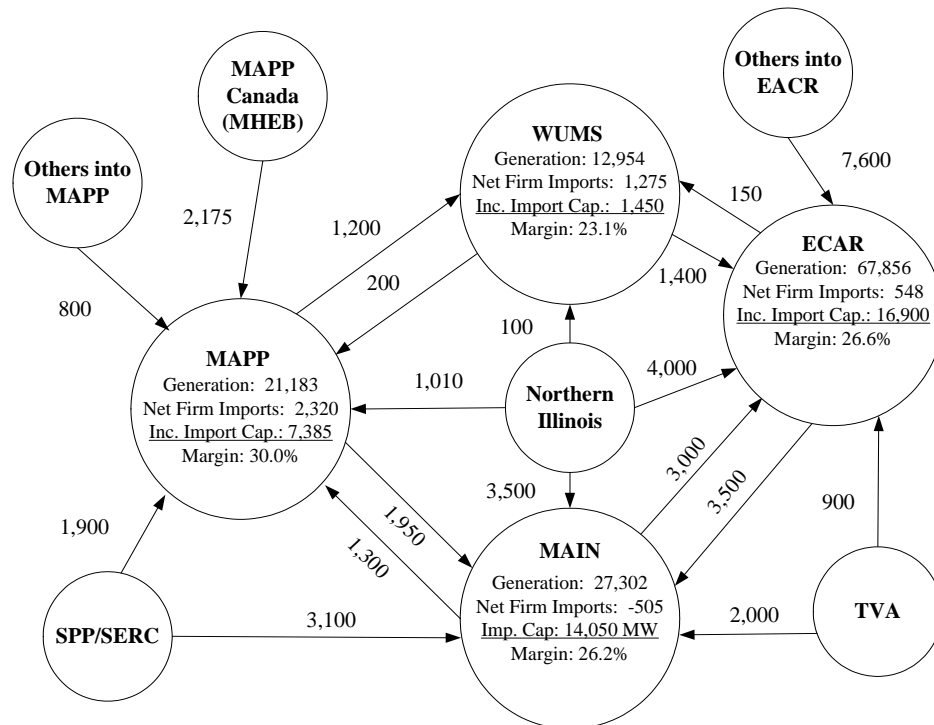
Table 1 shows that the Midwest ISO sub-regions have substantial firm resources with resource margins generally ranging between 20 percent and 30 percent. The resource margin in WUMS is the lowest and WUMS relies most heavily on its transmission interfaces to import power from adjacent areas. Overall, the resource margin for the Midwest ISO increased slightly from 2003 to 2004, as shown in Table 2. The resource margins increased because peak demand decreased slightly lower due to mild weather and resources increased slightly, causing the resource margin to increase by 2.5 percentage points.



**Table 2: Resource Margins 2003 and 2004**

	2004	2003	<i>Net Change</i>
Total Resources (MW)	132,933	131,162	1,771
Load (MW)	104,920	105,625	(705)
Resource Margin	26.7%	24.2%	2.5%

The Midwest ISO footprint extends over a relatively broad area and is heavily interconnected to adjacent regions. To provide more detail on the transmission capability and resource margins in the Midwest, Figure 2 shows a graphical representation of the Midwest transmission network. For each of the sub-regions, this figure shows the generating resources, the firm net imports, and the non-simultaneous transfer capability. This incremental transfer capability is the amount of power that can be transferred over the given interface in addition to the net firm imports, assuming no incremental transfers are occurring over the other interfaces. The values shown on the arrows between the sub-regions in this figure show the incremental transfer capability for that transmission path.

**Figure 2: Midwest ISO Transmission Interconnections and Resource Balance**

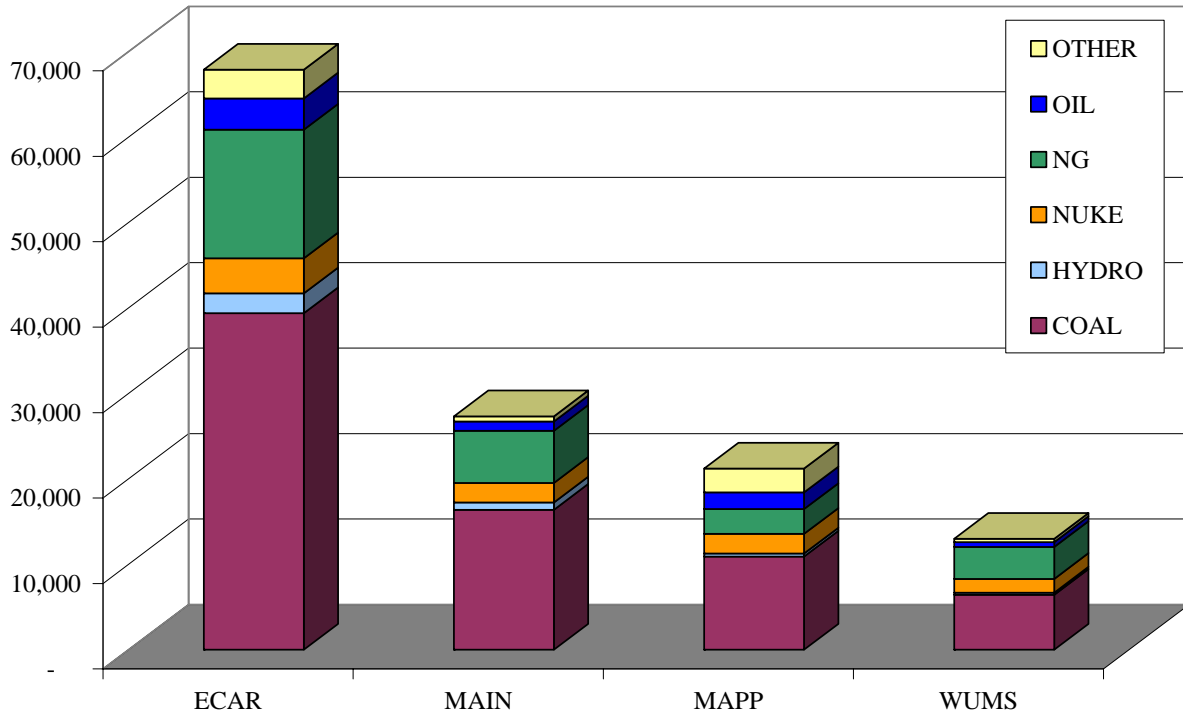
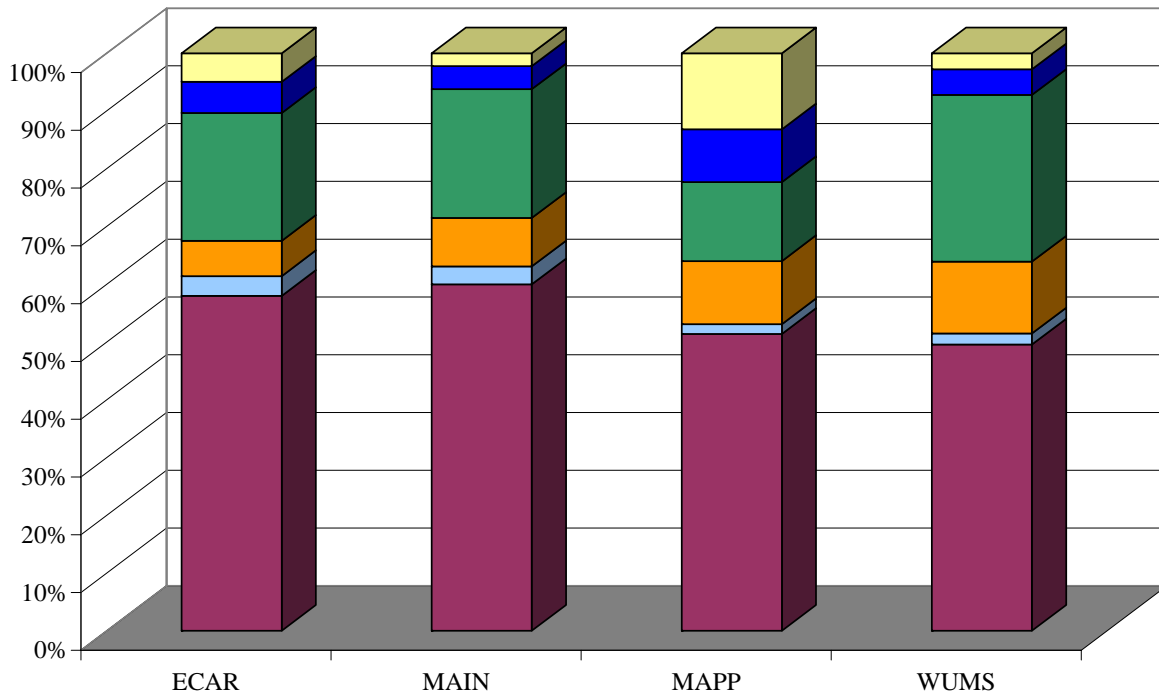
*Note:* “Inc. Import Capability” is the incremental transmission capability, which is the sum of non-simultaneous First Contingency Incremental Transfer Capability on all paths into the region.

Using data from the 2004 MAIN Summer Assessment, the diagram shows total generation, net firm imports, the incremental import capability, and the resource margin for each sub-region. The transfer capability shown is non-simultaneous capability, which means that the paths into an area may have a lower transfer capability if there are transfers occurring over other paths simultaneously. Hence, it may not be possible to increase imports into each of the sub-regions by the “incremental import capability” shown in the figure because this amount is a simple aggregation of the non-simultaneous import capability for each of the paths into the sub-region. The simultaneous capability can be significantly less than the non-simultaneous capability because when power is transferred over one path, some of the power will flow over the other paths into the area, reducing the available transfer capability over those paths.

As noted above, WUMS has a lower resource margin than the other sub-regions. In addition, Figure 2 shows that WUMS relies heavily on firm imports to satisfy its peak load. Consequently, its ability to import additional power to the area is limited. Although the figure shows 1450 MW of non-simultaneous incremental transfer capability, the total additional imports that can occur simultaneously over the different interfaces is less than this amount. The other sub-regions have higher resource margins and considerably more transmission capability to import additional power.

## **B. Midwest ISO Capacity Profile**

In this sub-section, we further examine the Midwest ISO generating capacity by showing the composition of generating capacity by fuel type. Figure 3 shows the total of each capacity type in each of the Midwest ISO sub-regions. Figure 4 presents the same data as percentage shares of the total capacity.

**Figure 3: Capacity by Fuel Type in Midwest ISO Sub-Regions****Figure 4: Capacity Shares by Fuel Type in Midwest ISO Sub-Regions**

The figures show that the Midwest ISO and each of its sub-regions continue to rely most heavily on coal-fired generation, which represents almost 60 percent of the generation in the Midwest ISO region. Nuclear, oil-fired, and hydroelectric resources together account for 17 percent of the total resources. Natural gas-fired generating resources represent 20 percent of the supply in the Midwest, although most of the new resources are natural gas-fired resources. Figure 4 reveals that Midwest ISO sub-regions are comparable in their generation mix. This most significant difference is MAPP, which has less natural gas capacity and more oil-fired capacity.

### **C. Market Concentration**

As a final analysis of generation resources in the Midwest, we calculate market concentration in the various sub-regions based on the ownership of generating capacity. We use the Herfindahl-Hirschman Index (“HHI”) to measure concentration. The HHI is calculated by summing the square of each participant’s market share. Economists use this statistic to assess the overall competitive structure of the market, because highly concentrated markets tend to perform less competitively and are more vulnerable to market power abuses. The Department of Justice and the Federal Trade Commission evaluate the competitive impact of mergers by measuring the HHI in the relevant market and comparing the change caused by the merger.

The HHI is most useful when it is calculated for well-defined geographic and product markets. Geographic markets in the electricity industry are generally defined by physical transmission constraints that limit the extent of competition and are, therefore, dynamic in nature. The sub-regions of the Midwest ISO are not defined as geographic markets in this sense and, therefore, the HHIs calculated in each sub-region cannot support any definitive competitive conclusions. Nonetheless, the market concentration within the Midwest ISO sub-regions can provide useful information and indicates areas of potential concern that may warrant further analysis.

**Table 3: Concentration in Midwest ISO Sub-Regions  
2004**

<b>Midwest ISO Subregion</b>	<b>HHI</b>
ECAR	770
MAIN	1,745
MAPP	1,275
WUMS	2,642
Midwest ISO	356

Table 3 summarizes the market concentration results, indicating that MAIN and MAPP have HHIs in the moderately concentrated range and WUMS exhibits an HHI value in the highly-concentrated range. However, the Midwest ISO region as a whole is in the un-concentrated range. Unlike the other sub-regions, WUMS is the one sub-region that most closely reflects a geographic market, given the frequent congestion that occurs on the interfaces into that area. The WUMS HHI is in the highly concentrated range.

Although HHI statistics can provide reliable competitive inferences for many types of products, this is not generally the case in electricity spot markets.<sup>2</sup> The HHI's usefulness is limited by the fact that it reflects only the supply-side, ignoring demand-side factors that affect the competitiveness of the market. The most important demand-side factor is the level of demand. Since electricity cannot be stored economically, production must match demand on a real-time basis. When demand rises, an increasing quantity of generating capacity is utilized to satisfy the demand, leaving less capacity that can respond to higher prices in the event a large supplier withholds resources. Hence, markets with higher resource margins tend to be more competitive, which is not

<sup>2</sup> It is true that the DOJ and FTC evaluate the *change* in HHI as part of its merger analysis. However, this is only a preliminary analysis that would typically be followed by a more rigorous simulation of the likely price effects of the merger. It is also important to note the HHI analysis employed by the antitrust agencies is not intended to determine whether a supplier has market power. For an explanation regarding why HHI statistics may not provide reliable indications of market power in electricity markets, see Severin Borenstein, James B. Bushnell, and Christopher R. Knittel, "Market Power in Electricity Markets: Beyond Concentration Measures," *Energy Journal* 20(4), 1999, pp. 65-88.

recognized by the HHI statistics. In addition, the scope of the geographic market can change hour to hour as the loadings on the transmission network change. Hence, the competitiveness of the market is more dynamic than can be reflected in HHI statistics.

To evaluate the competitiveness of a market or a particular market area, other analyses must be performed. For example, in the 2003 State of the Market Report we included a market power analysis that sought to identify suppliers whose resources are needed (i.e., “pivotal”) for resolving transmission congestion and satisfying load. Based on these analyses, we concluded that the most significant potential competitive concerns in the Midwest are in the WUMS area.<sup>3</sup> To address these concerns, we defined the WUMS area as a Narrow Constrained Area (“NCA”) under the market power mitigation measures in the Midwest ISO Tariff.<sup>4</sup> These measures apply tighter mitigation thresholds in these areas to ensure that suppliers with market power within WUMS cannot raise prices substantially above competitive levels.

#### **D. Midwest ISO Load Patterns**

The growth and changes in the pattern of the loads in the Midwest ISO are an important determinant of the outcomes of the bilateral electricity markets and the patterns of congestion that occurred in the Midwest in 2004. Hence, we analyze the load conditions in the Midwest ISO footprint during 2004 in this sub-section of the report.

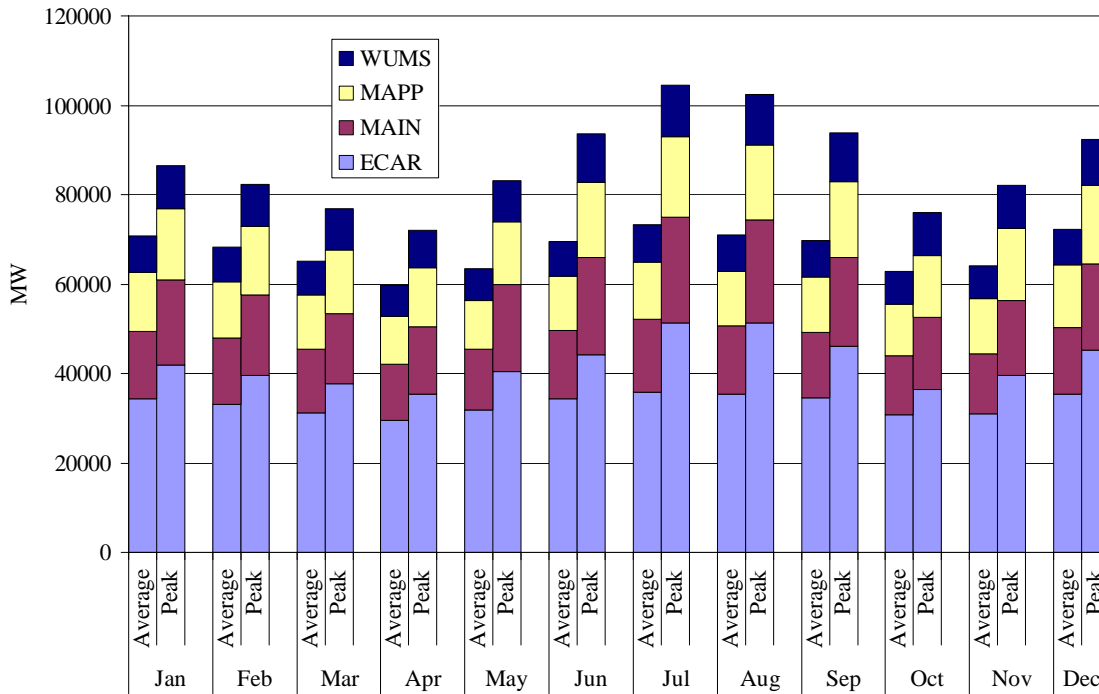
Both the peak and average loads are important. The peak loads are those that contribute to the tightest market conditions and the highest prices. However, the average loads are a more important determinant of the average prices that prevail over the year. Therefore, Figure 5 shows the monthly average and peak loads in each sub-region.

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<sup>3</sup> 2004 State of The Market Report Midwest ISO, Potomac Economics Ltd., May 2004.

<sup>4</sup> Midwest ISO Transmission and Energy Markets Tariff (“TEMT”), Module D.

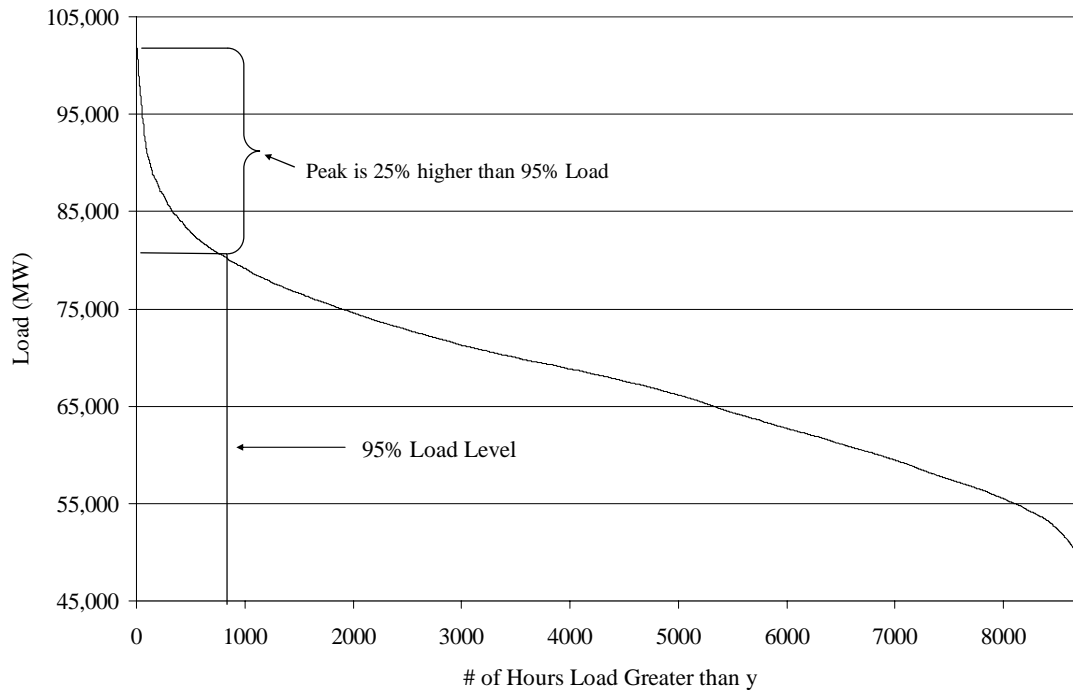
**Figure 5: Monthly Average and Peak Loads  
2004**



The figure shows that the MISO system-wide peak was in July, at 104,000 MW with a secondary peak in August. While some of the individual control areas in the Midwest ISO experienced peaks in the winter, all of the individual sub-regions have summer peaks. The weather conditions during the summer in 2004 were relatively mild, which contributed to lower peak load conditions. However, average demand in the Midwest ISO area continued to increase at a steady rate. Average demand increased by 2.4% from 2003 and was 67,500 MW, indicating that the system load factor was close to 65%. Like the generation shares shown in the prior sub-section, this figure shows that the largest share of the Midwest ISO's load is located in ECAR.

In addition to these monthly values, it is important to examine the load levels on an hourly basis. To evaluate these levels, Figure 6 shows a load duration curve for the Midwest ISO. A load duration curve shows the number of hours (on the *x*-axis) in which the load exceeds a given load level (on the *y*-axis).

**Figure 6: Midwest ISO Load Duration Curve  
2004**



The load duration curve in Figure 6 exhibits the typical sharp peak demand, which is characteristic of electricity markets. The figure shows that peak load is 25 percent higher than the 95<sup>th</sup> percentile of load hours. This relationship illustrates the need in any electricity market for peaking resources. It indicates that about one-fourth of the generation can be expected to run in less than 5 percent of the hours. This highlights the critical need for wholesale markets to price electricity efficiently in these hours so that peaking capacity will receive efficient price signals to guide investment decisions.

### **E. Generator Outages**

In this sub-section, we examine the generator outages that were reported to the Midwest ISO in 2004. Generator outages can be broadly classified as either planned or unplanned. Planned outages occur to accommodate routine maintenance or major capital improvements that are anticipated in advance. Planned outages are generally deferrable and are, therefore, typically undertaken during off-peak periods. Outages planned well in advance, such as those scheduled for annual maintenance are generally scheduled in the

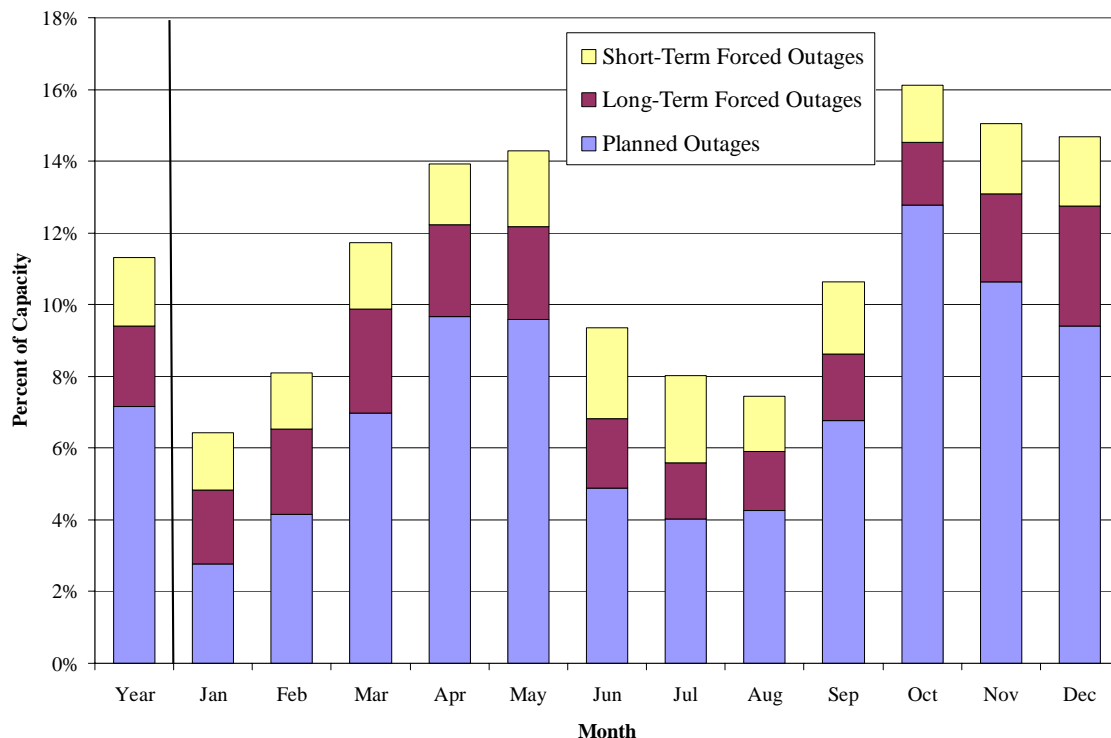


spring or fall. Shorter-term repairs or maintenance that arise during the year and can be deferred for short periods of time are generally scheduled at night or on weekends.

Unplanned or “forced” outages are usually the result of unexpected equipment failure or emergency maintenance requirements. Unplanned outages generally cannot be deferred, but there is normally time for a controlled shutdown.

Figure 7 shows the monthly generator outages during 2004. These values include only full outages -- no partial outages or deratings are included.

**Figure 7: Generator Outages in 2004**



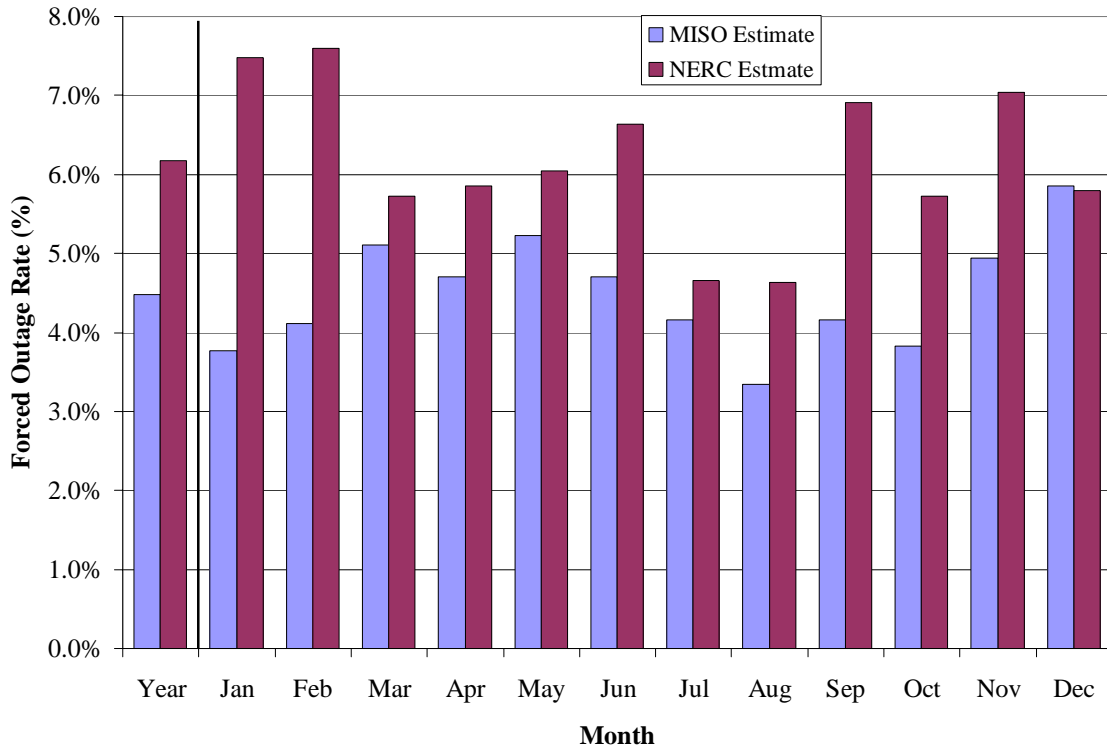
The figure shows that generator outages were highest in spring and fall. Planned outages increased substantially in March to May as expected, peaking in April at more than 18 percent of all capacity. The figure also shows that forced outage rates in total have been relatively low, averaging less than 4 percent of the MISO capacity. It is useful to divide the outages between short-term forced outages (less than 7 days) and long-term forced outages (longer than 7 days). This is because they have different effects on the markets (e.g., short-term outages are more likely to lead to unanticipated tight supply conditions)

and because suppliers aiming to physically withholding resources from the market by declaring a forced outage would generally declare a short-term outage due to the higher costs of a long-term outage. Because legitimate forced outages should be random, whether short-term outage are attempts to exercise market power or not can be detected by evaluating whether forced outages are occurring randomly.

Figure 7 shows that long-term forced outages account for a slightly larger portion of forced outages than short-term forced outages. Additionally, our analysis shows that short-term forced outages do not rise substantially during the summer high-load conditions. This supports the conclusion that forced outages have occurred randomly, indicating that strategic declarations of forced outages was not a significant concern during 2004.

The prior analysis shows that forced outage rates have been relatively low. Historical forced outage rates have generally ranged from 5 to 10 percent. To focus more specifically on forced outages, Figure 8 shows the forced outage rates for Midwest ISO generators on an annual basis in 2004 and for each month during 2004. Two values are shown for each month – the values based on the Midwest ISO Outage Scheduler and Generation Availability Data (“GADS”) values provided by NERC.

Figure 8 shows that the forced outage rates were relatively low during the peak summer months. Based on our ongoing monitoring of forced outages, we find that they occurred randomly in 2004 and provide little evidence of physical withholding of resources as described above. However, the two sources of forced outage information shown in Figure 8 show some significant inconsistencies. The annual forced outage rate based on reports to the Midwest ISO is about 4.5 percent whereas using the NERC method it is slightly more than 6 percent. Further, the forced outages reported to NERC are higher than those reported to the Midwest ISO in every month but December 2004, with the GADS values in January and February exceeding the Midwest ISO values by more than 3 percent.

**Figure 8: Forced Outage Rates in 2004**

The relatively low forced outage rates based on the Midwest ISO data suggest that market participants may not be reporting all of their forced outages to the Midwest ISO, despite the obligation to do so under the Midwest ISO Business Practice Manual. There are no sanctions for non-compliance with the Business Practice Manual's reporting requirements. Hence, the incentive to fully report all forced outages is relatively low, which could contribute to under-reporting of forced outages. As the Midwest ISO becomes increasingly responsible for generator commitment and dispatch under the LMP markets, it is important that forced outages be fully and accurately reported. Hence, we will continue to monitor this issue and may recommend that the Midwest ISO consider administrative sanctions to enforce their reporting requirements if this pattern continues under the LMP markets.

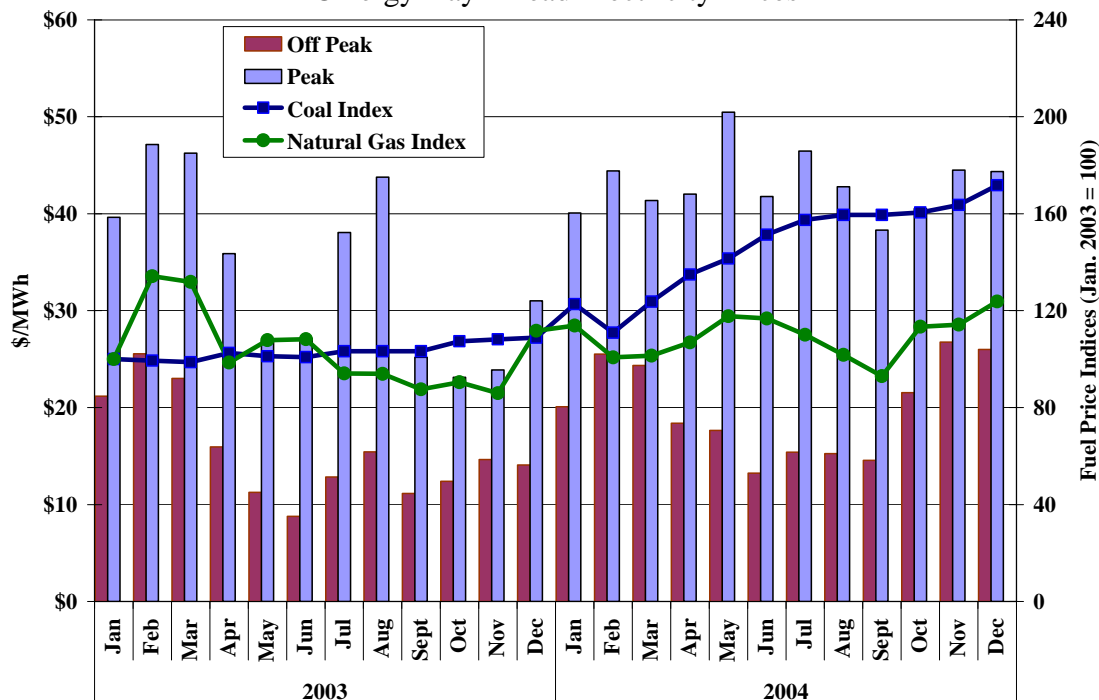
#### IV. Wholesale Electricity Prices in 2004

Until the LMP markets were implemented in April 2005, the Midwest ISO wholesale markets were comprised only of bilateral trading. The analysis in this section evaluates the price trends in the short-term bilateral markets in 2004. We rely mainly on bilateral trading data that is collected through survey by private services. One such service is the Megawatt Daily survey, published by Platts. In this section, we use the Megawatt Daily volume-weighted average prices associated with day-ahead forward contracts and comparable price data from the Intercontinental Exchange (“ICE”).

##### A. Summary of Price Trends

The first analysis in this section summarizes the daily electricity prices during 2004. Figure 9 shows monthly average prices at the Cinergy hub during peak and off-peak periods represented as side-by-side bars. The figure also shows price indices for coal, fuel oil, and natural gas. The fuel indices provide a reference to underlying input costs.

**Figure 9: Monthly Average Electricity and Fuel Prices -- 2003 and 2004**  
Cinergy Day-Ahead Electricity Prices



Note: Fuel Price indices are those published by Platts.

As one would expect, Figure 9 shows that electricity prices are substantially higher during peak than during off-peak hours. Likewise, prices during the summer months are higher than prices during the spring and fall months. These results show the importance of electricity demand in the determination of electricity prices. Because electricity cannot be stored economically, higher cost resources must be utilized in hours with higher demand, resulting in higher electricity prices in these hours.

The figure also shows that natural gas prices were a key driver of peak prices and, to a lesser extent, of off-peak prices in the winter months. The decrease in natural gas prices in late summer and early fall 2004 caused prices to moderate during these months, although both the fuel prices and electricity prices were higher in these months than during the same months in 2003. The higher electricity prices in 2004 are also due, in part, to the substantial increase in coal prices during the year.

However, natural gas prices remain a more significant determinant of electricity prices than do coal prices, even though most of the generating resources in the Midwest are coal-fired. Although natural gas-fired generating units constitute only 16 percent of the total generating capacity in the Midwest ISO region, they are the marginal source of generation in a large share of the peak hours. The data shows that these units are also marginal in a significant number of off-peak hours during the winter. This is likely due to relatively high heating load that can occur at low nighttime temperatures during the winter.

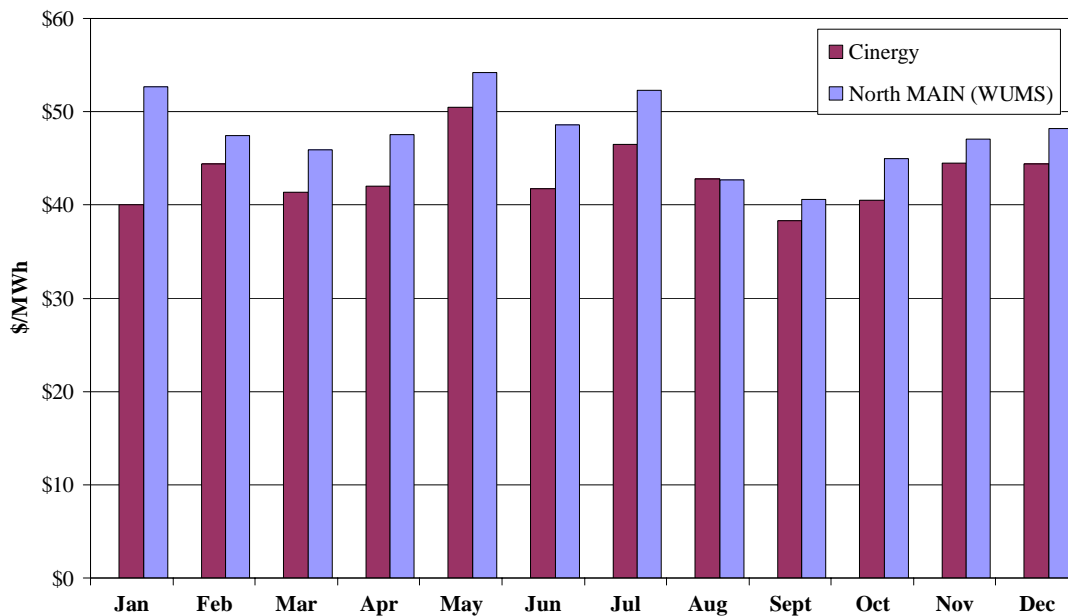
## **B. Inter-regional Price Differences**

Figure 10 shows the daily average prices during peak hours at the Cinergy hub and in North MAIN. The Cinergy hub is shown because it is the most liquid trading point in the Midwest. The North MAIN pricing point is shown because it corresponds to the frequently-congested WUMS sub-region.

When constraints into WUMS are not binding, the prices inside and outside of WUMS should be comparable -- significant price differences would create obvious arbitrage opportunities. When these constraints are binding and re-dispatch of generation within

WUMS is required to manage the constraint, the prices within WUMS should be higher to reflect the marginal cost of the required redispatch.<sup>5</sup>

**Figure 10: Day-Ahead Electricity Prices in 2004**  
**Monthly Average for Peak Hours**  
 Cinergy and North MAIN



The figure shows that the average prices in North MAIN were higher than prices at the Cinergy hub in every month except August, when they are roughly comparable. In general, this is consistent with the pattern of congestion in the Midwest. When transmission congestion arises as a result of binding transmission constraints, additional power is prevented from flowing into the constrained area and the price in the constrained area (“downstream price”) should rise relative to the price outside of the constrained area (“upstream price”). The following analysis investigates whether these pricing relationships exist under the current bilateral wholesale markets in the Midwest.

When transmission constraints arise on a flowgate under the congestion management system in place in 2004, the power flows were managed using TLR procedures. A TLR

<sup>5</sup> One caveat for the analysis in this section is that the price data often is based on very low trading volumes. On many days, no trading volume is reported. In these cases, Megawatt Daily publishes an indicative price based on available trade information, including bids and offers for energy.

event of level 3 or higher results in transactions being curtailed or generation being dispatched to manage the flowgate. Therefore, an hour when a TLR event is in effect on a flowgate is indicative of a binding constraint. In our next analysis, we compute the difference between the downstream price and upstream price associated with a particular flowgate and determine how these prices differ when the flowgate constraint is binding.

The WUMS area represents the most frequently congested region in the Midwest and, therefore, is the focus of this analysis. We conduct two statistical tests designed to evaluate the relationship between upstream and downstream prices. In our first analysis, we test whether the mean downstream-upstream price is statistically different in days with TLR events versus all other days. The analysis is conducted on each WUMS flowgate.

The analysis compares the peak prices for the day following the TLR event (prices associated with transactions initiated on the day with the TLR event) with prices on days without TLR events. We perform the same analysis on the prices for the day of the TLR event and the results were comparable. The results of the analysis are shown in Table 4.

**Table 4: Effects of TLR Events on Energy Prices  
Downstream – Upstream Price Basis**

Flowgate Name	<u>Without TLR</u>		<u>With TLR</u>		P-Value
	N	Mean	N	Mean	
PADDOCK XFMR 1 + PADDOCK-ROCKDALE	255	0.0106	6	-0.117	0.9429
Albers-Paris138 for Wemp-Padock 345	238	0.0127	24	-0.126	0.8812
Poweshiek-Reasnor 161 for Montezuma-Bondurant 345	355	-0.001	11	-1.545	0.433
Lore-Turkey River 161 (flo) Wempletown-Paddock 345	352	-1.875	14	-4.089	0.0468
MHEX_S	349	0.1655	17	-2.956	0.0583
MHEX_N	336	0.0249	30	-0.545	0.3978
MWSI	357	-0.016	9	0.6389	0.4585

The table shows the number of days in each category (i.e., with TLRs vs. without TLRs), the mean downstream-upstream price difference for each category, and the difference in these means. The “p-value” indicates whether the difference in the two means is

statistically different from zero.<sup>6</sup> Economists generally employ a 95 percent confidence interval to determine whether a result is statistically significant, corresponding to a p-value that is less than 0.05. Hence, a p-value equal to or less than 0.05 indicates a statistically significant result.

The results in Table 4 show that for only two of the flowgates the difference in the means is statistically different from zero (the flowgate defined by the Poweshiek-Reasnor 161 kV facility for a contingency on the Montezuma-Bondurant 345 kV facility and the flowgate defined as the Lore-Turkey River 161 kV facility for contingency on the Wempletown-Paddock 345 kV facility). Hence, only a weak relationship exists between the day-ahead bilateral market prices and transmission congestion. This is in contrast to what would be expected in a well-functioning market where price differences should be affected by congestion.

In our second analysis, we examine whether the difference in the means increases or decreases significantly when a TLR is invoked. This is done by determining whether the mean of the downstream-upstream price difference for the day following the TLR event (associated with transactions initiated on the day with the TLR event) is significantly different than the mean of the difference for days when the previous day did not have a TLR event. The hypothesis in this case is that the downstream-upstream price difference should become more positive when the TLR event occurs. Table 5 shows these results.

**Table 5: Effects of TLR Events on Changes in Energy Prices**

Flowgate Name	Flowgate ID	Count -- No		Est. Change (\$/MWh)	P-Value
		TLR	with TLR		
PADDOCK XFMR 1 + PADDOCK-ROCKDALE	3012	255	6	2.018	0.4096
Albers-Paris138 for Wemp-Paddock 345	3522	238	24	2.804	0.0218
Poweshiek-Reasnor 161 for Montezuma-Bondurant 345	3704	355	11	-0.617	0.8136
Lore-Turkey River 161 (flo) Wempletown-Paddock 345	3707	352	14	2.214	0.0468
MHEX_S	6002	349	17	0.6234	0.6755
MHEX_N	6003	336	30	-0.146	0.8927
MWSI	6004	357	9	1.121	0.4291

<sup>6</sup> The method of calculating the p-value depends upon whether the variances of the two samples are equal. When an additional statistical test indicates the variances are equal at the 95 percent confidence level, p-values are derived using the equal variance approach. Otherwise, p-values are derived using the unequal variance approach.



The table shows the change between the spread in the downstream and upstream prices on days after a TLR event and the following day is statistically different than zero in only two instances (i.e., p-value less than 0.05).

Taken together, the results from Table 4 and Table 5 indicate that the daily bilateral prices in the Midwest do not generally reveal the presence of transmission congestion and, therefore, fail to provide transparent and accurate price signals to market participants. These results reinforce the importance of the LMP spot markets that have been implemented by the Midwest ISO in April 2005.

These conclusions must be tempered by the fact that prices are daily prices associated with power sold one day forward, which is the most liquid short-term trading activity in the Midwest. These prices are not as accurate as intraday hourly prices that would reflect congestion at the time it is actually occurring. However, reliable intraday prices were not available for this analysis. Transmission congestion cannot always be accurately forecasted one day ahead because it is sometimes caused by random or unexpected factors (e.g., transmission or generation outages, weather patterns, and other load determinants).

Nonetheless, we conclude that the current wholesale electricity pricing in the Midwest could be much more transparent, particularly with regard to transmission congestion. The Midwest ISO's LMP energy markets should substantially improve the transparency and accuracy of prices at various locations throughout the region. This transparency will lead to better signals for new investment, retirement, and forward contracting by market participants.

### **C. PJM Expansion and Transmission Congestion**

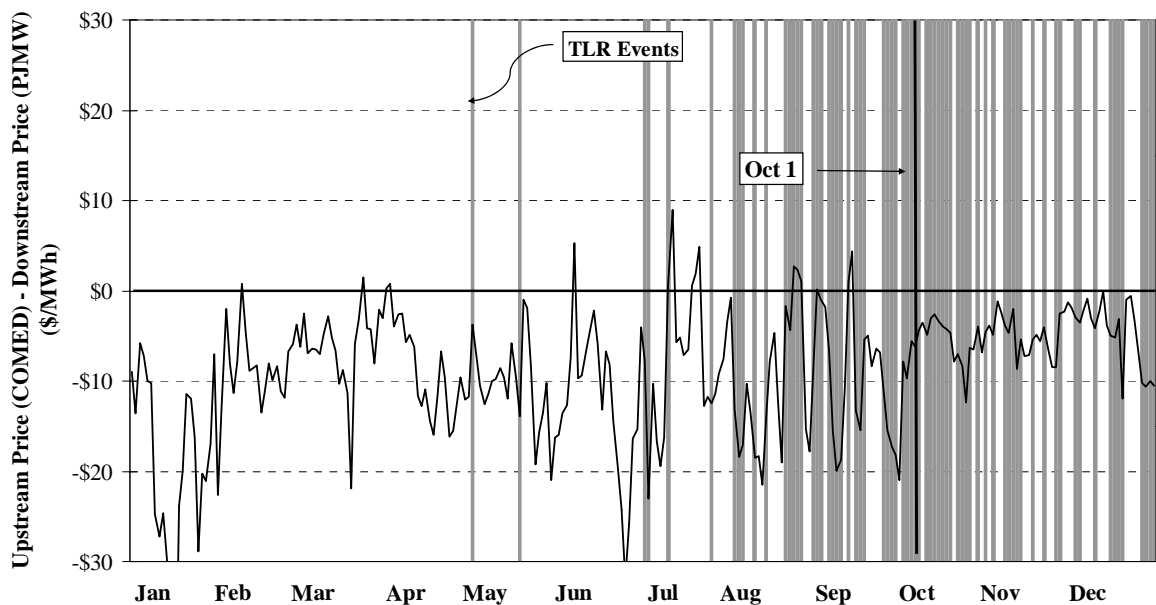
One of the most significant changes in the Midwest during 2004 was the integration of Commonwealth Edison ("CE") and American Electric Power ("AEP") into PJM. CE was integrated in May and AEP was integrated in October. After the integration of CE, but before the integration of AEP, transfers from CE to PJM were limited to 500 MW. After the integration of AEP, PJM could economically dispatch the path from CE to PJM

without being limited to 500 MW. This post-AEP-integration dispatch was conducted under a market-to-non-market process using “coordinated” flowgates.

Under the market-to-non-market process, when TLRs are necessary to unload the coordinated flowgates, PJM must redispatch its generation to reduce the flows to the level of their firm rights. Since the integration of AEP allowed a fuller use of the CE generation by PJM, this initially caused serious overloads on certain flowgates on the NIPSCO system. This was resolved by designating these flowgates as “coordinated” flowgates.

Figure 11 shows the incidence of TLR events on selected NIPSCO flowgates in Northern ECAR and the relationship of prices between PJM West (downstream) and CE (upstream) during 2004.

**Figure 11: TLR Events on the NIPSCO Flowgates**



The figure shows that the Midwest ISO called a large number of TLRs on the NIPSCO flowgates after the CE integration in May and especially after the AEP integration in October. This is consistent with the economic use of PJM’s resources, that is, the greater reliance on lower-cost CE generation to serve load in eastern PJM. The improved price

convergence between CE and PJM West after October 1 is evidence that these dispatch changes have improved the utilization of the transmission capability in the Midwest.

As explained more below, the TLR activity is part of the process that the Midwest ISO and PJM use to jointly manage the transmission constraints that both entities affect.

When the flow over one of the jointly managed flowgates on the Midwest ISO system approaches its limit, the Midwest ISO will call a TLR to reduce PJM's and others' use of the flowgate. This process is embodied in the Joint Operating Agreement ("JOA") between the Midwest ISO and PJM. Hence, although the AEP and CE integration into the PJM system has improved the utilization of the transmission capability, it has also increased the curtailments of transactions by non-PJM entities.

## **V. Assessment of Transmission Service**

Prior to the implementation of the LMP energy markets in April 2005, the primary functions of the Midwest ISO were to provide transmission service and perform reliability coordination functions. In this section, we summarize and assess the Midwest ISO's operations relating to providing transmission service and evaluate the behavior of market participants in reserving transmission service. We conclude that the Midwest ISO's transmission reservation and scheduling procedures have improved the coordination of transmission service in the Midwest, although further improvements were possible. A number of these improvements were restricted by the requirements of Order 888.

In this section, we analyze and evaluate:

- The overall disposition of transmission service requests;
- The patterns in the long-term ATC on key interfaces;
- The practice of “redirecting” firm transmission service to an affiliate control area;
- The patterns of transmission requests that are approved by the Midwest ISO, but not ultimately confirmed by the participant to see if the failure to confirm reservations may be consistent with strategic conduct; and
- The designation of Network Resources.

### **A. Disposition of Transmission Requests**

The vast majority of transmission requests eventually fall into one of two categories: (1) approved and confirmed; or (2) refused – generally due to a lack of available transmission capability. A third category, “Invalid/Other”, includes reservations that are: invalid, denied, annulled, or withdrawn. Dispositions in these categories ultimately do not result in transmission reservations due to the participant's action or the validity of the request.

Figure 12 summarizes the disposition of transmission requests showing the approved requests relative to refused and invalid requests. The approved requests include both new requests and requests to redirect existing service. Redirected service occurs when a firm reservation on a given contract path (defined by a point-of-receipt (“POR”) and a point-of-delivery (“POD”)) is redirected to an alternative contract path. This practice is discussed in more detail below. The values are shown by two-month increments from the period March 2002 to December 2004.

**Figure 12: Disposition of Reservation Requests (Number of Requests)**

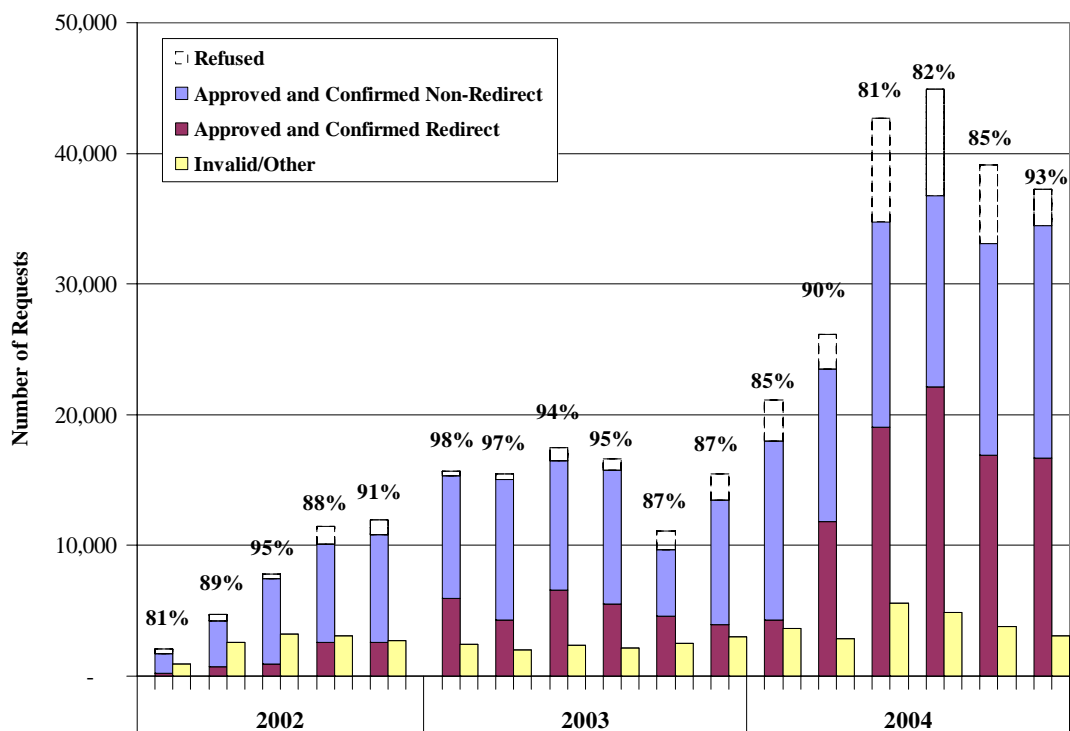
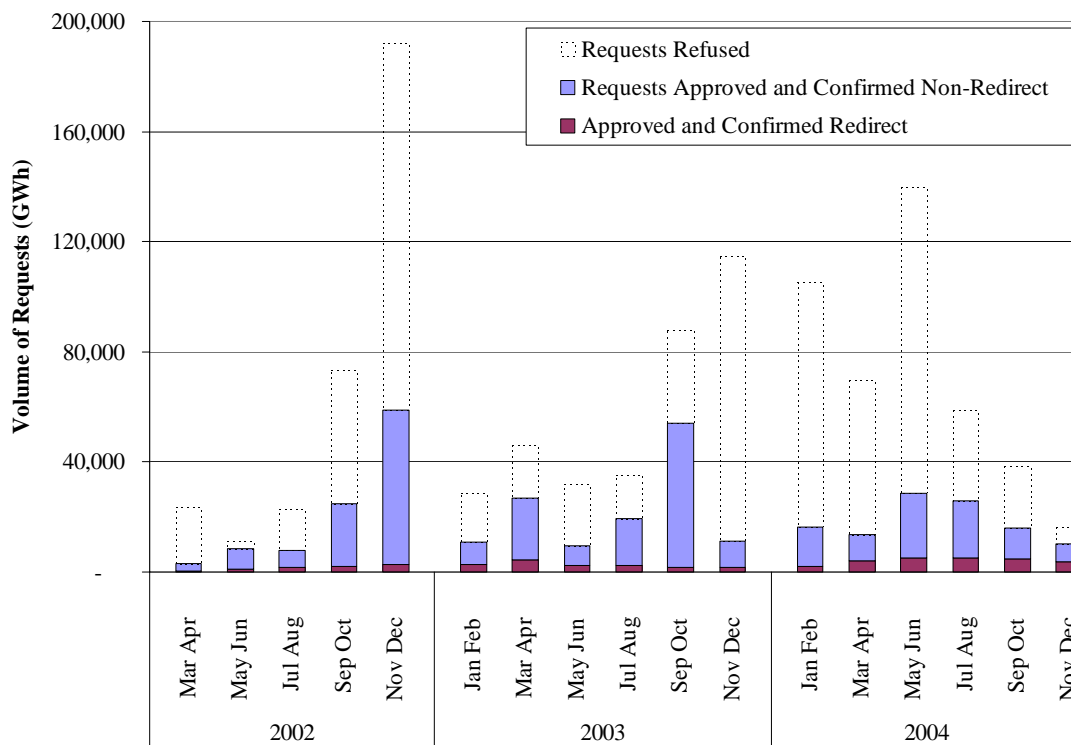


Figure 12 reveals a number of patterns. The number of approved requests increased each year from 2002 to 2004. On an average monthly basis, the approval rates ranged from 83 percent to 91 percent in 2004, which is comparable to 2002 and 2003. The “Invalid/Other” category remained at levels comparable to the levels of 2002 and 2003. This is noteworthy because as long-term transmission requests are approved, the system will become more fully subscribed and approval rates should decrease.

The figure also shows that redirected requests increased sharply in 2004, accounting for most of the increase in approved requests. The number of new requests that were approved in 2004 remained at levels comparable to 2003. Because this analysis is based on the number of requests, it does not measure the volume of the transmission service being requested, which is based on the magnitude and the duration of the service. In Figure 13, we present the disposition of requests on a volumetric basis, measured in gigawatt-hours (“GWh”).

**Figure 13: Disposition of Reservation Requests (GWh)**



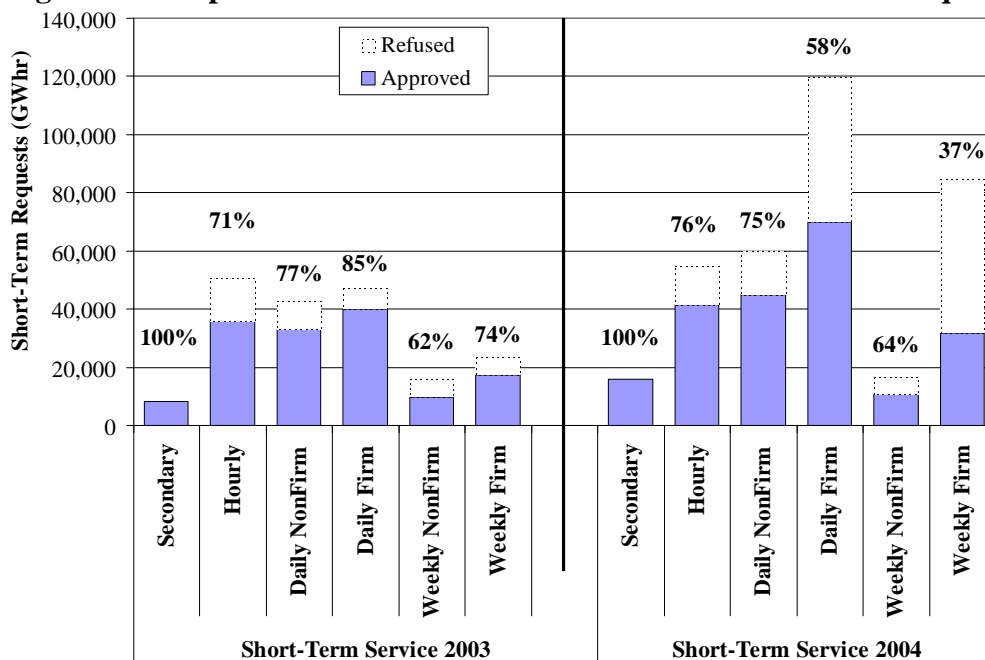
The figure shows that the volume of refused requests is very large relative to the number of requests. In other words, while the number of refused requests from the previous figure is small relative to all requests, they are a significantly larger portion of total requests on a GWh basis. A significant factor in the high volume of refused requests is the denial of long-term firm service, which tends to account for a large volume of transmission service due to their duration.

The figure also shows that the volume of confirmed redirect service is very small relative to the number of requests. In other words, while the number of confirmed redirects from the previous figure is a significant portion of the total number of confirmed reservations, they are a very small portion of the volume of confirmed reservations. This indicates that participants tend to redirect service on a short-term basis.

Overall, the high approval rates and increasing numbers of approvals in 2004 indicate that transmission has generally been available for participants, which contributes to efficient wholesale trading. However, the availability of long-term transmission service over key interfaces has been limited because it has been fully subscribed. The analysis also shows that the number of redirected transmission requests increased in 2004, but they remain a small share of the total requests on a volumetric basis. Redirect service is examined in more detail below.

To better understand the patterns of transmission service during 2004, it is useful to show the monthly quantities approved and refused by type of service (firm vs. non-firm) and duration of service. We first show firm and non-firm requests for short-term service (hourly, daily, weekly) in Figure 14.

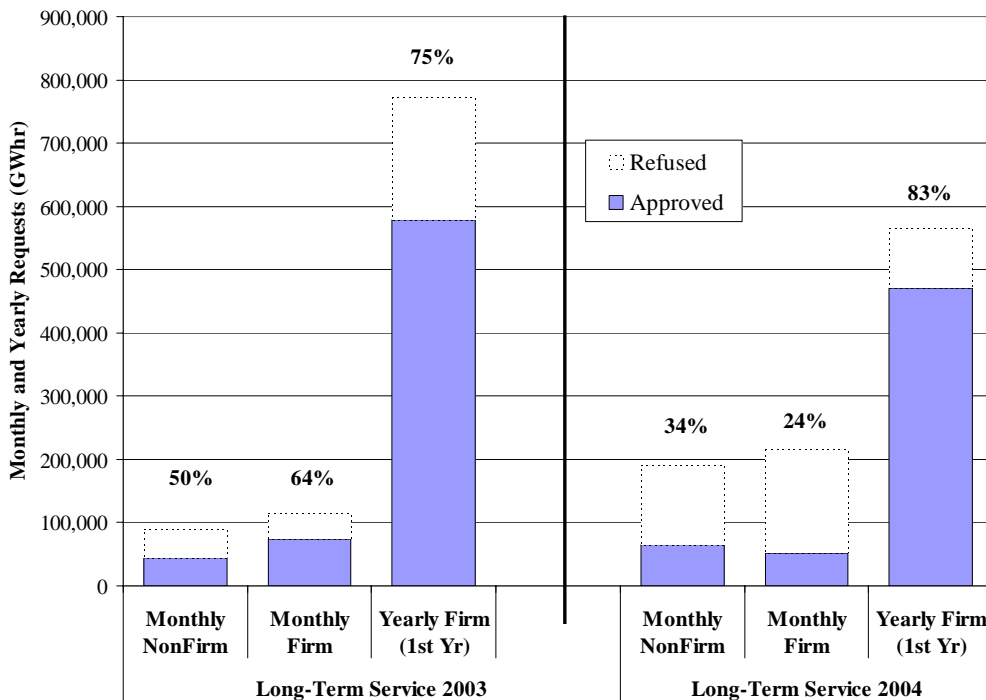
**Figure 14: Disposition of Short-Term Transmission Reservation Requests**



This figure shows that the volumes of approved requests for each type of transmission service increased in 2004. The approval rates in 2004 (compared to 2003) were slightly higher for hourly and weekly non-firm service but were somewhat lower for daily service, although the volume of approved requests for daily firm was significantly higher in 2004. Similarly, the approval rate for weekly firm was lower in 2004, but the volume was significantly higher.<sup>7</sup>

Figure 15 shows the disposition of long-term transmission reservation requests for 2003 and 2004.

**Figure 15: Disposition of Long-Term Transmission Reservation Requests**



The volume of approved requests was slightly lower in 2004 than in 2003. For monthly firm and non-firm service the total volume of requests was substantially higher, which contributed to the relatively low approval rates in 2004. For yearly firm service, the

<sup>7</sup> Secondary service is transmission scheduling to secondary points under a firm reservation. Secondary schedules are non-firm and always approved (because they can be curtailed if necessary). Therefore, we do not report the approval rate for secondary service, which is 100 percent by design.



volume of approved requests declined from 2003. However, because the volume of such requests decreased, the approval rate for yearly service increased.<sup>8</sup> Overall, the approval of long-term service decreased slightly in 2004. This is not surprising because the availability of such service has declined as participants have increased their reservations over key interfaces. Although the approval rates do not raise significant concerns, the process for obtaining long-term transmission service is not efficient. This issue is analyzed in the next sub-section.

## **B. Self Competing Requests and Transmission Availability**

In the section, we evaluate the connection between the transmission reservation process and transmission availability between the Midwest ISO and adjacent areas. The availability of transmission capacity between adjacent areas promotes the trading of long-term energy and capacity and improves the efficiency of regional markets.

The rules and procedures governing long-term requests for new service and for the renewal of existing services establish a queue to allocate scarce transmission capacity. Order 888 does not allow the Midwest ISO to allocate the capacity more efficiently by selling the service to the participant willing to pay the most for it. Instead, the current process compels participants to compete with one another through the queuing process. In particular, it creates incentives for participants that want to acquire or retain long-term capacity on congested interfaces to submit numerous requests for service. These rules allow a participant to benefit by having numerous requests in the queue, even if the participant intends to confirm only one of the requests. We refer to these types of requests as “self-competing” requests.

We analyze self-competing long-term requests and consider self-competing requests to be those requested by the same participant over the same path which straddle a fixed point in time (June 1, 2004 in our analysis). Additionally we define self-competing requests to not include the first request made by the participant or any requests that are ultimately confirmed by the participant. To evaluate whether the current rules may be causing

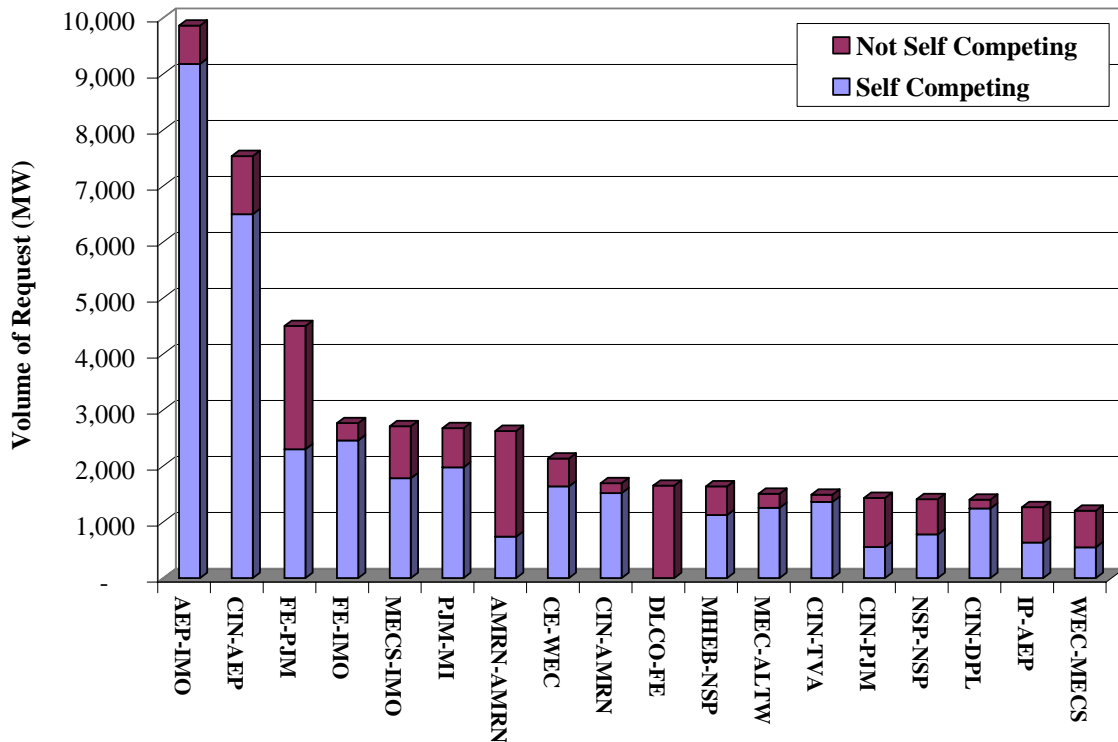
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<sup>8</sup> The volume for yearly service reflects only the first year of multi-year reservations.

participants to submit self-competing requests, Figure 16 shows the volumes of requests on the eighteen most heavily requested paths.

**Figure 16: Self-Competing Long-Term Transmission Requests**

Service Beginning Before and Ending After June 1, 2004



The figure shows that a high percentage of the requests on many of paths are self-competing. Self-competing transmission requests have little value from the perspective of efficient competition for the transmission capability. At little or no cost, participants can occupy a substantial portion of the queue to give themselves an option to buy the transmission service and restrict its availability to other participants. The result of this activity is that the transmission capability is made unavailable and may not be allocated to the participants that value it the most.

Although this analysis suggests a problem during 2004, the problem related to internal interfaces has been eliminated with the introduction of the LMP markets in April 2005. However, the interfaces with the most significant issues are those that interconnect the Midwest ISO with adjacent areas. For example, three of the top five interfaces with self-

competing requests are for capability from the Midwest ISO area to IMO. The other two interfaces are from the Midwest ISO to PJM. To the extent that the Commission considers modifications to the open access requirements under Order 888, we would recommend that the Commission consider allowing RTO's to establish a market-based price for its service when the demand exceeds the available supply.

### **C. Redirected Transmission Requests**

In this subsection we evaluate “redirecting” of firm service to an affiliated control area. Market participants with firm transmission reservations are able to redirect a firm reservation to alternative receipt or delivery points. Firm service that is redirected to secondary points on an hourly basis becomes non-firm. Firm service can also be redirected on a firm basis for a term that is less than or equal to the original reservation term (e.g., a firm monthly reservation can be redirected firm on a monthly or daily basis).

The ability to redirect firm service is a beneficial aspect of the Midwest ISO tariff. It increases the value of the transmission service to participants by allowing them to engage in transactions on those paths that are most valuable to them without having to purchase additional transmission service. This will be efficiency-enhancing when it leads to a higher utilization of the transmission system.

However, substantially all of the revenue associated with the redirected service is allocated to the control area associated with the redirected delivery point.<sup>9</sup> Hence, the ability to redirect transmission service can provide an incentive for participants to redirect service back to their affiliated control areas in order to retain the transmission revenues. Redirected reservations to an affiliate may not raise significant issues to the extent that they support actual transactions made to lower the costs or increase the profit of the participant (excluding the re-allocation of the transmission revenue). However, redirected service that is done solely to shift revenue has no competitive value.

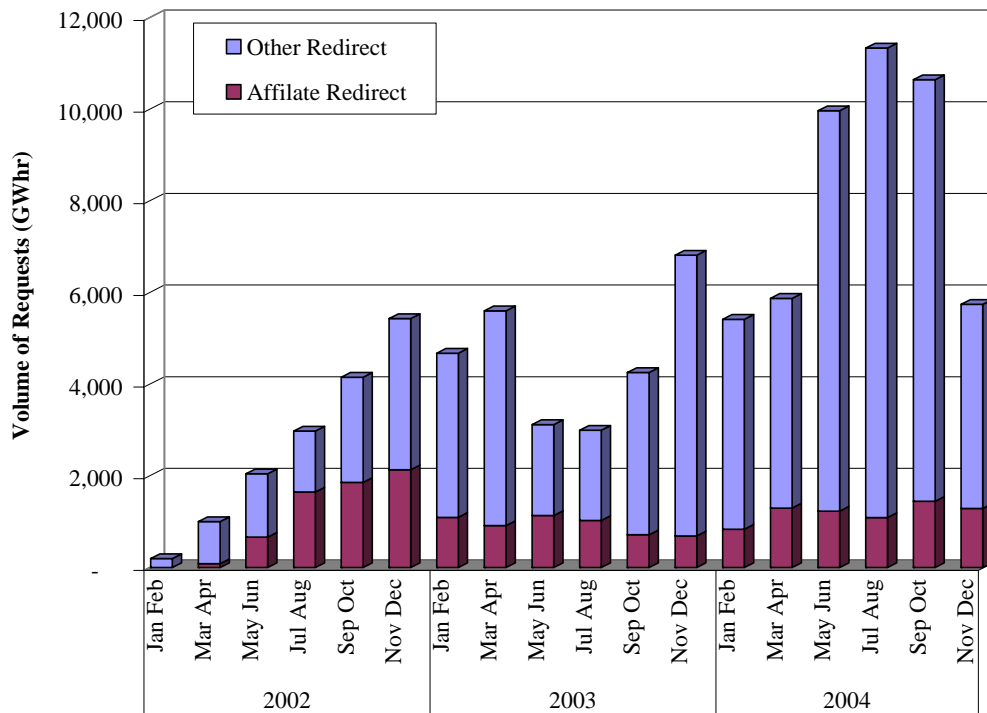
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<sup>9</sup> See §6.9 of the Business Practices Manual. When the redirected receipt point and delivery point are the same, i.e., within a control area, then approximately 94% of the revenue is allocated to that control area.

If the original point of receipt is the affiliate's control area and the point of delivery is another control area, and this is subsequently redirected so the point of delivery is the affiliate's control area (such that the receipt and delivery points are both the same), this schedule will not result in power flows and serves only to re-allocate revenue to the affiliate.

Our analysis evaluates the extent of this type of activity during 2004. Figure 17 shows the total monthly volume of transmission service redirected to an affiliate's control area and to other locations.

**Figure 17: Redirected Transmission Requests, 2002-2004**



This figure shows that the total volume of redirected service increased in 2004 from the trend in 2002-2003. However, the redirected service to an affiliated entity remained at levels comparable to previous years. Nonetheless, the rule does provide an incentive to engage in this conduct, which provides a competitive advantage to power marketers and other participants that are affiliated with a Midwest ISO transmission owner.

The practice also can distort the revenue requirements for Midwest ISO transmission service. This is true because the revenue allocated as a result of redirecting back to an affiliate's system is not credited against total revenue requirements that are the basis of the Midwest ISO formula rates (see Attachment O of the Midwest ISO OATT).

Therefore, the affiliate system that is the beneficiary of the re-allocated revenues will over-collect for transmission service while the system that "loses" the firm point-to-point revenue as a result of the redirected service will under-collect for its transmission service. With LMP markets, this issue will be less of a concern because participants will only use point-to-point service for through-and-out service. We will continue to monitor this conduct, however, and recommend potential changes if necessary.

#### **D. Unconfirmed Transmission Requests**

In this section, we evaluate the practice of participants not confirming transmission requests that have been approved by the Midwest ISO. Available transmission capability is reduced from the time a transmission request is made until it is refused or withdrawn. Hence, the capability will remain unavailable while the Midwest ISO awaits confirmation from the participant. If the approved request is not confirmed by the market participant within the time allotted for confirmation, the request is withdrawn and the capability is made available to the market.

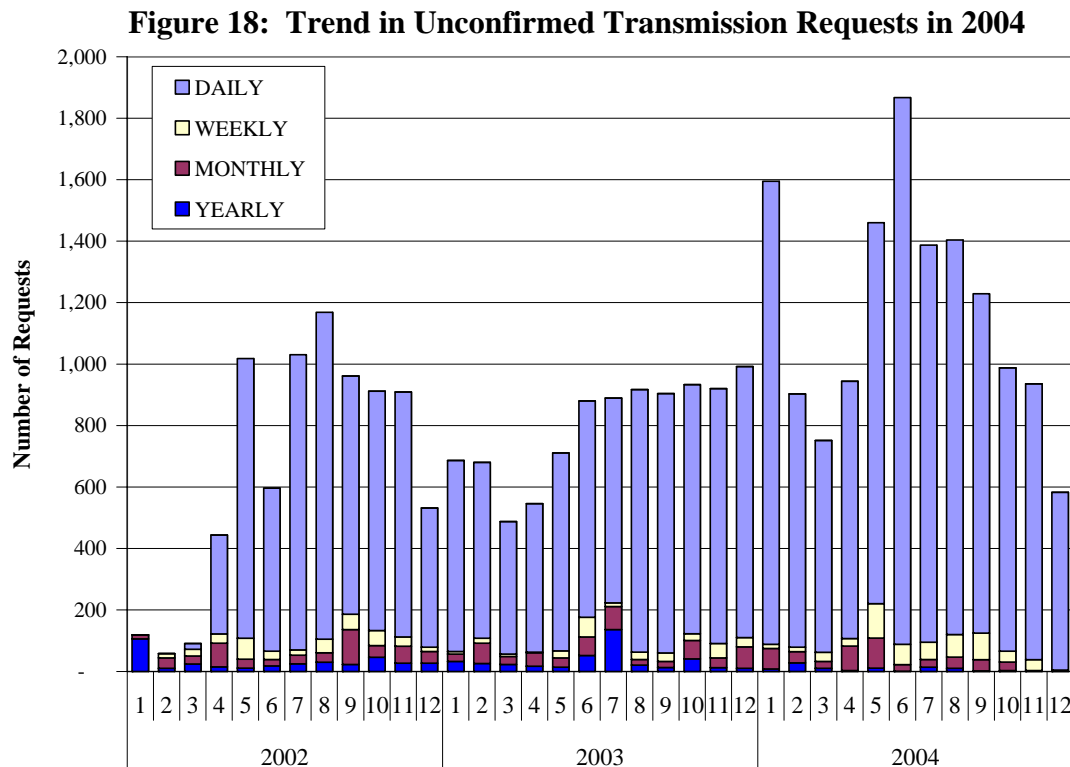
For daily firm service, requests can be made up to 14 days in advance. If the Midwest ISO approves the request, the participant has 24 hours to confirm the request, provided it is submitted more than 24 hours in advance, otherwise the service must be confirmed within two hours. Participants have a longer time to confirm longer-term service (e.g., 15 days for yearly firm service) as specified in Attachment J of the Midwest ISO's OATT.

Allowing time for participants to confirm an approved request is valuable for market participants, particularly if they must arrange service from other transmission providers to support a transaction. Perhaps the largest benefit of this process is that it provides participants with a free call on the transmission service. By holding an approved firm reservation, the participant receives an option at no cost to confirm and use the service or not to confirm the service and let it be withdrawn. Presumably, the participant would

exercise the option to confirm the service on those days when a profitable opportunity emerges to transfer power across the given interface.

Additionally, we note that capability can be secured well in advance by submitting a series of short-term firm requests. For example, daily firm requests can be submitted 14 days ahead to fully hold a given interface. Other requests will then be refused. The participant can then synchronize new requests for the same day for the time when its prior unconfirmed request is withdrawn and capability is momentarily available. When the day arrives, the participant will then have the option to use the service.

This conduct can adversely affect the market because the capability remains unavailable to other participants during the timeframe allotted for participants to confirm the request. Hence, large quantities of accepted requests that are ultimately unconfirmed and withdrawn can cause transmission to be under-utilized. It can also signal that participants are using the confirmation process to strategically hoard transmission capability, which we evaluate in this section. Figure 18 shows the number of unconfirmed requests in each month for various types of service.

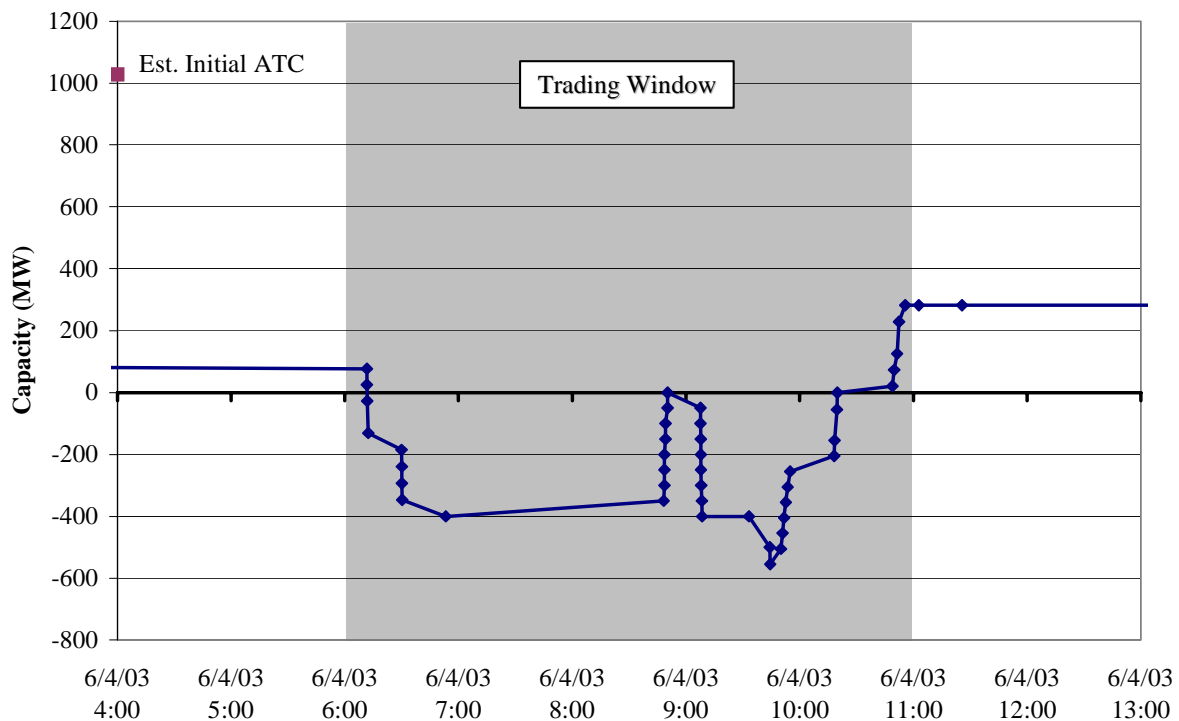


The figure indicates that the number of unconfirmed requests has increased slightly from previous years. The analysis also shows that the largest quantity of unconfirmed requests is for daily firm service. Hence, we evaluated the patterns of unconfirmed requests for daily firm service to determine whether they indicate potential hoarding of transmission. We define hoarding for these purposes as holding transmission capacity for the purpose of preventing access by rivals to the capacity. We considered an unconfirmed request to potentially indicate hoarding if three conditions were met:

- The daily firm ATC was zero during the trading window in which marketers and other participants make trades for the next day (6 AM to 11 AM central time);
- Midwest ISO refused requests for daily firm service on the path; and
- The ATC was greater than zero at the end of the reservation period for the service (i.e., daily firm capability went unsold).

Figure 19 shows an example of a day when these three conditions were met on the Cinergy to TVA path for a representative day.

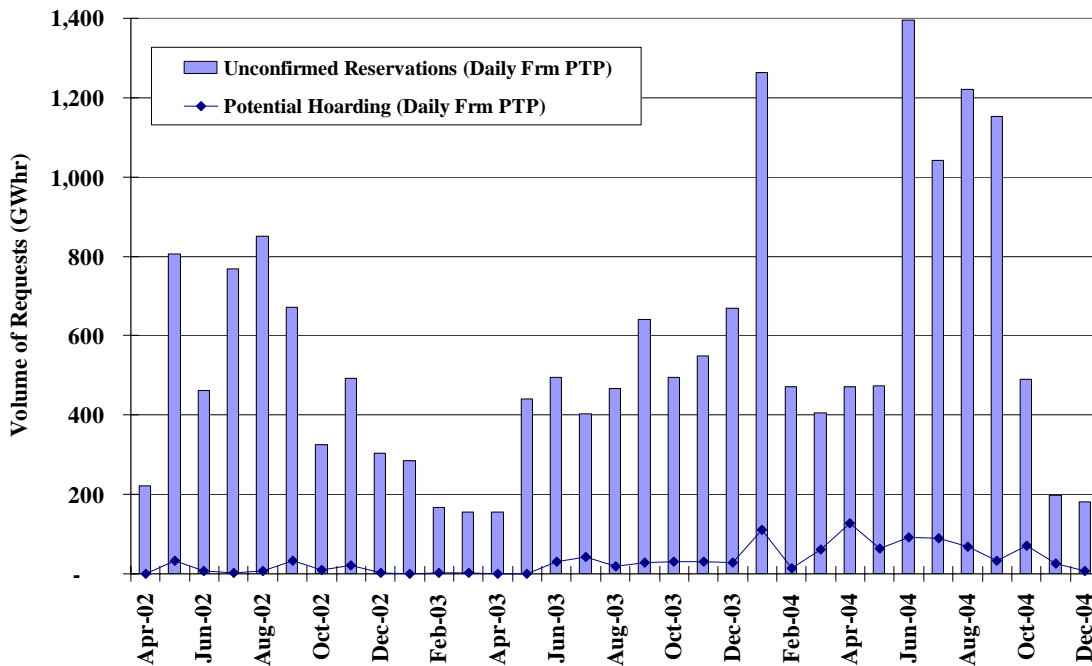
**Figure 19: Estimated Firm Daily ATC – Cinergy to TVA**



Although the initial ATC on the path was close to 1000 MW, the figure shows that there was no ATC during the most of the intervals in the trading window (6 AM to 11 AM). Due to the lack of ATC, a number of requests were refused during the trading window. One can see in the figure when new requests were made during the trading window (the ATC declines sharply) and when the requests are refused (the capability rises sharply, but remains less than zero). However, 300 MW of ATC became available after the trading window because the approved requests were not confirmed by the participants.

Figure 20 shows the total volume of unconfirmed daily firm requests by month for April 2002 – December 2004. To evaluate whether these unconfirmed requests may indicate transmission hoarding, we applied the three criteria described above. The requests that satisfy these three criteria are shown in the figure as “Potential Hoarding”.

**Figure 20: Approved and Unapproved Requests and Potential Hoarding**



These results show that there has not been a substantial quantity of unconfirmed requests that meet these criteria. Hence, we do not find that market participants have used the daily firm point-to-point transmission reservation process to hoard a substantial amount transmission. Although we do not find clear evidence of hoarding, the quantities of



unconfirmed reservation requests are relatively large. We find the cause of these patterns is most likely related to the incentives provided by the current tariff. As discussed above, the tariff provides participants a free call option on firm transmission service during the time allotted for them to confirm an approved request. This call option can be valuable on days when a significant basis differential emerges in the bilateral market. Because this conduct can block participants' access to firm service at times and lead to under-utilization of the transmission system, we recommend the Midwest ISO consider tariff revisions to eliminate this "free call" aspect of the tariff.

Like other transmission access issues discussed above, the move to LMP markets will make some of this concern less immediate. However, the problem can still arise for through-and-out service and we will continue to monitor this going forward.

#### **E. Designation of Network Resources**

In this section, we analyze the designation of network resources to evaluate the concern that some Network Integration Transmission Service ("NITS") customers systematically designate network resources that substantially exceed their load or do not meet the requirements of the Midwest ISO Tariff and Business Practices Manual ("BPM"). Designating network resources in excess of the network load, particularly from locations external to the control area of the load can result in significant inefficiencies by reducing the overall utilization of the transmission system.

Part III of the Tariff places a number of restrictions on the use of NITS and network resources, including the following:

1. Not to be used for sales to non-designated loads or third parties (Section 28.6);
2. Must be available to serve network load on a non-interruptible basis (Section 30.1);
3. The output of the network resources shall not exceed the designated network load plus non-firm sales plus losses (Section 30.4);
4. The NITS customer must be able to redispatch the network resources upon request of the Midwest ISO (Section 30.5);
5. For network resources not physically interconnected to the Midwest ISO system, necessary arrangements have been made for delivery (Section 30.6);
6. The NITS customer must own the network resources or have an executed contract for the generation (Section 30.7); and

7. The NITS customer's use of interface capacity may not exceed the customer's load (Section 30.8).

Section 6.18.2 of the BPM addresses the designation of network resources and associated restrictions, including the following:

1. NITS customer must certify that firm transmission service has been obtained for facilities not within the MISO (8);
2. NITS customer must certify that the resource is not being counted as a designated resource for another load on or off the MISO system (9);
3. NITS customer must certify that it has the contractual right to the resources and that schedules cannot be interrupted for economic reasons (10); and
4. The schedules from network resources may not exceed real-time load (13).

While the BPM provisions generally cover the Tariff requirements, they do not fully address the OATT requirements 3, 4 and 7 listed above. Data is not readily available to assess the extent to which NITS customers are in compliance with the Tariff and BPM. Three certifications are required in order for a NITS customer to designate network resources. However, verifying that NITS customers are in accord with these certifications would require examination of documents between the NITS customers and third parties. Several parties have reported that they have been designated as network resources without the NITS customer executing a contract for the capacity. Given the degree of excess to which some of the NITS customers are designating network resources, it is likely the case that some of the designated resources are not contracted.

Discussions with one participant that designates resources well in excess of its load revealed that its source of supply is often firm contracts that do not specify generation or a specific source system. These contracts include liquidated damages provisions for non-performance. Sometimes referred to a "Seller's Choice contracts", these generally allow the seller to deliver energy to the customer from a source that they choose after the contract is signed for delivery to any of the customer's interfaces. Ultimately, the source is specified when the energy is scheduled. The participant's method for designating the contract as a resource is to make separate designations from each surrounding source system that they anticipate the seller may use to schedule energy to one of its interfaces.

While the participant we contacted has a contract with the seller, it does not have contracts with the sources specified in its OASIS network resource designations. The

Tariff and BPM specifically allow firm liquidated damages contracts to be used as designated network resources.<sup>10</sup> However, neither the tariff nor the BPM specifically grant nor specifically prohibit the specifying of multiple sources associated with the contract, as is often practiced.

There are no disincentives for engaging in over designation of network resources. This is because settlements are based on the customer's actual loads, not on the amount of network transmission service that is reserved. If NITS customers properly contract for physical capacity, expenses would be incurred from suppliers since the supplier should lose the right to operate the contracted capacity except on a non-firm basis. Other than this supplier expense, the network customers have a free option on transmission paths in designating supply from any number of suppliers. In order to illuminate the extent of any problem with over designation, we evaluate the level of network designations relative to the NITS customers' peak loads. We then assess the effects of excessive designations on the availability of transmission capacity.

Network resources are divided into two categories; in-area and external. The in-area resources are located in the same control area as the sink. Designations of these resources do not affect AFC calculations for up to 30 days. External resources are those that are not located in the same control area as the sink and will affect AFC calculation for any service increment. Excessive designation of network resources in-area may be violations of the Tariff and BPM, but they are not likely to affect market efficiency because they do not affect AFC.

Both the Tariff and the BPM provide for a non-firm class of NITS. In the Tariff it is called "Secondary Service" (Section 28.4) and enables energy deliveries from resources that have not been designated as network resources. These reservations are referred to as "non-designated" in the BPM and on the OASIS. In our analysis, the designated network resources (firm) and the non-designated network resources (non-firm) are tracked separately. Excessive designated network resources are more detrimental because they

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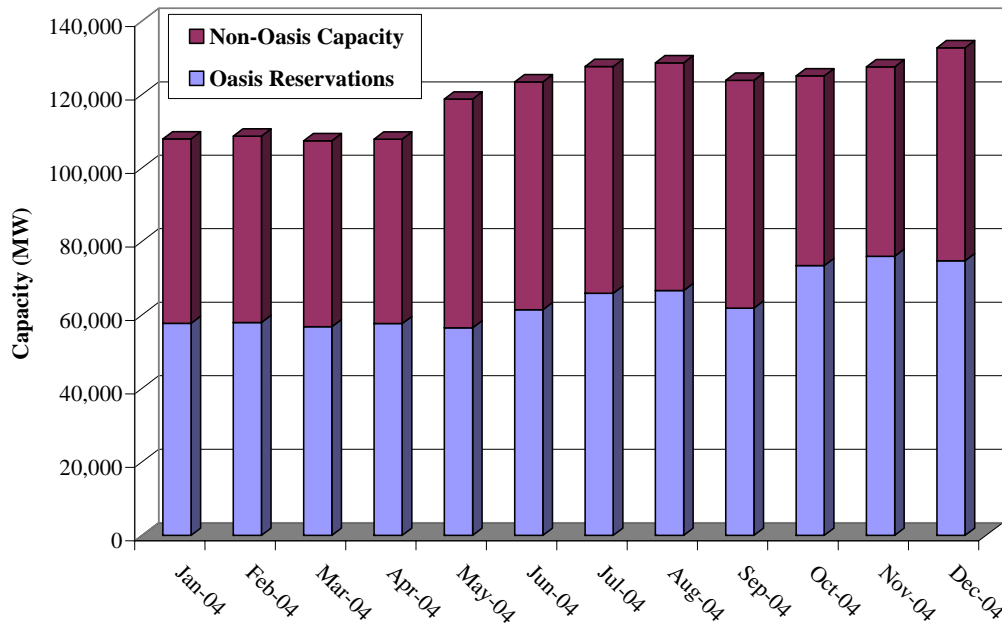
<sup>10</sup> This was addressed in FERC Docket No. EL02-6-000.

are firm, but excessive non-designated network resources still have an impact because Secondary Service has a higher priority than non-firm point-to-point service.

We analyzed the total network designations for the 19 generation owners that are NITS customers. We discovered that a large share of the network resources are not designated through the OASIS. Most of this capacity is generation owned by the Midwest ISO vertically-integrated utilities. We include this capacity in our analysis and refer to it as “Non-OASIS Capacity”. From an AFC perspective, Non-OASIS Capacity is treated the same as in-area resources and so treating it the same in our analysis is appropriate.

We calculate the total designations of NITS customers and the ratio of the designated capacity to the peak load. This helps determine whether NITS customers have a tendency to designate excessive quantities of network resources. The analysis was performed for 12 time points: 12:00 noon EST on the third Wednesday of each month from January 2004 through December 2004. Figure 21 provides a summary of the monthly network designations by MISO NITS customers in 2004.<sup>11</sup>

**Figure 21: NITS Contract Capacity and Reservations  
2004**

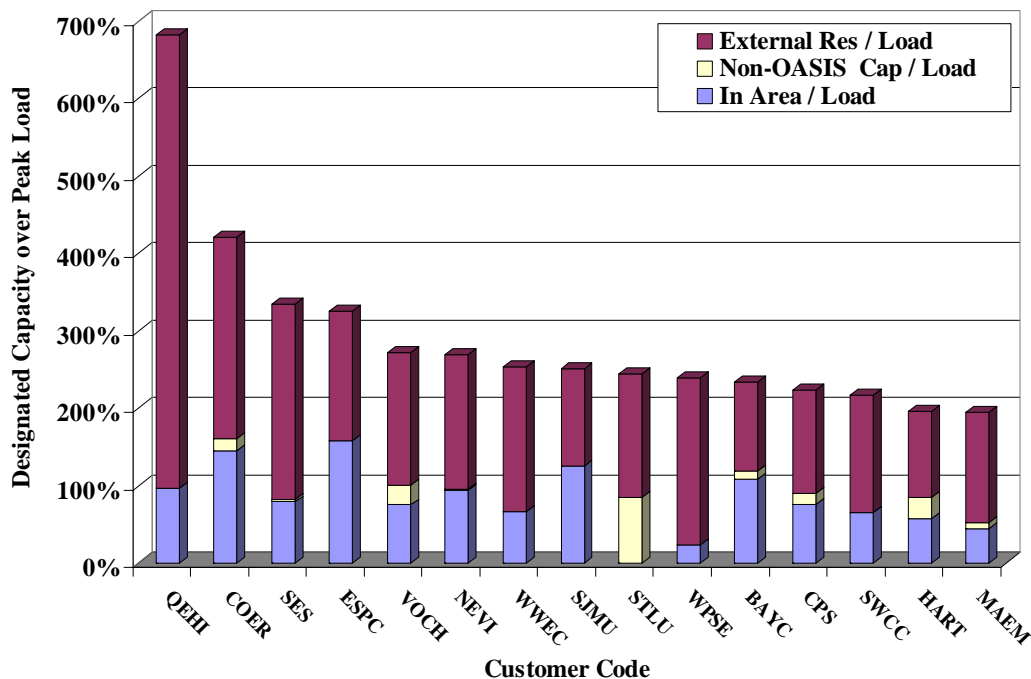


<sup>11</sup> To be consistent with AFC calculation methodology, Consumer Power and Detroit Edison are treated as separate control areas in this analysis even though they are both in the MECS control area.

This figure shows that the overall level of designations has increased from January to December. It also shows that close to one-half of the designated resources are not entered in the OASIS. This makes tracking and validating this information and ensuring that it is recognized in calculating AFC values much more difficult. However, to evaluate these results, it is important to show the designations by market participant.

Figure 22 summarizes the ratio of the average network designations to the peak load in 2004 for the 15 NITS customers with the largest ratios. The top portion of the bar is the average quantity of network resources that are external to the participant's control area, including designated and non-designated resources under all NITS contacts held by the customer. The middle portion of the bar is the assigned non-OASIS capacity (capacity owned by the participant that is not designated). The bottom portion of the bar is the average quantity of network resources within the participant's control area, including designated and non-designated resources.

**Figure 22: Designated and Non-Designated Network Resources  
2004**

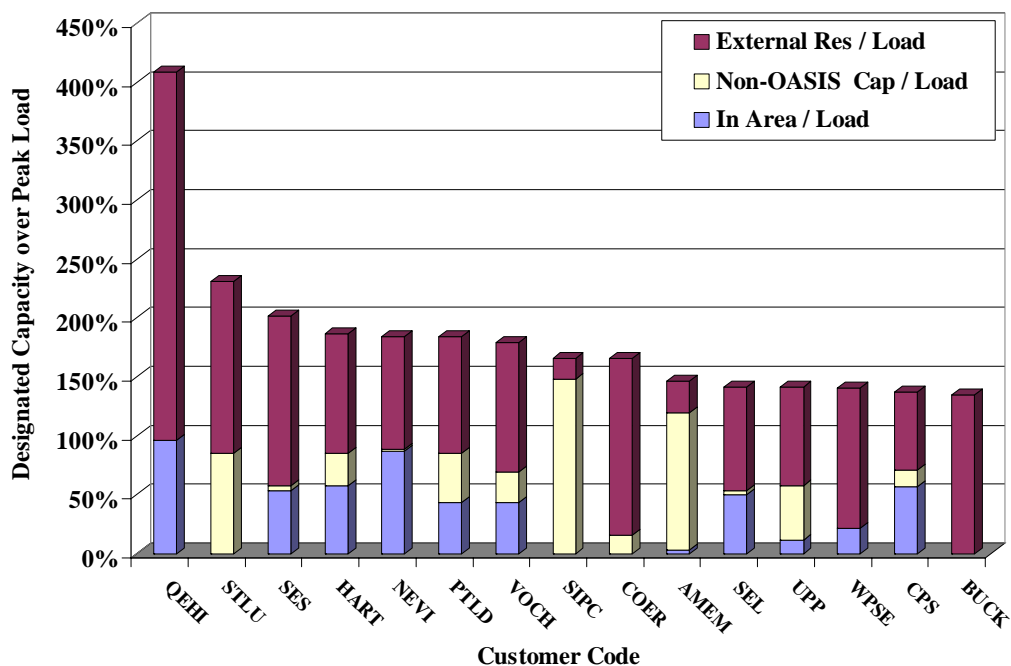


The figure shows that the total designations for 13 of these 15 customers was more than 200 percent of the customers' annual peak load, with two of the network customers

designating over 400 percent of their peak load and one designating almost 700 percent of its peak load. The figure also shows that all of the customers designate a significant amount of resources that are external to their control area, which can substantially affect AFC values in the region.

In the next analysis, we focus on only those resource designations that could potentially affect *firm* AFC values. In Figure 23 we show the 15 entities with highest ratio of firm designations to load by removing the non-designated network resources. Non-designated network resources are treated as non-firm and, thus, would not affect firm AFC values. Because this is a different measure than in the previous figure, the 15 entities that have the highest ratios are different than those in Figure 22.

**Figure 23: Ratio of Firm Network Designations to Network Load**



As expected, this figure shows lower ratios for each customer. Nine of the 15 customers exhibit ratios higher than 150 percent in this analysis, with the highest exceeding 400 percent. Hence, the number of customers designating *firm* resources that substantially exceed their annual peak load is limited. However, all of the customers designate a significant amount of external resources relative to their peak loads, which can significantly affect AFC values.

To evaluate this, we calculate the ATC effects of these designations in the next analysis. The ATC effect is calculated by subtracting the customer's peak load from its firm external network designations. For example, if an NITS customer with an annual peak load of 1000 MW designates 1500 MW of network resources external to its control area, the estimated ATC effect would be associated with the 500 MW excess designation.

Subtracting the peak load from the external designations is a conservative assumption. If internal resources were first designated to satisfy the peak load prior to the external resources, the external designation deemed to be excess designations would be larger and the estimated ATC effects would be larger. In addition, the real impact may be far greater than our analysis shows because these reservations can significantly affect multiple flowgates. The effect on these flowgates can reduce the ATC on many different transmission paths because any new request for service can only be granted if there is adequate available flowgate capability on the 15 most limiting flowgates affected by the request. Network reservations that would reduce the AFC on a key flowgate to zero would cause the ATC to be zero on any Midwest ISO path whose transactions cause significant flow on the flowgate.<sup>12</sup>

Hence, our analysis will tend to be conservative, showing a smaller effect on ATC levels than the excess designations actual have. The results of our analysis are shown in Figure 24. Because a single market participant was responsible for a large share of the excess designations, this participant is shown separately in the figure.

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<sup>12</sup> For a non-contingent flowgate, five percent of the power must flow over the path to be considered significant. Only 3 percent of the power must flow over a contingent flowgate to be significant.

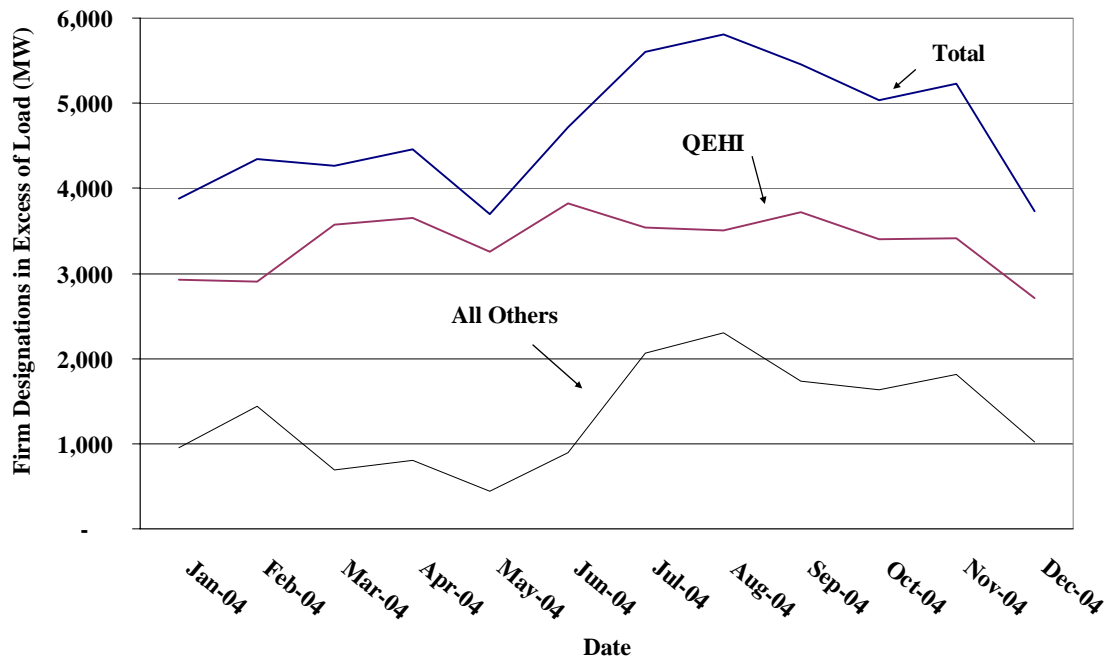
**Figure 24: Excess Designations by Month**

Figure 24 shows that the total effect on the ATC over the designated paths was significant, increasing during the summer before declining at the end of the year to levels comparable to the early part of the year. This figure also shows that about 80% of the over-designation is caused by one market participant: QEHI. The Midwest ISO and the IMM are currently engaged in a process to verify the contractual support for these designations and considering whether changes are necessary to reduce the impact of this conduct.

In summary, excess network designations can inefficiently reduce the firm ATC available to market participants and ultimately the capability of the system. The current market rules provide few restrictions or economic incentives to discourage over designation of network resources. Nevertheless, excess firm designations relative to the annual peak have not been a significant concern to date with the exception of a very small number of customers.

However, when the excess designations are considered relative to the monthly peak loads, we find that the excess designations are substantial. Because some of these excess



designations are from external sources, they will tend to substantially reduce available firm transmission capability. To address this issue, we previously recommended the following changes to the Midwest ISO's rules and procedures:<sup>13</sup>

1. Requiring the source to be specified when the designation is made. If a customer has a seller's choice contract, then wait until after the seller chooses so the source is known before granting designated network resource capacity. Those reservations that are on the system without a contract to a source as specific as used in ATC calculations should be annulled.
2. Clarify the treatment of "seller's choice" and other forms of firm liquidated-damages contracts in the Tariff and BPM.
3. Modify the BPM and related systems to enable NITS customers to profile their resource designations seasonally (one value per month) without sacrificing roll-over rights.
4. Consider a cap on the ratio of network designations to the monthly peak load for the customer. This would compel customers to reduce designations in off-peak months and make more transmission service available for others.
5. Record all network designations electronically in the OASIS to allow more effective monitoring of this issue.
6. Change service retroactively to point-to-point, if, in the future, NITS customers were found to have held transmission system capacity through network resource reservations that were not in compliance with the Tariff and BPM.

These changes and other changes were considered by the Midwest ISO and its market participants. However, no consensus was achieved. Hence, these recommendations have not been proposed by the Midwest ISO. In addition, the concerns associated with excess network designations are substantially mitigated under the Day 2 LMP markets that were implemented in April 2005 since the use of the internal transmission capability is governed by the LMP market rather than by transmission reservations and schedules.

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<sup>13</sup> *Assessment of Network Resource Designations*, Potomac Economics, August 2004.

## **VI. Midwest ISO Operations**

In this final section of the report, we examine Midwest ISO operations related to its management of congestion and hourly AFC calculations. We first examine the pattern and frequency of TLR events and transaction curtailments associated with these events. This includes examining TLR events by region and evaluating whether TLR procedures have been implemented consistently. Our second area of analysis is the efficiency of the TLR process as a method of managing congestion relative to operating RTO markets that employ market-based redispatch of generation to manage congestion. The third analysis addresses the hourly AFC values. In this analysis, we review the amount of physical capability available in real time on flowgates when the posted non-firm AFC is zero.

### **A. TLR Events: Patterns and Frequency**

The Midwest ISO manages transmission congestion through the NERC TLR Procedures.<sup>14</sup> Under these procedures, the Midwest ISO monitors real-time flows on flowgates relative to their operating limits. When a flowgate exceeds its limit or is expected to exceed its limit (based on next hour scheduled transmission service, current hour ramping schedules, or other factors), security coordinators will take actions under these procedures to reduce line loadings.

The TLR procedures have a number of levels. A Level 3a TLR event affects transactions in the next hour by holding or curtailing the lowest-priority non-firm schedules to allow higher-priority service to be scheduled or to decrease the flow on the relevant flowgate. A Level 3b TLR event affects transactions in the current hour, resulting in curtailments of non-firm transmission service (lowest priority first) as needed to maintain reliability. Under a Level 4 TLR event, generation will be redispatched or the transmission system will be reconfigured to provide relief for the flowgate. For example, American Transmission Company coordinates a redispatch process that is used to resolve

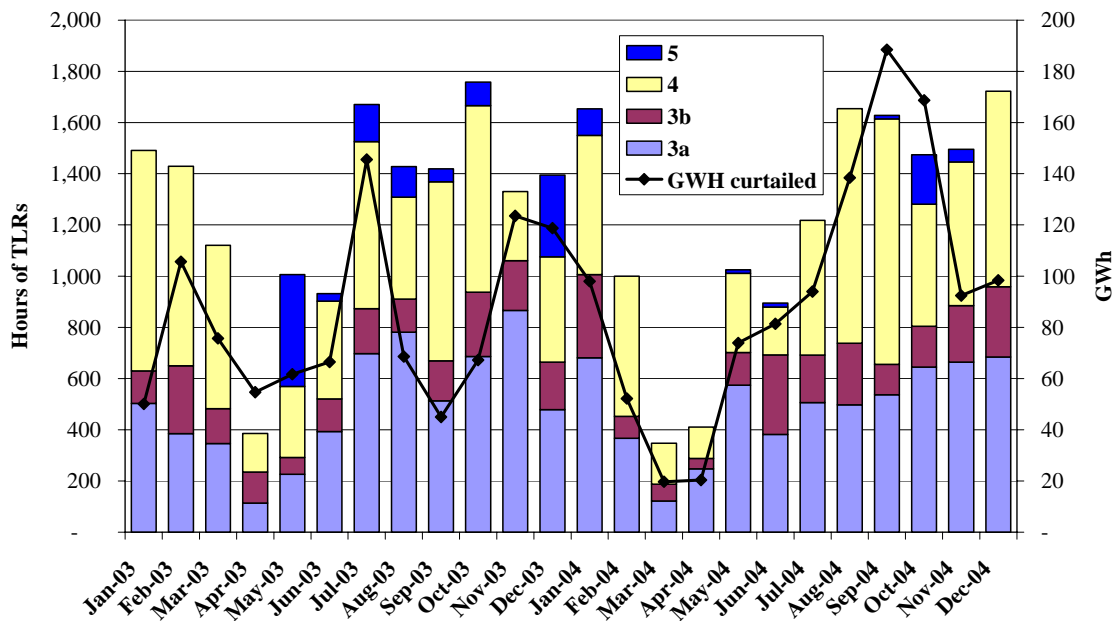
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<sup>14</sup> See NERC Policy 9 and Appendices 9C1, “Transmission Loading Relief Procedure – Eastern Interconnection”; 9C1B, “Interchange Transaction Reallocation During TLR Levels 3a and 5a”; 9C1C, “Interchange Transaction Curtailments During TLR 3b”; and the “Parallel Flow Calculation Procedure Reference Document”.

congestion within Wisconsin and Upper Michigan when a Level 4 TLR event is invoked. Under Level 5a and 5b TLR events, firm transmission schedules are put on hold or curtailed. Under a Level 6 TLR event, emergency actions are invoked.

The real-time flows over each of the Midwest ISO flowgates, based on information from meter readings and its state estimator, are captured in the Midwest ISO's real-time flowgate monitoring tool ("FGMT"). The FGMT alerts reliability coordinators when flows are approaching the operating security limit ("OSL") of a flowgate. When this occurs, the Midwest ISO operators use the Interchange Distribution Calculator ("IDC") to identify current and future transmission schedules for which 5 percent or more of the associated power flows occur on the given flowgate. These are the transactions that would be subject to curtailment if the Midwest ISO must invoke a TLR to relieve the flow on a flowgate. In addition, the Midwest ISO may consult with its control areas for additional information regarding current and expected changes in system conditions when monitored flows approach the OSLs. Figure 25 provides a summary of the Midwest ISO's TLR activity in 2003 and 2004, including the quantity of transactions curtailed.

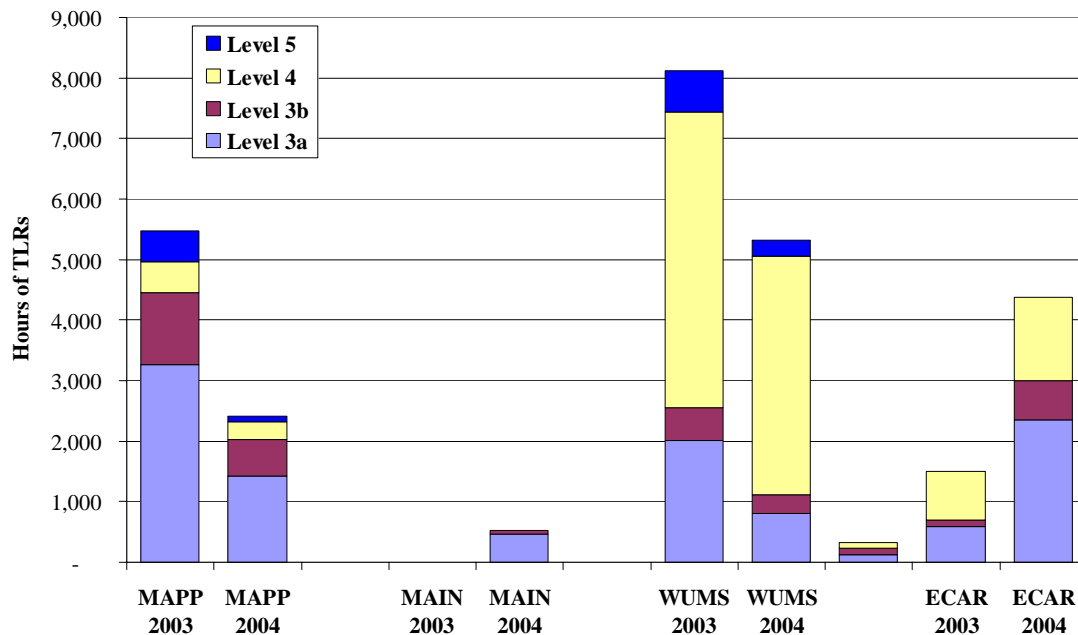
**Figure 25: TLR Events and Transactions Curtailed  
2003 - 2004**



The TLRs called on Midwest ISO flowgates (level 3 and above) accounted for more than one-half of all TLRs called in the Eastern Interconnect. This considerable share of total TLR events can be explained by the fact that much of the Eastern Interconnect is operated under LMP or other central markets that redispatch generation to manage congestion, rather than using TLR procedures.

Figure 25 shows that the curtailment quantities have increased slightly from 2003 levels. The figure shows that in some months, curtailments rise as TLR events increase. In some months, however, curtailments decline even as TLRs increase. Part of this is explained by the use of redispatch processes under a level 4 TLR. Level 3 and 5 TLRs result in curtailments of non-firm and firm transactions, respectively. However, Level 4 TLRs can result in the redispatch of generation to unload constrained transmission interfaces. This type of process is used by American Transmission Company to manage congestion in WUMS. To better understand the patterns of TLRs occurring within the Midwest ISO region, Figure 26 shows the TLR events and transactions curtailed by sub-region in 2003 and 2004.

**Figure 26: TLR Events by Sub-Region  
2003-2004**



The figure indicates that although the total TLR events in WUMS decreased in 2004 from 2003, the WUMS region experienced the most TLR hours. This is consistent with expectations because WUMS relies on imports to meet peak load and has limited transfer capability from neighboring regions. The large share of the Level 4 TLR events in WUMS reflect the use of American Transmission Company's redispatch process.

ECAR experienced a large increase in TLR hours in 2004. A primary cause of this increase was the PJM integration of CE and AEP. As discussed above, when AEP was integrated in October of 2004, generation on the CE system was dispatched at higher levels to replace higher-cost power in eastern PJM. This resulted in increased congestion in Northern Indiana. While this increased congestion in some of the Midwest ISO control areas, imposing costs on market participants as a result of curtailments, it also increased the utilization of the transmission capacity in the Midwest.

#### **B. Evaluation of TLR Events and Curtailments by the Midwest ISO**

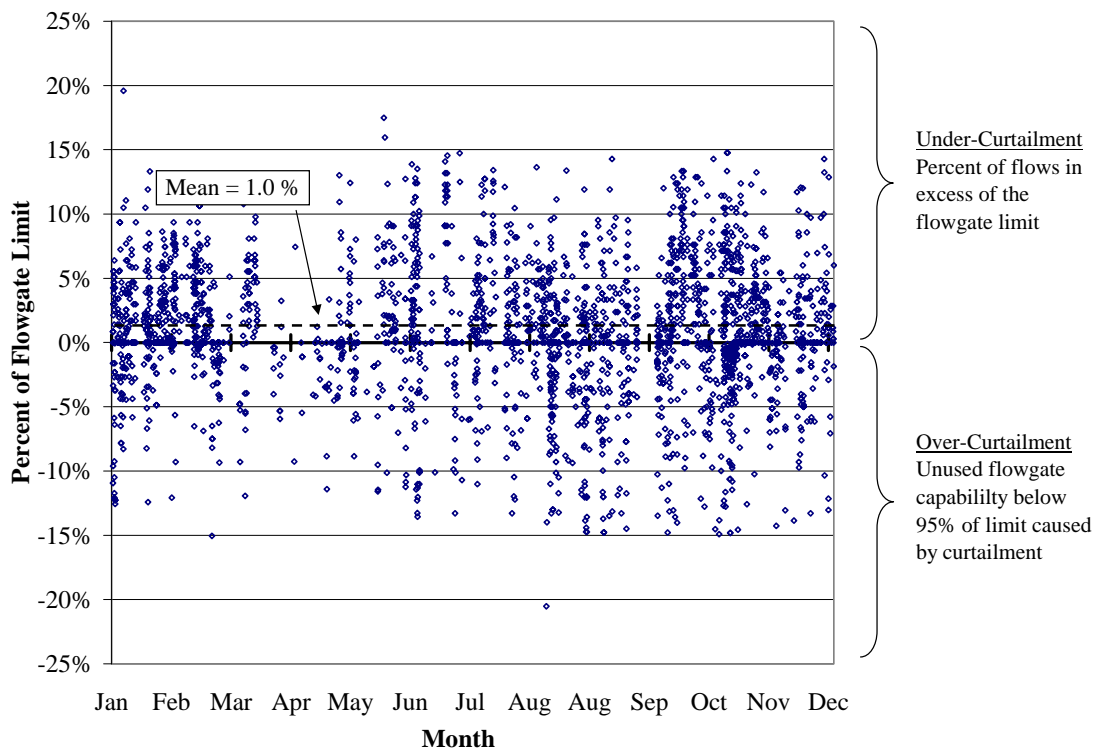
In our next analysis, we evaluate more closely the Midwest ISO's TLR events in 2004. To do this, we examine the flows on each of the flowgates in hours when TLR events occurred. A TLR should be called when the flow on a flowgate is approaching its limit. When a TLR is called, curtailments are requested in order to reduce the flow to 95 percent of the flowgate limit. This target range exists in part because there are significant uncertainties in the TLR process.

The uncertainties in the TLR process include the amount of relief that will be needed. Operators are forecasting the operating conditions for next hour more than 20 minutes before the hour, which can be more than an hour before the relief is forecasted to be needed. There is also uncertainty as to the level of the relief that any particular curtailment will provide because transactions are modeled from control area to control area. Because the actual redispatch of generation is not known, the resulting relief on the flowgate is uncertain.

To evaluate the Midwest ISO TLR events in 2004, we analyze the system conditions and results of each TLR event of level 3 or higher to determine whether the Midwest ISO's

actions resulted in an over-curtailment or under-curtailment. An over-curtailment is a curtailment that causes the flow to be less than 95 percent of the flowgate OSL. An under-curtailment is one in which additional relief is necessary to reduce the flow to the flowgate OSL. We measure the flow at the middle of the TLR hour to control for the effects of ramping, which can be higher or lower than the actual flow at the beginning or end of the hour. Level 4 TLR events are not included because they result in redispatch rather than curtailments. Figure 27 shows the over-curtailment or under-curtailment for each TLR event in 2004.

**Figure 27: Over-Curtailments and Under-Curtailments during TLR Events 2004**

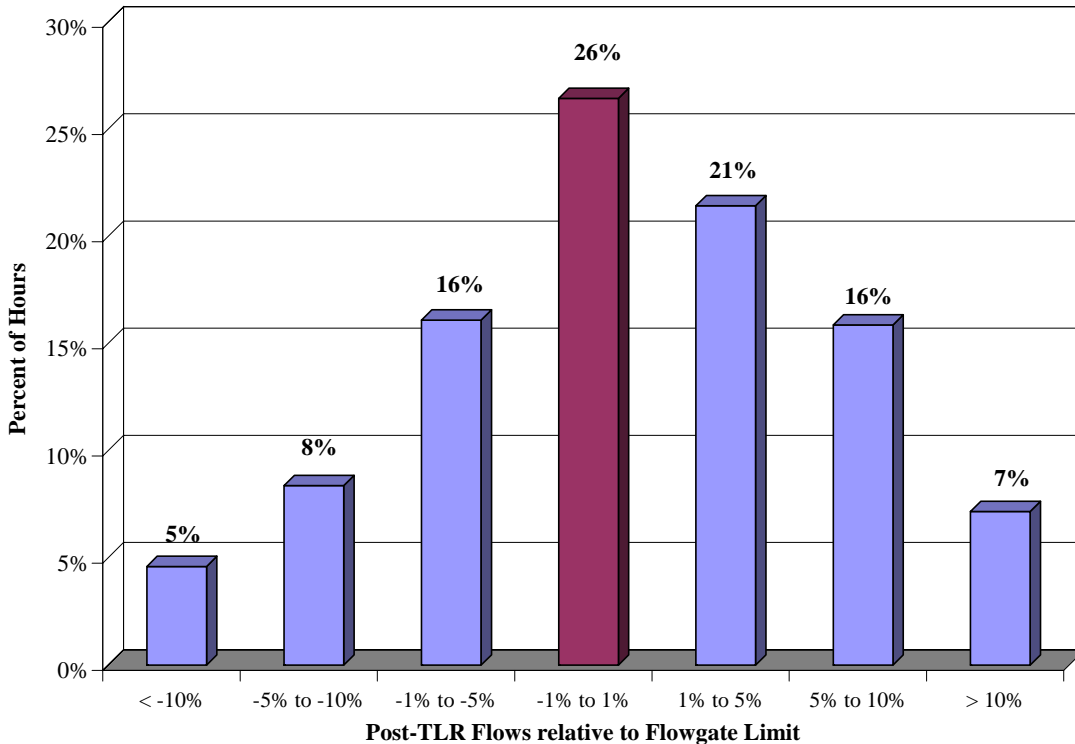


The analysis indicates the bulk of the curtailments are in the range of 10 percent over-curtailment to 10 percent under-curtailment, with some outside this band. On average, TLR events resulted in an over-curtailment of 1.0 percent.

To better show the relative quantities of over-curtailments and under-curtailments, we show how these curtailments were distributed during 2004. Figure 28 shows the

distribution of over-curtailments and under-curtailments over the year, indicating the percentage of TLR hours in which the over-curtailment or under-curtailment fell in specific ranges.

**Figure 28: Distribution of Over-Curtailments and Under-Curtailments 2004**



The figure shows that 26 percent of the curtailments are accurate, meaning over-curtailments or under-curtailments of less than 1 percent of the flowgate limit. About 63 percent of the curtailments are over-curtailments or under-curtailment amounts of less than 5 percent of the flowgate limit. These results are encouraging considering the uncertainties inherent in the TLR process.

As a further analysis of over-curtailments and under-curtailments, we sought to identify any cases when the Midwest ISO was slow in invoking a TLR, allowing the flow to rise above the flowgate limit. To do this we identified every interval on every flowgate when the flow was greater than 100 percent of the limit and no TLR was invoked. Our analysis showed that these cases were extremely rare. The average frequency of such conditions over all the flowgates was less than 0.01 percent of the intervals (i.e., close to 1 hour)

from January to December 2004. The highest frequency on any flowgate was 0.6 percent. Based on the results of these analyses, we conclude the Midwest ISO's operators generally invoked TLR procedures in a consistent and justified manner.

### **C. AFC Issues and Analysis**

The Midwest ISO calculates AFC to process requests for transmission service and to indicate to participants the amount of unreserved firm and non-firm capability that exists on each flowgate. The analytic approach for calculating AFC values is comparable to the approach used by other transmission providers to calculate ATC values. ATC values correspond to the available capability between two locations (i.e., over a "contract path"). Alternatively, AFC values represent the capability available on a particular transmission facility or group of closely-related facilities. Hence, a limitation on one flowgate could limit the ATC value for many contract paths. Likewise, the reservation of service over a particular contract path will effectively use the AFC on many flowgates.

The Midwest ISO's AFC calculations involve a complex process, including the use of multiple models to evaluate different time horizons, and the forecasting of generation, load, and loop flows from other systems. In addition, the Midwest ISO must make assumptions regarding the utilization of existing transmission reservations. For example, in assessing AFC in advance of scheduling for the operating hour, the Midwest ISO must make assumptions regarding how much of the reserved transmission on the flowgate will be scheduled.

The Midwest ISO continued to invest considerable time and effort on AFC improvements in 2004. The improvements have been focused on increasing the quality of data provided by members, increasing the accuracy of transmission system modeling, and improving the forecasting of generation and load. We do not expect the AFC values to be completely accurate because the AFC models rely on inputs that have some degree of uncertainty (e.g., forecast loads, generation, and other factors). In addition, AFC calculations are affected by conservative assumptions regarding system conditions.<sup>15</sup>

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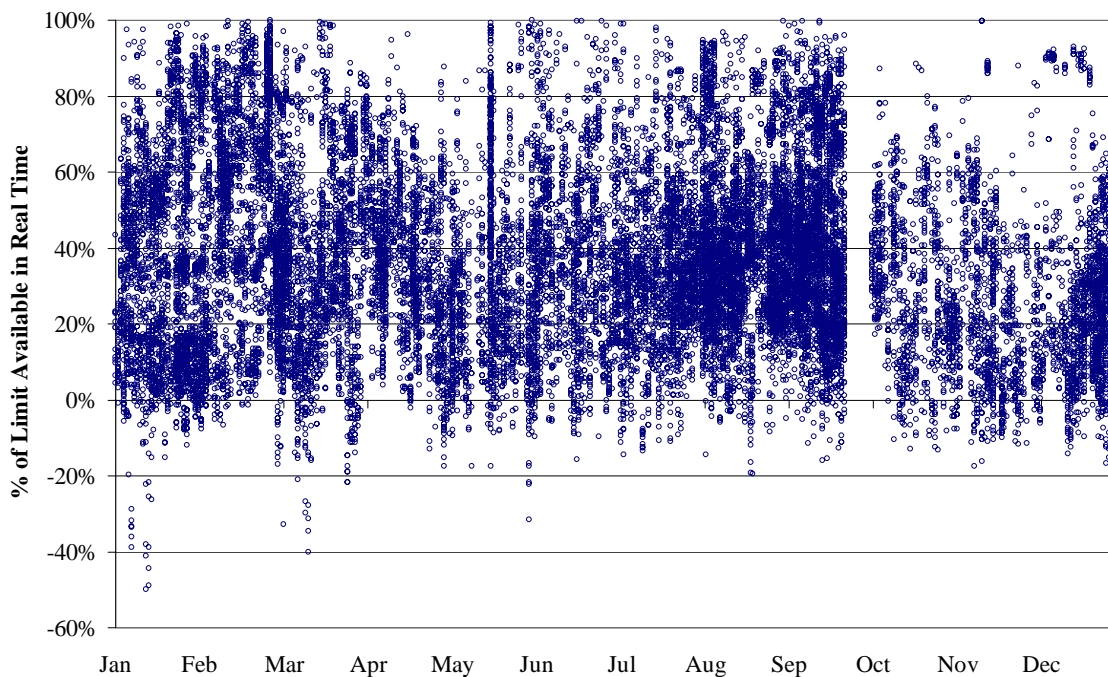
<sup>15</sup> In estimating firm AFC, reservations are assumed to be scheduled at a rate of 90 percent between the



To assess the accuracy of the AFC values, we have conducted an analysis of the AFC values relative to the physical capability of the flowgates. The analysis focuses on hours when Midwest ISO posted zero AFC for non-firm hourly point-to-point service on a flowgate. Hours with zero AFC are studied because they likely affect trading in the Midwest by causing short-term service requests to be refused, and by signaling to participants that capability is unavailable.

To perform the analysis, we calculated the percentage of flowgate capability that is physically available in real time (accounting for Transmission Reliability Margin) during hours when the hourly non-firm AFC was posted as zero. Figure 29 shows the scatter plot of these hourly values for 2004.

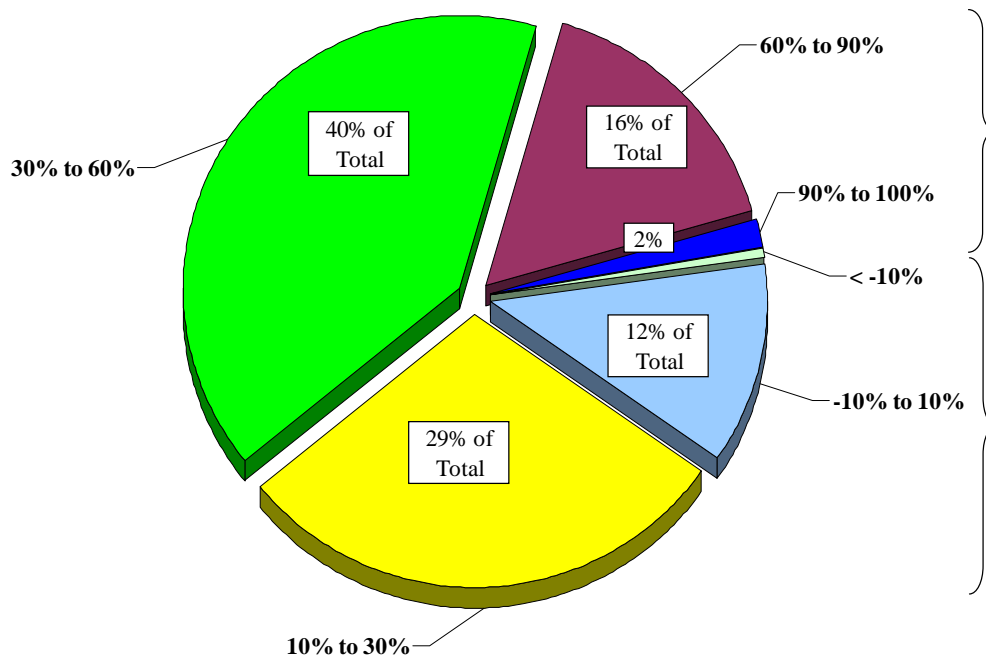
**Figure 29: Percentage of Flowgate Limit Physically Available in Real Time  
Hours with Zero Non-Firm AFC**



primary points while counter-flow reservations are assumed to be scheduled at only 10 percent. For non-firm AFC calculations, 100 percent of reservations between the primary points is assumed and 50 percent of the counter-flows. For firm reservations more than a month in the future, reservations are assumed to be scheduled at a rate of 85 percent between their primary points and counter-flow reservations are assumed to be scheduled at only 15 percent.

There should be a close relationship between hourly non-firm AFC and the un-used physical capability of a flowgate because it is calculated and posted close to the operating hour. In addition, it can be curtailed if necessary during the hour since it is non-firm. However, Figure 29 shows a wide variance in the unused physical capability of the flowgates. If the AFC values accurately reflected the physical capability of the flowgates, the points would be clustered close to zero, distributed evenly around the horizontal axis at zero. In contrast, the figure shows the average amount of capability available on the flowgates in hours with zero hourly non-firm AFC is not close to zero (in fact it is 41 percent). To summarize these results, Figure 30 shows this data in a pie chart to show how these hourly results are distributed.

**Figure 30: Real-time Flows relative to Flowgate Limits  
Distribution of Hours with Zero AFC -- 2004**



Each section of the figure represents a group of hours that have a common proportion of physical flowgate capability actually available in real-time. The top part of the chart in the figure represents the hours when the flows were least consistent with AFC (i.e., those hours when substantial physical capability was available). The bottom part represents hours when the flows were most consistent. For instance, the upper left portion of the

chart indicates that in 40 percent of the hours when a flowgate had an hourly non-firm value of zero, the actual unused flowgate capability was between 30 percent and 60 percent of the physical limit.

As the chart indicates, flows were relatively close to the limit in about 40% of the hours (physical availability was between 30 percent and -10 percent of the operating limit). The flowgates studied had more than 30 percent of the physical capability available in approximately 60% of the hours studied. These results likely overstate the effect of the zero AFC postings because the Midwest ISO will often approve hourly non-firm service in these hours, utilizing some of the capability in real-time that was posted as being unavailable.

#### **D. Market Operations Conclusions**

The analysis in this section focuses on the operations of the Midwest ISO in facilitating the bilateral markets during 2004. Based on these results, we find:

- TLRs that resulted in transaction curtailments or redispatch were generally less frequent, with the exception of the ECAR region. TLRs increased in this region due primarily to PJM's increased use of Midwest transmission capability following the integration of AEP and CE.
- The TLR process continues to result in market inefficiencies, although the Midwest ISO's implementation of the TLR process as the reliability coordinator for the Midwest was competent.
- The Midwest ISO has made improvements in its calculation of AFC values. However, short-term AFC values continue to show inaccuracies that could have resulted in lower utilization of the transmission capability in the region.

We are not making any recommendations in this report to address the inefficiencies associated with the TLR process or the accuracy of the AFC values. These issues have largely been rendered moot by the introduction of the LMP markets in the Midwest in April 2005. Market-based redispatch under the LMP markets has largely replaced the use

of TLRs for managing congestion, although TLRs are still invoked to cause external parties to reduce their use of the Midwest ISO system.

Likewise, the use of the transmission system no longer relies on the reservation and scheduling of AFC, with the exception of the external interfaces. We are monitoring the external interfaces to determine whether the scheduling processes for these interfaces are resulting in significant economic inefficiencies or other concerns.