Staff Report to the Federal Energy Regulatory Commission on the Causes of Wholesale Electric Pricing Abnormalities in the Midwest During June 1998

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Executive Summary

This report examines the dramatic price increases that occurred in wholesale electric markets in the Midwest during the week of June 22-26, 1998. What some have called a price "spike" was an extraordinarily high, but rather narrow and short-lived increase in wholesale spot market prices. The report concludes that a combination of factors caused the price increase. Among these factors were:

- An above-average amount of generating capacity was not available in the midwestern United States due to planned and unplanned outages, including weather-related damage to generating and transmission facilities.

- Unseasonably hot temperatures that were higher than forecasted continued over a sustained period and a broad region, increasing demand for electric power to near-record levels in the Midwest and neighboring areas.

- Transmission constraints reduced the ability of utilities to move power where it was needed.

- Market information systems did not communicate clear, current and reliable short-term price signals.

- Defaults on power sales contracts temporarily lowered market confidence and led parties to seek more short-term supplies than usual.

- Simple inexperience in dealing with the conditions listed above in markets that are becoming more competitive hampered effective responses by some market participants.

The report notes that these adverse circumstances did not compromise the reliability of the electric transmission grid or firm electric service to consumers. Some market participants did experience significant losses; others experienced significant gains.

The report finds that the particular combination of events that led to the magnitude of the June 1998 price increases is not likely to recur, although wholesale prices can be expected to rise and fall as a result of the dynamics of supply and demand. Moreover, the report concludes that over time participants in the wholesale electric market can be expected to develop effective ways to limit their exposure to future price volatility.

The report identifies issue areas for policy makers and others to focus on to prevent a recurrence of these events. It advises that the Commission, states, the North American Electric Reliability Council (NERC) and the electric industry work together to ensure that markets function efficiently, fairly and effectively and make available sufficient generation and transmission resources in the Midwest and surrounding areas. The report notes that the formation of regional entities that would independently operate and plan transmission systems could help markets for wholesale power and transmission function effectively. The report also suggests that the Commission, other regulatory bodies and institutions in the electric industry look for ways to improve the operation of markets and facilitate the availability of accurate market information.

The Reason for the Report

Substantial increases in the wholesale spot market for electricity in the Midwest occurred during June 25 and 26, 1998. Next-day prices for electric energy rose from the $25 per megawatt hour (MWh) range to as much as $2,600 per MWh, with at least one hourly price reaching $7,500 per MWh on June 25. In response, several utilities, power marketers and others in the industry asked the Commission to hold an emergency conference, to cap wholesale electric prices and to take other drastic action to restore "normalcy" to the market. Others stated that there is no need to rein in the burgeoning electric market that the Commission has fostered under Orders 888 and 889. That market includes hundreds of marketers and traders competing for customers across the country.

Chairman Hoecker asked an interdisciplinary team of Commission staff to answer the most important questions posed by the price increase, specifically: how and why it happened, and whether similar events are likely to recur. The Chairman primarily directed the team to examine the operation of the market as a whole and only secondarily to delve into the dealings of individual participants. This report is devoted almost entirely to the general state of market operations. The principal purpose of this study is to provide information that will help the Commission, state public utility commissions and other public policymakers make informed decisions on whether any immediate preventative measures or long-term policy initiatives are needed as wholesale power markets complete their move from cost-based rate regulation to market-based competitive pricing.

How the Team Conducted Its Study

To ascertain the answers, the staff study team interviewed representatives of investor-owned utilities, power marketers, state public service commissions, municipal utilities, Federal agencies, rural electric cooperatives, NERC, regional reliability councils, and the Pennsylvania-New Jersey-Maryland Interconnection (PJM). Many of these entities buy and sell in the Midwest wholesale power market. These entities also include owners, operators and users of the interstate electric transmission system.

The study team sent a broad range of transmission providers and marketers requests for data on their electric purchases and sales during the week of June 22. The team also received voluntary responses from a number of non-jurisdictional entities. It thanks all respondents for their promptness.

What Happened During the Price Spike?

The information the team gathered confirmed that the June 22-26 price "spike" was aptly named: an extraordinarily high, but relatively narrow and short-lived increase in wholesale spot market prices. Some load-serving utilities paid very high hourly prices for part of the electricity they resold, but most of those prices lasted only hours. Except for a smaller flare-up in July, wholesale electricity prices in the Midwest have remained low compared to the June event. For example, the average price during August 1998 for sales into the Cinergy hub in the Midwest was $39.15 per Mwh. These prices are *wholesale* prices, that is, the prices paid by resellers of electricity; whether retail customers will have to bear any of these costs is primarily a matter of state law.

During the week of June 22, market participants maintained reliability of the regional transmission system. No blackouts occurred. No curtailments of firm service to any retail consumer took place anywhere in the Midwest during that week.

What Caused the Dramatic Price Increases?

The team found that a combination of factors contributed to the June pricing abnormalities. Some of the factors are long-term trends. For example, in the Midwest, peak summer loads for electricity have grown substantially, without any significant addition of new generating capacity. As was the case in the summer of 1997, substantial amounts of nuclear baseload generation were out of service in the Midwest in June 1998. These factors have caused Midwest utilities to depend more and more on purchases of power from other regions to meet peak demands.

Weather played a key role in the June event. Unseasonably high temperatures were well above forecasted levels over much of the Midwest and neighboring regions in late June, pushing electric loads to record or near-record levels. Powerful storms in and around the Midwest damaged transmission lines and shut down generating facilities, further reducing available generating and transmission capacity just before weather-related demand peaked. Because the higher-than-forecasted temperatures and storm damage affected a large area, many entities in neighboring regions, that normally would have sold electricity to Midwest utilities, were themselves confronted by high demand and limited supply. Transmission constraints also hindered the movement of power to Midwest markets from adjoining regions.

Another factor was that several wholesale marketers defaulted on contracts to sell electricity, increasing uncertainty in the market about whether sellers could deliver their contracted quantities of electricity as loads increased. Market participants scrambled to secure power so that they would be able to meet their contractual commitments if called upon to do so, or to meet their obligation to serve electric customers. In those market conditions, as demand for power escalated, wholesale prices increased dramatically.

During its review of overall market conditions, the team received allegations that market manipulation may have occurred during the period of the price increases and may have been a contributing factor. The team could not confirm these allegations and did not find direct evidence that market manipulation was a contributing factor leading to the price increases.

Will Such Price Abnormalities Happen Again?

The team observes that the particular combination of factors that led to the June event was quite unusual. This combination of factors was not typical, is not likely to recur, and is not representative of how wholesale electricity markets usually work. However, price increases and decreases may be expected in the future depending upon the balance of demand and supply.

Nonetheless, the Commission, state public utility commissions and the electric industry must take into account that the types of contingencies that gave rise to the price abnormalities could recur, and plan accordingly. The team believes that as buyers and sellers gain experience in the emerging, competitive wholesale power market, they will develop ways to better manage their exposure to the risk of future price increases. Over time, market forces are likely to result in the construction of additional generating and transmission resources.

Issues for Further Consideration

The team believes that the participants in wholesale power markets are fully capable of developing standards, trading practices and risk-management tools to minimize their exposure to price swings and supplier defaults. The team does not believe that the findings of this study support Commission regulatory action to impose price caps on sellers with market-based rates. Neither do they tend to support Commission involvement at this time in setting standards for creditworthiness for electricity marketers or taking other direct action that might control or stifle the operation of the market.

However, the team does not believe that Commission efforts to address the issues raised by the June price event should end with this report. The team suggests the following issue areas for Commission consideration.

Market Monitoring and Assessment. The study team suggests reexamination of the Commission's monitoring activity to assess whether new competitive markets are functioning properly. Improved monitoring methods would permit the Commission to better detect whether any manipulation of wholesale markets or unduly discriminatory transmission practices are occurring. To assist this endeavor, the team believes that the Commission could formalize its working relationships and data-sharing arrangements with NERC and the network of control area operators and security coordinators.

Compliance Actions. The team suggests that staff review how to maximize compliance with the requirements and policies of Orders 888 and 889, including standards of conduct, and prevent or redress any attempts to manipulate the market or circumvent the Commission's rules governing the interstate electric industry.

Price Discovery and Reporting. The Commission and the industry should consider development of real-time reporting of the prices for and availability of wholesale power and interstate transmission. Such reporting would assist the market in real-time price discovery.

Regional Entities. Further steps to promote the growth of regional entities that would independently operate transmission systems and plan and coordinate transmission could address key issues. Eventually, such regional entities should have the capabilities to address transmission constraints and congestion management procedures that may unduly limit the imports of generation into the Midwest.

Cooperation with Other Key Players. Finally, the team notes that the FERC does not have jurisdiction over some matters that may affect the future operation of wholesale electricity markets. For example, the Commission has no authority over the siting of generation or transmission facilities, over retail electric rates, or methods to manage retail electric load. The team suggests that the Commission, the States (which have jurisdiction over the siting of generation and transmission facilities, retail rates and load management), NERC (which establishes reliability rules) and other relevant entities maintain open communication on ways to use their respective authorities or organizations to help ensure that power markets function efficiently.

1. Overview

A. Study Purpose and Description

This report describes the results of a fact-finding study of electric power system operations and wholesale power markets in the Midwest and neighboring regions during the week of June 22, 1998. The purpose of this study is to provide the Commission with a sound understanding of the critical events during this event (hereafter referred to as the June event) in order to make informed decisions as it continues to monitor and facilitate the transition of the wholesale energy market from a regulated to a competitive marketplace. It must be emphasized that the study was not intended to single out individual actions during the June event or to decide on the merits of formal and informal allegations raised by certain market participants during the course of this study. The Commission has other procedures in place for handling such complaints and allegations and can address these issues separately. Nor was the purpose of the study to directly address policy issues otherwise before the Commission.

During the June event, hot weather throughout the Midwest and neighboring regions drove up loads and storms damaged power lines and generating stations. In addition, many utilities in the Midwest and neighboring regions declared that they were experiencing emergency operating conditions. As a result, some interruptible loads were curtailed and public appeals were made to firm customers to conserve power. However, these utilities stopped short of cutting off power to firm retail customers. During these emergency conditions, the hourly spot price of electricity in the Midwest rose to levels as high as $7,500 per MWh.

In response to these events, some directly and indirectly affected market participants requested the Commission to convene a technical conference without further delay. Other participants affected by the June event called for the Commission to immediately establish a price cap on electricity or alternatively on the price of electricity during emergencies. On July 15, 1998, Chairman Hoecker announced the creation of a Commission staff team to examine the factors that contributed to the June event and to inform the Commission of its findings. Chairman Hoecker also indicated that the study team's findings would assist the Commission in making measured and reasoned judgments in its continuing efforts to formulate policies about the future wholesale energy market and how the Commission can best regulate it.

B. Study Objectives

While the focus of the study is on the June event, the primary aim of the study is to provide information to assist the Commission as it continues to monitor and facilitate competition in wholesale energy markets. Its objective is to find and report facts about electricity operations and markets that the Commission needs to develop sound policy for an industry in transition. The scope of the team’s inquiry included: (1) the amount, extent, nature and location of the price disparities during the June event; (2) identification of the causes that led to the price disparities; (3) identification of the impact of the price spike on wholesale power markets and market participants; and (4) identification of Commission actions, if any, that are needed in response to the June event.

The study was organized with a number of general issues and specific study questions in mind. The study also incorporated general questions about the market raised in the public fora and formal requests to the Commission. These questions included:

- Why did prices in wholesale markets rise to unprecedented levels during the week of June 22, 1998?
- Were the price spikes and shortages one-time events or might they recur?
- Did market manipulation drive up prices?
- What role was played by market immaturity and will the market correct itself?
- Would greater retail competition or imposition of price caps help minimize price volatility in the future?
- What was the impact of transmission line loading relief (TLR) and generation deficiency alerts (GDAs) during the June event?

C. Study Approach

The team collected information on the June event and other related events by: (1) researching available public information and data sources; (2) conducting interviews through telephone calls, personal interviews and field visits; and (3) collecting data informally during the interviews and through a formal data request for operational and market information. The data collected by the team were meant to address a series of research questions which included:

- What natural events, such as heat and storm damage, drove supply and demand conditions, and when and where did the effects of these events occur?
- What was the state of the generation and transmission system at the beginning of the week of June 22, in the light of systems assessments for the summer?
- How did the state of the generation and transmission system change during the week? In particular, what generation sources were not available at peak times and why were they not utilized? What were the causes and effects of actions taken by utilities to maintain the reliability of the transmission system, such as TLRs and system generation emergencies?
- What load management actions were taken, such as curtailing interruptible load, public appeals for conservation, and preparations for rolling blackouts?

- How did sellers find buyers for available power? Did sellers have any available power supplies that could not be delivered to buyers? If so, why could the power not be delivered?

- Were system or market operations affected by contract defaults? If so, what were the effects and what actions did participants take in response?

- What specific actions were taken during deviations from standards of conduct during the emergency conditions?

D. Report Organization

The report comprises five chapters including this introduction. The remaining chapters are as follows:

- Chapter 2 describes the power system operations during the June event, including conditions prior to this event that are relevant to its understanding. It focuses on the sequence and timing of events, using information collected through interviews, information provided directly by control area operators and security coordinators, and a formal request for operational data from security coordinators through NERC.

- Chapter 3 describes market conditions, including the evolution of power markets and the conditions of the June event. This chapter parallels the discussion in Chapter 2, in that it seeks to provide an understanding of the sequence of events, their background and their interrelationships. It is based on trade press reports, information from interviews and information provided in the formal data request.

- Chapter 4 combines operational and market factors to address some of the issues listed above, including the likelihood of a recurrence of price spikes and lessons learned by the market. It focuses on combining the information presented in previous chapters to highlight the facts relevant to these questions.

- Finally, Chapter 5 sets out the findings which, in the judgment of the study team, are important for the Commission to consider in its policy deliberations.

2. Operating Conditions

This chapter examines operating conditions related to the Midwest price spike, emphasizing events that occurred in the ECAR and MAIN regions (see regions in Figure 2-1) during the week of June 22, 1998. Although the focus on events during the week in ECAR and MAIN is appropriate, it is also important to realize that these events did not occur in isolation. Conditions leading up to this week and conditions in other areas were also important to the mix of factors that led to the spike in prices. The discussion therefore begins with a description of the operating background in the spring, and then describes operating conditions during the week. The chapter is organized into the following sections:

- Operating Background in Spring 1998
- Weather, Load and Capacity Conditions
- Available Generating Capacity in the Midwest
- Available Generating Capacity in Other Regions.

A. Operating Background: Spring 1998

Over the past several years, the Midwest has experienced load growth without a corresponding increase in either generating capacity in the region or transmission capacity to bring power from other regions. Lack of capacity has been a common theme of press reports and was also commonly cited in interviews during the study. In combination with the transmission constraints brought on by these situations, the inability of companies in these regions to serve peak native load through generation and firm power purchase commitments became a legitimate and serious threat by the Spring of 1998. The severity of the situation was exemplified in the *1998 Special Assessment of Michigan/Ontario* which stated, "should warmer-than-normal temperatures occur across the upper Midwest, available capacity resources in the area could fall short of the resultant higher-than-projected demand." [1]

Growth in the ECAR and MAIN regions is placing a significant strain on existing generation and transmission resources. From 1996 to 1998, the combined projected summer peak for ECAR and MAIN grew from 127,788 MW to 135,321 MW. This 5.9-percent increase is higher than the growth rate of 4.6 percent in the remainder of the United States. This indicates that peak load has grown 28 percent faster in these two regions than in the rest of the country.

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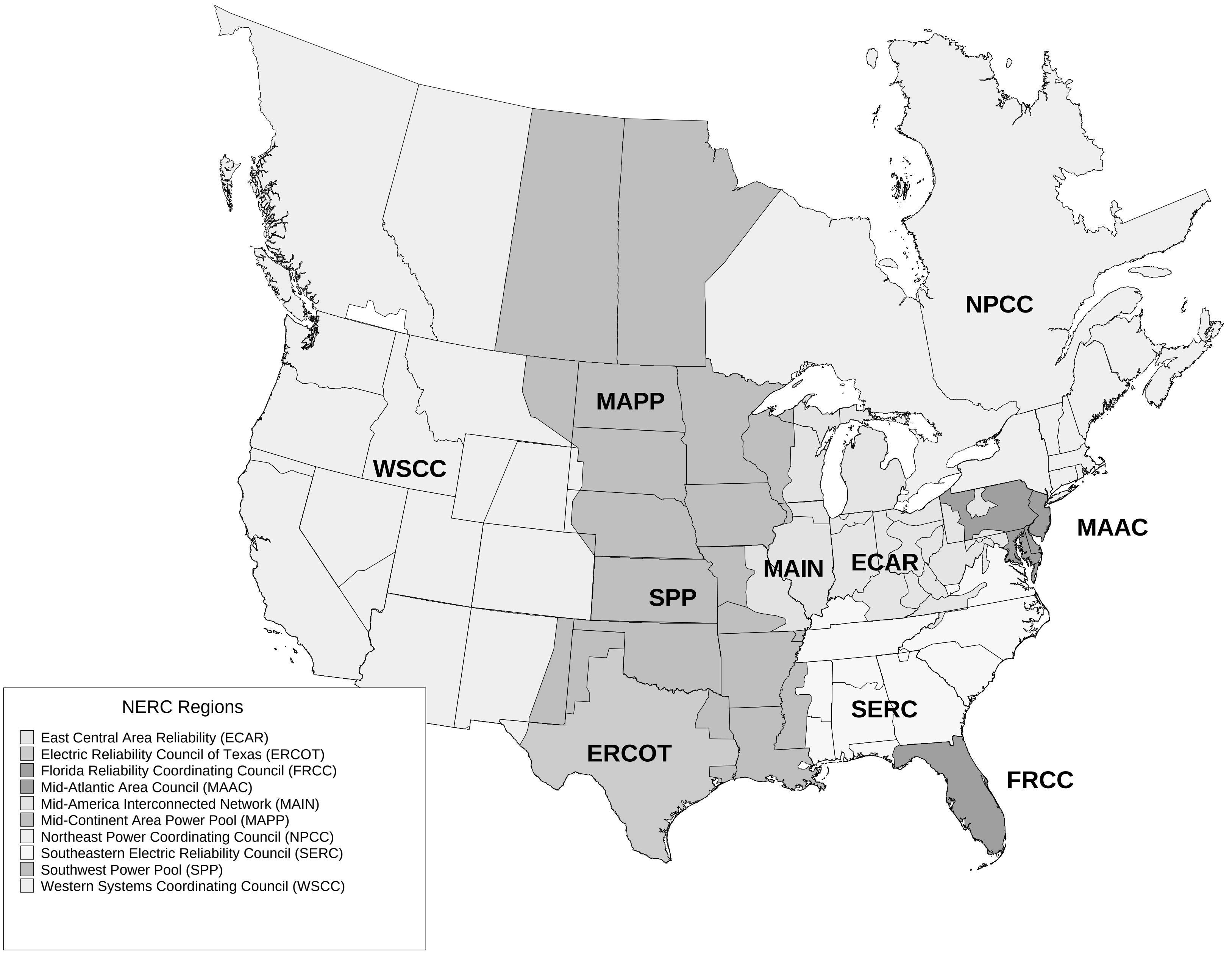
[1] North American Electric Reliability Council (NERC) Reliability Assessment Subcommittee: *1998 Special Assessment of Michigan/Ontario,* May, 1998, p. B-3.

Figure 2-1.
North American Electric Reliability Council Regions



As a result of this rapid growth, ECAR and MAIN will continue to face increasing difficulties in reliably meeting their projected loads.[2]

A related concern is the fact that ECAR and MAIN underestimated their peak loads in the NERC *1996* and *1997 Summer Assessments*. In 1996, ECAR's actual summer peak exceeded its projected summer peak by 4,360 MW. In 1997, the difference was 1,887 MW. Likewise, MAIN's actual loads exceeded its estimates by approximately 1,700 MW in 1996 and 868 MW in 1997.[3] For 1998, both regions projected peak loads below their previous all-time summer peak loads. The reasons for underestimates is not clear. However, the two-year trend was clear and another instance of actual loads exceeding projections should not have been a surprise. The surprise expressed by most respondents in interviews with the study team was not that peak loads exceeded projections, but that high loads occurred in late June, rather than in July or August.

Despite the growth in peak summer demand within the ECAR and MAIN regions since 1996, their available generation resources during summer months have actually declined, due in part to generation outages. Nationally, the situation is only slightly better as available resources have grown by only 3.3 percent. Due to declining available resources in comparison to the rapidly growing demand, available capacity margins in ECAR and MAIN have dropped from 17 percent in 1996 to 11.9 percent in 1998. This decline places much greater reliance on resources from outside the region to meet regional loads.[4]

As a result of the combination of the increase in load and the generation outages, transmission constraints are an increasing concern throughout the Midwest. MAIN, in particular, has become extremely dependent upon imports from its surrounding regions.[5] ECAR is in a much better situation from an import point of view, but has been restricted to transactions primarily to the East and South due to the problems in MAIN and additional generation shortages in Ontario Hydro and NEPOOL. Even in these areas, ECAR would be competing with MAIN for generation resources and run a risk of interruptions from line-loading-relief requirements.

Based on the supply deficiencies in the Midwest and the increased likelihood of transmission constraints, NERC predicted extensive use of line loading relief procedures this summer. NERC included a comment from MAIN that stated " installed total transfer capability on a Regional basis is inadequate to support all base firm transactions under peak load conditions."[6] Therefore, regardless of specific issues related to the new TLR policies, the fact

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2 North American Electric Reliability Council (NERC): *1996 Summer Assessment: Reliability of Bulk Electricity Supply in North America*, May 1996, p. 9 and *1998 Summer Assessment: Reliability of Bulk Electricity Supply in North America*, May 1998, p. 9.

3 NERC: *1996 Summer Assessment*, p. 9; *1997 Summer Assessment: Reliability of Bulk Electricity Supply in North America*, May 1997, pp. 12, 20; and *1998 Summer Assessment*, pp. 22, 25.

4 NERC: *1996 Summer Assessment*, p. 9 and *1998 Summer Assessment*, p. 9.

5 NERC: *1996 Summer Assessment*, p. 11 and *1998 Summer Assessment*, p. 18.

6 NERC, *1998 Summer Assessment*, p. 2.

that some form of line-loading relief would be a major feature of the 1998 summer was documented before the summer even began.

1. Planning

Based on the information discussed above, previous experiences, and market conditions, utilities and power marketers undertook a variety of planning measures in preparation for the summer of 1998. These plans included operational aspects in addition to planning for market fluctuations. For example, one company reported diversifying its supplies to spread its potential risk. For companies in areas of the system that could be interrupted by TLR, diversifying supplies reduces exposure to the operational risk of not having purchase options in other areas if power from one area is interrupted.

Although some companies were able to react promptly to signals last summer and warnings this summer, others were less fortunate. Companies that did not plan aggressively incurred susceptibility to adverse operational conditions as well as market fluctuations. One company that relied heavily on having a large plant back on line by the summer appears to have missed its window of opportunity to arrange firm contracts from outside the region. As a result, the company was forced to rely on non-firm contracts and hourly transactions for the entire summer.

B. Weather, Loads and Capacity

1. Weather Conditions

Weather conditions are the principal external factor driving short-term electricity load. Unanticipated heat, especially if it lasts for several days and extends over a wide geographic area, can cause emergency conditions in the electricity system. If severe storms accompany hot weather, potential damage to power lines or generating stations can increase the likelihood of emergency conditions. Emergency conditions brought on by weather remain unlikely, but are always a possibility. In that sense, the events of the week of June 22 were no exception. Hot weather drove up loads over a wide area and storms posed a threat to power lines and generating stations.

The severity of the heat wave at the end of June appears to have been generally unanticipated. In interviews, utilities reported that temperatures for the week were higher than had been expected at the beginning. Newspaper reports confirmed that actual temperatures were higher than the forecasted temperatures. At the end of the previous week, temperatures for the beginning of the week of June 22 to 26 were expected to be mild, with a gradual increase throughout the week. These expected temperatures were only slightly higher than normal for June. The temperatures rose much more dramatically and lasted longer than predicted (see Figure 2-2). On Thursday, June 25, 1998, the average temperatures in Chicago, Detroit, and Milwaukee were 12 to 16 degrees above normal. Some predicted temperatures were nearly 10 degrees below those that actually occurred. This disparity resulted in numerous utilities having unexpected difficulties covering their loads and forced them into the day ahead and hourly markets to meet their shortfalls.

To aggravate the situation, temperatures were high over a wide geographic area. As the heat increased throughout the week, the high temperatures extended to new areas but remained high in old areas as well. High temperatures for eight cities, covering an area from Milwaukee to Atlanta are shown in Figure 2-3. The figure shows how the heat spread over a large area by Thursday, when temperatures peaked at all eight locations and the range of temperatures across the area narrowed dramatically. Hot weather in all these areas simultaneously limited the likelihood that capacity would be available to serve loads in other areas.

2. Load Conditions

Projected loads for the week in ECAR and MAIN are shown in Figure 2-4. Although loads were high during the third week in May (See Figure 2-4) when day-ahead prices rose to $325 per MWh[7] in the region, the loads for the last week in June were considerably higher than May loads and approached the all time peak for the two regions. Table 2-1 below compares the peak load in the last week in June (on Thursday, June 25) with the all time peaks for ECAR and MAIN and with the peak loads for the last two years.

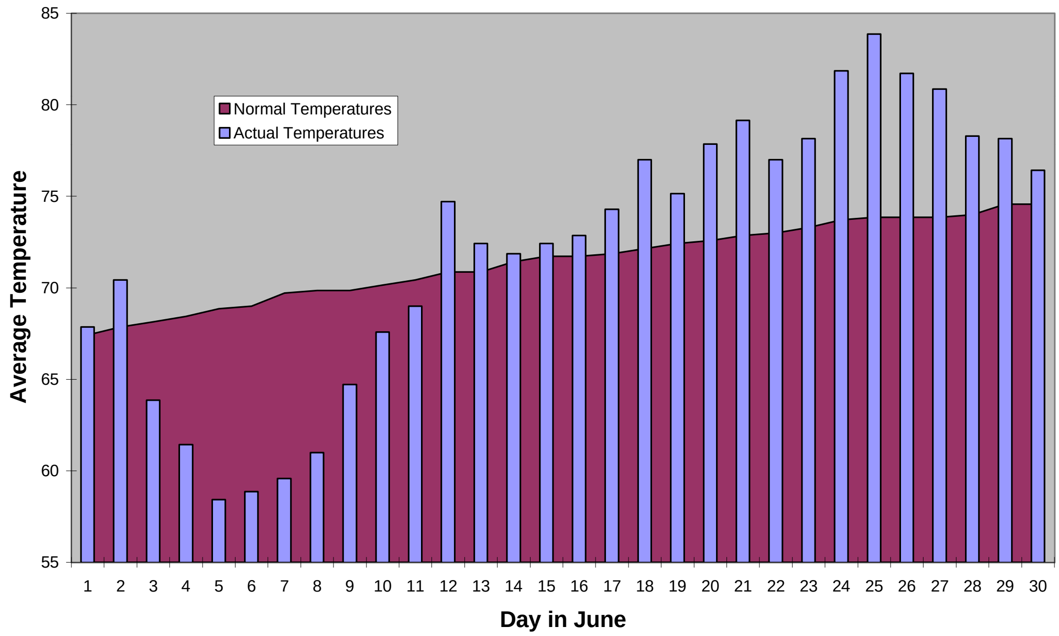
Table 2-1. Peak Loads in ECAR and MAIN

	All-time Summer Peak	June 1998 Peak	1997 Peak	1996 Peak
ECAR	91,254	89,642	89,847	89,424
MAIN	45,401	44,544	45,401	44,500
Total	136,655	134,186	135,248	133,924

Sources: NERC: *1998 Summer Assessment*, pp. 22, 25; *1997 Summer Assessment*, pp. 20, 21; NERC Hourly Demand Generation, and Interchange Data by Region.

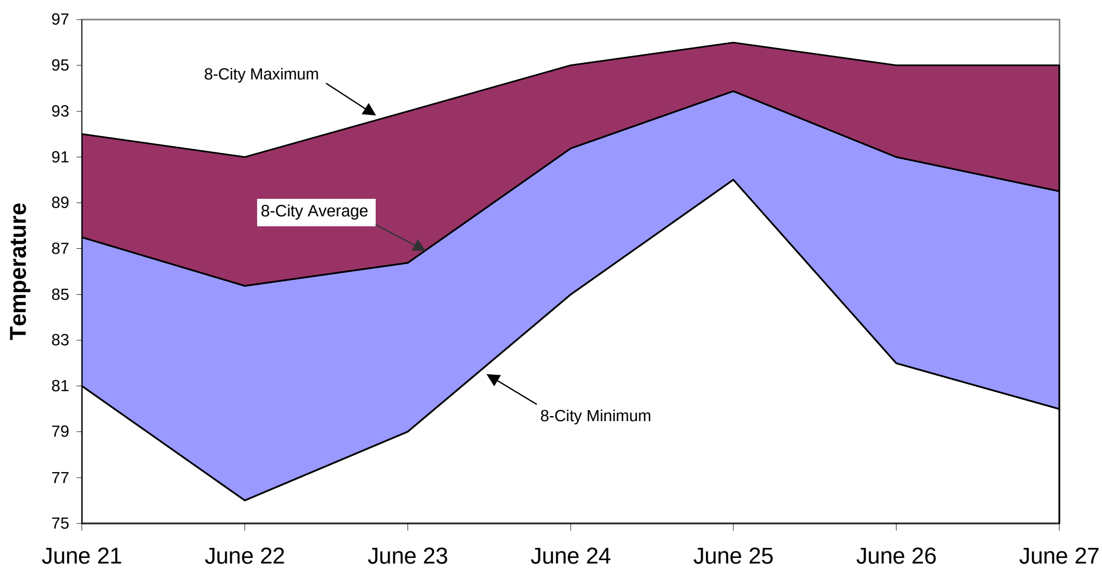
[7] *Power Markets Week*, Prices for Spot Electricity Table, May 25, 1998 .

Figure 2-2. Comparison of Historical Normal Temperature and Actual Temperatures



Source: National Climatic Data Center

Figure 2-3. Comparison of Temperature Range for 8 Cities in the Eastern Interconnection



Source: National Climatic Data Center

Historically, the summer peak occurs in July or August, and capacity planning follows these historical trends. An attempt is made to complete maintenance schedules before July, but some units are still scheduled for maintenance in late June. Therefore, the scheduling of generation becomes increasingly important for periods, such as late June, when high temperatures can occur, but are historically less likely. High temperatures drove up loads to a point where regional demand significantly exceeded regional generating capacity for the peak load during the week. The actual net interchange for June 25—the difference between regional demand and regional generation for the peak weekday—is shown in Figure 2-5. As this figure shows, 10,000 MW of actual demand was met by transfers from other regions.

The online operating capacity in both ECAR and MAIN was virtually all used at peak, as shown in Figure 2-6. This figure shows total generation as a percent of capacity, as reported by each control area to NERC for each hour on June 25, 1998. In ECAR, a maximum utilization of 95.8 percent occurred at 3:00 PM; in MAIN a maximum utilization of 94.4 percent occurred at 4:00 PM. These levels show that very little unutilized capacity was available at these hours, but they tell only a small part of the story. In MAIN, the daily surveys provided to the control areas show that loads as high as 46,870 MW (1,400 MW over the all time peak) were expected for June 25. These reports occurred during the day on June 25, and show that expectations of extremely high loads were based on the system conditions in the morning. Generation alerts (shown in Table 2-2) were common throughout the region on June 25, as expectations of excessive loads occurred throughout the region.

The fact that record loads were not reached in all cases may be partly a result of concerns over demands exceeding capacities, and the related curtailment of interruptible load and conservation actions taken in response. Curtailment of interruptible load and public appeals for conservation were necessary because loads were expected to exceed available power supplies that could be brought on line. The actions that were taken to balance supply and demand and to maintain the reliability of the transmission system appear to have succeeded in maintaining system reliability without the need for the drastic action of rolling blackouts. However, some interruptible loads could not be served and considerable efforts were needed to rearrange transmission schedules at the last minute. As we will discuss in the next chapter, these actions led to significant costs. It is therefore important to examine what those conditions were and how they might have been different.

C. Available Generating Capacity in the Midwest

As described in the last section, utilities called generation alerts when their loads rose to a level that was expected to exceed the available generation capacity to serve those loads. This fact gives rise to a question: why was more capacity not available online? There are two potential answers to this question. First, capacity that was not limited by the transmission system could not be brought online in time to serve load. Second, capacity could have been limited by the constraints of the transmission system. The first issue is addressed in this section, the second in the following section.

Table 2-2. Generation Deficiency Alerts (GDA) on June 25[8]

GDA Called By	Max. GDA level	Time	Comments
AEP	1	8:05-not specified	
MAIN	3	08:27-21:00	ComEd and Illinois Power in extreme shortage of power
Entergy	2	12:00-22:00	Curtailed interruptible loads
OTP, SMPPA	not specified	10:00-not specified	
PJM	not specified	10:00-16:06	Curtailed off system sales
Missouri PS	not specified	12:00-not specified	Interrupted transactions
DLCO	2	12:13-18:45	
FirstEnergy	3	12:34-not specified	FirstEnergy was close to interrupting firm load but did not actually do so
SMEPA	1	16:00-21:00	SMEPA foresaw being in short supply by 50-70 MW

The amount of generating capacity on scheduled maintenance was cited as an issue during the week of May 18, when prices in excess of $300 were reported in the Midwest. While the overall level of outages was high in May, the outage situation greatly improved by late June (see Figure 2-7). The percentage of unavailable capacity fell from around 22 to 23 percent in May to 12 to 13 percent in late June. Such reductions are to be expected, since plant maintenance is normally scheduled for the spring and phased out as the peak summer season approaches.

A key question concerning these outages is how much of the unavailable capacity was out for scheduled maintenance. If significant capacity was out for scheduled maintenance at a time so close to the summer peak season, rearranging maintenance schedules and better coordination might have helped to make more capacity available. To address this question, we examined

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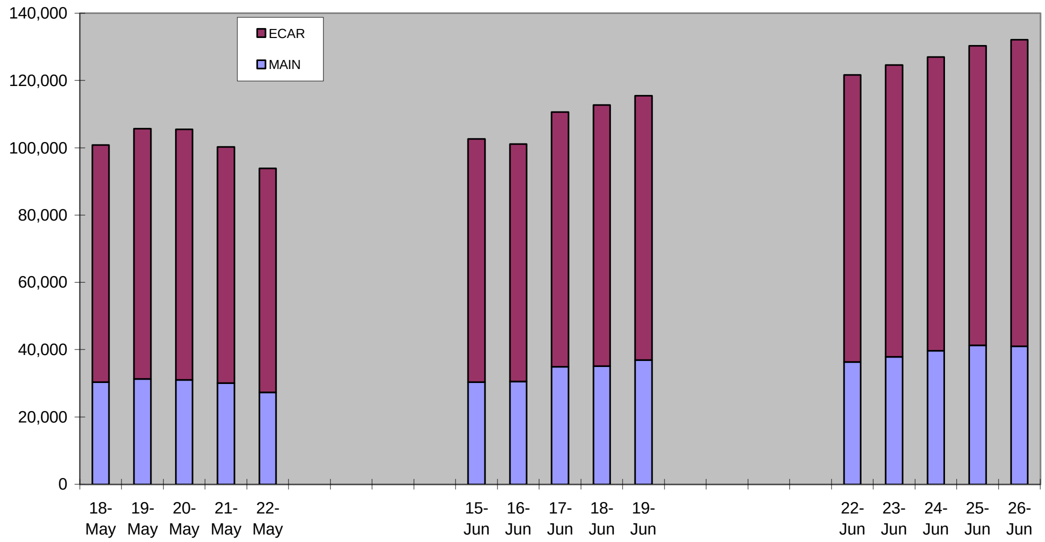
8 GDA Levels are defined as follows:

GDA Level 1: Generation reserves are such that a single contingency could result in violation of NERC/regional policy for normal operations by a control area.

GDA Level 2: A control area foresees, or has implemented, emergency procedures up to, but excluding, interrupting firm load.

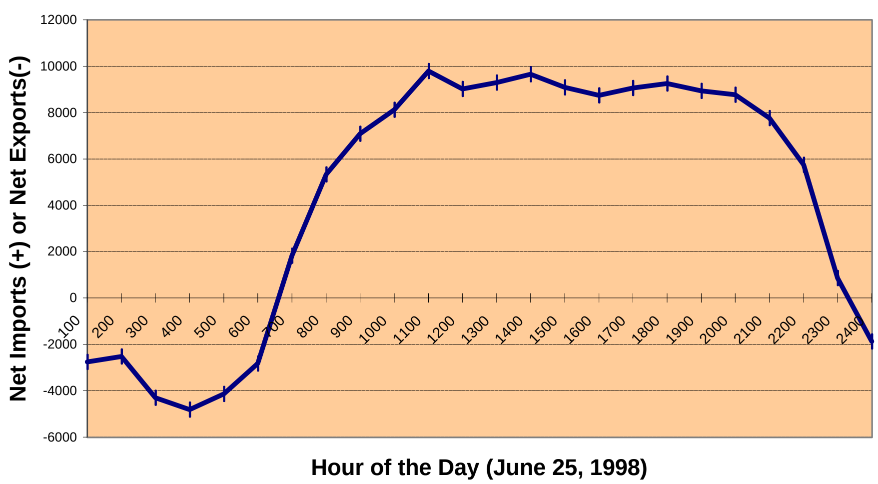
GDA Level 3: A control area foresees, or has implemented firm load interruption.

Figure 2-4. Day Ahead Projected Loads in MAIN and ECAR
Selected Weeks in May and June



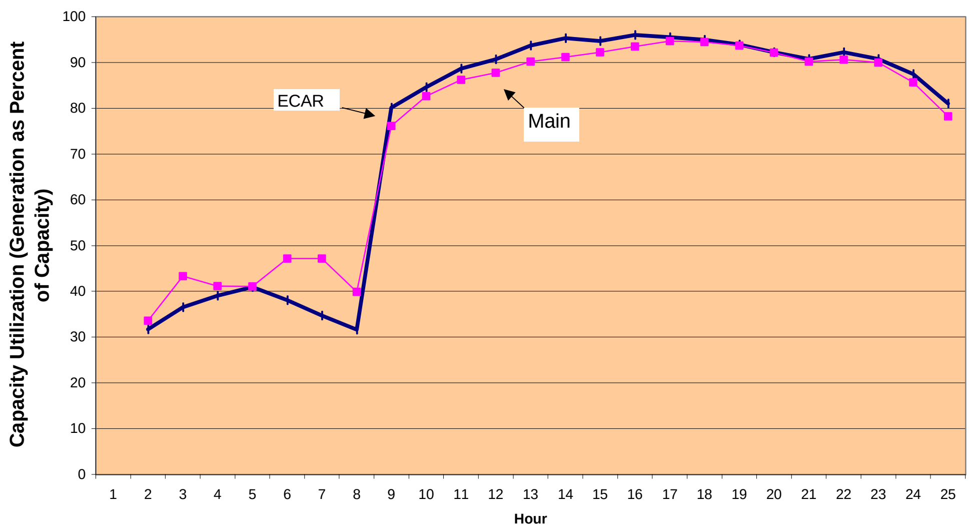
Source: ECAR Daily Operating Projection Reports, MAIN Day Ahead Load and Capacity Reports

Figure 2-5. Net Imports into the ECAR and MAIN Regions
June 25, 1998



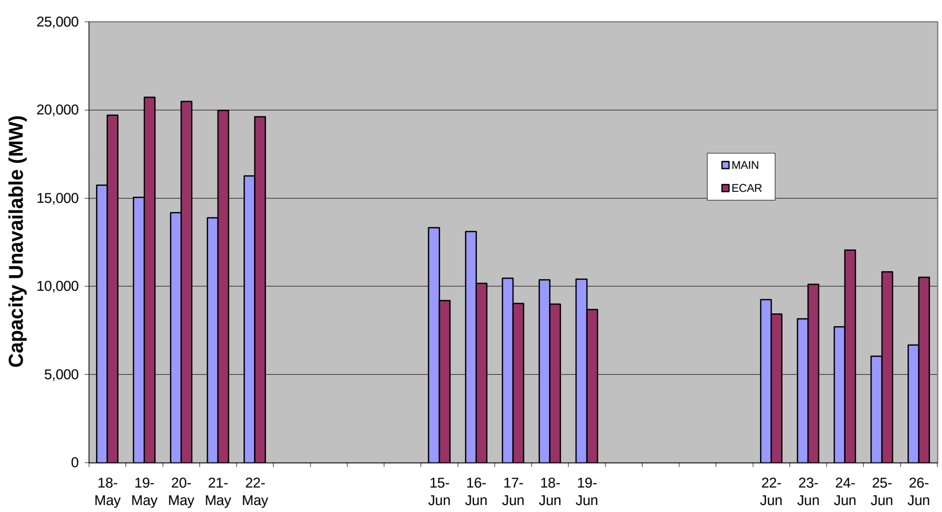
Source: Responses to Informal Data Request to NERC

Figure 2-6. Capacity Utilization in ECAR and MAIN
June 25, 1998



Source: Responses to Informal Data Request to NERC

Figure 2-7. Unavailable Capacity in MAIN and ECAR



Source: ECAR Daily Operating Projection Reports, MAIN Daily Generation Outage Reports planning reports used by control areas in ECAR and MAIN. These reports show the unavailable generating units for each control area. They also provide information on why units were unavailable. Unfortunately, this reporting is not easily comparable across the two regions. ECAR combines reports for units less than 200 MW into a single category, while MAIN reports all units separately. ECAR reports outages as “forced” or “scheduled,” while MAIN includes two additional categories for “partial” and “reserve shutdown.” The experience of each region was therefore studied separately. Forced and scheduled outages are shown for both regions in Figure 2-8.

In MAIN, total generation outages fell from around 14,800 MW in May to around 5,200 MW in late June. Most of the remaining outages (4,800 MW) were reported as scheduled outages; of these, 3,600 MW were large nuclear plants. Thus the capacity problem in MAIN at the beginning of the June event was primarily a problem of long-term outages at nuclear facilities. These outages are discussed further below.

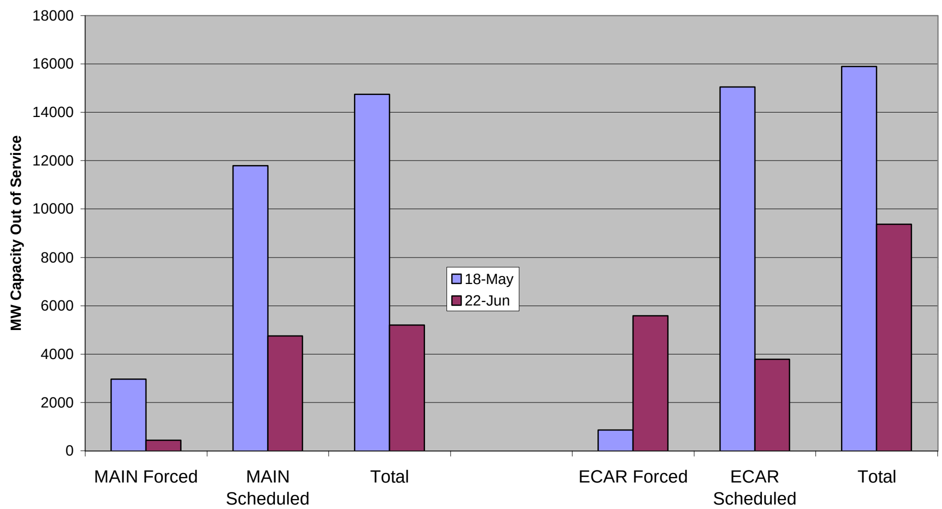
The situation in ECAR was somewhat different. Total outages were reduced from 15,900 MW to 9,400 MW by June 22. In May, there were a large number of scheduled outages, but few forced outages.[9] In June, there were more forced outages than scheduled outages. It is apparent from the data on scheduled return dates and forced outages that ECAR experienced some forced outages in June at plants that were scheduled to restart after being scheduled out in May, but experienced problems during startup or shortly thereafter. There were also an additional number of forced outages at other plants during June. Forced outages were an ongoing difficulty throughout June in the ECAR region.

Forced outage problems continued in ECAR during the June event, as shown in Figure 2-9. The changes in ECAR capacity shown in this figure all arose from forced outages during the week. Forced outages peaked on Wednesday, June 24 and declined on Thursday and Friday. Even though capacity was returned to service, around 2,000 MW went out of service in ECAR and PJM just as temperatures started to peak, providing an unsettling sign to a market already concerned about capacity limitations.

Nuclear outages also contributed to capacity problems during the week. Figure 2-10 shows the fluctuating pattern of nuclear plant outages during the week in ECAR, MAIN and PJM. Although not all the capacity went out at the same time, over 4,000 MW of nuclear capacity was forced out of service at some point during the week of June 22. NRC reports of

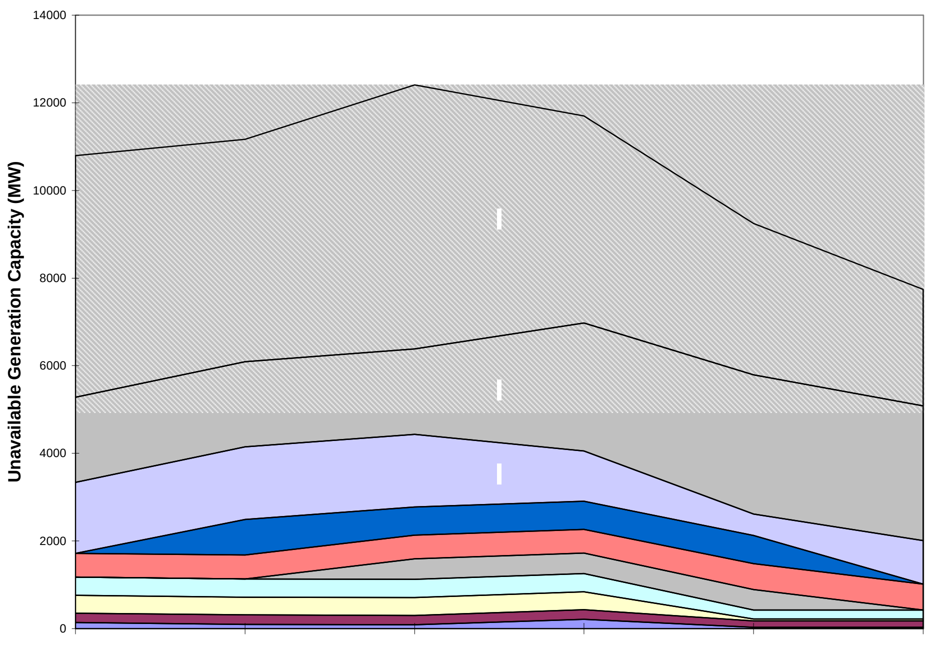
9 ECAR reported nuclear outages as forced outages, while MAIN reported the same outages as scheduled outages. Since the reasons for these outages appeared to be similar, ECAR nuclear plant outages were treated as scheduled for purposes of these statistics. It is possible that the ECAR classification is based on unanticipated problems when the plant was expected to return to service, but we treated both ECAR and MAIN nuclear outages as scheduled for comparison purposes here.

Figure 2-8. Comparison of Forced and Scheduled Outages in ECAR and MAIN



Source: ECAR Daily Operating Projection Reports, MAIN Daily Generation Outage Reports

Figure 2-9. Generation Capacity Outages in ECAR by Control Area June 22 to June 29, 1998



Source: ECAR Daily Operating Projection Reports these outages list them as hot shutdowns, several storm related, and the team did not hear any suggestions that they were other than forced, but the outages do appear to have contributed to the scarcity of capacity during the week.

The data on plant availability show that the principal reasons why more capacity was not available in the Midwest (ECAR and MAIN) at the time of the price spike were a high level of outages at nuclear plants, including forced outages caused by weather, and a high level of forced outage rates early in the week at fossil generating plants in ECAR. While scheduled outages at non-nuclear plants in MAIN may have played a role, it appears to have been a very minor one.

D. Available Generating Capacity in Other Regions

The supply and demand conditions in the Midwest led Midwestern utilities to seek additional power from other areas at a time when these areas were also experiencing high load conditions. This problem was particularly severe on June 25. As noted above, hot weather across the East peaked on Thursday and areas throughout the Eastern Interconnection experienced extremely high loads. The high loads and limited additional capacity are confirmed by the reports from control areas provided by NERC for this study.

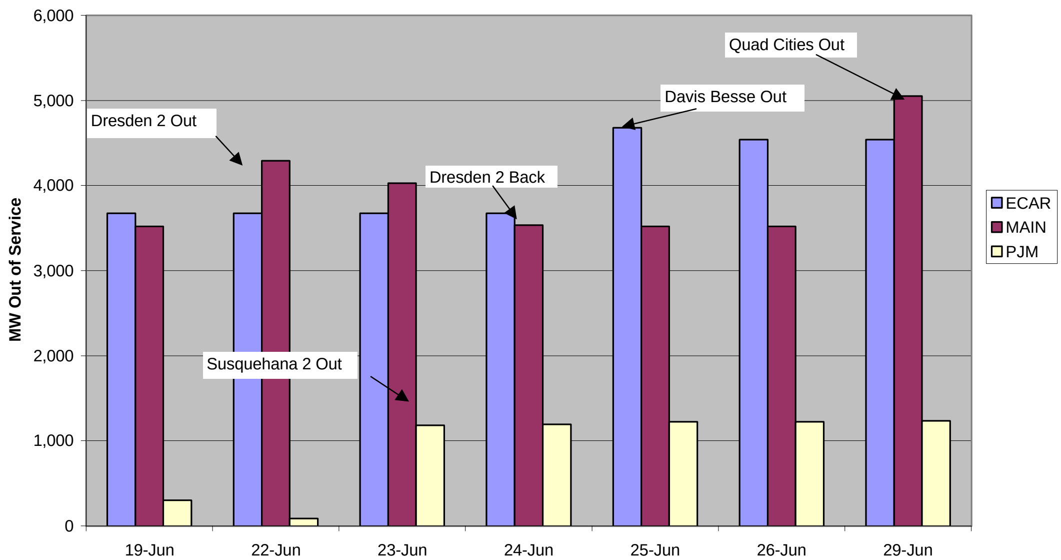
1. Generation Alerts and Regional Interchange

The limitations on acquiring generation from other regions to alleviate supply shortages in the Midwest had some significant impacts. For example, on Thursday and Friday, PJM experienced generation alerts that had a significant impact on the availability of capacity to the Midwest. PJM curtailed 5,300 MWh that had been scheduled to be transmitted out of PJM. These curtailments had two principal effects. First, it put additional stress on Midwest systems and worsened an already precarious balance. Second, it caused a significant shift in the pattern of interchange during the day.

The graph in Figure 2-11 shows the level and pattern of scheduled, hourly transfers into ECAR from other regions. The line in this graph shows the total interchange between ECAR and other regions. The bars show the interchange with PJM, SERC and other regions. Several important points are illustrated in this figure:

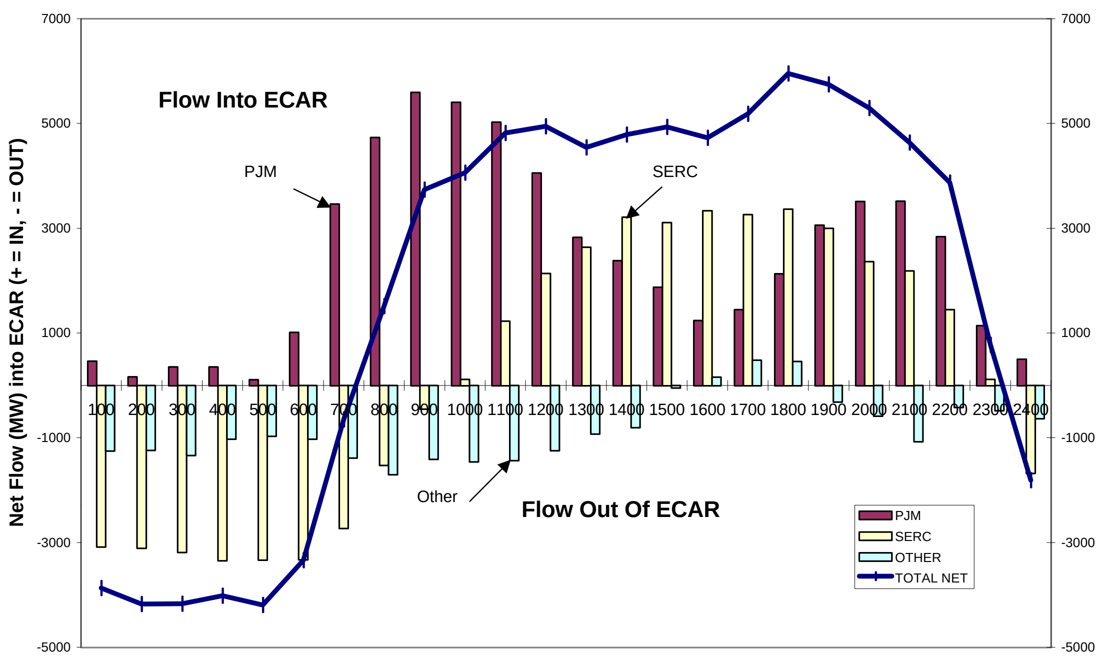
- As ECAR loads rose early on the morning of the 25th, power flow shifted dramatically from flows out of ECAR to flows into ECAR.

Figure 2-10. Nuclear Capacity Out of Service in ECAR, MAIN and PJM



Source: Nuclear Regulatory Commission

Figure 2-11. ECAR Interchange with Other Regions
June 25, 1998



Source: Responses to Informal Data Request to NERC

- Flows out of PJM into ECAR rose in response to ECAR loads until 9:00 or 10:00 AM, but then fell off as PJM experienced emergency conditions and cut back on transfers.

- Flows out of PJM into ECAR that declined as a result of the PJM declaring a generation emergency were replaced by flows from SERC into ECAR during the late morning, keeping total interchange relatively constant at late morning levels until 4:00 PM.

Interchange into the MAIN region showed an important pattern as well, although not as dramatic as ECAR (see Figure 2-12). Interchange into MAIN from ECAR was limited by generation alerts in ECAR, as shown by the reduction in interchange between ECAR and MAIN during the afternoon. Interchange with ECAR dropped from a high of 2,400 MW at 11:00 AM to a low of 1,200 MW at 5:00 PM. A substantial portion of this reduction is accounted for by curtailments of a large scheduled transfer from AEP to Commonwealth Edison, caused by generation conditions in AEP.

The interchange data confirm that generation alerts across the region contributed significantly to the difficulty of meeting loads. Problems in one area of the transmission system quickly became problems in other areas, as tight supply/demand conditions limited utilities' ability to shift generation to meet loads. These shifts began to cause overloads on the transmission system, leading to the need for line loading relief.

2. Line Loading Relief and TLR

The predominant line loading relief (LLR) procedure used in managing the transmission system of the Eastern Interconnection since the summer of 1997 has been NERC's Transmission Loading Relief (TLR) procedure.[10] The evolution of this procedure can be traced to efforts by various utilities seeking solutions to inadvertent or loop flows in the transmission system—most notably the GAPP Agreement participants[11]—and the Commission's functional unbundling of transmission and generation in Order Nos. 888 and 889. Prior to these Orders, transmission

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10 These procedures are detailed in NERC's Operating Policy No. 9 and is the subject of Docket No. EL98-52 pending before the Commission. These line loading relief procedures are still in transition. Strict adherence to NERC's TLR procedures is not universal as some of the regional reliability councils have had their own specific procedures which they have not completely abandoned. Save for the use of locational marginal pricing of transmission within the PJM region, it appears that the other regional practices are largely variations of the NERC procedures.

11 General Agreement on Parallel Paths (GAPP) Participation Agreement. The Commission approved a two-year experiment for this agreement beginning April 2, 1997 (Docket No. ER97-697). The GAPP Agreement is not a line loading relief procedure *per se* but rather involves efforts to get transmission users to choose contract paths more closely aligned with actual power flows. The primary export from GAPP to the NERC TLR procedures is the GAPP Information System (GIS) which allows system operators to determine the actual physical path electricity takes through their system.

system overloads were typically handled by the affected control areas first curtailing their wheeling services for third parties and, if that was inadequate, re-dispatching their generation to mitigate the problems.

Generally, past practices can be distinguished from NERC's TLR procedures by two significant differences. First, overloads were handled primarily by local procedures whereas the TLR procedures are regional. The affected control area attempted to mitigate the overloading problem largely by its own actions before asking neighboring utilities for assistance. NERC's TLR procedures rely on multi-control area regional security coordinators curtailing transmission flows over a much wider area (based on model-generated measures of their impacts on the constrained facilities). Second, the TLR approach is a flow-based approach that curtails transactions based on actual power flows over the transmission system and their estimated impacts on the overloaded facilities. Past practices instituted curtailments based on contract path flows. According to NERC, the past practices (when local utilities attempted to handle overloads) have proven inadequate to deal with the nature and increased volume of transactions on the transmission grid in recent years.

The need for TLR during the week rose as the loads rose throughout the Eastern Interconnection. Table 2-3 shows the line relief actions that were called during the week; the locations of the facilities where line relief was needed are shown in Figure 2-13. We focus on line relief at the eastern locations in Figure 2-13.

The Queenston Flow West (QFW) interface was important on the 25th, because line relief was required early in the day, just as loads and interchange rose rapidly. The line relief for this facility, called by Ontario Hydro, forced transmission to be rescheduled on an hourly basis and limited the available paths that could be scheduled. These TLR actions had important impacts on the power available to the Midwest:

- The TLRs at Queenston, Ontario Hydro/MECS and Kammer restricted scheduling of power from PJM and SERC into ECAR and MAIN. PJM and SERC were the two main areas from which utilities sought power to move into ECAR. The effects of one action led to another. For example, overloads on QFW limited flows west out of New York and PJM. As flows shifted to the south from PJM, the flows increased on Kammer to the south (see locations in Figure 2-13). TLR at Kammer limited flows from points further south into ECAR.

- Nuclear outages in Canada had reduced the ability of the Queenston (QFW) interface to support transfers of power from SERC and PJM into ECAR. The NERC Summer Assessment identified the Ontario Hydro/MECS interface as important, but the flow patterns that led to the need for TLR on the QFW interface were unusual and had not been closely studied. The relationship between nuclear outages and limitations on the QFW interface was confirmed by the study team in a power flow study of peak summer conditions using the Power World load flow computer program and the summer base case data used in the NERC *Summer Assessments*.

The impact of TLR actions on utilities' need to replace power was to further limit the sources of power to an already tight market. The team issued a data request to utilities to obtain their estimates of the cost of power needed to replace power that was lost when TLRs were called. A summary of responses to this data request is presented in the Chapter 3.

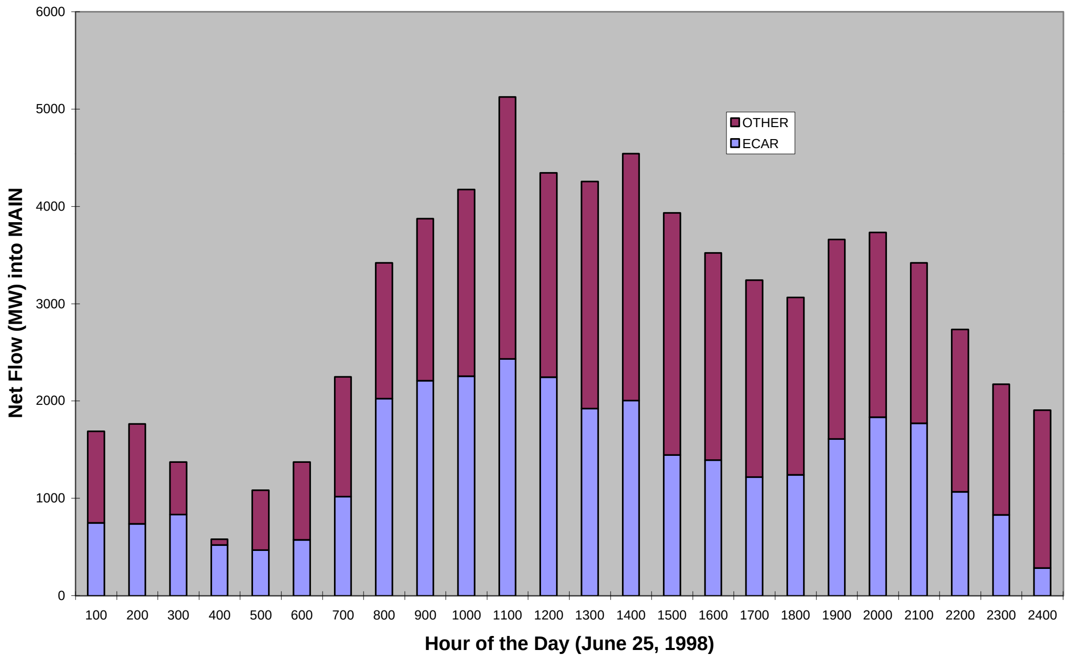
Table 2-3. TLR Actions Taken During the Week of June 22

Control Area	Flowgate	Highest TLR level	Relief requested	Time
6/22/98				
1 MAIN	Eau Claire-Arpin 345 KV line	3	50 MW	06:50-16:00
2 OH	OH-MECS	3	336 MW	09:06-22:15[2]
3 AP	Kammer 765/500 KV Transformer	2	0	17:15-20:45
6/23/98				
1 OH	QFW # 543	3	not specified	06:28-22:25
2 MAIN	Eau Claire-Arpin 345 KV line	3	50 MW	06:30-15:20
3 VP	Skimmer - Balcony Falls	2	0	11:49-21:45
6/24/98				
1 OH	QFW # 543	3	not specified	05:10-21:33
2 MAIN	Eau Claire-Arpin 345 KV line	3	75 MW	07:10-22:00
3 VP	Pleasant View - Dickerson	2	0	11:20-15:51
4 AP	Kammer 765/500 KV Transformer	3	100 MW	12:30-22:30
5 VP	Skimmer - Balcony Falls	2	0	13:15-20:15
6/25/98				
1 MAIN	Eau Claire-Arpin 345 KV line	3	50 MW	00:00-06:00
2 OH	QFW #543	2	0	05:28-11:12
3 AP	Kammer 765/500 KV Transformer	3	100 MW	930:20:30
4 MECS	OH-MECS	2	0	09:34-22:45
5 MAIN	Eau Claire-Arpin 345 KV line	3	30 MW	14:20-22:00
6/26/98				
1 MAIN	Eau Claire-Arpin 345 KV line	2	0	00:25-6:00
2 OH	QFW # 543	2	0	06:33-13:46
3 AP	Kammer 765/500 KV Transformer	2	0	08:35-10:40
4 MAIN	Eau Claire-Arpin 345 KV line	2	0	09:20-11:30
5 MAIN	Eau Claire-Arpin 345 KV line	2	0	13:15-20:10
6 OH	OH-ADIR # 534	3	not specified	18:45-22:14
7 OH	OH-MECS	3	not specified	19:56-22:14
8 MAIN	Eau Claire-Arpin 345 KV line	5	200 MW	22:40-22:00

[1]MAPP cut firm transmission service.
[2]2096 MW cut.
The TLR Level are:

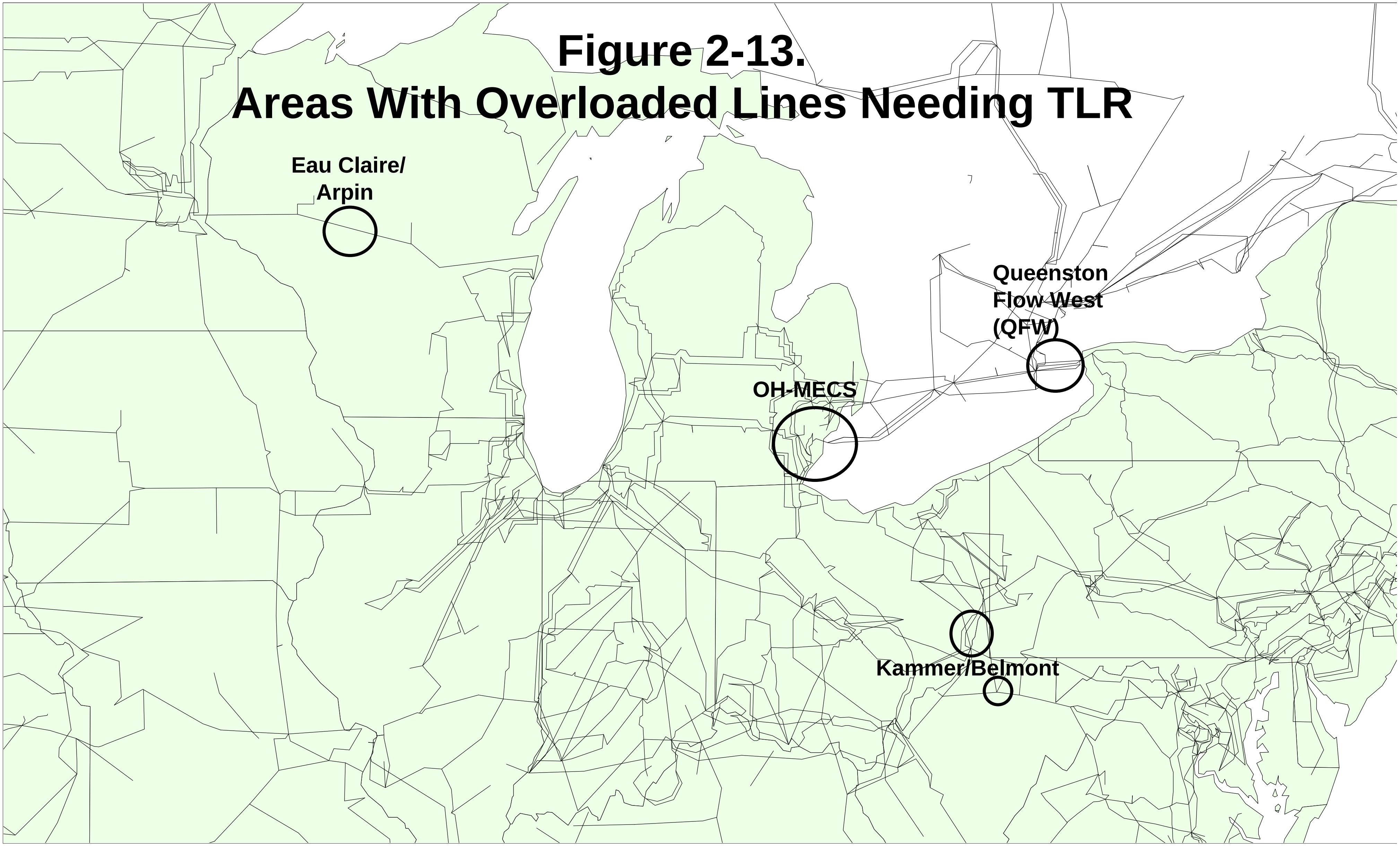
level 1 : Notify security coordinators of potential problems
level 2: Halt additional “contributing” transactions
level 3: Curtail non-firm transactions (state priorities being curtailed)
level 4: Reconfigure and redispatch to continue firm transactions if needed
level 5: Curtail firm transmission service
level 6: Implement emergency procedures

Figure 2-12. MAIN Interchange: Net Flows into the MAIN Region
June 25, 1998



Source: Responses to Informal Data Request to NERC

Figure 2-13.
Areas With Overloaded Lines Needing TLR



3. Market Conditions

This chapter examines market conditions leading up to the Midwest price spike. It first examines the development of wholesale power markets in the wake of Order 888.   It discusses the emerging market, explains the importance of studying price spikes and electricity markets and traces the major price trends leading up to the summer of 1998.   The chapter then turns to a description of the price spike during the week of June 22 and examines the reasons for the event.

A. Wholesale Power Markets Since Order 888

Electric power spot markets have grown considerably since the Commission issued Order 888 in April 1996, and they continue to evolve. The number of market participants and volumes of power traded have increased substantially. Numerous pricing points have developed to increase the flexibility of wholesale transactions. Risk management tools have emerged to help market participants protect themselves against uncertain price movements. Wholesale electric power markets, while still developing, are beginning to look like markets for other commodities.

1. Transition to Competitive Markets

The transition from tight regulation to a market orientation has created two conflicting regimes in the electric power industry. In the unbundled environment of Order 888, investor-owned utilities offer open access transmission service to wholesale customers. However, utilities continue to provide cost-based bundled services on behalf of their native load customers. This circumstance forces utilities to perform an awkward balancing act between the two regimes. It also permits utilities to “forum shop” for the regime that better suits their needs and may provide the opportunity for discrimination. The existence of these two regimes has created a degree of uncertainty for market participants and may have been a factor in the June event.

2. Growth in Wholesale Markets

There are more market participants than ever before. In the first quarter of 1995, there were eight marketers actively trading in wholesale power markets. By the second quarter of 1998, there were 108 actively trading power marketers (Figure 3-1). While a large number of marketers are active in wholesale markets, there are many that have received market-based rates but have not conducted transactions. A total of 337 independent power marketers and 123 affiliated marketers have been granted market-based rates by the Commission. In addition, the Commission has granted market-based rate authority to 73 investor-owned utilities.

The volume of transactions has increased dramatically. Power marketer quarterly filings show significant increases in wholesale transactions since 1995. In the first quarter of

1995, marketer sales totaled 1.8 million MWh. By the second quarter 1998, sales escalated to 513 million MWh (Figure 3-2).

Daisy chains are responsible for much of the increase in volume. While marketer sales have undeniably grown, a significant portion of the sales are part of extended "daisy chains." Daisy chains involve the retrading of power by a number of different market participants, primarily marketers, many of whom have no intention of physically delivering the power. These deals represent multiple resales of the same generation that used to flow directly from vertically integrated utilities to their ultimate customers or to other distribution utilities for resale to ultimate customers. Market participants have reported that, in some cases, marketers take title to power for the sole purpose of increasing their total volumes traded.

According to market participants, approximately 80 percent of power marketer transactions are "financially firm" transactions that do not involve the physical transfer of power. Sellers of financially firm products do not control actual physical generation but promise to pay the necessary price to procure supply if the buyer needs the power. The entrance of new marketers, many of whom deal only in financial transactions, has helped to increase liquidity—the ability to get into and out of financial positions—in power markets. However, since many of these transactions are not backed by the ability to physically deliver power, they add to the volatility of prices under peak conditions, as seen in the June event.

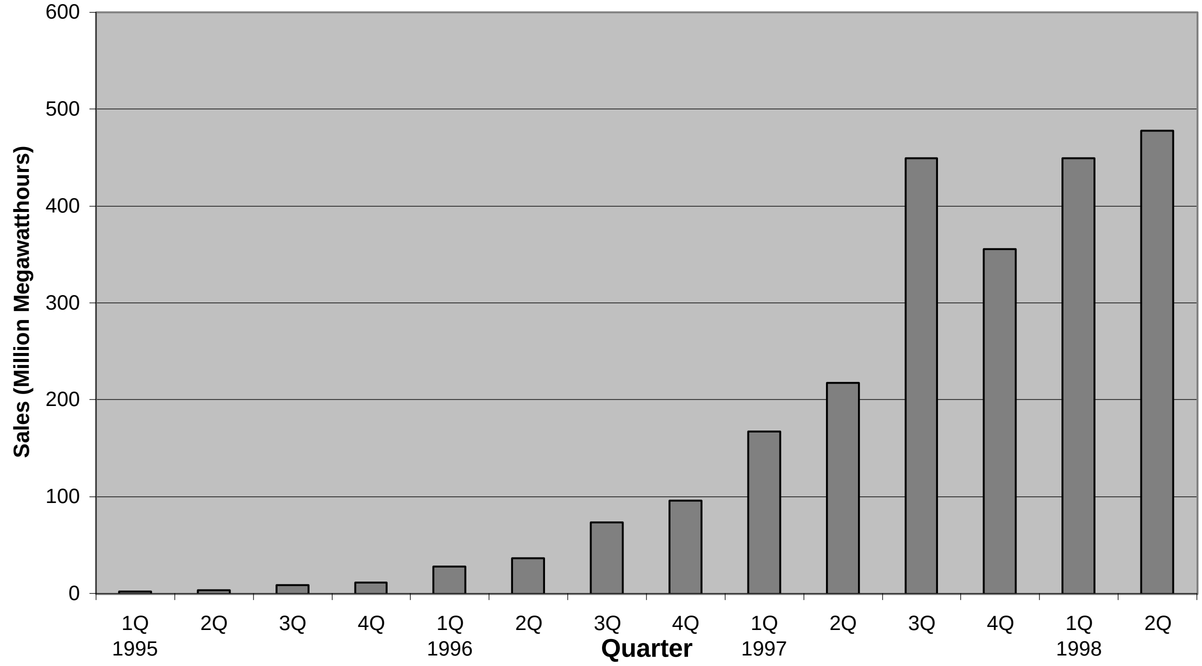
3. Spot Market Pricing

When the trade press began publishing bulk power prices in 1994, prices were available for only seven locations. Since then, price reporting has grown with the market and become more extensive, with published prices now available for approximately 24 locations.[12] Wholesale electricity markets appear to be evolving in much the same way as natural gas markets, in which numerous pricing points and market hubs developed over time. Trade publications report daily pre-scheduled, on-peak (16 hour) prices. Hourly prices are not published on any systematic basis.

Although electricity markets have advanced considerably, market participants still use old-fashioned methods of price discovery. For example, most traders continue to rely on telephone conversations or faxes with counterparties to discover prices. Many traders also contact brokers for price information. Brokers are market makers who bring together buyers and sellers, and receive a fee for their services. Brokers do not take title to power and therefore are not regulated by the Commission. While brokers help with price discovery, there is not a single, centralized mechanism for price discovery in electricity markets. Institutions such as power exchanges and futures markets will help in making prices more transparent but they only indicate

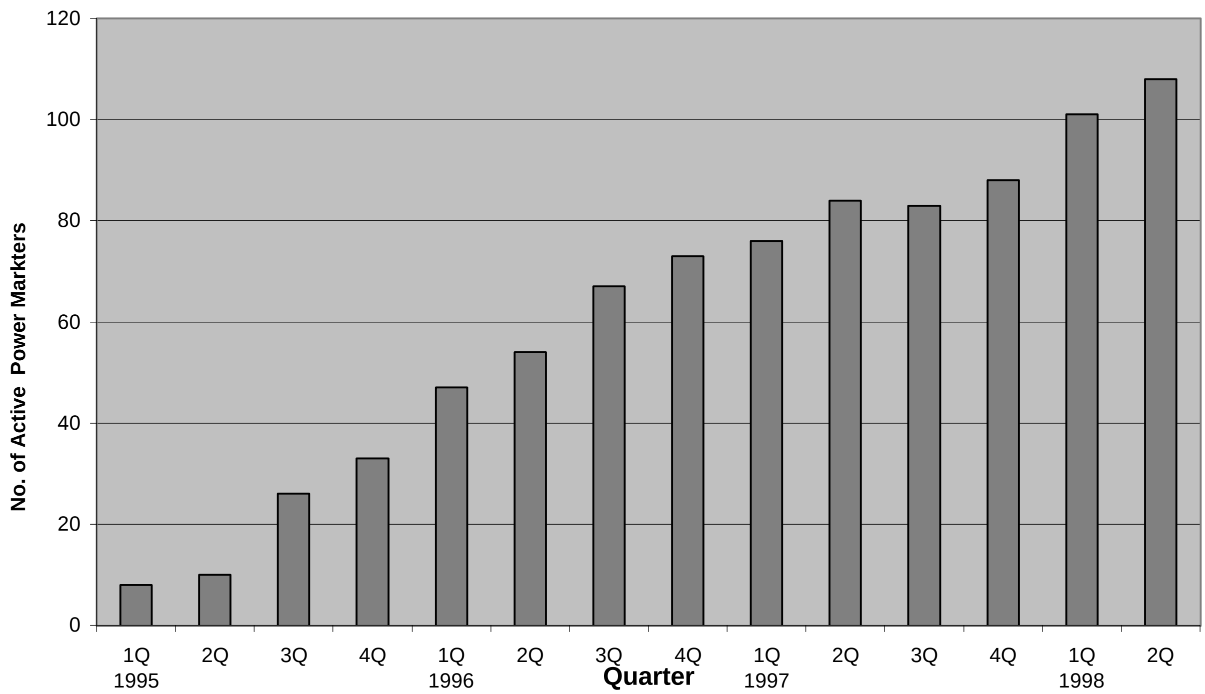
[12] A number of publications publish price information including: *Dow Jones*, *Megawatt Daily* and *Power Markets Week*.

Figure 3-1. Power Marketer Total Wholesale Sales (Million MWh)



Source: Power marketer quarterly filings as compiled by Resource Data International.

Figure 3-2. Growth in the Number of Actively Trading Power Marketers



Source: Power markter quarterly filings as compiled by Resource Data International.

prices on a daily basis or for longer periods and will not provide price discovery in hourly markets.

4. Managing Risk in Wholesale Power Markets

With the partial deregulation of wholesale power markets, risk management has become a necessary part of trading. Before Order 888, utilities traded to balance loads, buying power mostly from their neighbors with spare capacity. In that environment, cooperation rather than competition prevailed and management of market risk was not necessary. Post-Order 888 power markets involve many more market participants who compete with each other. In this setting, risk management is an essential component of wholesale trading.

One form of risk management the electric industry has long used is the forward contract. A forward contract is a contract for future delivery of a designated quantity of power at a designated price, time, and location. Buying forward allows a firm to ensure supplies for some future time at a known price. Forward contracts may be a less risky alternative than buying power on a short-term spot market, where prices may be higher. However, forward contracts obligate both the buyer and seller to accept the agreed-upon price, regardless of the market price when the delivery takes place.

Traders "hedge" deals to reduce exposure to the possibility of unexpected, adverse price change. A hedge is the purchase of a financial instrument to establish a position that is equal and opposite to a position in the cash market. A hedge provides a form of insurance that the buyer or seller of power can obtain or pay a certain price for power. A number of hedging instruments are available to traders. Only a small percentage of hedge transactions actually result in the delivery of power, a pattern typical of other commodities and also seen in natural gas.

Over-the-Counter Markets (OTCs) for Options. The physical daily option is the most commonly used of all the hedging tools available to traders.[13] An option is a contract granting the right, but not the obligation, to buy or sell an asset for an agreed upon price over a specific period of time. An option allows a trader to exercise a "call" (the right to buy power) or a "put" (the right to sell power), at a given price called a "strike" price before it expires. For example, a daily call option, if exercised, would enable a trader to buy a particular quantity of power at the strike price for a specific day.

Market participants buy and sell options through brokers in OTC markets that are linked together by telephones and computer screens. Options offer a kind of price insurance to traders. In exchange for selling an option, the seller collects a premium. If the price of power does not reach the strike price, then the seller keeps the fee.

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[13] "Players Rate Hedging Tools in West," *Megawatt Daily*, October 24, 1997, p. 5.

Traders buy options to cover physical trades. If a trader made a deal to buy a certain amount of power for a certain price, she would purchase a call to put an upper limit on her acquisition cost. The call option's strike price represents the amount up to which the buyer is willing to endure price increases. At the time the power is actually purchased in the cash market, the options position is liquidated. If the strike price is met, the trader pays the higher price according to the contract with her counterparty, but the financial offset provided by the option allows her to limit the expense of the purchase.

Futures trading. Options used to be one of the few risk management tools available to traders in the Eastern Interconnection. Recently, however, commodities exchanges began offering futures for electricity. Four electricity futures contracts sponsored by NYMEX are now underway—two in the Western Interconnection and two in the Eastern Interconnection. The two western futures contracts, based on delivery at the California-Oregon Border and Palo Verde, Arizona, respectively, have been trading since July 1997. NYMEX's Eastern Interconnection futures contracts for delivery at Cinergy and Entergy began trading in July 1998.

Other futures contracts are also underway. The Chicago Board of Trade (CBOT) began offering two contracts on September 12—one for delivery of power at ComEd, the other based on delivery at TVA. The Minneapolis Grain Exchange launched its electricity futures contract—for delivery at Northern States Power in Minneapolis—on September 15. In addition, NYMEX and CBOT both have plans for contracts in PJM, and CBOT is working on a contract in ERCOT.

Futures markets differ from OTC options in that they involve standard packages of power. The standard electricity futures contract is 736 MWh to be delivered over a monthly period on the NYMEX exchange, and 1,680 MWh to be delivered over a monthly period on the CBOT exchange. Futures trades are conducted in a manner similar to options, except that futures allow traders to create a hedge that will lock in a particular price. Futures bind buyers and sellers to the contract price, while options bind the seller to the price only if the buyer chooses to exercise the option.

An example of a futures hedge is as follows: a utility commits to purchase a package of power from a supplier for June delivery at the market price prevailing at the time of delivery. At the same time, the utility buys a futures contract at the current market price, and budgets that amount as its acquisition cost. By the time the June contract expires (a few days prior to June 1), market prices have risen, and the utility takes delivery of the contracted power at the prevailing spot market price. At the same time, the utility sells its futures position for that prevailing market price. The loss in the power purchase is offset by the gain in the futures position, thereby guaranteeing the utility the expected price for the purchase.

Other hedging tools. Insurance companies have entered the power marketing business by offering policies to help electricity traders reduce their risk. One company has introduced a line of products to reduce risk in a variety of circumstances. The policies allow traders to protect against the expensive cost of replacement power in the event of a unit outage, to manage counterparty risks or to protect against extreme price fluctuations. The insurance contracts differ from call options in that they protect against downside potential but do not hold the upside potential that could offer a payout simply based on how high prices go.[14]

Weather-related derivatives are another new tool for hedging risks. A small number of trading companies offer weather-related contracts to help manage the risks associated with unpredictable weather conditions. This is the only type of contract yet offered to give energy providers a way to manage volumetric risk. Some of the contracts offered are options contracts with a strike point set at a certain number of degree days. Other contracts are based on maximum or minimum temperatures.[15]

5. Why Focus on Price Spikes?

In this report, the primary focus is the June event, with a secondary focus on other price spikes in May and July. This approach might be thought to be too restrictive, since high prices appear to have been reported throughout the summer. A closer examination of the daily data reported in the trade press, however, shows that these spikes were indeed very important to wholesale power markets during the summer of 1998 and demonstrates why they were selected as the focus of the study.

Figure 3-3 shows the distribution of prices at the “Into Cinergy” hub, the most actively traded hub in the Eastern Interconnection. During the period from May through August, there were 13 days when the daily price index exceeded $100 per MWh. Of these 13 days, all but one fell within one of the three periods when prices “spiked.” Of these periods, the June event was by far the most important, both in terms of the prices that were reported in the trade press, and in the estimation of market participants interviewed during the study. Neither the May event nor the July event resulted in prices with levels as high, or as sustained, as those in June. Although prices were high during the week of July 21, the overall weekly average was not affected nearly as much by the spike as the weekly average during the June event. In June, prescheduled prices into Cinergy rose to $2,461 per MWh, the weekly average for the week of June 22 was $744, and the effects carried over to the following week when the reported prices were $1,704 on Monday. These prices all appear to have followed from the market crisis on Thursday, when buyers made forward purchases of supplies in the hourly market and subsequently scheduled these supplies in the day ahead market. In July, the high daily prices fell relatively quickly from a daily price

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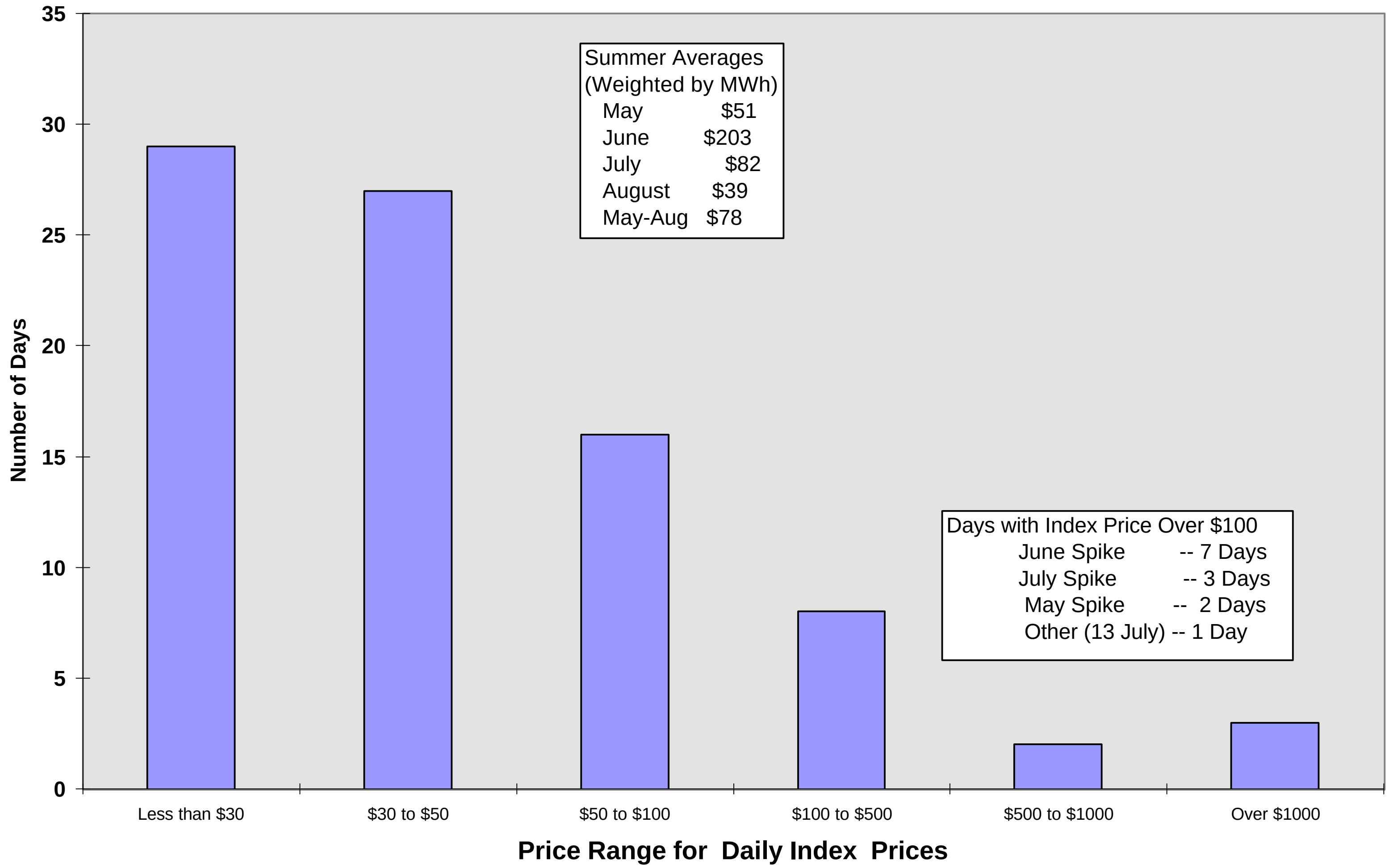
14 “New Line of Cigna Insurance Products Designed to Help Market Manage Risk,” *Power Markets Week*, August 10, 1998, pp. 4-5.

15 “Weather-Driven Risk Tools Taking Hold; A New Way to Manage ‘Volumetric’ Risk,” *Power Markets Week*, January 19, 1998, pp. 1, 13-14.

Figure 3-3. Distribution of Daily Index Prices "Into Cinergy"

(May through August, 1998)



Source: MegaWatt Daily Daily Price

Note: Index prices are for daily prescheduled, on-peak (16 hour) electricity in $/MWh.

index of $1,350 on Tuesday when weather moderated, and prices for the week averaged $206 per Mwh.

During both June and July, the unweighted index prices from *Megawatt Daily* differed considerably from the weighted averages. In June, the unweighted average of daily index prices into Cinergy was $257 per MWh, while the weighted average was $203 per MWh. In July, the difference was more pronounced: the unweighted average was $147 per MWh, but the weighted average was $82 per MWh. This trend may suggest that buyers had developed better alternatives in July, and were able to avoid the highest prices by reducing their purchases. It is also consistent with the information conveyed to the team during interviews, when respondents generally said that the volumes traded during the July spike were less than those during the June event, and also said the effects of the price spike were less severe.

Although the unweighted averages should not be relied upon as an overall indicator if weighted averages are available, they can be used to examine the impacts of days when prices spiked compared with other days. As shown in Figure 3-3, there were 13 days with prices into Cinergy over $100 per MWh, and 12 of these occurred during periods of the price spikes considered in this report. For the period from May through August, the unweighted average of daily prices was $128 per MWh. If the days during the periods of the price spikes are removed from the calculation, the average price for the period from May through August drops to $40 per MWh. This dramatic drop shows how important these periods were to the overall summer price picture. The fact that the price spikes appear to dominate the summer price levels should not be taken as an indication that the remaining periods need not be considered, but it does show why the price spikes have been selected as the primary focus of this report.

6. The Price Spike of July 1997

During the summer of 1997, wholesale power markets experienced a price spike similar to the June 1998 spike, although maximum price levels were much lower and operating conditions were less severe. In July 1997, scorching temperatures swept through the Midwest and East, driving up prices to then-unprecedented levels. Day-ahead prices into Cinergy reached an all-time high of $325 per MWh, with index prices in MAIN over $180 per MWh and prices in MAPP of $90 per MWh.[16] PJM index prices rose to $110 per MWh.

PJM set an all-time peak demand record in response to the heat. PJM implemented emergency generation procedures and cut power scheduled for delivery outside the pool. Traders were unable to move power into or out of PJM and thus were unable to capitalize on the even higher prices in the Midwest. PJM's reliability actions succeeded in maintaining system integrity, but by restricting supplies available outside the pool, may have driven up prices in adjacent areas.

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16 Spot electricity prices from *Power Markets Week,* July 21, 1997.

7. Market Events Leading up to the Summer of 1998

Early in 1998, the market showed signs of awareness that the summer could bring high prices. Early in the year, at least some traders planned for high summer demand and prices.

The First Quarter of 1998. Because of the warm winter temperatures brought on by El Niño, cold weather never emerged during the first quarter of 1998. Mild temperatures predominated across the Eastern Interconnection. The only significant weather event of this quarter was a brief cold spell in March, which pushed up prices in the East, Midwest and South. For the most part, first quarter prices were moderate (Figure 3-4).

During the first quarter, prices for the summer were expected to be high because of the El Niño-driven weather. In addition to hot weather, traders were concerned about a number of transmission constraints in the Midwest with the potential to drive up summer prices. Many traders expected high summer prices and positioned themselves in forward markets based on this expectation. Forward trading for the summer months became quite volatile early in the year, with traders trying to immunize themselves against a repeat of prices above $325 per MWh seen during the summer of 1997. In early February, the forward prices into Cinergy for July/August rose to over $50.00 per MWh.[17]

The Second Quarter of 1998. Until May, second quarter prices showed little movement. Mild weather continued but prices edged up in the Midwest because of outages at nuclear plants. Early in the spring, preliminary word on NERC's *Summer Assessment* indicated that the summer of 1998 should be "the most challenging to reliability in recent years."[18] Forward prices for the summer continued to increase, with record forward prices being paid for the summer months. In early April, the July/August forward price into Cinergy was $68.50 per MWh.[19] Many traders were nervous about the generation situation in the Midwest and decided that purchasing forward contracts was the best way to prepare for possible price increases.

The May 1998 "Mini-Spike." Prior to June's price spike, a smaller spike occurred in May. At the time, it brought the highest prices to date, with hourly power selling for as much as $500 per MWh. The May price spike was brought on by unseasonably hot weather which took hold in the Midwest in the middle of the month and increased demand. The high temperatures occurred when many generating units in the Midwest were shut down for routine spring maintenance. Numerous transmission problems arose in the wake of the heavy loads. Because

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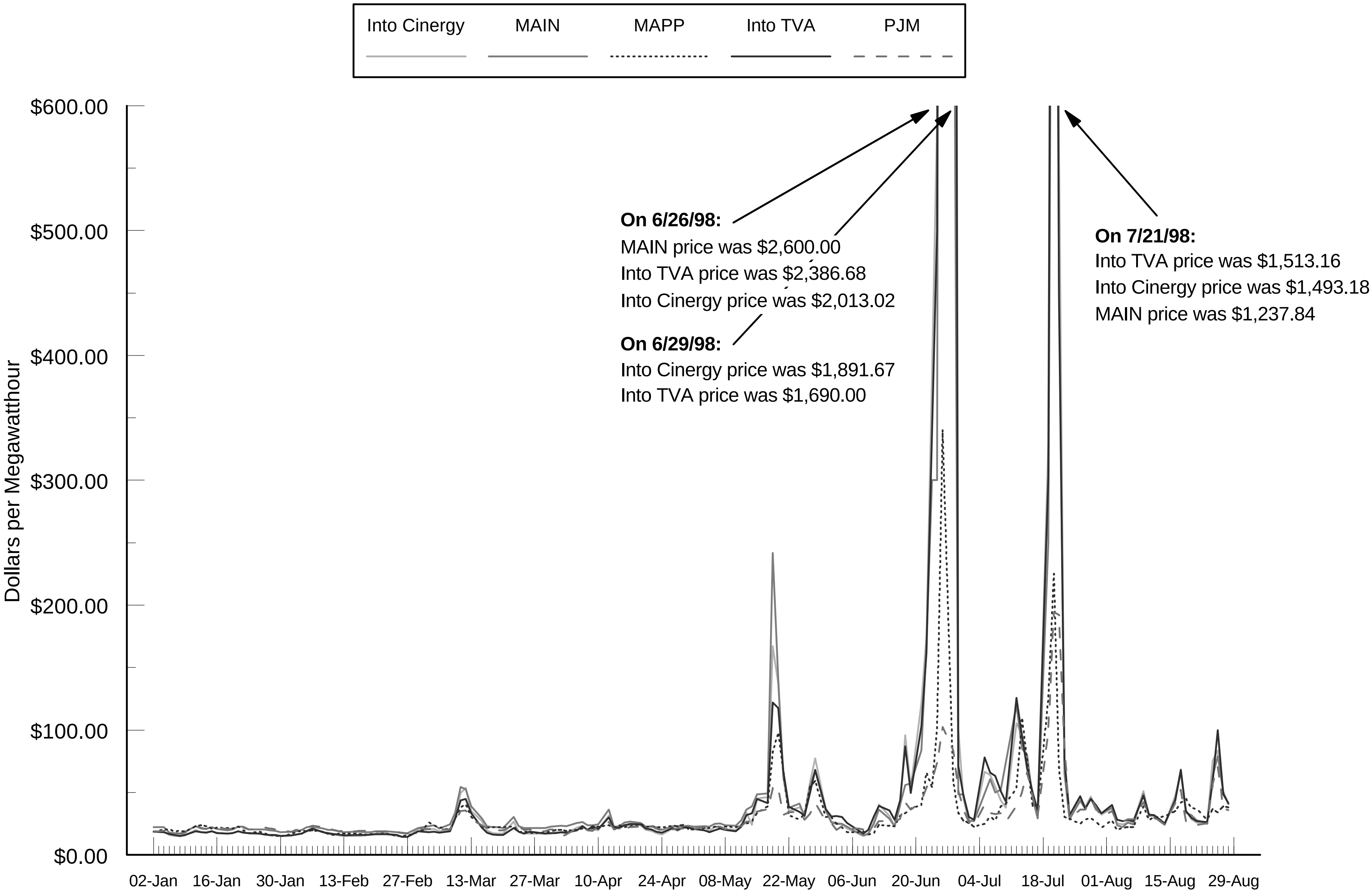
17 Monthly forward markets table from *Power Markets Week*, February 16, 1998.

18 "Too Darn Hot: Summer Could Send Grid to the Edge on Reliability, NERC Warns," *Power Markets Week*, May 11, 1998, pp. 1, 15.

19 Monthly Forward Markets table from *Power Markets Week*, April 13, 1998.

Figure 3-4.
Prices for Next Day On-Peak Spot Electricity Markets



Source: *Power Markets Week*. Data through August 29, 1998.
Note: Prices are index prices for daily prescheduled, on-peak (16 hours) electricity.

the Midwest was short on generation, delivery of replacement power to the Midwest loaded a number of transmission system interfaces to their maximum capabilities during the peak demand days in May.

The highest prices reported in the price run-up were into Cinergy, where hourly prices were reported to have reached $500 per MWh and pre-scheduled daily prices reached $300 per MWh. High prices were reported in MAIN as well, with average next-day prices on May 19 of over $240 per MWh. SERC next-day prices were just under $200 per MWh and prices in SPP, SERC and into TVA were well over the $100 mark. Utilities were said to have been the major purchasers of the high-priced power during the May mini-spike.

B. The June 1998 Price Spike

During the week of June 22, 1998, wholesale electricity prices reached unprecedented levels. While prices as high as $10,000 per MWh were rumored, the highest price the team confirmed was an hourly price of $7,500 per MWh for a 50 MW transaction, paid by one Midwest utility for one hour. However, some utilities paid high prices for substantial quantities of electricity in both the hourly and day-ahead markets, with significant levels of hourly purchases at $3,000 to $6,000 per MWh.

Power prices edged up throughout the week as high temperatures continued to drive up loads. On Monday, June 22, next-day and hourly prices were already high (at least compared with prices up to that point), with next-day prices ranging from $80 to $200 per MWh. The default of Federal Energy Sales on Tuesday, June 23, was said to have driven up prices as market participants became concerned about whether they could meet their supply obligations. In the wake of the default of Federal Energy Sales, several other traders defaulted on contracts. On Wednesday, June 24, temperatures and loads increased and prices continued to escalate to over $1,000 per MWh.

To make matters worse, some midwestern temperatures rose higher than projected Wednesday night. On Thursday morning, June 25, hourly prices opened at around $1,000 per MWh. Prices escalated rapidly from $1,000 to $5,000 per MWh. By Thursday afternoon, hourly prices peaked at $7,500 per MWh. On Friday morning, June 26, prices began to fall, ranging from $1,500 to $3,500 per MWh. Prices decreased relatively quickly thereafter as temperatures decreased and loads subsided.

Set forth below are the significant events that occurred each day during the week of June 22 and a brief discussion of the individual factors that contributed to the price volatility during the week. The narrative is drawn from the trade press and the team’s discussions with market participants.

Monday, June 22, 1998. The week began with high prices in both next-day and hourly markets, with hourly prices running higher than daily. For June 22, the highest day-ahead price reported was $200 per MWh into Cinergy. In contrast, blocks of power for 16 hours each day for the 5 business days of the week (16x5 sales) into the northern part of ECAR were priced much lower, at $65 per MWh.[20] Day-ahead prices in the Southeast were up to $140 per MWh at Southern, $130 per MWh into TVA and $167 per MWh at the Florida-Georgia border.[21] Prices rose more in anticipation of high temperatures and high demand in the southeastern United States than on predictions of hot weather in the East and Midwest.

Hourly prices in the Midwest on June 22 were reported as high as $400 per MWh in northern ECAR. This rise was attributed primarily to transmission "loop-flow" problems from Ontario Hydro into MECS. Hourly market prices into Cinergy were reported as high as $300 per MWh on the afternoon of June 22. These high hourly prices reportedly gave an incentive for marketers to sell power generated in PJM to markets in ECAR. Indeed, PJM reported that it was reducing its previous estimates of daily maximum native load by an average of 3,000 MW for the remainder of the week, implying that a comparable amount of generating capacity would be available for sales outside of PJM. Abnormally high temperatures in the Southeast also caused hourly market price increases of up to $275 per MWh at Southern, well over the reported high day-ahead figure for June 22 for sales at Southern.[22]

Tuesday, June 23, 1998. The reported high day-ahead prices for June 23 in Midwest markets ranged from $50.50 into north MAIN, to $90 in MAPP, $142 in Ameren, $190 into Cinergy and $275 into north ECAR. Trade press reports indicated that some market participants had been concerned whether high exports of energy from PJM would allow utilities within PJM to meet their native loads, but that PJM apparently allayed these fears somewhat by its June 22 announcement that it would lower its estimated peak demand for the remainder of the week. Some traders also expressed concern about prices in MAPP during the latter part of the week: temperatures of over 100 degrees were predicted, while interruptions in transmission paths were already occurring and line-loading relief continued for the Eau Claire-Arpin transmission line. However, day-ahead prices for June 23 generally were highest in the Southeast, with the highest reported sales prices of $200 at Southern, $205 at the Florida-Georgia border and $225 into TVA because of heat-related demand. One marketer was reported to infer that such high prices into TVA meant that, at the end of the month, purchasers were genuinely short of power, rather than seeking to resell it.[23]

On June 23, reports of Federal Energy Sales's default on its obligations, combined with concerns about the unseasonably high temperatures, had "thunderous repercussions" on hourly electricity markets. Hourly prices thereafter substantially increased in a number of ECAR markets, especially into Cinergy.[24]

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20 "Megawatt Daily Price Survey," *Megawatt Daily*, June 22, 1998, p. 1.

21 "Strong demand pushes Southeast prices higher," *Megawatt Daily*, June 22, 1998 , pp. 1, 5.

22 "Hourly markets explode, dailies not far behind," *Megawatt Daily*, June 23, 1998, pp. 1, 3.

23 "Megawatt Daily Price Survey," *Megawatt Daily*, June 23, 1998, pp. 1, 3.

24 "Marketer said to renege; Midwest prices skyrocket," *Megawatt Daily*, June 24, 1998, p. 1.

Wednesday, June 24, 1998. Day-ahead prices for June 24 substantially increased in many Midwest markets over comparable June 23 prices. In light of Federal Energy Sales's reported defaults, concerns that other traders might not meet their contract commitments were said to drive up prices. *Megawatt Daily* remarked about Federal Energy Sales's reported default that "Most marketers have predicted this type of scenario since last July, in the wake of $325 next-day power."[25] In reaction to the price increases, some large marketers attempted to reduce their trading volumes until price fluctuations leveled off.

Other events reported to have increased day-ahead prices for June 24 were: Ontario Hydro's request in the afternoon of June 23 for transmission line relief; TVA's report of an all-time peak demand on June 22 and near record demand levels on June 23, and its predictions of a new record demand later in the week; and high temperatures in Entergy, where the market was described as "severely short." *Megawatt Daily* noted that exports from PJM remained high, although the hot shutdown of PP&L's Susquehanna-2 nuclear plant (1,152 MW) was reported; a return of that unit to service was expected for the weekend. MAPP lost some generation when Northern States Power shut down its coal-fired 705 MW Sherburne County-2 unit to repair storm damage, although the Omaha Public Power District restarted its Gerald Gentleman-2 plant (648 MW).[26]

The highest reported day-ahead prices remained stable for north MAIN ($50.50) and decreased in MAPP (from $90 to $78) compared with prices for June 23. However, the highest reported day-ahead prices increased for other areas: to $180 for Ameren, $325 for ComEd and into Entergy, $500 for north ECAR and $600 for Cinergy.[27]

Intra-day prices into Cinergy on June 24 went as high as $1,400 per MWh, with the trade press speculating that a utility shorted by Federal Energy Sales was bidding up the price. Some utilities were said to have bought power at "whatever the market would bear" to account for disparities between available generation and predicted demand. As an example of price increases in the hourly markets on June 24, one trader cited a 16-hour transaction at market prices, with prices to be adjusted hourly. The hourly prices under this agreement went up from $17 to $1,000 per MWh.[28]

Thursday, June 25, 1998. Federal Energy Sales's defaults, coupled with predicted high temperatures and electricity demand, reportedly led to some higher day-ahead prices for June 25, compared to day-ahead prices for June 24. In particular, traders continued to refer to uncertainty about whether marketers other than Federal Energy Sales would default. The highest day-ahead price into Cinergy rose to $1,200 per MWh, despite a reported prediction by Cinergy that its 1,300 MW Zimmer-1 plant back would be back on line for June 25. While the highest day-ahead

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25 "Marketer said to renege; Midwest prices skyrocket," *Megawatt Daily,* June 24, 1998, p. 5.

26 "Marketer said to renege; Midwest prices skyrocket," *Megawatt Daily,* June 24, 1998, pp. 5-6.

27 "Megawatt Daily Price Survey," *Megawatt Daily*, June 24, 1998, p. 1.

28 "Cinergy hourly, dailies break the $1,000 mark," *Megawatt Daily*, June 25, 1998, pp. 1, 6.

prices stayed stable in north MAIN, MAPP and Ameren compared with those for the previous day, and decreased in north ECAR (from $500 to $425), the highest reported day-ahead prices increased to $450 for ComEd and into Entergy, $495 for the Florida-Georgia border and $700 into TVA.[29]

On June 25, hourly market prices in many areas of the Midwest soared far above the day-ahead prices.[30] The price information submitted by utilities and marketers in response to the team's data request confirm the trade press's statement that $4,000 per MWh was a common hourly price in much of the Eastern interconnection on June 25. For example, one utility reported paying a high of $7,500 per MWh for 50 MW of energy on the afternoon of June 25. Another utility paid $6,000 per MWh for hourly energy that afternoon.

Traders acknowledged that part of the reason for the price spike was unplanned outages at a number of generating plants during the night of June 24-25, such as FirstEnergy's 962 MW Davis-Besse nuclear plant (as a result of tornado damage to transmission lines in the immediate vicinity of the plant) and Northern States Power's 855 MW Sherburne County-3 coal-fired plant (shut down by storms, but then reopened June 25). Generating capacity available for Midwest markets further decreased when PJM interrupted power exports by declaring a maximum system generation emergency. A number of transmission facilities in MAPP and ECAR were also shut down by storm damage, including the Eau Claire-Arpin line. These outages reduced utilities' ability to transmit power among MAPP, MAIN and ECAR.[31]

On June 25, higher than predicted temperatures caused numerous utilities to reach record peaks. TVA, Consumers Energy, Detroit Edison, Alliant-Wisconsin Power & Light, Dayton Power & Light, Oglethorpe Power and Duke Power all hit record peak demands on their systems.[32] ComEd (which experienced near-record demand), AEP, FirstEnergy and other utilities issued appeals to consumers to conserve energy use. High demands in many surrounding areas hindered Midwest utilities' attempts to import power.

Some utilities reached generation emergency conditions on June 25. In at least one case, a utility in need of power contacted the control room of another to obtain power. Both parties agreed to the sale, but after the power flowed, a disagreement arose about the price of the power. The buyer claimed they agreed to $400 per MWh while the seller said the price was $4,000.

Friday, June 26, 1998. While the amount of hourly trading and hourly prices increased on June 25, day-ahead trading volumes for June 26 decreased. In light of the huge increases in hourly prices on June 25, sellers were said to discourage daily deals in hopes of being able to

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29 *Megawatt Daily*: "Cinergy hourly, dailies break the $1,000 mark," June 25, 1998, p. 6; "Megawatt Daily Price Survey," June 25, 1998, p. 1.

30 "Massive spike continues; ECAR hourly hits $5,000," *Megawatt Daily*, June 26, 1998, p. 1.

31 "Massive spike continues; ECAR hourly hits $5,000," *Megawatt Daily*, June 26, 1998, pp. 6-7.

32 *Megawatt Daily*: "Utilities appeal to customers to conserve power," June 26, 1998, pp. 1, 6; "Utilities strain to meet demand for power," June 29, 1998, pp. 1-2.

obtain high hourly prices again on June 26. Moreover, utilities reportedly did not want to enter into daily transactions for June 26 because they feared that such deals might endanger their ability to serve native load.

Day-ahead prices for June 26 reflected these developments: they were reported to reach unprecedented levels, but were lower than the highest hourly prices on June 25. Day-ahead prices per MWh climbed to maximums of $500 in MAPP, $1,300 in Southern, $2,000 into Entergy, $2,800 into ComEd, $3,600 into Cinergy and $4,900 into TVA. In contrast, the maximum reported per-MWh day-ahead prices for June 26 were stable for north MAIN, Ameren and north ECAR, as compared to the maximum day-ahead prices for June 25 for these areas.[33]

On June 26, high heat again increased electricity demand to record or near-record levels for a number of utility systems. The trade press reported that Cinergy and MAIN had predicted trouble in meeting electricity demand that day; PJM again declared a maximum generation emergency and cut off power exports; Virginia Power predicted that demand would rise to near-record levels. However, hourly prices on Friday afternoon were reported to retreat rapidly from the record-breaking levels of June 25. [34]

June 27- July 1, 1998. In the days following the huge price spikes, day-ahead prices decreased for the weekend days of June 27 and 28, going down to double-digit figures for many Midwest areas. The highest reported Midwest prices were for sales into Cinergy: $100 per MWh on June 27 and $110 per MWh on June 28. In contrast, the maximum reported day-ahead price for purchases in Southern's region for these days was $1,000. Day-ahead prices for Monday, June 29, edged back toward the levels of June 25 and 26. By region, the maximum reported per-MWh prices ranged from $90 in MAPP to $1,000 in Southern, $1,300 in north ECAR, $1,450 into Entergy, $2,000 into TVA and $2,500 into Cinergy. However, by Wednesday, July 1, day-ahead prices plummeted to levels that were well below the day-ahead prices of the previous week. Maximum Midwest day-ahead prices for July 1 were reported at $20 per MWh in MAPP, $50 into ComEd, $55 into Entergy, $60 into Cinergy and $70 into TVA.[35]

C. The July 1998 Price Spike

Late in July 1998, power markets experienced prices that, other than the June 1998 price spike, were the highest of the summer. Many of the factors that contributed to the June spike were also present in July. Yet the July price increases were not as high and did not last as long as the June spike. In addition, trading volumes during this period were reported to be thin.

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33 *Megawatt Daily:* "Utilities appeal to customers to conserve power," June 26, 1998, pp. 1, 6; "Utilities strain to meet demand for power," June 29, 1998, pp. 1-2; "Megawatt Daily Price Survey," June 26, 1998, p. 1.

34 *Megawatt Daily*: "Utilities strain to meet demand for power," June 29, 1998, pp. 1-2; "Prices begin their retreat from record levels," June 29, 1998, pp. 1, 5.

35 "Megawatt Daily Price Survey," *Megawatt Daily*, June 29, 1998, pp. 1-3.

Discussions with market participants indicated a lesser degree of concern about prices during this week than during the June event. While reported trade press prices were very high, not much trading occurred at these prices.

Monday, July 20, 1998. On Monday, July 20, the trade press reported that day-ahead energy prices for that day reached a maximum of $500 per MWh into Cinergy, $475 into TVA and $350 into Entergy. These prices represented substantial increases from day-ahead prices for the previous Friday, July 17. The price increases into Cinergy were attributed to traders' predictions that heat-related demand in PJM would be substantially higher than predicted and that PJM exports into Cinergy would increase. Entergy prices were higher on reports that Entergy's Waterford and Ritchie-2 units, with a total of 1,740 MW of capacity, might not be available.[36]

Maximum hourly prices into ECAR on July 20 hit $1,000 per MWh, approximately double the maximum day-ahead prices for that day. The hourly price rises were attributed to news that Detroit Edison's Fermi-1 nuclear unit, with a generating capacity of 1,139 MW, shut down on Sunday, July 19.[37]

A number of Midwest utilities experienced surges in demand on July 20. AEP, Northern States Power, Kansas City Power & Light and Interstate Energy cut power to customers with interruptible contracts; ComEd, Northern States Power and Virginia Power expected to meet or surpass records for demand; and Illinois Power and PP&L declared "conservation" days in which they asked customers to use less power.[38]

Tuesday, July 21, 1998. According to trade press reports, maximum day-ahead prices per MWh for Tuesday, July 21 increased, based on anticipated heat-related demand, to $1,800 into ComEd and TVA, $1,950 into Cinergy and $2,000 into Entergy. On that day, a number of utilities again experienced very high demand. ComEd reported that it expected a record peak demand. Ameren, Wisconsin Electric, Kansas City Power & Light, Duke Power and Indianapolis Power & Light also reported record peaks. Officials from MAIN and FirstEnergy stated that the loss of generating units would cause problems in meeting customer demand. Moreover, these high demand levels were accompanied by unscheduled generation outages and transmission constraints. Cinergy shut down its Zimmer-1 coal-fired plant, with a capacity of 1,300 MW, AEP shut down its 1,300 MW Mountaineer coal-fired plant, and a TLR from Ontario Hydro was reported to have curtailed every transmission path to the south and west, and to have cut power imports into the PJM pool. The PJM locational marginal price and the instantaneous price reached $990 on the afternoon of July 21.[39]

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36 "Megawatt Daily Price Survey," *Megawatt Daily*, July 20, 1998, pp. 1-2.

37 "Four-digit pricing returns to eastern hubs," *Megawatt Daily*, July 21, 1998, p. 6.

38 "Four-digit pricing returns to eastern hubs," *Megawatt Daily*, July 21, 1998, p. 5.

39 *Megawatt Daily*: "Megawatt Daily Price Survey," July 21, 1998, p. 1; "Utilities meet record demand as heat moves east," July 22, 1998, p. 3; "Eastern hubs drop but prepare for more heat," July 22, 1998, p. 1; "PJM, Nepool, Texas feel strain in supplies," July 23, 1998, p. 1.

Wednesday, July 22, through Friday, July 24, 1998. For July 22, Virginia Power predicted an all-time record demand and the New England ISO predicted that peak demand would be 213 MW higher than available capacity. Other utilities also predicted high customer demand. Nevertheless, reported day-ahead prices for Wednesday, July 22, were sharply lower than day-ahead prices for the previous day. Maximum per-MWh day-ahead prices dropped to $340 into ComEd, $550 into TVA, $800 into Entergy and $850 into Cinergy.[40]

By Thursday, July 23, reported day-ahead prices per MWh had dropped again, to $75 into ComEd, $90 into TVA, $75 into Entergy and $85 into Cinergy. Day-ahead prices for Friday, July 24, dropped further, to $30 per MWh into ComEd and Cinergy, $35.50 into TVA and $38 into Entergy. [41]

D. Market Data on Purchases and Sales During the June Event

To supplement the anecdotal information received from the trade press and market participants, the team requested detailed information about purchases and sales during the June event. These data provide additional information on the June event that cannot be gained through the review of public sources and interviews with market participants presented in the previous section. The data show an overall picture of the prices paid and the amount of power traded during the week, and also show how the prices of power bought and sold vary by hour throughout the week. In this section, the June event is analyzed using these data. The discussion is organized into the following areas:

- Overall impact of the June event on prices
- How selling prices and purchase costs varied by day through the week, and how hourly price patterns developed, particular on the critical day of June 25
- The estimated impact of TLRs and generation emergencies.

The information from responses to the data request provides an important background to the June event, because it provides estimates of the overall weekly impact of market prices. Without this context, it is difficult to weigh the meaning of reported high prices that may have been for limited quantities of power and for a short number of hours. The data provide a more accurate picture of when high prices occurred, and which parties paid and received those prices. However, the data do not permit us to make definitive judgments of wrongdoing or price

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40 *Megawatt Daily*: "PJM, Nepool, Texas feel strain in supplies," July 23, 1998, p. 1; "Eastern hubs drop but prepare for more heat," July 22, 1998, p. 6; "Megawatt Daily Price Survey," July 23, 1998, p. 1.

41 "Megawatt Daily Price Survey," *Megawatt Daily*, July 23, 1998, p. 1; July 24, 1998, p. 1.

manipulation, nor was their collection designed with that purpose in mind. Such judgments would require the collection of substantial case specific information, an effort which is beyond the scope of this study.

1. Net Impact of High Prices on Purchases and Sales for the Week

The impact of high prices on buyers of power depends not only on the prices themselves, but also on how much power was purchased and on the duration of the purchase. The weekly totals shown in Table 3-1 include all power purchases and sales and show the average prices for the week in addition to the highest prices reported in the data request responses. This table includes the total power purchases, including long-term purchases that were negotiated before the June event. The averages are therefore lower than the prices reported in the trade press and cannot be directly compared to them.[42] The averages for the week are much lower than the maximums, although they are also well above annual average prices, which were $23 to $37 per MWh for 1996 and $24 to $37 per MWh for 1997 for utilities in the regions included in the data request.[43] It is not unreasonable to expect high prices during the summer, and these averages do not appear to be much above what one might reasonably expect to see during a summer week with supply and demand conditions as tight as they were during the June event.

The pattern of purchase and sales prices indicates that the weighted average price received for the week was $60 per MWh, and the average price paid was $61 per MWh. The closeness of these prices indicates that the overall sample was reasonably balanced between buyers and sellers. However, price differences emerge when different types of buyers and sellers are examined (Table 3-1). Marketers received prices approximately $5 above the prices they paid on average, while investor-owned utilities received prices approximately $19 below the prices paid on average. Other entities received approximately $7 more per MWh than they paid, although their total sales and purchases were much smaller. There was variation within each category, however, and the overall distribution of net sales (sales revenues minus purchase costs) was fairly concentrated. The five entities with the largest net losses (negative net sales) accounted for approximately $215 million dollars, around 72 percent of the total net losses. Similarly, the five entities with the largest gains (positive net sales) accounted for approximately $155 million, or around 55 percent of total positive net sales. These groups—the top five losers and gainers—included both investor-owned utilities and marketers. None of the other entities responding to the request fell within either top five gainers or top five losers.

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42 The prices reported in the tables published by the trade press (*Power Markets Week* and *Megawatt Daily*) are generally for day-ahead prescheduled blocks of power, typically 16 hour blocks of on-peak power. Long-term deals not in the market for power day-ahead are not included in the trade press tables.

43 The data request included utilities in regions east of the Rocky Mountains, excluding ERCOT and New England. The annual average prices are based on Form 1 data obtained from the PowerDat software from Resource Data International (RDI). The lower number is the weighted average purchase price in these regions for energy only; the higher number includes a capacity charge.

Table 3-1. Summary of Total Weekly Sales and Purchases, All Hours

	Power Sales			Power Purchases		
	Volume (Billion kWh)	Average Price Received for Week	Maximum Price Received	Volume (Billion kWh)	Average Price Paid for Week	Maximum Price Paid
Marketers	13.9	$50	$6,000	13.7	$45	$5,000
Other Entities	0.5	$91	$5,000	0.5	$84	$4,900
Investor-Owned Utilities	4.5	$85	$7,500	4.6	$104	$7,500
Total	18.9	$60	$7,500	18.9	$61	$7,500

2. Daily and Hourly Variation in Sales and Purchase Prices

Table 3-2 shows how sales and purchase prices varied throughout the week. Total quantities bought and sold remained at a fairly even level throughout the week, but average sales and purchase prices rose to peak levels on Thursday and moderated only slightly on Friday. The pattern of sales and purchase prices across regions shows that investor-owned utilities in the Midwest generally purchased at higher prices than they sold, while utilities in other regions sold at higher prices than they purchased. These results confirm the pattern of sales and purchases throughout the Eastern Interconnection discussed previously, where the highest demands and prices paid were in the Midwest.

Figure 3-5 shows the maximum price paid and the weighted average price for all reported hourly purchases by investor-owned utilities in the Midwest. The hourly data reinforce the previous summary by day, and show clearly how prices changed in the Midwest, leading up to a peak on Thursday and falling thereafter. It also shows how the pattern of prices on Wednesday and Thursday differed from the pattern for the rest of the week. On both Wednesday and Thursday, prices peak sharply in the middle of the day. This peak occurs because high demands pushed Midwest utilities into hourly markets and pushed prices in these markets up within the day. As demand rose beyond the generation capacity and scheduled supplies available, Midwest utilities could no longer rely on either their own generation or their planned purchases and needed to find new supplies in the hourly market.

These high demands included any demand that arose because traders who were concerned about defaults were searching out sources of physical power in lieu of facing potential liquidated damage claims from other parties in a chain of defaults. Under normal circumstances, these traders would not be in the market for physical power. Instead, they would have “booked out” these transactions and these transactions would have been purely “financial.” However, because the transactions were still in a financial title chain, they were still potentially subject to liquidated damage claims. Traders did not know whether they might be in a chain of transactions that included a default. They did not want to be subject to damage claims from others who were seeking only to pass on their own costs and may have had no interest in minimizing the amount of a claim for liquidated damages.

Traders with such concerns were looking for physical power. This demand did not represent new, ultimate sources of needs for physical power during the day. No loads were added by the actions of traders looking for physical power. But the demands did add to the total demand, by adding to the number of parties looking for physical supplies. Since there was no way for buyers to know whether the prices reflected responses to real power needs or only responses to needs to cover financial positions pursuant to a default, prices rose in response to this financially-driven demand without the usual connection to the underlying physical needs. Utilities with an obligation to serve were in a position where they needed to make sure their system was reliable and that as much of their load as possible was served, and their responses also contributed to the rapid rise in prices.

Table 3-2. Summary of Wholesale Power Purchases and Sales During the June Event

	Date				
	22-Jun	23-Jun	24-Jun	25-Jun	26-Jun
Total Reported Sales in MWh					
Entities Assigned to Regions					
ECAR	376,592	374,361	377,088	376,412	386,828
MAAC/NPCC	279,853	275,404	287,041	295,363	296,293
MAIN	85,471	91,094	85,034	82,667	91,843
MAPP/SPP	98,589	97,116	104,477	97,277	106,689
SERC	144,647	149,354	135,162	149,195	146,148
All Other Reporting Entities	2,743,076	2,796,096	2,775,570	2,803,580	2,813,217
Average Selling Prices in $/MWh					
Entities Assigned to Regions					
ECAR	$34	$35	$83	$139	$115
MAAC/NPCC	$35	$35	$47	$94	$73
MAIN	$29	$30	$91	$178	$239
MAPP/SPP	$36	$35	$55	$132	$100
SERC	$67	$56	$131	$368	$129
All Other Reporting Entities	$33	$40	$45	$58	$74
Total Reported Purchases in MWh					
Entities Assigned to Regions					
ECAR	411,771	399,179	428,272	432,776	416,037
MAAC/NPCC	214,206	238,903	226,302	222,703	234,964
MAIN	113,408	113,095	133,107	146,819	146,551
MAPP/SPP	138,781	136,420	138,386	135,339	136,830
SERC	121,924	128,322	111,077	94,024	94,232
All Other Reporting Entities	2,726,149	2,781,818	2,758,375	2,765,960	2,761,030
Average Purchase Prices in $/MWh					
Entities Assigned to Regions					
ECAR	$44	$49	$109	$221	$145
MAAC/NPCC	$28	$30	$39	$72	$47
MAIN	$30	$32	$148	$413	$440
MAPP/SPP	$36	$37	$46	$83	$54
SERC	$70	$64	$70	$104	$76
All Other Reporting Entities	$32	$40	$40	$57	$57

This pattern of the highest prices occurring in hourly markets on Thursday confirms what the team was told during interviews about how the highest prices were paid in hourly markets. As reported in interviews, the pattern seen on Monday, Tuesday, and Friday was more typical of prices in hourly markets. On these days, the maximum price is relatively flat for most of the day, reflecting deals made in the prescheduled market. The team was told that hourly prices typically clear below the prescheduled price, and the data in Figure 3-5 are consistent with this claim, which show flat blocks that are not surpassed by hourly peaks. The high price level on Friday represents deals that were made on Thursday in the hourly markets when prices were high. During this time, some utilities felt that they needed to buy supplies for the day ahead, and executed transactions for the peak period on Friday (some deals through Monday were also reported to the team in interviews). But the pattern on Friday is similar to Monday and Tuesday—flat prices without price spikes in the middle of the day—because Friday's supply/demand balance improved and eased price pressure on hourly markets.

A more detailed look at the levels and durations of prices can be seen by constructing a "price duration" curve (See Figure 3-6). This figure shows the level prices reached on June 25, and the percentage of the total hourly purchases that were made at that level. The upper curve represents an estimate for hourly transactions. It shows, for example, that the hourly price was over $1,000 for about 40 percent of the MWh. The lower curve shows a similar estimate for all other transactions. Because these transactions include many transactions before the June event, the prices are lower than the hourly price curve. The figure shows that prices were high for a substantial portion of the purchases made in hourly markets, but that the overall impact of these high prices was diluted by the effects of other purchases. These results confirm what the team was told in interviews: the negative impacts were a small proportion of the total, but they fell heavily on utilities or other market participants that needed to rely on the hourly market during the week.

3. Estimated Impact of TLRs and Generation Emergencies

TLRs. Two factors identified as important in the June event were transmission line loading relief and generation emergencies. The data request asked for specific information on what these impacts were and when they occurred.

TLRs arise from the need to prevent overloads of key transmission facilities, and occur throughout the year when loads are high and the transmission system is heavily used. Figure 3-7 shows the quantity of power purchases that were interrupted[44] and the quantity of power purchases that were obtained to replace the power interrupted during the June event. Under normal circumstances, the impact of a curtailment on a load serving utility with generation

[44] Interruptions here include power that was scheduled but could not flow. As we show in Chapter 2, most TLRs did not result in cuts of actual power flows. Since this power needed to be rescheduled during the day, it could have had large impacts when prices were high.

Figure 3-5. Maximum and Average Hourly Prices for Purchases by Midwest Utilities

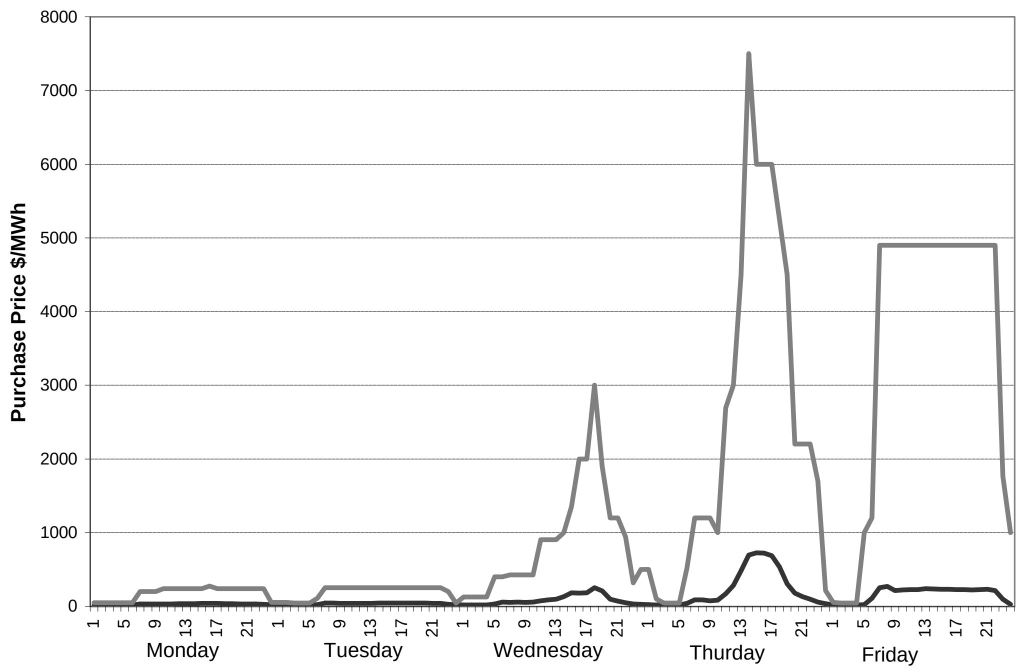
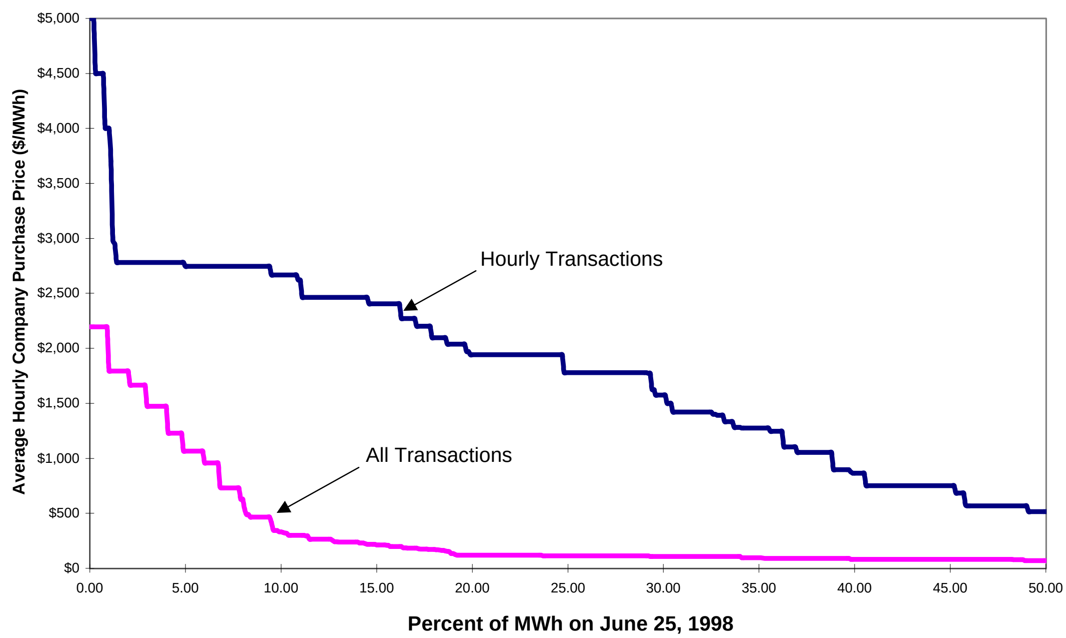
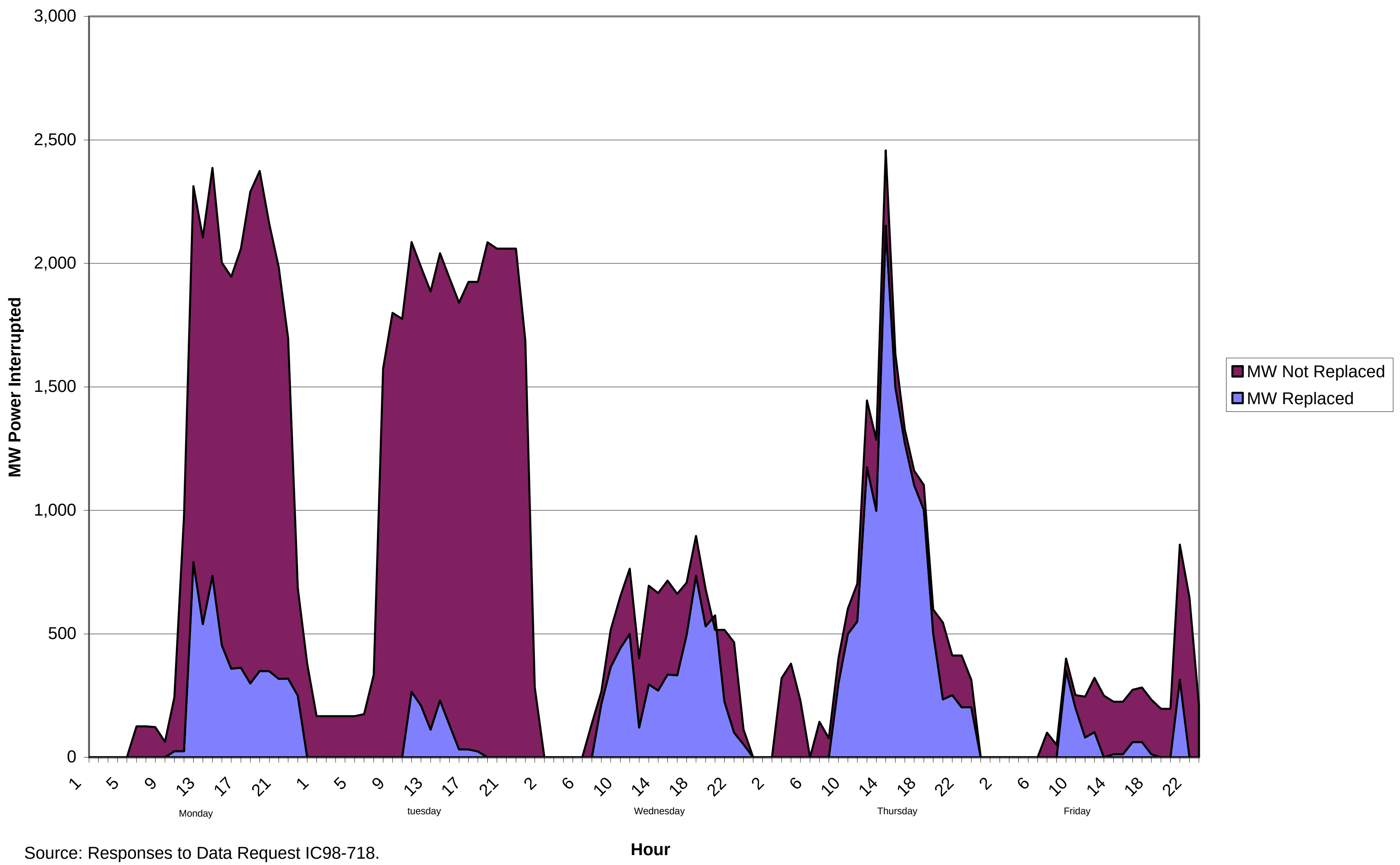


Figure 3-6. Comparison of Estimated Hourly and Estimated Overall Market Price Duration Curves in the Midwest on June 25, 1998



Source: Responses to Data Request IC98-718.

Figure 3-7. Power Interrupted and Replacement Purchases in Response to TLR



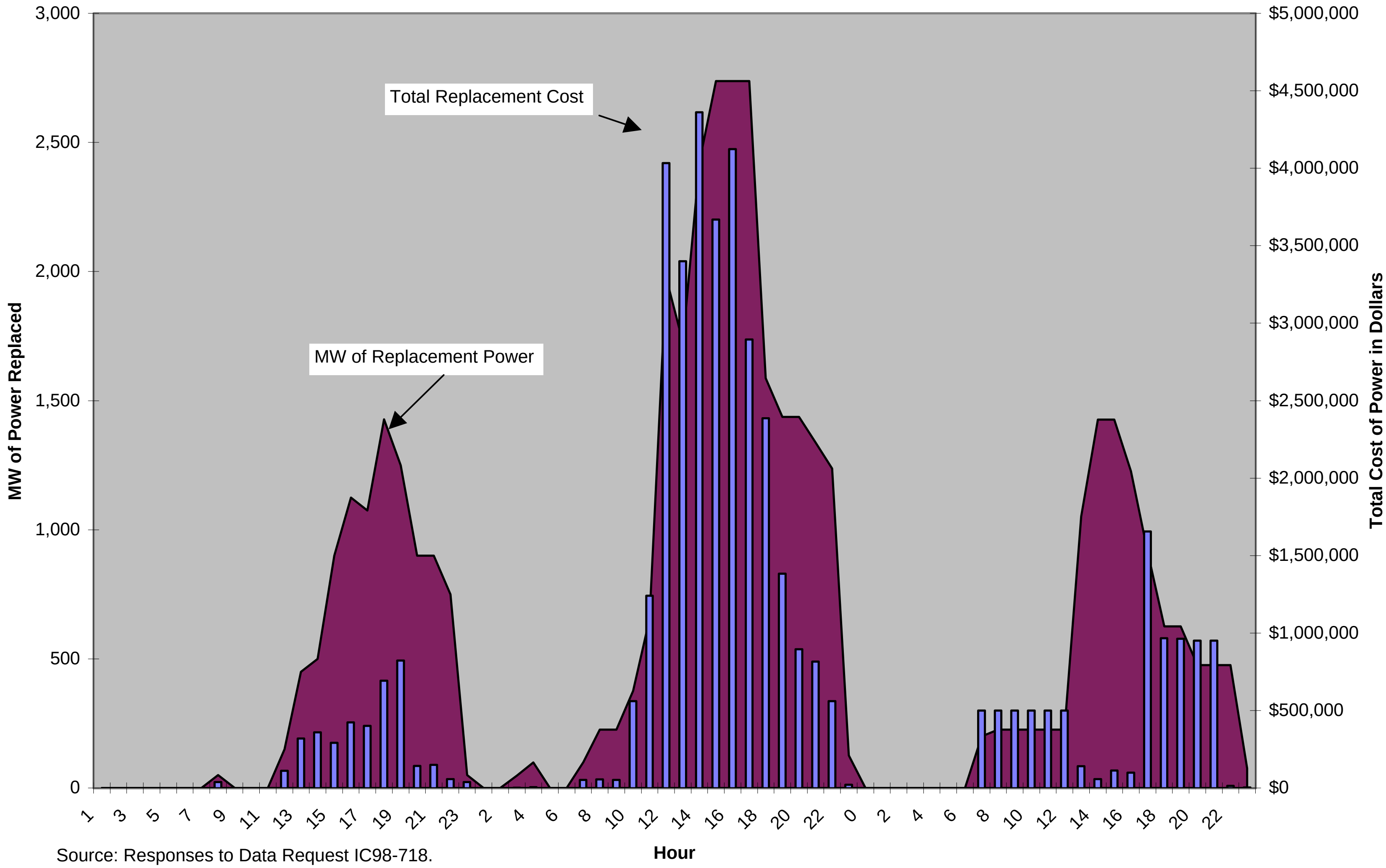
Source: Responses to Data Request IC98-718.

capacity might be small, because the utility could substitute its own generation for the power purchase. The resulting loss would be relatively small, equal to the difference between the cost of power and the cost of self generation. During the earlier part of the week, utilities replaced a fairly small proportion of the interrupted power with new power purchases. However, on Thursday and Friday, when their own sources of power were severely limited during generation emergencies, they were forced to replace a much greater proportion of the power affected by TLR actions. This pattern can be seen in Figure 3-7.

The pattern of purchase costs for replacement power follows the general pattern of prices during the week, but appears somewhat higher than the typical cost of hourly power. Prices for replacement power rose to around $450 per MWh on Wednesday, then hit a high of around $3,200 per MWh on Thursday before falling back to around $770 per MWh on Friday. These prices were especially high on Thursday, in part because of large reported purchases at high prices by a single utility. The high prices may have resulted, in part, from the inability of the buyer to react quickly enough in hourly markets to be able to search out any alternatives.

Generation Emergencies. Generation emergencies had little effect on the cost of purchasing power on Monday or Tuesday. Figure 3-8 shows the quantity of power replaced and the costs for Wednesday through Friday. On Wednesday and Thursday, the impact was similar to that of TLRs, with replacement power costs increasing on Wednesday (averaging $477 per MWh), and peaking on Thursday with an average of $1,536. On Friday, purchase costs returned to levels closer to those experienced on Wednesday ($602 per MWh).

Figure 3-8. Quantities and Costs of Power to Replace Power Interrupted by Generation Emergencies



Source: Responses to Data Request IC98-718.

4. Factors that Contributed to the Price Spike

This chapter examines in greater depth the operational and market factors that contributed to the Midwest price spike and analyzes some of the underlying reasons behind the events. The chapter also discusses the likelihood of a recurrence of future price spikes and identifies lessons learned by the market as a result of the June event.

A. Market Factors

Aside from the fundamental factors such as weather, generation shortages and transmission constraints, a number of behavioral factors appeared to affect the market and contributed to the surge in prices.

1. More Demand than Supply

With higher-than-predicted temperatures driving loads to record peaks and the existence of significant generation outages, a generation shortage developed in the Midwest. The shortage created a situation in which there were many buyers looking for more power than sellers could supply. Utilities that were experiencing peak loads were trying to fulfill native load obligations, and marketers were trying to secure power to avoid defaulting on contracts. With more demand than supply, prices increased drastically.

The desire by utilities to avoid blackouts at all costs fueled their determination to secure supplies. When prices reached thousands of dollars per MWh, utilities questioned whether they should purchase power or shed load. At that point, several utilities reported, senior management instructed trading personnel to pay whatever price was necessary to avoid blackouts. Discussions with various utilities indicated that, aside from their obligation to provide service, perceived pressure from state regulators and politicians was a significant factor in their decision to pay the prices they did for electricity.

Several utilities interviewed by the team reported that generation outages and curtailments of scheduled power deliveries were also factors that forced them into hourly markets in search of power to serve native load. The experience of one utility demonstrates how utilities were thrust into hourly markets at the last moment. Months in advance of the summer, the utility had contracted for a large amount of firm power from a nearby utility. On the morning of June 25, the utility was notified that the neighboring utility would be unable to deliver the power because of a demand surge in its service territory. The utility was forced to go into the hourly markets in search of power.

2. Defaults

The default of Federal Energy Sales on June 23 added to uneasiness in the market and caused traders to worry about the solvency of their counterparties. Federal Energy Sales had conducted business with a number of utilities and marketers, although some believed that Federal Energy Sales was engaged in questionable practices and had ceased to trade directly with the company. The default led to widespread uncertainty about the creditworthiness of counterparties and their ability to deliver.

In addition to the general nervousness in the market, Federal Energy Sales's default contributed to the price run-up because its cascading effect left others in these "daisy chains" holding unfilled positions. As a result of Federal Energy Sales's default on call options contracts, the municipal utility of Springfield, Illinois (Springfield) defaulted on its options contracts with four large utilities. Power Company of America, a larger marketer, also defaulted as a result of contracts not honored by Federal Energy Sales.

Interestingly, only one utility interviewed by the team indicated that it had suffered significant losses as a result of marketer defaults. While other utilities were not directly affected by the defaults, some thought they might be part of the chain of default. Market participants agreed that fears about further contract defaults contributed to the price spike.

The defaults resulted because firms sold call options without the ability to fulfill them if the options were exercised. A number of market participants sold call options because they were seen as a profitable endeavor. Before June 1998, it was rare for options with strike prices higher than $50.00 per MWh to be exercised, and unexercised options allowed the seller to simply pocket the premium. However, when prices began to climb and traders tried to exercise their calls, sellers who had not covered the calls could not honor them and were forced to pay liquidated damages or default.

Springfield was unable to honor its option commitments. According to Springfield, it had been trading in wholesale energy markets since 1997. The city sold call options to a number of firms for the summer. When prices increased and the firms tried to exercise their call options, Springfield refused to honor them because its counterparty, Federal Energy Sales, had defaulted on its contracts with Springfield. As a result, Springfield is being sued by at least three firms and its general manager was asked to resign.[45] City officials acknowledged that they did little to study the risks involved in energy derivatives markets. Springfield representatives told the team that credit checks were impossible because many companies are not rated by credit rating agencies and recommended that FERC regulate creditworthiness.

As of early September, court proceedings initiated as a result of the June event include suits filed by FirstEnergy Trading and Marketing and Stand Energy Corporation against Federal

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[45] "Fallout from June Heat Wave Dries Up OTC Trading in Electric-Power Options," *The Wall Street Journal,* August 17, 1998.

Energy Sales. The City of Springfield Water Light and Power faces lawsuits brought by three marketers: El Paso Energy Marketing, LG&E Marketing, and Southern Company Energy Marketing. The Power Company of America, LP has been forced into an involuntary Chapter 11 bankruptcy proceeding by three of its creditors—Southern Company, Entergy, and American Energy Solutions—and faces a separate lawsuit brought by American Energy Solutions. A number of other lawsuits have been filed against these entities pertaining to other transactions in May and June.

It is important to note that selling options is beyond the usual course of wholesale trading activities. Small utilities or municipals that need to engage in wholesale market transactions to balance loads would have no need to sell financial instruments such as call options unless they were interested in risky endeavors. Market participants who choose to engage in this type of speculative behavior should understand the risks involved.

Market participants need to understand that commodity trading carries significant risks, as well as rewards. They need to take actions to reduce those risks because not doing so could result in disastrous consequences. One of the results of the Midwest price spike may be a shake out in the industry. Marketers that do not manage their affairs well may not survive in the competitive market. In fact, some market participants view the price spike as a beneficial event that purged power markets of inferior players.

3. TLRs and Curtailments

As discussed earlier, transmission constraints, including transmission line loading relief procedures (TLRs) and curtailments contributed to the high prices in the Midwest. They reduced the ability of transmission providers to move power where it was needed, forcing utilities and others into the hourly market. Some transmission lines in the Midwest were also damaged by storms, and the numerous transmission problems were exacerbated by heavy loads. Because the Midwest was short on generation, power imports into the region caused a number of transmission system interfaces to be loaded to their maximum capabilities. In some instances, TLRs were instituted rendering power deliveries impossible.

According to one utility, TLR actions forced it to reschedule a large amount of power during the week. The problem was particularly acute on June 25, when FirstEnergy shut down the Davis-Besse nuclear plant as a result of tornado damage to power lines. The plant was taken down on the evening of June 24, and some of the transactions needed to replace lost power on June 25 were interrupted by TLR actions.

4. Lack of Objective Price Information

Many buyers apparently did not have good information about what other buyers were paying for hourly power other than by asking sellers or brokers. While sellers can determine prices for forward, weekly and day-ahead prices through brokers, hourly markets are less developed and hourly price information is not available on a systematic basis. During the week of June 22, some market participants were thrust into hourly markets on very short notice. Without sufficient time to find the going price for power, many utilities appeared to purchase whatever power they could find for whatever price was offered. This may have led them to pay more than they needed to obtain power.

Centralized trading institutions such as power exchanges and futures markets could have provided better price signals to the market and helped to reduce price volatility. Natural gas markets have shown futures contracts to be a valuable source of price discovery. For example, NYMEX's Henry Hub futures contract provides a reference point for prices in natural gas markets. Natural gas sales prices are often based on the Henry Hub price.

Eventually, electricity markets need to move toward electronic trading. Fast-paced hourly power markets require resources for determining prices on an up-to-the-minute basis. Accurate and timely information is key to well-functioning markets.

5. Market Inexperience

Lack of experience by market participants in commodity markets may have led some traders to pay higher prices than necessary. Some utilities believed that they could rely on the spot market for the summer rather than making forward commitments or long-term supply deals. Some had sold power forward for the summer earlier in the year when supplies seemed ample but then were caught short during the price spike. Were it not for those commitments, the utilities might have been able to avoid the high prices they paid. Utilities that do not normally depend upon hourly trading were thrust into hourly markets to buy replacement power after supplies were curtailed because of TLRs and generation emergencies.

Some companies reported to the team that they found it difficult to avoid paying high prices during the worst of the crisis on June 25 because of the short time required to decide on buying hourly power and their lack of experience in hourly markets. By June 26, some utility traders reported that they had already learned a few lessons, setting upper limits in advance on their hourly purchase prices. Although they learned quickly, the utilities' lack of trading experience cost them money.

Creditworthiness of counterparties. The June price spike provided a wake-up call to many market participants on the issue of creditworthiness. Companies that did not have credit checking practices were among those hurt the worst during the price spike. In a competitive market, market participants must take responsibility for inquiring into the creditworthiness of their counterparties to ensure contract performance. A number of firms reportedly stopped dealing with Federal Energy Sales long before the price spike because of questions about its ability to cover its obligations.

Prior to the price spike a number of market participants, including Federal Energy Sales and Springfield, engaged in trading practices known as "sleeves." In one type of sleeve transaction, a firm acts as an intermediary between two other firms when one of them does not meet the other's credit requirements. The intermediary would take title to the power on behalf of the two firms, or otherwise guarantee the performance of the contract, for a fee. One firm interviewed by the team described this type of sleeve as "paying a commission to hide bad credit." Another firm described it as "an administrative accommodation." However it is defined, this type of sleeving appears to provide creditworthiness to those who would not otherwise have it.[46] To the extent that this kind of transaction supports marketers that otherwise would not be able to enter into contracts, it increases the potential risk of default and adds to instability in the market.

Knowledge of contract language. Market participants need to understand the terms of their contracts. Some firms reportedly had contracts that did not contain liquidated damages provisions. They did not realize they were necessary until the contracts were curtailed and they were thrust into hourly markets. It is also essential to be aware of other contract terms, such as the curtailment provisions for firm transactions. Awareness of these provisions could have saved traders a lot of money.

During the price spike, disagreements arose about the price of emergency power. There does not appear to be a generally understood definition of what emergency power is and under what conditions it is sold. Some firms complained that they provided emergency power to utilities only to learn that the situation did not meet the specifications of an emergency. One utility that bought emergency power complained that it was quoted a price for the power at the time of the sale and later billed for an amount ten times as large. It seems that, in some cases, both those who bought emergency power and some of those who sold it may have taken advantage of the emergency designation. Especially in emergency circumstances, it is important that counterparties ensure that the terms of their agreements are clearly written and understood.

Unhedged risk. Several market participants were forced to buy power in hourly markets because their transactions were not properly hedged. According to press reports, LG&E, one of the top ten power marketers, relied on forecasts that prices would not increase above a certain level. Accordingly, it sold power in a year-long contract without hedging its position. LG&E reportedly was so poorly hedged that the price spike had a major role in its decision to fold its marketing operation.[47]

Some of the market participants that defaulted also had unhedged transactions. Some "call" options sold were "uncovered," that is, the sellers were not prepared to secure the physical delivery of the power if the "strike price" were reached. If they had sufficiently prepared for the eventuality that people would exercise their call options, the defaults might not have taken place.

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46 Some companies described to the team a more benign type of "sleeve," in which a party serves as an intermediary between two firms that have not entered into service agreements under tariffs permitting sales at market-based rates. Assuming that the two firms assisted by the intermediary are themselves creditworthy and otherwise able to perform, this type of transaction would not appear to increase the risk of non-performance.

47 "A 20,000% Bounce: Now That's Volatility," *The New York Times*, August 23, 1998.

As noted in Chapter 3 above, increasing numbers of hedging tools are available to market participants. These instruments can help traders to manage the price and counterparty uncertainty. Hedging is an essential component of trading in a competitive environment.

Insufficiently diversified supply portfolios. Some market participants relied on large packages of power from a single supplier. The loss of one such transaction was enough to force some utilities to try to buy large quantities of power in hourly markets. To ensure delivery of power, market participants should diversify their supplies across a number of regions so that if power cannot move across an interface or if generation outages occur, the participants have other supply alternatives.

How one utility benefitted from being prepared. One utility's experience demonstrates the importance of the planning and preparation required for transacting in wholesale power markets. This utility spent a significant amount of time planning for the summer of 1998 because of its experience the previous summer. During the summer of 1997, it was forced to pay $325 per MWh for electricity when a transaction was curtailed by another utility. Because its purchase contract did not contain a liquidated damages provision, the utility had to pay high prices for power on the spot market. It learned not to make the same mistake twice. The utility took great care in its planning for the summer of 1998, making substantial use of options and contracts with liquidated damages provisions. It also spread its purchases over many buyers in different regions, rather than dealing with a few neighboring suppliers as it had done in the past. That way, if transactions from one region were curtailed, it could still rely on power supplies from other regions. The utility survived the June 1998 price spike relatively unscathed.

6. Lack of Demand Response

The fact that retail customers had no incentive to adjust their usage based on price contributed to the price spike. Retail competition, coupled with the ability to respond in real time, could allow customers to see the price of the power they use and react accordingly. Current demand side management (DSM) measures, such as requests for voluntary cutbacks in electricity use, can help in times of crisis, but generally do not provide an incentive for customers to respond effectively to price signals.

When loads reach critical levels, utilities can implement certain DSM measures to help reduce loads. Utilities can issue public appeals to reduce consumption and interrupt customers in accordance with contractual arrangements. On Thursday, June 25, ComEd and public officials in Illinois issued public appeals for conservation. These appeals were effective in the sense that voluntary cooperation reduced peak demand when the price spike was at its height. However, if customers could have curtailed their usage in response to rising prices, the situation might not have become so critical as to require appeals for voluntary action.

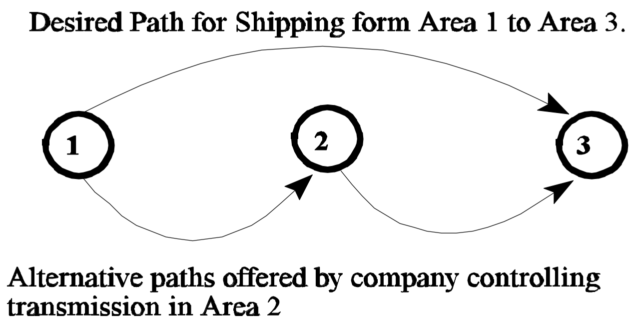
After the June price spike subsided, some utilities proposed mechanisms to promote a greater demand response by large retail customers. The proposed tariffs would allow certain industrial customers to sell their firm power entitlements back to their local utility when loads are at their peak or when other factors affect system reliability. These initiatives would help reduce the amount of power utilities would need to purchase on those days and would allow greater choice for customers.

7. Market Manipulation

Although market participants expressed many concerns about manipulation of the market that were not very specific, others described specific practices that they believed were questionable. Two specific practices identified during interviews with market participants were the use of swaps to circumvent maximum tariff rates and the use of brokers to create false impressions of the current price in the market. Neither of the practices appears to be a direct cause of the price spike, but both diminish confidence that market institutions are working in a fair and nondiscriminatory manner and appear to be potentially questionable. Each of these concerns is described below.

Swaps. Swaps are essentially exchanges of positions in time and/or space. For example, delivery of power at one destination in the present may be exchanged for delivery of power at another destination at some point in the future. These types of swaps are common transactions in both electricity and natural gas, and normally facilitate trading. But, they can also be used to circumvent regulations in some cases. The team heard several allegations that swaps were being used to circumvent maximum tariff rates. Figure 4-1 illustrates how such a swap might work.

Figure 4-1. Example of a Swap Transaction



In Figure 4-1, assume one company owns transmission facilities that are essential for moving power from Area 1 to Area 3. A shipper asks for transmission from Area 1 to Area 3, where the shipper has a customer willing to buy power. Assume the customer in Area 3 is willing to pay $40 for power, and that the shipper can acquire power in Area 1 for $25. Assume further that the maximum transmission rate across Area 2 is $5. Several parties have claimed that a transmission owner at Area 2 will refuse to move power across their system (Area 2), but offer to accept power at Area 1 and, at the same time, move an equal amount of power to Area 3. As one respondent put it, the transmission owner said, "If you can get the power to us, we can get the power to your customer." At the same time, the transmission owner was allegedly claiming that no transmission was available to ship power from Area 1 to Area 3. This type of swap might be done for several reasons, including:

- **To collect charges above the maximum tariff rate**. In the present example, the transmission owner might offer to do the swap for a rate higher than the maximum tariff rate of $5, say $14, that would let the sale go through, but take most of the profit away from the shipper and effectively circumvent the maximum rate for transmission.

- **To charge congestion-related prices in an unapproved form**. If the transmission owner is not able to exercise market power, then power prices would not diverge significantly across the owner's system unless congestion were present. The ability to profit from the swap would then depend on congestion and represent a form of transmission pricing. The Commission has approved congestion pricing by ISOs for transmission within the ISO, but not for individual transmission owners.

- **To extract monopoly rents when there is market power in transmission**. If the buyer of transmission service has alternatives, the transmission owner may not be able to extract monopoly rents. The buyer would be able to seek alternative transmission paths. The rate the transmisson service buyer faces may be above the tariff rate, but it might still be efficient. However, if the transmission owner has market power in transmission, then the result will not be efficient.

- **To circumvent TLR procedures.** Breaking a single transaction into two or more transactions might be the only way to move power if a TLR is in effect. The TLR procedure limits only those paths that have a greater than 5-percent impact on an affected facility ("flowgate"). As long as a cutoff rule of this type is used, it is possible that a transaction could be restructured into several independent transactions so that none of the individual transactions would be subject to a TLR. For example, there are cases where the path from Area 1 to Area 3 would be limited by a TLR, but neither the path from Area 1 to Area 2 nor the path from Area 2 to Area 3 would be. The impact of the sale on flows in the transmission system would be the same as long as the sources and sinks remained the same, but one type of sale (where two sales are substituted in order to replace a single sale) would be permitted by a TLR and the other would not. Restructuring the Area 1 to Area 3 transaction into an Area 1 to Area 2 and an Area 2 to Area 3 transaction would let the intended sale go through, but would amount to an attempt to circumvent TLR procedures.

The team found no reason to believe that using swaps in the manner described here was any more of a problem during the June event than at any other time, and found no direct evidence linking the practice to the high prices that occurred. However, the problem was mentioned by several respondents, and there are clearly powerful incentives to manipulate transmission capacities to take advantage of the value of transmission when the transmission grid becomes congested, so the lack of evidence does not demonstate the practice does not exist.

Brokers and "Two-Way" Transactions. A marketer complained to the team that other market participants had manipulated options and forwards contracts to increase the prices for power beyond levels that could be forecast by fundamental factors such as weather, the availability of generation, and transmission constraints. Among the manipulative schemes alleged by the marketer was the use of simultaneous bids to buy and sell power that had the effect of raising forward prices to levels at which marketers with generation capacity could be assured of profitable power sales. The scheme is sometimes called a " two-way" transaction.

These two-way transactions involve the use of brokers and their role in attempts to manipulate prices by sending false signals about the state of the market. As trade volumes have escalated and daisy chains have lengthened, brokers are being used as sources of information and independent facilitators of trade. Even large marketers often feel they have insufficient knowledge of the deals being made in the market, and use brokers is a way of knowing "where the market is." Large marketers also use brokers as a way of dealing with each other without revealing their positions. It is difficult to get evidence of the level of brokered transactions, because the brokers never take title to the power and are not entities jurisdictional to the Commission. By one estimate given to the team, however, brokers are involved in up to 90 percent of the deals.

Since brokers do not take possession of power and make revenues from its sale, their revenues come from fees on transactions. As market makers, their incentives are to have as many deals made as possible. In a "two-way," a company takes a position on both sides of its own transaction through a broker. A marketer might submit an offer to sell power at $25 per MWh and an offer to buy the same power at $40 per MWh. If the transaction goes through, the only result is that the marketer buys back the same power (which might have existed only on paper) and establishes a market price. When someone calls the broker and asks where the market is, the broker reports that the market is at $40 per MWh, even though the broker knows that the sale was not an arms-length sale between separate parties. For this process to work, the broker must have received no offers to buy between $25 and $40. (We have not heard allegations that brokers simply misrepresented the market by not revealing real transactions.) Some parties report that they will ask whether the price is a "two way" when dealing with certain brokers. Others say that the practice is restricted to brokers that deal predominantly with only a few sellers; knowledgeable players in the market deal with many brokers and are not faced with the problem of "two-ways."

The team has not received any direct evidence linking the use of two-way transactions and the specific conditions of the June event. Further examination of these allegations may be warranted.

B. Standards of Conduct Issues

Under Order 889, the Commission requires transmission providers to follow standards of conduct. The standards are intended to prevent wholesale merchants affiliated with a transmission provider from obtaining better, faster or greater access to information about the transmission provider's wholesale transmission operations than persons who are not affiliated with the transmission provider. Transmission providers must show that they are complying with the standards, and violations of them are subject to the Commission's remedial authority under the Federal Power Act.

The Commission does not intend the standards to compromise the reliability of electric systems. In emergency circumstances affecting system reliability, transmission providers may take whatever steps are necessary to keep the system in operation, notwithstanding any standard of conduct, according to Commission regulations. The Commission expects transmission providers to be able to justify why they have deviated from the standards of conduct in particular circumstances. If a transmission provider's deviations from the standards are not necessary to deal with reliability concerns under emergency conditions, the transmission provider has violated the standards.

The Commission thus far has not identified in the abstract whether particular circumstances are emergencies that justify a temporary suspension of the standards. Because the context and surrounding circumstances are crucial to determining whether a legitimate emergency implicating reliability has occurred, the Commission has not required transmission providers to identify beforehand particular situations in which they are authorized to deviate from the standards.[48] The Commission does require transmission providers to file reports in "EY" dockets when emergencies have caused them to take actions that may be inconsistent with the standards.

Six midwestern and southern utilities, plus PJM, an independent system operator, filed EY reports for events that occurred during the period from June 25 through June 29, 1998. Table 4-1 summarizes these EY filings. The filings raise the question whether the utilities took any actions that were inconsistent with the standards, yet unnecessary to resolve reliability concerns in emergency situations.

Table 4-1. Reports on Emergencies Occurring, June 25-June 29, 1998

EY Docket; Transmission Provider; Deviation Date	Type of Deviation	Stated Reason for Deviation
EY98-1-000 Illinois Power Company June 24, 1998	Based upon discussions with other control areas and NERC Security Coordinators, transmission personnel directed generation control personnel to investigate whether generation was available from specific sources (9:25 am - 7:30 pm).	Deviation was necessary to prevent shedding load and to provide operating reserves after Illinois Power declared a NERC Level 2 Generation Deficiency.
EY98-2-000 Alliant Utilities June 25, 1998	(1) The door between the transmission & the generation/marketing operations control rooms was unlocked while transmission personnel requested an increase in generation to facilitate the reclosing of the 345 kV Arpin/Eau Claire/ King transmission line (2:18am - 5:00 am). (2) The door was opened while transmission personnel informed generating and marketing personnel that MAIN had requested utilities to interrupt customers served under interruptible tariffs, and transmission personnel shared trans-mission & loading information with generating & marketing personnel (11:30 am - 6:00 pm).	Deviations were necessary: (1) to coordinate increases in generation from Alliant and other Wisconsin utilities needed to reclose the transmission line due to high phase angle differences following storm damage that dropped system frequency; and (2) to aid in implementing reliability actions requested by MAIN.
EY98-3-000 Illinois Power Company June 25, 1998	Based upon discussions with other control areas and NERC Security Coordinators, transmission personnel directed generation control personnel to investigate whether generation was available from specific sources. (7:50 am - 8:30 pm)	The deviation was necessary to prevent shedding load and to provide operating reserves after Illinois Power declared a NERC Level 3 Generation Deficiency.

[48] American Electric Power Service Corporation, *et al.*, 81 FERC ¶ 61,332 at 62,515 (1997); at 62,519.

Table 4-1. Reports on Emergencies Occurring, June 25-June 29, 1998

EY Docket; Transmission Provider; Deviation Date	Type of Deviation	Stated Reason for Deviation
EY98-4-000 Southern Company Services, Inc. June 25, 1998	(1) The transmission function made an emergency sale. (2) No timely OASIS request was made for transmission necessary for the emergency sale; the transmission function made an OASIS request for transmission on behalf of the merchant function. (12:24 pm - 7:00 pm)	Deviations were necessary for Southern to make emergency sales to Illinois Power after the MAIN Security Coordinator requested emergency assistance for Illinois Power following MAIN's declaration of a NERC Generation Deficiency Alert Level 3 .
EY98-5-000 Northern States Power Company June 25, 1998	(1) Personnel cut all transactions related to transmission facilities that were out of service in MAPP and redispatched generation to help stabilize system frequency (2:23 am - 5:00 am). (2) Standards of conduct were suspended (11:00 am - 6:00 pm).	(1) The deviation was necessary to stabilize the power system in the Upper Midwest after a massive storm shut down numerous generating & transmission facilities. (2) The deviation was needed to anticipate actions necessary to deal with generation outages in MAPP, high predicted loads & high temperatures throughout the utility's system.
EY98-7-000 Alliant Utilities June 29, 1998	Transmission operations control centers in Iowa shared information with generation/marketing operations in Wisconsin. (4:15 pm - 8:00 pm).	Widespread storm damage in the Iowa area of Alliant shut down generation & transmission facilities, and Alliant implemented curtailment of interruptible tariff customers, mainly for voltage support in southeast Iowa.
EY98-8-000 MidAmerican Energy Company June 29, 1998	MAPP provided MidAmerican's transmission system operations and wholesale merchant function with information regarding generation availability from a specific source.[1]	MidAmerican lost generation, transmission & load as a result of severe thunderstorms & tornadoes. It requested that MAPP notify other control areas that MidAmerican had invoked system emergency procedures under Order 889.
EY98-9-000 PJM Interconnection, L.L.C. June 25-26, 1998	PJM filed a report on its use of emergency procedures.[2]	While temperatures reached seasonal highs, PJM experienced peak demands exceeding 47,000 MW on both days. On June 25, PJM recalled approximately 5,300 MW of Capacity Resources (generating capacity that is committed to PJM) that had been delivered to entities outside PJM. On June 26, PJM recalled about 3,800 MW of Capacity Resources.

Table 4-1. Reports on Emergencies Occurring, June 25-June 29, 1998

EY Docket; Transmission Provider; Deviation Date	Type of Deviation	Stated Reason for Deviation
EY98-10-000 American Electric Power Service Corporation June 25-26, 1998	A person from AEP's merchant function was present in AEP's transmission control center assisting control room operators to assure that power purchases and curtailments were made to protect system reliability (8:00 am June 25 - 7:00 pm June 26).	The deviation was necessary to address AEP's invocation of Emergency Operating Procedures on its system. AEP was using the third most stringent step in its procedures: appealing for voluntary curtailment of usage.

[1]MidAmerican asserted that it did not engage in any specific deviations from the standards of conduct after it invoked system emergency procedures.

[2] Technically, PJM need not have made this EY filing because, as an independent system operator, it has no wholesale merchant function and cannot deviate from the standards of conduct. However, PJM's filing contains information that is valuable to help understand the context in which the price spike occurred. The team encourages PJM to continue to submit EY filings to explain the circumstances under which it declares Maximum Generation Emergencies under its procedures.

Note: Western Resources filed an emergency report in Docket No. EY98-6-000 with respect to its deviations from the standards of conduct during the night of June 29-30, 1998. In the team's judgment, this report is unrelated to the price spike. Therefore, the report is not listed in this table.

C. Could Similar Midwest Price Spikes Happen Again?

As noted above, a number of factors led to the June 1998 price spike. An above-average amount of nuclear and fossil generating capacity was unavailable in the Eastern Interconnection; unseasonably hot temperatures continued over a sustained period that increased the demand for power to near-record levels; transmission constraints and TLR procedures reduced the ability of utilities to move power to where it was needed; weather-induced damage to transmission lines took power plants off-line; defaults on power sales contracts shook market confidence and led more parties than usual to seek short-term supplies; market mechanisms did not provide clear, current and reliable price signals; PJM implemented emergency generation procedures, cutting off energy exports to areas that were depending on them to serve load; and many parties were simply inexperienced in dealing with such adverse conditions during the ongoing change from a regulated to a highly competitive electric power industry.

The combination of these factors was an extraordinary event. A number of market participants interviewed by the team compared the events of the week of June 22-26 to the “1 day in 10 years” in which there is a probability for losing load in planning models used by some utilities to assess the costs of serving future load. This comparison suggests that an operational situation leading to price spikes of the magnitude of June 1998 is unlikely to recur. Nevertheless, some of the operational conditions that led to the price spike causes are likely to be present during the next several years.

Under these circumstances, the team has identified two issues that are crucial for assessing whether Midwest price spikes are likely to recur. The first issue is whether, in light of long-term trends, short-term or unpredictable events are apt to so increase the demand for power or reduce available energy as to create operating conditions like those that led to the June 1998 spike. As discussed below, we believe that similar conditions may well recur though infrequently. Markets are expected to mature, reducing price volatility. The second issue is: under operational conditions that could lead to price spikes, is the market likely to significantly raise short-term prices for power? This issue will be addressed later in this chapter.

1. Are The Operational Conditions that Led to the Price Spike Likely to Recur?

Some of the operational causes were predicted ahead of time and reflect long-term trends in the industry. For example, the NERC *1998 Summer Assessment* issued in May 1998 indicates that summer reserve margins in MAIN and ECAR declined over the past few years. While a number of companies have announced intentions to increase generating capacity in the Midwest and plans for some new generating plants have been announced, the minimum lead time for installing new generating capacity is at least one year (for natural gas-fired combustion turbines). For many larger plants, the lead time will be much longer.

Particular transmission constraints, such as the limit on interchange capacity available from MAPP to MAIN through the Eau Claire-Arpin interconnect in Wisconsin, are long-standing and unlikely to be improved in the near future. Thus, limits in generating and transmission capacity in the Midwest are likely to continue.

Moreover, peak summer electricity demand in the Midwest has increased over the last five years. From 1992 through 1997, the actual annual growth in internal summer peak demand for ECAR, MAIN and MAPP increased an average of 3.6 percent, 3.47 percent, and 5.75 percent, respectively.[49] These demand increases are the product of long-term economic trends and are forecasted to continue. Load serving entities in the Midwest must prepare to meet significant annual increases in peak demands, at least in the near future.

From an operational standpoint, one of the more notable events leading to the June price spike was the large quantity of baseload nuclear generating plants in the Midwest that were unavailable (see Chapter 2). If even one of these plants had been on line during the week of June 22-26, it could have supplied some of the power that was purchased at extremely high hourly prices, or could have alleviated transmission problems. The team notes that several Midwest nuclear plants were also out of service during the summer of 1997. The unavailability of baseload nuclear plants cannot be discounted as a short-term factor tending toward possible future price spikes.

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49 NERC, *1998 Electricity Supply and Demand Report*; results summarized in "Forecasted Summer Peaks, Power Usage Raised Again, In 1998 NERC ES&D Report," *Electric Utility Week*, August 24, 1998, p. 5.

Some fossil-fired generating units were shut down for regularly scheduled maintenance during the week of the price spike; other generating plants were forced out earlier in June and had not returned to service. Some utilities interviewed stated that they plan maintenance of their plants so that they will be most available during July and August, which are generally when summer demand peaks. The fact that both the June 1998 price spike and the May 1998 "mini-spike" occurred before the traditional months of peak summer demand suggests that deferring scheduled maintenance on generating plants until the end of spring and early summer may risk imbalances between generation and demand that could lead to price spikes.

A more unpredictable factor is weather-related, forced outages of generating plants or transmission lines leading from them. Just as the tornado-induced failure of the transmission line leading from FirstEnergy's Davis-Besse plant rendered that unit's approximately 900 MW unavailable on June 25, violent summer weather may reduce Midwest generating or transmission capacity on any given date. While summer storms often reduce load (by damaging distribution systems) as well as available generating capacity, the storms on the night of June 24-25 did a disproportionate amount of damage to Midwest generation and transmission systems. In a situation in which significant baseload capacity is likely to be shut down during summer load peaks, weather-related outages may knock out enough generation to require load serving entities to turn to short-term power purchases to meet demand.

In light of these factors, and the time it will take to substantially increase generating capacity and relieve transmission constraints, the team concludes that, at least in the short term, operational conditions could allow other price spikes to occur.

2. Are the Market Conditions that Led to the Price Spike Likely to Recur?

Because the immaturity of the power market was a cause of the June price spike, the team concludes that maturing market conditions should reduce the severity of future price spikes. We believe that wholesale power market participants are likely to develop tools for moderating prices under such conditions.

Since a price spike of such a large magnitude has now occurred, market participants must plan for the possibility of future spikes. One factor repeatedly identified by market participants interviewed by the team was that the June price spike took place so quickly and was so unprecedented that it was difficult to fashion a strategy to address it. Some load serving utilities concluded that, at least for the short term, they must do what was necessary to avoid interrupting service to firm retail customers, whatever the price. While successful in terms of protecting reliability, the substantial cost associated with this strategy should encourage power purchasers to plan ahead for possible price spikes.

The team found some evidence that power purchasers began to change their short-term buying strategy after they "got through" the June 25 price spike without disrupting service to native load retail customers. Several load serving utilities told us that, after assessing their power purchases on June 25, they set upper bounds on the prices they would pay for power on June 26. It is possible that such price decisions played a role in moderating hourly prices on June 26.

Moreover, advancing this "learning curve" is important to many entities that paid high prices on June 25, because their shareholders had to absorb higher power prices. These entities have every incentive to plan ahead to meet peak demand while minimizing power purchase costs. In a market in which participants can no longer pass through increased power purchase costs to a captive customer base, participants that are unwilling or unable to plan to meet supply obligations in periods of high demand will exit the market or be forced to exit by others.

In this regard, some persons interviewed by the team believed that defaults by marketers during the week of June 22 were a major factor in the price spike. These persons suggested that, by generally decreasing confidence that counterparties would perform, the defaults led to higher demand than would have been expected for hourly power in the latter part of the week. This higher demand was said to have stimulated higher prices, and contributed to the price spike.

Market participants with whom the team talked acknowledged that traders who are thinly capitalized or improperly hedged have a higher risk of defaulting on contract obligations, and that such defaults would likely occur while prices rise, when a trader cannot cover options to sell at a price lower than the market. Such defaults could tend to increase prices by further increasing demand and by undermining confidence in the remaining market players. Nevertheless, the majority of participants suggested that the market, not the Commission, should police creditworthiness. They noted that the Commission has not imposed any creditworthiness standards on gas marketers, and that there have been no suggestions that such requirements are necessary.[50] The participants who advocated a Commission role in directly regulating creditworthiness of power marketers tended to be those who had directly or indirectly dealt with a defaulting marketer.

It is difficult for the team to assess whether other marketers will default in the future, because the Commission and its staff generally do not track the financial condition of entities that sell power at market-based rates. However, participants in the electric power industry have been put on notice that defaults can occur. In light of the financial risks entailed by the default of a counterparty, market participants told the team that they are actively reviewing the creditworthiness of their counterparties and asking for increased assurances of performance in appropriate cases. In addition, as discussed above, a number of risk management tools are available to help buyers and sellers of power increase coverage of the risks of counterparty default. We anticipate that as the electric power market matures, parties will find ways to limit the risk of default to acceptable levels. At that point, we do not expect that the possibility of default will significantly increase the chance for future price spikes.

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50 Interstate natural gas pipelines also set creditworthiness standards for their transportation customers through tariffs filed at the Commission.

We therefore expect that market participants will develop effective financial and marketing strategies to manage the short term operational factors we identified that could lead to price spikes. As discussed separately above, the events in the Midwest, eastern and southern power markets during the week of July 20-24, 1998, offer some evidence that the electric market may well be learning how to handle demand peaks without unduly increasing sales prices.

The operational situation for July 20-22 appears to have been much the same as during June 24-26: a number of baseload nuclear units were off-line, while heat-related demand approached or exceeded record levels and unplanned outages occurred at several large generating units. Yet the reported maximum day-ahead price increased to $2,000 per MWh—a level much lower than in June—and decreased rapidly after reaching that level. If operational factors for July 20-22 were similar to those observed for June 25, yet power prices peaked at substantially lower levels, one explanation is that marketers and load serving entities learned lessons from the June price spike and responded in a more rational way to adverse operational conditions. This suggests that market factors have already begun to act to reduce price spikes, and can be predicted to do so in the future.

5. Issues for Further Consideration

This chapter presents the issues for consideration developed by the team during the course of its study. They fall into a number of areas where the facts of the June event have led the team to believe there may be a need for further examination as the Commission moves forward to promote well functioning competitive markets. Some areas for suggested action arise directly from the June event and are new areas to consider; others areas simply emphasize the importance of continued attention to issues already before the Commission.

The concerns fall into the following areas:

- Operational Concerns
  - Generation Availability
  - Transmission Availability
- Risk Management by Market Participants
- Information Issues
- Price Caps
- Creditworthiness
- Conduct and Market Practices Concerns
- Transmission Line Loading Relief
- Cooperation with Other Government Entities and with the Electric Industry

A. Operational Concerns Regarding Generation and Transmission Availability in the Midwest

As discussed in Chapter 2, load growth in the MAIN and ECAR regions has increased over the past several years without a corresponding increase in new generating resources. As a result, the summer reserve margins in these regions have declined significantly. Consequently, the Midwest increasingly relies on imports from neighboring systems to support the higher load growth which has eroded available transmission capability in those regions.

The June event indicates that these factors have not yet diminished the ability of the Midwest utilities to serve their firm retail customers during periods of peak loads. However, as NERC's *1998 Summer Assessment* emphasizes, the level of generating capacity reserve and available transmission capability in the Midwest has been identified as a serious and legitimate concern. The NERC report also warned that certain utilities within the MAIN and ECAR regions may not be able to meet their obligations in 1998 should unseasonably higher temperatures occur. The concerns raised by the NERC and others emphasize that, unless some corrective action is taken, the ability of the Midwest utilities to continue to meet their peak loads in the future will likely deteriorate.

1. Generation Availability

Several market participants have publicly indicated that they intend to construct new generation facilities in or around the Midwest. However, the amount of new generation actually built may depend on whether developers believe that they can recover their costs within a reasonable time. Market participants told us that higher prices are necessary to induce them to build these new facilities. Our discussions with various market participants, trade press articles and reports made available after the June price spike, indicate that a number of entities are continuing their plans to construct a number of new generating units in or around the Midwest over the next several years. Therefore, it appears that the market is resolving the lack of generation capacity — at least over the longer term — on its own without any regulatory action.

Because the construction and siting of most generation facilities is a matter of state jurisdiction, the Commission's role with respect to generation is limited. The Commission has nonetheless established market-based rate and open-access transmission policies which, in addition to promoting the free trade of power, have encouraged the building of new generating facilities where they are needed. In addition, the Commission has promoted the creation of independent regional transmission entities which should also assist in fostering the construction of new generating capacity by minimizing transmission constraints and allocating existing and new transmission capacity.

The team also notes that the scheduling of maintenance on generating plants can affect whether sufficient generation is available to meet demand in "shoulder" months, such as May and June, when the price spikes took place this year. The team suggests that the industry should consider whether changes in maintenance schedules would increase available generation in shoulder months without degrading reliability at other times.

2. Transmission Availability

With respect to the availability of transmission capacity into the Midwest, the construction of new generation should tend to reduce the Midwest's reliance on imports, at least over the long term. Because the Commission has no authority over the siting of transmission facilities, the states have the principal role in assuring sufficient transmission capacity. The team understands that Midwest state regulators have undertaken a cooperative effort to relieve transmission congestion on at least one transmission interface in the Midwest. The Commission could encourage such regional efforts. In addition, the Commission could continue to monitor the situation in the Midwest, coordinate with state regulators, and promote transmission rate policies that attract sufficient capital for an efficient transmission system. The team believes that regional independent transmission entities could help in the development of regional transmission systems as well.

B. Risk Management by Market Participants

Both operational and market planning were shown to be important factors in the June event. On the market side, the team found evidence that market participants who suffered financial losses during the summer of 1997 as a result of not being prepared, then had developed demand and supply portfolios and other market strategies in preparation for the summer of 1998, fared better than those market participants who had not done so. This suggests the while the market is still immature, market participants are quickly adapting to the new market environment. As the market continues to mature, market participants will likely undertake new and innovative risk management measures to minimize their risks of being financially harmed in the future as a result of price fluctuations and counterparty defaults.

In this regard, the team believes that the June event was a wake up call to those market participants who were not as prepared as they should have been.   Based on the information obtained through this study, the team concludes that many of the market participants have already begun to heed the call and have undertaken a variety of measures to minimize their risks in the event of any future price fluctuations.

For these reasons, the team does not believe the Commission ought to play a major role in addressing risk management other than (1) to encourage all market participants to plan for the uncertainty inherent in competitive markets and (2) to address the prudence of risk management as it affects cost-based wholesale and transmission rates. However, generally speaking, the states have the primary regulatory role in addressing risk management, because they determine the prudence of actions that load-serving utilities take to provide service.

C. Information Issues

The Midwest price spike investigation brought to light a number of issues concerning the collection and utilization of data required to monitor the market as it moves from a regulated to a competitive environment. The team believes that data needed by the Commission to monitor a competitive market are different than those needed to monitor a tightly regulated cost-based market.   In a largely deregulated market, the types and price of transactions undertaken are primarily the responsibility of the market participants.   In this type of market, the Commission must have sufficient data available to it to ensure that the market is operating properly, e.g., that reliability is maintained, the wholesale price of electricity continues to be reasonable and no anticompetitive activity is taking place.

The team reached a number of conclusions about the type of data necessary for market monitoring in a competitive marketplace as a result of its investigation into the Midwest price spike. The team’s primary conclusion is that future monitoring activities could be improved by having more real time market data readily available to the Commission. The team believes that availability of this type of data can greatly facilitate the examination of significant market events.

More broadly, the market itself could benefit if more information about electric power transactions were publicly available on a real-time basis (with appropriate safeguards against public disclosure of proprietary information about specific transactions). Information on the general availability of transmission and specific offers and acceptances for some types of transmission capacity is now available on OASIS. In addition, the industry is continuing to develop standards for expanding the amount and accuracy of information available on OASIS.

However, there are currently no clearinghouses for real-time reporting of information on market-based sales. No one has available accurate and timely information on current markets -- neither the market participants, who want to more accurately send and receive market information, nor the Commission, which needs this information to keep abreast of the market. These difficulties would be reduced if the electric industry were to develop real-time sources of information on electric sales as well as transmission offers and deals.

In this regard, the team found that while the wholesale power market data currently collected by the Commission are valuable, much more value could be extracted if marketers reported pricing data for purchases and sales with greater consistency and frequency and, perhaps, identified specific transactions. In addition, it would be helpful if traders were to retain transaction-specific information. The Commission then could request it if unusual market events like the June price spike occur. This concept is similar to NERC’s information-gathering procedure for reviewing unusual reliability events. NERC asks for information on what transmission control operators and security coordinators actually do in the event of a major electric system disturbance. Some regional reliability councils also have information-gathering policies similar to NERC's. With due regard for the treatment of proprietary information, the availability of transaction specific information may speed up the Commission’s analysis of unusual market conditions and allow it to predict future market developments with greater accuracy.

The team relied on data supplied through NERC for its assessment of operational conditions. To a large extent these data are already collected and available, but are used for day-to-day operational purposes rather than more general purposes such as market monitoring. The Commission could consider developing a more formal arrangement with NERC and regional reliability councils for obtaining such operational data.

D. Price Caps

Several market participants have asked the Commission to impose general price caps on market-based rates, price caps on emergency transactions, or “circuit breakers” that act as temporary price caps on wholesale prices when they rise. By and large, those proposing such action note the risks that price spikes pose, particularly those as imposing as the June price spike. They argue that without imposing price caps on volatile prices, the Commission acts against the consumer interest that it is required to protect pursuant to the Federal Power Act.

The team believes that price caps, whether they are applied generally or intended for specific emergency situations, create a situation in which prices are not allowed to perform their rationing function. In addition, they can distort market signals and prevent the efficient allocation of resources resulting in shortages. The team also notes that the Commission recently proposed the removal of price caps on shippers' short-term releases of capacity on interstate natural gas pipelines because it had the "unintended effect of reducing capacity during peak periods, the time at which the industry would most benefit from having as much pipeline capacity as possible." [51]

Price caps appear to be inconsistent with the Commission's basic policy since issuing Orders 888 and 889: let competition itself drive down average prices over time while increasing the availability of electricity. In the team's opinion, no person proposing price caps has made a compelling argument that the Commission should abandon this policy, even during emergency conditions, or that price caps are appropriate as an interim measure to stabilize power markets during their transition from a regulated to a competitive marketplace.

E. Creditworthiness

The creditworthiness of counterparties is a major issue brought to light by the Midwest price spike. Apparently, a number of market participants did not have specific or accurate procedures for assessing the creditworthiness of their counterparties. In some cases, this resulted in significant financial losses.

While the team believes that good credit practices are essential to a well functioning market, it does not support proposals suggesting the Commission undertake the responsibility for ensuring creditworthiness of market participants. In competitive markets, market participants must take responsibility for determining the creditworthiness of their counterparties. The team believes that industry credit practices are best addressed by market participants. The team therefore suggests that the industry establish a working group to develop a uniform set of credit requirements to assure the creditworthiness of the market participants. The team also suggests that the industry consider creditworthiness standards used by transmission providers for their tariff customers as models for such requirements.

F. Conduct and Market Practices Concerns

[51] Federal Energy Regulatory Commission, Notice of Proposed Rulemaking, "Regulation of Short-Term Natural Gas Transportation Service" (RM98-10-000) at 23.

Several transmission providers reported to the Commission that during the June event, they had deviated from the Commission's standards of conduct to protect system reliability during emergency conditions. In addition, the Commission has received general allegations that market participants used various practices to manipulate the wholesale power market in their favor or to circumvent Commission requirements concerning transmission access and pricing. While the primary purpose for the study was to gather operational and marketing data to develop an overview of the June price event, the team also looked into issues raised by the standards of conduct filings and particular allegations of market manipulation.

1. Standards of Conduct

The EY filings the Commission received that concern the June price spike, as well as the operational conditions set forth elsewhere in this report, leave no doubt that emergencies existed that adversely affected system reliability during the price spike. Moreover, the EY filings reveal that some transmission providers took actions that were inconsistent with the standards of conduct.

Inquiries into the particular EY filings listed in Table 4-1 were beyond the scope of the present report. However, the team believes that further investigation of the filings is appropriate. Some of the EY filings do not include enough information to enable the team to determine whether particular transmission providers' actions could have affected the price spike or unduly favored wholesale merchant affiliates. Although it is important to ensure that transmission providers can protect reliability in emergency situations, it is also important to ensure that transmission providers take only those actions that are needed to protect reliability. The team believes that investigation of the circumstances of the EY filings for this summer is warranted.

The Commission has not yet defined whether any particular situations are "emergency circumstances affecting system reliability" in which deviations from the standards of conduct may be justified. Nor has it identified specific emergency responses by transmission providers that would be inconsistent with the standards. Under these circumstances, it is possible that some transmission providers did not make appropriate EY filings for events that took place during the price spike. [52] The team suggests that the Commission consider providing guidance on what constitutes an emergency situation affecting system reliability and what actions are reasonable in such situations.

The Commission may wish to consider whether to require transmission providers that make EY filings preserve all records, including tapes of conversations and documents concerning transactions by its transmission and merchant functions, relating to the period covered by the filing. Preserving these records would make it easier for staff to review EY filings and analyze

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[52] A transmission provider currently is under no obligation to report that it has violated the standards of conduct. Therefore, transmission providers have an incentive to avoid making EY filings by narrowly interpreting whether emergencies actually occurred, whether they affected system reliability, or whether responses to emergencies were inconsistent with the standards of conduct.

whether the transmission providers took only those actions that were justified to address reliability.

2. Market Manipulation Concerns

Possible manipulation of the transmission market using swaps or similar transactions in the manner described in Chapter 4 was mentioned by several respondents to the team's data request. There are clearly powerful incentives to manipulate transmission capacities to take advantage of the value of transmission when it is congested. The team does not have any direct evidence that these kinds of transactions occurred around the time of the price spike. However, given the incentives for transmission providers to engage in swaps, the team suggests that staff improve its methods for detecting and monitoring them, and for determining whether they are unduly discriminatory or preferential.

With respect to the wholesale power market, the use of two-way transactions in deals made through brokers may be of limited concern unless certain conditions are present. If a buyer deals with only one broker and the market is thin, there may be problems with two-way transactions. Otherwise, these two-way schemes would seem likely to have little influence on market prices seen by buyers. The team feels that staff should remain knowledgeable about this and similar practices and look into allegations the Commission may receive about this type of activity.

The team believes that the Commission's normal compliance and enforcement functions are the appropriate processes for investigating any allegations received concerning market manipulation or unduly discriminatory or preferential practices concerning power sales or interstate transmission. In general, the team suggests that staff review how to maximize compliance with the requirements and policies of Order 888 and 889, and how best to prevent or redress attempts to manipulate wholesale power markets or to circumvent the Commission's restructuring policies.

G. Transmission Line-Loading Relief

The NERC's current TLR procedures are interim and are before the Commission for review. The team does not take any position on any specific TLR proposal or procedure; however, the team does emphasize the importance of transmission line-loading relief during peak demand times such as those that occurred during the June price spike. During the price spike, TLR actions succeeded in their primary aim: preserving the reliability of the transmission system. Nevertheless, the need for line relief during the price spike contributed to the need to make significant short term shifts in generation sources. These short term changes may have resulted in significant losses for some market participants during the June event. Even so, the impact of TLR was only one factor that affected the price spike. Moreover, TLR procedures are evolving, and many parties involved in this process appear to be committed to improving TLRs to the extent possible.

H. Regional Transmission Entities

The necessity for cooperation in meeting reliability concerns and the Commission's intent to foster competitive market conditions underscores the importance of better regional coordination in areas such as maintenance of transmission and generation systems and transmission planning and operation. Several types of regional entities exist or have been proposed to facilitate increased regional coordination, including independent system operators (ISOs) and regional transmission companies (TRANSCOs). Many of the allegations of market manipulation the team heard focused on issues related to the independence of the operation of the Midwest transmission system from activities in the power markets by owners of the system or their affiliates. Concerns over unfair operation of the system will be diminished if regional entities contribute to greater confidence that transmission providers are truly independent.

I. Cooperation with Other Governmental and Industry Entities

The FERC does not have primary jurisdiction over all matters that may affect whether future price spikes occur. For example, the Commission has no authority over the siting of transmission or most generation facilities, retail electric rates, or methods to manage retail electric load. These issues are within the jurisdiction of state and local governments. The team notes that at the Commission's August 14, 1998 Chicago conference on the June price spike, representatives of a number of state public utility commissions indicated that they are making inquiries about the price spike and considering taking actions to address relevant issues within their jurisdictions. Moreover, organizations within the electric industry establish rules and standards that may affect whether future price spikes occur. The team believes that the Commission, the states, NERC, and other relevant entities should maintain good communications on ways to use their respective authorities or organizations to help ensure that power markets function efficiently.

GLOSSARY

Available Transfer Capability
A measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. ATC is defined as the Total Transfer Capability (TTC), less the Transmission Reliability Margin (TRM), less the sum of existing transmission commitments (which includes retail customer service) and the Capacity Benefit Margin (CBM).

Broker
A third party who establishes a transaction between a buyer and seller for a fee. A broker does not take title to capacity or energy and is non-jurisdictional to the FERC.

Call Option
An option that gives the buyer the right, but not the obligation, to buy capacity and/or energy in the future for a specified price within a specified period of time in exchange for a one-time premium payment. It obligates the seller of the option to sell the capacity and/or energy at the designated price if the option is exercised.

Capacity Benefit Margin (CBM)
That amount of transmission transfer capability reserved by load serving entities to ensure access to generation from interconnected systems to meet generation reliability requirements. Reservation of CBM by a load serving entity allows the entity to reduce installed generating capacity below that which may otherwise have been necessary without interconnections to meet its generation reliability requirements.

Control Area
An electric system or systems, bound by interconnection metering and telemetry, capable of controlling generation to maintain its interchange schedule with other Control Areas and contributing to frequency regulation of the Interconnection.

Day-Ahead Market
Market involving trading of multi-hour energy blocks for delivery during the following day. Off-peak market involves daily prescheduled energy for the eight off-peak hours of the following day. On-peak market involves daily prescheduled energy for the sixteen on-peak hours of the following day. The trades reported in the trade press are typically for financially firm or physically firm power transactions. Other terms used to refer to this market include prescheduled and next-day market.

Derivative
A financial instrument, traded on or off an exchange, the price of which is directly dependent upon (i.e., “derived from”) the value of one or more underlying securities, equity indices, debt instruments, commodities, other derivative instruments, or any agreed upon pricing index or arrangement (e.g., the movement over time of the Consumer Price Index or freight rates).

Derivatives involve the trading of rights or obligations based on the underlying product, but do not directly transfer property. They are used to hedge risk or to exchange a floating rate of return for fixed rate of return.

Forward Contract
A supply contract between a buyer and seller, whereby the buyer is obligated to take delivery and the seller is obligated to provide delivery of a fixed amount of a commodity (e.g., electric energy) at a predetermined price on a specified future date. Payment in full is due at the time of, or following, delivery. This differs from a futures contract where settlement is made daily, resulting in partial payment over the life of the contract.

Futures Contract
A supply contract between a buyer and seller, whereby the buyer is obligated to take delivery and the seller is obligated to provide delivery of a fixed amount of a commodity (e.g., electric energy) at a predetermined price at a specified location. Futures contracts are traded exclusively on regulated exchanges and are settled daily based on their current value in the marketplace.

Hedge
The initiation of a position in a futures or options market that is intended as a temporary substitute for the sale or purchase of the actual commodity. The sale of futures contracts in anticipation of future sales of cash commodities acts as a protection against possible price declines, or the purchase of futures contracts in anticipation of future purchases of cash commodities as a protection against the possibility of increasing costs.

Hourly Market
The market in which hourly blocks of energy are traded.

Liquidated Damages Contract
Any contract with a provision which obligates the seller of power to pay the buyer's replacement energy costs in the event that the seller fails to deliver the contracted for energy.

Long Position
The position of a trader in the futures market who has less contracts obligating him to deliver a commodity at some time in the future than contracts obligating others to deliver the commodity to him.

Operating Reserve
That generating capability above firm system demand required to provide for regulation, load forecasting error, forced and scheduled equipment outages and local area protection. It consists of spinning and non-spinning reserve.

Option Contract
A contract which give the holder the right, but not the obligation, to purchase or to sell a commodity in the future at a specified price within a specified period of time in exchange for a one-time premium payment.

Power Marketer
A wholesale power entity approved by the FERC to buy and sell wholesale power from and to each other and other public utilities at market-based prices. In contrast to Brokers, marketers take title to the power in their transactions.

Price Discovery
The manner in which traders find out the bid and offer prices of other buyers and sellers. Mechanisms range from one-on-one phone calls to formal exchanges with posted bids and offers.

Put Option
An option that gives the buyer the right, but not the obligation, to sell capacity and/or energy in the future for a specified price within a specified period of time in exchange for a one-time premium payment. It obligates the seller of the option to buy the capacity and/or energy at the designated price if the option is exercised.

Security Coordinator
An entity that provides the security assessment and emergency operations coordination for a group of control areas.

Short Position
The position of a trader in the futures market who has more contracts obligating him to deliver a commodity at some time in the future than contracts obligating others to deliver the commodity to him.

Sleeve
A third party trader used as an intermediary between two other traders. Sleeves, which are usually large entities with good credit standing, are used for various reasons including to circumvent credit requirements of one of the parties, to enhance the risk profile of one of the traders, or shield the positions of one or both of the traders.

Spot Market
A market where goods are traded for immediate delivery.

Strike Price
The price at which the underlying options contract is bought and sold in the event the option is exercised. Also called the exercise price.

Transmission Reliability Margin (TRM)
That amount of transmission transfer capability necessary to ensure that the interconnected transmission network is secure under a reasonable range of uncertainties in system conditions.