REPORT TO

THE SWISS FEDERAL OFFICE OF ENERGY

THE AUGUST 14, 2003 BLACKOUT

IN THE UNITED STATES:

TECHNICAL AND REGULATORY ISSUES

By:

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EXECUTIVE SUMMARY

The blackout that struck the Northeast and Midwest of the United States, and portions of Canada, on August 14, 2003 had no simple, single cause, as far as is currently known. It appears to have been physically caused by one or more regional power plant and transmission line contingencies located in Indiana and Ohio, coupled with computer problems and information limitations at both the FirstEnergy and the Midwest Independent Transmission System Operator (MISO) control centers. This led to a voltage collapse in Ohio due to a shortage of reactive power, probably because independent power producers were not providing enough reactive power along with the real power they were selling. It also appears that the FirstEnergy system, where the blackout began, was over-relying on firm power imports for its operating reserves during the entire summer.

However, while this blackout cannot be definitely attributed to the restructuring of the electricity industry in the Midwest, it appears that the restructuring process, especially the unbundling of certain electric services, did create conditions that led to the blackout. Certainly, the restructuring process contributed directly to the lack of clear authority for which institution in the region had ultimate control of the transmission grid for the purpose of maintaining system reliability, the Midwest ISO or each utility control area. Restructuring also contributed to the blackout due to the significant economic conflicts that it creates between various corporate entities that own generating units in the region, and the utilities that continue to operate local distribution and transmission facilities. The attempt to develop competitive wholesale markets for electricity has led to the much more frequent long-distance transmission of power in the Midwest, particularly power from merchant plants. For example, there were probably more bilateral trades of power occurring on August 14 in MISO than were compatible with preserving adequate system reliability. Merchant plants also had little incentive to supply sufficient levels of reactive power without the presence of an ISO with actual dispatch authority and control.

This lack of clear authority relative to which institution had responsibility for maintaining system reliability is related to the fact that the State of Ohio had begun to restructure its electric utility industry as a step towards the goal of universal retail competition. When a state or region adopts retail competition as a goal, the traditional regulatory boundaries between the state public utilities commission and the Federal Energy Regulatory Commission (FERC) become more confused and ambiguous than they were prior to the start of restructuring. Furthermore, as part of the process of attempting to facilitate the development of regional competitive generation markets, FERC had established the Midwest ISO (MISO), but it was only in an early stage of development as of August 2003. MISO could not even provide a central dispatch of the generators within its control area as the older power pools in the Northeast had done for many decades. Nor did MISO have a transmission planning function in place. Thus, transmission planning and the appropriate level of investment in transmission system upgrades was left to each local utility, many of which had little incentive to invest at appropriate levels given the retail rate caps established during the restructuring process. Nor had MISO been involved in the siting of new generating units in order to try to minimize any negative impacts that they might have on the reliability of the existing transmission grid.

These critical flaws in the system planning process derived from the fact that the process for establishing MISO as an effective regional transmission organization was very problematic relative to the processes relied on to establish the three other such transmission organizations in the Northeast; namely, the Pennsylvania-Jersey-Maryland (PJM) ISO, the New York ISO, and the New England ISO. The result was that MISO could only attempt to maintain system reliability through verbal communications with the scheduling coordinators at each utility control center.

However, the problems with the way in which the MISO was established simply reflect the generic problems with the way in which electric industry restructuring has been attempted in the US. There has been no coherent plan for restructuring the US electric industry, and much of what has been done so far has been based on flawed economic theories about what restructuring would likely accomplish, and how these goals of restructuring could be achieved. FERC has adopted many of these flawed theories as part of its plans for establishing ISOs and Regional Transmission Operators (RTOs).

INTRODUCTION

The detailed causes underlying the blackout of August 14, 2003, are still under investigation. However, preliminary conclusions can be reached based on the data and other information that have been made available to date. The evidence seems to clearly indicate that the deregulation process directly contributed to the causes of the power failure. It would, therefore, be instructive to outline key features of deregulation in the US that may have played a role in causing the blackout. This report paper is organized with a description of the regulatory background and important entities in the electricity sector first, followed by a discussion of the probable causes of the blackout.

REGULATORY BACKGROUND

In order to better understand the historical context for the Northeastern blackout of August 14, 2003, it is necessary first to understand how utilities in the US are regulated. In brief, there are three important institutions involved: the state economic regulatory agencies, generally called "public utilities commissions" ("PUCs"); the federal regulatory body called the Federal Energy Regulatory Commission ("FERC"); and the North American Electric Reliability Council ("NERC"), which is a <u>voluntary</u> organization of electric utilities. The key distinction between these agencies is that the state PUCs regulate the terms and conditions of <u>retail</u> electric rates; FERC regulates the terms and conditions of <u>wholesale</u> power sales between utilities, including the transmission tariffs used for wholesale power sales; and NERC establishes "voluntary" rules, which are fairly strictly obeyed, to ensure the preservation of adequate system <u>reliability</u>. NERC has established ten regional reliability councils to implement and monitor its reliability rules. (See Figure 1 below.)

In the past, most electric utilities in the US have been privately owned vertically integrated companies that provided almost all of the generation requirements of their customers, in addition to all transmission and distribution system services. They were regulated monopolies. Until recently, only a little of the generation that these vertically integrated companies sold at retail was purchased wholesale from other utilities, perhaps a few percent, and the price was not set by a market mechanism. It was a cost-of-service price determined by FERC. However, during the late 1990s many state PUCs in the Northeast decided to attempt to lower retail rates by creating competitive generation markets at both the retail and wholesale levels, where the prices for purchased power would be set by market mechanisms, and, thus, both the retail and wholesale prices would be deregulated. FERC also began to encourage the construction of new power plants owned by independent power producers (not regulated utilities) in the early 1990s based on a 1992 federal law.

Of course, the initial intention of the advocates of deregulation was that transmission system prices would remain regulated prices for both retail and wholesale sales. However, once transmission services were unbundled from generation services in those cases where a utility's generating plants were sold to either an unregulated subsidiary of the original utility owner, or to an unregulated third party, FERC had the authority to set cost-of-service transmission rates for wholesale transactions between those parties. Surprisingly, in the last few years, FERC has allowed some degree of market-based pricing for transmission services, as well.

During this initial process of restructuring the electric utility industry, many mergers and acquisitions also occurred between utilities in the hope that future economies of scale and scope would help make the new, larger companies more profitable and more able to compete in and dominate the restructured electricity markets. No privatization of utility assets has occurred as part of US electricity restructuring, since most utilities were already investor-owned.

Thus, to understand electric industry "restructuring" in the US (the term "liberalization" was never used), it is critical to understand the separation of regulatory authority between FERC and the state PUCs, and the role that the two kinds of regulatory agencies played in the process. This is particularly important when thinking about the lessons that Europe can learn from the recent history of electric industry restructuring in the US, because Europe has not yet seriously considered establishing an equivalent of FERC to regulate wholesale transactions between utilities throughout Europe, or even within just one country. I believe that it is very important for Europe to appreciate the potentially positive role that a "FERC equivalent" could play in Europe, or even in Switzerland by itself, if liberalization and deregulation has any hope of being successful. In the US, if FERC did not exist, wholesale electricity markets would be impossible, either deregulated or cost-of-service based. However, this does not imply that FERC has always played a positive role with respect to electric industry restructuring. In fact, FERC's role has been quite negative on the whole.

In addition, it is very important to understand that the state PUCs (and other state agencies) have all the authority to review utility planning, whether the plans are for new investments in generation, transmission, distribution, or energy conservation technologies. FERC has no planning oversight authority at all. It can only urge utilities to do regional transmission planning on a voluntary basis. Thus, FERC has no authority to order the construction of new transmission lines or generating units, if capacity reserves of either type fall below adequate minimum levels. Only the states have that authority. The states also have sole legal authority to site new electric generating and transmission facilities. FERC can only review the prudence of new investment for inclusion in wholesale power cost-based rates, as the state PUCs can for retail sales.

THE FORMATION OF POWER POOLS

Beginning in the 1960s, many of the utilities in the Northeastern parts of the US found that it was in their common interest to form and join what they called "power pools." They did this on a voluntary basis (consistent with federal law) in order to better share generation capacity reserves, and in order to establish the central dispatch of their generating units so that the costs of energy production could be minimized. However, each utility still had to invest in sufficient generation capacity reserves to cover its annual peak demand plus its required reserve margin. The power pool determined the required reserve margin. Once a power pool was formed, this new entity became FERC regulated, because it was basically a wholesale arrangement between individual vertically integrated utilities. Thus, FERC came to regulate all the rules under which power pools operated. Again, until the mid- 1990s, all power exchanges (sales and purchases) between utilities in a power pool were priced on a cost-of-service basis, not a deregulated market price basis.

The three main regional power pools that were formed in the 1960s in the US were also formed partly in response to the Northeast blackout of 1964. They were the New England power pool (NEPOOL), the New York power pool, and the PJM power pool. Since by the late 1990s these three organizations had had about three decades of experience with operating and centrally dispatching the power systems in each of their respective regions, it was fairly easy for each to become an ISO, or Independent System Operator, when the deregulation of wholesale electricity markets began in the late 1990s. In becoming an ISO, each of these three organizations established new market mechanisms such as day-ahead and real-time electricity spot markets, and ancillary service markets, as FERC advocated. Even as of today, except for the addition of new ISOs in California and Texas, there are no other ISOs in the US that centrally dispatch all the power plants and transmission lines in a multi-state region. Of course, there are many large utility holding companies, such as the Southern Company or American Electric Power, which act like power pools for their own utility subsidiaries. As we will discuss below, the Midwest ISO that spans the region in which the August 14, 2003 blackout occurred does not yet have the authority to operate and control the Midwest regional electric system that contains at least 23 separate utilities, as power pools used to do.

THE MIDWEST ISO

After the California, Texas, PJM, New York, and New England ISOs were established in the late 1990s, the Midwest ISO was the next one that FERC tried to get organized. However, it can not be stressed strongly enough that organizing the Midwest ISO has been very difficult, in part because no similar pre-existing regional entity had ever existed. The Midwest ISO had to start from scratch. Under directions from FERC, MISO also tried to be very ambitious by attempting to organize the utilities in a very large geographical area. The boundary of the PJM ISO initially ended in the middle of Pennsylvania, but it was recently extended to include Western Pennsylvania, as well. In contrast, the Midwest ISO tried to organize utilities all the way from Ohio to the Dakotas, and from Minnesota down to Iowa. However, as the Midwest ISO was organizing, some utilities in this huge region wanted to join other ISOs due to policy disputes with MISO.

Yet, FERC kept encouraging MISO to organize a very big ISO to form in order to establish larger electricity markets. But this attempt might have been far too ambitious given all the disputes and disagreements that occurred among all the utilities in the region that the Midwest ISO attempted to organize. These disputes probably led to the situation which still exists; namely, that the Midwest ISO still does not have a set of rules in place to run its regional transmission grid the way the other ISOs do. In addition, some important and very large utilities in the Midwest, such as the American Electric Power system, still do not want to join the Midwest ISO. Thus, the Midwest ISOs geographical coverage looks like "Swiss cheese," and the Midwest ISO is a very weak ISO. In spite of this situation, FERC can not simply order all utilities in the Midwest region to join MISO because it does not have authority under federal law to do so. To repeat, utilities can voluntarily join power pools or ISOs, but they cannot be required to do so. Once they join, they can also leave the ISO if they want to. This issue has been the subject of several recent US court cases.

THE STRUCTURE OF ISOs

In general, ISOs are required by FERC to have an "independent" Board of Directors. This is why they are called Independent System Operators. Of course, FERC has no clear definition of what independent means, and most ISOs do not have representatives of consumers on the Board.[1] But the members are not supposed to come from the transmission or generation owning stakeholders in each region. Each ISO is also supposed to establish an independent Market Monitoring Unit (MMU), once generation markets are established. The MMU is a group of technical analysts who monitor the behavior of all of the markets run by the ISO (or RTO) in order to ensure that the market players are following the rules that dictate appropriate market

[1] See FERC Order No. 888 and Order No. 2000 for a complete list of ISO and RTO criteria and functions. An RTO or Regional Transmission Organization is FERC's new name for the kind of regional grid operator that it wants to establish.

behavior, and that the market prices meet the appropriate legal standards. If the MMUs determine that there are problems with the market rules leading to unfair or non-competitive market prices, they can propose changes in the rules. In fact, the MMUs in the Northeast have already been fairly active in trying to improve each ISO's rules. The MMUs are also supposed to identify the exercise of market power. However, the Midwest ISO does not have a MMU yet, since they have not yet begun to operate any formal market mechanisms. Of course, wholesale sales and purchases in the Midwest region are primarily priced at market-based rates now through bilateral and spot market contracts, even though there are no official ISO operated markets. There also is a trading hub operated by Cinergy (an Ohio utility) in the region.

Once a MMU is established by an ISO, the responsibility for monitoring market prices in that ISO is shared between the MMU and FERC. FERC has established an Office of Markets, which is supposed to monitor all electricity and natural gas markets in the US, in all regions, and in all hours of the year. Obviously, this is a huge job, and this new office at FERC has only existed for less than 2 years, so it is still hiring staff and establishing its market review procedures. If market players violate the market rules, and/or exercise market power, under certain conditions FERC has the authority to order that refunds be paid, as they did to a very limited extent after the California market crisis.

The basic reason that FERC monitors market prices is because federal law states that all wholesale electric prices must be "just and reasonable." This standard was established in 1935, so there is a very long history of regulatory and federal court decisions in the US that help to define what "just and reasonable" means. Some legal analysts argue that just and reasonable means that market-based rates can be no higher than cost-of-service based rates would have been for the same power. It is very important to understand that this is an extremely controversial issue in the US, in part because FERC has not been clear over the last few years about how the just and reasonable legal requirement would apply to market-based rates. Other legal analysts have argued that any market-based rates that are not filed with FERC prior to being charged are illegal under federal law. This would make spot markets illegal. (The relevant federal law is the Federal Power Act of 1935, as amended since then.) If, at a minimum, the federal law governing wholesale prices had not established a vague legal standard, there would be no legal basis at all for either the ISO or FERC to monitor the market prices for electricity.

THE NATURE OF UTILITIES IN THE MIDWEST

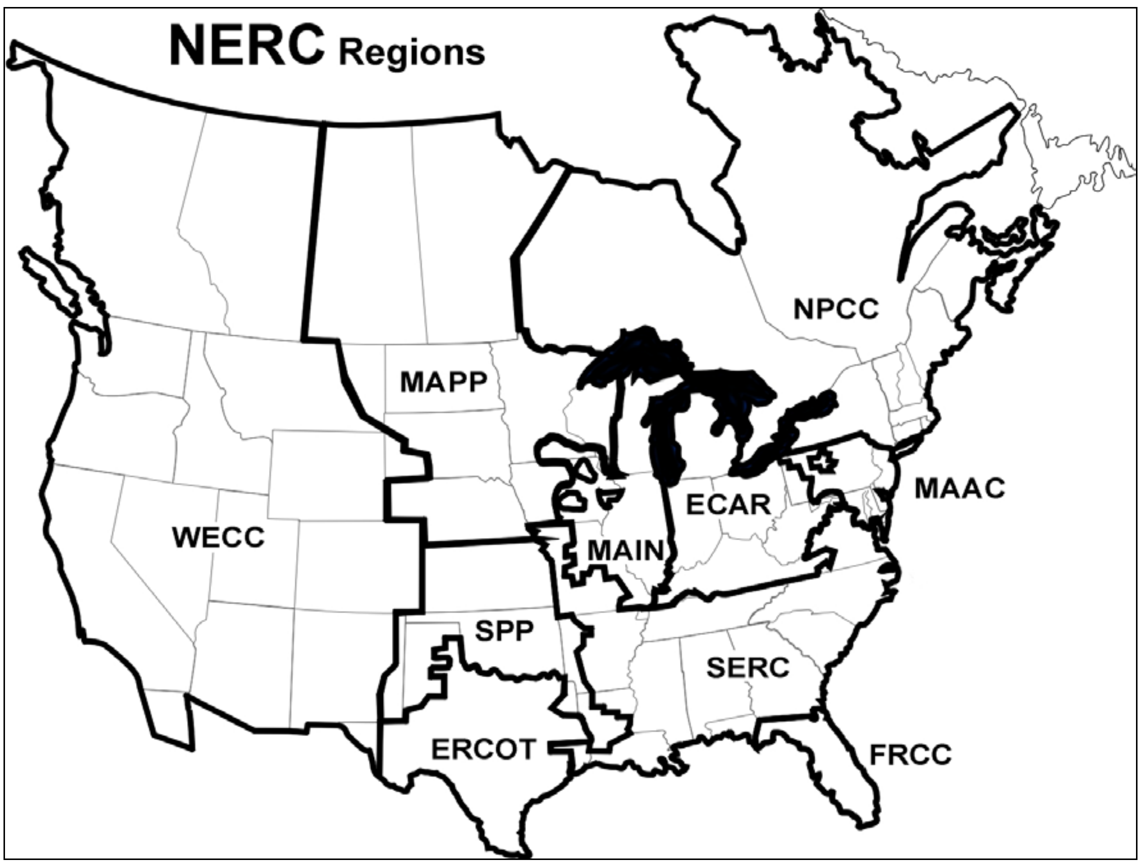
The utilities that exist in the Midwest (not just the members of the Midwest ISO) include a widely varying group. Most of the utilities are still vertically integrated, except in Ohio. In addition, there are many small public power utilities, municipal utilities, and coops. A number of the Ohio utilities may have sold some power plants since retail competition became the official state policy, and there are many independent power producers (IPPs) that have begun operations in the region. However, almost all utilities in Indiana, Kentucky, Virginia, Illinois, Wisconsin, Iowa, Missouri, Michigan, and Minnesota remain traditional vertically integrated utilities that have not yet restructured by selling off their power plants. In contrast, in Michigan and Wisconsin the private utilities have unbundled their transmission assets and sold them to new independent transmission owning companies. Yet, these utilities continue to own most of the electric generation in their states.

In summary, then, the degree of restructuring among Midwest ISO member utilities is somewhat different in each state, though the functional “bottom line” is that not much has changed since the 1980s, except that a lot more IPPs exist which can sell power into either the wholesale power market, or directly to individual customers in the states that allow some retail competition such as Illinois, Ohio, and Michigan. Kentucky, Missouri, Indiana, Virginia, Wisconsin, Iowa, and Minnesota do not allow retail competition, and have no current plans to do so. (Generally, any movement towards allowing retail competition in states such as Virginia has completely halted since the California market crisis of 2000-2001.) Most if not all distribution utilities still own their own transmission lines, except, as noted above, in Michigan and Wisconsin. Thus, most distribution utilities in the Midwest still own most if not all of the generating units that serve their retail load, even though some of those plants may be owned by an unregulated subsidiary of the utility.

CONTROL AREAS

As noted above, the operation of the transmission and generation systems of the 23 utilities that have joined the Midwest ISO is still primarily under their own control. Generally, each large utility is a "control area," which means that the real and reactive power flows into and out of the control area must be carefully balanced on a net basis in order to equal the demand. Each control area often includes some smaller utilities, such as municipals. The control area operators are responsible for obeying the operating rules that each NERC regional reliability council has established. This means that the system operators for each control area are responsible for making sure that proper voltage levels and frequency are maintained, and that the operating conditions will not damage any of the generation and transmission equipment. The individual utility control area operators also act as "scheduling coordinators" for the Midwest ISO, whereby they coordinate with the operators at the Midwest ISO to schedule the transmission flows that cross more than one control area. However, since the Midwest ISO operators can not dispatch the entire generation and transmission system that they oversee, they can only verbally try to convince any of the 23 individual control area operators to change their system dispatch to allow as many transmission transactions to occur as possible, subject to reliability constraints. Some of the big generation owners in the Ohio region are FirstEnergy, Allegheny, American Electric Power, and Cinergy. Also, it is important to know that the Midwest ISO overlaps three different regional reliability councils, which are ECAR, MAIN, and MAPP. (See map below in Figure 1.)

Figure 1: Map of the Ten NERC Regions



ECONOMIC CONFLICTS EMERGE DURING RESTRUCTURING

Even when a transmission pathway or flow is contracted for and scheduled by the ISO, system conditions often change such that the transmission flow must be interrupted, either partially or completely. This is called a TLR, or “transmission load relief.” Again, it is important to reiterate that the other ISOs besides the MISO can all perform a central dispatch, and, thus, the other ISO system operators can themselves interrupt any transmission contract or flow whenever it is necessary to do so. In contrast, the Midwest ISO must coordinate with all the scheduling coordinators of its member utilities. The data are readily available which show that with the onset of restructuring and market-based pricing for electric generation, the number of transmission transactions has greatly multiplied, and the number of TLRs has similarly increased. This is particularly true in the Midwest,[2] probably because of the new IPP generators

As expected, then, once the restructuring process began, new types of conflicts of interest emerged that did not exist when vertically integrated utilities existed. In particular, FERC has been very concerned about transmission system owners using their control of the grid to give the generating units that they own preference in selling to the commercial deregulated generation markets that have been established, to the disadvantage of other generation owners in the region. FERC considers this type of behavior discriminatory under federal law, and has tried to counteract it by advocating the creation of ISOs and RTOs (Regional Transmission Organizations) in Order No. 888 and Order No. 2000 in the first place. (These important FERC orders were issued in 1996 and 1999, and are available on the FERC website.) FERC has also strongly supported “functional unbundling” where a vertically integrated utility is required to operate its transmission division and its generation division completely independently of each

[2] See NERC website for details.

other, so that either division will not discriminate in favor of the other. Of course, this type of unbundling can also lead to the loss of the economic and other benefits that can be obtained from vertical integration, particularly in terms of preserving system reliability due to the close coordination that is possible between the two divisions, if "fair" competition was not an issue. FERC has also supported structured unbundling by supporting the idea that utilities should sell their transmission assets to an independent transmission company.

Conflicts of interest can even develop, then, within a single utility, once unbundling has been accomplished. In addition, conflicts develop between IPPs and the transmission owners because the primary job of the transmission system owners and operators is to maintain adequate system reliability, and to operate the transmission system in a conservative fashion to ensure that all NERC reliability rules are obeyed. On the other hand, IPPs and other power traders and marketers usually want to send their power supplies to the highest bidder, no matter how heavily loaded the required transmission routes already are, and no matter how far away that bidder might be located. These conflicts often take the form of IPPs and traders pushing the ISO operators hard to overload the transmission system relative to safe operating levels. In the US, and especially in the Midwest, these conflicts occur very frequently, as more and more wholesale power is transmitted greater, and greater, distances. It is also very likely that most control area operators feel under significant pressure <u>not</u> to declare a TLR and interrupt a commercially viable transmission contract, even when system reliability is endangered, in order to avoid being accused of discriminatory treatment by the sellers of the power, and, ultimately, FERC.

Obviously, the answer to the economic question of how far it is cost-effective to transmit power is a strong function of the degree to which the transmission prices increase with distance. In theory, of course, transmission prices should increase with the distance that power is transmitted, since over the long run the farther power is transmitted on average, the more new transmission lines will be needed. However, in contrast, FERC has advocated transmission pricing policies which go in the opposite direction in order to facilitate power trades over long distances in an attempt to create large markets. FERC has advocated "postage stamp" pricing over very large areas, which is one reason it wants each ISO such as the Midwest ISO to be very large. Obviously, this is one of the economic irrationalities and inefficiencies that has developed in FERC's proposed deregulation policies. It appears to discriminate in favor of power traders.

CONGESTION MANAGEMENT

In order to manage congestion on the transmission systems operated by ISOs, FERC has mandated that all ISOs establish market-based mechanisms for congestion management. FERC has generally required that each ISO develop different market prices for electric energy at each key node in the transmission grid. FERC has also supported allowing market-based prices for Firm Transmission Rights (FTRs), at least for wholesale sales. FTRs are the right to move power from one point to another on a firm basis. In the past, FERC has claimed that these two congestion management mechanisms will provide a more economically efficient means for the management of congestion, and will provide the proper price signals to both existing generators who are considering use of the existing transmission system, and to potential generation and transmission investors to indicate where new investments should be located.

However, this claim of FERC's is false, since market-based congestion prices can never lead to a more economically efficient dispatch than can a least-cost dispatch based strictly on the variable dispatch costs for each generator. Market-based systems can only be <u>less</u> economically efficient. This is a simple mathematical point. In a partial change of view, FERC has also recently acknowledged that congestion pricing at market rates will not likely lead to sufficient transmission or generation investment in the correct locations, which is true. (See FERC's discussion of this issue in its Standard Market Design proposed rule of July 31, 2002.) Part of the reason why market-based nodal prices do not create the correct price signals for investment decisions, is that the relevant prices will necessarily fall significantly once the new investments are made. Thus, this market-oriented pricing approach would lead to unstable investment decisions, if implemented.

Either way, the Midwest ISO had not yet established congestion cost pricing for the region under its control, so this change in FERC's position was not a factor contributing to the blackout. Each of the utility control areas within the Midwest ISO region has been free to manage congestion according to its own procedures, though one can presume that most utilities follow the NERC guidelines. One can also presume that, in most cases, it is in the interests of each individual utility to meet its own retail load using a least variable cost dispatch, with other wholesale load flows and trades scheduled above and beyond the flows required to meet the retail load requirements.

UTILITY PLANNING AND TRANSMISSION INCENTIVES

Because FERC has no planning authority, almost all utility planning is reviewed solely by state PUCs. In the past, most utilities had to present integrated resource plans or least-cost plans for generation, transmission, and energy conservation investments to these PUCs every 2-3 years. The utilities would propose to invest in a sufficient number of new transmission lines and power plants to serve existing and new retail load over a 10-20 year planning period. Once the PUC was convinced that a particular set of investments to serve retail load was part of a least-cost plan, the utility was allowed to raise the required funds in the capital markets, and make the investments for its service territory.

Usually regional bodies set up by the utilities, such as the regional reliability councils, would review the collective plans of all the individual utilities in the region in order to check for internal consistency among the plans, and to identify any remaining weaknesses. This was done particularly for regional transmission planning purposes. Often a regional reliability council would initiate the identification of a new transmission line that was needed to help preserve regional system reliability, and then this council would work on an informal basis with all the relevant utilities through whose service territories such a line would need to pass in order to make sure that all the sections of such a line were proposed to be built by each relevant utility, in each relevant state. Thus, usually there was good coordination of transmission line planning between regional utility bodies, the utilities, and the state regulatory bodies, including state siting authorities that had to approve the location of each proposed transmission line.

In the US, there is no distinction made between new transmission investment made to allow an increased number of trades or <u>wholesale</u> sales, and new investment made to serve <u>retail</u> or "domestic" electric power consumption. Since construction authorization can only be given by the state PUC (or state siting council), any new transmission investment is included in the total cost-of-service for all transmission, and the transmission rate that results is supposed to be the same for both retail and wholesale use of the grid. In fact, one of the principles that FERC established early on was that each distribution utility should pay the same for its own use of its own transmission grid to serve retail customers as it charges wholesale customers to use its grid. (See, again, the important FERC Order No. 888 (1996) which attempted to open up the transmission grid for all new users on a non-discriminatory basis.)

Thus, once the correct transmission line investments were approved as "prudent" by the state PUCs, and the investments were made, the investment became part of the cost-of-service of the local transmission owning utility when the next state or federal ratecase occurred. (Ratecases are the process by which regulated utilities have their rates changed by the relevant state PUCs or by FERC.) In all instances up until now, the investment funds for almost every transmission line built or under construction in the US were raised in the capital markets by the local distribution utility, which also owned its own transmission system. An incentive to make these transmission (or distribution) investments in a timely way exists based on the assumption that utility managements want to avoid the bad publicity and punishments that can be implemented by the state PUC if poor system reliability results from poor transmission investment decisions, or from too few investments. This applies to distribution system reliability, as well as to transmission system reliability. (One punishment available to PUCs is monetary fines, or, similarly, a reduction in the allowed rate of return on the equity investment in the company during the next ratecase.)

Furthermore, FERC has recently proposed that transmission owning utilities, and other investors in new transmission lines, receive additional financial incentives in the form of slightly higher rates of return on their equity investments in the lines, if the owners join an RTO. However, many analysts believe that these financial incentives would just serve to raise electric rates for consumers, but would not be nearly large enough to cause any new transmission lines to be either upgraded or built if the utility were not motivated to do so for other reasons.

Others have argued that to the degree that the aggregate investment in the transmission grid has been too low to lead to an economically efficient system over the last 10 years, the cause is simply that utility managements have had their priorities diverted from relatively boring issues such as transmission planning, to trying to maximize their profits in their newly unregulated subsidiaries, that they established in response to deregulation. Also, energy trading had become a booming business in the deregulated marketplace, at least until 2002. Often, companies chose to spend large amounts of money developing their hoped-for high-margin, high-risk activities, rather than investing in upgrading nuts-and-bolts transmission resources. Of course, the siting of new transmission lines is also usually very controversial in the US with the local populace who would be directly affected by having a new line in their "backyard," and the construction of most new transmission lines faces strong local opposition.

One important point that is often overlooked in the frequent debates regarding how much transmission system investment there should have been over the last 10 years, or so, is that most state PUCs have established reasonably clear criteria for when new transmission system investments should be made. Those criteria relate to the long established concept of "least-cost planning." This concept implies that new transmission lines should not be constructed or upgraded just to help create a more competitive wholesale electricity market, if the incremental savings to retail customers from doing so are less than the incremental investment costs to these consumers. Thus, more trading in electric power and the lower wholesale market prices that would result from having more new transmission lines are only of value to society if they lead to overall lower costs of providing power to consumers. Finally, I am not aware of any regional least-cost planning studies that have been done in recent years for the ECAR region in which the August 14 blackout began that would indicate whether or not the construction of new transmission lines would be cost-effective.

In fact, lowering market prices of generation alone may not change the costs to society at all, if the underlying direct costs of supplying electric generation do not change. This could happen if building new transmission lines merely causes a decrease in the extent to which generators can exercise market power by artificially raising prices above competitive (cost-based) levels. In such a case, building new transmission lines to lower market prices would be much more expensive than simply re-regulating the price of generation at cost-based levels.

RETAIL COMPETITION AND CONSUMER PROTECTION

As indicated above, only a few states in the Midwest allow for "retail competition" at all, which means that wholesale power suppliers are allowed to sell power directly to retail customers. In all cases where retail competition is allowed, most of the power sold directly to customers is sold to large industrial customers. Very few small residential customers are served directly by individual power marketers. The underlying economic reason for this is because the "retail margin" (the incremental cost above the wholesale price of power to serve a customer directly) is very small for large industrial customers, but is rather large in proportion to the total cost of generation for small residential customers. (The retail margin is hard to estimate, but it is probably in the range of 1.5-2.0 cents per kWh for small customers.) This means that power marketers can not compete with the regulated Standard Offer price for generation that state PUCs have established for small customers who do not choose to switch to an alternative retail power provider other than their traditional local utility. This is because the price of the Standard Offer is usually set at the cost of wholesale power, or very close to it, because this is all it costs to obtain this power on an aggregated basis for large numbers of customers. Thus, state regulators have not chosen to help a competitive retail generation market develop for small customers begin by artificially inflating the price of the Standard Offer well above the wholesale price, because such a rate increase would be politically very unpopular, and would be economically inefficient.

Most state utility regulators had mistakenly promised customers that establishing competitive markets for electricity would lead to lower prices for all (or almost) customers. But no one had really thought carefully about how high the retain margin for small customers would be before making these promises, even though even only a little thought should have convinced the advocates of retail competition that a distribution utility could more economically purchase power on behalf of all of its customers, especially small customers, compared to having many power marketers compete to do the same thing. And, mathematically, it is true that the more the loads of customers get aggregated together, the cheaper the average price is for long-term power supply contracts to serve that load is likely to be, everything else being equal. There generally are economies of scale and scope when creating a large-scale portfolio of power supplies.

Thus, one major form of consumer protection that exists in states that have adopted retail competition is that a Standard Offer has been established that caps (adopts a maximum) retail rates at the wholesale market price, or, even, at a level close to the old regulated generation cost-of-service if it was significantly below the market price. This Standard Offer is usually established by signing a power supply contract with the existing generation owner, even if it is still the local distribution utility, which requires this owner to serve the Standard Offer at these lower prices for many years into the future. Often this was done for 5 years or more. While advocates of retail competition had hoped that the Standard Offer would end at the end of the official "transition" period to full competition, this has usually proved to be wishful thinking.

The "transition" periods to full retail competition are coming near their end in some states, but often the end date for the Standard Offer supply contracts is being extended due to political pressure to keep electric rates as low as possible. Many PUCs that had believed that establishing retail and wholesale markets for electricity would lead to lower electricity prices are starting to realize that this will not likely be the case, and they are trying to shield consumers from future market prices for generation that might be higher than the prices that customers are currently paying under the Standard Offer. This process for establishing Standard Offers and transition periods is different in each state, as are all features of restructuring in the US.

THE AUGUST 14, 2003 BLACKOUT

Given the brief historical and regulatory context described above, it should be fairly clear why the probability of having a blackout on August 14, 2003 at 4:10 pm was increased significantly by electric industry restructuring as a process, and specifically by the deregulation of electricity prices for generation in the Midwest region of the country which led to the construction of many new merchant power plants (IPPs). The blackout was due, in part, to the early, formative stage of development of the Midwest ISO, which was one aspect of the restructuring process, since this ISO had neither the authority nor the technical means to operate the generation system and the transmission grid in the region. But, since the Midwest ISO had not yet established formal spot markets, those types of markets certainly did not contribute to the blackout. Rather, it was probably the presence of too many bilateral contract trades originating with IPPs in the region on the day of the blackout that contributed most to the increased likelihood of its occurrence. The transmission grid was probably being utilized far too fully to survive intact from an independent series of additional power plant outages and transmission line outages that occurred that afternoon. This was due, in part, to a lack of reactive power provided by the IPPs.

The North American Electric Reliability Council (NERC) had issued a report this spring stating that a section of the grid covering Ohio and other parts of the Midwest was particularly vulnerable to “cascading events” (*The New York Times*, August 21, 2003). This is because the Midwest ISO often records as many as 200 such power transactions per hour during times of peak usage. In addition, utility companies such as FirstEnergy were probably not as focused on transmission system planning, especially for making simple and relatively cheap transmission equipment upgrades to existing lines, as they should have been, because restructuring actually <u>reduced</u> their incentives to do so. Finally, FirstEnergy seems to have been short of firm capacity reserves this summer, and it had to overly rely on power imports to meet its reserve requirements.

However, the further verification of each of these hypotheses will need to await further analysis of the events of August 14. Note that I will not take the time to describe the detailed events of the blackout in this report, since they can be obtained from the US DOE website, and from other sources such as the November 2003 report by the Michigan Public Service Commission. (For example, see the September 12, 2003 “Initial Blackout Timeline” from DOE attached to this report as Appendix A.)

I will now discuss each of the four main causes of the blackout separately, in greater detail:

1. <u>The Midwest ISO was in a formative stage of development.</u> – I think it is quite likely that if the Midwest ISO had been as fully developed as PJM or the other ISOs by August 14, 2003, the blackout would not have occurred. This is because the main physical symptom of the blackout appears to have been a voltage collapse in the Ohio region, implying a shortfall in reactive power being provided to key load centers.[3] However, this shortage of reactive power seems to have taken several hours to develop, thus there likely was time to

[3] See the September 12, 2003 DOE summary, and NYTimes article of September 23, 2003 by Richard Perez-Pena and Eric Lipton referenced below.

reverse it if the shortage had been recognized. This voltage collapse led to the cascading impact on neighboring states, first Michigan, and then New York and Ontario (Canada). The key fact here, as noted above, is that the Midwest ISO did not have the technical capability of controlling transmission line flows and the generation dispatch throughout the region. If the Midwest ISO had had this capability, its computer system would have been able to reveal the lack of reactive power at key points in the grid to the system operators so that corrective action could have been taken.

Thus, given the Midwest ISO's lack of detailed information on the system conditions on that day, and the computer problems (perhaps due to a virus) that FirstEnergy was experiencing that same day, the Midwest ISO could not either direct FirstEnergy as to how to control its own developing problems, or request other neighboring utilities to assist FirstEnergy in controlling these problems. In addition, FirstEnergy was not clearly aware of its own system conditions to a sufficient degree. Finally the Midwest ISO's attention had been focused on developing reliability problems in the neighboring state of Indiana earlier in the day on August 14, and this problem may have detracted from its ability to identify impending problems in Ohio through much of the afternoon. The Midwest ISO was also hampered in the process of solving the Indiana reliability problems, which brought the Indiana grid close to collapse, due to a computer software problem at its own headquarters. (The state estimator program for the transmission system was not functioning.)

2. <u>There were too many bilateral power trades throughout the region on August 14</u>. – At the present time we do not know how many bilateral power trades were being accommodated on that day in Ohio. However, we do know that only a little earlier in the day (about 2:30

pm) a neighboring utility control operator (Cinergy) had a serious conflict with power traders at the Allegheny Power Company. For a significant time Allegheny would not back down one of its trades, and it wanted to increase certain other power flows for marketing purposes that the Cinergy operator claimed would clearly prevent him from putting his system on a more secure footing, since his system was developing a potentially serious reliability problem.

Furthermore, we know that, in general, the Midwest has experienced a very high level of TLRs in the last year or two due to an increasing number of power trades, especially from IPPs. As a key witness from ECAR stated on September 3, 2003 at the hearings held in Washington, DC by the House Committee on Energy and Commerce:

> The existing transmission infrastructure was initially designed primarily to enable neighboring utilities to exchange power in the event of a loss of generation or for economic reasons. With the deregulation of the generation segment, many transmission lines are now often heavily loaded as large amounts of power are transferred across the multi-state regions. This has resulted in a situation where some transmission lines are now being operated closer to their design limits more of the time than before deregulation opened use of the transmission systems to foster wholesale competition. This is not to say that the transmission systems are being operated beyond their allowable limits, but only to point out that some transmission systems are being operated with less margin than before for contingencies.[4]

Thus, on average, there appear to have been too many bilateral trades that were allowed to be initially scheduled by the relevant system and control area operators, and which eventually had to be interrupted. Clearly, the deregulation of wholesale generation markets, which encouraged the higher levels of trades that the Midwest has experienced in recent years, contributed to the "brittleness," or lack of flexibility in the regional power grid on August 14, as well. We also know that the weather was not a significant factor in

[4] Testimony of Mr. Brantley H. Eldridge, Executive Manager, ECAR, September 3, 2003.

itself in causing the blackout, because overall customer demand on August 14 was not very high. In fact, some analysts have claimed that there probably were several unscheduled power flows, most likely from IPPs, on August 14.

This hypothesis that electric industry restructuring played an important role in contributing to the blackout is supported by the analysis that NERC published in May of 2003 as part of its "2003 Summer Assessment" for the ECAR region, which includes Ohio. NERC stated:

> There is a continuing need for the reliability coordinators, transmission planners, and operators to communicate and coordinate their actions to preserve the continued reliability of the ECAR system. It is anticipated that the ECAR transmission system could become constrained as a result of unit unavailability and/or economic transactions that have historically resulted in large unanticipated power flows within and through ECAR. If these conditions occur again this summer, local operating procedures, as well as the NERC Transmission Loading Relief procedure (TLR), will need to be invoked in order to maintain transmission system security. As long as transmission limitations are identified and available operating procedures are implemented when required, no cascading events are anticipated.

NERC concluded its May 2003 ECAR assessment by stating:

> In general, using total import capability as a measure, the ECAR transmission system will be *more constrained* [emphasis added] this summer as compared to last summer."[5] (p. 17)

Furthermore, NERC found that the Michigan-Ontario interface was going to be susceptible to large parallel flows and TLR curtailments, which was an early hint of the way in which the blackout cascaded from Michigan to Ontario. Finally, the ECAR summer assessment recognized the need for new operating procedures involving utility control areas around Lake Erie in order to be able to use generation redispatch to mitigate emergency TLR procedures and curtailments in situations where local blackouts were

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[5] NERC, *2003 Summer Assessment — Reliability of the Bulk Electricity Supply in North America*, May 2003.

about to occur. Of course, it was around Lake Erie that many of the earliest events leading to the cascading blackout occurred on August 14.

The best summary of how the power plant outages in and near Ohio early on August 14 might have caused a voltage collapse in the region has been presented in a *New York Times* article dated September 23, 2003.[6] The authors point out that several utility-owned power plants were out for maintenance that day, and several merchant (IPP) power plants were running instead. However, the authors point out that, according to their sources, merchant plants have little or no incentive to produce enough reactive power to keep the system in balance with respect to voltage and frequency. FirstEnergy did notice that voltage was low on its transmission system hours before the blackout occurred. FirstEnergy was importing thousands of megawatts of real power, but,, surprisingly, they were exporting reactive power most of the day. As early as 1:15 pm on August 14, voltage on the FirstEnergy system had dropped by 3-4 percent, near to the 5 percent threshold established by NERC as dangerous.

FirstEnergy tried to solve this serious voltage problem over the next two hours, but their efforts led to additional problems. At 3:05 pm a series of transmission lines linking Cleveland, Ohio to Southern Ohio failed. Again, FirstEnergy could not stabilize its system over the next hour, and by 4:10 pm the blackout spread from small areas within Ohio to Michigan, Ontario, and New York.

3. <u>Restructuring in Ohio could have led to inadequate transmission system upgrades</u>. – Another way in which electric industry restructuring could have contributed to the blackout is by leading to a situation where FirstEnergy, in particular, and all other

[6] Richard Perez-Pena and Eric Lipton, *New York Times*, "Elusive Force May Live at Root of Blackout," September 23, 2003.

transmission system owners had little incentive, or even strong disincentives, to invest sufficiently on a continuing basis in their existing transmission grid to ensure that it would continue to operate reliably. There are at least two ways in which this could have happened. The first is, as noted above, that FirstEnergy's management might have been more focused on running its unregulated subsidiaries in an attempt to enhance its profits or to avoid serious financial losses, than on worrying about its own system reliability. For example, it might have tried to save its cash for these unregulated and frequent investments in upgrading its own transmission system which it hoped would have high profit levels, rather than making regulated investments which might provide lower regulated returns. Secondly, given the cap or ceiling on the transmission component of its retail rates imposed by state utility regulators, FirstEnergy might have been faced a cash squeeze between the level of its retail rates, and its transmission system costs, implying that any increase in its transmission system investment would not have been able to be recovered from its retail customers until after the rate cap was removed at the end of the "transition period." Because of restructuring, most utilities had their transmission rates capped during a transition period lasting many years as part of the overall restructuring plan. Thus, they were not able to apply to the state PUC for a transmission rate increase if transmission system costs increased, as they could have done under traditional regulatory procedures prior to restructuring. (Most states allowed utilities to request rate increases about once per year if they wanted to.) Thus, a continuation of traditional rate regulation might have provided utilities with more financial incentives and opportunities to maintain system reliability at a higher level than was likely to occur once transmission rate caps were implemented

4. FirstEnergy was short of internal generation capacity to meet its firm reserve requirements – A little-known fact that has not been discussed yet in the media is t hat FirstEnergy itself issued a 2003 Summer Assessment on May 22, 2003, stating that its projected summer peak demand (excluding interruptible loads) would be about 500 MW higher than its net available generating capacity. (Load was forecast to be 13,545 MW on the FirstEnergy/Penn Power system versus net generation capacity of 13,044 MW.) In order to achieve an operating reserve margin of 11.0 percent, FirstEnergy alone was planning on importing 3,066 MW of power at the time of system peak demand. While the peak demand on August 14, 2003 was not as high as the forecast peak demand for the entire summer, these figures indicate that FirstEnergy was planning to rely on firm imported power for a very high proportion of its peak demand during the summer. This risky approach, which was planned on, could have been an underlying cause of the blackout by making it much harder for FirstEnergy to re-balance its system if any of those planned imports were interrupted, as they were on August 14. Thus, it appears that FirstEnergy should not have been allowed to depend on such a higher level of imports to make up its operating reserves during the summer of 2003. More plants internal to its system should have been either built or returned from maintenance sooner in order to meet its operating reserve requirements.

APPENDIX A

"Initial Blackout Timeline" from DOE

September 12, 2003