

**ANNUAL REPORT-2004**  
**MONITORING OF**  
**“CONDITION CERTAIN” ISSUES**  
**IN NEB. REV. STAT. § 70-1003(6)**  
(Formerly referred to as Legislative Bill 901)

**OCTOBER 2004**

## TABLE OF CONTENTS

<b>Introduction</b>	<b>i</b>
<b>Executive Summary</b>	<b>iii</b>
<b>Chapter 1 – Whether or not a viable regional transmission organization and adequate transmission exist in Nebraska or in a region that includes Nebraska.</b>	
1.0 Purpose	I-2
2.0 Team Members	I-2
3.0 Summary	I-2
4.0 MAPP	I-3
4.1 MAPP RTC	I-3
4.2 MAPP/Midwest ISO Seams Agreement	I-4
4.3 MAPP RRC	I-5
5.0 Midwest ISO	I-5
6.0 SPP	I-6
7.0 TRANSLink	I-7
8.0 Crescent Moon	I-7
9.0 Conclusions	I-7
<b>Chapter 2- Whether or not a viable wholesale electricity market exists in a region which includes Nebraska.</b>	
1.0 Introduction	II-2
1.1 Group’s Purpose and Membership	II-2
1.2 Approach	II-2
2.0 Viable Wholesale Market Definition	II-3
2.1 Economic Logic	II-3
2.2 Evolution of FERC Definition and tests for Market Power	II-3
2.3 Basic Elements of Traditional FERC “Hub and Spoke” Market Power Analysis	II-4
3.0 Region Defined	II-6
3.1 East/West Interconnection Description	II-6
3.2 Nebraska’s Portion of Each Interconnect	II-6
3.3 Eastern Interconnection Defined	II-6
3.4 ERCOT Interconnection	II-6
3.5 Western Interconnection Defined	II-6
3.6 Comparison of Region to that in Technical Group #1	II-7
4.0 New FERC Methods for Assessing Market Power	II-7
4.1 Reasons for Instituting New Methods	II-7
4.1.1 New Tests of Market Power	II-8
4.1.1.1 Modified “Hub and Spoke” Test	II-8
4.1.1.2 Electricity Market Models	II-8
4.1.1.3 Supply Margin Assessment	II-8
4.1.1.4 Interim Generation Market Screen and Mitigation Policy	II-9
4.1.1.4.1 Relevant Market Area for Interim Generation Market Screens	II-9

4.1.1.4.2	“Pivotal Supplier” Market Screen	II-9
4.1.1.4.3	“Market Share” Market Screen	II-11
4.1.1.4.4	“Delivered Price” Market Screen	II-12
4.1.1.4.5	Mitigation Measures	II-12
4.1.1.4.6	Implications for Public Power	II-12
5.0	RTO Market Monitoring and Market Power Mitigation	II-12
5.1	Marketing Monitoring	II-12
5.2	Market Power Rules and Mitigation	II-13
6.0	Midwest Independent Operator (MISO) State of Market Report 2003	II-13
6.1	Report Overview	II-13
6.2	MISO Subregions Used in Market Power Tests	II-13
6.3	Reserve Margin Analysis	II-13
6.4	Transmission Request Analysis	II-14
6.5	Transmission Curtailment Analysis	II-15
6.5.1	Number and GWH Amount of MISO Electricity Transactions Curtailed	II-15
6.5.2	Justification of MISO TLR’s	II-16
6.5.3	TLR Price Effects Analysis	II-16
6.6	Pivotal Supplier Analysis	II-17
7.0	Conclusion	II-18
7.1	Status of Viable Midwest Wholesale Market in the Eastern Region	II-18
7.2	Status of Viable Midwest Wholesale Market in the Western Region	II-18

**Chapter 3 – To what extent retail rates have been unbundled in Nebraska.**

1.0	Status of Unbundling in Nebraska	III-2
2.0	Team Members	III-2
3.0	Introduction	III-2
4.0	Survey Results	III-3
5.0	Estimated Unbundling Costs	III-5
6.0	Conclusion	III-6

**Chapter 4-A comparison of Nebraska’s wholesale electricity prices to prices in the region.**

1.0	Introduction	IV-2
1.1	Purpose and Group Membership	IV-2
1.2	Approach	IV-2
2.0	Wholesale Market Terminology	IV-2
2.1	Market Product Definition	IV-2
2.2	Comparison Concepts	IV-3
2.3	Physical Product Definitions	IV-3
2.4	Market Product Time Period	IV-3
2.5	Market Product Categories	IV-3
2.6	Market Price and Production Cost Difference	IV-4
2.7	Market Price Volatility and Production Cost Stability	IV-4
2.8	Market Product Price	IV-5
2.9	Transmission Cost & Loss Considerations	IV-5
2.10	Nebraska Production Cost	IV-5

2.11	Long-Term “Obligation to Serve” Considerations	IV-6
2.12	Various Generation Unit Types Serving Load	IV-6
2.13	Ancillary Services Component	IV-6
2.14	Load Factor Considerations	IV-6
3.0	Market Product Pricing and Nebraska Production Cost Comparison Methodology	IV-7
3.1	Alternative Comparison Methods	IV-7
3.2	Comparison Modeling Tool Detail	IV-7
3.3	Comparison Modeling Tool Application	IV-9
4.0	Results of Modeling Tool Comparisons	IV-10
4.1	Time Period Utilized	IV-10
4.2	Sensitivity Cases Analyzed	IV-11
4.3	Median Market Pricing	IV-11
4.4	Megawatt-Hour (MWh) Weighted Fixed Cost Allocations	IV-12
4.5	Other Cost Allocation Issues	IV-12
4.6	Value of Long Term Obligation to Serve	IV-13
4.7	Results Based on Median Market Product Pricing Indices and Applying MWH-Weighted Fixed Cost Allocations to Nebraska Production Costs for 2001 through 2004	IV-13
5.0	Expected Differences Eastern Region to Western Region	IV-17
5.1	North American Electrical Interconnection	IV-17
5.2	Eastern Interconnection and Western Interconnection Generation Supply and Demand	IV-17
5.3	Western Region Market Compared to Eastern Region Market	IV-18
5.3.1	“Markets” or “Hubs”	IV-18
5.3.2	Volatility and Price Comparison	IV-18
5.4	Nebraska Production Costs	IV-18
5.4.1	Western Nebraska versus Eastern Nebraska Costs	IV-18
5.4.2	Stability	IV-19
6.0	Conclusions	IV-19

**Chapter 5-Any other information the board believes to be beneficial to the Governor, the Legislature, and Nebraska’s citizens when considering whether retail electric competition would be beneficial, such as, but not limited to, an update on deregulation activities in other states and an update on federal deregulation legislation.**

1.0	Purpose	V-2
2.0	Team Members	V-2
3.0	Introduction	V-2
3.1	Deregulation Overview	V-2
4.0	Texas	V-2
5.0	Federal Issues	V-7
6.0	Conclusions	V-8

**Glossary**

## INTRODUCTION

In 1996, the Nebraska Legislature passed Legislative Resolution 455 (LR 455) which directed the Legislature's Natural Resource Committee to perform a two phase study to examine issues related to competition and restructuring of the electric utility industry and the possible effects on the state. Advisory groups and task forces were formed and utilized along with a consultant.

The first phase of the study examined the history and current status of Nebraska's electric industry. The report produced in Phase I provided a comprehensive overview of the structure, governance, operations, financing and comparative effectiveness of Nebraska's consumer-owned electricity industry. Phase I was completed in December 1997.

Phase II of LR 455 examined the transition of the electric utility industry nationwide and developments at the federal level and in other states related to possible impacts and options for Nebraska's electric industry. Based on these examinations, the Phase II report provided a planning framework for Nebraska centered on a "condition certain" approach to retail competition. Several states that pursued a 'date certain' approach to retail competition encountered problems which probably could have been avoided had a "condition certain" approach been followed. The "condition certain" approach requires that specific preconditions in structure and market be in place when, and if, a transition to retail competition is to be made for Nebraska's electric industry. The Phase II report was completed at the end of 1999.

In early 2000, the elements of the "condition certain" approach as outlined in the LR 455 Phase II report were incorporated in legislation that was introduced in the Nebraska Legislature. Legislative Bill 901 (LB 901) was passed by the Legislature on April 11, 2000.

LB 901 (2000), the pertinent part of which is now codified at Neb. Rev. Stat. Chapter 70-1003 (5), (6) and (7) (Reissue. 2003), directs the Nebraska Power Review Board (NPRB) to hold annual hearings concerning the benefits of retail competition in the electric industry in Nebraska and what steps, if any, should be taken to prepare for retail competition. LB 901 also directs the NPRB to submit an annual report to the Governor, with copies to the Clerk of the Legislature and the Natural Resources Committee, analyzing five items or conditions concerning the electric system in Nebraska and the region to help determine when and if retail competition should be initiated in Nebraska.

To carry out the mandate of LB 901 (2000), the NPRB formed Technical Groups comprised of experts from Nebraska's electric industry to conduct research and prepare the part of the study corresponding to each of the five conditions outlined in the legislation. The members of the Technical Groups that addressed the five issues are shown in the individual issue reports.

The NPRB also formed a Review Group to allow for participation in the process by a wide spectrum of interested parties. The Review Group includes representatives from government agencies, consumer groups, public power entities, investor-owned electric utilities, residential, agricultural, commercial and industrial consumers and other groups. The Review Group acts as a sounding board for the Technical Groups' information and findings, and offers suggestions for the final report. The members of the Review Group have changed during the period the LB 901 (2000) issues have been monitored. A listing of the current members follows.

<b>NAME</b>	<b>REPRESENTING</b>
Doug Bantam	Lincoln Electric System
Fred Bellum	American Association of Retired Persons
Tim Burke	Omaha Public Power District
Richard Duxbury	NMPP Energy
Marvin Fishler	Irrigation Customer
Joe Francis	Nebraska Department of Environmental Quality
Gary Hedman	Southern Public Power District
Jay Holmquist	Nebraska Rural Electric Association
Clint Johannes	Nebraska Electric Generation & Transmission
Don Kraus	Central Nebraska Public Power & Irrigation
Richard Kuiper	IBEW/NE State Utility Workers
Gary Mader	Grand Island Utilities
Derril Marshall	Fremont Utilities
John McClure	Nebraska Public Power District
Dave Mazour	Tri-State Generation & Transmission
Steve Pella	UtiliCorp United
Bruce Pontow	Nebraska Electric Generation & Transmission
Mary Powers	Nebraska League of Women Voters
Frank Reida	Residential Customer
Marvin Schultes	Hastings Utilities
Adam Smith	Industrial Customer
Tim Texel	Nebraska Power Review Board
Robert White	Loup River Public Power District

The NPRB retained PAPE CONSULTING SERVICES as the Coordinating Consultant. The Consultant is responsible for coordinating the activities and meetings of both the Technical and Review Groups, and for assembling the annual report. The first Annual Report was issued in October 2001, with subsequent reports in October 2002 and 2003.

Although Nebraska is unique in the United States in that it's electric utilities are exclusively consumer-owned, Nebraska's major public power utilities have historically participated in the initial development and growth of the region's high voltage electric transmission system. It is critical that a reliable and adequate transmission system exists in Nebraska and in the region. Nebraska is not and cannot be an island. Nebraska is electrically interconnected to numerous investor-owned and consumer-owned utilities, and regularly trades wholesale electricity with these utilities as well as other energy service providers for reliability and economic purposes.

Nebraska needs to be aware of the successes and failures of customer choice programs in other states, and congressional and regulatory activities at the federal level. Although the "Condition Certain" approach to customer choice being followed in Nebraska is more conservative than the approach being taken in other states, it should enable Nebraska to move towards customer choice in a more orderly manner with reasonable assurance of success, when, and if, the State believes that Nebraska's electric consumers will benefit.

In order for customer choice to be effective in Nebraska, it would not be adequate to only have a viable regional transmission organization and adequate transmission in Nebraska or in a region that includes Nebraska, only a viable wholesale electricity market in a region that includes Nebraska, or only wholesale electricity prices in the region comparable to Nebraska prices. For an effective customer choice program, all three of these conditions must be favorable.

This 2004 report is the fourth report following up on the five "Condition Certain" issues identified in LB 901 (2000) .

## EXECUTIVE SUMMARY

The five 'Condition Certain' issues identified in LB 901(2000) were assigned to five separate Technical Groups. The Executive Summary that follows includes the new findings and conclusions that are incorporated in the 2004 Update, as well as the findings and conclusions from the prior years Reports.

### Issue #1 (Chapter 1)

**2004 REPORT UPDATE-**The development of Regional Transmission Organizations remains unsettled. Approximately half of the original Mid-Continent Area Power Pool (MAPP) members have joined the Midwest ISO, while the remaining MAPP members, who include the Nebraska utilities, other than the Lincoln Electric System, most of the Dakotas, and parts of Iowa and Minnesota, have chosen to remain as members of MAPP, and keep their transmission facilities under the MAPP regional tariff. MAPP members are now focusing their efforts on developing a seams operating agreement with the Midwest ISO, and investments to upgrade the MAPP software and hardware infrastructure to make the MAPP regional transmission tariff processes more compatible with other regional transmission tariffs, so that MAPP transmission customers will not be at a disadvantage when conducting interregional energy transactions. A seams agreement is needed to coordinate transmission service between the MAPP and Midwest ISO transmission tariffs to ensure that both parties respect the transmission capacity limits on the others' system. This becomes particularly important as the Midwest ISO prepares to implement energy markets, which will use an entirely new method of operating the electric system in the Midwest, known as least cost security constrained economic dispatch. Unless proper procedures can be agreed upon through the seams agreement, MAPP members may find their ability to conduct regional wholesale energy transactions adversely affected by this new method employed by the Midwest ISO. In August 2004, The Federal Energy Regulatory Commission (FERC) issued an Order conditionally approving the Midwest ISO Transmission and Energy Market Tariff. In that order, FERC requires the Midwest ISO to execute seams agreements with the regional transmission entities that surround the Midwest ISO. The Midwest ISO received FERC approval to start its Day-Ahead and Real Time Energy Markets in March 2005. MAPP will also need to develop a seams agreement with the Southwest Power Pool that received conditional approval to become an RTO in February 2004.

As a result of the August 2003 blackout, there has been a renewed focus on reliability and many changes have been, or will be, implemented in the reliability requirements that must be met by the entities involved in the operation of the electric system. The North American Electric Reliability Council is leading the effort to convert its operating policies into standards by January 2005.

The TRANSLink project was officially terminated in November 2003.

As concluded in previous years' reports, the development of an RTO that is both economically and operationally viable for Nebraska remains very much a work in progress. Tremendous uncertainty remains as to whether the energy markets being developed by the Midwest ISO or SPP would provide economic benefits, or result in increased costs to customers in Nebraska. An answer to this question will not likely be determined with any degree of certainty until after the markets start and actual market experience is obtained. Nebraska's utilities continue to plan and upgrade their transmission systems so that there is adequate transmission in Nebraska to meet customer needs. However, there is not adequate regional transmission capacity to support all of the desired regional wholesale energy transactions.

**SUMMARY OF 2003 REPORT** -The August 14, 2003 blackout, the most wide-ranging in U. S. electric history, will cause a significant review of the nation's transmission infrastructure and the organizational entities controlling it. Congressional hearings have been scheduled and a joint U. S. and Canadian Task Force has been appointed to investigate the blackout. Many are calling for passage of the long debated federal energy legislation. How this will impact the continued development of Regional Transmission Organizations (RTOs) remains to be seen. The Midwest ISO has indicated that it will be reevaluating the timing for the start-up of its energy markets, and will make a recommendation to its Board of Directors in September. Progress on the development of TRANSLink has been slowed due to the lack of state

regulatory commission approvals, and as a result the TRANSLink participants are reevaluating their options for continued development of TRANSLink. In light of the pending investigations of the blackout, and uncertainty about federal legislation which may be enacted, it seems prudent for Nebraska utilities to wait until such time as more is known so they can make an informed decision before proceeding to join a RTO. At this time there is not a RTO that has been shown to be economically, technically and operationally viable. There is adequate transmission capacity in Nebraska to deliver the generation output of plants in Nebraska to the Nebraska customer load, but there is not sufficient capacity to support all of the wholesale power transactions that are requested in the region.

**SUMMARY OF 2002 REPORT** -There have been numerous filings at FERC proposing RTO's since Order 2000 was issued. While conditional approval has been granted to several proposals, FERC has only given full approval to the Midwest RTO (MISO). MISO was approved in December 2001 and the MISO tariff went into effect in February 2002. The geographic size of MISO continued to grow as new members have joined. The Southwest Power Pool (SPP) has agreed to merge with MISO and the SPP transmission system should be integrated into the MISO transmission tariff by late 2002. It can be said that MISO is viable from a legal, financial, and operational viewpoint, but it is still in the early stages of operation and has many issues to resolve before it can perform all of its functions and duties satisfactorily. Other considerations in determining whether MISO is viable to participate in are dependent on the legal aspects of a participation agreement with MISO to recognize Nebraska state law restrictions, MISO's costs to participate, and the impact on the utilities' transmission revenue due to the MISO transmission tariff. The MAPP/MISO merger has been completed and some of the MAPP members have joined MISO. One of the conditions of the merger was that MISO would continue to provide transmission services for six years to MAPP members that do not join MISO. Certain transmission facilities in western Nebraska would need to participate in a RTO in the western interconnection because those facilities are not electrically connected to the rest of the state.

Since RTO's have not developed as envisioned in Order 2000, FERC took another step to further the development of competitive wholesale electric markets when it issued another Notice of Proposed Rulemaking on July 31, 2002, which is known as FERC's Standard Market Design (SMD). This Order proposes sweeping changes to the development of wholesale electric markets. The Order will not go into effect for many months, until FERC has considered comments submitted by all interested industry participants. Nebraska utilities will need to thoroughly evaluate the economic and legal impacts of this Order as many of the requirements will be implemented by the RTO. The reader is referred to page I-8 for a full listing of items proposed by FERC in the SMD rulemaking. The development of competitive wholesale electric markets continues to be a moving target. Just as utilities think they understand the rules FERC has set forth, FERC pushes the industry in a new direction. Until the FERC rules stabilize, it will be difficult to assess the economic impacts of RTO participation with any degree of certainty.

FERC issued an order in April 2002 accepting certain aspects of the TRANSLink filing and requiring changes to other parts. Since then a TRANSLink Development Company, LLC has been formed and it is expected additional FERC filings will be made in September 2002. In the TRANSLink ITC proposal NPPD and OPPD will no longer be control area operators. They will continue to balance generation and load within their area, but TRANSLink will operate one control area for the MAPP member's facilities. NPPD and OPPD will retain operational control under certain emergency conditions. In the TRANSLink Order, FERC ruled that TRANSLink cannot have its own transmission tariff, but can have its own rate design under a MISO rate schedule.

In the last year a number of new generation resources have been announced by Nebraska utilities. In each case a transmission adequacy study must be completed and approved by MAPP. Thus far all new generation additions have been able to be accommodated without significant transmission additions. This reinforces the conclusion that adequate transmission exists in Nebraska to deliver the generation resources located in Nebraska-to-Nebraska customers. However, the ability to export generation located in Nebraska for off-system sales, or to purchase generation outside of Nebraska for delivery into Nebraska will be dependent on several factors. In general, it is fair to say that the adequacy of the regional transmission system to accommodate these types of transactions is limited.



**SUMMARY OF 2001 REPORT**-The issue addressed by this Technical Group was “whether or not a viable regional transmission organization and adequate transmission exist in Nebraska or in a region that includes Nebraska”. The development of Regional Transmission Organizations (RTOs) has been underway since the Federal Energy Regulatory Commission (FERC) issued Order No. 2000 in December 1999. FERC stated that RTOs would promote competition in the wholesale electric market, enhance reliability, and remove any remaining opportunities for discriminatory practices by transmission owning utilities. In that Order FERC called for all transmission owning utilities to work towards the voluntary formation of RTOs in collaboration with state regulators, transmission dependent utilities, and other market participants.

However, in a series of orders issued on July 12, 2001 FERC reversed its course and now suggests that only four RTOs should be formed, one in the Northeast, Southeast, Midwest and West. This change in direction by FERC has caused considerable confusion in the industry. As a result, this Issue is in a state of flux. At this juncture the only organization that has the potential to become a viable RTO for Nebraska utilities to participate in is the Midwest ISO (MISO), assuming FERC decides that MISO is to become the Midwest RTO it envisions. This report will serve to identify key issues that could significantly affect the way the electric transmission system in Nebraska is planned, operated and priced.

The Nebraska transmission system is adequate to serve Nebraska customers when system conditions are normal. However, under abnormal system conditions, such as the loss of major transmission lines or a large generation plant, Nebraska customers depend on the interconnected utilities in surrounding states and the generation reserve sharing pool to maintain reliability. Nebraska utilities contribute to the reliability of the region in a reciprocal manner. The Nebraska system does experience significant usage due to the wholesale transactions occurring in the region. Reliability is maintained by setting limits on the constrained interfaces and curtailing transactions when system conditions approach those limits.

Because the wholesale market has become regional in nature, it requires regional solutions to fix the constrained interfaces. Additional high voltage transmission lines will need to be built that cross several utilities service areas in order to accommodate much more wholesale activity than what currently exists. Several transmission projects have been identified to relieve the transmission constraints, but until the projects can be funded and paid for by a regional transmission tariff, utilities will be unlikely to build new transmission.

## **Issue #2 (Chapter 2)**

**Summary of 2004 Report**-The new information gathered for this year’s analysis is sending mixed and ambiguous signals regarding market power in the Midwest portion of the Eastern Interconnect. On one hand, “traditional” tests of market power used by FERC suggest that this market has a large number of buyers and sellers and appears to be viable. A defined process for accessing wholesale transmission is available through MAPP, utilizing Schedule F for a period of up to 12 months, or by utilizing Midwest Independent System Operator (MISO) or individual transmission provider’s tariff for durations ranging from hourly service to multi-year service. In short, the wholesale market appears to be reasonably efficient and workable, supporting many useful trades each day. On the other hand, the Midwest wholesale market, at times, has limited access to reliable transmission for delivery, conditions that are conducive to the exercise of market power. The MISO State of the Market Report shows that while this has not led to widespread exercise of market power, the potential clearly exists. This is evidenced by the large number of Transmission Loading Relief’s (TLR) in the area, the existence of pivotal suppliers and the anecdotal evidence that many transmission requests are not attempted because of the likelihood that they would be rejected. Furthermore, the newly approved FERC market power tests suggest most of the utilities in the region would be found to have market power, at least until all are members of an RTO that has centralized dispatch, a formal power market and established market power mitigation measures, a status not yet attained by MISO. The final conclusion is that a reasonably efficient and workable wholesale market does exist in the Midwest region, but it cannot be judged as being free from market power given the new FERC rules.

There have been disruptions in Western wholesale power markets in recent years. In spite of these disruptions, energy deliveries have been maintained to customers in Nebraska located on the Western Interconnection. These customers are primarily served by MEAN and Tri-State.

The viability of the wholesale market has been hampered in recent years by transmission constraints, adverse hydro conditions, and lack of a viable regional transmission organization. Unless these conditions are addressed, it is unlikely that a viable wholesale market will exist on the Western Interconnection in the foreseeable future.

**SUMMARY OF 2003 REPORT** -In the past, Technical Group #2 conducted FERC's standard test of market viability using public domain data. Two factors have changed that approach. First, the data used for conducting this analysis is no longer available to the Group. Second, FERC has proposed that Regional Transmission Organizations (RTO) assume the responsibility of testing for market viability in the regions they serve. Conducting annual market viability tests is one of those responsibilities. The Midwest Independent System Operator (MISO) is the approved RTO for the Midwest region that includes the Eastern Interconnection of Nebraska. In May 2003 MISO issued their first "State of the Market Report". This analysis includes all the current and prospective utility members of MISO. Therefore the major transmission owning utilities in Nebraska are included. Since the MISO report is the definitive analysis for "whether or not a viable electricity market exists for the region which includes Nebraska", it is the primary source for this report. The reader is referred to Chapter 2, Section 6.0 for a full discussion of the information included in the first MISO "State of the Market Report".

The standard test for market power is called the "Hub and Spoke" test. It has been the basis for this report for the last two years. The "Hub and Spoke" test conducted by MISO for the MAPP region in 2003 produced results that are very similar to the results produced by Technical Group #2 for a similar region in 2001 and 2002. The MISO analysis confirms the previous year's conclusions that the MAPP area of MISO has an unconcentrated market and is relatively free of market power.

As wholesale electric markets matured and market power became a prevalent issue, FERC acknowledged that the "Hub and Spoke" test alone was not sufficient to detect all market power. Notably, FERC recognized the effect of transmission constraints on the exercise of market power. The latest evolutionary cycle of market power testing and mitigation is defined in the "Standard Market Design" (SMD) Notice of Proposed Rulemaking. SMD proposes that RTO's assume the function of Market Monitoring and Market Power Mitigation. The RTO will be required to periodically report on the status of market power in their region. The assumption is that RTO's are uniquely qualified to assess market power in the region they serve. RTO's are independent. They will run the regional spot market and operate the transmission system, and therefore will have all the operational data required to run the appropriate tests. RTO's will also have the transmission and market models, the budget and the expertise to conduct market power analysis. The reader is referred to Chapter 2, Section 4.0 for a full discussion of the new FERC methods for assessing market power.

The Eastern Interconnect wholesale market appears to be viable in that it has a large number of buyers and sellers. However, at times, it has limited access to reliable transmission to either deliver into Nebraska or export from Nebraska generation, depending on system loading conditions. There have disruptions in the Western wholesale power markets in recent years. In spite of these disruptions, energy deliveries have been maintained to customers in Nebraska located on the Western Interconnection. The viability of the wholesale market in the Western Interconnect has been hampered in recent years by transmission constraints, adverse hydro conditions, and lack of a viable regional transmission organization. Unless these conditions are addressed, it is unlikely that a viable wholesale market will exist on the Western Interconnect in the foreseeable future.

**SUMMARY OF 2002 REPORT** -FERC's methodology for assessing market power has been evolving. Notably, FERC has taken steps to recognize the effect of transmission constraints on the exercise of market power. Initially, FERC began using variations to the traditional hub and spoke analysis that compensated

for transmission constraints. This evolution culminated in a new FERC order issued on November 20, 2001 entitled "ORDER ON TRIENNIAL MARKET POWER UPDATES AND ANNOUNCING NEW INTERIM GENERATION MARKET POWER SCREEN AND MITIGATION POLICY". The order introduced a new test for market power called the "Supply Margin Assessment" which laid out mitigation measures for companies failing the test and found a number of companies not in compliance with the order.

This Group used the same definition of a viable market that was used for the 2001 Report. The Group considered an alternative market region that was basically a footprint of the proposed Midwest Independent System Operator (MISO). However, it was decided to use the same market region that was used for the 2001 Report since MISO has not yet been completely formed, nor are all of the protocols and rules completely developed. As a result, Nebraska utilities and MISO do not currently function as a single market and may not do so for the foreseeable future.

It was concluded that the Eastern Interconnect appears to be a viable market in that it has a large number of buyers and sellers. However, at times it has limited access to reliable transmission to either deliver into Nebraska loads or export from Nebraska generation, depending on system loading conditions. The presumption that the region will be served by MISO, which will migrate to a standard transmission tariff, manage congestion and monitor the members for market power, suggests that this viability will be maintained in the future.

If one applies the FERC logic, Condition # 1, "Whether or not a viable regional transmission organization and adequate transmission exist in Nebraska or in a region that includes Nebraska", and Condition # 2, "Whether or not a viable wholesale electricity market exists in a region that includes Nebraska", merge into one. In other words, if Condition # 1 is satisfied, Condition # 2 by definition, will also be satisfied. If the TRANSLink ITC is accepted by FERC as part of the MISO, then the portion of Nebraska included in the Eastern Interconnect will be part of one RTO. By FERC's definition, this entire region, which includes the majority of Nebraska, will therefore be free of market power.

There continue to be significant capacity short falls and transmission interconnect problems that have caused a substantial lack of continuity to energy deliveries to loads in the Western Interconnect.

**SUMMARY OF 2001 REPORT**-This Technical Group dealt with the question "whether or not a viable wholesale electricity market exists in a region which includes Nebraska". The LR 455 Phase II report stated "that a viable wholesale market requires an operational regional 'market hub' through which transactions may take place. It requires sufficient buyers and sellers to make an active market. It requires clear and equitable trading rules. While judgment of what level of these requirements is sufficient may be considered subjective, viability should be reflected in stable or predictable pricing patterns".

Before moving toward retail competition, wholesale markets must be viable. The portion of a retail customer's bill that will be open to competition is the electric commodity (wholesale) portion. It is, therefore, important that the wholesale electric market be adequately established and be viable. The Group defined the term 'viable' using several alternate methodologies. Next the size of the region was determined. Since the Nebraska electric system is in two portions of the United States interconnected systems, the region for each (Eastern and Western) was determined.

The Eastern Interconnect wholesale market appears to be viable in that it has an adequate number of buyers and sellers. However, at times it has limited access to reliable transmission facilities to either deliver electricity to Nebraska loads or export electricity generated in Nebraska to surrounding states, depending on the demands on the transmission system. Since Nebraska's electricity supply is cost-based and consumer owned, there is considerably less volatility than that of the regional indices, which are based on the hourly, daily and monthly wholesale spot market. There are considerable capacity shortfalls and transmission interconnect problems that have caused significant lack of continuity to energy deliveries to loads in the Western Interconnect. There could be significant economic implications to Nebraska utilities if large coal-fired generation are unavailable, de-rated or off-line to Western Nebraska utility members, which includes

primarily MEAN which serves most of the municipalities in western Nebraska, and Tri-State G&T in Westminster, Colorado which serves all of the rural electric utilities in the panhandle of Nebraska.

### **ISSUE # 3 (Chapter 3)**

**2004 REPORT UPDATE**-There were no new developments regarding unbundling of retail rates in Nebraska in 2004. Technical Group # 3 did conduct another survey of Nebraska's utilities in 2004 to obtain the current status of information gathered from a survey several years ago. Surveys were sent to 165 retail electric utilities. A response rate of 97.6% (161 utilities) produced the following results.

- One utility has formally unbundled their retail rates.
- Over half (78%) of the utilities did not have unbundled cost of service studies.
- Less than half (40%) of the utilities' billing systems will accommodate unbundling.
- Only 50% of the utilities believe they have enough information to unbundle.

These results are almost identical to the 2001 survey results.

**SUMMARY OF 2003 REPORT** -There were no new developments in 2003 for Technical Group #3 to address.

**SUMMARY OF 2002 REPORT** -For this year's report, this Technical Group was requested to estimate the cost that would be incurred if retail electric bills were to be unbundled in Nebraska. The cost associated with moving to retail competition is hard to estimate because of the different issues and concerns to be addressed. Unbundling of retail bills is but one small part of the entire deregulation process and can be impacted by the unique requirements that each state imposes on the process. In the 2002 report, this Group presents information regarding the estimated costs for unbundling bills in Nebraska for informational purposes only. It is not intended to estimate the total cost of deregulation.

The consumer-owned utilities in Nebraska were contacted to obtain their estimated costs of unbundling based on guidelines provided by the Technical Group. In addition, using information obtained from other states, a component for consumer education was derived and applied uniformly on a per customer basis to all of the utilities. Information from the utilities was aggregated to obtain a total cost for the State of Nebraska.

The expenses were identified in three categories. The total one-time Set-Up Expenses are estimated to be approximately \$7 million, the Annual On-Going Expenses are estimated to be approximately \$1 million, and the State-Wide Consumer Education Expenses are estimated at approximately \$1.2 million. These are preliminary estimates for informational purposes only and should not be relied on as the costs to unbundle retail electric bills in Nebraska if deregulation of the State's electric utility industry were to occur.

**SUMMARY OF 2001 REPORT**-This Technical Group was charged with determining "to what extent retail rates have been unbundled in Nebraska". To do this, the Group surveyed 162 municipal, rural electric cooperative, federal, state, and district electric utilities. The survey results showed that, except for one case, retail electric rates in Nebraska are not unbundled. The majority of electric utilities in Nebraska do not have unbundled cost of service studies, although half of all electric utilities surveyed believe they have enough information to unbundle their rates. The survey also disclosed that only half of the utilities' billing systems would handle unbundling. Seventy percent of the utilities stated they would not unbundle their electric rates unless mandated.

There are many issues that are involved in unbundling retail electric rates. These issues will require resolution by the utilities or the state legislature in order to implement unbundling. Issues such as upgrading of billing systems and educating customers will involve significant time and expense. Discussion of these issues is contained in this report. The results of the survey, sample bills from other out-of-state utilities, and a summary table of unbundling activity nation-wide are included in the appendixes.

#### **Issue #4 (Chapter 4)**

**2004 REPORT UPDATE-**This Technical Group was assigned the task of making “a comparison of Nebraska’s wholesale electricity prices to the prices in the region”. The same fixed and variable cost allocation tool used in prior year comparisons was utilized for the 2004 comparisons. The results of this years comparisons between the market product indices and the Nebraska production costs show that Nebraska production costs are approximately 21% lower than the equivalent wholesale “median” market price based on the period 2001-2004 (three years actual and one year estimated) and weighted based on MWH. These results are slightly better than the 18% results for the prior period 2000-2003, due mostly to the upward trend of market prices driven by higher natural gas prices. Nebraska utilities do not have as high of concentration of natural gas-fired units when compared to the entire electric industry. The “median” market price comparison compares favorably with rate comparisons. The Energy Information Administration annually compiles data from the Form EIA-861 for approximately 3,300 public and investor-owned electric utilities including active power marketers and other energy service providers. The most current data for 2002 shows that Nebraska’s average retail rate of 5.55 cents/kWh is approximately 23 % lower than the national average retail rate of 7.21 cents/kWh.

The calculated volatility is about the same for Nebraska production and the market. In the past, Nebraska production volatility was lower than the market. Nebraska production volatility is slightly higher than the past, but the market volatility has decreased. There are three possible reasons the market volatility is lower than in previous years: 1) maturing of the market and better risk management practices, 2) the higher natural gas market driving all months prices higher and closer to one another, and 3) the present overbuilt capacity market in the Eastern Interconnect has reduced the capacity premium paid by the market in the summer, causing the monthly market costs in July and August to be closer to the other months. Reasons the Nebraska production costs have been rising include: 1) when Nebraska utilities baseloaded units are off-line, the utilities need to use higher variable cost units, and due to the rise in natural gas prices, there is a larger gap between the variable costs of a coal or nuclear unit vs. a natural gas unit, and 2) no new low variable cost baseloaded units have come on line within the last few years, thus new native load is more likely to be served from the higher variable cost units.

**SUMMARY OF 2003 REPORT -**Technical Group # 4 utilized the same fixed and variable cost allocation tool in 2003 that was used in the prior two reports. The results of this year’s comparisons between the market product indices and the Nebraska production costs show that Nebraska production costs are approximately 18% lower than the equivalent wholesale “median” market price based on the period 2000-2003 (three years actual and one year estimated) and weighted based on MWH. These results are slightly better than the 15% results for the prior period 1999-2002 due primarily to the upward trend of market prices driven by higher natural gas prices and stable generation. The price volatility associated with Nebraska production costs remains stable compared to market price, providing a fairly consistent, less volatile, cost expectation for Nebraska’s ratepayers. The “median” market prices compare favorably with retail rate comparisons. The Energy Information Administration (EIA) annually compiles data from Form EIA-861 for approximately 3,300 public and investor-owned electric utilities including active power marketers and other energy service providers. The most current data for 2001 shows that Nebraska’s average retail rate of 5.39 cents/kWh is approximately 26 % below the national average of 7.32 cents/kWh.

The Nebraska power system product is based on a long-term “obligation to serve” that is not inherent in market-based electricity products. Typically, there is a thirty to forty year obligation stemming from the commitment to build various physical generation unit types to provide stability in power resources that is derived from having “iron in the ground”, and limited dependence on the market. This translates to a long-term commitment to providing physical resources that meet or exceed Nebraska’s power systems “obligation to serve”. A market-based electricity product provider does not share this same responsibility, hence, there is downward pressure on the price for the market-based electricity product as compared to local providers. This actual value is difficult to quantify since this is a subjective criteria that may be different for each customer depending on individual risk tolerance for price changes. Four different analytical approaches were developed and modeled to establish the value of the long-term “obligation to serve”. The results of the four different analyses indicate that it appears reasonable that the value of the

long-term obligation to serve is in the \$3-\$5/MWH range for a 5X16 peaking type product. These results are presented for subjective consideration only, and are not specifically accounted for in the 2000-2003 Nebraska production cost comparison to market pricing.

**SUMMARY OF 2002 REPORT** - Although there are other cost allocation issues that could be considered for equitable comparison purposes, the modeling tool that was initially developed last year was updated and enhanced in 2002 to include user options to incorporate transmission cost adders that reflect the additional cost of actually delivering a market product to the Nebraska system (both losses & tariffs). Although this flexibility is built into the modeling tool, this year's overall comparison results are based on these values being set to zero so that an equitable comparison to last year's results can be made and any market bias perception is eliminated. A model user option to include an "obligation to serve" value was also incorporated, but, again, this option was set to zero for the same reasons described above. Additional model flexibility and information detail was incorporated to allow users to determine the effect of allocating fixed costs when the market price would allow higher price signals, even in winter months. This is for informational purpose only, and strictly impacts the market price weighted results, so the MWH-weighted results, considered the bottom-line comparison values, are not affected. Also, in order to compare various generation resource types, (baseload, intermediate & peaking) the model is enhanced to provide informational detail and comparisons on multiple physical resources as opposed to only an intermediate-type unit.

The results of this year's comparisons between the market price indices and the Nebraska production costs show that Nebraska production costs are approximately 15% lower than the equivalent wholesale "median" market price based on the period 1999-2002 (three years actual and one year estimated) and weighted based on MHW. The results for the 1999-2002 study period are slightly lower than the results for the previous period, 1998-2001, due mostly to the downward trend of market prices driven by lower natural gas prices and increased generation, as well as a slight increase in Nebraska production costs. However, the price volatility associated with Nebraska production costs remains stable compared to market price, providing a fairly consistent, less volatile, cost expectation for Nebraska's ratepayers.

The "median" market prices compare favorably with retail rate comparisons. The Energy Information Administration (EIA) annually compiles data from Form EIA-861 for approximately 3,300 public and investor-owned electric utilities including active power marketers and other energy service providers. The most current data for 2000 shows that Nebraska's average retail rate of 5.31 cents/kWh is approximately 22% lower than the national average retail rate of 6.78 cents/kWh.

**SUMMARY OF 2001 REPORT**--The task assigned to this Technical Group was to make "a comparison of Nebraska's wholesale electricity prices to the prices in the region". There are no directly comparable electric price indices available for the electricity product currently provided to and expected by Nebraska customers. The Nebraska product is a firm, total requirements product, available 24 hours per day, seven days a week in quantities that usually vary hourly, weekly, monthly, seasonally and annually based on individual customer needs. This obligation to serve includes both existing and new customers. The typical index provides a price for a fixed hourly quantity of energy, possibly with a premium for financial firmness, but with no obligations on the part of the seller beyond the current month or in the case of daily indices, beyond that day. The forward market does not have a published product that goes beyond an 18 to 24 month period. To make a price comparison using these available market product indices required the conversion of Nebraska's electricity prices to the market product indices.

There are several methods of approaching a fair and equitable comparison. As outlined in the report, the development of a fixed and variable cost allocation tool was deemed to be the best approach for modeling Nebraska's costs to the price indices that are publicly available, independent and credible.

The results of the comparisons between the market product indices and the Nebraska production costs show that Nebraska production costs are approximately 18% lower than the equivalent wholesale "median" market price based on the period 1998-2001 (three years actual and one year estimated) and weighted based

on MWH. The “median” market prices compares favorably with retail rate comparisons. The Energy Information Administration (EIA) annually compiles data from Form EIA-861 for approximately 3,300 public and investor-owned electric utilities including active power marketers and other energy service providers. The most current data for 1999 shows that Nebraska’s average retail rate of 5.31 cents/kwh is approximately 20% lower than the national average retail rate of 6.61 cents/kwh.

## **Issue #5 (Chapter 5)**

**2004 REPORT UPDATE-**Little has changed in the development of retail choice around the nation in the past year. Most state retail choice programs are either struggling or inactive. A recent press release from the State Corporation Commission of Virginia noted, “that the electricity supply industry continues to struggle following price run-ups, disclosures of accounting and dated improprieties, credit worthiness issues and volatile fuel prices, particularly natural gas”. The release concludes “that Virginia is not the exception when it comes to the lack of competitive activity for electricity service. In other states with retail choice, energy markets are generally inactive with few customers able to purchase power at a price lower than their traditional utility company”.

Texas continues to receive attention as the most successful retail choice state. It is important to note that much of Texas is operated as a separate electrical interconnection. This limits and confines the size of the restructured area and restricts the impact of wholesale energy deliveries from potentially lower cost resources. When Texas initiated the retail choice program, the impacted region was operating with significant generation in reserve and significant new Independent Power Producer projects underway. In addition, retail rates were relatively high, in the 10cents/kWh range, compared to other regions of the country. With these conditions in place, Texas provided a prime opportunity to initiate retail choice. This is not to discount what has been accomplished in Texas, but it does confirm that for retail choice to be successful, the appropriate preconditions need to be in place. Positive results have occurred in Texas, with residential participation in 2003 at 14%, and small industrial at 19%.

Driven in part by the electricity supply and reliability problems in the western United States, as well as the large blackout in the Northeast in August 2003, the focus of restructuring has been expanded to include energy supply and infrastructure concerns, as well as reliability. Legislation addressing regional transmission entities, eminent domain, transmission reliability standards, and other issues has been the focus of both Congress and the FERC. Infrastructure/pipelines for natural gas have not kept up with the growing demand for natural gas, which has become the most common fuel for generating facilities built in the last ten years.

Although there were renewed efforts to pass national energy legislation in 2004, it is highly unlikely national energy policy legislation will pass in 2004, and it is unknown whether Congress will push for passage of such legislation next year.

**SUMMARY OF 2003 REPORT** -Retail deregulation gained considerable popularity between the late 1990’s and January 2001 with 25 state legislatures or regulatory agencies committing to various forms of retail customer choice. This trend reversed considerably by June 2003 when only 18 states and the District of Columbia were pursuing such action and some of these states have retail choice on only a very limited basis. Five other states have suspended or repealed retail choice, while retail choice is not being pursued in the remaining 27 states.

In 2003, Arkansas repealed retail choice with the caveat that their PUC would study the possibility of retail choice for the largest power users. New Mexico also repealed retail choice in 2003, while in Oregon, retail choice has commenced for non-residential customers only. In late 2002, Arizona eliminated a key provision of their deregulation plan that would have required two of the state’s large investor-owned utilities to move their power plants into a separate subsidiary or sell them to another unrelated company.

By June 2003 new developments were emerging in California's efforts to restore stability to its electricity markets. Pacific Gas & Electric reached a tentative settlement with the PUC on a plan to allow the company to emerge from bankruptcy. Also in June 2003, the California Legislature was working on a proposal to dismantle the state's retail choice law and return to traditional rate regulation. The Legislature is experiencing difficulty in writing the new law in the face of opposition from consumer, business and utility interests. The legal effort to recoup nearly \$12 billion in energy costs under contracts signed during the height of the 2000-2001 wholesale power crisis was set back when FERC voted to uphold the contracts despite massive evidence of market manipulation during the time frame which they were entered into.

In Montana, the PUC approved guidelines for NorthWestern Energy to follow as the company procures electricity on behalf of its 290,000 mostly residential and small business customers who have not chosen an alternative supplier. In its role as default supplier, NorthWestern must assemble a portfolio of supply contracts to provide electricity to these retail customers, and can recover its prudently incurred costs for that service.

Pennsylvania has seen deterioration in retail choice over the last three years as measured by the energy sold to all customers and industrial customers by competitive suppliers.

Some customer switching has occurred in New York, although the numbers are but a fraction of those that are eligible.

Although retail choice has technically been in effect in Connecticut since July 2000, the concept remains more theory than reality as most suppliers have shown little interest in the Connecticut market. In January 2003 Green Mountain Energy Co. pulled out of the Connecticut market after less than a year of doing business in the state.

In Maine there has been some progression of the percentage of load served by competitive suppliers but mostly to customers with attractive load profiles. There is virtually no competition in the residential or commercial markets.

In Massachusetts retail choice accounts for about 15% of all energy sold, with the majority being sold to the largest customers. There has been some minimal success in marketing to residential customers via a municipal aggregation program in the Cape Cod region of the state.

Some analysts of the New England electricity markets are now raising flags of caution on the region's increasing reliance on natural gas as the fuel choice for new generating facilities. The region's fuel diversity is now undergoing substantial revision due to environmental concerns and the cost of construction associated with coal and nuclear construction. According to a 2003 report of the Associated Industries of Massachusetts, "New England's reliance on natural gas to fuel all new plants has raised concerns that new plants may cause existing natural gas pipeline capacity to be approached or exceeded within a few years. In addition, up to 75% of the new power plants being built or currently in operation are located on just two of the region's five major pipelines. As a result, the security of the gas grid is becoming increasingly important to the reliability of the electric grid."

In a May 2003 report the Ohio PUC indicated that most of the success of retail choice in Ohio is a result of the customer aggregation provisions of the retail choice law.

In Illinois, there was a small increase in the number of customers participating in retail choice. However, of the 15 alternative energy suppliers certified by the state, none have requested certification to serve residential customers

In a January 2003 report, the Texas PUC detailed the status and progress of retail competition after one full year of implementation. The PUC estimates that retail customers have saved over \$1.5 billion in electricity costs during the first year, and low-income customers have received almost \$70 million in discounts through the System Benefit Fund through October 2002. In all areas open to competition, there are multiple retail electric providers, with as many as ten offering residential service in some areas. The PUC indicated



that the competitive market is small but growing. There have been some problems in the Texas market. New Power was one of the more aggressive marketers in Texas. After signing up 78,000 customers, it filed for bankruptcy in June 2002. Technical problems have delayed bills and blocked some switching requests. A far more serious problem emerged in March 2003 when a surge in wholesale power prices indicated evidence of market manipulation, prompting a Texas PUC official to state that some regulation of the merchant energy business may be needed.

Arkansas has been through a series of legislative actions dealing with retail choice since 1999, the latest of which was in early 2003 to repeal the retail choice in Arkansas.

Driven in large part by the electricity supply and reliability problems in the western United States, the issues of restructuring have now been expanded to include energy supply and infrastructure concerns. Transmission across the United States is frequently inadequate to support retail deregulation. Legislation addressing regional transmission entities, eminent domain, transmission reliability standards, and other issues has been the focus of both Congress and the FERC. Infrastructure/pipelines for natural gas supply have not kept up growing demand for natural gas which has become the most common fuel for generating facilities built in the last ten years.

**SUMMARY OF 2002 REPORT** -On March 21, 2002 the California PUC took the long anticipated step of suspending the direct access program effective back to September 20, 2001. The order announced a remarkable shift in philosophy on the part of the PUC that has long championed the merits of customer choice and market efficiency. In February 2002, the California PUC filed a complaint with the FERC against certain sellers of long-term power contracts to the state alleging that a significant number of wholesale power contracts entered into by the state were at prices some \$21 billion in excess of what could be considered “just and reasonable” and that the state was forced to procure enormous amounts of electricity under conditions of extreme market power. Recent disclosures in the Enron bankruptcy matter have given new ammunition to California’s claim.

In Montana very few residential customers have selected a competitive supplier and no competitive suppliers are currently marketing to them. Montana Power Company faded into history when it’s electricity assets were purchased by NorthWestern Energy Company based in South Dakota.

Although Pennsylvania is often cited as the one state where retail competition exists in a meaningful way, there are fewer customers switched today than there were three years ago. Both the energy sold by competitive suppliers to all customers and the quantity of energy sold by competitive suppliers to industrial customers is considerably below that of three years ago.

In Illinois, residential customers were given the retail choice option as of May 1, 2002. The Illinois Commission continues to find signs of retail electric market growth in the service territories of the three largest utilities in the state, but customer switching is still negligible or non-existent in the service territories of the state’s smaller utilities. The Commission explained in it’s 2001 report that growth in the retail market is dependent on the competitiveness of the wholesale market, but there are indications that the wholesale market is not yet capable of supporting a competitive retail market.

In February 2002, Vermont halted its investigation into retail competition stating that significant changes and uncertainty in the wholesale market for electricity make conditions inappropriate for the implementation of retail choice for several years.

In November 2001, a Florida Study Commission issued a final report calling for the State of Florida to transition to a competitive wholesale market. However, the Commission recommended that the retail electric market remain regulated.

The Louisiana Public Service Commission issued an order in December 2001, which reaffirmed their earlier conclusion that retail competition in Louisiana, which is a low cost state, would not be in the public interest for any class of retail customer.

In December 2001, the Arkansas PUC provided a report to the legislature recommending either a repeal of the Electric Consumer Choice Act of 1999, or a delay in the start of retail competition until 2012. The Commission estimated that retail competition could result in rate hikes of up to 13%. The legislature will consider this recommendation when it next meets in 2003.

The jury is still out on the State of Texas Electrical Deregulation. After a brief pilot program last summer to test the waters, nearly all the State of Texas was deregulated on January 1, 2002. Information on the number of customers that have switched is limited. In southeast Texas, deregulation of retail sales has been delayed to 2003 due to the lack of a regional transmission organization. Despite aggressive promotional campaigns, the average Texas consumer isn't convinced there is much value in switching providers, and interest is not much higher among commercial and industrial customers. Startup delays, lag in switching customers to new suppliers and computer problems have contributed to customer reluctance to switch providers. Texas Utilities recently announced that as many as 150,000 customers have gone without power bills for several months and many municipalities report hundreds of thousands in lost savings because of billing problems. The aftermath of the California troubles and the bankruptcy of Enron have cast a shadow over deregulation. Recent disclosures of trading irregularities at Dynegy and Reliant have also created further doubts in consumer's minds. Texas has plenty of power plants to supply power, and Texas incumbent utilities can raise rates twice a year when natural gas prices change, shielding them from bankruptcy when power prices skyrocket. Until the switching process is smoothed out, consumers will continue to resist deregulation as they see no positive value in changing providers.

At the Federal level, House Bill HR4 and Senate Bill S517 have both been passed and are now in conference. Whether compromise legislation can be agreed to should be known by October 2002. Depending on its final form, this legislation could dramatically impact the electric industry throughout the nation.

**SUMMARY OF 2001 REPORT**-This Technical Group was asked to assemble "any other information the board believes to be beneficial to the Governor, the Legislature, and Nebraska's citizens when considering whether retail electric competition would be beneficial, such as, but not limited to, an update on deregulation activities in other states and an update on federal deregulation activities".

Retail deregulation gained considerable popularity between the late 1990's and 2001 with 25 state legislatures or regulatory agencies committing to various forms of customer choice. However, developments during the summer of 2000 in California, Washington, Montana, New York and certain other states have created significant questions about the benefits of retail choice and have resulted in delays or repeals of retail choice in six states.

This section contains a brief summary of the status and implementation of retail competition in a variety of states. Some of these states have attempted a retail competition regime for a number of years while others are just now beginning to implement retail competition legislation. No state was found that had a vibrant competitive retail electricity market. The crisis in California affected all 11 states in the western grid. Volatile wholesale markets resulting, in part, from poorly implemented retail deregulation can have tremendous impacts in states that have formally rejected retail choice.

On the federal level, two national energy policy bills have been introduced in the Senate, but neither has been passed. In the House, national energy policy legislation (H.R. 4) was introduced on July 27, 2001 and was passed on August 2, 2001. The Bush Administration has released its recommendations for a national energy policy, but no action has taken place to date. FERC recently extended wholesale price controls over California's spot market as well as spot market sales in the entire 11 state Western System Coordinating Council area.

In July 2001, the FERC issued orders, the purpose of which is to create four regional transmission organizations. FERC's orders mandate action designed to create Southeast and Northeast RTO's. The orders do not require immediate action for the Midwest or West RTO's. FERC's ability to make that happen and how Nebraska's public power, cooperative and federal transmission facilities might be voluntarily integrated in the process remain as open questions.

## **Chapter 1**

**“Whether or not a viable regional transmission organization  
and adequate transmission exist in Nebraska or in a  
region that includes Nebraska.”**

## 1.0 Purpose

Technical Group #1 dealt with the question “whether or not a viable regional transmission organization and adequate transmission exist in Nebraska or in a region that includes Nebraska”.

## 2.0 Team Members

Paul Malone	Nebraska Public Power District
Dan Witt & Dan Dahlgren	Omaha Public Power District
Bill Leung	NMPP Energy
Bruce Merrill	Lincoln Electric System
Lloyd Linke	Western Area Power Administration

## 3.0 Summary

At this juncture, the development of Regional Transmission Organizations (RTOs) remains unsettled. While approximately ½ of the original Mid-Continent Area Power Pool (MAPP) members have joined the Midwest ISO, the remaining MAPP members, who include the Nebraska utilities, most of North and South Dakota, and parts of Iowa and Minnesota, have chosen to remain as members of MAPP, and keep their transmission facilities under the MAPP regional transmission tariff. MAPP members are now focusing their efforts on developing a seams operating agreement with the Midwest ISO, and investments to upgrade the MAPP software and hardware infrastructure to make the MAPP regional transmission tariff processes more compatible with other regional transmission tariffs, so that MAPP transmission customers will not be at a disadvantage when conducting interregional energy transactions. A seams agreement is needed to coordinate transmission service between the MAPP and Midwest ISO transmission tariffs to ensure that both parties respect the transmission capacity limits on the other’s system. This becomes particularly important as the Midwest ISO prepares to implement energy markets, which will use an entirely new method of operating the electric system in the Midwest, known as least cost security constrained economic dispatch. Unless proper procedures can be agreed upon through the seams agreement, MAPP members may find their ability to conduct regional wholesale energy transactions adversely affected by this new method employed by the Midwest ISO.

On August 6, 2004 the Federal Energy Regulatory Commission (FERC) issued an Order conditionally approving the Midwest ISO’s Transmission and Energy Market Tariff (TEMT). Among other things, the FERC Order requires the Midwest ISO to execute seams agreements with the regional transmission entities that surround the Midwest ISO. Although there are still many contentious issues to resolve, along with additional FERC filings and approvals required on various aspects of the markets, the Midwest ISO received FERC approval to start its Day-Ahead and Real-Time Energy Markets on March 1, 2005.

MAPP will also need to develop a seams agreement with the Southwest Power Pool (SPP), which is in the process of establishing an initial phase of an energy market that they plan to implement in the spring of 2005. SPP received conditional approval from the FERC in February 2004, to become a Regional Transmission Organization (RTO).

As a result of the investigation of the August 14, 2003 blackout, there has been a renewed focus on reliability and many changes have been, or will be, implemented in the reliability requirements that must be met by the entities involved in the operation of the electric system. The North American Electric Reliability Council (NERC) is leading the effort to convert its operating policies into standards by January 2005. The new standards will be monitored under compliance programs adopted by the Regional Reliability Councils.

The Midwest Reliability Organization (MRO) will replace MAPP as the NERC Regional Reliability Council (RRC) effective January 2005. The MRO was formed and a Board of Directors was seated early in 2004. The NERC Board approved the MRO in June. A transition process is underway to establish MRO committees and move the MAPP standards to the MRO. This will require further revisions to the MAPP Restated Agreement, which is the primary governing MAPP agreement, to remove all of the NERC Regional Reliability Council functions. When approved by the MAPP Members later this year, the MAPP agreement will then govern only the Regional Transmission Committee (RTC) functions and the Generation Reserve Sharing Pool (GRSP).

As concluded in previous years' reports, the development of a RTO that is both economically and operationally viable for Nebraska remains very much a work in progress. Tremendous uncertainty remains as to whether the energy markets being developed by the Midwest ISO or SPP would provide economic benefits, or result in increased costs to customers in Nebraska. Due to the major changes in the way regional wholesale energy business will be conducted in the new markets, compared to the present business procedures, and the incredible complexity of the new energy market processes, an answer to this question will not likely be determined with any degree of certainty until after the markets start and actual market experience is obtained. Thus, the Nebraska utilities, and the other remaining MAPP members have concluded the most prudent course of action is to maintain the MAPP regional transmission tariff and work diligently to develop seams agreements with neighboring RTOs.

Nebraska utilities continue to plan and upgrade their transmission systems so that there is adequate transmission in Nebraska to meet customers energy needs. However, there is not adequate regional transmission capacity to support all of the desired regional wholesale energy transactions.

## **4.0 MAPP**

The MAPP organization continues to undergo change to adapt to the member needs, industry changes, and the need to coordinate operations and business procedures with neighboring RTOs. The organization's governing document, the MAPP Restated Agreement, provides for a NERC RRC, RTC, and a GRSP. The Restated Agreement is again in the process of being revised to adapt to changes taking place.

### **4.1 MAPP RTC**

Based on a recommendation from the Midwest Energy Marketing Association, which is comprised of utilities and marketers conducting wholesale energy transactions in the MAPP region, the MAPP RTC voted affirmatively in June 2004 to extend the length of transmission service that a customer can request under the MAPP transmission tariff, known as Schedule F, from six months to one year. This will allow entities conducting wholesale energy transactions to better serve their customers by enabling them to arrange service on a yearly basis, rather than just a seasonal basis. In addition, the RTC approved the recommendations of a study group to invest up to \$4.5 million in improvements and upgrades to the software and hardware infrastructure to make the MAPP processes more compatible with the Midwest ISO and SPP processes. These changes will enable MAPP transmission customers to more easily conduct interregional energy transactions. A FERC filing has been submitted for approval and arrangements are being made for vendor modifications. It is expected these improvements should be completed by the spring of 2005. Funding for the investments will come through the Administrative Fee that is part of Schedule F service.

These changes are a distinct change in direction for the RTC. In October 2001 the RTC voted to reduce the duration for Schedule F service to six months and set a membership threshold for the termination of Schedule F. At that time it appeared that the preponderance of MAPP members would either join the Midwest ISO or TRANSLink, thus ending the viability of Schedule F as a regional transmission tariff. Since that time no enhancements have been made to the software and hardware infrastructure to keep it up to date. With the demise of TRANSLink and no further members joining the Midwest ISO, it is now clear that the Schedule F membership threshold will not be crossed anytime in the near future.

Although MAPP can remain a viable organization for some period of time, it is important to understand that MAPP is in some respects a shell organization because it owns almost no assets and has only a handful of employees. Under the 2001 merger agreement between MAPP and the Midwest ISO, the Midwest ISO acquired essentially all of the MAPP assets, and the MAPP staff was reduced to less than 20. The merger agreement obligated the Midwest ISO to maintain and staff the MAPP Center in St. Paul, Minnesota and provide transmission related services for six years to the MAPP members that do not join the Midwest ISO. That agreement will terminate in February 2008. Until then, the remaining MAPP members will be able to continue providing Schedule F transmission service, and have some additional time to evaluate the effectiveness and benefits of the Midwest ISO energy markets after the markets have been in operation, and explore other alternatives for participation in a RTO, such as SPP.

It is also important to note that MAPP is not a FERC approved RTO. It is a FERC approved Regional Transmission Group (RTG). The distinction between a RTO and a RTG involves the geographic scope and operational functions performed. A RTO has authority over short-term reliability functions, whereas a RTG does not. Basically, a RTG was a predecessor organization that FERC proposed when it issued Order 888 in 1996. Since that time the concept has evolved to the now current RTO. Thus, the options for the remaining MAPP members to participate in a RTO appear to be limited to joining the Midwest ISO or SPP. However, participation in a RTO is not mandatory. FERC never issued a final rulemaking on its proposed Standard Market Design, which would have mandated participation in a RTO for FERC jurisdictional utilities. However, FERC has no authority under the Federal Power Act to order public power utilities to join a RTO. New federal legislation would be required to give FERC that authority. If the remaining MAPP members determine that joining the Midwest ISO or SPP are not in the customers' best interest, they can maintain the RTG and Schedule F transmission service, and seek to continue a contract with the Midwest ISO, develop a contract with SPP, or some other organization, to provide transmission services.

A further complexity to the relationship between MAPP and the Midwest ISO is that the transmission services provided by the Midwest ISO consist of three basic parts: administration of Schedule F tariff service, administration of the MAPP GRSP, and NERC Reliability Coordinator services. The Midwest ISO must administer the Schedule F transmission service and GRSP functions in accordance with MAPP established procedures. However, the duties and functions performed by the Midwest ISO as the NERC Reliability Coordinator are established by NERC, not MAPP members.

The MAPP members that joined the Midwest ISO no longer have their transmission facilities under the MAPP Schedule F tariff, but they are still part of the GRSP. The MAPP members that did not join the Midwest ISO continue to have their transmission facilities under Schedule F and remain a part of the GRSP. However, all former and remaining MAPP members are under the authority of the Midwest ISO with respect to the reliability functions the Midwest ISO performs as the NERC Reliability Coordinator. There is only one NERC approved Reliability Plan, and all MAPP members are required to follow the directives of the Midwest ISO in responding to emergency conditions. In addition, the Midwest ISO is in the process of developing requirements for its members for generation supply adequacy, which will in all likelihood be different than the MAPP GRSP requirements.

Other MAPP RTC Subcommittees, including the transmission planning, transmission operations, schedules and compensation, and design review will continue to carryout their functions on behalf of the Members. In particular, regional planning and the evaluation of transmission adequacy to support new generation resources and long term transmission service requests continue to provide a valuable service to the members. MAPP will continue to develop a regional transmission plan that is updated every two years.

## **4.2 MAPP/Midwest ISO Seams Agreement**

Currently, there are procedures in place to coordinate transmission service between the Midwest ISO and MAPP Schedule F tariffs. However, when the Midwest ISO starts its energy markets in March 2005 they

will adopt totally new practices for approving wholesale energy transactions in the Midwest region. Managing this complex relationship between MAPP and the Midwest ISO requires an additional agreement to address seams issues between the MAPP Schedule F tariff and the Midwest ISO tariff, as well as distinguish between reliability issues, and tariff or market issues.

The core principle of the seams agreement between MAPP and the Midwest ISO is the Congestion Management Process (CMP). Basically, the CMP is a method to address the parallel flows that exist on the interconnected electric network. When either MAPP or the Midwest ISO approves transmission service under its respective transmission tariff, parallel flows are created on the other entity's system. The CMP is a method to account for the parallel flows and limit the approval of transmission service so that it does not cause transmission facilities on the other entity's system to exceed the transmission capacity limits. The CMP proposes to allocate, or divide up, the transmission capacity between MAPP and the Midwest ISO on facilities that have been established as constraints, otherwise referred to as flowgates.

It is not the intention in this report to go into all of the complexities of the CMP, or all of the other issues in the seams agreement. Suffice to say that there are contentious issues that need to be resolved so that when the Midwest ISO starts its energy markets, the MAPP Schedule F transmission customers are not adversely affected and at a disadvantage to Midwest ISO customers when conducting wholesale energy transactions. A seams committee comprised of MAPP members and Midwest ISO staff has been meeting over the last six months to try and resolve the issues. To date, agreement has not been reached, but progress is being made. The Midwest ISO is required to submit a FERC filing by October 6, 2004 reporting on the status of the seams efforts with MAPP. It is doubtful a full agreement will be reached by then, but both sides are committed to continuing to work on the issues. The "do nothing" option will result in negative impacts to MAPP members.

### **4.3 MAPP RRC**

In 2003 it was decided by the MAPP membership that the RRC should be an organization separate from MAPP, so as to provide independence and avoid potential conflicts of interest between reliability standards and wholesale market functions. Thus, the Midwest Reliability Organization (MRO) was formed to replace the MAPP RRC. In early 2004, a Board of Directors was elected, and in June, the NERC Board officially approved the MRO to replace the RRC. All previous members of the RRC have joined the MRO, as well as other utilities, and the Midwest ISO. The MRO will adopt NERC reliability standards that address both operating and planning issues, taking into account any needed regional variances, monitor compliance of members to the standards, assess penalties for non-compliance, and perform reliability assessments. The MRO Board and Committee seats and voting will be done by sector. There are seven sectors: IOUs, Municipalities, Cooperatives, Federal, Canadian, Transmission System Operator, and Generators and Marketers.

Currently, the MRO is in a transition process to establish committees, select committee members, and transfer MAPP reliability standards to the MRO. The plan is for the MRO to be fully functional in January 2005. Another step that needs to be completed is to revise the MAPP Restated Agreement to remove all items related to the RRC.

### **5.0 Midwest ISO**

On August 6, 2004 FERC issued an Order conditionally approving the Midwest ISO Transmission and Energy Markets Tariff (TEMT). This Order provides the Midwest ISO the necessary approval, subject to further FERC proceedings to revise certain provisions of the TEMT, to start its energy markets on March 1, 2005. Affected utilities, customers, state regulators, industry associations, and other market participants have submitted numerous protests and requests for rehearing. It is doubtful that FERC will alter its overall approval of the MISO TEMT.

The TEMT will employ security-constrained economic dispatch of generation to establish wholesale energy prices using a locational marginal pricing mechanism. The market will include both a Day-Ahead and Real-Time market. Further, the market will offer Financial Transmission Rights (FTRs) as a hedge against congestion costs. This type of market has been established in PJM, the New York ISO, and New England ISO. Of significant difference is that those RTOs have been using a centralized generation dispatch scheme for many years, but the Midwest ISO has not. What kinds of changes this causes in the Midwest is completely unknown. Because of the unknown impacts FERC established various market readiness and startup safeguards. FERC states that the safeguards should provide additional confidence in the reliable operation of the energy markets and provide some additional limits on exposure to market prices and transmission usage charges. Included in the safeguards are achievement of reliability and readiness metrics prior to the start of the market, a cutover plan to revert back to prior tariff service should the market systems fail, a temporary cap on supply bids into the market, and protection against congestion charges for five years for load pockets.

A particularly contentious issue that has not yet been completely resolved is the treatment of transmission rights under Grandfathered Agreements. The Midwest ISO has taken the position that these transmission rights must be converted to service under the TEMT. There were over 400 contracts submitted as meeting the definition of Grandfathered Agreements, i.e. those contracts for transmission service entered into prior to September 1998, the date the Midwest ISO received its initial approval from FERC for tariff service. The parties to the Grandfathered Agreements contend that the Midwest ISO cannot abrogate their contracts and assign them additional costs due to the Midwest ISO markets. There are long-standing legal precedents concerning changing contract rights. Parties are likely to take these issues to court if FERC does not uphold the sanctity of the contract rights.

The Midwest ISO will be allocating FTRs to the market participants in the next few months. There has been a great concern that many of the market participants will not receive sufficient FTRs to protect the deliveries to their native load customers, thereby exposing their customers to congestion charges of unknown magnitude. The Midwest ISO claims that the study they performed projects annual gross savings to consumers of roughly \$713 million. The validity of the study has been challenged by many of the market participants. A study by Wisconsin participants showed that their customers would experience a significant cost increase. Whether there are significant costs savings remains to be proven, but what does seem certain is that the new energy markets will result in cost shifts. Some areas may indeed see some cost savings, but other areas will very likely see significant cost increases. Because the new security constrained economic dispatch has never been performed for this part of the country, there is simply no way to predict the magnitude of any cost change.

## **6.0 SPP**

SPP received a FERC Order in February 2004 conditionally approving SPP as a RTO. SPP submitted a compliance filing on August 2, 2004 in an attempt to satisfy the FERC Order. Of particular note is that SPP does not intend to implement to complete energy markets proposed by the Midwest ISO. Instead, SPP formed a Regional State Committee composed of regulators from each of the States within its footprint to oversee a cost-benefit study. The cost-benefit study will be funded by the SPP at a cost of \$866,000 and performed by an outside consultant to determine if there is sufficient cost savings to customers to proceed with establishing energy markets.

One requirement of the FERC Order was for SPP to develop a seams agreement with the Midwest ISO and other neighboring transmission entities. SPP and the Midwest ISO were unable to reach agreement on the CMP, so SPP filed an unexecuted seams agreement at FERC. The Midwest ISO protested the filing and requested FERC set the issue for hearing. The basic issue of contention is the same difficult issue MAPP and the Midwest ISO are wrestling with, the allocation of flowgate capacity. Asking FERC to decide how to allocate flowgate capacity may be precedent setting, so it behooves MAPP to find a resolution with the Midwest ISO before FERC acts.



MAPP will also need a seams agreement with SPP. To date, there has been no contact between MAPP and SPP to work on a seams agreement. However, it is not as critical as the MAPP/Midwest ISO seams agreement. Initial efforts to work with SPP will probably begin in the next few months.

## **7.0 TRANSLink**

The TRANSLink effort was officially terminated in November 2003. TRANSLink received conditional FERC approval, but after failing to receive state regulatory approval in Minnesota and Iowa, Xcel Energy, which was the largest transmission owning participant, determined that they could no longer support the development effort. Without Xcel participating, the remaining members concluded that TRANSLink lacked sufficient size and therefore agreed to terminate the development.

## **8.0 Crescent Moon**

The Crescent Moon members continue to meet to discuss issues of common interest and develop positions they feel are needed to be put forward, but they are not pursuing the development of a separate transmission organization. The members are actively engaged in the MAPP/Midwest ISO seams agreement effort.

## **9.0 Conclusions**

The options for participation in a RTO have been narrowed down since last year's report. Only the Midwest ISO and SPP have received FERC approval, although still conditional for SPP, to function as a RTO. However, both of these organizations are still in the developmental stage and the economic benefits are dubious. Because of the uncertainty of how the RTO markets will perform from both a reliability and cost standpoint, the conclusion remains unchanged from previous reports. There is no viable regional transmission organization for Nebraska utilities to participate in. Transmission adequacy in Nebraska continues to be studied and built sufficient to deliver generation resources to Nebraska customers, but transmission adequacy to support interregional wholesale energy transactions is limited.

The most prudent course of action for Nebraska utilities is to remain in the MAPP organization and work to address seams issues with the adjoining RTOs. If the Midwest ISO and SPP markets begin operating as planned in 2005, we will be able to observe and evaluate the effects without being impacted directly.

## **Chapter 2**

**"Whether or not a viable wholesale electricity market exists in a region which includes Nebraska."**

## 1.0 Introduction

### 1.1 Groups' Purpose and Membership

The purpose of the second “condition-certain” issue group was to determine "whether or not a viable wholesale electricity market exists in a region which includes Nebraska." The Technical Group #2 that worked on this issue was combined with the Technical Group #4 because of the common backgrounds required and the similarities of the issue and included the following individuals:

Clint Johannes (Chair)	-	Nebraska Electric Generation & Transmission Cooperative, Inc. (NEG&T)
Deeno Boosalis	-	Omaha Public Power District (OPPD)
Jim Fehr	-	Nebraska Public Power District (NPPD)
Dennis Florom	-	Lincoln Electric System (LES)
Kevin Gaden	-	Municipal Energy Agency of Nebraska (MEAN)
Burhl Gilpin	-	Grand Island Utilities
John Krajewski	-	MEAN
Derril Marshall	-	Fremont Utilities
Allen Meyer	-	Hastings Utilities
David Ried	-	OPPD
Jon Sunneberg	-	NPPD

One critical "condition-certain" factor is whether there is a viable wholesale market in place. The LR455 Phase II report (released in December 1999) stated, "that a viable wholesale market requires an operational regional 'market hub' through which transactions may take place. It requires sufficient buyers and sellers to make an active market. It requires clear and equitable trading rules. While judgment of what level of these requirements is sufficient may be considered subjective, viability should be reflected in stable or predictable pricing patterns."

Before moving toward retail competition, wholesale markets must be viable. The primary lesson from the California experience with deregulation is, if the wholesale market is dysfunctional, the retail market will be as well. The portion of a retail customer's bill that will be open to competition is the electric commodity (wholesale) portion. The transmission and distribution wires will be utilized much the same with any electric commodity supplier – only one set of electric wires can be financially or operationally supported. It is, therefore, important that the wholesale electric market be adequately established and be viable. This chapter addresses that viability for Nebraska.

### 1.2 Approach

To accomplish the purpose described, the Group first defined the meaning of the term “viable” and the alternative methodologies for testing the viability of a market. This definition and the evolution of standard tests for market viability are outlined in Section 2. Next the regional markets that include Nebraska were defined. Nebraska is somewhat unique in that it transcends two major transmission grids in the U.S., the Eastern Interconnection and the Western Interconnection. Therefore Nebraska has two separate and distinct regional electricity markets. Both of these markets are defined in Section 3. The general approach for completing this year’s report is different than previous years. This is because the Federal Energy Regulatory Commission’s (FERC) thinking has evolved significantly since the initial LB901 report. Experience that FERC has gained in regulating emerging wholesale markets has provided valuable lessons learned which they have applied by trying new tests and techniques. Technical Group #2 has endeavored to follow these changes and modify our approach to reflect the FERC’s latest thinking. In the past, Technical Group #2 conducted FERC’s standard test of market viability using data obtained by the group. Two factors have changed this approach. First, the data used for conducting this analysis is no longer available to the group. Second, FERC has proposed that Regional Transmission Organizations (RTO) assume the responsibility of testing for market viability in the regions they serve. Conducting annual market viability tests is one of these responsibilities. The Midwest Independent System Operator (MISO) is the approved RTO for the Midwest region that includes the Eastern Interconnection of Nebraska. In May 2003 they published their first *State of the Market Report*. The analysis includes all the current and prospective utility members of MISO. Therefore the major transmission owning utilities in Nebraska are included. Since the MISO report is the definitive analysis for “whether or not a viable electricity market exists for the region which includes Nebraska”, it is the primary source for this report.

## 2.0 Viable Wholesale Market Definition

### 2.1 Economic Logic

According to the Merriam-Webster Collegiate Dictionary Tenth Edition, the term “Viable” means:

- 1** : capable of living; *especially* : capable of surviving outside the mother's womb without artificial support <the normal human fetus is usually *viable* by the end of the seventh month>
- 2** : capable of growing or developing <*viable* seeds> <*viable* eggs>
- 3 a** : capable of working, functioning, or developing adequately <*viable* alternatives> **b** : capable of existence and development as an independent unit <the colony is now a *viable* state> **c** (1) : having a reasonable chance of succeeding <a *viable* candidate> (2) : financially sustainable <a *viable* enterprise>

For the purpose of this report, the definition shall be deemed as “having a reasonable chance of succeeding” financially.

### 2.2 Evolution of FERC Definition and Tests for Market Power

A “viable market” must be one in which no single utility, or group of utilities, is able to exercise “market power.” The standard test for market power is called the “Hub and Spoke” test. It was first used by FERC to assess the impacts of electric utility mergers on market concentration as set out in FERC Order 592, Merger Policy Assessment. This has been considered the “official” test of market power since FERC started using it in 1996. It has been the basis of this report since the inception of LB901. This test is described and presented in Section 2.3. The appropriate size of the region used in the conduct of this test is defined in Section 3.

As wholesale electric markets matured and market power became a prevalent issue, FERC acknowledged that the Hub and Spoke test alone was not sufficient to detect all market power. Notably, FERC has recognized the effect of transmission constraints on the exercise of market power. Initially, FERC began using variations to the traditional hub and spoke analysis that compensated for transmission constraints. This culminated in a FERC order issued on November 20, 2001 entitled “ORDER ON TRIENNIAL MARKET POWER UPDATES AND ANNOUNCING NEW, INTERIM GENERATION MARKET POWER SCREEN AND MITIGATION POLICY (Docket No. ER96-2495-015, et al). This order proposed a new standard test called “Supply Margin Assessment.” A moratorium on this test was initiated soon after it was released because of political opposition. A complete review of the new FERC tests and the specific reasons for using them are discussed in Section 4.

On April 14, 2004 FERC released the ORDER ON REHEARING AND MODIFYING INTERIM GENERATION MARKET POWER ANALYSIS AND MITIGATION POLICY (Docket nos. ER96-2495-016 et. al.). This order adopts two new screens to assess generation market power and proposed new measures for mitigating market power in the future. The new screens were intended to replace the Supply Margin Assessment (SMA) generation market power analysis proposed in November of 2001 but suspended shortly thereafter. The new order was released after several rounds of comments and a technical conference examining the issues surrounding the SMA. The new interim generation market power order is presented in Section 4.1.1.4.

The “Standard Market Design” Notice of Proposed Rulemaking (Docket RM01-12-000) was issued July 31, 2002. This rulemaking along with a FERC Whitepaper clarifying certain issues introduced in the rulemaking (Issued April 28, 2003) is known by the abbreviation “SMD.” The SMD is a very far-reaching and prescriptive outline of how Regional Transmission Organizations (RTO) should be organized and how they should operate. SMD proposes that RTO’s assume the function of *Market Monitoring and Market Power Mitigation*. This includes the responsibility to constantly watch for the abuse of market power and also grants authority to implement defined corrective actions when market power is detected. As it is anticipated by FERC that all utilities will eventually belong to an RTO, every utility in the country will be subject to this oversight. A review of the *Market Monitoring and Market Power Mitigation* responsibilities as outlined in the SMD is shown in Section 5. The proposed rules will set out prescribed tests for market power but also gives considerable leeway to each RTO in devising new tests they believe are appropriate for their region. The RTO will be required to periodically report on the status of market power in their region. The assumption is that RTO’s are uniquely qualified to assess market power in the region they serve. RTO’s are independent. They will run the regional spot market and operate the transmission system, therefore they will have all the operational data required to run the appropriate tests. RTO’s will also have the transmission and market models, the budget and the expertise to conduct market power analyses. As of this writing the SMD

rulemaking has not been implemented because of controversy over the far-reaching powers afforded to FERC through the RTO's. The voluntary RTO's that have been established, however, have generally followed the guidelines set out in the SMD proposed rulemaking and whitepaper.

### **2.3 Basic Elements of Traditional FERC “Hub and Spoke” Market Power Analysis**

The Federal Energy Regulatory Commission (FERC) established procedures for determining whether a proposed merger or settlement will impact certain regions or individual utilities, and enhance the ability of certain utilities to control prices or exclude competition. This is known in the regulatory community as “market power.” FERC provides the following definition: Market power exists if there are concerns with market concentration.

In its merger guidelines, FERC defines “market concentration” in Order No. 592, Merger Policy Statement. In Order No. 592, FERC defines two relevant products for this assessment: economic capacity and available economic capacity. Economic capacity includes all generation in a given area that can be delivered at a price not exceeding 105% of the market price. Available economic capacity is similar to economic capacity, except it does not include capacity required to serve native load. For purposes of determining how viable the wholesale market is, available economic capacity is of greater relevance. Resources committed to serving existing native load would not provide suitable competition to create a “viable market,” as that term is defined in this report.

In determining the market concentration for available economic capacity, FERC looks at suppliers that can supply the product (wholesale capacity and energy) at a cost no greater than 5% above the competitive price. The concentration of suppliers that have available economic capacity and energy that can be supplied is less than the FERC-defined threshold for an “unconcentrated” market. FERC defines this using the Herfindahl-Hirschman Index (HHI), which is calculated by summing the squares of the market share of all competitors that can supply power at a price no greater than 5% above the competitive price. An HHI of less than 1,000 indicates an unconcentrated market while an HHI of over 1,800 indicates a concentrated market.

In general arithmetic terms, to achieve an unconcentrated market, there would need to be roughly 10 suppliers each with roughly 10% of the market. No single supplier should have more than 20% of the market and there should be at least 10-15 other competitive suppliers. Each of these suppliers must be capable of providing capacity and energy at prices competitive with the prevailing market price.

For every year that this report has been completed, Technical Group #2 has conducted the Hub and Spoke test by calculating the HHI index using public domain data. This year the complete set of data was not publicly available. Fortunately, MISO calculated the HHI as part of their *State of the Market Report*. This analysis was conducted for the entire MISO region as well as sub-regions of MISO corresponding to the reliability areas that are represented in MISO. This is shown in Exhibit II-1. The results of the 2004 HHI analysis are shown in Exhibit II-2. It shows that the MAPP region has an HHI of 938, indicating that it is free from market power. It is lower than last year's index of 1,128. It should be noted that last year's index included Iowa, which has been broken out separately this year. The HHI statistic calculated for the entire MISO region as shown in Exhibit II-2 sheds some light on the deficiencies of the hub and spoke test. The very low index number of 261, as compared to 408 last year, suggests the entire MISO area is a very unconcentrated market. This is because the larger the area, the more suppliers, the smaller the HHI. This is misleading because the entire MISO area does not behave as one big market; rather it is divided into sub markets because of transmission constraints. The WUMS (Wisconsin –Upper Michigan) area has a high HHI of 2,656. This suggests a concentrated market with high potential for market power. In fact, the WUMS area is a known load pocket created by transmission constraints that isolate local generators.

Exhibit II-1

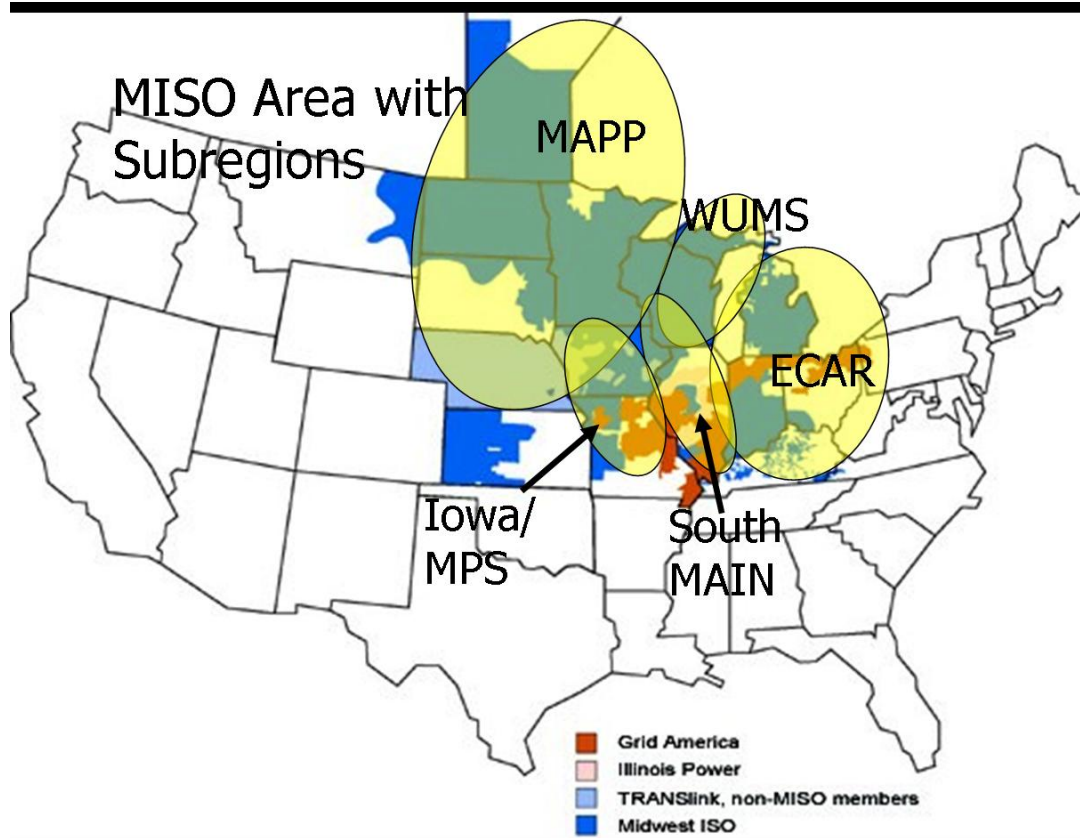


Exhibit II-2

<b>MISO Subregion</b>	<b>HHI</b>
ECAR	563
North MAPP	938
South MAIN	1,736
Iowa/MPS	1,343
WUMS	2,656
<b>MISO</b>	<b>261</b>

Last Years Results

- MAPP (including Iowa) – 1,128
- MISO – 408

### **3.0 Region Defined**

#### **3.1 East/West Interconnection Description**

The Eastern and Western Interconnections are separated by seven alternating current/direct current/alternating current (AC/DC/AC) tie converter stations, which are located throughout various states in the U.S. and provinces in Canada. These include ties such as the Miles City Tie in Montana, the Rapid City Tie in Western South Dakota, the McNeill Tie in Western Saskatchewan, Canada, the Blackwater Tie and the Artesia Tie, both in Eastern New Mexico. Two of those ties are located in the State of Nebraska: (1) the Stegall converter station located just southwest of Scottsbluff, Nebraska, which is a 110 MW facility that is owned and controlled by Basin Electric Power Cooperative from North Dakota; and, (2) the Virginia Smith converter station (also known as the Sidney tie), which is located just north of Sidney, Nebraska, is a 200 MW converter station that was installed by Western Area Power Administration (WAPA), and controlled by the WAPA-Rocky Mountain Regional office in Loveland, Colorado. In essence, the potential market that interconnects to the West to/from Nebraska has an impact of 310 MW; however, most of that capacity is committed for the long term by utilities and marketers outside Nebraska.

#### **3.2 Nebraska's Portion of Each Interconnect**

The converter station owned and controlled by Basin (Stegall) is used at the discretion of Basin operational staff. The Sidney tie is placed under WAPA's Open Access Tariff that is being applied on a uniform tariff basis by WAPA. Therefore, it uses FERC approved Open Access Same Time Information System (OASIS) and all the other tariff provisions that are required including on-line reservations and ancillary charges that are Internet subscription based. There are a few Nebraska based utilities that have rights to deliver WAPA allocations over the Sidney Tie from the Loveland Area Office to utilities located in western Nebraska. Other utilities, specifically NPPD and MEAN, have contracted paths for deliveries from the West system to the East system. There are also long-term rights that are held by some Nebraska utilities to serve loads via the Sidney Tie. Concerning the Stegall Tie, there is no contractual commitment by any Nebraska utilities to transmit power through this facility.

#### **3.3 Eastern Interconnection Defined**

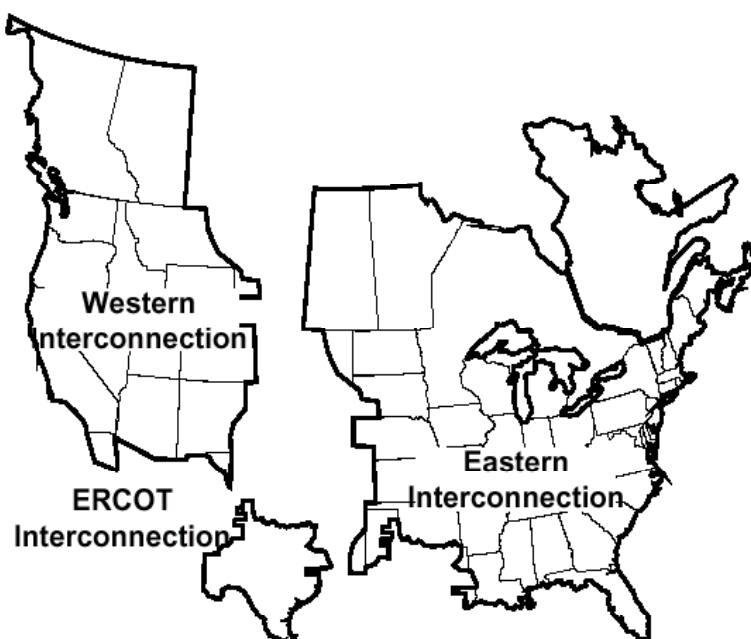
The Eastern Interconnection is defined as any generation and load that is synchronously connected to the grid that includes the entire eastern, southern and central United States and eastern Canada. Generally, this includes the states and provinces of North Dakota, South Dakota, Nebraska, Kansas, Oklahoma, a small portion of Texas and all states to the east as well as Saskatchewan and provinces to the east. However, there are a few locations including the far western edge of South Dakota (divided at Rapid City) and everything located west of Sidney, Nebraska, that are not on the Eastern Interconnection. This includes most all of NERC reliability regions such as MAPP, MAIN, SPP, ECAR, NECC, FRCC, MAAC and SERC as defined in the glossary. The regions that specifically impact Nebraska include the MAPP region, the MAIN region and the SPP region because some Nebraska utilities have contracted to receive or deliver power to those locations. (See Exhibit II-3)

#### **3.4 ERCOT Interconnection**

The Electric Reliability Council of Texas (ERCOT) operates its own interconnect, separated from the rest of the Eastern Interconnection by two AC/DC/AC ties. The amount of transfer capability between ERCOT and the Eastern Interconnection is 800 MW.

#### **3.5 Western Interconnection Defined**

The Western Interconnection is defined as all load and resources that are synchronously connected with the reliability region of the Western Systems Coordinating Council (WSCC). States and provinces in this region include most of Montana, with the exception of a small part of eastern Montana that is located on the Eastern Interconnect (basically, everything west of Miles City, Montana); Wyoming; Colorado (with the exception of a small portion in the northwest corner that is connected on the Eastern Interconnect); New Mexico; Nevada; Idaho; Washington; Oregon, California; Alberta, and British Columbia.



### 3.6 Comparison of Region to that in Technical Group #1

Technical Group #1 was assigned to review the viability of the transmission in the region including Nebraska. The regional definition of Technical Group #1 is essentially the same as the definition used in this report.

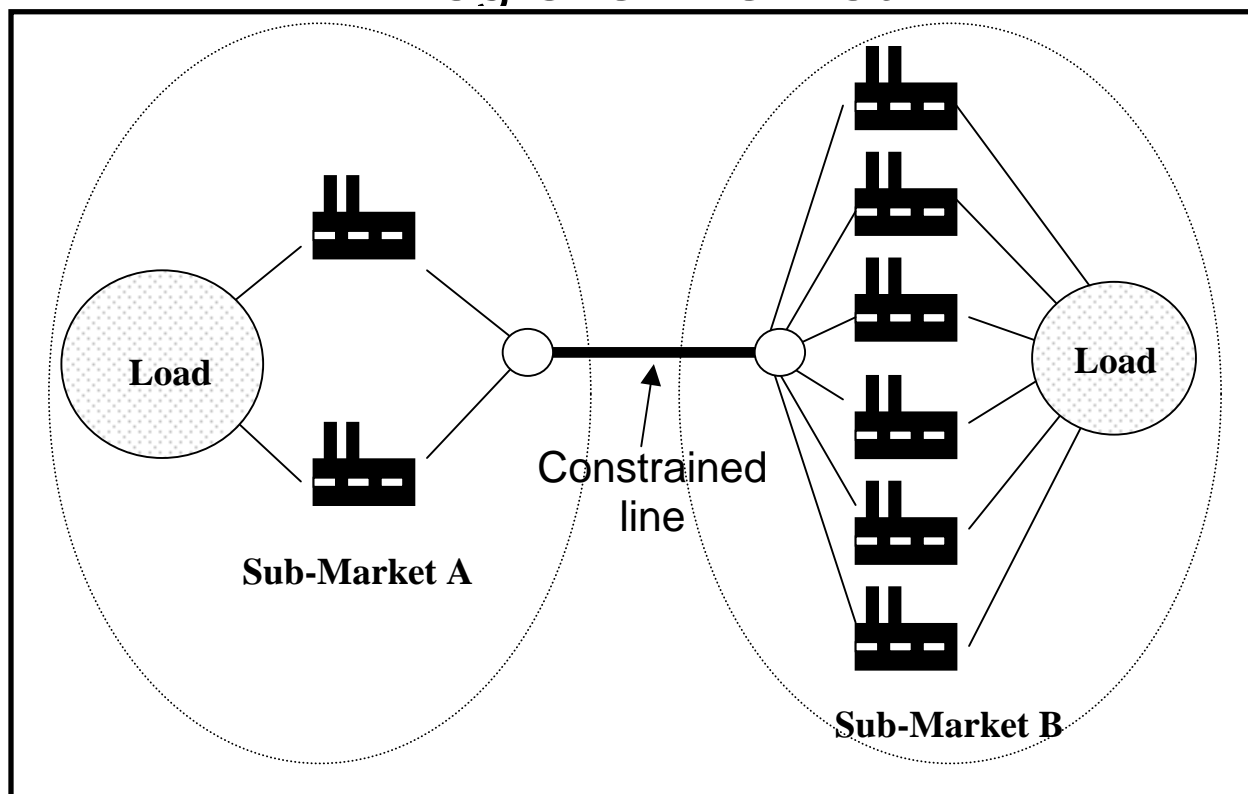
## 4.0 New FERC Methods for Assessing Market Power

### 4.1 Reasons for Instituting New Methods

FERC began to consider alternatives to the hub and spoke method because of concerns that transmission constraints can create pockets of market power. This was brought to the attention of FERC by many parties who intervened in FERC dockets attesting to market power created by constraints. The traditional hub and spoke analysis does not consider the effects of limited transmission when defining market share. According to FERC, “Hub and spoke worked reasonably well for almost a decade when the markets were essentially vertical monopolies trading on the margin and retail loads were only partially exposed to the market. Since that time, markets have changed and expanded. Because markets are fundamentally different from years ago, the hub and spoke may no longer be a sufficient test for granting market-base rates”. An implicit assumption in the hub and spoke analysis is that market power derived from transmission will not be an issue if the utility in question has filed an open access tariff. Transmission constraints have been shown to cause market power for generators by subdividing a large market area into two or more sub-markets during times of high transmission usage. For example Exhibit II-4 shows a simplified, hypothetical market with eight generators serving total customer load (represented by the shaded circles). Assuming none of the eight generators has more than 20% market share, this would be a viable market. However, a constraint on a major transmission line will split the market into two sub-regions, A and B. The two generators left serving the lion’s share of load in Sub-Market A can exercise market power by withholding generation. Experience from California and other areas have provided strong evidence that this can indeed happen. Even though the constraints may last for a limited period time, they generally coincide with periods of high wholesale prices. Therefore the effect of these short periods of market power can be dramatic.



## Regional Market



### 4.1.1 New Tests of Market Power

#### 4.1.1.1 Modified “Hub and Spoke” Test

One test FERC has used to assess market power caused by transmission constraints is a variation of the traditional hub and spoke test. This test is similar to the analysis shown in Exhibit II-1 except that it calculates utility market shares for non-requirement wholesale power during peak periods as opposed to the entire year. During peak periods some utilities may not be able to sell wholesale power because of transmission constraints raising the market shares for the utilities unaffected by transmission constraints. Therefore a traditional hub and spoke test may show a relatively unconcentrated market whereas the same test during peak periods may show a concentrated market. Conducting this analysis requires data that may not be publicly available, notably the wholesale sales and available capacity for each utility during the peak time period.

#### 4.1.1.2 Electricity Market Models

FERC has started to employ electricity market simulations to assess market power in electric markets. This is especially true for merger analysis. These simulations attempt to model both the price determination (bid-auction) of wholesale and the electricity flows in the regional market. The advantage of using such a simulation is that it captures some of the nuances and gaming that can occur in electric markets. For example, a simulation may demonstrate that a company can run one generating plant at a loss but create a transmission constraint that will create market power for another generating plant that will more than compensate for the loss. The disadvantages of such models are that they are time-consuming and costly to run, and they are somewhat subjective in the sense the test does not deliver a “number” like the HHI index. The Technical Group considered employing such a model for both Issue #2 and Issue #4. It was decided that the cost was prohibitive.

#### 4.1.1.3 Supply Margin Assessment

On November 20, 2001 FERC issued a new order entitled “ORDER ON TRIENNIAL MARKET POWER UPDATES AND ANNOUNCING NEW, INTERIM GENERATION MARKET POWER SCREEN AND MITIGATION POLICY (Docket No. ER96-2495-015, et al). The order introduced a new test for market power

called the “Supply Margin Assessment”, laid out mitigation measures for companies failing the test and found a number of companies not in compliance with the order. The Supply Margin Assessment is designed to test for market power within a utility control area. A control area is defined as the area transcribed by an individual utility’s transmission system in which the utility has responsibility of balancing supply and demand of electricity and maintaining the stability of the system. FERC has stated that a utility has market power if the utility’s generation capacity in the control area is greater than the Supply Margin in the control area. The Supply Margin is defined as the total generation in excess of the peak load (reserve margin) in the area plus the total transmission capacity interconnected to the area. If a utility fails this test, FERC will judge the utility as having market power unless the utility joins a Regional Transmission Organization (RTO). If the utility joins an RTO they are absolved of having market power by FERC. Ostensibly, this is because an RTO will have market monitoring capabilities and transmission congestion management protocols that will mitigate market power within the RTO. If a utility refuses to join an RTO, FERC has set out a number of onerous mitigation measures including revoking the utilities ability to charge market-based rates for wholesale market transactions as well as requiring that an independent third party operates the utility’s open access, real-time information system. With this order FERC has migrated from the hub and spoke method where it was relatively difficult to demonstrate market power to the Supply Margin Assessment where virtually every vertically integrated utility in the country will fail the test unless they join an RTO. In this regard, the order seemed designed to “encourage” all utilities to join RTO’s. In a dissent to the order, FERC commissioner Linda K. Breathitt stated, “If forming RTO’s is the goal here, then we should be straightforward about that and do a rulemaking to mandate them, going through the front door and not the back door”. This FERC ruling has interesting consequences for the Conditions Certain of LB901. If one applies the FERC logic, then Issue #1, “Nebraska being part of an RTO” and Issue #2 “Whether or not a viable wholesale market exists in a region which includes Nebraska” merges into one. In other words if Condition #1 is satisfied, Condition #2, by definition, will also be satisfied. The Supply Margin Assessment Order generated so much controversy that FERC suspended implementation. In the two and a half years following the suspension, FERC solicited many rounds of comments, held a two day technical conference and issued a whitepaper to gather feedback on various options and proposals.

#### **4.1.1.4 Interim Generation Market Screen and Mitigation Policy**

On April 14, 2004 FERC released the ORDER ON REHEARING AND MODIFYING INTERIM GENERATION MARKET POWER ANALYSIS AND MITIGATION POLICY (Docket nos. ER96-2495-016 et. al.). This order adopts two new screens to assess generation market power and proposed new measures for mitigating market power in the future. The new screens were intended to replace the Supply Margin Assessment (SMA) generation market power analysis proposed in November of 2001, but suspended shortly thereafter. The two new screens are called the “Pivotal Supplier Analysis” and the “Market Share Analysis”. Both tests attempt to take into account some of the objections to the SMA such as adjusting for native load and contract obligations when assessing market power.

If a utility fails to pass either screen there is a “rebuttable presumption of market power”. This means that the utility can request to submit additional analyses to FERC demonstrating an absence of market power or waive that right and accept the mitigation measures outlined in the order. The additional analysis would include, among others, the “Delivered Price Test”.

AEP, Southern Company and Entergy, (the original utilities involved in the SMA controversy) were ordered to file the results of the new tests by June 13, 2004. All other jurisdictional utilities currently possessing market-based rate authority would have to file test results according to schedule published by FERC.

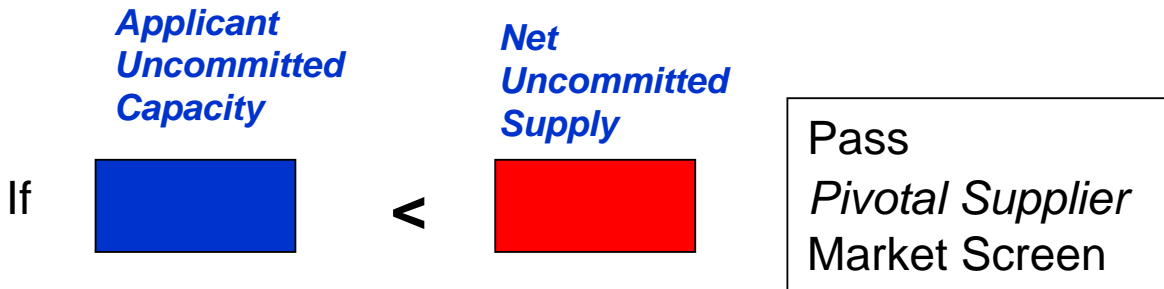
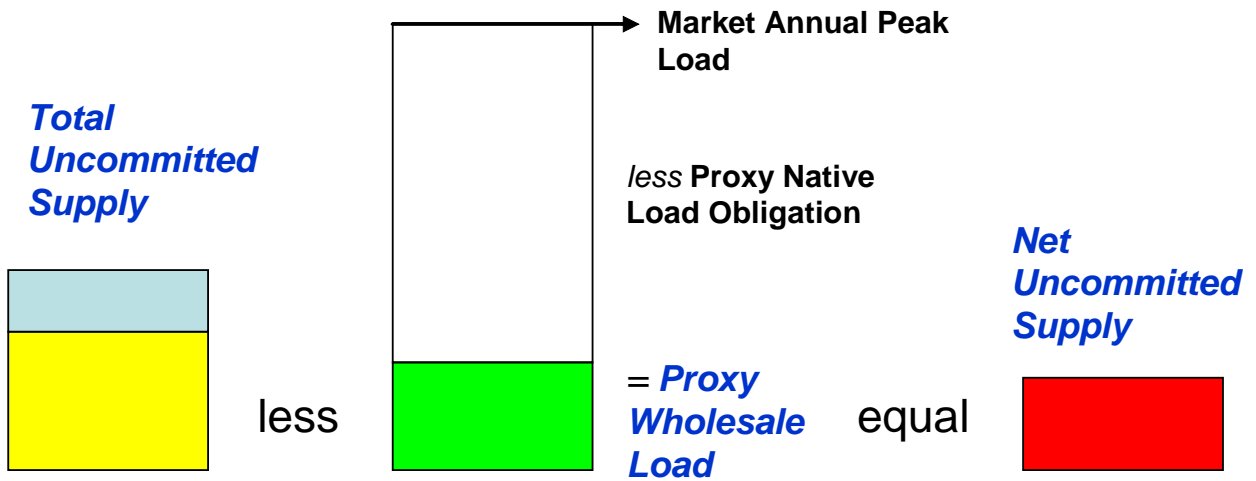
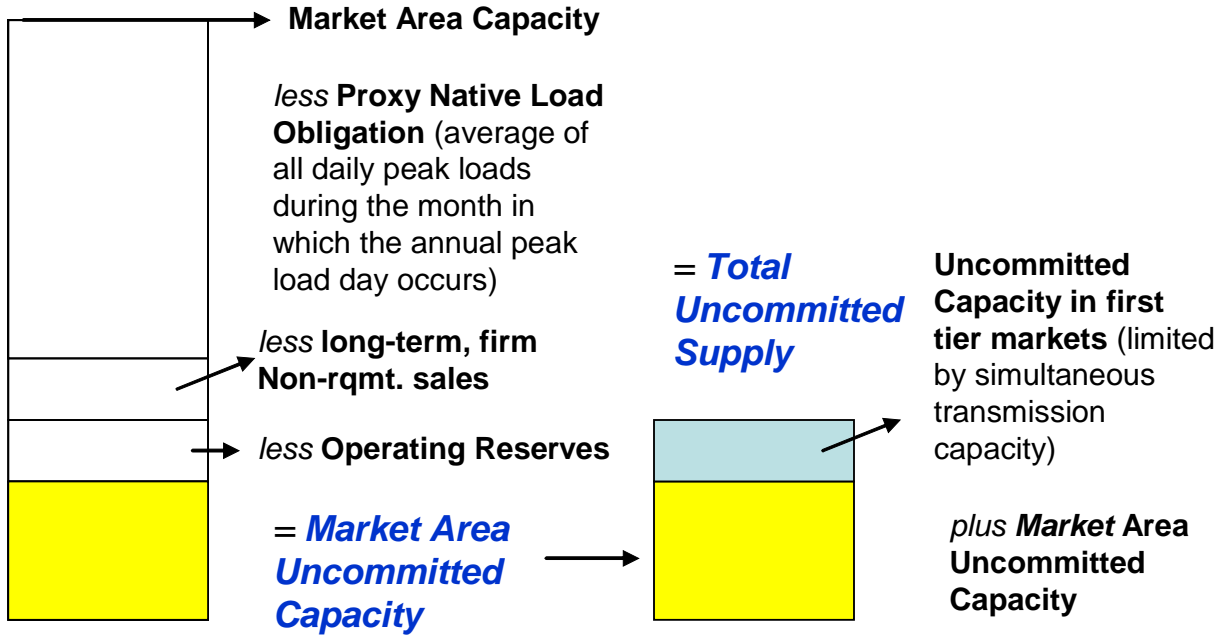
##### **4.1.1.4.1 Relevant Market Area for Interim Generation Market Screens**

The relevant market area used when conducting the two market screens has a profound effect on the results of the test. The greater the size of the relevant market area the less likely the applicant will be found to possess market power. For utilities belonging to an RTO, the entire geographic region under the RTO will be considered the relevant market area, provided the RTO has a sufficient market structure and a single energy market. The rehearing order stated that this would include PJM, ISO-NE, NYISO and CAISO, but would not include MISO or SPP because neither performs single central commitment and dispatch at this time. For all utilities that do not belong to a qualified RTO, the control area in which they operate would be the relevant market area.

##### **4.1.1.4.2 “Pivotal Supplier” Market Screen**

The Pivotal Supplier Analysis seeks to determine if the applicant utility has the ability to manipulate market prices by unilaterally withholding generation from the market during peak period conditions. If the applicant’s generation is absolutely essential to meeting peak wholesale market demands of the relevant market area (control area), the applicant will fail the screen. Exhibit II-5, shows how the Pivotal Supplier screen is calculated.

### Pivotal Supplier Market Screen



*(Calculated for Applicant just like market area Uncommitted Capacity)*

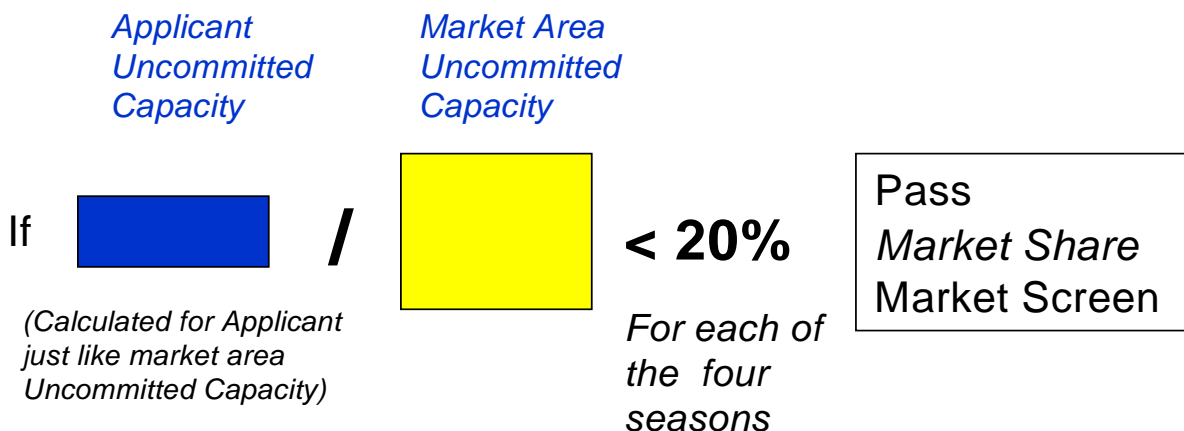
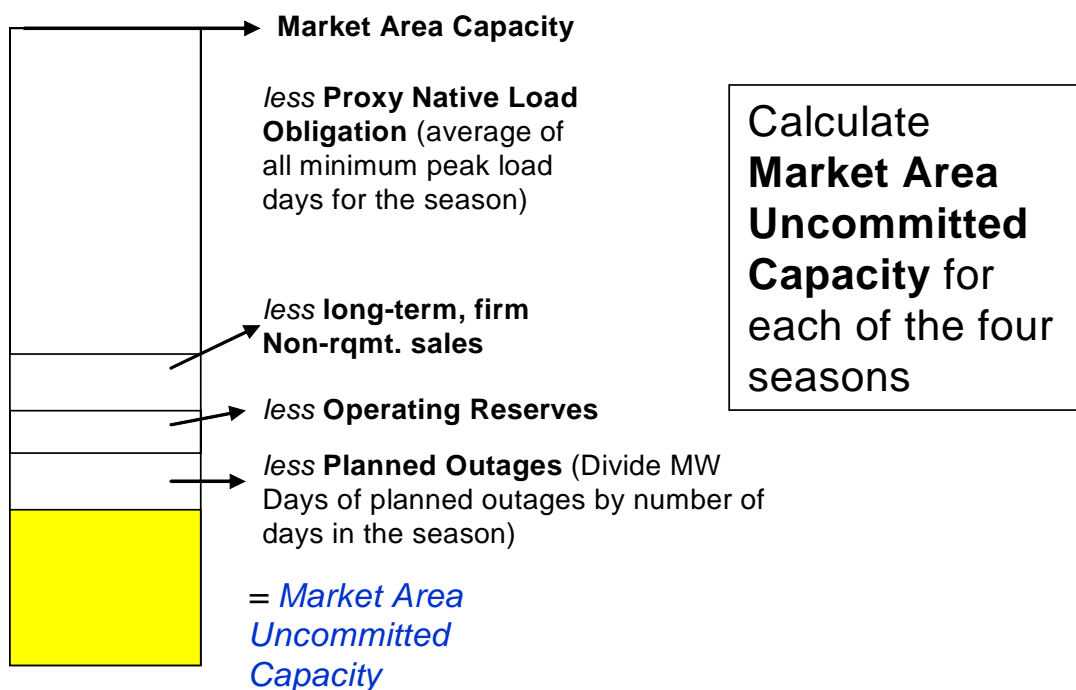
As shown in Exhibit II-5, if the applicant’s uncommitted capacity is less than the uncommitted capacity offered by all other competitors than it will not be required (or pivotal) in satisfying all of the wholesale market demands in the area. On the other hand if the applicant’s uncommitted capacity is more than that of all other suppliers to the area, the applicant’s uncommitted capacity would be essential in meeting the wholesale demands. In that case the applicant could effectively withhold generation and unilaterally raise prices for electricity.

#### 4.1.1.4.3 “Market Share” Market Screen

The Market Share Analysis considers the percentage of total uncommitted generation that is owned or controlled by the applicant during each of the four seasons of the year. If the applicant has more than 20% of the total market it is considered to have market power. Where the pivotal supplier analysis tests for market power under specific peak conditions, the market share analysis is a general test of market power attributed to sheer size.

**Exhibit II-6**

### Market Share Analysis



The calculation for the “Market Share” test is shown in Exhibit II-6. Note that the definition of Uncommitted Capacity changes under this test. The native load obligation used to calculate the Uncommitted Capacity is defined as the minimum peak load day for the season. This focuses the test on the off-peak market. The Uncommitted Capacity is also adjusted for planned generation outages that generally occur during non-peaking times.

#### 4.1.1.4.4 “Delivered Price” Market Screen

The Delivered Price Analysis can be submitted (along with other specialized tests) if the applicant fails the first two market screens. The delivered price test is similar to the first two tests, except that the price at which the capacity can be delivered is taken into consideration. For example, an applicant may have a high market share of uncommitted capacity relative to total uncommitted capacity. However, if the applicant can prove that the capacity cannot be delivered at competitive prices (i.e. it is high cost) they would be incapable of realizing market share. This capacity can be effectively eliminated from the market power calculations.

#### 4.1.1.4.5 Mitigation Measures

If an applicant fails the first two market screens and fails to prove a lack of market power with subsequent analysis or chooses not to submit such analysis, they will be required to implement measures to mitigate their market power. An applicant may propose mitigation measures tailored to their particular circumstance. If FERC finds these remedies inadequate, it will rescind the applicants market-based rate authority and order cost-based rates. The cost-based rates for mitigation are shown in Exhibit II-7.

**Exhibit II-7**

<b>Term of Sale</b>	<b>Cost-based Rate allowed</b>
<b>Short-term - &lt; 1 week</b>	<b>Marginal cost + 10%</b>
<b>Mid – term - &gt; 1 week and &lt; 1 year</b>	<b>Embedded costs “up to” unit providing service</b>
<b>Long-term - &gt; 1 year</b>	<b>System embedded costs</b>

#### 4.1.1.4.6 Implications for Public Power

As non-jurisdictional utilities, Public Power is not directly impacted by this order. The Large Public Power Council in an opinion paper stated “...members are not generally required to perform the tests and make filings with FERC. However, they could be asked to provide proprietary information to be used in the preparation of the market power analysis for neighboring jurisdictional utilities. They could also be ‘dragged into’ the mitigation phase where a jurisdictional utility argues that mitigating their market power would place them at a disadvantage relative to neighboring non-jurisdictional utilities (this argument has already been made in a rehearing requests) or that non jurisdictional participation in an RTO is an essential part of the required mitigation.”

Indirectly, Public Power could see some near-term impacts. If a number of jurisdictional utilities fail the market screens and are required to sell at cost-based prices, this may dampen wholesale electric prices, notably during peak periods when excess demand would normally drive prices above marginal costs. This is especially true for the MISO area, where most jurisdictional utilities are more likely to not pass the screens because they are vertically integrated and because MISO does not yet qualify as a single market RTO. This would be positive for net buyers and the market and negative for net sellers.

The longer-term consequences may be more profound. It would difficult for any vertically integrated utility with control area responsibilities to pass both market screens without being a member of an RTO. This rehearing order is clearly intended as a strong incentive for jurisdictional utilities to join RTO’s expeditiously. Non-jurisdictional utilities are probably on the radar screen. As more jurisdictional utilities join RTO’s, public power will become more isolated. RTO’s may began to implement reciprocity conditions for sale into the RTO market. Eventually, Public Power may have to join an RTO or sell into the wholesale market at cost-based rates.

## 5.0 RTO Market Monitoring and Market Power Mitigation

### 5.1 Market Monitoring

As stated in Section 2, the Standard Market Design (SMD) proposes that RTO’s are given the responsibility for monitoring market power and implementing mitigation measures when it is found to exist. Monitoring will include close daily monitoring of the day ahead and real-time markets as well as tracking of transmission transactions. The Final Rule would specify how often reports must be prepared. At least annual reports on the status of market power in the region will be prepared for FERC, the regional state committee and other appropriate state regulatory authorities.

## 5.2 Market Power Rules and Mitigation

The SMD Whitepaper states: “The Final Rule would require that each RTO or ISO have an independent market monitor either for the individual RTO or ISO or for a larger region. The RTO or ISO tariff must contain appropriate market power mitigation measures to address market power problems in the spot markets. These mitigation measures must work together with measures on resource adequacy to ensure that the measure do not suppress prices below the level necessary to attract needed investment in infrastructure in the region.”

Furthermore the RTO will be empowered to take action if market power abuse is found. This will include: enforcement of Reliability Must Run agreements for generation units with localized market power; enforcement of price caps; and the potential to adjust a generator’s bid downward automatically if it is out of line with its historical bidding behavior.

## 6.0 Midwest Independent Operator (MISO) State of the Market Report 2003

### 6.1 Report Overview

The Midwest Independent System Operator (MISO) is the approved RTO for the Midwest region that includes Nebraska. In May 2004 they published their second *State of the Market Report* assessing market power in the Midwest. The analysis includes all the current and prospective utility members of MISO. Therefore the major transmission-owning utilities in Nebraska are included. The report includes a number of market power tests for the region. These tests are described and presented in Sections 6.2 – 6.6 below. They range from simple to complex. Many of them require detailed transmission and market price data that only MISO has. At the same time, they require sophisticated loadflow and market models. Taken together they offer a complete picture of market power in the wholesale electric market that includes Nebraska.

### 6.2 MISO Subregions used in Market Power Tests

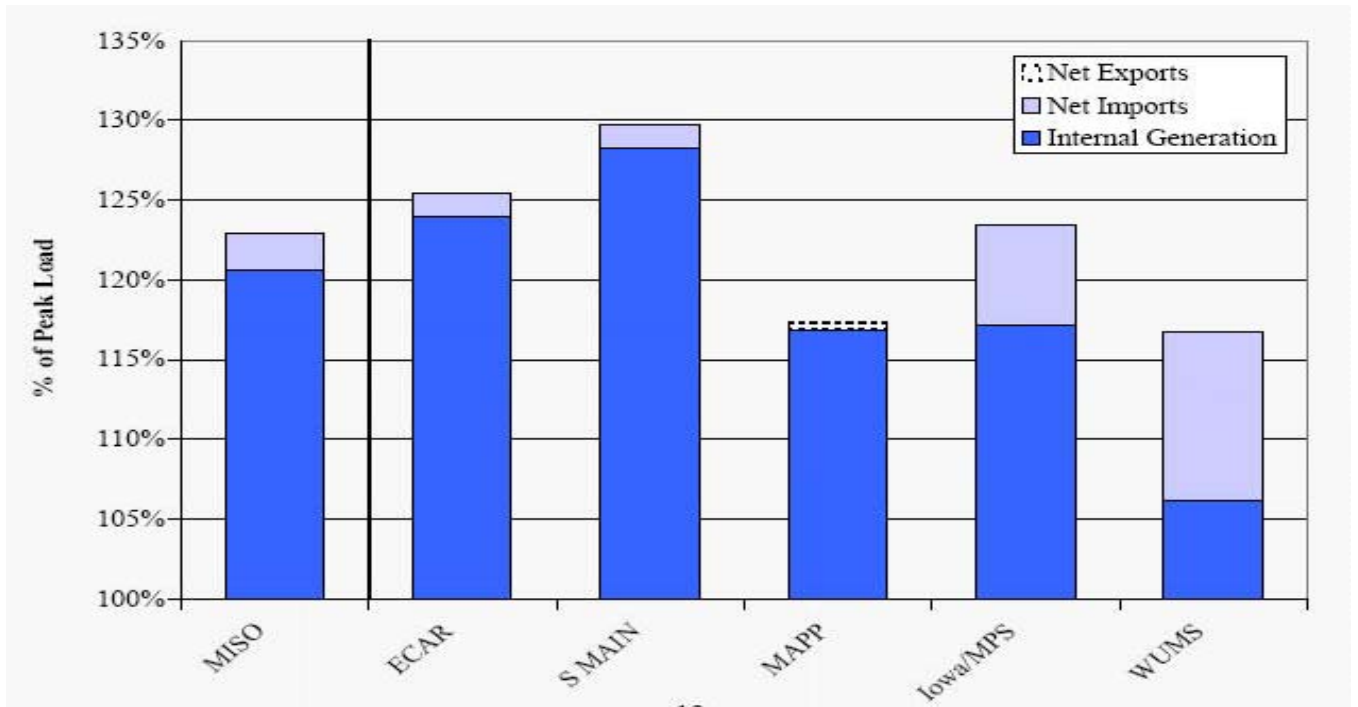
Many of the tests use MISO subregions to provide geographic detail. These subregions are generally defined as MISO areas that fall into different NERC reliability regions. Some special regions are also defined. The regions are shown below:

MAPP.....	Current or prospective MISO members in Nebraska, North Dakota, most of Minnesota, most of South Dakota, Western Iowa and Eastern Montana
South MAIN ...	Illinois, Southeastern Minnesota, eastern Iowa and eastern Missouri
WUMS.....	This is not a reliability region. It is separated out because lack to transmission makes it a particularly troublesome area as far as market power. It includes North MAIN, Specifically Eastern Wisconsin and the Upper Michigan peninsula
ECAR.....	Lower Michigan, Indiana, Ohio, Kentucky and Western Pennsylvania
Iowa/MPS.....	Mid-American Energy, Alliant West (including Muscatine) and Missouri Public Service

### 6.3 Reserve Margin Analysis

This is a very simple but effective test. For each region in MISO it shows the total generation as a percentage of peak load as shown in Exhibit II-8. This is called reserve margin. It is the amount of excess generation in a region. Overall, MISO has a reserve margin of 22.9%. Regions with low reserve margins (like WUMS) are susceptible to market power. Generators can increase prices by unilaterally withholding generation from the market. In tight supply situations this will raise the price of electricity. In regions with high reserve margins,, if a utility tried to withhold power, it would simply be compensated for by others with excess generation.

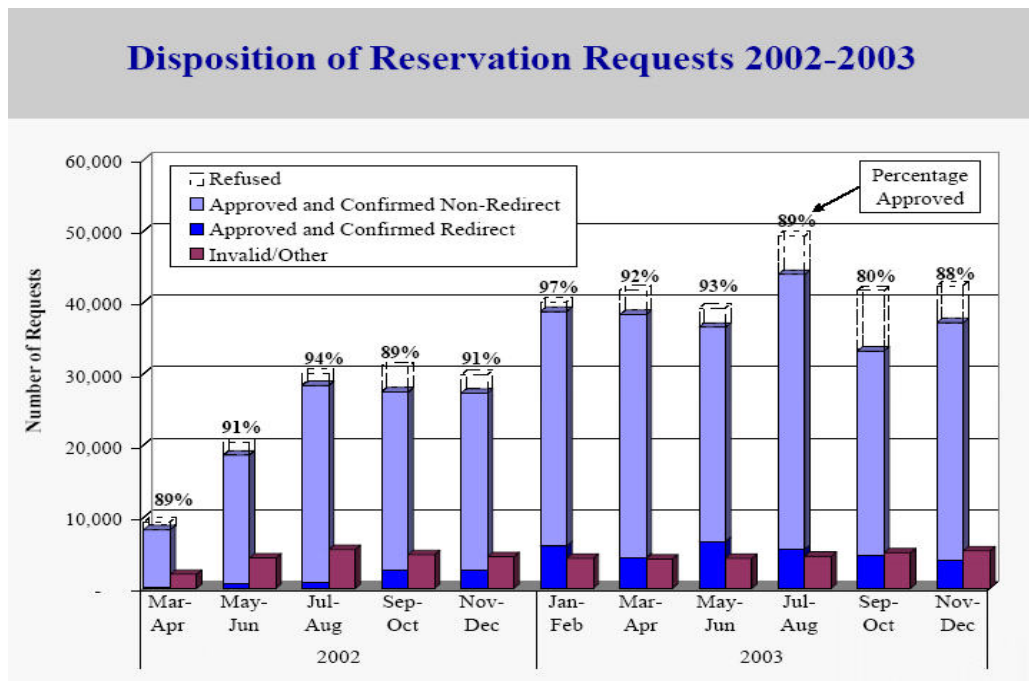
**Exhibit II-8**



**6.4 Transmission Request Analysis**

This is a simple test that seeks to determine if the transmission system is being used to prevent competitive suppliers from getting to the market. The report finds that both the requests and approvals of transmission service have risen substantially from 2002 to 2003. As Exhibit II-9 shows, approvals ranged from a low of 80% to 97% with most months showing approval rates in the mid 90's. At the same time approved firm requests increased by 73% from 2002 to 2003. This suggests that parties who want to move power generally can get the transmission they need. This test may make the situation appear better than it is, however, because often transmission users will not even make a request if they know it will be denied. The OASIS Scenario Analyzer system facilitates this by providing an indication of transmission availability even before the request is made. Based upon the experience of Nebraska utilities on Technical Group #2, this is a fairly common occurrence. An exact measure of this self-declination is unknown, but it is thought to be significant.

**Exhibit II-9**



## 6.5 Transmission Curtailment Analysis

### 6.5.1 Number and GWH Amount of MISO Electricity Transactions Curtailed

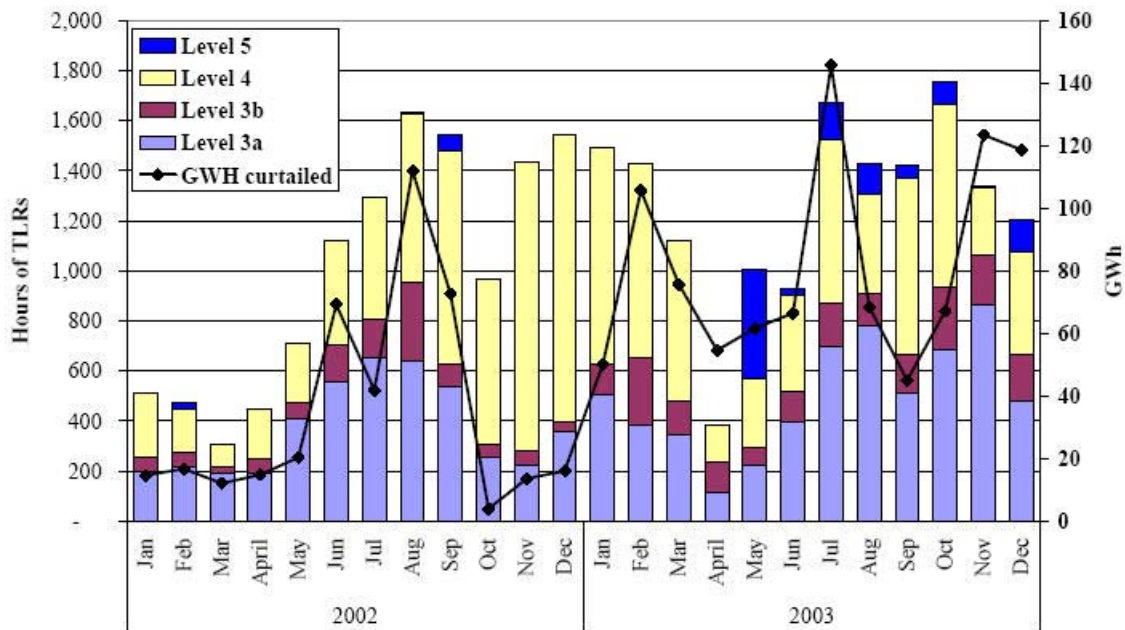
Whenever a transmission line becomes loaded to the point it is operating near its total capacity, the reliability of the system is threatened. In these situations, a TLR or Transmission Loading Relief can be called. If a TLR is invoked several actions may be taken depending on the severity of the situation. The first step, called TLR level 3a, is to curtail non-firm electricity transactions for the next hour. TLR level 3b is the next step, curtailing non-firm transactions for the current hour. If this is not enough, a TLR level 4 is invoked whereby the system is redispatched by asking generators to increase or decrease their power output. Next a TLR level 5 is called where firm transactions are curtailed. Finally, TLR level 6 requires emergency actions to protect the integrity of the system.

Whenever a TLR is called, there is an opportunity to exercise market power on the downstream side of the constrained line. The curtailment can create a load pocket where an isolated generator can manipulate the price.. Therefore the number of TLR's called and the GWH amounts involved in the curtailments are an indicator of the potential for market power. Exhibit II-10 shows the number of TLR's and GWH curtailed in MISO have both risen significantly in 2003 when compared to 2002. This was more TLR's than any other RTO, representing 62% of the TLR's in the Eastern Interconnect. This indicates at least the potential that isolated submarkets may exist that give generators the opportunity to exercise market power.

One mitigating factor is that a large percentage of the MISO TLR's called were in the WUMS area. It is a known load pocket where mitigation measures can be implemented. A number of TLR's also occurred in Iowa. This was due to relatively light hydro conditions for Manitoba Hydro, which significantly affected the schedules and flows through the regions.

**Exhibit II-10**

### TLR Events and Transactions Curtailed 2002 to 2003



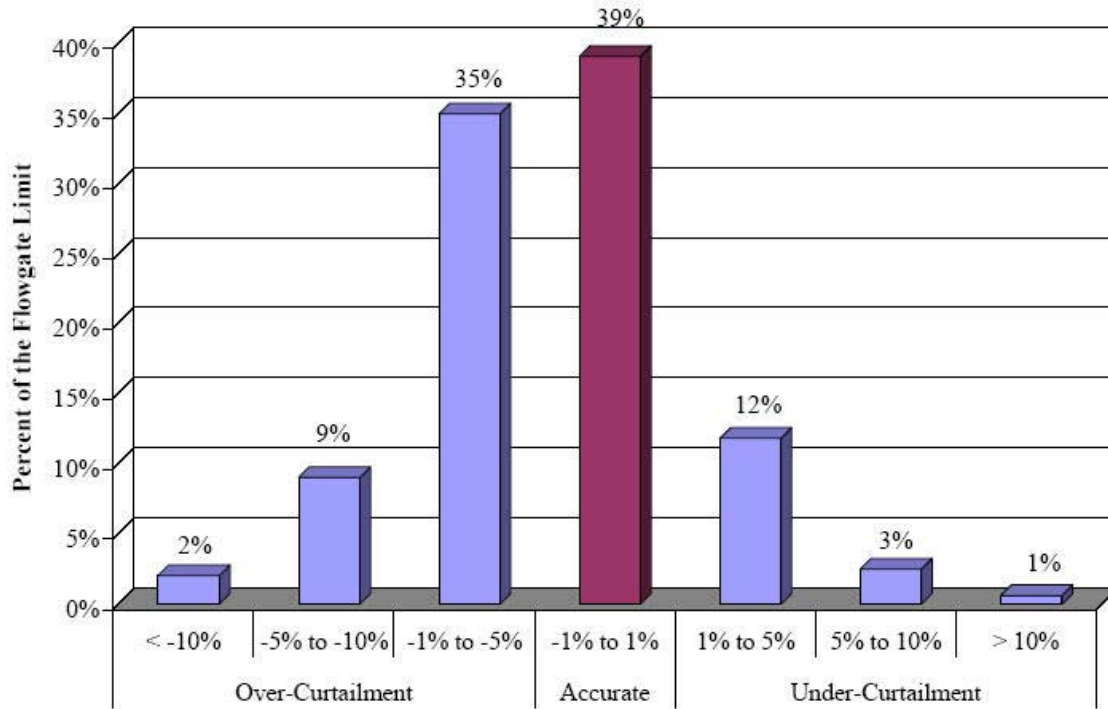


### 6.5.2 Justification of MISO TLR's

Another question is whether the MISO TLR events were justified. If TLR's are called when the conditions are not warranted, it may indicate use of the process to support the exercise of market power. A way to test this is to conduct studies that compare the real-time electricity flows relative to transmission capacity at the time that TLR's were called. Exhibit II-11 shows of all the TLR's that were called in MISO, 39% brought the actual electric flows over the flowgate to within +/-1% of the actual flowgate capacity. 86% of the TLR's were accurate to within 5. This demonstrates that TLR's were justified for reliability purposes and not to exercise market power.

Exhibit II-11

### Distribution of Over and Under-Curtailments During TLR Events in 2003



### 6.5.3 TLR Price Effects Analysis

The most important question about TLR's is whether they actually result in the exercise of market power. When constraints are binding, and additional power is prevented from flowing into the constrained area, the price in the constrained area ("downstream price") should rise relative to the price outside of the constrained area ("upstream price"). The analysis was conducted on major transmission lines or "flowgates" within the MISO area. There are about 600 flowgates that MISO routinely monitors. A sample of flowgates with a history of many TLR's was selected for the analysis. For each of the flowgates selected, the upstream-downstream wholesale price differential was calculated for times when the flowgate did not have a TLR called and for times when there was a TLR invoked. The price differential is simply the wholesale market price on the upstream side of the constraint minus the price on the downstream side. By statistically comparing the non-TLR differentials with the TLR differentials it can be determined if the TLR had an effect on the market price in the constrained region. This year the analysis demonstrated that there were not significant differences in upstream prices and downstream prices during a TLR event. Very few flowgates had differences that were statistically significant. The flowgates that were identified are in known localized load pockets where it is expected that market power would exist.

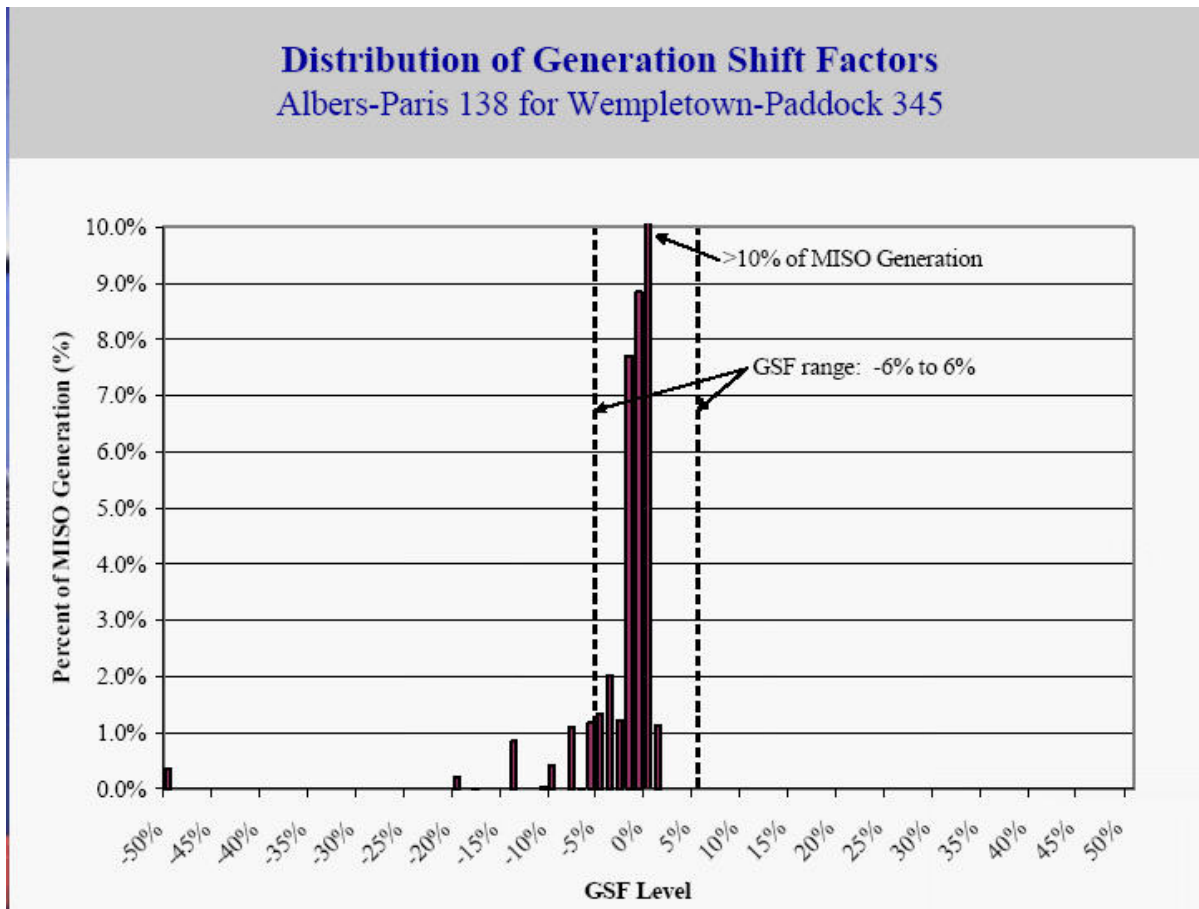
Even though there appear to be a significant number of TLR's in MISO, this analysis demonstrated that the TLR's do not generally result in the exercise of market power.

## 6.6 Pivotal Supplier Analysis

Every generator in a region will affect the loading on every transmission flowgate in a region. If one generator has a very significant impact on the loading of a flowgate and there are few other generators in the position to counteract that dominance, the generator is said to be a Pivotal Supplier. Pivotal Suppliers have the ability to create congestion on a line. This can induce transaction curtailments that may favor the Pivotal Supplier. In many cases it is economically more efficient to “redispatch” generators in order to relieve a transmission constraint as opposed to arbitrarily curtail firm transactions. The RTO redispatches by taking bids from generators who will either increase or decrease generation to relieve the constraint. Pivotal Suppliers would be in a position to bid up the price of redispatch because they lack competition. Both the ability to induce curtailments or create an advantage in redispatch bidding result in localized market power for the Pivotal Supplier.

Some generators that are very large and are in close proximity to the transmission line will have significant effects on the loading of the flowgate. Other generators that are small or are far away from the flowgate will have a negligible effect. The portion of each generator’s output that will flow over a flowgate is called a Generation Shift Factor or GSF. A positive GSF indicates that additional production from the generator will increase the flow on the flowgate in the normal direction of the flow (i.e. it will increase the congestion). A negative GSF indicates that additional production from the generator creates flows in the opposite direction of normal flow. An increase in production from this unit would decrease congestion. Pivotal Suppliers can be identified by calculating all of the GSF’s for every flowgate in the region. To identify potential Pivotal Suppliers, MISO calculated the GSF’s for 121 of the most congested flowgates. The GSF values came from the results of the MISO Load Flow Case using the PowerWorld Transmission simulation Model. For example, Exhibit II-12 shows the GSF’s of all generators in MISO over one Flowgate. In this example it is the Albers-Paris 138 for Wempletown-Paddock 345 Flowgate. As would be expected, this graph shows that almost all the generators in MISO have very little influence on the additional flows through the flowgate, i.e. the GSF’s are between -5% and 5%. This means less than 5% of additional output from those units flow through the flowgate. .

**Exhibit II-12**



However, this flowgate has very few generators that can significantly affect the flowgate in this load flow case. This would give each of the generators a greater opportunity to cause congestion on the flowgate and to have an advantage in redispatch bidding. This flowgate is more likely to have a pivotal supplier.

For the Pivotal Supplier Test, MISO considered a supplier to be pivotal when it was able to cause a constraint to be binding on the MISO system that cannot be resolved by redispatching other supplier's generation. In the least conservative scenario used to identify Pivotal Suppliers, a total of 52 Pivotal Suppliers were identified. However, of all the flowgates that exhibit one or more pivotal suppliers, generally only flowgates into or within WUMS are frequently congested. This means of all the pivotal suppliers identified, only those in the WUMS area would be able to effectively use that position to exercise market power. To mitigate the market power of Pivotal Suppliers, MISO suggests that "reliability must run" agreements be signed with those generators. MISO has designated WUMS and North WUMS as narrow constrained area for purposes of the market mitigation measures filed in March 2004.

## **7.0 Conclusion**

### **7.1 Status of Viable Midwest Wholesale Market in the Eastern Region**

The new information gathered for this year's analysis is sending mixed and ambiguous signals regarding market power in the Midwest portion of the Eastern Interconnect (as shown in Exhibit II-1). On one hand, "traditional" tests of market power used by FERC suggest that this market has a large number of buyers and sellers and appears to be viable. A defined process for accessing wholesale transmission is available through MAPP, utilizing Schedule F for a period of up to 12 months, or by utilizing Midwest Independent System Operator (MISO) or individual transmission provider's tariff for durations ranging from hourly service to multi-year service. In short, the wholesale market appears to reasonably efficient and workable, supporting many useful trades each day. On the other hand, the Midwest wholesale market, at times, has limited access to reliable transmission for delivery, conditions that are conducive to the exercise of market power. The *MISO State of the Market Report* show that while this has not lead to widespread exercise of market power, the potential clearly exists. This is evidenced by the large number of TLR's in the area, the existence of pivotal suppliers and the anecdotal evidence that many transmission requests are not attempted because of the likelihood that they would be rejected. Furthermore, the newly approved FERC market power tests suggest most of the utilities in the region would be found to have market power, at least until all are members of an RTO that has centralized dispatch, a formal power market and established market power mitigation measures, a status not yet attained by MISO. The final conclusion is that a reasonable efficient and workable wholesale market does exist in the Midwest region, but it cannot be judged as being free from market power given the new FERC rules.

### **7.2 Status of Viable Midwest Wholesale Market in the Western Region**

There have been disruptions in Western wholesale power markets in recent years. In spite of these disruptions, energy deliveries have been maintained to customers in Nebraska located on the Western Interconnection. These customers are primarily served by MEAN and Tri-State.

The viability of the wholesale market has been hampered in recent years by transmission constraints, adverse hydro conditions, and lack of a viable regional transmission organization. Unless these conditions are addressed, it is unlikely that a viable wholesale market will exist on the Western Interconnection in the foreseeable future.

**Chapter Three**  
**“To what extent retail rates have been unbundled in Nebraska”**

## 1.0 Status of Unbundling in Nebraska

There have been no new developments regarding unbundling for Technical Group #3 to address. However, we did survey all the electric utilities in Nebraska to determine their current unbundling status, should deregulation occur. The results of the survey are listed below.

The purpose of Technical Group #3 has been to determine “To what extent retail rates have been unbundled in Nebraska.” It was not our purpose to determine the merits or problems with deregulation, but to identify the current status of unbundling in Nebraska, and to give the consumer a better understanding of the complexity and costs for the current infrastructure to be unbundled. It is important to remember that all effects of retail competition are very hard to predict, as each state has moved to competition with different issues and concerns.

## 2.0 Team Members

Jay Anderson	Omaha Public Power District
Rich Andrysik	Lincoln Electric System
Don Cox	Hastings Utilities
Chuck Eldred	Omaha Public Power District
Jim Gibney	Wahoo Utilities
Jamey Pankoke	Perennial Public Power District
Dawn Petrus	Nebraska Public Power District

## 3.0 Introduction

Neb. Rev. Stat. § 70-1001.01(6) defines unbundling as “the separation of utility bills into the individual price components for which an electric supplier charges its retail customers, including, but not limited to, the separate charges for generation, transmission, and distribution of electricity.”

There are various reasons why utilities may unbundle electrical service. The most compelling and the main reason that a utility unbundles is due to state statute or regulatory rule as part of a comprehensive deregulation plan. “The unbundling of retail electricity related services is a means to achieve direct access between consumers and competitive electricity supply. The overall objective of direct access is to reduce the total cost of electricity to society. Unbundling is therefore a means to develop a framework to facilitate consumer choice such that the overall cost of electricity to society is reduced.”<sup>1</sup>

Another reason that some utilities unbundle, which may not have been required to unbundle, is due to the need for better information on the costs of serving customers. In some states where deregulation has been instituted, municipal and public power entities have had the ability to opt out of deregulation, but have chosen to unbundle as a result of customer demand. Even in Nebraska one utility has chosen to unbundle and others are willing to consider it if their customers request it. Nebraska is in an enviable position of having low rates, so consumers are not pushing for deregulation. However, some

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<sup>1</sup> Dr. Artie Powell, Utah Division of Public Utilities position paper presented to Utah Public Service Commission, Unbundling Electricity-Related Services (Utah: 1998) p.1.

consumers are requesting unbundled billing information to compare the costs of individual components of their energy bill with those costs in their facilities in other states. This process on its own may cause other utilities in Nebraska to have to unbundle as customers may begin to ask for comparisons at the same level that they are receiving in other states.

To determine “To what extent retail rates have been unbundled in Nebraska,” a survey was assembled, and mailed to the 165 retailing electric entities of Nebraska. Technical Group #3 received a response rate of 97.6% of customers. Only four utilities did not respond.

Of those utilities that responded, the study basically found these main points.

- One utility stated that they have formally unbundled.
- Over half (78%) of the utilities did not have unbundled cost of service studies.
- Less than half (40%) of the utilities’ billing systems will accommodate unbundling.
- Only (50%) of the utilities believe they have enough information to unbundle.

**4.0 Survey Results**

The detailed information from the surveys follows in the tables below. The surveys were mailed out one time by the Nebraska Power Review Board. The surveys that were not returned were followed up by a telephone call asking for a response. In addition to the first follow-up telephone call, the Nebraska Power Review Board also made a follow-up call to those that did not respond.

**# OF RESPONES**

<b>TYPE</b>	<b>SENT OUT</b>	<b>RESPONDED</b>	<b>% RESPONSE</b>
Municipal	123	119	96.7%
Federal, State & District	30	30	100.0%
Rural Electric Cooperative	12	12	100.0%
<b>Total</b>	<b>165</b>	<b>161</b>	<b>97.6%</b>

**# OF ELECTRICAL CUSTOMERS REPRESENTED**

<b>TYPE</b>	<b>SENT OUT</b>	<b>RESPONDED</b>	<b>% RESPONSE</b>
Municipal	298,412	297,435	99.7%
Federal, State & District	596,162	596,162	100.0%
Rural Electric Cooperative	14,069	14,069	100.0%
<b>Total</b>	<b>908,643</b>	<b>907,666</b>	<b>99.9%</b>

**Q1A. - HAS YOUR ORGANIZATION FORMALLY UNBUNDLED YOUR BILLS FOR ELECTRIC SERVICE?**

<b>TYPE</b>	<b>% - YES</b>	<b>% - NO</b>	<b># OF RESPONSES</b>
Municipal	0%	100.0%	119
Federal, State & District	3.3%	96.7%	30
Rural Electric Cooperative	0%	100.0%	12
<b>Total</b>	<b>.62%</b>	<b>99.4%</b>	<b>161</b>

One utility in Nebraska has unbundled. The utility that has unbundled is Loup River Public Power District. They have one rate class that is unbundled (per customer request.) The unbundling breaks down the customer's charges into the following:

Production Demand  
Transmission Line  
Transmission Substation  
Sub-transmission Line  
Sub-transmission Substation  
Energy

**Q1B. - IF YOU HAVE NOT UNBUNDLED, HAS YOUR ORGANIZATION COMPLETED ANY UNBUNDLING RATE STUDIES?**

<b>TYPE</b>	<b>% - YES</b>	<b>% - NO</b>	<b># OF RESPONSES</b>
Municipal	9.7%	90.4%	114
Federal, State & District	62.1%	37.9%	29
Rural Electric Cooperative	50.0%	50.0%	10
<b>Total</b>	<b>22.2%</b>	<b>77.8%</b>	<b>153</b>

**Q2A. - WILL YOUR CURRENT BILLING SYSTEM ACCOMMODATE UNBUNDLING?**

<b>TYPE</b>	<b>% - YES</b>	<b>% - NO</b>	<b># OF RESPONSES</b>
Municipal	31.2%	68.8%	112
Federal, State & District	58.6%	41.4%	29
Rural Electric Cooperative	81.8%	18.2%	11
<b>Total</b>	<b>40.1%</b>	<b>59.9%</b>	<b>152</b>

**Q2B. - IF YOU ANSWERED "NO" TO QUESTION "2A," ARE YOU PLANNING TO CHANGE SYSTEMS TO ACCOMMODATE UNBUNDLING OR ARE YOU**

**CONSIDERING THIS ISSUE IN THE PURCHASE OF ANY NEW BILLING SYSTEM?**

<b>TYPE</b>	<b>% - YES</b>	<b>% - NO</b>	<b># OF RESPONSES</b>
Municipal	7.8%	92.2%	77
Federal, State & District	58.3%	41.7%	12
Rural Electric Cooperative	50.0%	50.0%	2
<b>Total</b>	<b>15.4%</b>	<b>84.6%</b>	<b>91</b>

**Q2C. - DOES YOUR ACCOUNTING AND COST OF SERVICE INFORMATION PROVIDE ENOUGH DATA FOR YOU TO UNBUNDLE YOUR ELECTRIC BILLS?**

<b>TYPE</b>	<b>% - YES</b>	<b>% - NO</b>	<b># OF RESPONSES</b>
Municipal	40.0%	60.0%	110
Federal, State & District	86.7%	13.3%	30
Rural Electric Cooperative	50.0%	50.0%	12
<b>Total</b>	<b>50.0%</b>	<b>50.0%</b>	<b>152</b>

**5.0 Estimated Unbundling Costs**

Technical Group #3 also previously estimated what the total cost for unbundling in Nebraska would be, should the electric utility industry open to competition. Costs associated with moving to retail competition were addressed, but were very hard to predict.

Separating unbundling from deregulation is very complicated. Deregulation impacts the unbundling process. Therefore, when determining the costs to be included in unbundling, which is a small piece of the deregulation process, certain assumptions had to be made. The cost methodology was highly speculative and subject to many assumptions. Because there is no rate making authority in Nebraska, most costs were estimated based on the input of OPPD, LES, NPPD, and Rural Public Power Districts. For municipalities, the technical group used information from the Nebraska Municipal Power Pool (NMPP). Various items determined to be unbundling costs were obtained. To determine the estimated costs, the entities involved completed a spreadsheet with the estimated costs that would be incurred by them. The individual results were then accumulated into categories, and a state-wide total cost to unbundle was estimated. (See Annual Report-2002 for detailed information).

The technical group estimated the cost for only unbundling in Nebraska to be approximately \$9 million. This would include an estimated one-time cost of approximately \$8 million. The on-going cost per year would be approximately \$1 million. A state-wide consumer education program would be needed to communicate to the consumer a new billing process, so consumer education on a state-wide basis was included in these estimated costs. The estimated cost per customer was based on other



deregulated states. The technical group used a \$1.36 average cost per customer (which was based on the information received from Pennsylvania), and then applied this cost to the number of customers in each public power entity in Nebraska.

The unbundling portion is only a small part of total deregulation costs, evidenced by the magnitude of the costs associated with unbundling and consumer education in other states. A determination of the level of unbundling for the state of Nebraska has currently not been made. However for purposes of determining a cost, we assumed generation, transmission, distribution, a customer charge, and up to two other items would be included, (i.e. probably no more than 5 or 6 line items).

## **6.0 Conclusion**

These are the results that were gathered over the past years. Technical Group #3 will continue to review the status of unbundling in Nebraska, and report the results as needed.

## **Chapter 4**

**"A Comparison of Nebraska's Wholesale Electricity Prices  
to the Prices in the Region"**

## 1.0 Introduction

### 1.1 Purposes and Group Membership

The purpose of the fourth “condition-certain” Technical Group was to make “a comparison of Nebraska’s wholesale electricity prices to the prices in the region.” The Technical Group #4 that worked on this issue was combined with Tech Group #2 because of the common backgrounds required and the similarities of the issue and included the following individuals:

Clint Johannes (Chair)	-	Nebraska Electric Generation & Transmission Cooperative, Inc. (NEG&T)
Deeno Boosalis	-	Omaha Public Power District (OPPD)
James Fehr	-	Nebraska Public Power District (NPPD)
Dennis Florom	-	Lincoln Electric System (LES)
Kevin Gaden	-	Municipal Energy Agency of Nebraska (MEAN)
Burhl Gilpin	-	Grand Island Utilities
John Krajewski	-	MEAN
Derril Marshall	-	Fremont Utilities
Allen Meyer	-	Hastings Utilities
David Ried	-	OPPD
Jon Sunneberg	-	NPPD

Before moving toward retail competition, there should be the reasonable chance of the customers’ ability to obtain lower electricity prices. The portion of a retail customer’s bill that will be open to competition is the electric commodity (wholesale) portion. The transmission and distribution wires will be utilized much the same with any electric commodity supplier. Only one set of electric wires can be financially or operationally supported. It is therefore important that the wholesale electricity prices in the region be at or below Nebraska’s prices. This issue addresses Nebraska’s electric prices compared to the region.

### 1.2 Approach

There are no directly comparable electric price indices available for the electricity product currently provided to and expected by Nebraska customers. The Nebraska product is firm and available 24 hours per day, seven days per week and the consumption will vary based on the individual customer’s need. The regional price indices typically represent a predetermined fixed amount of energy for a specified portion of a day or week, not the customers’ total electrical full requirements. To make a price comparison using these available market product indices required the conversion of Nebraska’s electricity prices to market product indices.

A major component of “condition-certain” criteria is the ability to compare Nebraska costs to regional or market prices. To accomplish this task, current Nebraska wholesale electricity production costs were compared to available market price based electricity products on an equitable basis, utilizing publicly available, independent, and credible indices.

There is no formalized method to value an electricity product without the market making an offer to buy or sell the same product, so comparing Nebraska wholesale electricity production costs to available market indices is a viable approach to determining differences between Nebraska cost and regional or market prices.

## 2.0 Wholesale Market Terminology

### 2.1 Market Product Definitions

Currently, the only publicly available, independent, and credible indices for electricity products are indices known as “Monthly Forwards” and/or “Monthly Futures,” as well as historical “Daily Settlement Prices” for electricity products at certain geographical locations called “markets” or “hubs.”

The “Monthly Forward Price” of an asset is the price established today with a non-exchange traded bilateral contract, for delivery of the asset on a designated future date at a specified location (“hub” or “market”). The

“Monthly Futures Price” is a contract associated with a particular “hub” or “market” for future delivery of a commodity, exchange traded (physical delivery is possible, but not required).

The “Daily Settlement Price” is an index of the weighted average of trading prices for the asset within the market closing range for the day, and a multitude of daily price indices are more readily available than the limited quantity of publicly available forward prices (bilateral contracts).

The “markets” or “hubs” represent specific transmission systems where the electricity can be obtained at the price listed on the specified index.

## **2.2 Comparison Concepts**

To be able to make the appropriate comparisons on a fair and equitable basis, the market product offerings have to be clearly defined through the determination of the product definitions for various available price indices and which of these independent price indices represents the “market” that Nebraska customers could purchase their power supply from. There are certain additional benefits that Nebraska power systems provide customers that a market product may not provide or would charge extra for the service. Examples of these services include, but are not limited to, consistency or firmness of delivery, reserve capability to serve load, ancillary services, as well as non-generation production services such as economic development, advertising and community web-site services.

## **2.3 Physical Product Definitions**

To help understand the concept of comparisons, some basic definitions of the product and nomenclature should be clarified. When a customer flips a light switch and the light comes on, the electrical power required to turn on the bulb is considered “load,” and the power that serves the load is nearly instantaneously created at a power plant and transmitted through transmission & distribution lines to serve that particular customer. Electricity that serves a given load over a specified time period (usually an hour) is called “energy,” and the physical unit of energy (in large quantities) is called a Megawatt-hour (MWH). The physical capability to provide this “energy” on an instantaneous basis is called “capacity,” so “energy” is different from “capacity” because “energy” is over a greater, more useful and easier measured unit of time, such as a single hour.

This description helps explain why market products are typically defined on a dollar per Megawatt-hour (\$/MWH) basis over a specified time period and either include or exclude a physical capability component (capacity), or possibly a financial guarantee of performance (Firm Liquidated Damages – FLD).

## **2.4 Market Product Time Period**

The time periods associated with market products are divided into times when there tends to be a higher demand for electricity called “Peak,” and a lesser demand called “Off-peak.” These general time periods are then further subdivided into days and number of hours each day as listed below:

- 5 x 16 (5 days per week – Monday thru Friday, 16 hours per day typically hour beginning 6:00 AM to hour ending 10:00 PM) – considered “Peak”
- 7 x 8 (7 nights per week, 8 hours per night typically hour beginning 10:00 PM to hour ending 6:00 AM) - considered mostly “Off-peak”
- 2 x 16 (2 days per week-ends) – considered mostly “Off-peak” some include Saturday as “Peak”
- 7 x 24 (7 days per week, 24 hours per day - around the clock) – “Peak” + “Off-peak”

## **2.5 Market Product Categories**

The market also divides its products into categories that are defined by guaranteed and non-guaranteed availability. If the market guarantees availability it is called “firm.” This “firmness” is either backed up by a pro-rata cost share of physical capability (either cost of new capacity or fixed cost of existing capacity), or the promise of money – FLD to compensate for possible additional costs to procure energy. If the customer will accept non-guaranteed availability conditions, then the price of this “non-firm” product is usually lower because the customer is sharing the risk of availability with the market, and does not need to compensate the market for guaranteed physical capability. It should be noted that these blocks of power are provided at a fixed amount,

100% of the time within the time periods, and is termed a “100% Load Factor” product. Few end-use customers require this amount of power all the time; however, the market product is priced as such since the current market price index mechanisms do not account for varying customer load patterns. For example, within a period of a year, a typical residential customer has a lower need for electrical power, as demonstrated with a “load factor” of less than 50%, whereas a commercial customer, such as a grocery store would typically be between 50 & 75%. Industrial customers load factors typically range in 60% - 95%, depending on the type of production process involved. However, on the other end of the scale, an irrigation customer may only have a load factor of 10-20%, because of the limited amount of time within a year the energy is required.

## **2.6 Market Price and Production Cost Difference**

Prices and costs are fundamentally different concepts. The cost of producing a product can vary dramatically from the price of a product, which is determined by what customers are willing to pay.

When a particular product is in very high demand, buyers competing against each other bid the price up irrespective of the underlying cost. For example, parents competing against each other for the hottest new toy at Christmas (high demand chasing limited supply) will bid up the price to extraordinary levels.

On the other hand, if the supply of a product exceeds the number of people who want to buy it, suppliers will compete with each other driving the price downward (the same toy, after Christmas). If supply far exceeds demand, prices will even fall below the total cost of production. This is because suppliers are better off receiving some money for their product than none at all, as long as the price will cover the cost of raw materials for the product (variable costs) and contribute, even a little, to recovering cost of the production plant (fixed costs). This price-below-cost situation will prevail until: 1) the demand for the product increases; or 2) weak suppliers go out of business, reducing supply to match demand.

## **2.7 Market Price Volatility and Production Cost Stability**

Price volatility is a measure of the rate at which price swings up & down in a market and is caused by abrupt changes in the demand and supply for a product as described above. An industry can have a fairly stable cost structure but still experience high price volatility for this reason.

The electric utility industry is a classic example of price volatility issues. Traditionally, regulated utilities with a guaranteed market could keep cost of production relatively stable by financing generation plants over long periods of time and entering into long-term fuel contracts. On the other hand, the competitive electric utility industry has very high price volatility when compared to other commodities, such as grain, oil and natural gas. This is because power markets have several unique characteristics based on the physics of electricity. Probably the most important economic characteristic of electricity is its inability to be stored easily. Unlike the market for more storable commodities in which storage ability reduces price fluctuations, electricity is primarily balanced in a real time spot market. Thus, in addition to a power market for energy, there is a value attributed to owning “capacity” (or capability to produce) in power markets which does not exist in other commodity markets.

For these reasons market prices may fall below Nebraska production costs at times, but these losses are typically made up during peak price periods, thereby contributing to higher peak season prices than Nebraska’s production costs. Furthermore, if the volume the market wishes to buy or sell is large relative to the volumes traded; this single purchase itself could cause the market price to move significantly.

Power markets are specific to each region’s unique supply and demand characteristics. For example, in the Illinois region, unforeseen plant outages and transmission problems combined with warmer than normal temperatures to cause the prices to spike in the summer of 1998 for a short time. In contrast, western power markets hydroelectricity plays a significant role; a dry year can cause prices to remain relatively high until the reservoirs are replenished. These types of issues can combine to provide multiple sources of considerable supply uncertainty, thereby making demand subject to high prices.

To add to this situation, there is a lack of a flexible market in financial risk management products with which to hedge physical and transmission risks. Although financial options are beginning to become part of the electric price volatility hedging tool chest, the vast majority of the trades in power settle into physical delivery.

Markets will increase price because the commodity has become more valuable and because electricity consumers virtually have an unlimited option on power supply at a fixed price, the market will recover any losses suffered earlier during times when supply was plentiful and prices were below cost to produce.

The electric consumer should therefore be aware that while low market prices may fall below the cost of production, this situation put forces into motion that will serve to correct this situation resulting in, at various times, market prices that are well above cost of production.

## **2.8 Market Product Price**

The market price that is quoted in the indices based upon the above-defined criteria represents product availability at the particular “market” or “hub” that the price indices are named after, not delivered to the customer, unless clearly specified. For example, the “Entergy” price index is for a financially firm (includes FLD) energy product provided 5 days per week (Monday-Friday), 16 hours per day available at the Entergy transmission system which covers part of Arkansas, Mississippi, Louisiana and Texas. The “Cinergy” price is available under similar conditions at the Cinergy transmission system, which covers Central and South Indiana, Southwest Ohio and North Kentucky. The “ComEd” price represents the North Illinois region.

Since the market price is tied to these specific locations the customer would have to pay an additional charge to transmit this power to another location. This transmission charge is an additional cost to deliver that is not part of the price indices that are published, therefore, when directly comparing market prices to Nebraska costs, the transmission delivery charge should be accounted for in the comparison methodology.

## **2.9 Transmission Cost & Loss Considerations**

The Midwest Independent System Operator (MISO) transmission region covers a larger geographical area than the previous Mid-Continent Area Power Pool (MAPP) transmission region, thereby increasing the physical delivery costs & losses associated with moving market-priced electricity products to the customers within the state of Nebraska. Currently, electricity traders are experiencing as much as 17 % in delivery losses, which add similar percentages to the price of a market product. Also, the standard market transmission tariffs associated with delivering these market products from external regions to Nebraska customers can add an additional \$4 – 6 / MWH to the market product price.

## **2.10 Nebraska Production Cost**

The cost to produce electricity by Nebraska power systems should be clearly determined on the same basis, applying the same type of definitions the market uses in order to determine a fair and equitable comparison. The issue becomes separating the various components of Nebraska power system costs to match the available market product indices, because Nebraska power systems provide a much more sophisticated product to its customers than the product as defined by the market price indices.

The Nebraska power system product includes a physical capability component (capacity) that is over and above the requirement for Nebraska electrical load in order to make sure that if a power plant fails or the weather becomes unusually severe, the Nebraska power systems have “reserves” available to serve the customers’ load as expected. This “reserves” component of Nebraska costs is part of a minimum 15% capacity reserve requirement that provides a higher level of reliability that is not part of the market product pricing. Some Nebraska systems even carry additional reserves over and above the 15% minimum as a matter of policy for physical risk hedging due to severe weather fluctuations that would increase load, fuel disruptions, and/or unforeseen extended plant outages.

## 2.11 Long-term “Obligation to Serve” Considerations

The Nebraska power system product is based on a long-term “obligation to serve” that is not inherent in market-based electricity products. The long-term, in this case, is typically a thirty to forty year obligation stemming from the commitment to build various physical generation unit types to provide stability in power resources that is derived from having “iron on the ground”, and limited dependence on the market providing the power resources and prices to serve the expectations of Nebraska’s electric customers. The current public power structure is based on the premise that the Nebraska state legislature expects, or “obligates”, Nebraska’s power systems to serve the electric customers of Nebraska in a reliable and cost-efficient manner, which translates to a long-term commitment to providing physical resources that meet or exceed Nebraska’s power systems “obligation to serve”. A market-based electricity product provider does not share this same responsibility, hence, there is downward pressure on the price for the market-based electricity product as compared to local providers.

## 2.12 Various Generation Unit Types Serving Load

Power resources can be categorized as Baseload, Intermediate, and Peaking capacity, based on the number of hours (or capacity factor) a given resource is expected to operate.

–Peaking Units:	0 - 25% of the year
–Intermediate Units:	15 - 75% of the year
–Baseload Units:	60 - 100% of the year

Some forms of generation, such as nuclear and large fossil steam units, are well suited for Baseload operation because of their relatively low operating cost, even though their installed capital cost may be higher. Conversely, other forms of generation that have a lower installed capital cost, such as Combustion Turbines, generally have a higher operating cost (principally due to fuel and heat rate), thus making them appropriate to utilize as Peaking units. An example of an Intermediate unit would be a Combined Cycle, which has the flexibility to run at lower or higher capacity factors. Renewable technologies, such as wind generation, when compared to these conventional power resources, are considered a customer-specific option used as a “load-reducer”, as opposed to a generation resource available on-demand.

## 2.13 Ancillary Services Component

Another component of Nebraska power systems that is not included in general market product pricing are items called “Ancillary Services.” These services are additional benefits that customers can receive that provide improved power flow benefits and increase the value of the electrical product utilized. These services include Scheduling, System Control and Dispatch; Reactive Supply and Voltage Control; Regulation and Frequency Response; Energy Imbalance; and Operating Reserves (both Spinning and Supplemental). Detailed descriptions of these “Ancillary Services” were provided in Appendix 4-A of the 2001 and 2002 LB 901 Reports. The “reserves”, the long-term “obligation to serve”, and “Ancillary Services” should be accounted for in the comparison methodology for market prices and Nebraska costs.

## 2.14 Load Factor Considerations

Lastly, the Nebraska power systems are designed to serve varying customer load patterns and have lower load factors, as discussed earlier in Section 2.5, whereas the market products are for blocks of 100% load factor products, so Nebraska power system costs should be allocated appropriately over the higher load factor product in order to equitably match the market product pricing. No matter what the load factor or when the energy is required, Nebraska utilities are obligated to maintain the physical capability, or capacity, to provide the energy when needed even though it may not be utilized by every customer 100% of the time.

### **3.0 Market Product Pricing & Nebraska Production Cost Comparison Methodology**

#### **3.1 Alternative Comparison Methods**

There are several methods of approaching a fair and equitable comparison:

- (1) Send out a Request for Proposal (RFP) on electricity products to serve customers on the exact same basis as currently served,
- (2) Purchase a regional electricity price application model from a vendor to determine an estimated market value,
- (3) Develop a fixed and variable cost allocation tool to determine Nebraska's "cost to provide" electricity that is on an equivalent basis with market products that have price indices and are publicly available, independent and credible.

Method three, the development of a fixed and variable cost allocation tool, was deemed the best approach of the three for the following reasons:

- (1) The RFP could be perceived by the market as a price discovery process only, so the respondents may not provide "real" bids, or the prices offered may be extremely low initially just to gain market entry. This implies that the prices would not be truly reflective of market value, and the process involved would be extremely time-consuming and labor-intensive to develop the RFP, let the bids, and evaluate the bids on an equitable basis just for price comparison purposes,
- (2) Purchasing a regional electricity price application model from a vendor would be cost prohibitive with an estimated cost of up to \$150,000 depending on level of detail and service provided, also the set-up and training required to determine equivalent electricity products could be labor-intensive,
- (3) The self-developed tool approach allows for all of the Nebraska power systems to have input on how the model should work to equitably compare costs and prices; fixed and variable cost allocations can be determined by each utility on the same basis as a market product for appropriate matching; the contract-sensitive data remains confidential; the modeling can be applied quickly and efficiently for each utility and then consolidated easily for a single state-wide result; the costs are minimal, and there is Nebraska utility acceptance of process and results.

#### **3.2 Comparison Modeling Tool Detail**

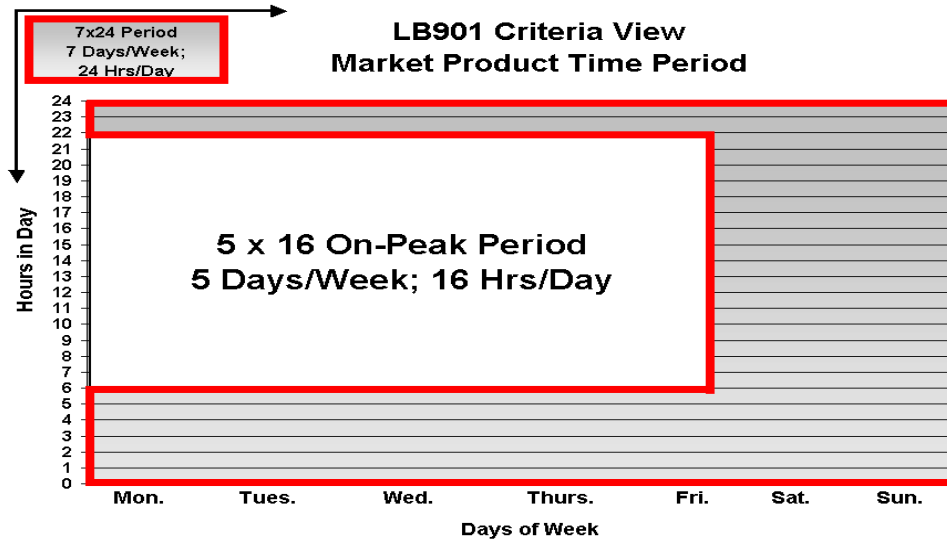
To develop a modeling tool that separates the various components of Nebraska power system costs to match the available market product indices requires clearly defining these costs. Therefore, since the available market price indices are for products located at specific transmission systems outside of the state, then Nebraska's electricity production costs should be calculated for availability within the Nebraska transmission systems only, so that additional transmission charges for delivery would be price neutral in the calculations. On this basis the following represents the methodology to define Nebraska power system costs in a manner that will allow a fair and equitable comparison to market products:

- (1) Determine the total annual production revenue requirements for all the Nebraska utilities' power resources,
- (2) Apply a consistent set of fixed and variable production cost accounts based on Federal Energy Regulatory Commission (FERC) accounting definitions to calculate the production cost to serve load,
- (3) Break down the total cost to serve (as determined in (2) above) to an hourly basis to determine a cost per hour to serve each utility's load based on an hourly load shape for each year (typically 8760 hours per year), which is accomplished by appropriately allocating the fixed and variable costs on a per hour basis to each utility's load that each utility is obligated to serve by weighting the costs on a MWH per year or market price basis, by time period (Peak and Off-peak), calculating an hourly \$/MWH cost to serve load in each of the 8760 hours of the year,

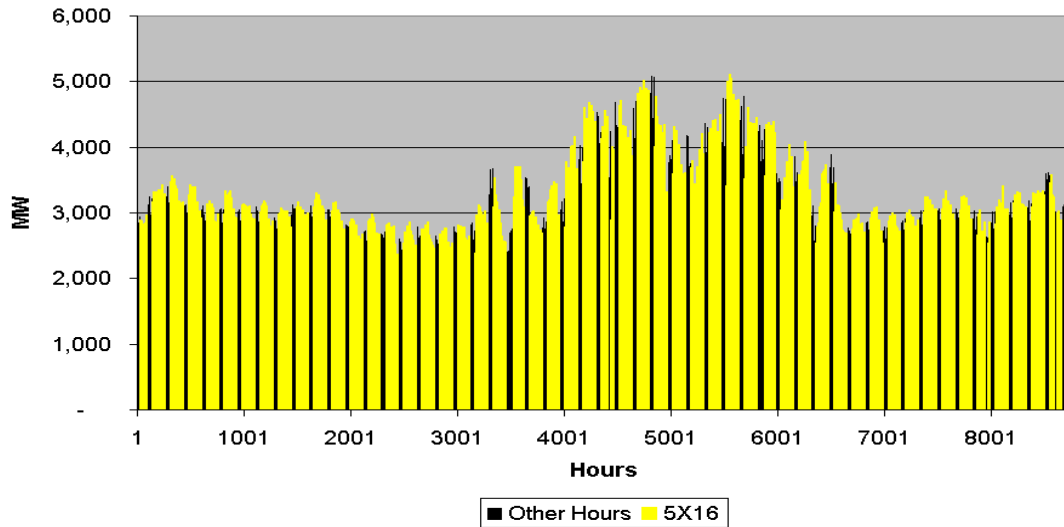


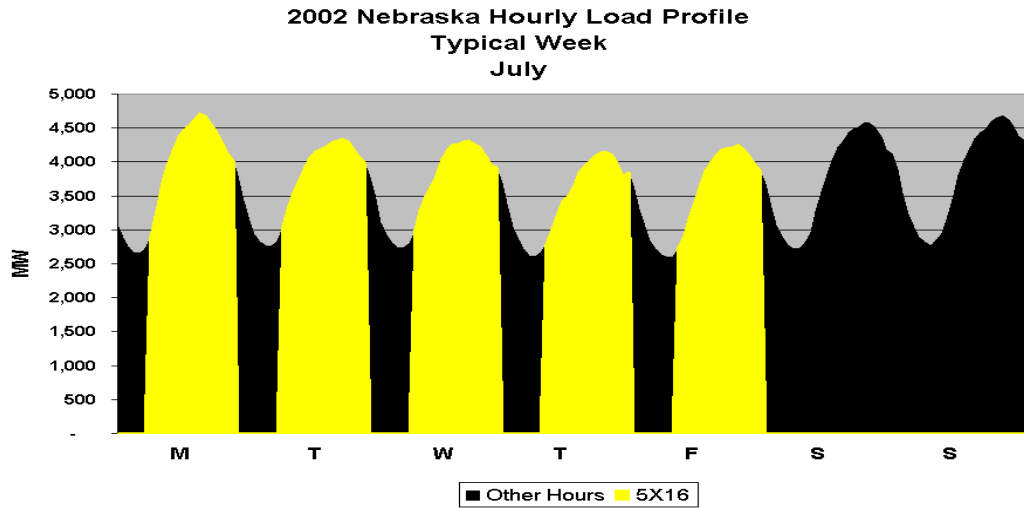
- (4) Since the costs have been calculated on a \$/MWH basis for each hour (as determined in (3) above), sum the hourly fixed cost and variable cost, less any obligation adders such as reserves, “obligation to serve” values and ancillary services, and adjust the load factors to match available market product indices which are on a 5 x 16 basis (5 days per week – Monday thru Friday, 16 hours per day). Exhibit IV-I below provides a graphical description of how much and during which times the load profile information is utilized.

**Exhibit IV-1**



**Nebraska Hourly Load Profile**





### 3.3 Comparison Modeling Tool Application

Based on the definitions and methodologies described previously, a comparison model and process were developed, applied by each Nebraska utility, and then consolidated for a single, state-wide Nebraska power system cost and market price comparison based on the following criteria:

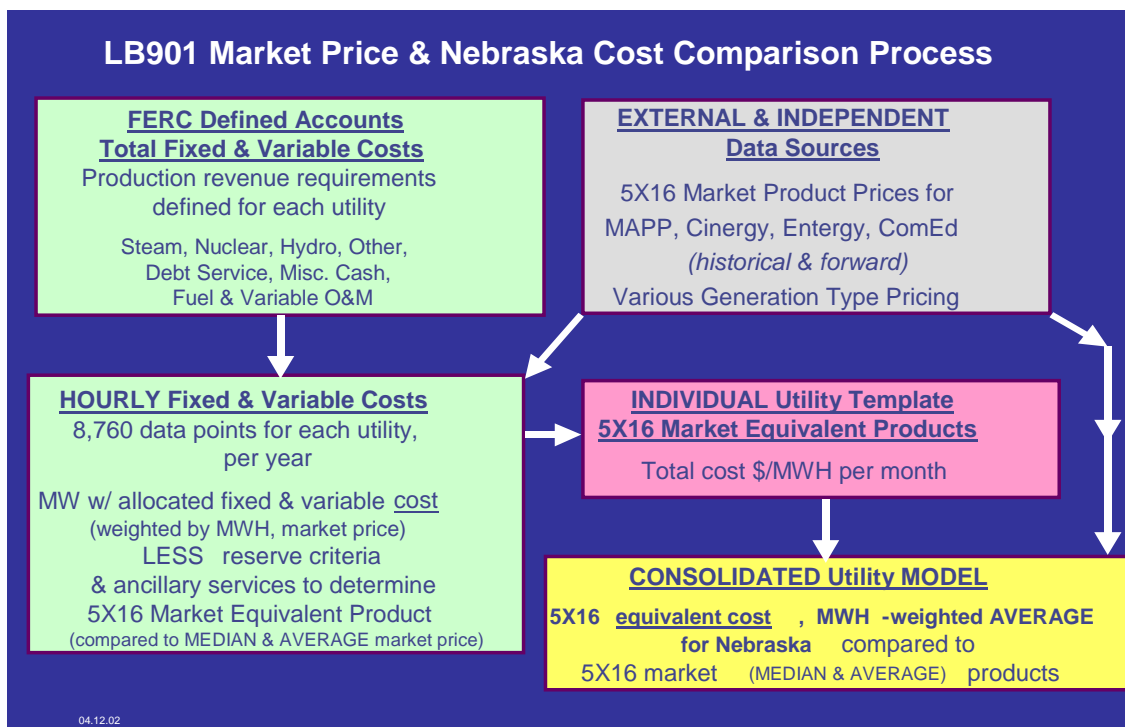
- (1) Costs and prices were compared on a total annual amount calculated per month for an equivalent 100% load factor, 5 x 16 market product since there were a multitude of market price indices available for this type of product,
- (2) Both “average” and “median” monthly market price history were calculated based on the daily price settlement indices utilizing the raw data from ‘Platt’s Global Energy - Power Markets Week - Price Index Database’ as the detailed source,
- (3) The market indices chosen to best represent a potential product availability for Nebraska customers located at the particular “market” or “hub” but not delivered to the customer, were “MAPP” (as available), “Cinergy,” “Entergy,” and “ComEd”; (“MAPP” history is available, but because of limited trading, or an “illiquid” market, no future pricing index currently exists); also, for physical resource comparison purposes, supposing customers built their own resources to serve their own load, various new generation unit types (peaking, intermediate & baseload) were priced & calculated, based on market cost allocation methods, then compared,
- (4) Two different methods of allocating the fixed costs of existing power resources for each utility were modeled in order to provide a range of possibilities in cost allocations for discussion to determine how most utilities would allocate fixed costs; these two methods were (a) January thru December monthly MWH-weighted, and (b) January thru December monthly market price-weighted; also, Ancillary Services, Planning Reserves, and Additional Capacity hedging values from existing utility price were subtracted from the utility costs in order to determine an appropriate market product price comparison,
- (5) For the study period, an anomaly occurred in 2000 when winter prices (specifically December) were higher than summer prices. It was recommended to “force” the fixed cost allocation when considering market price weighting of fixed costs to the summer because the single winter season of 2000 / 2001 was considered “unusual” and not typical of market pricing patterns. In March 2002, it was noted that actual January 2001 market prices were the highest prices in 2001, so the detailed market price comparison tool was updated to include the user-option of “forcing” the actual fixed cost allocations (for the market-price weighting of fixed costs portion only) into the summer months (June, July,

August) so that a single winter season price anomaly would not corrupt the overall comparison results. Also, for the Peaking unit only, the user has an option to compare Peaking unit costs when the market price warrants dispatching this type of resource (the market price is either equal to or higher than the Peaking unit cost).

- (6) The cost to serve Nebraska customers from Nebraska power systems was then compared to the cost to serve Nebraska customers from the market, calculated on an annual MWH-weighted basis from which a percentage of market price was calculated to quantify differences between Nebraska power systems and available market product pricing on a rolling average basis for 2001-2004 (3 years of history and 1 year of future pricing); annual price volatility (fluctuation) comparisons were also performed.

A process flow diagram describing the comparison model application and model names is provided in Exhibit IV-2 below:

**Exhibit IV-2**



## 4.0 Results of Modeling Tool Comparisons

### 4.1 Time-period Utilized

One of the key elements to comparing prices and costs deals with the time period over which the comparisons are actually made. For example, market prices may be higher during unusually high weather or transmission-constrained years and lower in others. Nebraska costs may be higher during nuclear unit re-fueling outage or emission-constrained production years and lower than others. In order to “smooth-out” these events on both sides of the comparisons and to maximize future pricing and cost data availability, three years of history and one year future (total of four years) were chosen as the appropriate time period for comparisons. The publicly available, independent, and credible market price indices are only currently available 12 –18 months forward, so the “future view” comparisons are limited, and future expected costs of utilities (e.g., production costs, required purchases, emission compliance impacts) can change many times over the next 18 months.

For 2004 modeling comparison purposes the time period of 2001 through 2004 is modeled and compared for the following reasons:

- The basic concept and current comparison modeling is to apply three years history and a one-year estimate that are developed on an annual basis so that a four-year rolling average is provided every year. The current time period being modeled is 2001-2004 with 2004 being the estimated year for both market pricing & production costs.
- Incorporating the future year 2005 into the modeling introduces another layer of “assumptions” & “speculation” that may reduce the credibility of an agreed upon modeling process that provides reasonable conclusions.
- Market pricing is changing on a month-to-month basis and comparing too early may provide a false signal of difference between market price and expected production costs both on a price & volatility basis. For example, the May 2001 price for an August 2001 market product was approximately \$83/MWh; in June 2001 the price for the same August 2001 market product was approximately \$55/MWh. With this price volatility just two months out, greater price swings can be expected 12 to 18 months out.
- Historical weighting reflects actual market prices & actual production costs which are more credible & accurate than projections or expectations. The four-year rolling average allows for anomalies & unusual fluctuations in both the market price & production costs to be smoothed out for more reasonable comparison purposes.
- Need to be cautious that legislative action is not triggered on projections or expectations which are subject to larger errors (e.g., California), but on actual experience and estimations that have a higher confidence of accuracy (e.g., just one year).

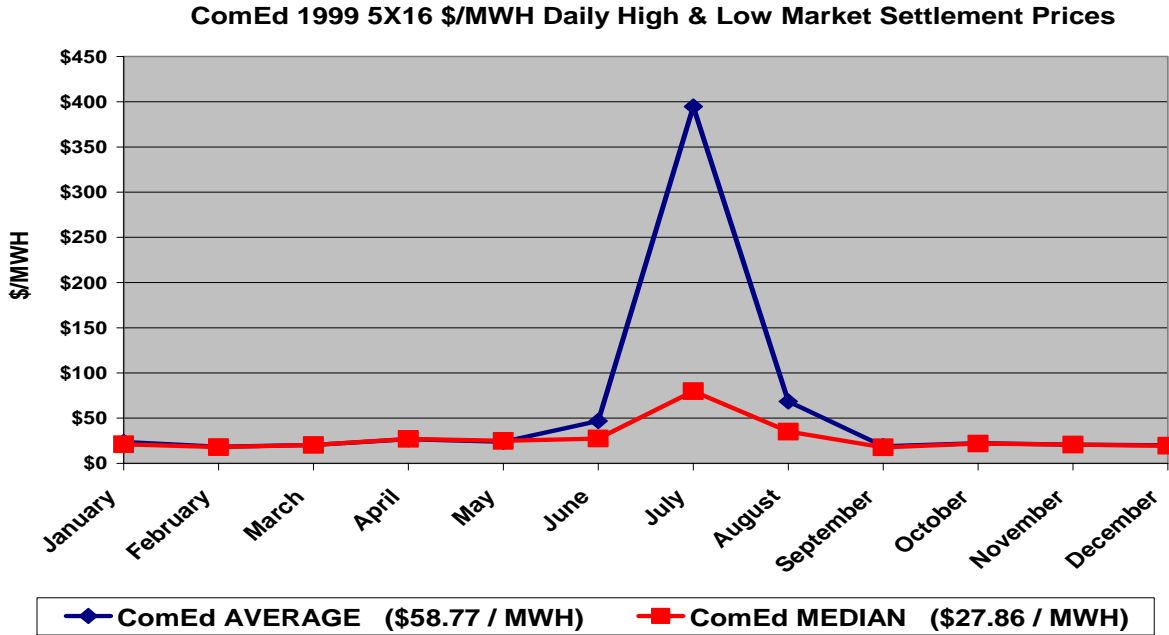
## **4.2 Sensitivity Cases Analyzed**

Based on performing several sensitivity analyses associated with “average” and “median” market pricing, fixed cost allocation by MWH-weighting, fixed cost allocation market price weighting, for fixed cost allocations, and time period for comparisons to market, the following conclusions were calculated.

## **4.3 Median Market Pricing**

Exhibit IV-3 below shows two distributions for 5X16 monthly market prices in the ComEd market for 1999, based on high & low daily settlement prices. One is based on the “average” of the daily high & low settlement prices, and the other is based on the “median” of the daily high & low settlement prices. The “average” represents the summation of all the prices divided by the number of prices, whereas the “median” is the middle number of the price after sorting from low to high. The “median” is considered more “typical” since it is not biased or skewed by a single high number, whereas the “average” can be biased or skewed by a single high number. Therefore, to avoid inherent biasing of the Nebraska cost comparisons to a higher market price (possibly driven by one or two high numbers), median market pricing was chosen as the better market criteria to compare and set the threshold for Nebraska costs.

### Exhibit IV-3



#### 4.4 MegaWatt-Hour (MWH) Weighted Fixed Cost Allocations

The comparison modeling developed allows for sensitivities to be performed applying two different methods of allocating fixed costs; (1) weighted by Peak & Off-peak period evenly over every MWH produced during each month of the year, and (2) weighted by the variation in market price – the higher the market price in a particular month then the more fixed cost is allocated to that month.

The MWH-weighted fixed cost allocation method was chosen since it more closely represents how Nebraska utilities are currently allocating their fixed costs (more evenly over every MWH produced during each month of the year) and does not overstate differences to market prices. When a market price – weighted fixed cost allocation method was used, Nebraska costs differences to market were only slightly better when compared to the MWH-weighted comparison to market.

#### 4.5 Other Cost Allocation Issues

As discussed in Sections 2.7 through 2.14 earlier in this chapter, there are other cost allocation issues that could be considered for equitable comparison purposes. For 2002, the modeling tool, that was initially developed in 2001, was updated & enhanced to include user options to incorporate transmission cost adders that reflect the additional cost of actually delivering a market product to the Nebraska system (both losses & tariffs). Although this flexibility is built into the modeling tool, the 2004 overall comparison results are based on these values being set to zero so that an equitable comparison to last year’s results can be made and any market bias perception is eliminated. A model user option to include an “obligation to serve” value was also incorporated, but, again, this option was set to zero for the same reasons described above.

Additional model flexibility & information detail was incorporated to allow model users to determine the effect of allocating fixed costs when the market price would allow higher price signals, even in winter months. This is for informational purposes only, and strictly impacts the market price weighted results, so the MWH-weighted results, considered the bottom-line comparison values, are not affected. Also, in order to compare various generation resource types (baseload, intermediate & peaking), as described earlier in Section 2.12, the model is enhanced to provide informational detail & comparisons on multiple physical resources as opposed to only an intermediate-type unit that last year’s model version utilized.

Again, only additional informational detail has been added to this year's modeling, and no additional cost adders are included as part of this year's comparison results.

#### **4.6 Value of Long-term Obligation to Serve**

The Nebraska power system product is based on a long-term "obligation to serve" that is not inherent in market-based electricity products. Typically, there is a thirty to forty year obligation stemming from the commitment to build various physical generation unit types to provide stability in power resources that is derived from having "iron on the ground", and limited dependence on the market. This translates to a long-term commitment to providing physical resources that meet or exceed Nebraska's power systems "obligation to serve".

A market-based electricity product provider does not share this same responsibility, hence, there is downward pressure on the price for the market-based electricity product as compared to local providers. This actual value is difficult to quantify since this is a subjective criteria that may be different for each customer depending on individual risk tolerance for price changes. Four different analytical approaches were developed & modeled for the 2003 Report. The results were included in Section 4.8 of the 2003 Report. The analyses indicated that the value of the long-term obligation to serve was in the \$3-\$5/MWH range for a 5x16 product. These results are for subjective consideration only, and are not specifically accounted for in the 2001-2004 Nebraska production cost comparison to market pricing.

#### **4.7 Results Based on Median Market Product Pricing Indices and Applying MWh-Weighted Fixed Cost Allocations to Nebraska Production Costs for 2001 through 2004.**

Exhibit IV-4 provides a tabulation of the results comparing median market product pricing indices and applying MWh-weighted fixed cost allocations to Nebraska production costs for 2001 through 2004. As shown in the table, on an equivalent basis, Nebraska production costs consistently rank below the market product throughout the study period. Three LB901 historical study period comparisons are also included, describing the four-year rolling average results for the various study periods completed. The gap between Nebraska production costs and the market has widened since 2002. A main driver of this gap appears to be natural gas prices. Nebraska utilities do not have as high of concentration of natural gas-fired units when compared to the entire electric industry.

**Exhibit IV-4**

**COMPARISON TABLE for NEBRASKA PRODUCTION COSTS**

PERCENTAGE BELOW **MEDIAN** MARKET PRICING

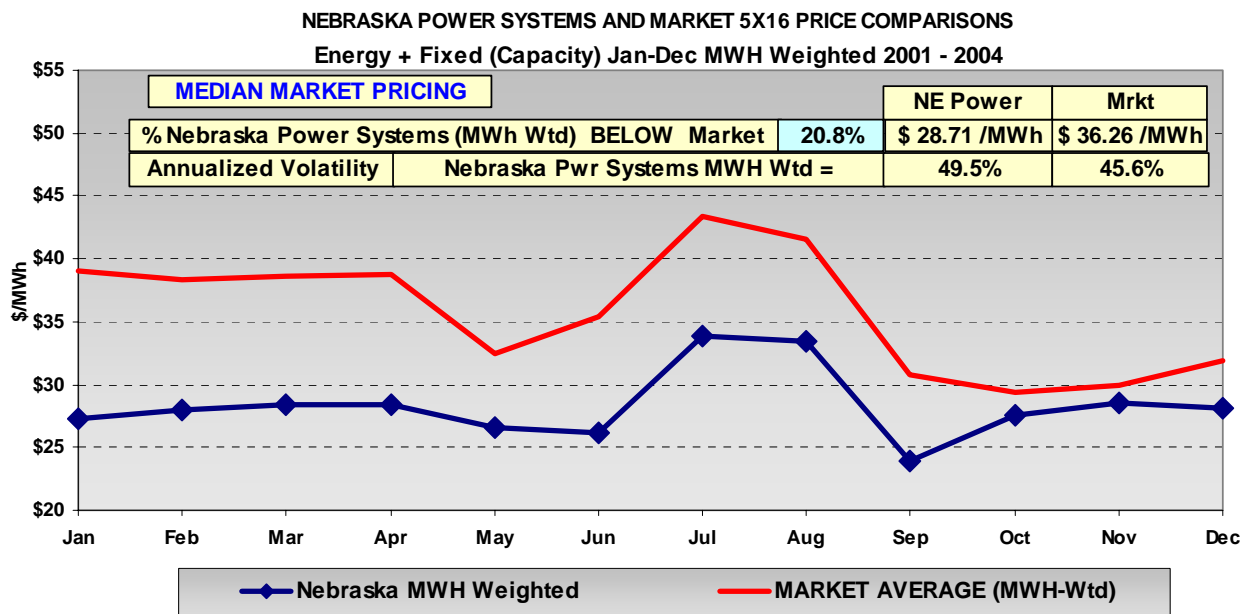
Year	MWh - Weighted Fixed Cost Allocations	Market Price - Weighted Fixed Cost Allocations
2001	21.2%	23.2%
2002	2.4%	2.3%
2003	20.4%	20.2%
2004	33.4%	33.5%
Straight Average	19.4%	19.8%
Four Year Average (MWh-weighted)	20.8%	21.4%

HISTORICAL LB901 STUDY PERIOD COMPARISON

Study Period Years	% Nebraska Systems Below Market	Nebraska Cost Annualized Volatility	Market Price Annualized Volatility
1998-2001	18.6%	34.4%	84.5%
1999-2002	15.3%	41.2%	92.2%
2000-2003	18.1%	43.4%	62.4%
2001-2004	20.8%	49.5%	45.6%

Exhibit IV-5 provides a monthly comparison for the four-year study period (2001-2004) between the median market product pricing indices to Nebraska production costs. In every month, Nebraska production costs are lower. The calculated volatility is about the same for Nebraska production and the market. In the past, Nebraska production volatility was lower than the market. Nebraska production volatility is slightly higher than the past, but the market volatility has decreased. Three (3) possible reasons the market volatility is lower than previous years: 1) maturing of the market & better risk management practices (i.e., lessons learned from the 2000 California market), 2) the higher natural gas market driving all months prices higher and closer to one another, and 3) the present overbuilt capacity market in the Eastern Interconnect has reduced the capacity premium paid by the market in the summer, causing the monthly market costs in July and August to be closer to the other months. Reasons the Nebraska production costs have been rising include: 1) when Nebraska utilities baseloaded units are off-line they need to use higher variable cost units, and due to the rise in natural gas prices, there is a larger gap between the variable costs of a coal or nuclear unit vs. natural gas unit, & 2) no new low variable cost baseloaded units have come on-line within the last few years, thus new native load is more likely to be served from the higher variable cost units.

**Exhibit IV-5**





For comparison purposes, Exhibit IV-6 is provided to describe the detail associated with the 2004 market prices and physical generation resource costs, as applied in this year's model.

### Exhibit IV-6

#### LB901 "Condition-Certain" Criteria Historical Market Pricing for Comparison Purposes

  = Manual Entry      = Special Calculation  
  = Calculated Value

#### AVERAGE 5X16 \$/MWH Daily Settlements for 2004

	HISTORICAL			FORWARD INDICES (as of March 31, 2004)								
	January	February	March	April	May	June	July	August	September	October	November	December
MAPP	53.21	47.21	43.52	41.34	42.21	45.92	65.69	68.66	47.13	50.12	53.54	45.45
Comed	42.26	43.38	39.79	38.06	36.95	40.22	50.31	50.31	37.74	35.27	35.27	35.27
Cinergy	41.05	44.42	41.36	40.51	39.27	43.15	52.61	52.61	40.34	38.05	37.89	37.89
Entergy	43.96	43.20	41.94	41.60	41.13	44.38	53.13	52.31	42.00	42.75	42.75	42.75
MAPP CALC	125.4%	108.1%	106.1%	103.2%	107.9%	107.8%	126.3%	132.7%	117.8%	129.5%	138.6%	117.7%

#### MEDIAN 5X16 \$/MWH Daily Settlements for 2004

	HISTORICAL			FORWARD INDICES (as of March 31, 2004)								
	January	February	March	April	May	June	July	August	September	October	November	December
MAPP	53.50	48.25	44.88	40.70	43.92	45.80	67.46	66.36	47.93	48.63	50.01	45.40
Comed	45.29	42.83	41.00	38.06	36.95	40.22	50.31	50.31	37.74	35.27	35.27	35.27
Cinergy	44.43	44.09	43.77	40.51	39.27	43.15	52.61	52.61	40.34	38.05	37.89	37.89
Entergy	45.38	43.50	42.65	41.60	41.13	44.38	53.13	52.31	42.00	42.75	42.75	42.75
MAPP CALC	118.8%	111.0%	105.7%	101.6%	112.3%	107.6%	129.7%	128.2%	119.8%	125.7%	129.4%	117.5%

MAPP Capacity Only Price \$/kW-yr for 2004 = 15.00

New Peaking Unit \$/MWH for 2004 = 86.0 @ 85% CF and Fuel of \$5.50/ mmBTU    125.0 @ 10% CF  
 New Combined Cycle \$/MWH for 2004 = 49.0 @ 85% CF and Fuel of \$5.50/ mmBTU  
 New Baseload Coal \$/MWH for 2004 = 27.0 @ 85% CF and Fuel of \$0.65/ mmBTU

(All generation units Exclude transmission cost adders)

FORWARD PRICES FOR APRIL THRU DECEMBER BASED ON INTERCONTINENTAL EXCHANGE AVERAGE BID/ASK PRICES FOR MARCH 26-31.

The results for the 2001-2004 study period show a widening gap between the Nebraska production costs and the market. The Nebraska production costs are similar to the previous study period, while the market costs are significantly higher. It appears that the higher pricing trend of the market is being driven by higher natural gas prices.

## 5.0 Expected Differences Eastern Region to Western Region

### 5.1 North American Electrical Interconnection

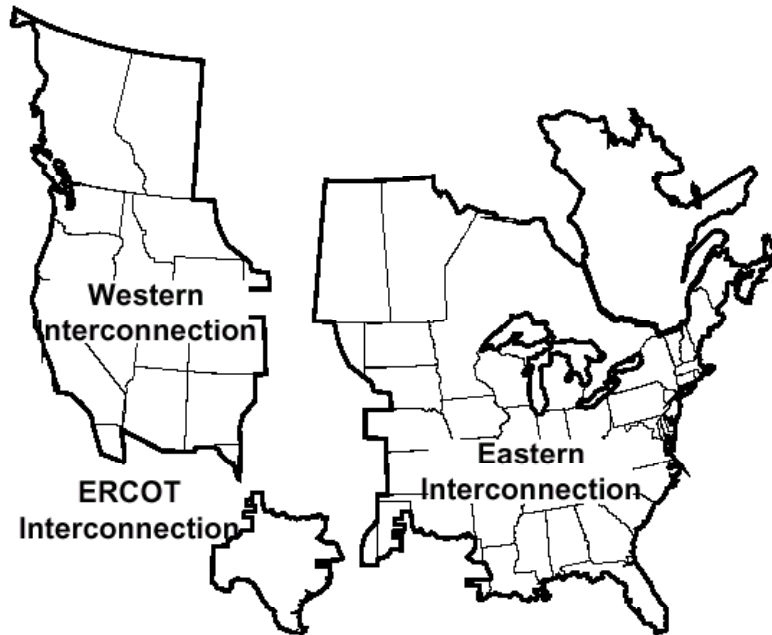
The majority of the electric systems in North America are comprised of three Interconnections as shown on Exhibit IV-8 and described below:

Eastern Interconnection - the largest Interconnection covers an area from Quebec and the Maritimes to Florida and the Gulf Coast in the East and from Saskatchewan to eastern New Mexico in the West. It has HVDC connections to the Western and ERCOT Interconnections.

Western Interconnection - second largest Interconnection extends from Alberta and British Columbia in the North to Baja California Norte, Mexico, and Arizona and New Mexico in the south. It has several HVDC connections to the Eastern Interconnection.

ERCOT Interconnection – includes most of the electric systems in Texas with two HVDC connections to the Eastern Interconnection.

Exhibit IV-8



### 5.2 Eastern Interconnection and Western Interconnection Generation Supply and Demand

The Eastern Interconnection is relatively large as compared to the Western Interconnection in terms of internal energy demand (607,003 MW compared to 141,698 MW) and generation (732,645 MW as compared to 182,819 MW). The interconnection DC tie capacity between the Eastern and Western Interconnection is 1,080 MW. Source: (NERC Reliability Assessment, December, 2003). Nebraska's projected growth rate is approximately 1.8% and the current summer peak is approximately 5700 MW.

The Western Electric Coordinating Council's (WECC) outlook regarding the reliability of the Western Interconnection is comprised of four sub-regions – Northwest Power Pool Area, Rocky Mountain Power Area, Arizona-New Mexico-Southern Nevada Power Area, and California-Mexico Power Area. A resource

assessment on a region-wide basis is not considered appropriate because of transmission constraints. This also explains the marketing limitations in the region due to the lack of firm transmission to facilitate such transactions and the limited interconnection tie capability to the Eastern Interconnection.

The Rocky Mountain Power Area (RMPA) consists of Colorado, eastern Wyoming, and portions of western Nebraska and South Dakota. This is the sub-region that includes the western Nebraska load in the Western Interconnection and has the most direct impact when comparing utility cost of generation and market prices to those that are seen in the rest of Nebraska that is part of the Eastern Interconnection.

RMPA is projected to have demand growth rates somewhat higher than the WSCC as a whole with projected growth at a 2.9% annual rate. The RMPA is projected to have generation capacity margins above the projected load of between 18.8% and 25.9% for the next ten years.

The Mid-Continent Area Power Pool (MAPP) encompasses the Nebraska load and generation in the Eastern Interconnection. The demand forecast is for a projected demand growth of 1.8% per year through the 2012 period. Generation reserve margins in MAPP are projected to decline from 17.9% in 2003 to 12.7% in 2006. The majority of generation serving Nebraska is located in Nebraska.

In making this market comparison of Eastern to Western Interconnections, the market drivers have to be considered as well as the relationship of Nebraska's electrical capacity requirements associated with each interconnection. The market price drivers that influence the market differences include generation regulatory requirements, generation fuel type, fuel cost, generation availability/dependability, load demand, weather, and transmission availability.

The current Nebraska total capacity requirements include approximately 98% of the total residing within the Eastern Interconnection and 2% residing within the Western Interconnection. The Eastern and Western Interconnections are separate systems other than the relatively small amount of DC tie transfer capability between the systems.

## **5.3 Western Region Market Compared to Eastern Region Market**

### **5.3.1 "Markets" or "Hubs"**

The Eastern Interconnection "market" indices or "hubs" used for the Nebraska market in the Eastern Region were based on the published market product prices designated as "MAPP," "Cinergy," "ComEd," and "Entergy." These are the market product indices that are geographically located closest to the Nebraska power system.

The Western Interconnection includes several "market" indices or "hubs." The published price index designated as "Palo Verde" is considered as representative of the Nebraska market that is in the Western Region.

### **5.3.2 Volatility and Price Comparison**

The price levels for 2001 through 2004 shows a higher volatility in the Western Region for this time frame than in the Eastern Region, although the most volatile time period was in 2000. This fluctuation of volatility has decreased to where both regions are currently seeing similar volatility.

Market price levels for both the Eastern and Western Regions have been fairly similar with the Eastern region pricing levels being slightly higher in recent months.

## **5.4 Nebraska Production Costs**

### **5.4.1 Western Nebraska versus Eastern Nebraska Costs**

Power costs in Nebraska reflect the cost of power primarily generated from within Nebraska. However, WAPA is a partial requirements wholesaler to a number of Nebraska utilities; Tri-State of Westminster, Colorado,

serves rural systems in western Nebraska; and LES and MEAN receive some power from the Laramie River Station in Wyoming.

Nebraska's proximity to the low sulfur coal in Wyoming contributes to the state's low production costs. Nebraska has a relatively small amount of power produced by gas and oil that have a much higher cost of production due primarily to the high cost of fuel. Additional reasons that Nebraska's production costs are kept low are the WAPA purchases, sales of surplus energy into the market and returning margins. In general terms the western Nebraska load supplied from generation in the Western Region has a similar cost of production as that of the Nebraska load in the Eastern Region. The fuel source is primarily coal from Wyoming for the generation that serves western Nebraska.

#### **5.4.2 Stability**

It is difficult to predict what Nebraska's cost of production will be in the future. However, Nebraska should generally be in a stable position through the 2005 time period. There is adequate generation to meet the load requirements per the NERC Reliability Assessment. Recent market prices in the Western Region have trended higher and been more volatile than the Eastern Region; therefore Western Nebraska does have more exposure to the market during periods that normal generation supply is unavailable due to planned or forced outages.

### **6.0 Conclusions**

The challenge for Technical Group #4 was to develop an equitable comparison between the credible indices that were identified and the product provided by Nebraska electric utilities to their customer-owners. The product that Nebraska providers sell is a firm, total electrical requirements product, available 24 hours a day, 7 days a week, in quantities that vary hourly, weekly, monthly, seasonally, and annually. This obligation to serve includes both existing and new customers. The typical index described in the previous sections provides a price for a fixed hourly quantity of energy, possibly with a premium for financial firmness, but with no obligations on the part of the seller beyond the current month or, in the case of daily indices, beyond that day. The typical index is not a comparable product to that provided by a Nebraska utility to its customers.

When a Nebraska utility decides to build a power plant, they are not building it to serve a customer for a day or month. They are in effect building the plant to serve a forward obligation for the next 30 to 40 years. The forward market does not have a published product that goes beyond an 18 to 24 month period.

The results of the comparison between the market product indices and the Nebraska production costs show that Nebraska production costs are approximately 21 % lower than the equivalent wholesale "median" market price based on the period 2001 – 2004 (three years actual, one year projected), and weighted based on MWH. Based on the "average" market price, Nebraska production costs are approximately 21 % lower than the "average" market price.

These results for the 2001 – 2004 study period are slightly higher than the results for the previous period, 2000-2003, due mostly to the upward trend of market prices driven by higher natural gas prices. Nebraska utilities do not have as high of concentration of natural gas-fired units when compared to the entire electric industry. The price volatility associated with Nebraska Production costs remains stable compared to market price, providing a fairly consistent, less volatile, cost expectation for Nebraska's ratepayers.

In addition, the results of an analyses performed in 2003 that applied four different approaches to determining the value of the long-term obligation to serve that is provided by Nebraska utilities appears to be in the \$3 – 5 / MWH range, and this is added value that Nebraska utilities provide customers over and above market products.

Currently, electricity traders are experiencing as much as 17 % in delivery losses (equivalent to approximately \$5 / MWH), which add to the price of a market product. Also, the standard market transmission tariffs associated with delivering these market products from external regions to Nebraska customers can add an additional \$4 – 6 / MWH to the market product price.

These additional differential impacts (obligation to serve, transmission losses, transmission tariffs), together result in potential cost adders of \$7 - 16 / MWH for a market product to be delivered to Nebraska ratepayers even if the market product price and the Nebraska production costs were exactly the same.

The “median” market price comparison, approximately 21 % lower than the market price, compares favorably with retail rate comparisons. The Energy Information Administration (EIA) annually compiles data from the Form EIA-861 for approximately 3,300 public and investor-owned electric utilities including active power marketers and other energy service providers. The most current data for 2002 shows that Nebraska’s average retail rate of 5.55 cents/kWh is approximately 23% lower than the national average retail rate of 7.21 cents/kWh.

That Nebraska production costs are lower than the market price is not by accident. Nebraska utilities have several financial advantages that include: their non-profit status and their ability to access tax exempt financing. Many Nebraska utilities have an allocation of low-cost federal preference power (WAPA) from the six dams on the Missouri River. In addition, the public power utilities in the state have made good resource planning decisions in that the generation portfolio mix is diverse with coal, hydro, natural gas, nuclear, oil, and most recently renewable resources. The state has invested in base-load capacity and therefore Nebraska utilities generate very little energy with premium (expensive) fuels such as natural gas and oil. Also, the state has a geographic advantage in that it is in close proximity to coal in Wyoming, Nebraska utilities are further able to keep electric rates low by selling surplus energy into the wholesale market and using the margins to stabilize rates.

## **Chapter 5**

**“Any other information the board believes to be beneficial to the Governor, the Legislature, and Nebraska’s citizens when considering whether retail electric competition would be beneficial, such as, but not limited to, an update on deregulation activities in other states and an update on federal deregulation legislation.”**

## **1.0 Purpose**

Provide information on deregulation activities in other states, an update on federal deregulation legislation, and other public policy developments relating to electric deregulation.

## **2.0 Team Members**

Doug Bantam – Lincoln Electric System  
Tim Grove – Omaha Public Power District  
Jay Holmquist – Nebraska Rural Electric Association  
John McClure – Nebraska Public Power District  
Tom Richards – Omaha Public Power District

## **3.0 Introduction**

### **3.1 Deregulation Overview**

Little has changed with the development of retail choice around the nation in the past year. Most state retail choice programs are either struggling or inactive. On September 1, 2004, the State Corporation Commission of Virginia issued a press release describing the findings of its fourth annual report on retail choice in Virginia. The press release notes "that the electricity supply industry continues to struggle following price run-ups, disclosures of accounting and dated improprieties, creditworthiness issues and volatile fuel prices, particularly natural gas." The press release concludes "that Virginia is not the exception when it comes to the lack of competitive activity for electricity supply service. In other states with retail choice, energy markets are generally inactive with few customers able to purchase power at a price lower than their traditional utility company."

Because Texas continues to receive attention as the most successful retail choice state, there is a Texas update in this report, but last year's report is deemed adequate to describe the status of retail choice in other states. This report also contains a new section on federal developments. Comprehensive energy legislation passed both the House and the Senate, but the two versions had significant differences. A conference committee reached a compromise and the legislation passed the House, but has been bogged down in the Senate.

## **4.0 Texas**

Because of the national significance of the public policy choices adopted in Texas, the material below contains background on the Texas retail electric program as well the most recent results of their efforts.

Legislation was enacted in 1999 to begin the process. Under the new law, the Texas PUC began the process of certifying competitive retail electric providers. On June 1, 2000 a pilot retail competition program commenced and on January 1, 2002 full retail choice began for all customers at which time retail rates were reduced by 6%.

Following are the key provisions of the new law:

- Froze electric rates for investor-owned electric utilities in Texas through 2001.
- Prohibits large utilities from lowering their rates for residential and small commercial customers before 2005, or until 40 percent of their customers are served by competitors.
- Exempts electric cooperatives and city-owned electric companies from customer choice unless their governing boards decide to open their markets to competition.
- Allows customers the choice of using renewable energy (wind and solar power for example).
- Requires older electric generators to meet current environmental rules by 2003 or be shut down.
- Creates a fund to pay for lower rates for low-income families and property tax losses for affected school districts.
- Provides for automatic enrollment of qualified low-income families in low-income assistance programs.
- Prohibits disconnection of service for nonpayment during periods of extreme weather.
- Allow customers to receive one bill for their electric service in an easy-to-read format and understandable language.

- Creates a Do Not Call list for customers who do not wish to be called by telemarketers on behalf of electric service providers.
- Provides customer protection against discrimination, against being billed for unauthorized charges (cramming), against unauthorized change of service provider (slamming) and other unfair, misleading and deceptive practices.

It is important to note that much of the Texas region is operated as a separate electrical interconnection. This limits and confines the size of the restructured area and restricts the impact of wholesale energy deliveries from potentially lower cost resources. When Texas initiated the retail choice program, the impacted region was operating with significant generation in reserve and significant new Independent Power Producer (IPP) projects underway. In addition, retail rates are relatively high, in the 10¢/kWh range, compared to other regions of the U.S. With high reserves, new generation coming on line and high retail rates, Texas becomes somewhat of a special case. With excess generation capacity, numerous new, highly efficient, independent generation projects and a high underlying retail electric rate level, the Texas region provided a prime opportunity to initiate retail choice. This is not to discount what has been accomplished by the Texas electrical industry. It is, however, a confirmation that for retail choice to be successful, the appropriate preconditions need to be in place.

Under the Texas deregulation program, electric utilities were divided into three areas: retail, power generation and transmission and distribution. Any investor-owned companies that wish to enter the retail market must create an affiliate company. To ensure deregulation, the Texas Public Utilities Commission created a price-to-beat for investor-owned affiliates that will remain in place until 2005 or until 40% of customers switch to another retail company. In February of 2004 the price-to-beat in the five distribution areas ranged from 9.7 to 11.66¢/kWh and the percent of customers who have switched stands at 14% for residential and 19% for small industrial.

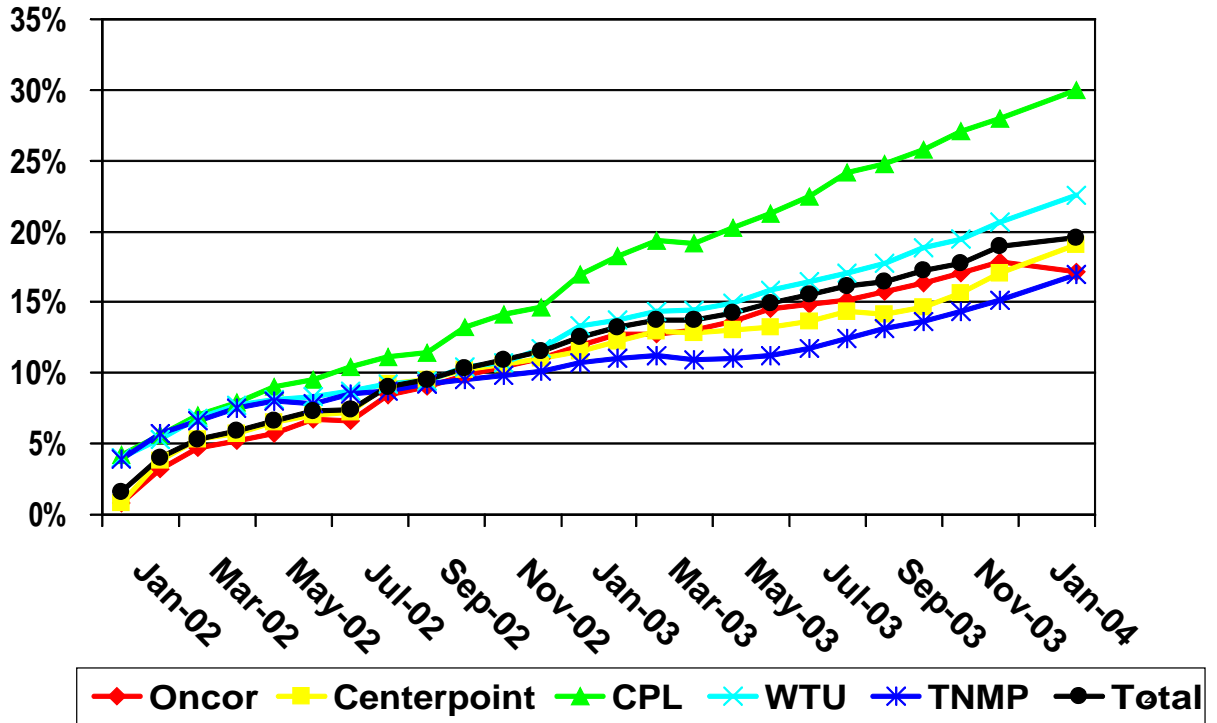
The Texas Public Utility Commission continues to monitor and report on the status of retail choice in Texas. These "Report Cards" remain positive. Generally, retail choice participation is growing. During 2003, participation at the residential level has grown from just over 7% to 14% and small industrial participation has increased from 11% to 19%.

The report indicates that, as of the end of December 2003, 1,285,145 individual customer electric service provider switches have occurred. The percentage of megawatt hours (MWhs) served by non-affiliated retail electric providers (REPs) in December of 2003 included 15% of the residential load and 42% of the small industrial load. These percentages are higher than the percentage of customers who have switched because the larger commercial and industrial customers comprise a significant portion of the energy consumption in the state.

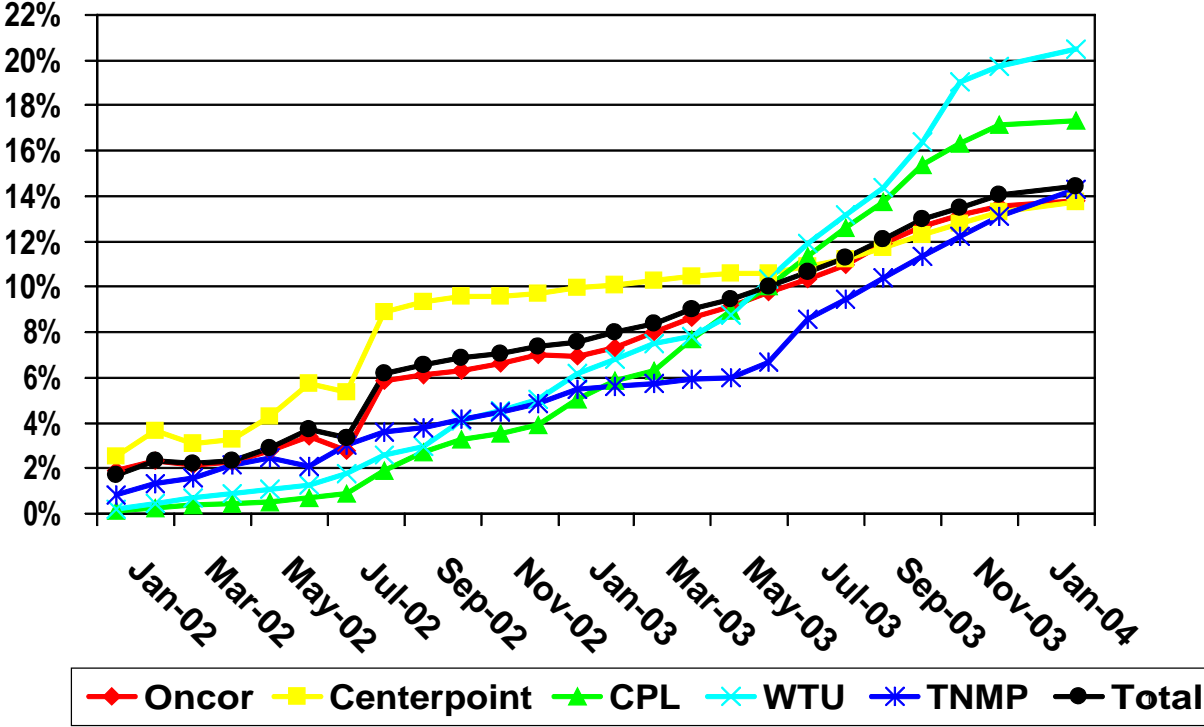
The following charts have been extracted from the most recent Texas Public Utility Commission "March 2004 Report Card on Retail Choice." The Texas Retail Choice Program continues to grow and is considered by the Texas PUC to be a successful and cost-effective program.



# Secondary Voltage Level Customers Served by Non-Affiliated REPs

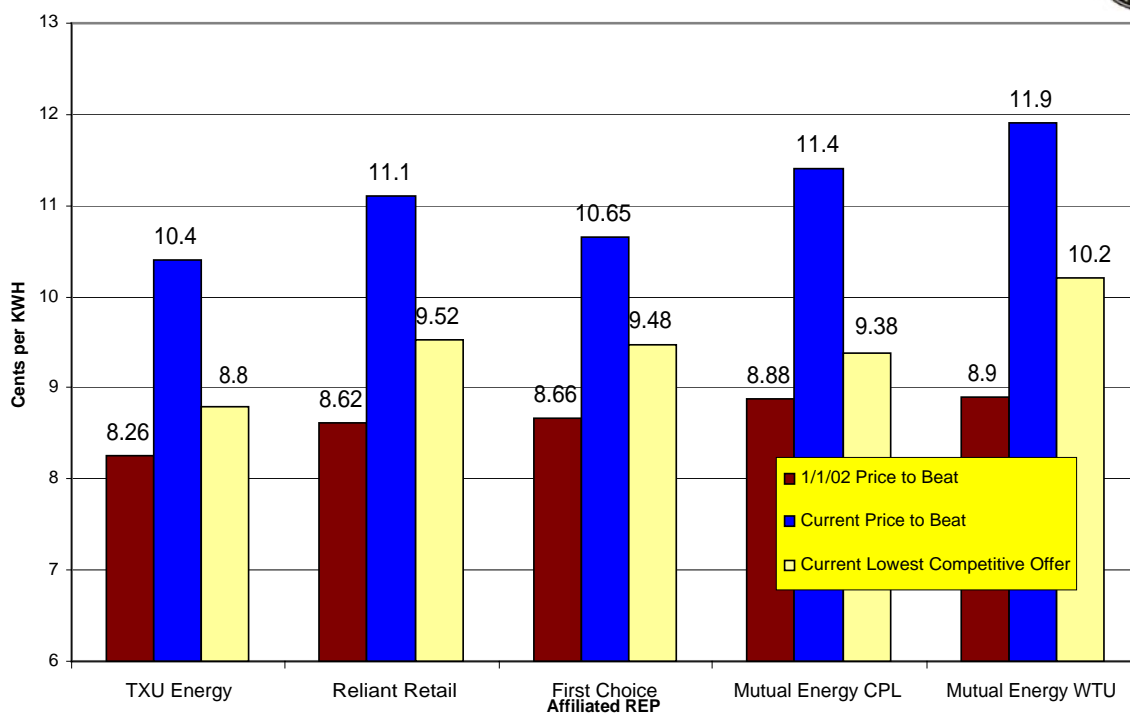


# Residential Customers Served by Non-Affiliated REPs





### Changes in Residential Rates (1/1/02-7/1/04)



## 5.0 Federal Issues

Driven in large part by the electricity supply and reliability problems in the western United States, as well as the large blackout in the Northeast in August 2003, the focus of restructuring has been expanded to include energy supply and infrastructure concerns, as well as reliability. Transmission across the United States is frequently inadequate to support retail deregulation. Legislation addressing regional transmission entities, eminent domain, transmission reliability standards, and other issues has been the focus of both Congress and the FERC. Infrastructure/pipelines for natural gas supply have not kept up with growing demand for natural gas, which has become the most common fuel for generating facilities built in the last 10 years.

**A major focus of both the Bush Administration and Congress has been on development and passage of national energy policy legislation.**

### Background/Status

- Bush Administration National Energy Policy Development Report Released – May 2001
- House of Representatives responded quickly and passed H.R.4 – August 2, 2001.
- Senate delayed consideration of energy policy legislation until early 2002. S.517 passed Full Senate – April 25, 2002.
- House/Senate Energy Conference failed to reconcile differences between H.R.4 and S.517 – legislation died at the end of the 107<sup>th</sup> Congressional Legislative Session in November 2002.
- House of Representatives in the 108<sup>th</sup> Congress passed H.R.6 on April 11, 2003.
- Senate passed legislation (also designated as H.R.6 after passage) on July 31, 2003.
- House/Senate Energy Conference commenced in September 2003 to resolve legislative differences with final agreement reached on November 16, 2003.
- Energy Conference Report passed by the House on November 18, 2003.
- Energy Conference Report contains XVI Titles/Sections, including an electricity title (Title XII).
- Senate cloture vote to end debate and move forward on the Energy Conference Report on November 21, 2003 failed by a vote of 57 Yeas to 40 Nays, 3 Not Voting (60 votes needed).
- Renewed efforts of passage in 2004 in the Senate have failed with energy legislation likely dead for the remainder of the 108<sup>th</sup> Congress.

### Some of the Major Provisions of Interest to Electric Utilities in the H.R.6 Conference Report Include:

Repeal of the Public Utility Holding Company Act of 1935

Repeal of the Public Utility Regulatory Policy Act of 1978 – eliminates mandatory electric utility purchase requirements for electricity generated by qualifying cogenerators or small power producers.

FERC Lite – limited expansion of FERC jurisdiction over public power to promote wholesale power markets. Public power would provide transmission services at non-rate terms and conditions that are comparable to what we have for ourselves. No FERC ratemaking authority over public power.

Service Obligation/Native Load Protection – requires FERC to ensure that load service entities are allowed to reserve their transmission assets to serve native load customers before transmission capacity is made available to others.

Uniform Refund Authority – authorizes FERC to order refunds from large public power systems if short-term wholesale sales are made in violation of FERC rules.

Participant Funded Transmission – transmission upgrades would be paid for by those requesting the upgrades consistent with FERC criteria.

Transmission Reliability Standards – standards would be FERC approved, mandatory, and enforceable with penalty provisions.

Transmission Siting Authority – FERC authorized to permit and approve needed new transmission if state(s) cause obstacles.

Renewable Energy Production Incentive (REPI) – reauthorizes the REPI program for 10 years, landfill gas projects on equal funding priority as wind, solar, biomass, etc. Comparable to IOU production tax credits in that the payout for generation is over a 10-year period. Funding is dependent on annual congressional appropriations.

RTO Development – includes a sense of Congress that all transmitting utilities should voluntarily join regional transmission organizations. No formal requirement for mandatory RTO membership.

Climate change – Sense of Congress – no mandatory carbon emission reduction requirements

Standard Market Design (SMD) – FERC SMD rules delayed until December 2006

## **Outlook**

With passage of national energy policy legislation in 2004 highly unlikely, it is unknown at this time if Congress will push for passage in the new 109<sup>th</sup> Congress next year. The outcome of the 2004 elections and Administration and Congressional priorities for 2005 will determine future efforts on national energy policy legislation.

## **6.0 Conclusions**

- Retail choice programs have achieved mixed results ranging from failure (CA) to no impact (AZ) to some success (TX).
- Natural gas prices are at an all time high significantly increasing the cost of gas-fired generation.
- Retail choice has taken a back seat to energy supply and other wholesale issues at the federal level.
- Promises of wholesale or retail competition driving down energy prices have been generally unfulfilled thus far.
- Retail choice is still alive and continues to evolve.
- Must get wholesale markets right prior to implementing retail choice legislation.
- Adequate power supply and reserves are crucial.
- Increased stability of fuel prices is needed for retail choice programs to function properly.
- Better customer response to wholesale price signals is needed.
- Development of comprehensive energy legislation has gained significant attention in Congress and the Bush Administration, but passage is uncertain.
- FERC is actively involved in developing and addressing the transition to a more competitive wholesale market.
- Most observers acknowledge that retail choice initiatives are generally struggling to be successful.

## GLOSSARY

**Ancillary Services:** Interconnected operations services for operating reserve, voltage control, regulation and frequency response, scheduling and system control and dispatch, and other power supply necessary to effect a reliable transfer of electrical energy at specified contract terms between a buyer and seller.

**Availability:** A measure of time that a generating unit or transmission line, or other facility is capable of providing service, whether or not it is actually in service, Typically this measure is expressed as a percent available for the period under consideration.

**Avoided Cost:** The cost the utility would incur but for the existence of an independent generator or other energy service option. Avoided cost rates have been used as the power purchase price utilities offer independent suppliers.

**Baseload:** The minimum amount of power delivered or demanded over a given period at a constant rate.

**Bilateral Contract:** A direct contract between a power producer or end user outside a centralized power pool.

**Bottleneck Facility:** A point on a system, such as a transmission line, through which all electricity must pass to get to it's intended buyers. If there is limited capacity at this point, some priorities must be developed to decide whose power gets through. It also must be decided if the owner of the bottleneck may, or must, build additional facilities to relieve the constraint.

**BPA:** The Bonneville Power Authority is one of five federal power marketing administrations that sell electric power produced by federal hydro electric dams.

**Broker:** An agent that arranges power transactions. The agent may aggregate customers and arrange for transmission, firming and other ancillary services as needed. The broker does not take title to the power supply.

**Bulk Power Supply:** This term is often used interchangeably with wholesale power supply. In broader terms, it refers to the aggregate of electric generating plants, transmission lines and related equipment and can refer to one utility or a group of interconnected utilities.

**Capacity:** The continuous load carrying ability, expressed in megawatts [MW] or mega volt-amperes [MVA] of generation, transmission, or other electrical equipment.

**Capacity Factor:** The ratio of total energy generated by a plant for a specified period of time to the maximum possible energy it could have produced if operated at the maximum capacity rating for the same period, expressed as a percent.

**Competitive Power Supplier:** A supplier of retail energy and capacity and ancillary services, other than the incumbent supplier, that may own generation, buy and resell, and who has title to the electricity.

**Competitive Transition Charges:** A charge that allows utilities to recover historic costs related to electric generating facilities and power purchase contracts.

**Contract Path:** The most direct physical transmission tie between two interconnected entities. When utility systems interchange power, the transfer is presumed to occur over the contract path notwithstanding the fact that power flow in the network will distribute in accordance with network flow conditions.

**Control Area:** An electric system or systems, bounded 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.

**Control Area Operator:** The operator of a Control Area in which transmission facilities used for transmission services are located.

**Cooperative Electric Utility [Co-op]:** An electric utility owned and operated for the benefit of those using its service.

**Cost Based Electricity:** A term used by consumer-owned electricity meaning that only the costs of generation, transmission and distribution are included in the cost, and that there is no “margin” or “profit” included.

**Cost of Service Study:** An analysis of all of a utility’s costs at a very detailed level for purposes of assigning these costs to the various customer classes.

**Customer Classes:** A term used in ratemaking to segregate customers by types such as residential, commercial and industrial. The main segregation occurs due to the amount and way customers use electricity.

**Curtaibility:** The right of a transmission provider to interrupt all or part of a transmission service due to constraints that reduce the capability of the transmission network to provide that transmission service.

**Default Provider:** In the case where an electric consumer does not choose a new supplier once competition begins, a supplier is automatically assigned. This supplier is known as a ‘default supplier’.

**Demand:** The rate at which electric energy is delivered to or by a system, generally expressed in kilowatts or megawatts, at a given instant or averaged over any designated interval of time.

**Direct Access:** The ability of a retail customer to purchase commodity electricity directly from the wholesale market rather than thru a local distribution company.

**Distribution Charges:** Charges for the use of local wires, transformers, substations and other equipment used to deliver electricity to homes and businesses.

**ECAR:** East Central Area Reliability Coordination Agreement.

**Economic Dispatch:** The allocation of demand to individual generating units on line to effect the most economical production of electricity.

**EPAct:** The Energy Policy Act of 1992 addresses a wide range of energy issues. The legislation created a new class of power generators, exempt wholesale generators that are exempt from the provisions of the Public Utilities Holding Company Act and grants the authority to FERC to order and condition access by eligible parties to the interconnected transmission grid.

**ERCOT:** The Electric Reliability Council of Texas.

**FTR:** Future Transmission Right

**Federal Energy Regulatory Commission [FERC]:** The FERC regulates the price, terms, and conditions of power sold in interstate commerce, and regulates the price, terms and conditions of all transmission services.

**Firm Power:** Power that is guaranteed by the supplier to be available at all times during a period covered by a commitment.

**Franchise:** A franchise is a grant of right or privilege to occupy or use public streets, ways and facilities located on public streets and ways to deliver service to customers. Local governments typically grant franchises.

**Franchise Fee:** A payment to a city or government for the exclusive right to sell a product in a specified area.

**FRCC:** Florida Reliability Coordinating Council

**Generation:** The process of producing electricity from other forms of energy.

**Generation Charges:** The charge for generating or creating the electricity used. This charge includes the cost of fuel and power plant costs, but not the cost of delivering the electricity to the customer.

**Generation Dispatch and Control:** Aggregating and dispatching generation from various generating facilities, and providing backup and reliability services.

**Grid:** A system of interconnected power lines and generators that is managed so that the generators are dispatched as needed to meet the to as a payment in lieu of taxes.

**Independent System Operator [ISO]:** An independent system operator is an independent third party who takes over ownership and/or control of a regions transmission system for the purpose of providing open access to retail and wholesale markets for supply.

**LB 901:** The Nebraska State Legislature passed LB 901 on April 11, 2000. LB 901 encompasses the elements of the “condition certain” approach to electric deregulation in Nebraska that resulted from the prior LR 455 studies.

**LES:** Lincoln Electric System

**LMP:** Locational Marginal Price is the wholesale electric price at a particular location on the transmission system that reflects the cost to meet the next unit of demand at that location

**Load:** An end use device or customer that receives power from an electrical system.

**Load Factor:** A measure of the degree of uniformity of demand over a period of time, usually one year, equivalent to the ratio of the average demand expressed as a percentage.

**Local Distribution Company:** The regulated electric utility company that constructs and maintains the distribution system that connects the transmission grid to the end use customer requirements of the customers connected to the grid at various points.

**Gross Revenue Tax:** A tax that is applied to the gross revenue of a utility. Often referred to as a payment in lieu of taxes.

**LR 455:** Legislative Resolution 455 was a three- year review of the electric industry in Nebraska, commissioned by the Nebraska State Legislature in 1997, that recommended and formed the basic premise of the “Condition Certain” approach to electric deregulation in Nebraska.

**MAAC:** Mid-Atlantic Area Council

**MAIN:** MidAmerican Interconnected Network



**MAPP:** See Mid-Continent Area Power Pool

**MAPP Restated Agreement:** The original MAPP organizational contract among members was renegotiated to comply with federal requirements and provided for new classes of members including independent power producers and non-transmission owning utilities. The restated agreement has been recently unbundled to facilitate membership in ISOs and other organizations by parties to the restated agreement.

**Megawatt (MW):** One million watts

**Metering:** The process and methods of utilizing devices to measure the amount and direction of electrical energy flow.

**Meter Reading Charges:** The supplier's costs of providing customers with metering and/or meter reading services.

**Mid-Continent Area Power Pool [MAPP]:** One of the nation's nine electricity reliability councils that covers a geographic area including the eastern two-thirds of Nebraska, South Dakota, North Dakota, Montana, Minnesota, western Wisconsin, Iowa, and parts of Saskatchewan and Manitoba.

**Midwest ISO** - The non-profit Midwest ISO is an Independent Transmission System Operator that serves the electrical transmission needs of much of the Midwest.

**MRO:** Entity formed in 2003 consisting of over 20 MAPP Reliability Committee. The MRO would adopt, implement and enforce NERC and regional reliability standards, governed by a balanced stakeholders' board.

**MTEP-3:** Midwest Transmission Expansion Plan

**NAERO:** North American Electricity Reliability Organization. (Also see NERC).

**NERC:** North American Reliability Council. (Also see NAERO).

**NPCC:** Northeast Power Coordinating Council

**NPPD:** Nebraska Public Power District

**Nuclear Decommissioning:** Mandated charges to pay for dismantling nuclear power plants after they are retired from service.

**Open Access Same Time Information System [OASIS]:** An electronic information system posting system for transmission access data that allows all transmission customers to view the data simultaneously.

**OPPD:** Omaha Public Power District.

**Pancaking:** Refers to multiple transmission tariffs that are applied when electricity is transferred across multiple utility systems.

**Parallel Path Flows:** The flow of electricity on an electric system's transmission facilities resulting from scheduled electric power transfers between two electric systems. Electric power flows on all interconnected parallel paths in amounts inversely proportional to each path's resistance.

**Payments in Lieu of Taxes:** Payments made to local governments in lieu of property and other taxes.

**Peak Load or Peak Demand:** The electric load that corresponds to a maximum level of electric demand in a specified time period.

**Power Exchange:** An entity that would provide a centrally dispatched spot market power pool.

**Public Power:** Consumer-owned electric utilities, either political subdivisions of the state such as public power districts and municipal systems, or cooperatives owned by their members.

**Public Purpose Funds:** State mandated programs, such as low-income discounts and energy efficiency programs.

**Restructuring:** The reconfiguration of the vertically integrated electric utility. Restructuring refers to the separation of the various utility functions into individually operated and owned entities.

**Retail Sales:** Sales of electric energy to residential, commercial and industrial end use customers.

**Retail Competition:** A market system under which more than one provider can sell to retail customers, and retail customers can buy from more than one supplier.

**Regional Transmission Group [RTG]:** A voluntary group of transmission owners and users interested in coordinating transmission planning and expansion on a regional basis.

**Regional Transmission Organization [RTO]:** An umbrella term used to describe a variety of transmission organizations.

**Rural Utility Service [RUS]:** Under the U S Department of Agriculture, a program that provides direct loans and loan guarantees to electric utilities to serve customers in rural areas.

**SERC:** Southeastern Electricity Reliability Council.

**Service Schedule F:** MAPP's open access transmission tariff

**Spot Market:** A market in which commodities are bought and sold for cash and delivered immediately.

**SPP:** Southwest Power Pool.

**SMA:** Supply Market Assessment (FERC concept)

**SMD:** Standard Market Design (FERC concept)

**Stranded Benefits:** Public interest programs and goals that could be compromised or abandoned by a competitive market for electric services.

**Stranded Costs:** Above market costs of utilities and other power producers that would be stranded by consumers choosing a different power supplier.

**TLR:** MAPP transmission loading relief procedures

**TRANSLink:** Organization of transmission owning utilities in upper Midwest attempting to form an organization for independent transmission operation.

**Transmission Charges:** Charges associated with transporting electricity over long distances, such as from generating stations to substations in the consumer's neighborhood.

**Transition Costs [Charges]:** These include existing costs that are stranded, and incremental costs of the new market system for both start-up and on-going expenses ranging from consumer protection to power exchange and access fees.

**Unbundling:** The separation of utility bills into the individual price components for which an electric supplier charges its retail customers, including, but not limited to, the separate charges for generation, transmission, and distribution of electricity.

**Uniform Business Practices:** A consensus driven set of uniform business practices for competitive electricity markets.

**Vertically Integrated Utilities:** Utilities that own the generating plants, transmission system, and distribution lines to provide all aspects of electric service.

**WAPA:** Western Area Power Administration