

ANNUAL REPORT-2006
MONITORING OF
“CONDITION CERTAIN” ISSUES
IN NEB. REV. STAT. § 70-003(6)
(Formerly referred to as Legislative Bill 901)

OCTOBER 2006

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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 'time 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. Section 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.

NAME	REPRESENTING
Fred Bellum	- American Association of Retired Persons
Tim Burke	- Omaha Public Power District (OPPD)
Marvin Fishler	- Irrigation Customer
Gary Hedman	- Southern Public Power District (SPPD)
Jay Holmquist	- Nebraska Rural Electric Association (NREA)
Clint Johannes	- Nebraska Electric Generation & Transmission (NEG & T)
Don Kraus	- Central Nebraska Public Power & Irrigation District (CNPP & ID)
Richard Kuiper	- IBEW/NE State Utility Workers
Gary Mader	- Grand Island Utilities
Derril Marshall	- Fremont Utilities
John McClure	- Nebraska Public Power District (NPPD)
Dave Mazour	- Tri-State Generation & Transmission
Steve Pella	- Aquila
Bruce Pontow	- Nebraska Electric Generation & Transmission (NEG & T)
Mary Powers	- Nebraska League of Women Voters
Frank Reida	- Residential Customer
Marvin Schultes	- Hastings Utilities
Adam Smith	- Industrial Customer
Neal Suess	- Loup River Public Power District
Tim Texel	- Nebraska Power Review Board (NPRB)

The NPRB retained PAPE CONSULTING SERVICES as the Coordinating Consultant for the report periods of 2001 through 2005. RON MORTENSEN, P.E., became the Coordinating Consultant for reports beginning with the 2006 report. 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 issued in October 2002, 2003, 2004, 2005 and 2006.

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 some 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 2006 report is the sixth report following up on the five “Condition Certain” issues identified in LB 901 (2000).

Chapter 1

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

1. 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. Team Members

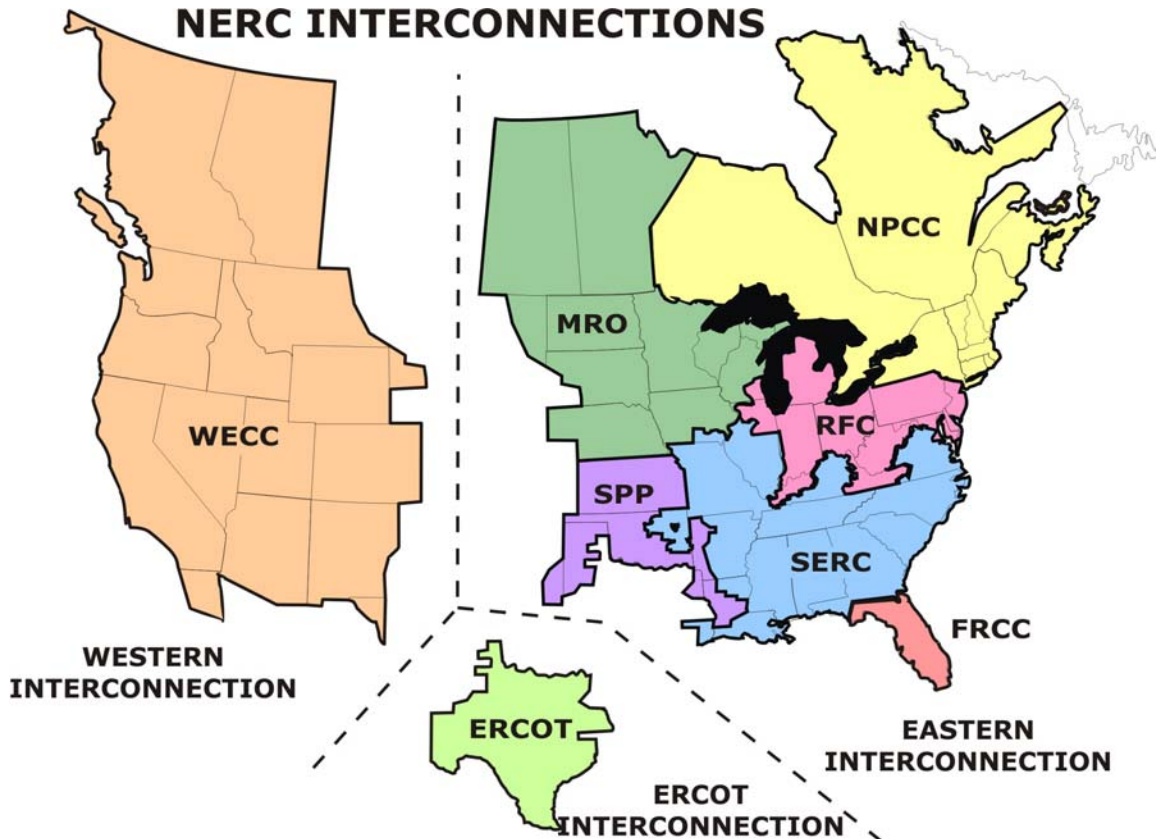
Paul Malone	-	Nebraska Public Power District (NPPD)
Dan Dahlgren	-	Omaha Public Power District (OPPD)
John Krajewski	-	Nebraska Municipal Power Pool Energy (NMPP)
Bruce Merrill	-	Lincoln Electric System (LES)
Lloyd Linke	-	Western Area Power Administration (WAPA)

3. Energy Policy Act of 2005

Since the enactment of the Energy Policy Act of 2005, which reaffirmed a commitment to competition in wholesale power markets as national policy, the Federal Energy Regulatory Commission (FERC) has been extremely busy carrying out the new responsibilities and authorities assigned to the Commission in the Energy Policy Act. In the last year FERC has completed nine final rulemakings, issued three additional notices of proposed rulemakings and submitted seven reports to Congress as required to meet the deadlines specified in the Energy Policy Act. With respect to the issues that effect transmission access, FERC is no longer pursuing any mandatory participation by utilities in a FERC approved Regional Transmission Organization (RTO). Instead, FERC has turned its attention to revising its Open Access Transmission Tariff policies, which were first established in 1996 under FERC Order 888. FERC claims further revisions are needed to prevent remaining discriminatory practices concerning access to the transmission system by customers competing in the wholesale electric markets. In addition, FERC intends to require jurisdictional utilities to participate in an open transmission planning process so that all interested parties can participate.

The other major rulemaking that FERC has undertaken that relates directly to the transmission system is to approve the North American Electric Reliability Council (NERC) as the nation’s Electric Reliability Organization. In the coming months FERC will issue a rulemaking to approve over 120 reliability standards that NERC has proposed. When approved by FERC, these reliability standards will become mandatory for all owners, operators and users of the bulk electric power system. This effort as required by the Energy Policy Act is a response to the blackout of 2003 that affected millions of customers in the Northeast and Midwest. Reliance on compliance to voluntary standards was determined to be one of the causes of the blackout. Thus, FERC will now have the authority to mandate compliance and issue significant financial penalties to entities that are found non-compliant with the reliability standards. This rulemaking will be just the start of an on-going process to establish additional reliability standards and periodically review existing standards to ensure the standards represent the best practices to maintain the reliability of the nation’s bulk power system. Compliance with the reliability standards will be monitored by Regional Entities (REs), a defined term in the Energy Policy Act, who must have a delegation agreement with NERC and must be certified by FERC to carryout those functions for a specific region. It is expected that the existing NERC Regional Reliability Councils will all be certified by FERC

as REs. The Midwest Reliability Organization (MRO) is one of the eight Regional Reliability Councils in North America. NPPD, OPPD, LES, MEAN, and Hastings are members of the MRO. Pictured below is a map showing the three Electric Interconnections in North American and NERC Regional Reliability Councils.

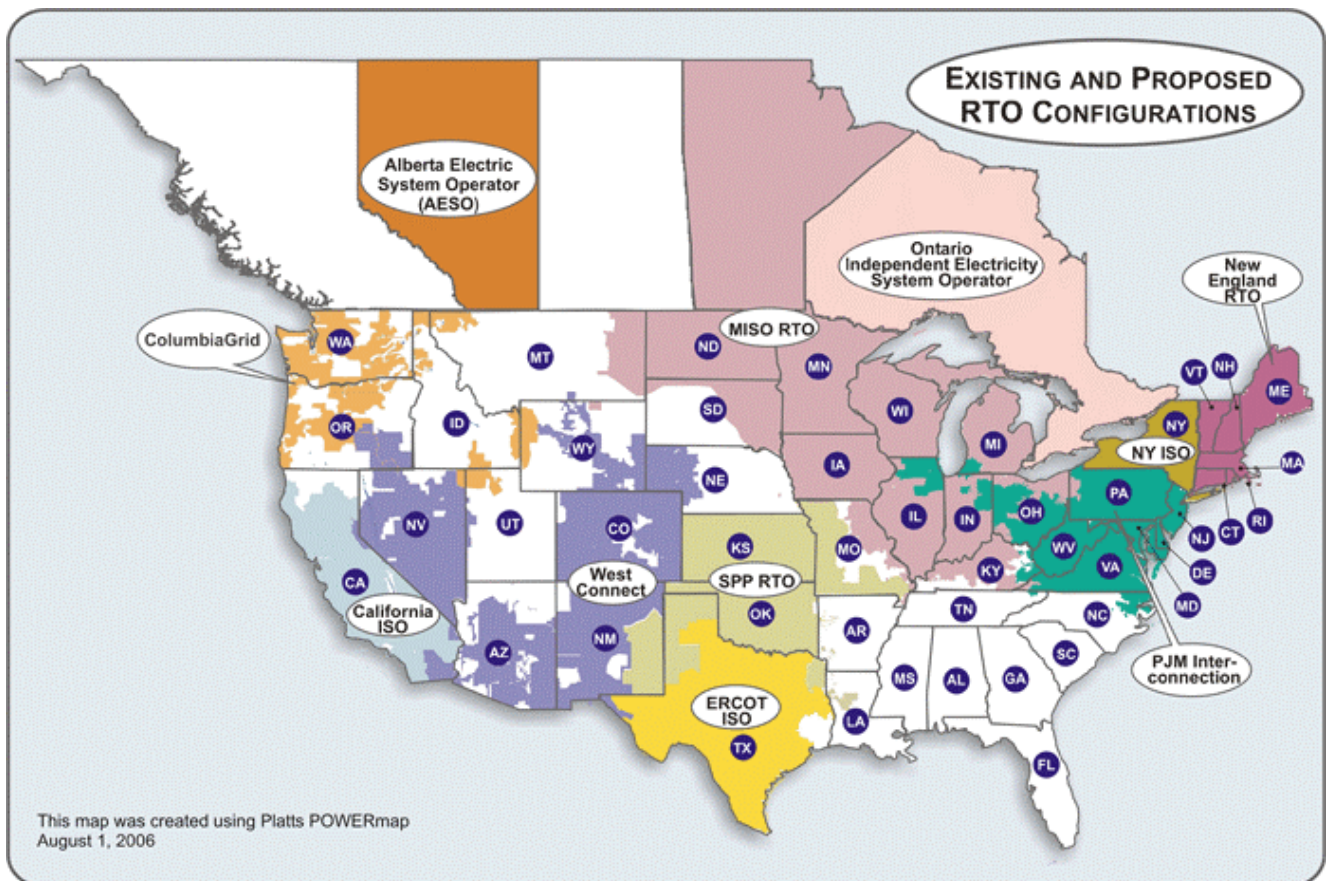


4. Roles and Responsibilities of Regional Transmission Entities

To avoid confusion about what is meant by the term “regional transmission organization” it is important to spend some time discussing the functions performed so as to distinguish between the roles and responsibilities of the various organizations. There are three basic types of regional organizations, those that provide transmission service, those that monitor compliance with reliability standards (as described in Section 2 above), and those that provide marketing functions. For purposes of this report the generic term “regional transmission organization” will be used to refer to any organization that provides regional transmission service. FERC has created many defined terms over the years concerning regional transmission organizations, starting with Regional Transmission Groups (RTGs), Independent System Operators (ISOs), and Regional Transmission Organizations (RTOs). Generally, there has been a progression from RTGs first defined after the Energy Policy Act of 1992, then the term ISO in FERC Order 888 in 1996, and finally the term RTO in FERC Order 2000, issued in 1999. With each new defined term, FERC has given more authority to the regional transmission organization and required the utilities that join to relinquish decision making authority concerning transmission service and planning activities. Utilities

that join a RTO must turn over operational control of their transmission system to the RTO and must take service for all of their native load under the RTO tariff, basically eliminating their own transmission tariff. The picture below (which is posted on the FERC website-www.ferc.gov) shows the geographic footprint of the entities that FERC has approved as RTOs or are proposed RTOs. To date, FERC has approved New England, New York, PJM, the Midwest ISO (MISO), SPP and the California ISO as RTOs. ERCOT is not subject to FERC jurisdiction, and obviously neither are the Canadian entities. West Connect and Grid West are still in the formation stage. On the map, West Connect is shown as including portions of western Nebraska. The area represented is partially served by Tri-State G&T Cooperative, headquartered in Colorado. Only those facilities and customers located in Nebraska that are served by facilities that are electrically part of the Western Interconnection could become part of the proposed West Connect.

One other point to note is that the geographic boundaries of the RTOs and the Regional Reliability Councils shown in the picture above are not the same, which can give rise to complications in operating the transmission system. In any case, both RTOs and Regional Reliability Councils are under the jurisdiction of FERC.

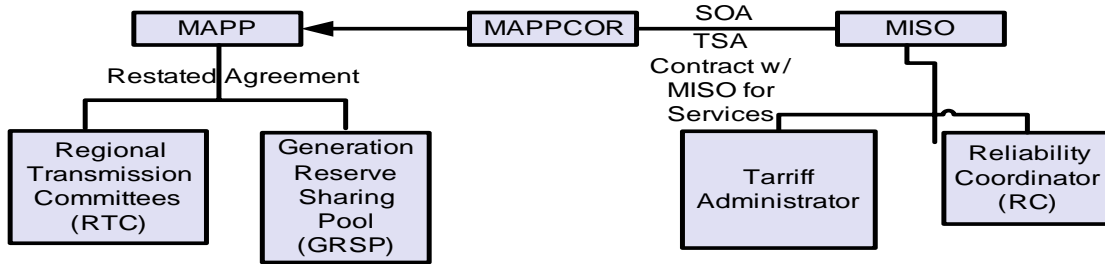


5. Status of the Mid-Continent Area Power Pool (MAPP)

As described in more detail in the previous year's report, the MAPP organization has undergone a number of changes in recent years by removing both the energy marketing and Regional Reliability Council functions from its governing document, the MAPP Restated

Agreement, into new stand-alone organizations independent from MAPP with their own governing agreements. The new independent organizations are the Mid-Continent Area Marketers Association (MEMA) and the MRO. The remaining functions governed by the MAPP Restated Agreement are the Regional Transmission Committee (RTC) and the Generation Reserve Sharing Pool (GRSP). MAPP is a FERC approved RTG that provides regional transmission service under its tariff known as Schedule F for up to one year of service, and has a regional transmission planning process open to all interested parties. NPPD, OPPD, LES, MEAN and Hastings are MAPP members. Shown below is a depiction of the MAPP organizational structure.

Current MAPP Organization



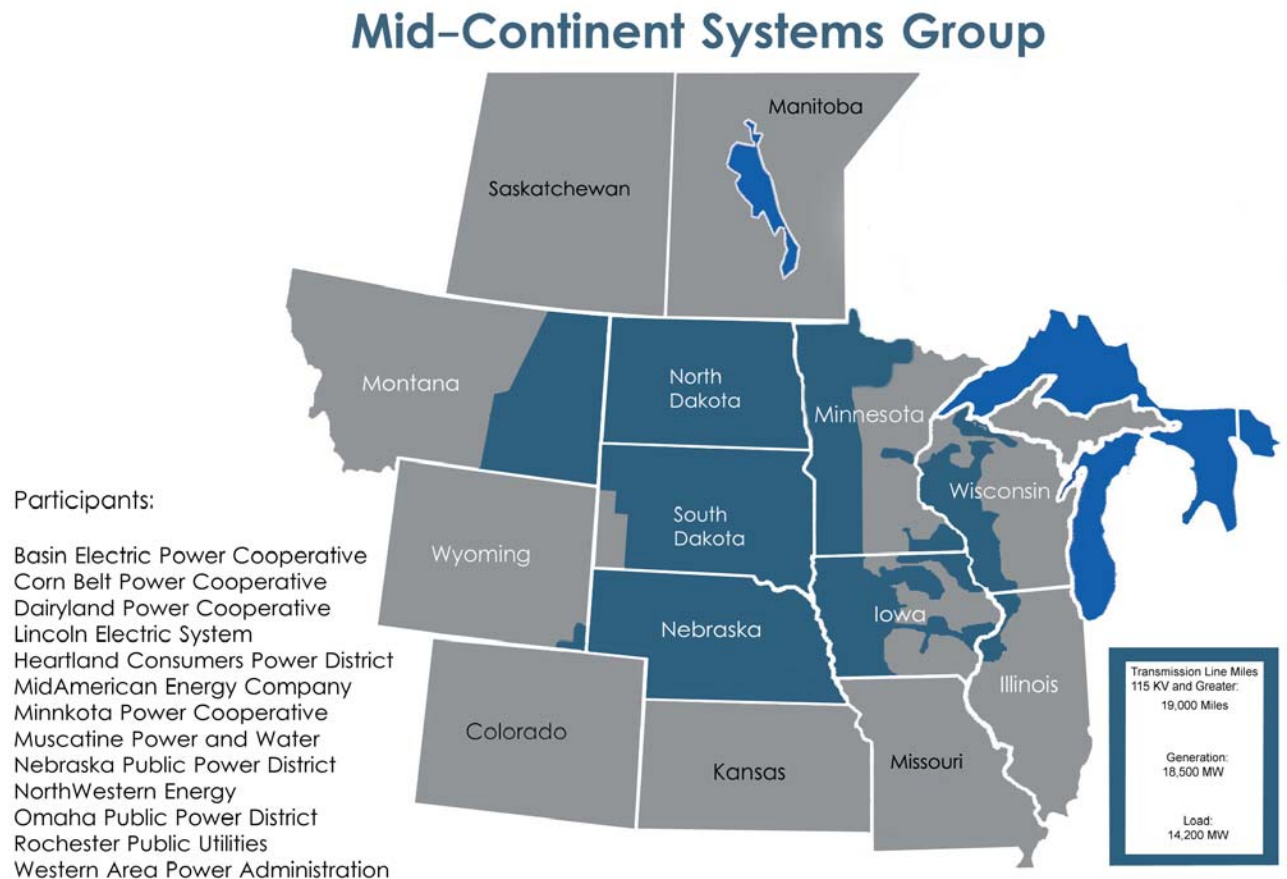
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MAPP is an association of members, whereas MAPPCOR is the legal entity organized as a non-profit corporation. In 2002, MAPP sold off its assets to the Midwest ISO, and most of the staff left or became employees of the Midwest ISO, concurrently when approximately one-half of the members left to join the Midwest ISO. A Transmission Services Agreement (TSA) was executed to provide tariff administration services and reliability coordination services to the remaining MAPP members. The issue facing the MAPP members is that the TSA terminates in February 2008, and the members must find an alternative arrangement for those services.

To that end the transmission owning members of the MAPP executed a Memorandum of Understanding in January 2006 to develop a Transmission Service Coordinator (TSC) to provide transmission tariff administration services, and is exploring the feasibility of a new regional transmission tariff. A TSC is a new type of transmission entity that has been accepted by FERC to provide tariff administration services for a single utility. Most recently, MidAmerican Energy, an Iowa based utility that is a MAPP member, turned over administration of its transmission tariff to TranServ, a new corporation created for that purpose that is independent of MidAmerican and any other market interest. The significant difference between a TSC and a RTO is that participation in a RTO requires utilities to turn over operational control of their transmission system to the RTO and to take tariff service for all of its native load customers under the RTO tariff, whereas participation in a TSC does not.

The TSC Participants believe the TSC concept for a regional transmission organization is much more suitable for the primarily public power utilities in the MAPP region. NPPD, OPPD and LES are participating in the effort to determine if a TSC can provide tariff administration service for the 13 remaining transmission-owning members of MAPP. This effort will require a vote by the MAPP members to approve necessary changes to the MAPP Restated Agreement and approval by FERC, but it is believed the TSC will result in a viable and strong regional transmission organization with adequate dedicated staff to represent the interests of the TSC Participants. The TSC will need to be operational by February 2008.

While it is much smaller geographically than it was four years ago when a number of utility members left to join the Midwest ISO, the remaining utilities and the geographic footprint they serve still constitute a viable region with over 19,000 miles of transmission lines and 18,500 MW of generation serving 14,200 MW of load. The TSC Participants have chosen the name of Mid-Continent Systems Group (MCSG) to distinguish it from MAPP. Shown below is the geographic footprint of the MCSG.



6. Transmission System Adequacy

Concerning the question of adequate transmission in Nebraska or in the region, the utilities in Nebraska are in the process of significantly expanding the transmission system in Nebraska due to load growth and the addition of large new generation facilities. A Nebraska Sub regional Transmission Plan was published in August 2006 identifying all of the specific transmission additions that are planned for the 2006 – 2015 time period. The Nebraska Sub

regional Plan, along with other Sub regional Plans for the MAPP region will be rolled up into a comprehensive 10 year Transmission Plan for the MAPP region, which will be published by the end of 2006. Elsewhere in the MAPP region, plans have been announced for significant additional transmission facilities. Shown below is a chart from the 2004 MAPP Regional Transmission Plan which depicts the incremental additions (over and above the existing transmission lines) that are planned for the MAPP region in the coming years.

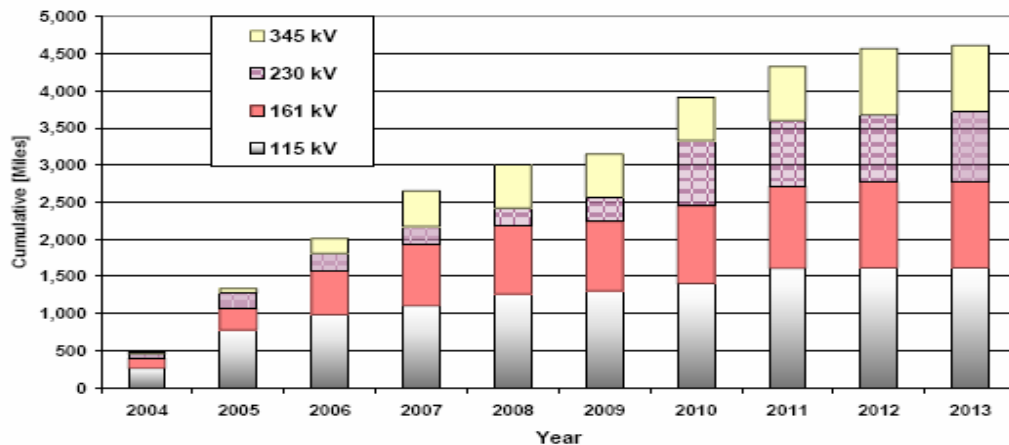


Figure 2.1-1 Cumulative New and Upgraded Transmission Lines [Miles]

It has been well documented that investment and expansion of the nation’s transmission system has languished for the last decade and has not kept pace with increased load growth and generation additions. That trend appears to be changing as transmission expansion plans are being announced across the region and the country on a regular basis. While this is a positive sign, it will take a number of years before transmission expansion will catch up. In the meantime, transmission congestion will continue to be problematic when trying to make wholesale market transactions that cross regions. To manage transmission congestion and better coordinate transmission service approvals MAPP and the Midwest ISO implemented a Seams Operating Agreement (SOA) that includes a technically complex congestion management process. This same process is being used by other regions, including the PJM, TVA, and SPP regions. All five regions have established this reciprocal congestion management process to coordinate the seams issues between the regions.

7. Conclusions

In summary, MAPP does currently serve Nebraska utilities as a viable regional transmission organization. Its continued viability beyond 2008 is uncertain, but a new organization, MCSG, is under development to replace MAPP as the regional transmission organization.

Adequate transmission exists in Nebraska to deliver the output of Nebraska generation resources to the customers in Nebraska, and while the prospect for regional transmission expansion is improving, there is not adequate transmission in the region at this time to make all of the wholesale market transactions that are sought by utilities and marketers.

Chapter 2

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

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:

Team Members

Clint Johannes (Chair)	-	Nebraska Electric G&T 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
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 transmissions 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. In May 2003 they published their first *State of the Market Report*. The analysis included 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 became the primary source for past Technical Group #2 reports.

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 No. 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. In July, 2005 FERC officially removed SMD from consideration as a rulemaking because of controversy over the far-reaching powers afforded to FERC through the RTO’s. This is a moot point, however, as the voluntary RTO’s that have been established, have generally followed the guidelines set out in the SMD proposed rulemaking and whitepaper. Furthermore, FERC has developed other means to persuade utilities to voluntarily join RTO’s as outlined in Section 4.1.1.4.

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. After 2003, the data necessary to conduct this test was not publicly available. Fortunately, MISO calculates the HHI as part of their *State of the Market Report*. This analysis was conducted for the entire MISO reliability region as well as sub-regions of MISO corresponding to the reliability areas that are represented in MISO. These sub-regions represent logical groupings of transmission interconnections for the purpose of monitoring reliability. The MISO area and sub-regions are shown in Exhibit II-1. The HHI statistic calculated for the entire MISO region, as shown in Exhibit II-2, was 548 for 2005. Even though the concentration has been trending upward over the last couple of years, this still suggests the entire MISO area is a very unconcentrated market as the statistic is well below 1,000. This is because the larger the area, the more suppliers, the smaller the HHI. In this case the HHI 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. For instance, the West region (including Nebraska) and

the East region show HHI statistics of 2,397 and 2,072 respectively. This indicates that these sub-markets are fairly concentrated and hold the potential for exercising market power.

Exhibit II-3 demonstrates the market concentration by showing the market share of the top three suppliers in MISO and in each sub-region. In MISO as a whole the top three suppliers have only 26% of the market. In the East and West regions the top three suppliers control over 70% of the market. The WUMS (Wisconsin-Upper Michigan) is also shown because this is an area known for serious transmission constraints that isolate the generators in the area.

Exhibit II-1

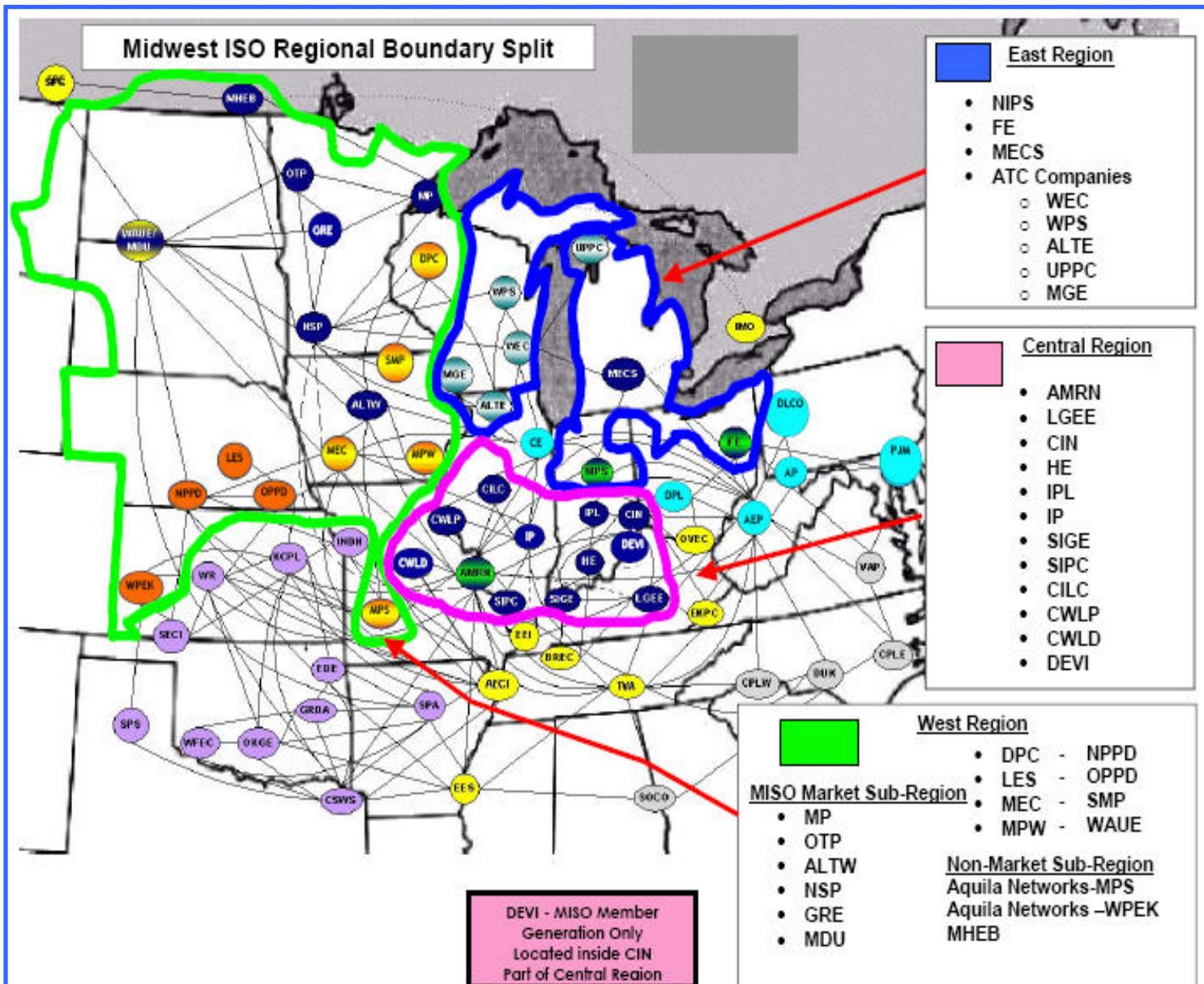


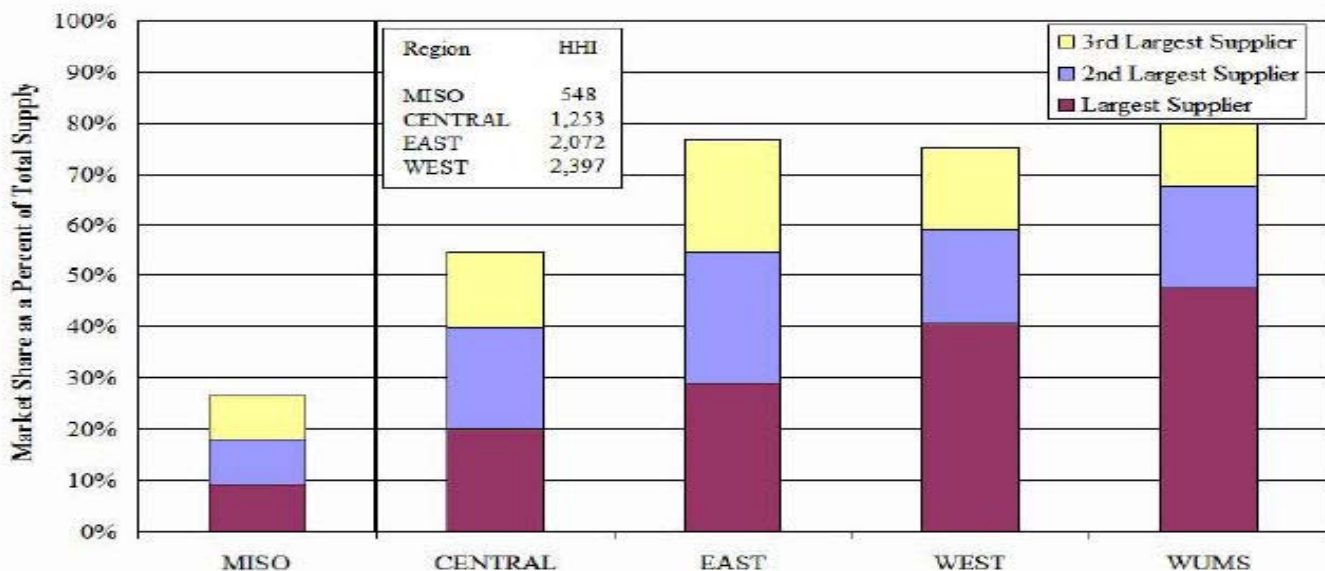
Exhibit II-2

MISO HHI Index			
Region	2005	2004	2003
All MISO	548	261	408
Central	1,253		
East	2,072		
West	2,397		

- < 1000 – Unconcentrated market – no market power
- > 1800 – Highly concentrated – market power

Exhibit II-3

Market Concentration



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)

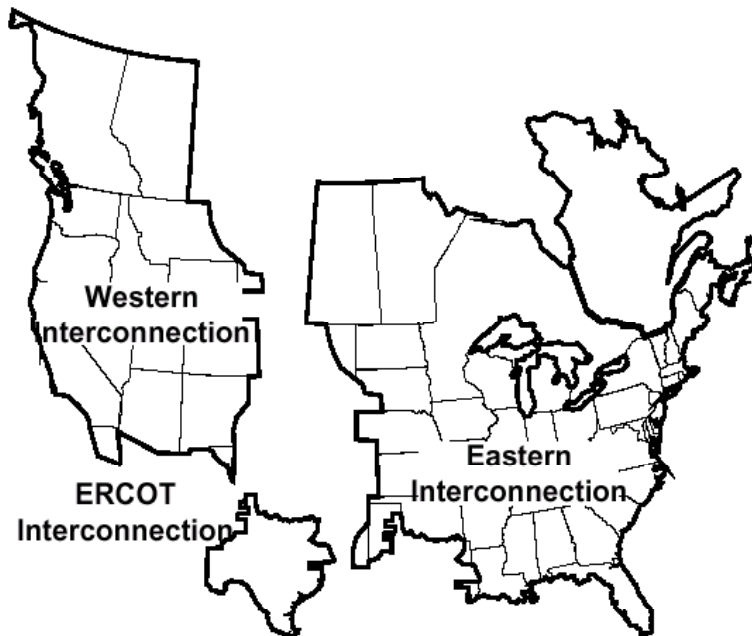
3.4 ERCOT Interconnection

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.

Exhibit II-4



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

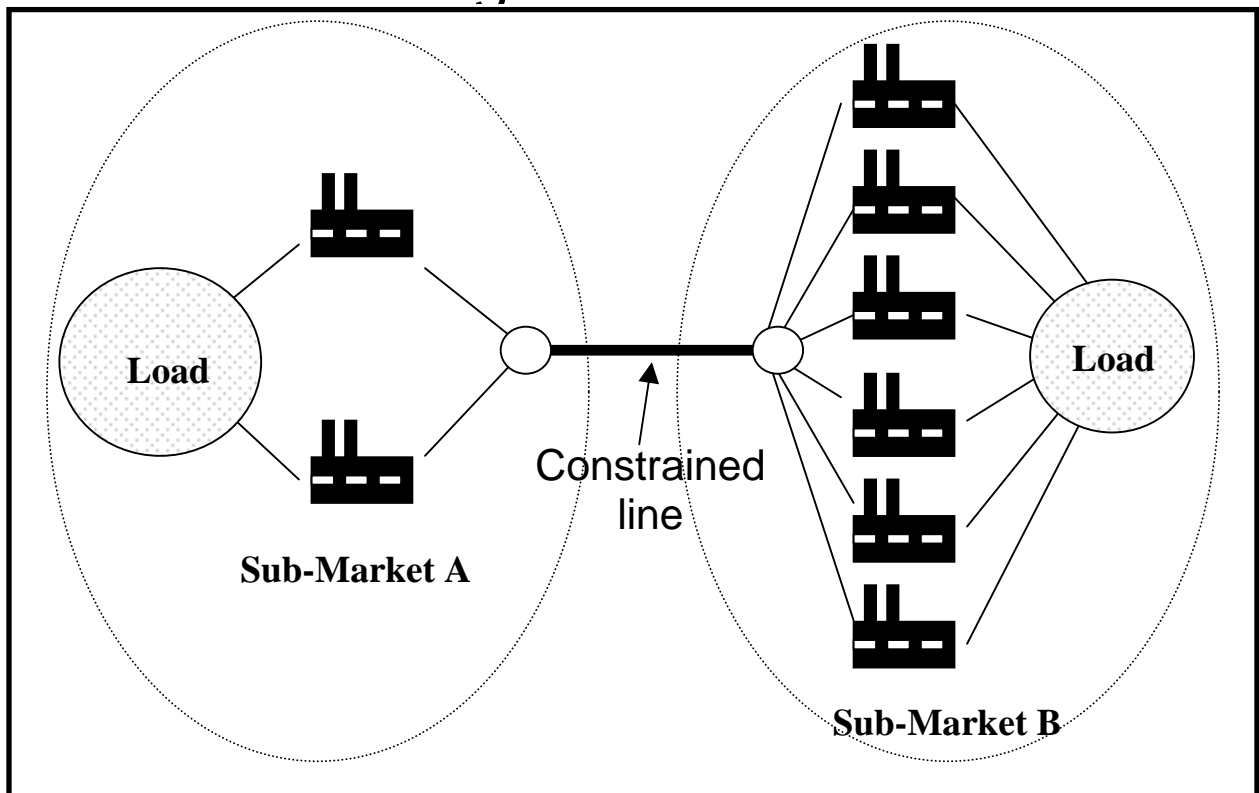
4.1 Reasons for Instituting New Methods

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.

Exhibit II-5

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, then 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 No. 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

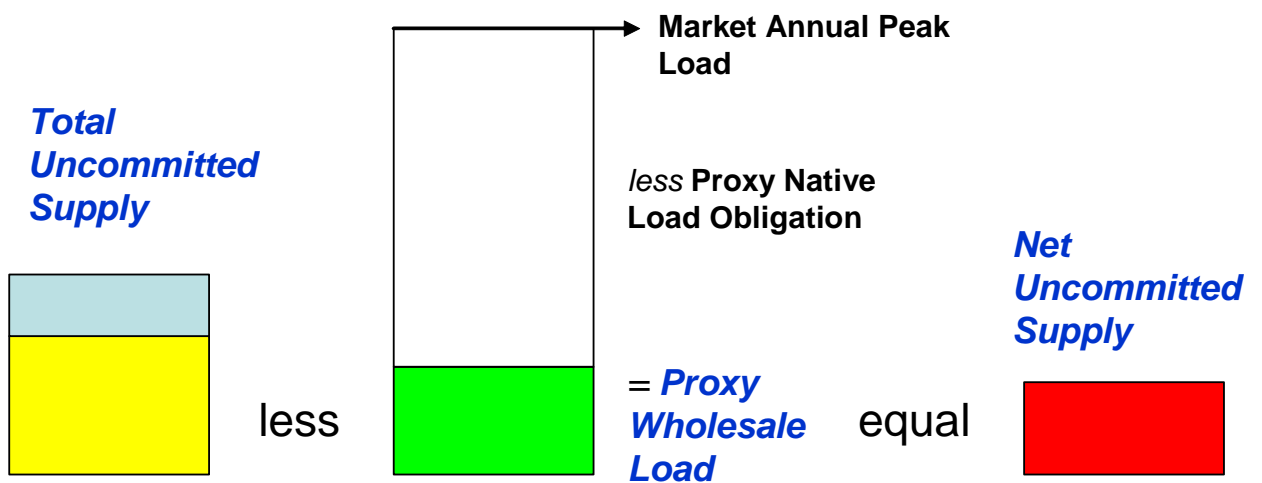
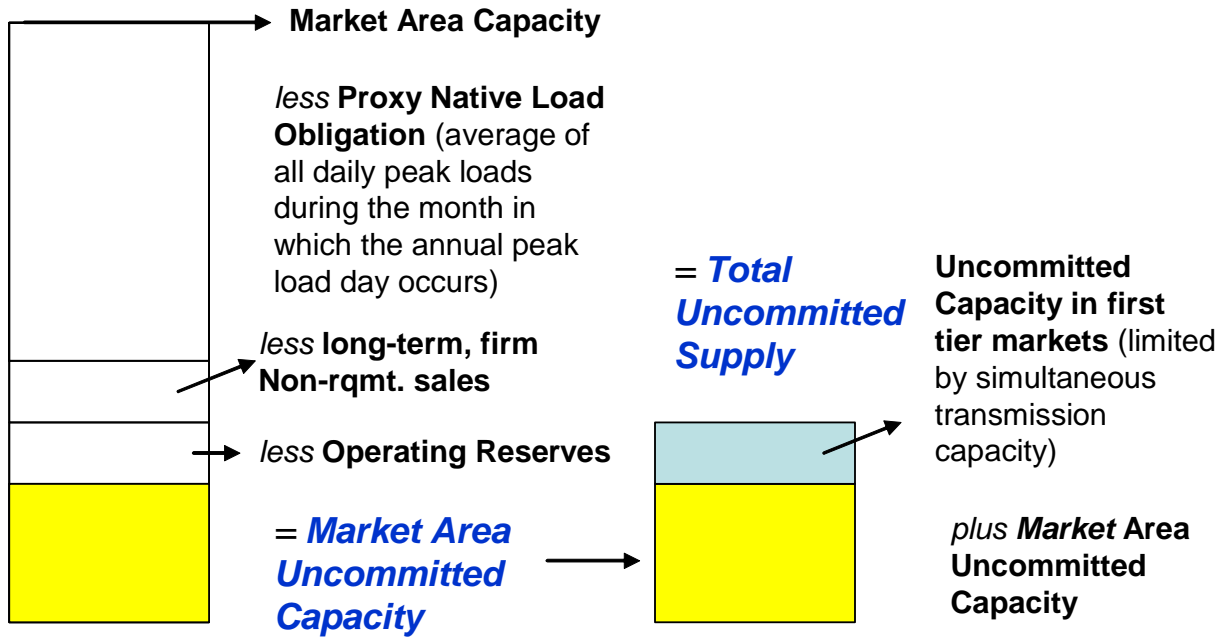
The relevant market area used when conducting the two market screens has a profound effect on the results of the test. The greater the size of the relevant market area the less likely the applicant will be found to possess market power. For utilities belonging to an RTO, the entire geographic region 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)

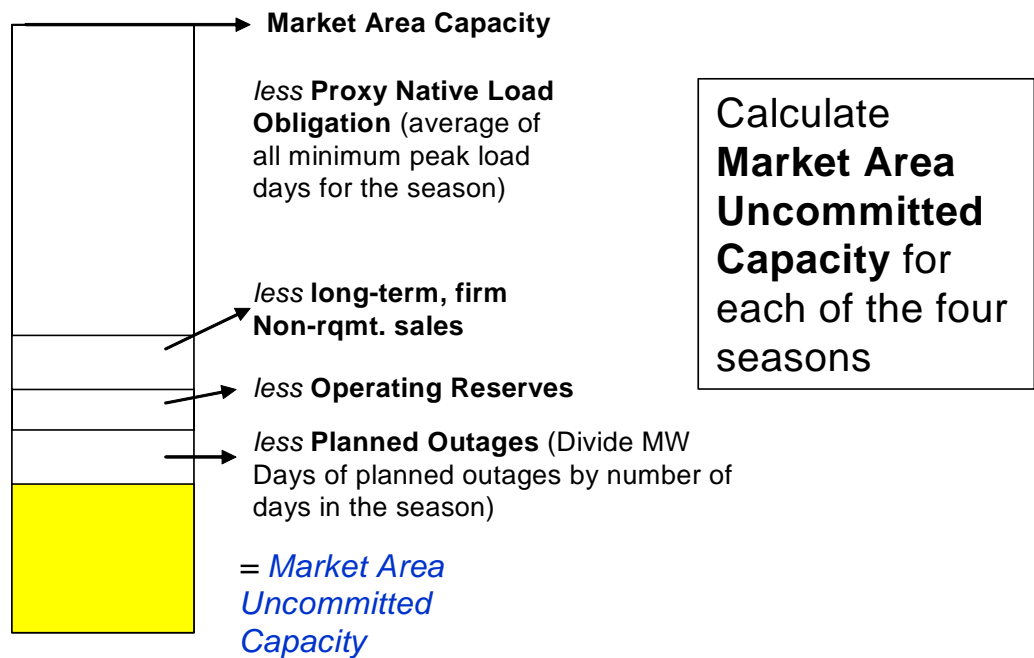
As shown in Exhibit II-5, if the applicant’s uncommitted capacity is less than the uncommitted capacity offered by all other competitors than it will not be required (or pivotal) in satisfying all of the wholesale market demands in the area. On the other hand if the applicant’s uncommitted capacity is 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-7

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-8

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

4.1.1.4.6 Current Status of the Midwest area utilities regarding the Generation Market Screen and Mitigation Policy

Exhibit II-9 shows the disposition of Midwest Utilities in regards to the FERC market power screens.

American Electric Power (AEP), representing 9 operating utilities, had 5 of them pass the initial screens. All of these utilities were members of the qualifying PJM RTO. The remaining 4 utilities that failed the screens were all in the non-qualifying Southwest Power Pool (SPP). For these utilities, AEP has accepted cost-based wholesale rates as mitigation. Because the utilities in the Midwest were part of an RTO, they used the entire RTO region as the relevant market area. This allowed AEP to pass both the market share and pivotal supplier tests in the Midwest.

Alliant filed its market screens before MISO became a qualifying RTO and failed the screens for their control area. After MISO became a qualifying RTO in April 2004, the tests were recalculated using the entire MISO area as the relevant market. This allowed Alliant to pass the market power screens.

Aquila, Inc. failed screens for Missouri Public Service and West Plains and were deemed to have market power. Aquila submitted to cost mitigation for wholesale sales.

Mid-American failed screens for the Mid-American control area and must submit to cost mitigation. In addition FERC has also conducted investigations into the improper administration of the Open Access Transmission Tariff (OATT), unreasonably denying transmission access to utilities requesting it and erecting artificial barriers of entry for competing utilities. FERC found these allegations to be true and required Mid-American to turn over tariff administration and transmission operation to an independent third party operator to guarantee unbiased service.

Excel passed screens for their Northern States operating utility as member of MISO. They failed screens for their Public Service of Colorado and Southwestern Public Service operating utilities. They accepted cost mitigation for these utilities.

The Empire District failed the market screens for their service territory and submitted to cost mitigation for wholesale sales.

Louisville Gas and Electric (LG&E) also failed the market power screens and lost their right to sell wholesale power at market prices.

Kansas City Power and Light (KCP&L) initially failed the market power screens, but offered additional information and had the ruling overturned.

In summary, four out of the nine utilities in the Midwest that have had FERC market power reviews were identified as having market power. Of the five utilities that passed the market screens, four were members of a qualifying RTO and benefited from the advantage of using the entire RTO as the relevant market area in calculating the market screens. KCP&L is the only utility to date to pass the market screens without being a member of an RTO.

Exhibit II-9
Midwest Results of FERC Market Power Proceedings

Midwest Utility	Market Screen Results	FERC Mitigation	Market Power in Midwest
AEP	Failed in SPP area, passed in Midwest – MISO member	Yes	No
Aliant	Failed in Aliant and Dairyland areas but passed after joining MISO	No	No
Aquila	Failed in MPS and West Plains Areas	Yes	Yes
Empire District	Failed in Empire District	Yes	Yes
KCPL	Originally failed in KCPL and KACY area, but successfully rebutted	No	No
LG&E	Failed in LF&E and BREC areas	Yes	Yes
Mid-American	Failed in Mid-American Area	Yes	Yes
Xcel Energy	Failed in SPS and PSCo areas, passed in Midwest – MISO member	Yes	No

4.1.1.4.7 FERC Notice of Proposed Rulemaking on Market-based rates

In 2005 FERC initiated a review of Interim Generation Market Screen and Mitigation Policy. At issue is the relative ease in which utilities can pass the market power screens. This may dramatically change the results of the market power screens in coming years.

4.1.1.4.8 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 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 Other Regulatory Reviews of relating Market Power in the Wholesale Market

5.1 FERC Notice of Proposed Rulemaking on Open Access Transmission Tariffs

FERC is currently reviewing FERC orders 888 & 889. These are the FERC orders that initially opened the wholesale market by requiring utilities to allow others use of their transmission facilities. The stated reason for reopening these orders is to address deficiencies that, in FERC’s opinion allow transmission owners to exercise market power. This suggests that FERC believes market power is still be exercised.

5.2 Report to Congress on competition in the Wholesale and Retail Markets for Electric Energy – June 5 2006, Draft

This draft report is a requirement of Congress to assess the competitiveness of emerging electric markets. The Task Force was comprised of officials from FERC, Department of Energy, the Justice Department, the Federal Trade Commission and the Department of Agriculture’s Rural Utility Service.

While no final judgments about the competitiveness of the wholesale market were offered in the report, it did conclude that “many wholesale buyers sought to enter into long-term contracts but found few or no offers”. The postulated reasons for this situation are; current high prices in the spot wholesale markets, lack of financial hedging instruments and significant transmission risk (i.e. no long-term transmission rights at known prices) for the seller when entering into a long-term contract.

This lack of long term contracts is considered a significant deficiency in the wholesale market.

6.0 Conclusion

6.1 Status of Viable Midwest Wholesale Market in the Eastern Region

The traditional test of market power, the hub and spoke test, demonstrated that two out of the three regions in the wholesale market that includes Nebraska, experienced market power. The newly approved FERC market power screens of individual utilities indicate that nearly all of the area utilities not belonging to an RTO have market power. Additionally, new proposed FERC rulemakings that will review the validity of these screens for identifying market power as well as a review of the initial orders responsible for the deregulation of the wholesale market suggest that FERC is very concerned about the effectiveness of these rulemakings in detecting market power. Finally, a draft report to Congress states that the market for long-term wholesale power is illiquid and represents a deficiency in the market. 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.

6.2 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 3

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

1.0 Purpose

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 Status of Unbundling in Nebraska

There were no new developments regarding unbundling for the Group to address in 2005 and 2006. In 2004, all the electric utilities in Nebraska were surveyed to determine their current unbundling status. The results of that survey are shown in 5.0 Survey Results.

3.0 Team Members

Jay Anderson	-	Omaha Public Power District (OPPD)
Rich Andrysik	-	Lincoln Electric System (LES)
Don Cox	-	Hastings Utilities
Jim Gibney	-	Wahoo Utilities
Jamey Pankoke	-	Perennial Public Power District
Dawn Petrus	-	Nebraska Public Power District (NPPD)

4.0 Introduction

LB901 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.”¹

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.”²

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

¹ State of Nebraska, Legislature of Nebraska, Legislative Bill 901, (Lincoln, Nebraska, 2000) p.3.

² Dr. Artie Powell, Utah Division of Public Utilities position paper presented to Utah Public Service Commission, Unbundling Electricity-Related Services (Utah: 1998) p.1.

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 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.

5.0 Survey Results

The detailed information from the surveys follows in the tables below. The Nebraska Power Review Board mailed the surveys out one time. 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 RESPONSES

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

OF ELECTRICAL CUSTOMERS REPRESENTED

TYPE	SENT OUT	RESPONDED	% RESPONSE
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%
Total	908,643	907,666	99.9%

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

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

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?

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

Q2A. - WILL YOUR CURRENT BILLING SYSTEM ACCOMMODATE UNBUNDLING?

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

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?

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

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

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

6.0 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 central 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 statewide 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 statewide consumer education

program would be needed to communicate to the consumer a new billing process, so consumer education on a statewide 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).

7.0 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. During the study year 2007, there may be activity in the area of privately owned generation that might require limited unbundling and Technical Group #3 may look in to those activities.

Chapter 4

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

1.0 Introduction

1.1 Purpose 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:

Team members

Clint Johannes (Chair)	-	Nebraska Electric Generation and 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 and 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 and 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 and 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 and 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 and 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 and 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.

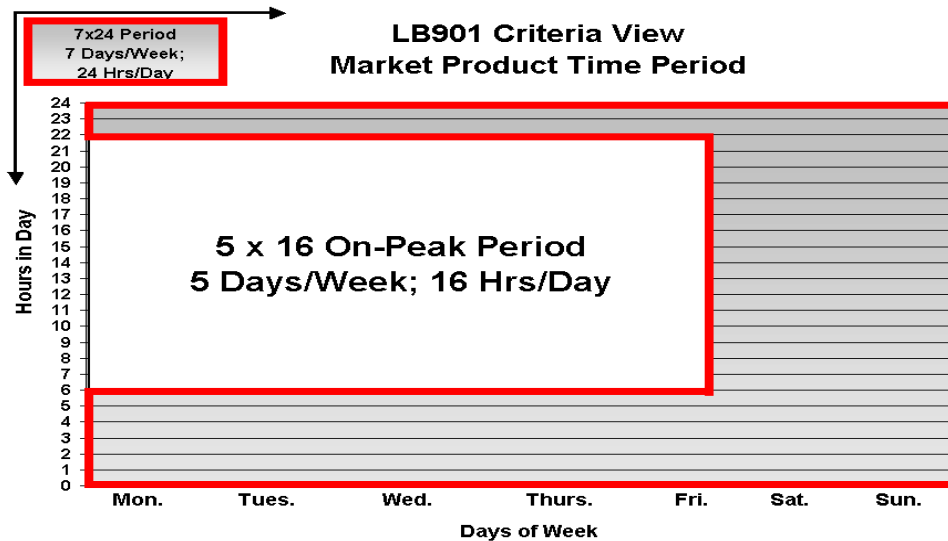
3.2 Comparison Modeling Tool Detail

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:

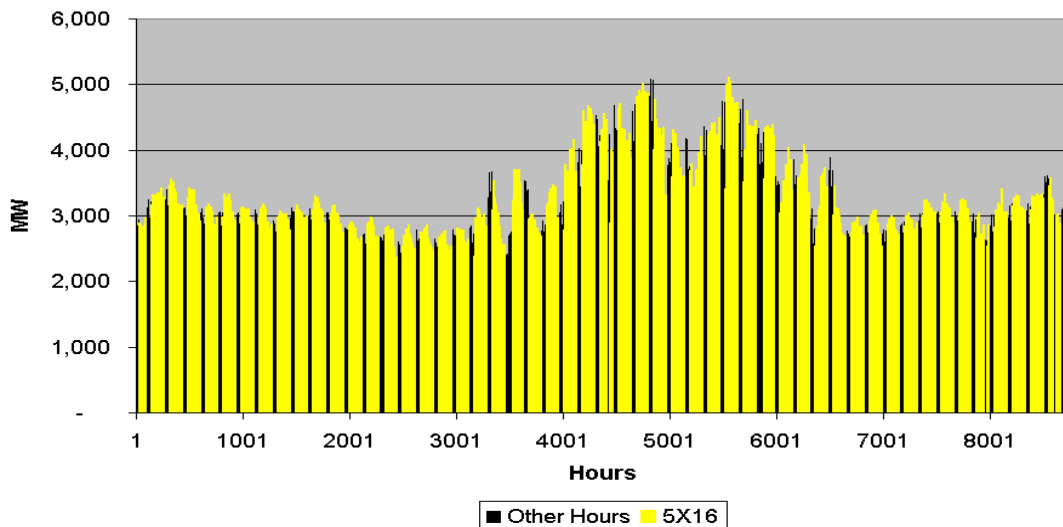
- (1) Determine the total annual production revenue requirements for all the Nebraska utilities' power resources,
- (2) Apply a consistent set of fixed and variable production cost accounts based on Federal Energy Regulatory Commission (FERC) accounting definitions to calculate the production cost to 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

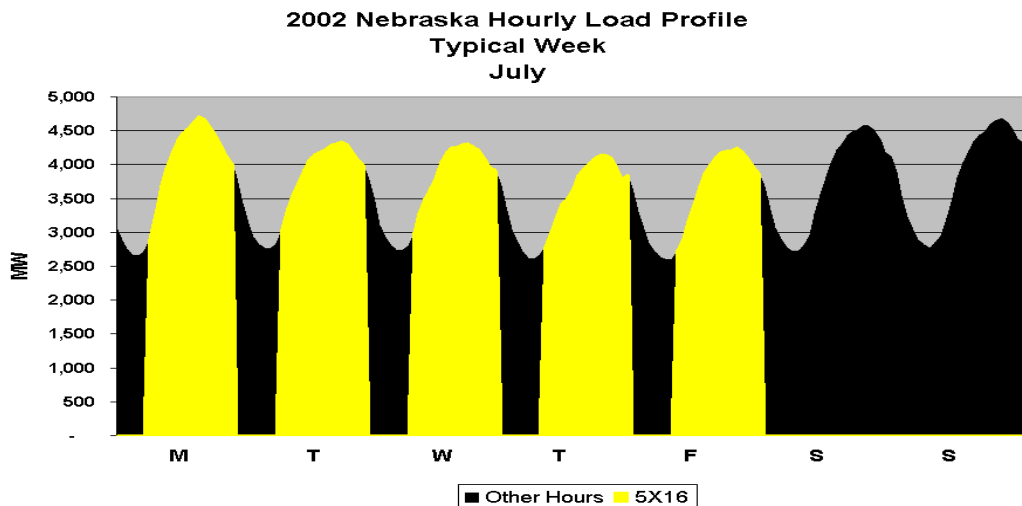
load factors to match available market product indices which are on a 5 X 16 basis (5 days per week – Monday thru Friday, 16 hours per day). Exhibit IV-I below provides a graphical description of how much and during which times the load profile information is utilized.

Exhibit IV-1



2002 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:

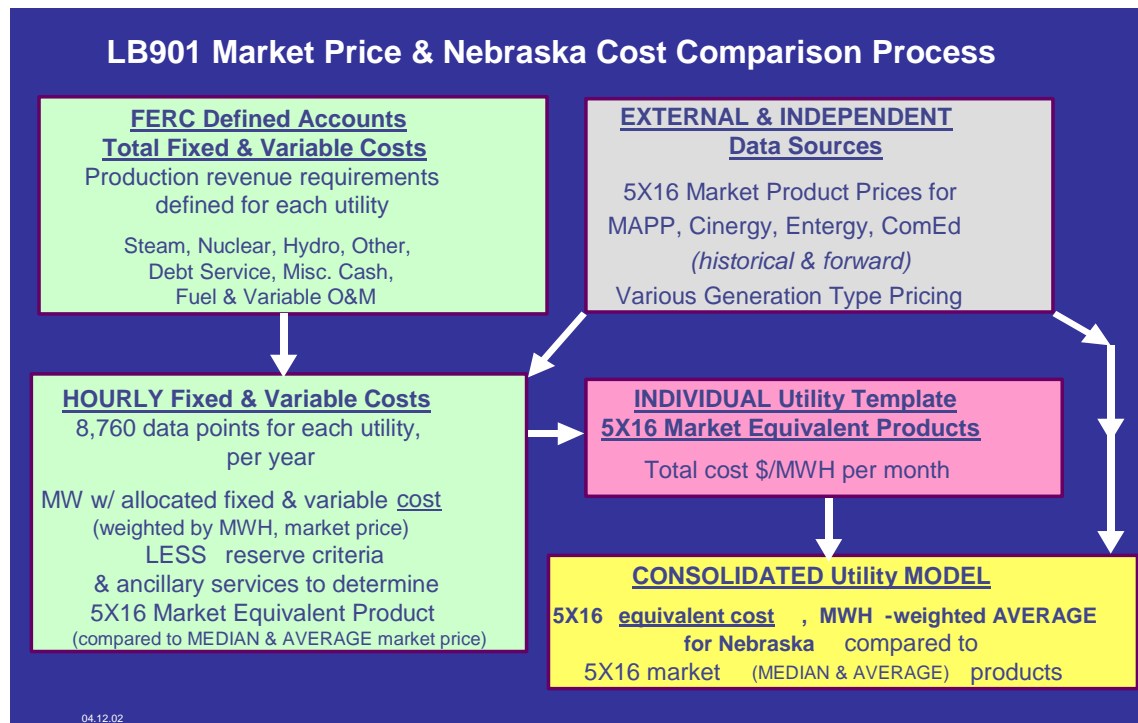
- (1) Costs and prices were compared on a total annual amount calculated per month for an equivalent 100% load factor, 5 x 16 market product since there were a multitude of market price indices available for this type of product.
- (2) Both “average” and “median” monthly market price history were calculated 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,
- 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 “CommEd”; (“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 and baseload) were priced and calculated, based on market cost allocation methods, then compared,
- (3) 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.

- (4) 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).
- (5) 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 2002-2005 (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 may. 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 2006, modeling comparison purposes the time period of 2003 through 2006 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 2003-2006 with 2006 being the estimated year for both market pricing and production costs.
- Incorporating the future year 2007 into the modeling introduces another layer of “assumptions” and “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 and 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 and actual production costs, which are more credible and accurate than projections or expectations. The four-year rolling average allows for anomalies and unusual fluctuations in both the market price and 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).

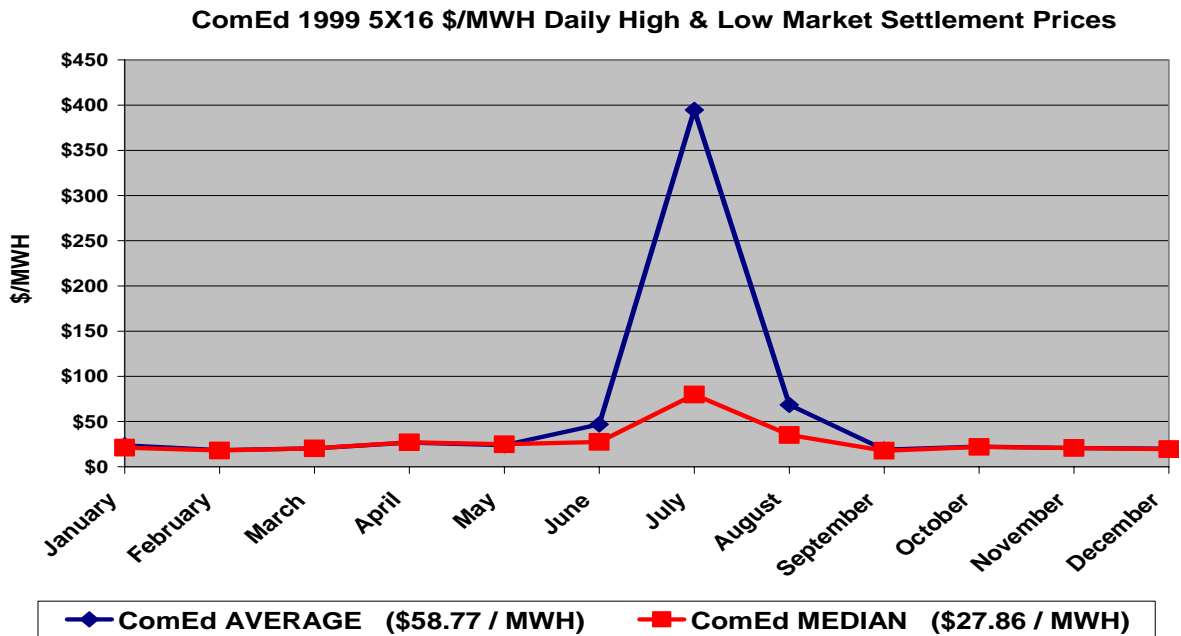
4.2 Sensitivity Cases Analyzed

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 on the following page shows two distributions for 5 X 16 monthly market prices in the ComEd market for 1999 based on high and low daily settlement prices. One is based on the “average” of the daily high and low settlement prices, and the other is based on the “median” of the daily high and 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 and 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 and 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 and tariffs). Although this flexibility is built into the modeling tool, the 2005 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 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 and peaking), as described earlier in Section 2.12, the model is enhanced to provide informational detail and 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 and 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 2002-2005 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 2003 through 2006.

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 2003 through 2006. As shown in the table, on an equivalent basis, Nebraska production costs consistently rank below the market product throughout the study period. Five (5) LB901 historical study period comparisons are also included, describing the four-year rolling average results for the various study periods completed. A main driver of the gap between Nebraska production and market prices appears to be natural gas prices. Refer to Exhibit IV-4a. 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
2003	23.4%	23.6%
2004	35.9%	35.8%
2005	53.5%	53.0%
2006	39.1%	39.2%
Straight Average	38.0%	37.9%
Four Year Average (MWh-weighted)	39.6%	39.4%

HISTORICAL LB901 STUDY PERIOD COMPARISON					
Study Period Years	% Nebraska Systems Below Market	Nebraska Cost		Market Price	
		Annualized Volatility	Monthly Std Dev	Annualized Volatility	Monthly Std Dev
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%	
2002-2005	28.3%	35.8%	\$1.97/MWh	34.2%	\$3.29/MWh
2003-2006	39.6%	32.0%	\$2.17/MWh	34.3%	\$5.68/MWh

Note: Monthly Standard Deviation calculation was started in the 2005 report

Exhibit IV-4a

Natural Gas vs. Market Prices Annual Basis

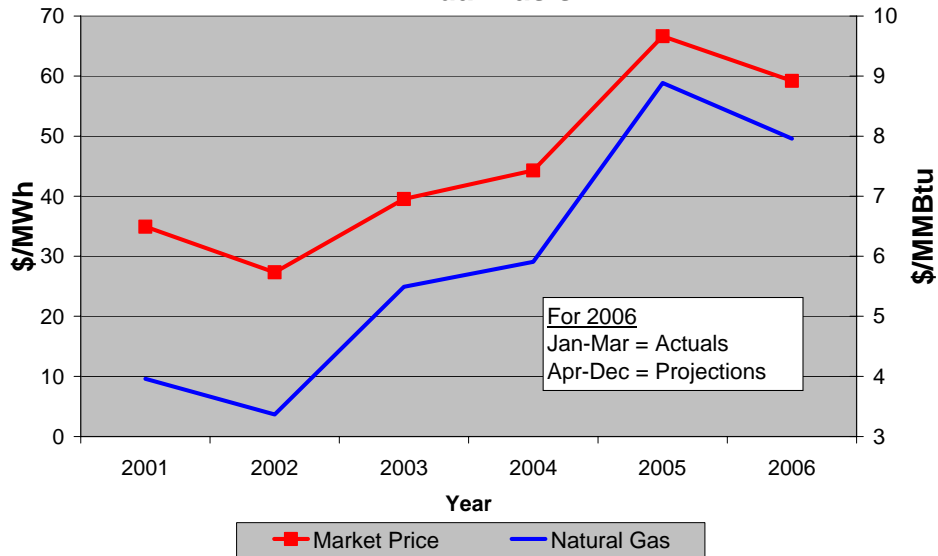
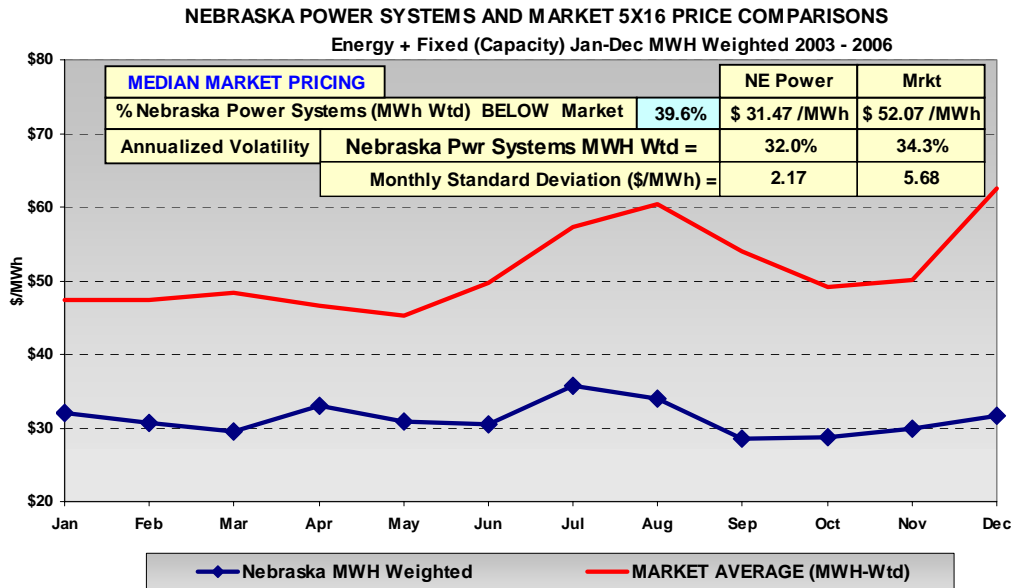


Exhibit IV-5 provides a monthly comparison for the four-year study period (2003-2006) between the median market product pricing indices to Nebraska production costs. In every month, Nebraska production costs are lower. The calculated volatility is slightly lower for Nebraska production and the market. Even though the annualized volatility is approximately the same, the standard deviation for the Nebraska Power Systems is roughly \$3.5/MWh less than the market.

Exhibit IV-5



For comparison purposes, Exhibit IV-6 is provided to describe the detail associated with the 2006 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 ■ = Automatic Link

AVERAGE 5X16 \$/MWH Daily Settlements for 2006

	Historical			FORWARD INDICES (as of March - 2006)											
	January	February	March	April	May	June	July	August	September	October	November	December			
MAPP	53.24	52.23	49.50	51.63	51.39	61.32	71.39	67.51	53.74	48.09	62.68	76.30			
NI	51.15	51.15	48.39	51.15	52.25	58.22	68.80	68.75	61.10	52.20	53.35	61.80			
Cinergy	50.65	48.48	47.70	52.00	53.50	58.45	69.45	69.25	61.00	52.25	55.60	63.20			
Entergy	55.36	54.59	51.26	54.63	59.08	62.86	70.22	71.15	64.49	57.31	65.15	80.55			
MAPP CALC	101.6%	101.6%	100.8%	98.2%	93.5%	102.5%	102.7%	96.8%	86.4%	89.2%	108.0%	111.4%			

Intercontinental Exchange (ICE) Data is very limited beyond the next month. Much of this information was obtained from a reliable trading source that get broker quotes. Since no quotes were available for Entergy in some months, the Entergy price was developed using natural gas prices and heat rates.

MEDIAN 5X16 \$/MWH Daily Settlements for 2006

	Historical			FORWARD INDICES (as of March - 2006)											
	January	February	March	April	May	June	July	August	September	October	November	December			
MAPP	52.78	50.76	50.95	50.70	51.47	63.50	73.31	68.43	55.02	48.82	65.33	71.13			
NI	50.00	48.75	48.00	51.15	52.25	58.22	68.80	68.75	61.10	52.20	53.35	61.80			
Cinergy	50.97	46.85	48.00	52.00	53.50	58.45	69.45	69.25	61.00	52.25	55.60	63.20			
Entergy	55.32	54.45	51.00	54.63	59.08	62.86	70.22	71.15	64.49	57.31	65.15	80.55			
MAPP CALC	101.3%	101.5%	104.0%	96.4%	93.7%	106.1%	105.5%	98.2%	88.5%	90.5%	112.6%	103.8%			

MAPP Capacity Only Price \$/kW-yr for 2006 = 15.00

New Peaking Unit \$/MWH for 2006 = 117 ⁸⁵ @ 85% CF and Fuel of \$8.0/ mmBTU 155 @ 10% CF
 New Combined Cycle \$/MWH for 2006 = 67 @ 85% CF and Fuel of \$8.0/ mmBTU
 New Baseload Coal \$/MWH for 2006 = 30 @ 85% CF and Fuel of \$0.80/ mmBTU

(All generation units EXclude transmission cost adders)

The results for the 2003 - 2006 study period shows the continuing gap between the Nebraska production costs and the market. 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

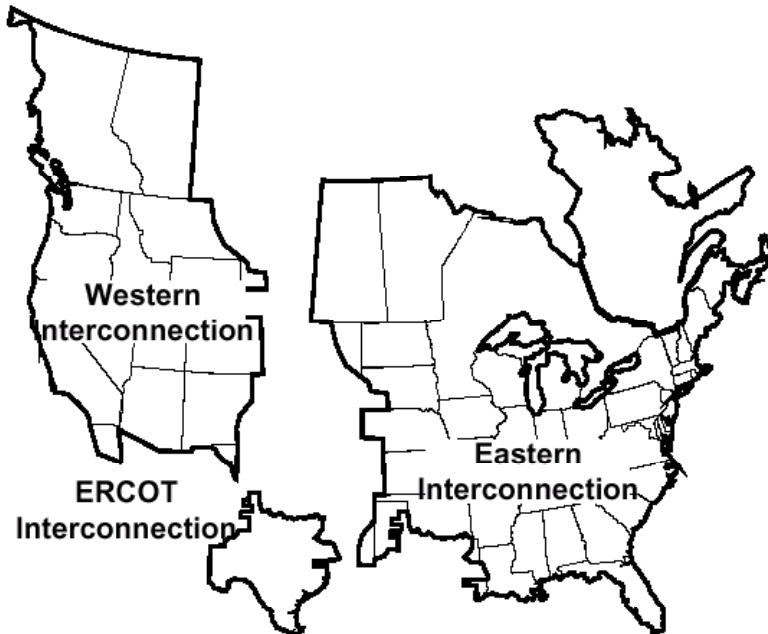
5.1 North American Electrical Interconnection

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 2003 through 2006 show 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 Westminister, 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 2007 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 39% lower than the equivalent wholesale "median" market price based on the period 2003-2006 (three years actual, one year projected), and weighted based on MWH. Based on the "average" market

price, Nebraska production costs are approximately 39% lower than the “average” market price.

These results for the 2003-2006 study show a widening gap between the Nebraska production costs and the market, 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), 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 39% 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 2004 shows that Nebraska’s average retail rate of 5.70 cents/kWh is approximately 25 % lower than the national average retail rate of 7.62 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

Kurt Stradley	–	Lincoln Electric System (LES)
Tim Grove	–	Omaha Public Power District (OPPD)
Jay Holmquist	–	Nebraska Rural Electric Association (NREA)
John McClure	–	Nebraska Public Power District (NPPD)
Tom Richards	–	OPPD

3.0 Introduction and Deregulation Overview

Approximately 1/3 of the states have some form of retail electric competition, but in many cases, the incumbent local utility is providing the service. No state has enacted retail choice legislation since 2000 and several states have scaled back or repealed retail choice initiatives. State retail electric markets have gained considerable attention in the last year due to significant increases in retail electricity prices. Escalating and volatile fuel prices are a key driver, but do not fully explain all the cost increases. Many state retail choice programs are either struggling or inactive. As noted in a previous report, 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."

On September 1, 2005, the State Corporation Commission of Virginia issued its fifth annual report stating that "retail competition" in Virginia has not lead to lower prices than would have been charged under traditional regulation. The executive summary ends with the following assessment of retail choice:

"It appears that, from the data so far, most retail customers (especially residential) in restructured states where the transition period has ended and the price is now based on the wholesale market, are seeing prices increase faster than in the non-restructured states or states still in transition with a price cap. At best, at this point in time, no discernable overall benefit to retail consumers can be seen from restructuring."

The September 2006 Virginia report confirms the findings of previous reports.

Several states are facing significant challenges under retail choice as rate caps are removed under retail restructuring programs. Earlier this year, 72% retail rate increases were proposed in Maryland as retail price caps were ending. In Illinois, another state with retail

rate caps, a 30% rate increase was proposed for January 1, 2007, but has been modified to a 10% increase for each of the next four years.

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 and the status of the program 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 Texas 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 in 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 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, average retail rates are relatively high, in the 9¢/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 utility (IOU) that wishes 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 September of 2004 the price-to-beat in the five distribution areas ranged from 10.9 to 13.0¢/kWh with the average residential at 11.7¢. Price-to-beat rates have increased significantly since January 2002. For 2006, the residential price to beat jumped dramatically and was over 18¢/kWh for one IOU and over 19¢/kWh for another.

The Texas Public Utility Commission monitors and reports on the status of retail choice in Texas. By 2006, more than 60% of the state's total electric load is being served by alternative suppliers.

Under state law, the PUC reports to the Texas Legislature every two years on the status of the electric markets. The next report is due in January 2007. There have been other reports praising the economic benefits of the retail markets in Texas, yet there have also been numerous media reports of consumer frustration over increasing retail electric rates.

Below is a comparison of average retail electric revenue per kWh in Nebraska, which has not adopted retail choice and three states that have choice. Retail rate caps have been in place in Texas and Illinois.

	<u>Nebraska</u>	<u>Texas</u>	<u>Illinois</u>	<u>Pennsylvania</u>
1996	5.32¢	6.16¢	7.69¢	7.96¢
1997	5.30¢	6.17¢	7.71¢	7.99¢
1998	5.30¢	6.07¢	7.46¢	7.86¢
1999	5.31¢	6.04¢	6.98¢	7.67¢
2000	5.31¢	6.49¢	6.94¢	7.65¢
2001	5.39¢	7.38¢	6.90¢	8.01¢
2002	5.55¢	6.62¢	6.97¢	8.01¢
2003	5.64¢	7.50¢	6.88¢	7.98¢
2004	5.70¢	7.95¢	6.80¢	8.00¢
2005	5.82¢	9.11¢	6.97¢	8.27¢

Source: U.S. Energy Information Administration

5.0 Pennsylvania

An example of retail choice is reflected in the summary from Pennsylvania that shows three of seven investor-owned utilities have no customers choosing alternative supplies and another having only 95 commercial and industrial customers choosing an alternate supplier.

Number of Customers Served By An Alternative Supplier As Of 7/1/2006				
	Residential	Commercial	Industrial	Total
Allegheny Power	0	0	0	0
Duquesne Light	94,086	9,504	618	104,208
MetEd/Penelec	0	0	0	0
PECO Energy	6,528	32,326	7	38,861
Penn Power	0	0	0	0
PPL	0	87	8	95
UGI	0	0	0	0
Total	100,614	41,917	633	143,164

Pennsylvania Office of Consumer Advocate
7-10-2006

Percentage of Customers Served By An Alternative Supplier As Of 7/1/2006				
	Residential	Commercial	Industrial	Total
Allegheny Power	0	0	0	0
Duquesne Light	17.96	15.84	40.85	17.8
MetEd/Penelec	0	0	0	0
PECO Energy	0.5	21	0.2	2.5
Penn Power	0	0	0	0
PPL	0	0	0	0
UGI	0	0	0	0

Totals may differ due to rounding. Percentages are rounded to the nearest tenth of a percent.

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6.0 Conclusions

- Natural gas prices have been at all time highs, significantly increasing the cost of gas-fired generation and setting the market price in most wholesale and retail markets.
- Promises of wholesale or retail competition driving down energy prices have not occurred.
- Competitive wholesale markets are a necessary precedent to successfully implementing retail choice.
- Adequate power supply, reserves and infrastructure 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.
- FERC is actively involved in developing and addressing the transition to a more competitive wholesale market.
- Customers served by regulated retail markets have generally experienced lower electric rate increases than customers served by “competitive” retail markets.

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 and 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 its 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 hydroelectric 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 also 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.

FERC: Federal Energy Regulatory Commission

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 electrical demands.

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.)

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.

LR 455: Legislative Resolution 455 was a three- year review of the electric industry in Nebraska, commissioned by the Nebraska State Legislature in 1997, which 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: 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.

RTO – Regional Transmission Organization

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.

Seams Operating Agreement [SOA]: An agreement to coordinate the granting of transmission service between adjoining regions so that neither region oversells transmission service that would overload transmission facilities in the adjoining region.

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