ANNUAL REPORT-2009
MONITORING OF
“CONDITIONS CERTAIN” ISSUES
IN NEB. REV. STAT. § 70-1003(6)

OCTOBER 2009

TABLE OF CONTENTS

INTRODUCTION

In 1996, the Nebraska Legislature passed Legislative Resolution 455 (LR 455) which directed the Legislature's Natural Resources 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 "conditions certain" approach to retail competition. Several states that pursued a 'date certain' approach to retail competition encountered problems which probably could have been avoided had a "conditions certain" approach been followed. The "conditions 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 "conditions 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. § 70-1003(5), (6) and (7), 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 in § 70-1003(6), 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 issues in § 70-1003 (6) 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
Marvin Fishler	-	Irrigation Customer
Gary Hedman	-	Southern Public Power District
Jay Holmquist	-	Nebraska Rural Electric Association
Clint Johannes	-	Nebraska Electric Generation & Transmission Cooperative
Eric Hixon	-	Central Nebraska Public Power & Irrigation
Gary Mader	-	Grand Island Utilities
Derril Marshall	-	Fremont Utilities
John McClure	-	Nebraska Public Power District
Dave Mazour	-	Tri-State Generation and Transmission Association, Inc.
Charlie Perkins	-	IBEW Local 763
Bruce Pontow	-	Nebraska Electric Generation & Transmission Cooperative
Virginia Bigelow	-	Nebraska League of Women Voters
Nancy Packard	-	Nebraska League of Women Voters
Frank Reida	-	Residential Customer
Marvin Schultes	-	Hastings Utilities
Adam Smith	-	Industrial Customer
J. Gary Stauffer	-	Municipal Energy Agency of Nebraska
Kurt Stradley	-	Lincoln Electric System
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. Emeritus, the current Coordinating Consultant, began 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 each October since then.

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 "Conditions 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 2009 report is the ninth report following up on the five Conditions Certain issues identified in § 70-1003(6). To date, these nine reports are similar in format and content in order to carry background information forward for new readers. Beginning in 2010 the report will be simplified, as three of five conditions have been met and will not be discussed extensively in the preparation process for the 2010 Conditions Certain report.

EXECUTIVE SUMMARY

The five Conditions Certain issues identified in § 70-1003(6) were assigned to five separate Technical Groups. This Executive Summary includes an overall summary and the specific findings and conclusions of those Technical Groups that are incorporated in the report.

A significant item considered by the Conditions Certain study process in 2009 is that key Nebraska utilities joined the Southwest Power Pool (SPP) in early 2009. Chapters One and Two of this report discuss those changes because SPP membership allows conditions one and two to be met.

Overall Summary
As outlined on page (iii) of the introduction to this report, for customer choice to be effective and beneficial to the citizens of Nebraska, all of the following three conditions must be met:

- A viable regional transmission organization and adequate transmission exist in Nebraska or a region that includes Nebraska, and,
- A viable wholesale electricity market must exist in a region which includes Nebraska, and,
- Wholesale electricity prices in the region must be comparable or competitive to Nebraska prices.

The overall results of the 2009 conditions certain report indicate that two of three conditions have been met, as indicated by the following:

- Viability of a regional transmission organization and adequate transmission exist in Nebraska or a region that includes Nebraska:
    - A viable regional transmission organization now exists with the membership of key Nebraska transmission owners in the Southwest Power Pool on April 1, 2009
    - Adequate transmission exists in the region to make transactions sought by utilities and marketers and will improve when development through the Southwest Power Pool Transmission Expansion Planning process which will include Nebraska.
    - **This condition has been met.**
- A viable wholesale market in a region including Nebraska:
    - A reasonably efficient and workable wholesale market exists in the Southwest Power Pool market which includes Nebraska.
    - **This condition has been met**.
- Wholesale electricity prices in the region must be comparable or competitive with Nebraska prices:
    - Nebraska prices for the 2006-2009 study period are approximately 27.5 percent below the regional market, this is approximately a 16 percent decrease over the 2005-2008 study period

- Because of drops in natural gas prices, regional bulk market prices have become significantly more competitive during the 2009 study year. Whether this is a trend or not is yet to be determined in subsequent studies.
- **This condition has not been met.**

Other conditions certain in this report include the extent that retail rates have been unbundled and 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. Several significant items should be mentioned:

- There has been no significant unbundling of retail rates in Nebraska.
- In other states, customers served by regulated retail markets have generally experienced smaller electric rate increases than customers served by "competitive" retail markets. The expectation of wholesale and retail competition driving down prices has not taken place.
- Retail choice is no longer significant in utility policy discussions nationally.
- Projected Energy Information Administration annual data for the year 2008 shows that Nebraska's average retail rate of 6.51 cents/kWh will be approximately 34 % lower than the national average retail rate of 9.81 cents/kWh.
- In the EIA projection shown in detail in Chapter 5, Nebraska ranks second in lowest rates for 2008 compared to states contiguous with Nebraska shown as follows:
    - Wyoming 5.68
    - **Nebraska 6.51**
    - Missouri 6.85
    - Iowa 7.00
    - Kansas 7.59
    - South Dakota 7.07
    - Colorado 8.62

Chapter 1

"Whether or not a viable transmission organization and adequate transmission exist in Nebraska or in a region which includes Nebraska"

1.0 Purpose and Study Team Members

The purpose of this section of the report is to address the first question of the "conditions-certain" requirements of "whether or not a viable regional transmission organization and adequate transmission exist in Nebraska or in a region which includes Nebraska."

<u>Team Members</u>

Paul Malone (Primary Author)	–	Nebraska Public Power District
Dan Dahlgren	–	Omaha Public Power District
Bruce Merrill	–	Lincoln Electric System

2.0 Summary – Southwest Power Pool (SPP) Participation Completed

Last year's report stated that NPPD, OPPD and LES had made the decision to join SPP after conducting a quantitative economic analysis of the benefits compared to the costs of joining SPP or the Midwest ISO, as well as evaluating the qualitative aspects of SPP and the Midwest ISO, such as the governance structure and member participation in policy direction. The three Nebraska utilities signed the SPP membership agreement contingent upon the Federal Energy Regulatory Commission (FERC) approval of changes to the membership agreement, SPP Bylaws and Tariff needed to accommodate the unique legal requirements of public power utilities under Nebraska state law. The utilities also submitted their withdrawal notices to the Mid-Continent Area Power Pool (MAPP), the Midwest ISO for the Reliability Coordination Service Agreement, the Midwest Contingency Reserve Sharing Group, and the Midwest Reliability Organization (MRO) to be effective concurrent with start-up under SPP.

In a November 28, 2008 Order, FERC approved all of the changes to the SPP governing documents, and the three Nebraska utilities became SPP members on December 1, 2008. Other FERC Orders in January 2009 accepted the SPP filings which included the transmission revenue requirements, list of transmission facilities to be included in the SPP tariff, and the Grandfathered Agreements for the Nebraska utilities.

With acceptance by FERC, and completion of an enormous amount of work by the utilities and SPP to integrate all of the data and models associated with the transmission and generation facilities of the Nebraska utilities into the SPP processes, the Nebraska utilities began operations in SPP on April 1, 2009. The transition to SPP was a success that was completed without any significant problems.

SPP provides Reliability Coordination Service, Tariff Administration Service, Generation Reserve Sharing, Energy Imbalance Market Service, and Transmission Planning service to the three Nebraska utilities. The Nebraska utilities have placed their transmission facilities under the SPP Tariff and no longer grant transmission service for new transmission service requests under their own transmission tariffs. This includes requests for interconnection of new generation to the utilities' transmission facilities. Instead, requests for generation interconnection will be submitted to and studied by SPP.

The only transition issue that has not been completed is the transfer of the utilities' North American Electric Reliability Corporation (NERC) registration from the MRO to the SPP Regional Entity. NERC deferred action on the utilities' request to transfer from the MRO to the SPP Regional Entity until NERC has completed other regulatory review activities. The utilities expect that NERC will give the transfer request due consideration in 2010. While this has caused some additional workload for the utilities, it has not hampered the participation in SPP to any significant degree.

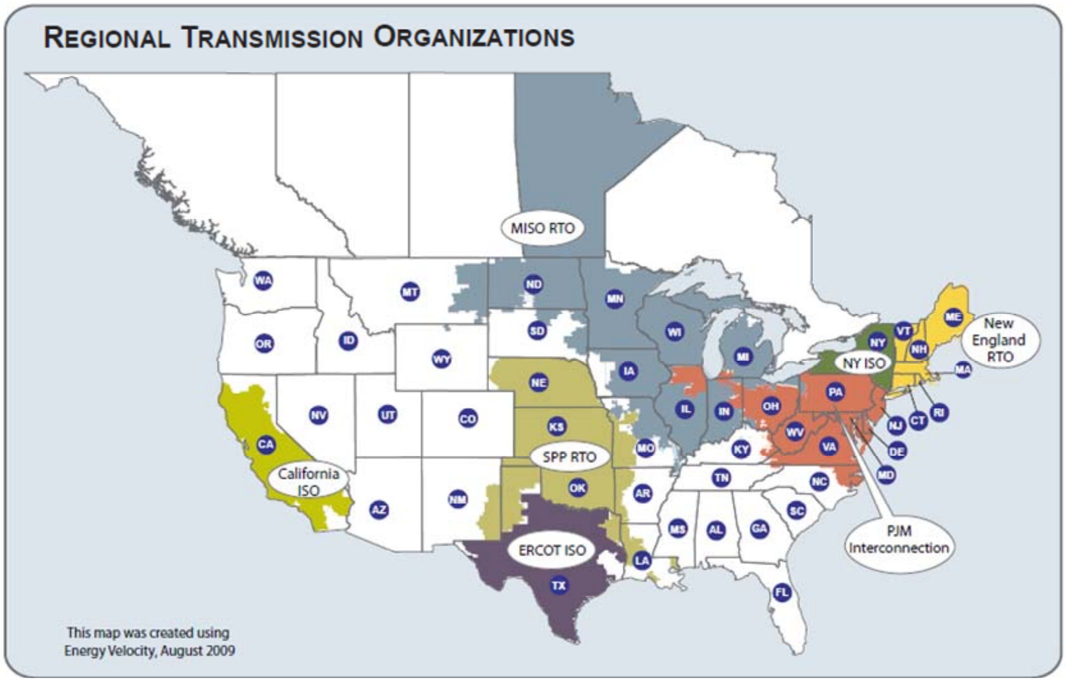
While NPPD, OPPD and LES own the large majority of transmission facilities and serve most of the load in Nebraska, other Nebraska utilities have not joined SPP to date. MEAN has registered as a Market Participant in SPP and is in the process of joining SPP as a member. Tri-State is considering having its power supplier, Basin Electric Power Cooperative, register as a Market Participant in SPP for the Tri-State Generation and Transmission Association, Inc. load in western Nebraska. Other municipalities in Nebraska such as Grand Island, Hastings, Nebraska City, and Fremont have decided not to join SPP at this time. The Nebraska utilities joining SPP have met with the non-SPP Nebraska utilities to discuss whether this will cause any difficulties for the non-SPP Nebraska utilities in transacting their traditional regional transmission service activities, and concluded that it should not adversely affect them.

The Nebraska utilities that are participating in SPP have spent significant time this past year engaging in all of the SPP committees, working groups and task forces that are evaluating some significant new initiatives in SPP concerning transmission expansion and future market design. The remainder of this report will describe the SPP organization and the new initiatives under consideration.

For purposes of the LB 901 conditions certain requirement concerning this section of the report, joining SPP has satisfied that condition. SPP is a FERC-approved Regional Transmission Organization (RTO) and there is adequate transmission in Nebraska to deliver the energy from existing generation to Nebraska customers. In addition, by joining SPP Nebraska utilities will be part of the current efforts within SPP to significantly expand the regional transmission system.

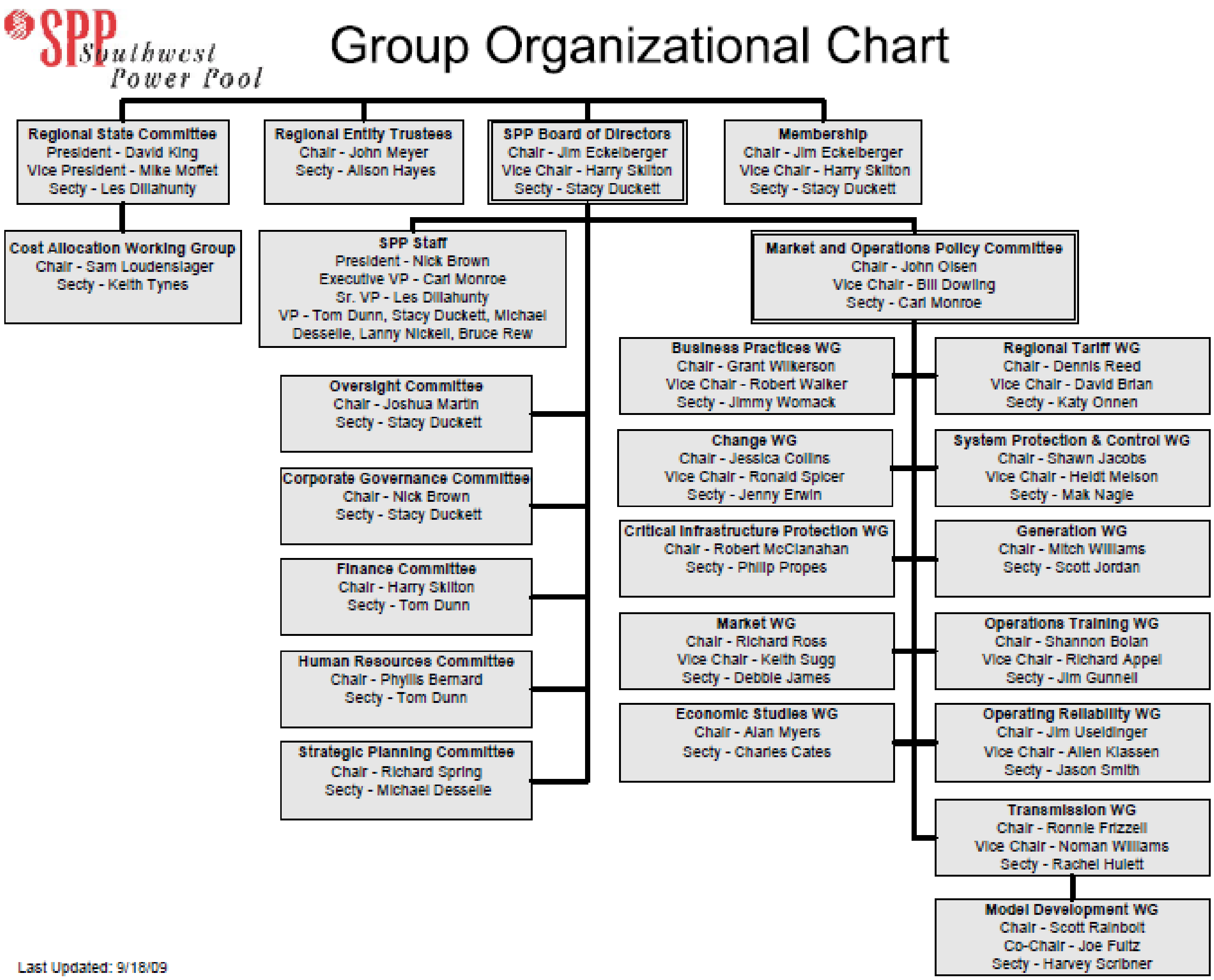
3.0 SPP Overview

The map below depicts the geographic areas included in the nation's Regional Transmission Organizations. SPP is headquartered in Little Rock, Arkansas with a staff of over 400 employees. SPP has 54 members, including investor-owned utilities, municipalities (including LES), cooperatives, state agencies (including NPPD & OPPD), independent power producers, power marketers, and independent transmission companies who serve more than five million customers in eight states, including portions of Arkansas, Kansas, Louisiana, Missouri, Nebraska, New Mexico, Oklahoma, and Texas. The peak load in SPP is approximately 47,000 MW.



The SPP Tariff provides Nebraska utilities access to the SPP Energy Imbalance Market which allows utilities to make sales of excess energy or purchases in the next hour with the price established through a Locational Imbalance Pricing methodology. In addition, utilities are able to make bilateral energy transactions within SPP or with neighboring regions. Transactions with neighboring regions however, require an additional transmission reservation to access the neighboring system.

SPP is governed by an independent Board of Directors. Independence from utilities and energy market interests is a fundamental requirement of FERC approved RTOs. However, SPP provides for significant member participation in SPP governance, as well as a role for state regulators. The chart below shows the organizational governance structure of SPP.



Some of the more significant aspects of the governance structure are:

- <u>Board of Directors and Board Committees</u> – The SPP Board is comprised of six independent members and the SPP President & CEO who have final decision making authority
- <u>Members Committee</u> – comprised of 19 member representatives; four from investor-owned utilities, four from cooperative utilities, two from municipalities (including joint action agencies), two from state or federal power agencies, three from independent power producers or marketers, two from alternative power/public interest members, one from a large retail customer and one from a small retail customer. Currently 14 of the members committee positions are filled. One very unique aspect about the SPP governance is that while the Board has the ultimate decision making authority, the Members Committee meets jointly with the Board and votes on all issues on the Board agenda just prior to the Board vote. In this way, the Board is fully informed of the Members Committee's position on every matter before the Board takes action.

- <u>Regional State Committee & Cost Allocation Working Group</u> – The Regional State Committee is comprised of one representative from each state regulatory commission. The Regional State Committee has certain responsibilities assigned to it as defined in the SPP Bylaws, including determining certain transmission pricing mechanisms. The Regional State Committee is funded by SPP and operates under its own set of Bylaws. In April 2009, those Bylaws were revised to allow participation by the Nebraska Power Review Board, and the Board's request to join the Regional State Committee was approved. The Cost Allocation Working Group is comprised of one representative from the commission staff from each state. Their role is to provide analysis and recommendations to the Regional State Committee. This group is open to participation by all SPP members, but voting is limited to the state commission staff.

- <u>Market and Operations Policy Committee & Working Groups</u> – This committee is comprised of a representative from each SPP member and acts on all matters that are developed by the working groups reporting to it. The working groups are comprised entirely of SPP members and chaired by a SPP member. SPP staff serves to support the working groups.

- <u>Regional Entity Trustees</u> – SPP is a FERC-approved RTO and a Regional Entity, which is responsible for monitoring compliance with NERC standards for members registered in this region. The Regional Entity function is independent of the RTO function and as such has its own group of Trustees who have decision making authority for NERC compliance issues.

With this organizational structure, it is clear that the members, as well as the regulatory commissions, have a great deal of input into the SPP direction, even though the ultimate decision making authority resides with the Board for RTO matters and the Trustees for NERC compliance issues.

4.0 SPP Transmission Expansion Planning & Cost Allocation

SPP has a transmission planning process, referred to as STEP (SPP Transmission Expansion Planning) described within its Tariff. Each year a plan is developed and approved by the Board that includes projects needed to meet reliability criteria, generally due to load growth, and projects that are considered economic upgrades, meaning that the project will reduce congestion on the transmission system. In addition, transmission expansion projects are identified through separate studies to interconnect new generation or to provide requested transmission service. Projects in STEP needed to meet reliability criteria are referred to as "base plan funded" and are cost-shared by the SPP members. The annual transmission revenue requirement for a reliability project is determined, and one-third of that revenue requirement is allocated to each SPP transmission owner <u>zone</u> on a load-ratio share basis (i.e., if a zone has 10% of the load in SPP, it is allocated 10% of the annual revenue requirement). The remaining two-thirds is allocated to the zones based on a power flow analysis of which zone's transmission system benefits due to the new project. The term "transmission owner zone" is used since only those members that own transmission have a revenue requirement. Other SPP member loads in the transmission owner zone, such as a joint action agency, will pay the transmission owner's zonal rate which will include an allocation of costs for all member loads in the zone.

Projects in STEP that are identified as economic projects require a Project Sponsor to fund the entire project.

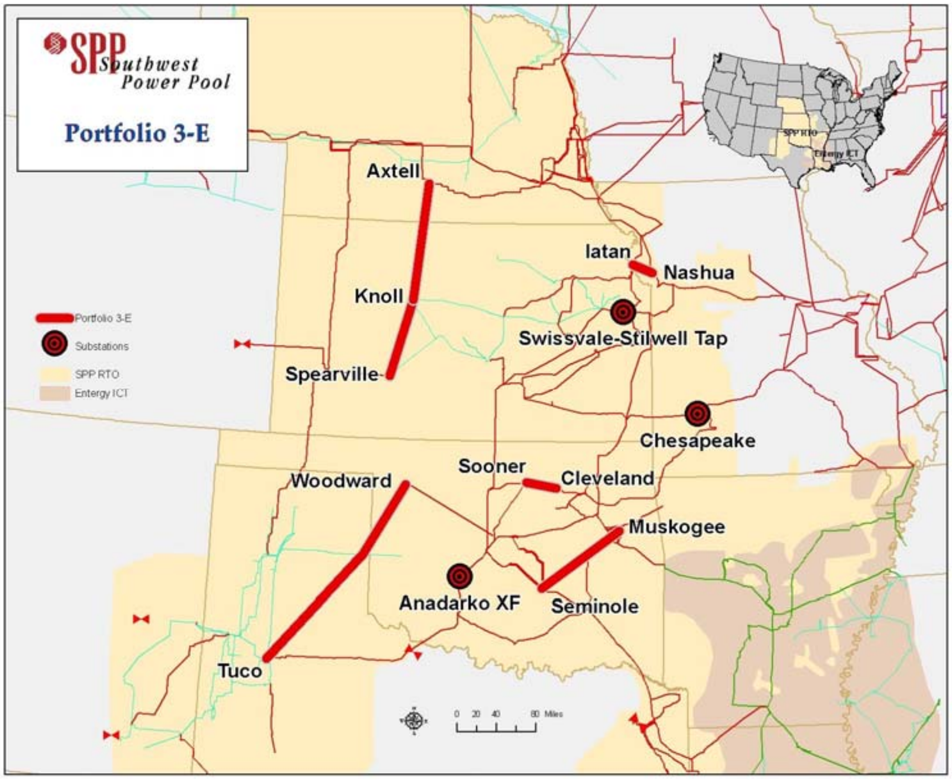
The cost for transmission expansion projects required to grant new long-term firm point to point transmission service is directly assigned to the customer requesting service. If the service request is for new network service then the cost is treated as "base plan funded."

Transmission expansion cost for generator interconnection is allocated differently depending on the type of generation, whether it is located in the same or different transmission owner zone as the load being served from the generator, and whether the generator is serving a member's load or is a merchant generator supplying energy to the SPP market. It is a rather complicated process and will not be explained here.

Balanced Portfolio

Because transmission congestion continues to be a significant and on-going problem on the SPP transmission system that can only be resolved by transmission expansion projects that cross one or more of the members' service areas, the members and Board approved a new cost allocation process known as a Balanced Portfolio of projects. Tariff changes were made and approved by FERC. The basic concept is to identify a group of 345 kV transmission projects that will provide a benefit to cost ratio greater than one for each member transmission zone. By reducing congestion on the transmission system lower cost generation can more readily serve load that otherwise would have limited access to that generation resource. SPP performed a benefit-cost study using an industry recognized software that simulated the production cost savings when new transmission is added.

Since not all transmission owner zones had benefit-cost ratios greater than one (i.e. the production cost savings are less that the transmission revenue allocated to the transmission zone on a load-ratio share basis), the Tariff provides that transmission revenue transfer payments are made from the zones with benefit-cost ratios greater than one to zones with benefit-cost ratios less than one, such that all zones have a benefit-cost ratio of at least one. After a number of iterations of various project groupings and discussions with the members, a final portfolio was approved by the SPP Board in April 2009 as shown in the map below.



The project identified as Axtell-Knoll-Spearville is a new 345 kV transmission line that will provide another strong interconnection between Nebraska and SPP. It will greatly relieve transmission congestion that occurs on the existing 345 kV interconnection between western Nebraska and western Kansas, and also reduce transmission congestion on the 345 kV facilities that extend south from Cooper Nuclear Station interconnecting to systems in Missouri. The new interconnection will enhance reliability and provide increased ability to deliver renewable energy resources outside of Nebraska.

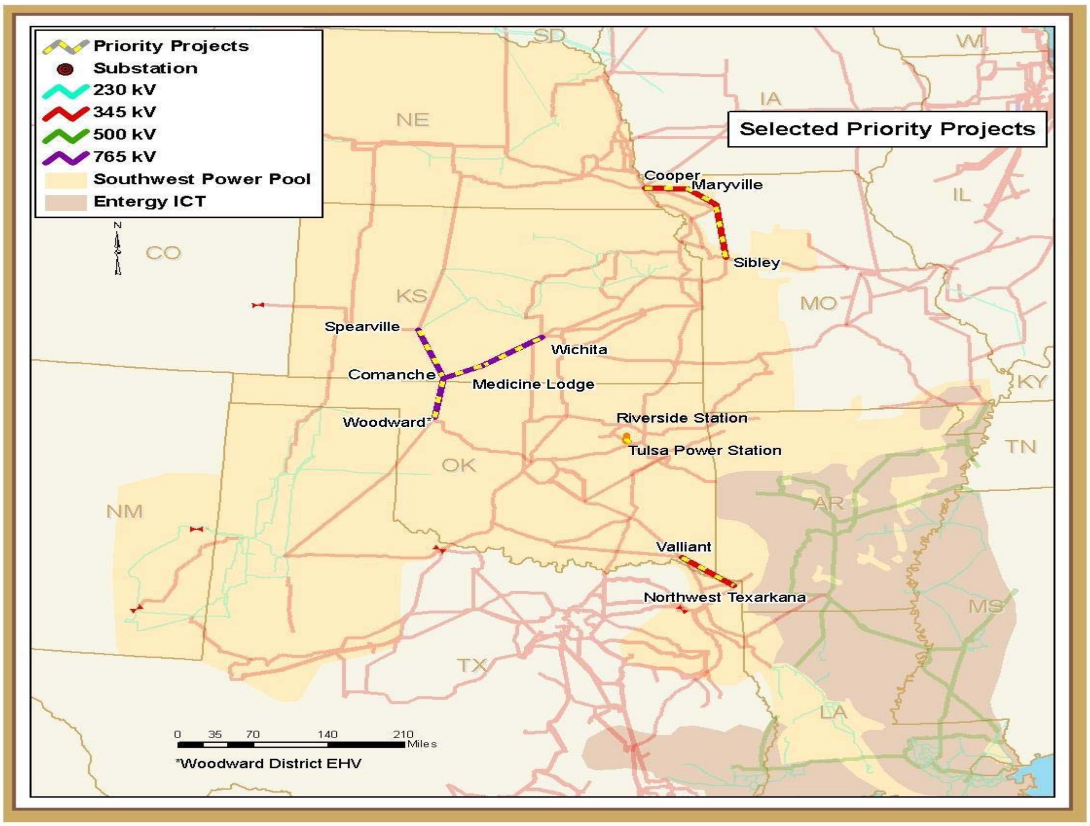
NPPD has been sent a Notice to Construct the portion of this project from Axtell to the Nebraska/Kansas state border. The project in-service date is June 2013 and NPPD has begun the public process to gather input to determine potential line routing opportunities, and coordinate with the Kansas utilities that have been assigned responsibility to construct the Kansas portion of the project.

Priority Projects

In December 2008, the SPP Board directed staff to propose a new transmission planning process to address deficiencies in the current process. The concern was that SPP has multiple transmission planning processes and cost allocation methodologies which have not resulted in a clear plan to create a robust transmission system capable of supporting the development and interconnection of the large amount of wind generation potential in the SPP region. A selected group of members and state regulators worked with SPP staff to develop a Synergistic Planning Project report.

The report recommended that SPP develop an Integrated Transmission Planning (ITP) Process that would combine the reliability planning, Balanced Portfolio planning and Extra High Voltage plan for large scale wind development into one new process. The goal of the ITP is to create a transmission backbone plan that makes transmission an enabler rather than a constraint, and improves transmission connections between SPP's western area, where all of the potential wind development is located, and the eastern area where the majority of the load is located. The report further recommended that (a) SPP develop a list of Priority Projects (facilities rated 345 kV and above) that would address the areas of transmission congestion and transmission deficient areas that have been identified in past SPP transmission studies, and (b) the Regional State Committee consider a new transmission rate design called a "highway/byway" rate design. This rate design would assign the costs for the 345 kV and above transmission facilities to all load in SPP on a load-ratio share basis (also called a "postage stamp" rate) and assign costs for transmission facilities rated less than 345 kV to the local transmission owner zone.

At a stakeholder meeting on September 29, 2009, SPP staff presented the results of their analysis and recommendations for Priority Projects as shown in the map below. The total cost of the recommended projects is approximately $1.3 billion. SPP performed a cost-benefit study using similar production cost modeling as the basis to determine which transmission owner zones showed cost reductions and which zones showed cost increases.



The SPP Board has requested that recommendations for Priority Projects and the Highway/Byway rate design be presented at their October, 2009 Board meeting. However, there is considerable concern amongst many of the SPP members, including the Nebraska members, that there has not been ample time to review the cost-benefit study assumptions and analysis. There is also a concern that the Priority Projects should not be cost-shared on a load-ratio basis, but instead use the Balanced Portfolio methodology of transfer payments to ensure that all zones have a benefit-cost ratio of at least one. Another important consideration that has not been addressed is that the cost of the Priority Projects should also be allocated to merchant wind developers and not just to the load-serving members.

While it is commendable that SPP is taking a forward-looking approach to transmission expansion to accommodate large scale wind development, it may be too early to commit to such expansion plans before it is known whether there will be a national renewable energy mandate. Also, many stakeholders believe there must be a cost-sharing methodology that allocates a portion of the transmission expansion cost to merchant wind developers who want to export wind energy outside of the SPP region.

5.0 SPP Future Energy Market Design

Another significant change that has been under consideration in 2009 is the development of a Future Energy Market, which includes a Day Ahead and Ancillary Services Market utilizing Financial Transmission Rights as a hedge for congestion. This is very similar to the type of energy market now in place at the Midwest ISO. It represents a tremendous change from the current SPP Energy Imbalance Market. The current market only covers energy purchases and sales in the next trading hour. Typically about 8% of the energy is settled in this market, the remaining 92% of energy is covered by utilities scheduling their own generation resources to serve their load. In contrast, the proposed Future Market design will require members to schedule 100% of their generation and load in the market and the members will be allocated Financial Transmission Rights, which may or may not cover transmission congestion charges.

A cost-benefit study was performed and presented to the membership in early 2009. It showed that there was a savings of $100 million/year under the Future Market design. This appears to be a large savings, but when compared to the total generation fuel cost in SPP, it only represents a savings of 6-8%. Considering that the accuracy of the modeling is highly dependent on the assumptions that are used in the model, that the staffing increases and capital and operating costs of the Future Market are likely underestimated, it is questionable whether the move to a Future Energy Market is justified. In addition, the complexity of the Future Market will add significant burdens on the members to participate in such a market.

The Future Market has not been approved for implementation as yet. The plan at this time is to develop Market Design specifications and seek a vendor in 2010 to design the market, with an implementation in 2012. It is expected that review and recommendations on further development will be up for approval at the January 2010 Board meeting.

6.0 Conclusion

The transition to SPP operations by NPPD, OPPD and LES was completed on April 1, 2009 without any significant problems. Thus far, the results of participation in SPP have not been entirely as expected. Some of this is attributable to a new learning curve on how to best conduct business in the SPP market, some due to a remarkable drop in wholesale energy prices brought about by a dramatic decrease in natural gas prices this last year.

Membership in SPP does satisfy the conditions-certain requirement of Nebraska being part of a viable regional transmission organization. The aspect of whether there is adequate transmission in Nebraska and the region is being addressed in the SPP transmission expansion planning process. The addition of the Axtell-Knoll-Spearville 345 kV transmission line will definitely strengthen the transmission interconnections between Nebraska and SPP. The move to approve the Priority Projects is arguably premature and many believe it should await further review and resolution of proper cost allocation methodologies.

Chapter 2

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

1.0 Introduction

1.1 Purpose

The purpose of the second "condition-certain" issue is to determine "whether or not a viable wholesale electricity market exists in a region which includes Nebraska."

Team members

Clint Johannes (Chair)	-	Nebraska Electric Generation and Transmission Cooperative
Travis Burdett	-	Grand Island Utilities
Deeno Boosalis (primary author)	-	Omaha Public Power District (OPPD)
Billie Joe Cutsor	-	Municipal Energy Agency of Nebraska (MEAN)
Jim Fehr	-	Nebraska Public Power District (NPPD)
Dennis Florom	-	Lincoln Electric System
Kevin Gaden	-	MEAN
Derril Marshall	-	Fremont Utilities
Jeff Mead	-	Grand Island Utilities
Allen Meyer	-	Hastings Utilities
Jon Iverson	-	OPPD
Jon Sunneberg	-	NPPD

A critical "conditions-certain" factor is whether there is a viable wholesale market in place. The LR 455 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 meaning of the term "viable" was defined and alternative methodologies for testing the viability of a market were identified. This definition and the evolution of standard tests for market viability are outlined in Section 2. Next, the regional markets that include Nebraska were defined. Nebraska is somewhat unique in that it transcends two major transmission grids in the U.S., the Eastern Interconnection and the Western Interconnection. Therefore, Nebraska has two separate and distinct regional electricity markets. Both of these markets are defined in Section 3.

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 FERC Definition and Tests for Market Power

A viable market must be one in which no single utility is able to exercise market power. Market power exists when conditions allow one entity to unilaterally manipulate the market price of electricity. There are two distinct types of market power. Each type requires different tests to evaluate.

2.2.1 Horizontal Market Power

Horizontal market power exists when the market is highly concentrated with very few sellers. In this situation there are often one or two sellers that dominate the market. These companies are called price leaders. They set a price in the market which smaller companies tend to follow because there is no economic advantage in trying to undercut it. This process works without collusion or price-setting between companies, which is illegal. Rather the price is set through market trial and error and by watching the reaction of competitors. The market tends to settle at a price above what a competitive market would produce.

There are standardized tests for evaluating horizontal market power. These have been used by the Anti-Trust Division of the Federal Justice Department for many years across many industries. The Federal Energy Regulatory Commission (FERC) has codified these tests in a number of orders and policy statements.

The first test used is simply the market share of the top seller in a defined market. This gives an indication of market concentration. FERC has established that a market share greater than 20% for the largest seller in a market indicates a concentrated market. A similar test calculates the market share of the top three sellers in the market.

A broader test of market concentration is the Herfindahl-Hierschman Index (HHI). This test is calculated by summing the squares of the market shares of all competitors in a given market. An HHI of 1,000 or less indicates an unconcentrated market while an HHI of over

1,800 indicates a concentrated market. A score of 1,000 to 1,800 shows a modestly concentrated market.

In general arithmetic terms, a market with 10 suppliers each with roughly 10% of the market would yield an HHI of 1,000 i.e. $10*(10^2)$. When examining this formula, it becomes evident that a high market share for one company dramatically increases the value of the HHI.

2.2.2 Vertical Market Power

Vertical market power occurs when there are artificial obstacles that deny market access to competitors. If a company (no matter how small) can limit competitive access to its local market, it alone can set the price in that market. An example would be a regional market where the only cost-effective way for a competitor to deliver product would be via railroad. If the regional producer of the product also owned the regional railroad, they could artificially deny market access to competitors by setting rail rates high for them. This, in fact, is the reason that the Sherman Anti-Trust Act (which led to railroads being designated as common carriers) was passed in the early part of the 20th century.

This type of market power is of particular interest to the electric utility industry because the delivery of wholesale electricity relies on the electric transmission grid that has historically been owned by regional electric utilities. The current FERC policy of open access requires transmission owning utilities to allow others to use their system without discrimination. Even with this provision, vertical market power can still be an issue for electricity because of transmission congestion. Transmission congestion occurs in periods of high demand for electricity. During these times the need to trade and deliver electricity outstrips the physical capacity of the transmission grid. When transmission constraints occur, it divides the overall electricity market into smaller isolated markets because it becomes physically impossible for competitors to deliver their product. Under these conditions it is possible for some electricity sellers to exercise market power. Furthermore, market power of this type is very transitory (it may occur for only a couple of hours) and difficult to detect and measure. It is only with the establishment of Regional Transmission Organizations (that manage the electric grid over multi-state areas) and the advent of new information technology (capable of detecting where transmission congestion exists) that identification of specific instances of vertical market power from transmission congestion became possible. Given this situation, there are no standardized tests for vertical market power. Some of the tests that have been used to identify vertical market power are described below.

The *Pivotal Supplier Test* seeks to determine if a company has the ability to manipulate market prices by unilaterally withholding generation from the market during congested conditions. If the company’s generation is absolutely essential to meeting peak wholesale market demands in the constrained market area, the company is a pivotal supplier for the duration of time that condition exists. Running this test requires system capable collecting real-time transmission flow and pricing information. This only exists in areas served by Regional Transmission Organizations (RTO) that have implemented a price-based, constrained dispatch methodology over a broad area. For companies operating in this type of RTO, their ability to set market prices is revoked by the RTO during this time of congestion.

The *Price Cap Test* seeks to determine if prices in known congested areas exceed the price that would be expected if a theoretical competitively priced generator were available for that area. The Price Cap Test is calculated only for generation resources that can materially change the congestion in the area. The price of a "theoretical competitive generator" is set at variable costs of new peaking power plant with the fixed costs spread over the estimated hours of congestion for affected area. If price offers during times of congestion are seldom accepted near this competitive price cap, is indicates prices are not being manipulated.

The *Price Volatility Test* makes the assumption that large swings in prices over short periods of time are associated with transmission congestion. The thought is that only a condition of market power could allow for the price to change that dramatically.

3.0 Market Region Defined

The title of this chapter is *"Whether or not a viable wholesale electricity market exists in a region which includes Nebraska*". This begs the question: what geographical region should be used to determine if a viable wholesale market exists?

3.1.1 Major Transmission Interconnections in North America

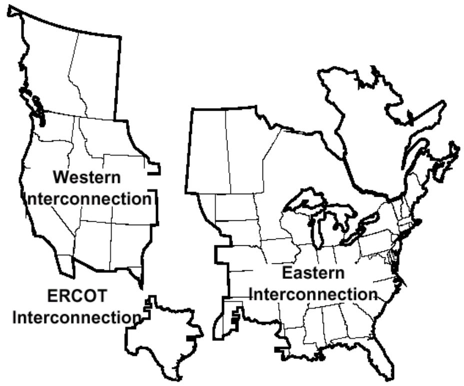
There are three major electrical interconnections in North America as shown in Exhibit II-1. These interconnections are independent of each other. Within each interconnection, all generators are linked to each other through the transmission system and the alternating current (AC) they produce is synchronized in terms of frequency. The only link between the major interconnections is via limited direct current (DC) ties. The map shows that Nebraska is in the Eastern Interconnection, but that is not completely true. The divide between the Western and Eastern Interconnection is actually in far western Nebraska. DC ties marking the Eastern and Western Interconnection are located just southwest of Scottsbluff, Nebraska and, just north of Sidney, Nebraska. The preponderance of electricity used in Nebraska is in the Eastern Interconnection. The third interconnection in the U.S. is the Electric Reliability Council of Texas (ERCOT) which operates its own interconnection, separated from the rest of the Eastern Interconnection by two ties.

3.1.2 The Wholesale Electricity Region that includes Nebraska

The regional markets for electricity are increasingly being defined by Regional Transmission Organizations (RTO's) as defined in Chapter 1 of this report. RTO's are multi-state organizations that provide: a regional transmission use tariff; regional transmission planning; generation reserve sharing; reliability coordination; and management of the regional electric wholesale market.

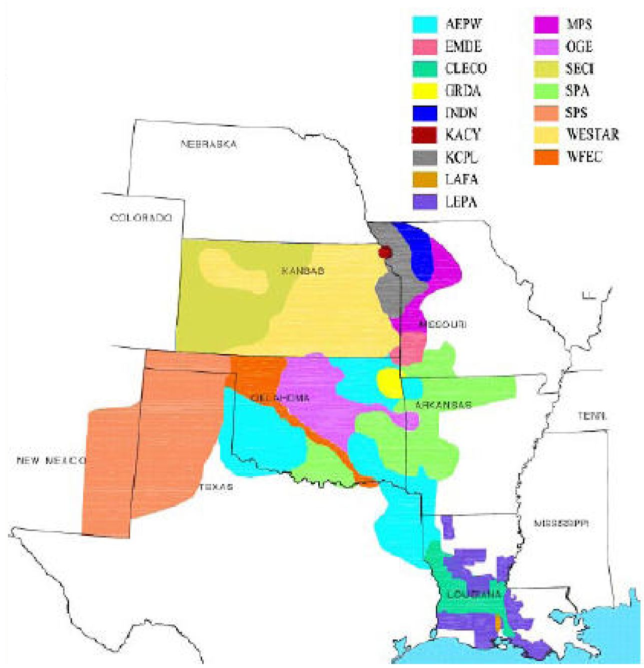
Since 1972, OPPD, NPPD, MEAN and Hastings have been members of the Mid-Continent Area Power Pool (MAPP) which offered Generation Reserve Sharing and a regional tariff. In 2002, the assets of MAPP were sold to the Midwest Independent System Operator (MISO), a large RTO. At that time about half the members of MAPP joined MISO. As part of the agreement, MISO provided MAPP with reliability coordination services, transmission tariff administration and transmission congestion management. This allowed the remaining MAPP members to continue wholesale market operations. During this period of time, the MISO geographical area (including MAPP) was used to define the regional wholesale electricity market for past versions of this report.

Exhibit II-1, 3 Major North American Interconnections



In 2008, MISO terminated the reliability coordination and transmission congestion management services with MAPP. It became incumbent upon the remaining MAPP members to join an RTO. The members entered into negotiations with MISO and a second RTO called the Southwest Power Pool (SPP). The geographical footprint of SPP is shown in Exhibit II-2 below.

Exhibit II-2, SPP Footprint



On May 16, 2008, NPPD, OPPD and LES signed a Memorandum of Understanding to join the SPP RTO contingent upon FERC approval and execution of related agreements. In April 2009, NPPD, OPPD and LES became members of the Southwest Power Pool. The Nebraska utilities will participate in the SPP market, however Nebraska utilities will remain in the MRO for reliability purposes and will not be included in the SPP footprint until approval is received for the transfer to the SPP reliability organization, probably to occur in 2010 (see chapter 1 of this report for details).

4.0 Information Sources Used for this Report

FERC requires that every certified RTO prepare an annual *State of the Market Report*. This report reviews the performance of the market, including any evidence of market power and mitigation recommendations if market power is shown to exist. The report must be completed by an Independent Market Monitor and submitted to FERC.

The report used in this year's report is the SPP 2008 State of the Market Report, compiled by Boston Pacific Company, Inc. of Washington DC, and published in May 2009.

5.0 2008 Market Power Analysis for SPP

5.1 Horizontal Market Power Tests

The 2008 calculations for market share (top 3 participants), market share (top participant) and the Herfindahl-Hierschman Index (HHI) are shown for the SPP.

Exhibit II-4, SPP Horizontal Market Power Measures

SPP Horizontal Market Power	
Market Share – Top 3 Participants	45.9 Percent
Market Share – Top Participant	14.7 Percent
HHI – Without Nebraska Participants	1037
HHI – With Nebraska Participants	950

* SPP Market Monitoring and Analysis Manager – April 14, 2009

The *SPP State of the Market Report* when referencing that no participant has over 14.7% of the market share stated *"Again, this is another indicator that the EIS Market is a competitive market."*

The HHI measure of 1,037 for SPP is very close to the 1,000 mark which is used as the gauge in determining unconcentrated market. It should be noted that if Nebraska utilities were included in the 2008 calculation, the HHI for SPP would have been about 950. The *SPP State of the Market Report* stated, "*The HHIs also indicate a competitive market."*

5.2 Vertical Market Power Tests

Pivotal Suppliers are generators that are essential to meeting load or reserve requirements in an area that becomes transmission constrained during times of high electricity demand. During those times the pivotal supplier can withhold offering power to the market in order to drive up prices.

The SPP Independent Market Monitor conducted a Price Cap test also described in Section 2.2.2. SPP has a price cap that is put into effect only in areas where the transmission system becomes congested. It is applicable only to generation resources that can materially change the congestion in the area. Finally, the price cap is set at variable cost of a new peaking power plant (the lowest cost generation that the competitive market would provide) with the fixed costs spread over the estimated hours of congestion for the affected area. An analysis of the SPP Price Cap was conducted to determine how often a price offer is accepted near the SPP Price Cap. According to the *SPP State of the Market Report, "if price offers are seldom accepted near the SPP Cap, then we believe this indicates prices are comfortably below this one measure of a competitive price level."* The results of the test indicated that in 2008 offers within 5% if the price cap were accepted less than three thousandths of one percent of all resource intervals. The *SPP State of the Market Report* concluded, *"The bottom line is that price offers were almost never accepted near the SPP Cap."*

Finally, the SPP Independent Market Monitor conducted a Price Volatility test. The comparative prices are shown in Exhibit II-5 below

Exhibit II-5, 2008 Prices of SPP

	Comparative Prices SPP ($/Mwh)		
	Average Price	Maximum Price	Volatility
SPP	$53.21	$541.26	62%

6.0 Conclusion

6.1 Status of a Viable Wholesale Electricity Market in the Eastern Region

The final conclusion is that a reasonably efficient and workable wholesale market exists in the SPP market area and will be further improved during the year 2009 because of the addition of the Nebraska utilities joining the SPP in April of 2009. It would be appropriate to conclude that "A viable wholesale electricity market exists in a region which includes Nebraska"

6.2 Status of a Viable Wholesale Electricity Market in the Western Region of US

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 Generation and Transmission Association, Inc.

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, 2006 , 2007, 2008 and 2009. In 2004, all the electric utilities in Nebraska were surveyed to determine their current unbundling status. The results of that survey are shown in Section 5.0 Survey Results.

3.0 Study Team – The study team consisted the following 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

4.0 Introduction

LB 901 defined 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] This is now codified in Neb. Rev. Stat. § 70-1001(6).

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 consider it if their customers request it. Nebraska is in an enviable position of having low

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[1] State of Nebraska, Legislature of Nebraska, Legislative Bill 901, (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.

rates, so consumers are not pushing for deregulation. However, some commercial and industrial 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 retail 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 it has 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 NPRB 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 NPRB 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. It has 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 needed for retail competition 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. There may be activity in the area of privately owned generation that might require limited unbundling and Technical Group #3 may look into 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 "conditions-certain" Technical Group was to make "a comparison of Nebraska's wholesale electricity prices to the prices in the region." 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
Travis Burdett	-	Grand Island Utilities
Deeno Boosalis	-	Omaha Public Power District (OPPD)
Billie Joe Cutsor	-	Municipal Energy Agency of Nebraska (MEAN)
Jim Fehr	-	Nebraska Public Power District (NPPD)
Dennis Florom	-	Lincoln Electric System
Kevin Gaden	-	MEAN
Derril Marshall	-	Fremont Utilities
Jeff Mead	-	Grand Island Utilities
Allen Meyer	-	Hastings Utilities
Jon Iverson	-	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 wholesale 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 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 "conditions-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-priced 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 from 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 have a virtually 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 puts forces into motion that will serve to correct this situation resulting in, at various times, market prices that are well above the 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, 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,

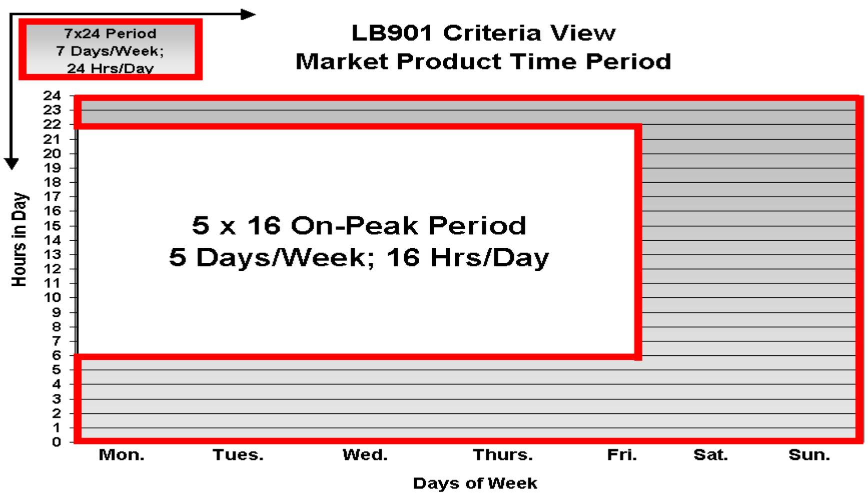
(2) Apply a consistent set of fixed and variable production cost accounts based on Federal Energy Regulatory Commission (FERC) accounting definitions to calculate the production cost to serve load,

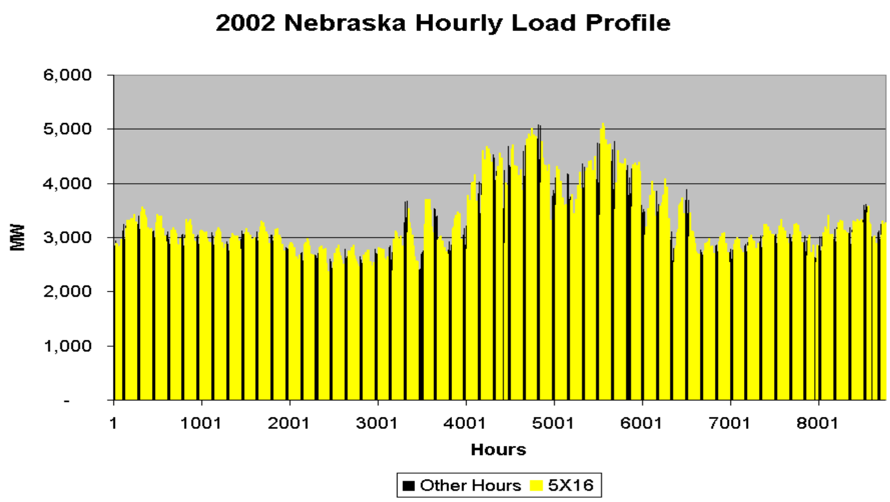
(3) Break down the total cost to serve (as determined in (2) above) to an hourly basis to determine a cost per hour to serve each utility's load based on an hourly load shape for each year (typically 8,760 hours per year), which is accomplished by appropriately allocating the fixed and variable costs 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 8,760 hours of the year,

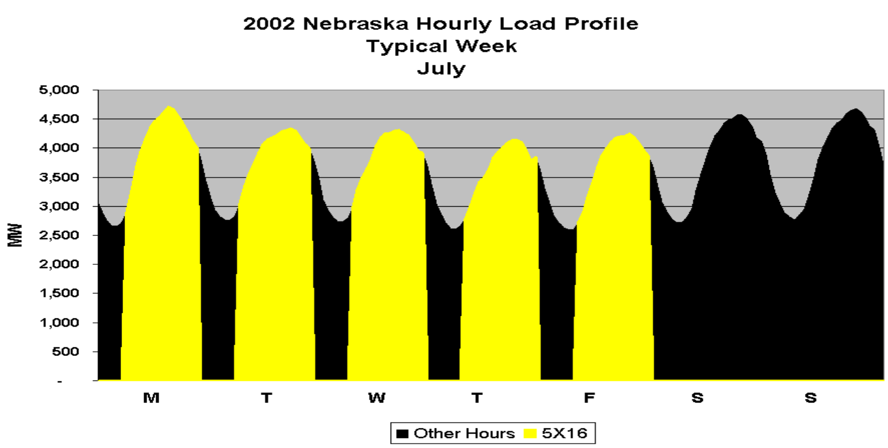
(4) Since the costs have been calculated on a $/MWH basis for each hour (as determined in (3) above), sum the hourly fixed cost and variable cost, less any obligation adders such as reserves, "obligation to serve" values and ancillary services, and adjust the

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-1 below provides a graphical description of how much and during which times the load profile information is utilized.

Exhibit IV-1







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.

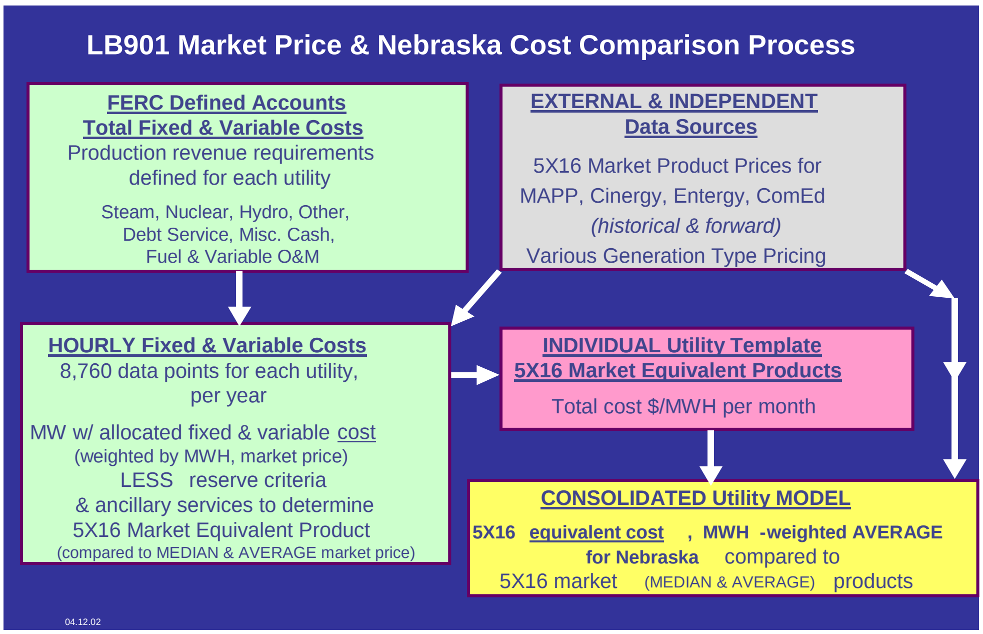
(3) Two different methods of allocating the fixed costs of existing power resources for each utility were modeled in order to provide a range of possibilities in cost allocations for discussion to determine how most utilities would allocate fixed costs; these two methods were (a) January thru December 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 2006-2009 (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 refueling outage or emission-constrained production years and lower in others. In order to "smooth-out" these events on both sides of the comparisons and to maximize future pricing and cost data availability, three years of history and one year future (total of four years) were chosen as the appropriate time period for comparisons. The publicly available, independent, and credible market price indices are only currently available 12 –18 months forward, so the "future view" comparisons are limited, and future expected costs of utilities (e.g., production costs, required purchases, emission compliance impacts) can change many times over the next 18 months.

For 2009 modeling comparison purposes, the time period of 2006 through 2009 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 2006-2009 with 2009 being the estimated year for both market pricing and production costs.

- Incorporating the future year 2009 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 (as happened in California), but on actual experience and estimations that have a higher confidence of accuracy (such as a four-year rolling average).

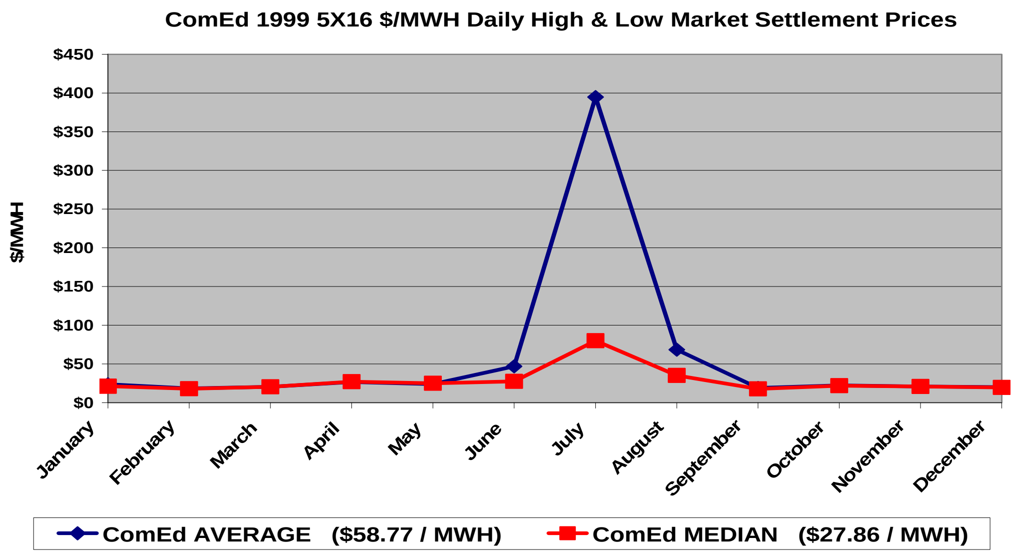
4.2 Sensitivity Cases Analyzed

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 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 2006-2009 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 2005 through 2008.

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 2006 through 2009. Except for 2009, Nebraska production costs rank below the market product in the study period. Eight (8) LB 901 historical study period comparisons are also included, describing the four-year rolling average results for the various study periods completed. The major difference in 2009 vs. the other years is the significant drop in natural gas prices in 2009. Refer to Exhibit IV-4a. Natural gas price is the main driver of on-peak electricity market prices. Since Nebraska utilities generate a low amount of electricity using natural gas units, its production costs are not as dependent on natural gas prices as the market.

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
2006	32.0%	32.7%
2007	40.0%	40.2%
2008	41.0%	41.0%
2009	-15.7%	-15.7%
Straight Average	24.3%	24.6%
Four Year Average (MWh-weighted)	27.5%	27.6%

HISTORICAL LB901 STUDY PERIOD COMPARISON

Study Period Years	% Nebraska Systems Below Market	Nebraska Cost Annualized Volatility	Nebraska Cost Monthly Std Dev	Market Price Annualized Volatility	Market Price 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
2004-2007	41.3%	25.5%	$1.77/MWh	29.0%	$5.98/MWh
2005-2008	43.7%	30.9%	$2.39/MWh	33.9%	$7.10/MWh
2006-2009	27.5%	34.1%	$2.57/MWh	41.5%	$6.29/MWh

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

Exhibit IV-4a

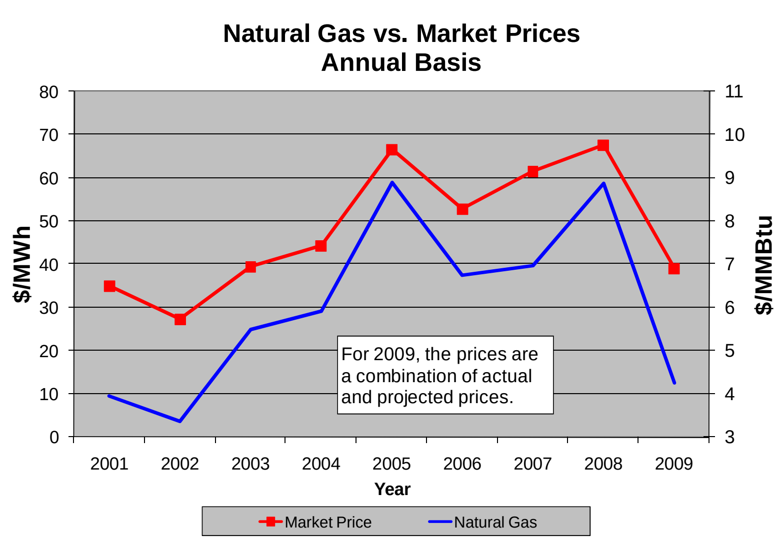
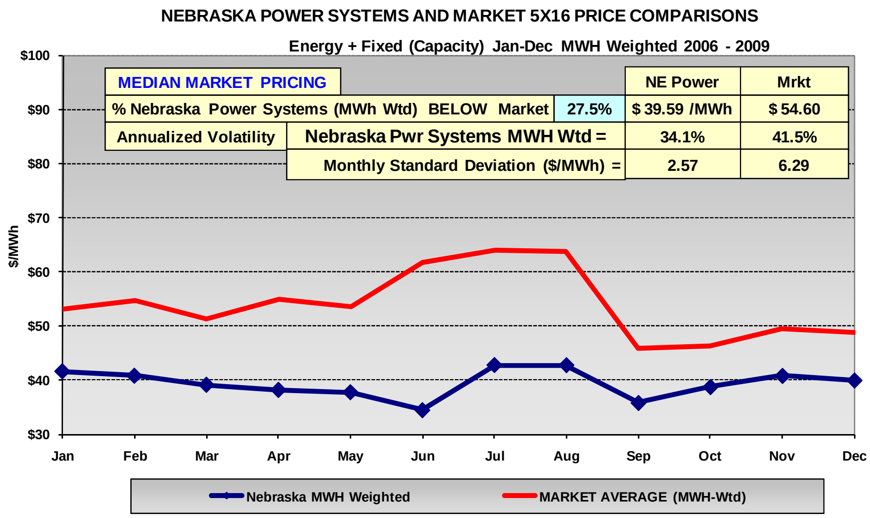


Exhibit IV-5 provides a monthly comparison for the four-year study period (2005-2008) between the median market product pricing indices to Nebraska production costs. In every month, Nebraska production costs are lower. Nebraska Power Systems annualized volatility and monthly standard deviation are lower than the market.

Exhibit IV-5



For comparison purposes, Exhibit IV-6 is provided to describe the detail associated with the 2009 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
= Calculated Value
= Special Calculation
= Automatic Link

AVERAGE 5X16 $/MWH Daily Settlements for 2009

	Historical			FORWARD INDICES (as of March - 2009)								
	January	February	March	April	May	June	July	August	September	October	November	December
MAPP	47.52	36.16	31.05	32.00	34.00	39.00	49.00	49.00	42.00	40.00	44.00	50.00
NI	49.93	37.64	33.28	30.25	31.35	35.00	43.50	43.50	33.50	34.25	34.25	34.25
Cinergy	46.44	37.61	33.66	32.00	31.00	34.75	43.50	43.50	33.50	34.25	34.25	34.25
Entergy	42.50	36.44	32.66	39.18	39.80	41.50	45.34	47.57	44.96	44.48	49.29	51.62
MAPP CALC	102.7%	97.1%	93.5%	94.6%	99.9%	105.2%	111.1%	109.2%	112.5%	106.2%	112.1%	124.9%

Intercontinental Exchange (ICE) Data is very limited beyond the next month. Much of this information was obtained from a reliable trading source that gets broker quotes.

MEDIAN 5X16 $/MWH Daily Settlements for 2009

	Historical			FORWARD INDICES (as of March - 2009)								
	January	February	March	April	May	June	July	August	September	October	November	December
MAPP	46.25	35.94	30.13	31.54	34.07	38.76	47.48	47.21	42.27	39.06	44.30	49.86
NI	48.25	36.25	31.13	30.40	31.24	34.38	41.00	41.10	33.69	33.13	34.33	34.67
Cinergy	45.75	36.75	31.88	31.54	30.30	34.40	41.03	41.89	33.55	33.30	34.74	33.85
Entergy	42.50	36.75	32.25	38.94	39.94	41.89	44.03	45.16	44.46	42.71	50.53	50.88
MAPP CALC	101.6%	98.2%	94.9%	93.8%	100.7%	105.1%	113.0%	110.5%	113.5%	107.4%	111.1%	125.3%

MAPP Capacity Only Price $/kW-yr for 2009 = 15.00

85

New Peaking Unit $/MWH for 2009 = 102 @ 85% CF and Fuel of $7.0/ mmBTU 165 @ 10% CF

New Combined Cycle $/MWH for 2009 = 71 @ 85% CF and Fuel of $7.0/ mmBTU

New Baseload Coal $/MWH for 2009 = 70 @ 85% CF and Fuel of $2.00/ mmBTU

(All generation units EXclude transmission cost adders)

The results for the 2006 - 2009 study period still show Nebraska production costs to be less than the market. For 2009, it is projected that the market will be less than the Nebraska production costs. Nebraska production costs continue to rise, but the regional market price dropped more. Economic conditions played a part in this drop, but the biggest impact on the market is the extremely low natural gas price of just over $4/million Btu (MMBtu). These low prices are not expected to continue in the future. As of August 1st, natural gas futures on the NYMEX are trading just under $6/MMBtu for 2010 and in the $6.7/MMBtu range for 2011.

5.0 Expected Differences Eastern Region to Western Region

5.1 North American Electrical Interconnections

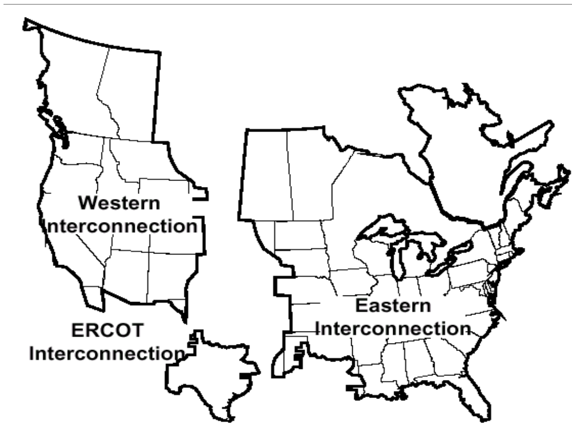
The majority of the electric systems in North America are comprised of three Interconnections as shown on Exhibit IV-8 and described below:

- 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 (High-Voltage Direct Current) 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 5,700 MW.

The Western Electricity 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.

In making market comparisons of the 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 Westminster, Colorado, serves rural systems in western Nebraska; and LES and MEAN receive some power from the Laramie River Station in Wyoming.

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

5.4.2 Stability

It is difficult to predict what Nebraska’s cost of production will be in the future. However, Nebraska was generally in a stable position through the 2008 time period. Projections for 2009 reflect an increase in coal purchase and transportation costs. 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 26% lower than the equivalent wholesale “median” market price based on the period 2006-2009 (three years actual, one year projected), and weighted based on MWH.

These results for the 2006-2009 study indicate that the former widening gap between the Nebraska production costs and the market, previously due mostly to the upward trend of market prices driven by then higher natural gas prices, has narrowed and exceeded the region for the 2009 study year. Nebraska utilities do not have as high a concentration of natural gas-fired units when compared to the entire electric industry. The recent increase in coal prices and coal transportation costs, in a year with declining natural gas costs has contributed to this change.

In addition, the results of an analysis 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.

That Nebraska production costs were previously 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.

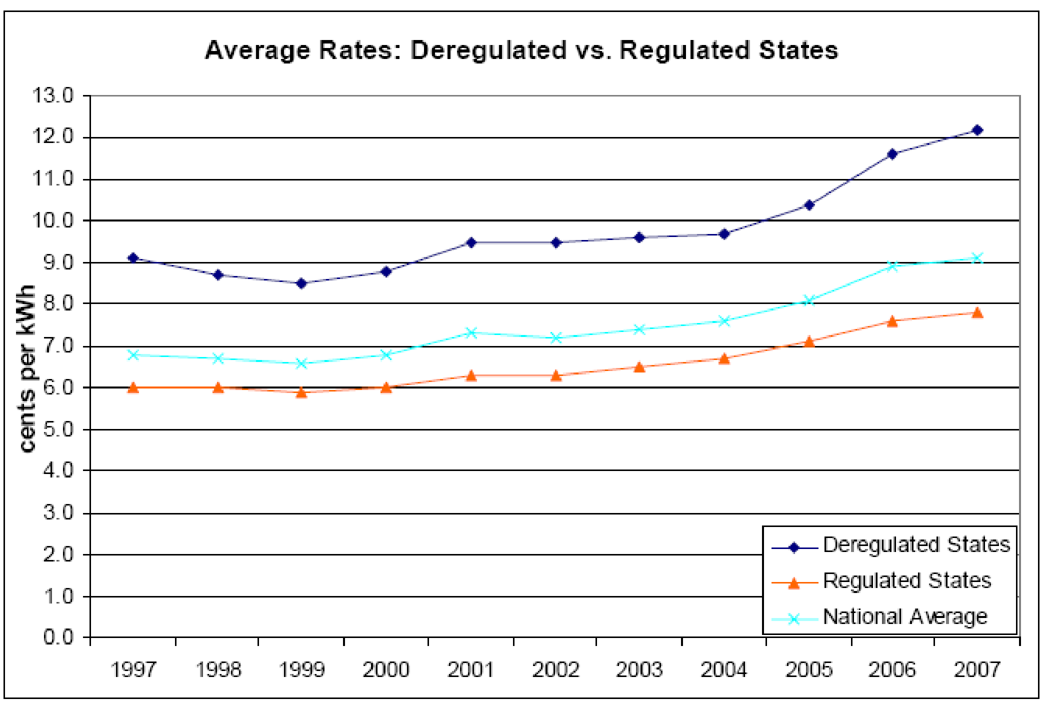
2.0 Team Members

Kurt Stradley	–	Lincoln Electric System
John McClure (Primary Author)	–	Nebraska Public Power District
Jay Holmquist	–	Nebraska Rural Electric Association
Tom Richards	–	Omaha Public Power District
Kelly Fleming	–	Omaha Public Power District

3.0 Deregulation Overview

There have been no major developments in state-implemented electric deregulation. The information regarding statutory/regulatory deregulation framework provided in previous reports remains generally unchanged. In a nutshell, retail choice initiatives have been modified, scaled back or eliminated in several states in order to minimize the adverse impacts caused by the failure of competitive electricity markets to develop and provide cost reductions to electric consumers. In the past 12-18 months, the recession has reduced demand for electricity and natural gas which has significantly reduced the price of both in spot markets. How long the spot prices will remain low is unknown.

Below is a chart comparing electricity costs in regulated and deregulated states. It basically shows that low cost states have remained relatively low cost by remaining regulated and that high cost states have remained high cost through deregulation.



Source: Retail Electric Rates in Deregulated and Regulated States – APPA, March, 2008

The table below compares costs per kWh in Nebraska, which is regulated (no retail competition), and three states that have deregulated. The last several years show market impacts in deregulated states which have generally followed rate caps.

Year	Nebraska	Texas	Illinois	Penn.	US Ave.
1996	5.32	6.16	7.69	7.96	6.86
1997	5.30	6.17	7.71	7.99	6.85
1998	5.30	6.07	7.46	7.86	6.74
1999	5.31	6.04	6.98	7.67	6.64
2000	5.31	6.49	6.94	7.65	6.81
2001	5.39	7.38	6.90	8.01	7.29
2002	5.55	6.62	6.97	8.01	7.20
2003	5.64	7.50	6.88	7.98	7.44
2004	5.70	7.95	6.80	8.00	7.61
2005	5.82	9.11	6.97	8.27	8.14
2006	6.07	10.34	7.07	8.68	8.90
2007	6.28	10.11	8.46	9.08	9.30
2008*	6.51	10.93	9.21	9.35	9.81

*2008 are preliminary Source: US Energy Information Administration

4.0 Pennsylvania

An example of the limited success of retail choice is reflected in the recent summary from Pennsylvania that shows several of the investor-owned utilities have no customers choosing alternative suppliers and others have few commercial and industrial customers choosing an alternative supplier.

Number of Customers Served By An Alternative Supplier As Of 7/1/2009				
	Residential	Commercial	Industrial	Total
Allegheny Power	0	1	0	1
Duquesne Light	106,691	11,091	610	118,392
MetEd/Penelec	0	1	3	4
PECO Energy	2,794	20,122	3	22,919
Penn Power	18,815	2,789	155	21,759
PPL	0	23	4	27
UGI	0	14	3	17
Total	**128,300**	**34,041**	**778**	**163,119**

Pennsylvania Office of Consumer Advocate
7-15-2009

Percentage of Customers Served By An Alternative Supplier As Of 7/1/2009				
	Residential	Commercial	Industrial	Total
Allegheny Power	0	0	0	0
Duquesne Light	20.4	18.4	51.4	20.2
MetEd/Penelec	0	0	0.1	0
PECO Energy	0.2	12.9	0.1	1.5
Penn Power	12.7	13.4	67.1	12.9
PPL	0	0	0.1	0
UGI	0	0.2	1.9	0

Totals may differ due to rounding.

Pennsylvania Office of Consumer Advocate
7-15-2009

Customers Load (MW) Served By An Alternative Supplier As Of 7/1/2009				
	Residential	Commercial	Industrial	Total
Allegheny Power	0	52.4	0	52.4
Duquesne Light	229.9	1,208.7	689.3	2,127.9
MetEd/Penelec	0	0.1	53.7	53.8
PECO Energy	5.9	140.5	1.3	147.7
Penn Power	18.8	156.4	169.1	344.3
PPL	0	1	0	1
UGI	0	1.1	0.6	1.7
Total	**254.6**	**1,560.2**	**914**	**2,728.8**

Totals may differ due to rounding.

Pennsylvania Office of Consumer Advocate
7-15-2009

Percentage of Customers Load (MW) Served By An Alternative Supplier As Of 7/1/2009				
	Residential	Commercial	Industrial	Total
Allegheny Power	0	4.2	0	4.2
Duquesne Light	18.9	56	89.3	51.3
MetEd/Penelec	0	0	5.6	1.2
PECO Energy	0.2	5.8	0	1.8
Penn Power	12	53.8	95.9	55.2
PPL	0	0	0	0
UGI	0	1.8	2.9	0.9

Totals may differ due to rounding.

Pennsylvania Office of Consumer Advocate
7-15-2009

The following testimony from September 5, 2007, provides an excellent summary of many retail choice experiences around the nation:

> *When the Pennsylvania electric restructuring law was enacted in 1996, it was widely assumed that competition would drive down the price of generation (which is why we allowed our utilities to recover billions of dollars of "stranded" costs) and that the great majority of customers would flock to lower-priced competitive retail markets (which is why we required that retail choice be phased-in gradually over three years). Rate caps were implemented just in case rates did not go down as anticipated, in order to prevent utilities from charging both for stranded costs and for higher than expected generation rates. As it turned out, however, due in large part to high natural gas and other fossil fuel prices, and the manner in which wholesale prices are set in the PJM market, wholesale generation prices have increased substantially in the last several years, while retail competition – particularly for residential customers – has been dormant, both in Pennsylvania and in most other restructured states.*
>
> *Testimony of Sonny Popowsky, Consumer Advocate of Pennsylvania before PA House Consumer Affairs Committee*

5.0 National Rate Comparison

Nebraska remains one of the lowest cost states for electricity, ranking 5th lowest overall based on 2008 preliminary data from the Energy Information Administration.

Table 5.6.B – Average Retail Price of Electricity to Ultimate Customers by End-Use Sector, by State, Year-to-Date through December 2008 (cents per Kilwatt hour) www.eia.doe.gov/cneaf/electricity/epm/matrix96-2000.html

State	**2008**
West Virginia	5.59
Wyoming	5.68
Idaho	5.70
Kentucky	6.25
Nebraska	6.51
Utah	6.53
North Dakota	6.64
Washington	6.69
Missouri	6.85
Iowa	7.00
South Dakota	7.07
Indiana	7.13
Oregon	7.26
Montana	7.44
Kansas	7.59
Arkansas	7.76
Minnesota	7.83
South Carolina	7.93
Oklahoma	7.97
Tennessee	8.02
Virginia	8.06
North Carolina	8.12
New Mexico	8.30
Ohio	8.44
Alabama	8.61
Colorado	8.62
Mississippi	8.93
Georgia	8.96
Wisconsin	9.04
Arizona	9.09
Michigan	9.14
Illinois	9.21
Pennsylvania	9.35
Louisiana	9.38
Nevada	9.91

Florida	10.79
Texas	10.93
Delaware	12.25
Vermont	12.32
California	12.96
Maryland	13.01
District of Columbia	13.49
Maine	13.71
Alaska	14.50
New Hampshire	14.64
New Jersey	14.91
Rhode Island	16.13
Massachusetts	16.22
New York	16.74
Connecticut	16.95
Hawaii	29.20

6.0 Conclusion

- Fundamental assumptions going into retail choice have generally been wrong.
    - Stranded assets have been minimal.
    - Price reductions have been minimal.
- New Reality
    - Retail choice is no longer driving electricity policy debate.
    - Renewable energy (and necessary transmission), energy efficiency and climate change now dominate electricity policy debate.
    - Local, state, regional, and national policy initiatives.
        - Regional differences in fuel mix (coal, nuclear, hydro, and wind) impacting discussion.
    - Expanded natural gas supplies will further increase its role as a fuel source for electricity.
- Nebraska expanding the use of renewables
    - Nebraska utilities are adding wind generation
        - 2009 Nebraska Legislature passed numerous bills promoting wind energy development, but no mandate.
        - NPPD and OPPD have adopted 10% renewable energy goals.

- Nebraska remains relatively low cost, but is experiencing significant cost increases:
    - Fuel
    - Fuel Transportation
    - New Facilities
        - Generation
        - Transmission
- Nebraska utilities have or are adding baseload coal at relatively low cost – Council Bluffs 4, Nebraska City 2, Whelan 2.
- Nebraska utilities rely far less on natural gas than many other states.
- Competitive markets may not provide best long-term generation mix.
- Regulatory uncertainty regarding environmental policies creates great challenge for all utilities.

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 not withstanding 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.

Curtailability: 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 "conditions 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 "Conditions 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 nations 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.

MISO – Midwest ISO

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 paths 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