ANNUAL REPORT-2002
MONITORING OF LEGISLATIVE BILL 901
‘CONDITION CERTAIN’ ISSUES

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Glossary

INTRODUCTION

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

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

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

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

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

To carry out the mandate of LB 901, 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 were as follows.

NAME	REPRESENTING
Jim Anest	Agricultural Customer
Jeff Baker	Industrial Customer
Doug Bantam	Lincoln Electric System
Chuck Barrett	Commercial Customer
Fred Bellum	American Association of Retired Persons
Anne Boyle	Nebraska Public Service Commission
Tim Burke	Omaha Public Power District
Richard Duxbury	NMPP Energy
Jon Empson	UtiliCorp United
Marvin Fishler	Irrigation Customer
Joe Francis	Nebraska Department of Environmental Quality
Jody Gittins	Natural Resources Committee
Gary Hedman	Southern Public Power District
Jay Holmquist	Nebraska Rural Electric Association
C. G. Holthus	Commercial Customer
Clint Johannes	Nebraska Electric Generation & Transmission
Don Kraus	Central Nebraska Public Power & Irrigation
Richard Kuiper	IBEW/NE State Utility Workers
Gary Mader	Grand Island Utilities
Derril Marshall	Fremont Utilities
William Mayben	Nebraska Public Power District
Dave Mazour	Tri-State Generation & Transmission
Larry Pearce	Governor's Policy Res./ Nebr. Energy Office
Bruce Pontow	Nebraska Electric Generation & Transmission
Mary Powers	Nebraska League of Women Voters
Frank Reida	Residential Customer
Rodney Schroeder	Commercial Customer
Marvin Schultes	Hastings Utilities
Adam Smith	Industrial Customer
Jennifer States	Community Action of Nebraska
Tim Texel	Nebraska Power Review Board
Alfred Thomsen	Residential Customer
Robert White	Loup River Public Power District

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

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

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

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

This report is the second report following up on the five "Condition Certain" issues identified in LB 901.

EXECUTIVE SUMMARY

The five 'Condition Certain' issues identified in LB 901 were assigned to five separate Technical Groups. The Executive Summary that follows includes the conclusions from the 2001 Report as well as the major new findings that are incorporated in the 2002 Report.

Issue #1 (Chapter 1)

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

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

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

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

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

RTO in the western interconnection because those facilities are not electrically connected to the rest of the state.

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

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

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

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Issue #2 (Chapter 2)

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

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

The Eastern Interconnect wholesale market appears to be viable in that it has an adequate number of buyers and sellers. However, at times it has limited access to reliable transmission facilities to either deliver electricity to Nebraska loads or export electricity generated in Nebraska to surrounding states, depending on the demands on the transmission system. Since Nebraska's electricity supply is cost-based and consumer owned, there is considerably less volatility than that of the regional indices, which are based on the hourly, daily and monthly wholesale spot market.

There are considerable capacity shortfalls and transmission interconnect problems that have caused significant lack of continuity to energy deliveries to loads in the Western Interconnect. There could be significant economic implications to Nebraska utilities if large coal-fired generation are unavailable, de-rated or off-line to Western Nebraska utility members, which includes primarily MEAN which serves most of the municipalities in western Nebraska, and Tri-State G&T in Westminster, Colorado which serves all of the rural electrics in the panhandle of Nebraska.

2002 REPORT UPDATE-FERC's methodology for assessing market power has been evolving. Notably, FERC has taken steps to recognize the effect of transmission constraints on the exercise of market power. Initially, FERC began using variations to the traditional hub and spoke analysis that compensated for transmission constraints. This evolution culminated in a new FERC order issued on November 20, 2001 entitled "ORDER ON TRIENNIAL MARKET POWER UPDATES AND ANNOUNCING NEW INTERIM GENERATION MARKET POWER SCREEN AND MITIGATION POLICY". The order introduced a new test for market power called the "Supply Margin Assessment" which laid out mitigation measures for companies failing the test and found a number of companies not in compliance with the order.

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

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

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

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

ISSUE # 3 (Chapter 3)
SUMMARY OF 2001 REPORT-This Technical Group was charged with determining "to what extent retail rates have been unbundled in Nebraska". To do this, the Group surveyed 162 municipal, rural electric cooperative, federal, state, and district electric utilities. The survey results showed that, except for one case, retail electric rates in Nebraska are not unbundled. The majority of electric utilities in Nebraska do not have unbundled cost of service studies, although half of all electric utilities surveyed believe they have enough information to unbundle their rates. The survey also disclosed that only half of the utilities' billing systems would handle unbundling. Seventy percent of the utilities stated they would not unbundle their electric rates unless mandated.

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

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

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

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

Issue #4 (Chapter 4)

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

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

The results of the comparisons between the market product indices and the Nebraska production costs show that Nebraska production costs are approximately 18% lower than the equivalent wholesale "median" market price based on the period 1998-2001 (three years actual and one year estimated) and weighted based on MWH. The "median" market prices compares favorably with retail rate comparisons. The Energy Information Administration (EIA) annually compiles data from Form EIA-861 for approximately 3,300 public and investor-owned electric utilities including active power marketers and other energy service providers. The most current data for 1999 shows that Nebraska's average retail rate of 5.31 cents/kwh is approximately 20% lower than the national average retail rate of 6.61 cents/kwh.

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

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

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

Issue #5 (Chapter 5)

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Chapter 1

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

1.0 Purpose

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

2.0 Team Members

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3.0 Summary

The development of Regional Transmission Organizations (RTOs) has been underway since the Federal Energy Regulatory Commission (FERC) issued Order No. 2000 in December 1999. FERC stated that RTOs would promote competition in the wholesale electric market, enhance reliability, and remove any remaining opportunities for discriminatory practices by transmission owning utilities. In that Order FERC called for all transmission owning electric utilities (investor-owned and public power utilities) to work towards the voluntary formation of RTOs in collaboration with state regulators, transmission dependent utilities, and other market participants. FERC required investor-owned utilities to make certain filings in late October 2000 and January 2001 such that RTOs could be operational by December 15, 2001 across the country.

Since the issuance of Order 2000 there have been numerous filings at FERC by utilities proposing a RTO for various regions of the country. While FERC granted conditional approval to several of the RTO proposals (subject to changes in the proposal required by FERC), to date FERC has given its full approval to only one RTO, the Midwest ISO (see Figure 2). FERC granted the Midwest ISO approval in December 2001 and the Midwest ISO transmission tariff went into effect in February 2002. The geographic scope of the Midwest ISO has continued to grow as new members have joined. The Southwest Power Pool reached a merger agreement with the Midwest ISO . The plan is to integrate the Southwest Power Pool transmission system into the Midwest ISO transmission tariff by late 2002.

Thus, FERC's goal of having RTOs operational across the country by December 15, 2001 has not been met. However, it can be said that the Midwest ISO is viable from a legal, financial, and operational viewpoint. As might be expected with a start-up organization, the Midwest ISO is still in the early stages of operation and has many issues to resolve before it can perform all of its functions and duties satisfactorily. Other considerations when determining whether the Midwest ISO is viable to participate in are dependent on the legal aspects of a participation agreement with the Midwest ISO to recognize Nebraska state law restrictions, Midwest ISO costs to participate, and the impact on the utilities' transmission revenue due to the MISO transmission tariff.

As the formation of RTOs has languished compared to FERC's vision of Order 2000, FERC has taken another dramatic step to further the development of competitive wholesale electric markets. On July 31, 2002 FERC issued a Notice of Proposed Rulemaking, which has been called FERC's Standard Market Design (SMD). This Order proposes sweeping changes to the development of wholesale electric markets and will be discussed later in the chapter. The Order will not go into effect for many months, until FERC has considered comments submitted by all interested industry participants, but suffice it to say that Nebraska utilities will need to thoroughly evaluate the economic and legal impacts of this Order as many of the requirements will be implemented by the RTO.

The development of competitive wholesale electric markets continues to be a moving target. Just as utilities think they understand the ground rules FERC has set forth, FERC pushes the industry in a new direction. Until the FERC rules stabilize, it will be difficult with any degree of certainty to assess the economic impacts of RTO participation.

It should be noted at the outset of this report that electric utilities in Nebraska which are public power districts or municipalities are not subject to the general jurisdiction of FERC, and therefore cannot be ordered by FERC to comply with the formation of RTOs. Cooperative utilities may be subject to FERC's jurisdiction, depending on whether they have certain financial debt obligations with the Rural Utility Service. FERC recognized it's jurisdictional limitation in Order 2000 and stated it would attempt to accommodate the special legal restrictions of public power utilities. That said, the focus of this report is not to delve into the legal restrictions of Nebraska law, which are addressed in detail in the LR 455 Phase II report, but to identify the implications for the operation, planning and expansion of the transmission system, and the rate setting authority of the utilities' governing bodies. In essence the issue becomes one of local control versus federal control.

However, the unique interconnected and interdependent nature of the electric system does not make it simply a choice of Nebraska utilities deciding whether or not to participate with utilities in the neighboring states in the formation on a RTO. Nebraska utilities have adequate transmission to deliver their generation resources to their customers under normal system conditions. However, when system conditions are abnormal, like the unexpected loss of a major generation plant or transmission line, Nebraska customers depend on the utilities in the surrounding states to maintain the reliability of the electric system. Conversely, when the utilities in surrounding states experience abnormal system conditions, Nebraska utilities are called upon to maintain system reliability. In addition, Nebraska utilities will need to participate in a RTO if the perceived benefits of RTOs are to be realized by Nebraska's utilities and ratepayers.

One additional point to keep in mind is that RTOs are not structured to facilitate retail competition. Significant additional business practices and infrastructure must be put in place by each state to facilitate retail competition.

For Nebraska utilities the path ahead is tenuous. Nevertheless, efforts to participate in a RTO by Nebraska utilities are continuing to move forward, as recommended in the LR 455 report.

Nebraska Public Power District (NPPD) and Omaha Public Power District (OPPD) are participating in the development of TRANSLink (see Figure 1), an independent transmission company (ITC), along with

MidAmerican Energy, Alliant Energy, Xcel, and Corn Belt Power Cooperative. The participants made a filing at FERC in September, 2001 in which TRANSLink sought FERC's approval as an ITC and would become a member of the Midwest Independent System Operator (MISO) (see Figure 2). FERC issued an order in April 2002 accepting certain aspects of the TRANSLink filing and requiring changes to other parts. Since then a TRANSLink Development Company, LLC has been formed and it is expected additional FERC filings will be made in September 2002. Lincoln Electric System (LES) has become a member of MISO.

Other transmission facilities in Nebraska owned by WAPA, Tri-State G&T, and municipalities such as Hastings and Grand Island, are expected by FERC to become part of a RTO. Certain transmission facilities in western Nebraska would need to participate in a RTO in the western interconnection because those facilities are not electrically connected to the rest of the state. WAPA, Upper Great Plains Region, is participating in the development of Crescent Moon, a proposed RTO primarily for North Dakota, South Dakota, Manitoba, Canada, and a cooperative utility in Kansas. Transmission facilities owned by municipalities like Grand Island and Hastings would likely need to participate in the RTO which NPPD participates due to the transmission interconnections they share.

No doubt the alphabet soup of acronyms described above is confusing. The distinctions about what does a RTO, ISO or ITC actually do will hopefully become clearer later in the report when specific functions and duties are described, such as operational authority and tariff administration.

4.0 Background

The LR455 Phase II report issued in December 1999, the same time as FERC Order 2000, did an excellent job of describing the history of the transmission system development and the institutions and organizations which have grown up to support the reliable operation of the electric grid. There is no need to repeat that here, but rather to discuss the developments since then.

When FERC issued Order No. 2000, it did so because it was FERC's determination that sufficient progress had not yet been achieved in establishing broad, competitive wholesale electric markets, as mandated by the Energy Policy Act of 1992. In 1996, FERC issued Orders 888 and 889 that required all utilities to provide non-discriminatory open access to their transmission facilities. This was expected to promote competitive wholesale electric markets. These orders required investor-owned utilities to file non-discriminatory open access transmission tariffs, and encouraged public power utilities to do likewise. Further, the orders required utilities to separate their marketing and generation functions from their transmission operations functions, establish a code of conduct between employees engaged in these two functions, and required the establishment of an Open Access Same-Time Information System (OASIS). The OASIS is basically an internet system for customers to acquire transmission service.

Order 888 also encouraged the voluntary formation of a new organization FERC titled an Independent System Operator (ISO). FERC identified 11 criteria for an ISO, but the key concepts behind an ISO were a governance structure independent of market participants, and a transmission tariff that had a regional scope to eliminate the pancaking of rates. Among other things the ISO would have operational control of the transmission system, would plan for the expansion of the system, and would grant access to the transmission system to market participants. Since the ISO was independent of any market participants, primarily the vertically integrated utilities, it would not favor one customer over another.

In 2000, four years after the issuance of Orders 888 and 889, only a few ISOs had been approved by FERC, and there were complaints that movement to achieve wholesale competition was moving too slowly. Another common complaint was that discriminatory practices were still taking place by the investor-owned utilities in their granting of access to their transmission systems. From the perspective of some utilities, ISOs did not make any good business sense. The few ISOs that had formed, like California, required enormous amounts of money to establish and duplicated much of the infrastructure already in place. Further, the ISO did not own any transmission assets, yet could make decisions concerning those assets without any fiduciary liability. It was during this time period that the concept of an independent transmission company (ITC or Transco) emerged. Primarily conceived as a for-profit entity, the investor-owned utilities proposed placing their transmission assets into entirely separate companies, with no financial ties to the parent company and with its own Board of Directors. The ITC would be in the transmission business only. The basic difference between the ISO and the ITC is that the ITC is an owner-operator business model as compared to the ISO that operates the transmission system but does not own any transmission assets. Utility proponents of the ITC concept argued that no other industry was organized like an ISO and it didn't make any good business sense to do so with the electric industry. An ITC would have an inherent interest in operating the transmission system efficiently and reliably.

RTO's, as described in FERC Order 2000, have to satisfy four characteristics and eight functions. These items are described later in this report, but suffice it to say that an RTO was much the same as an ISO, but did add a few additional items to the list of duties, such as market monitoring, to determine if market abuse was taking place, and interregional coordination between the RTO's, so that wholesale transactions could take place across RTO"s without difficulty. Even though FERC had already approved a few ISO's, it required the ISO's to make a filing at FERC by January 15, 2001 to gain approval as an RTO. With the issuance of Order 2000, the ISO acronym has been replaced by the RTO acronym. FERC also acknowledged in Order 2000 the concept of ITC's and the possibility that a hybrid organizational structure for an RTO, one in which an ITC performs certain of the functions and fits under the oversight of an RTO which performs the remaining functions. While some critics of this hybrid structure argue it is duplicative, the proponents contend it is a more efficient allocation of duties.

On July 31, 2002 FERC issued a Notice of Proposed Rulemaking on Standard Market Design (SMD). FERC said that this third in the series (Order 888 & Order 2000) rulemaking is needed to remedy remaining undue discrimination in the provision of transmission service. This rulemaking proposes:

1. A new transmission tariff, Network Access Service, applicable to all users of the grid, including bundled retail customers. In a case decided before the U.S. Supreme Court, the Court ruled the FERC does has jurisdiction over all types of transmission service, including bundled retail service. Previously, bundled retail service had been under the jurisdictions of the states.
2. All FERC jurisdictional utilities to become, turn over control of their transmission facilities to, or contract with an Independent Transmission Provider (ITP). This is a new term FERC has coined.
3. An ITP administers day-ahead and real-time energy and ancillary service markets. The ITP is independent of any market participant.
4. To establish an access charge to recover the embedded transmission costs based on the customer's load ratio share of the of the ITP's costs.
5. Use Locational Marginal Pricing for transmission congestion management and provide tradable financial rights – Congestion Revenue Rights – as a means to lock in a fixed price for transmission service.
6. Establish an auction for Congestion Revenue Rights.
7. Establish Energy Imbalance Markets
8. Maintain Rights under existing transmission service contracts, to the greatest extent feasible.
9. Establish procedures to mitigate market power in day-ahead and real-time markets.
10. Establish procedures to assure there is adequate transmission, generation and demand-side resources
11. Provide a forum for state representatives to participate in the ITP decision-making process.
12. Obligations for users of the transmission system to comply with security standards.

For Nebraska utilities, some of who are originating members of the Mid-Continent Area Power Pool (MAPP) which was formed in 1972 (see Figure 3), the options for participating in a RTO are few. The MAPP membership voted down a proposal to become a RTO. Subsequently, the decision for MAPP to merge with MISO was approved, if certain conditions are met. In preparation for the potential merger with MISO, MAPP members also approved breaking up MAPP functions and placing them into separate organizations. MAPP previously served three functions under one Agreement: a Regional Transmission Group (RTG another outdated acronym coined by FERC) , a North America Electric Reliability Council (NERC) regional reliability council, and a power and energy market. The RTG functions, primarily transmission planning and establishing and administrating a regional transmission tariff for the MAPP system, would be taken over by MISO, whereas the other functions would remain with MAPP. The MAPP/MISO merger has been completed. Some of the MAPP members have joined MISO. However, one of the merger conditions was for MISO to continue to provide transmission services for a period of six years to MAPP members that do not join MISO.

The role of NERC regional reliability councils in conjunction with RTOs is not entirely clear. NERC was formed in 1968 as a voluntary membership association of electric utilities to establish standards for the reliable operation of the electric system and to conduct studies to assess the adequacy of generation. NERC is comprised of 10 regional reliability councils. FERC has assigned the responsibility for short-term reliability of the transmission system to the RTO. NERC has been undergoing a reorganization process for the last few years. It has adopted a new moniker, NAERO (North American Electric Reliability Organization) and created an independent Board of Directors. In addition, federal legislation has been introduced to make participation in NAERO mandatory. Currently, utility participation in NERC is voluntary. It appears that NAERO will focus itself on setting standards for reliability and monitoring compliance with those standards, rather than conducting studies to assess the reliability of the transmission system and the adequacy of generation.

One critical function of the MAPP Agreement, as it concerns Nebraska electric utilities, is the generation reserve sharing pool. Generation reserve sharing allows a utility in need of power due to unexpected events such as severe weather or equipment failures, to draw on the excess power that other members of the agreement may be able to provide. Without this sharing agreement Nebraska utilities would have to install extra generation capacity to maintain system reliability. Generation reserve sharing is not part of the duties fulfilled by a RTO and will have to be maintained through contractual relationships amongst interested utilities, if the function is no longer provided after the consolidation of MAPP with MISO. The recent FERC SMD rulemaking does require that the ITP forecast the future demand for its area and assign each load-serving entity in its area a share of the needed future resources based on the ratio of its load to the regional load.

5.0 Current Status of Transmission Adequacy and Availability

The previous section of this report discussed the background of the various existing transmission organizations and the requirements of the FERC Orders for utilities to participate in the newly forming RTOs. All of the changes required by FERC are intended to promote a vibrant competitive wholesale electric market. This section will discuss the impact on the adequacy and availability of transmission that has resulted from the change to a competitive wholesale market.

Without going into detail about the history of the transmission system development, it can be said that the transmission system was generally built to deliver the power output of large generation plants to utilities that serve their end-use customers in a defined geographic service territory. Utilities in adjoining areas interconnected their transmission systems to maintain reliability, and in so doing were able to make wholesale power transactions on a limited basis. Generally, these transactions tended to range from seasonal to multi-year agreements.

With the advent of FERC Orders 888 and 889 in 1996, the usage of the transmission system has changed dramatically. The number of wholesale power transactions has increased, but the duration of the transaction has decreased. The net result is that the nature of wholesale transactions has changed from long term to short term. Instead of seasonal and multi-year transactions, the norm is now hourly and daily transactions. In addition, a great deal of the wholesale transactions are regional in nature, meaning transmission customers desire to move their transactions across several states, not just across one utility's service area. Another factor impacting the transmission system is that considerable new generation has been built in the region, but there has been very little new transmission built. The reasons little new transmission has been built include: short term transactions do not provide an incentive for long term investment in transmission, and the difficulty in permitting and siting new transmission lines. As a result of the increased wholesale activity most industry experts agree that the transmission system is being stressed, but thus far system reliability has been maintained through strict adherence to NERC operating standards.

Transmission customers are no longer just the utilities, but many new market participants including, power marketers, independent power producers, and others. Transmission customers are able to request transmission service through the internet-based OASIS. There are two basic types of transmission service, network service or point-to-point service. Network service is best described as long-term use of the entire transmission network, which is required when service is provided to customers spread across a wide geographic area, and may be supplied from multiple generation plants dispersed at various locations. Network service is used by utilities for service to native load wholesale and retail customers. Point-to-Point transmission service is a request to deliver a specific amount of power output from a generation plant, labeled a Point of Receipt, to another point on the transmission system, labeled a Point of Delivery, for a set time period of time.

Point-to-Point transmission service is further characterized as either "firm" service or "non-firm" service. The distinction is that firm service has the same service rights as network service, whereas non-firm service can be "curtailed" (cancelled) if system conditions become overloaded. NERC has established a curtailment policy, known as Transmission Loading Relief (TLR), which details the priority for curtailments. Basically, non-firm transactions are curtailed first, and then firm transactions and network service are curtailed in proportion to the system use. Non-firm curtailments occur fairly frequently, but firm and network service curtailments occur much less frequently. It can also be said that transmission capacity for firm service is not always available to meet the requests of the market. Point-to-Point service can be requested for hourly, daily, weekly, monthly or long term service.

The FERC SMD rulemaking proposes a new transmission tariff, which combines both network and point to point transmission service into one type of service – Network Access Service. The basic idea is that generation resources can be delivered to any load on the system. When the transmission system becomes congested then customers will have to pay the locational marginal price calculated due to the congestion, unless the customer has previously arranged or held congestion revenue rights. This is a very complicated system of calculating congestion costs and assigning the costs to those most willing to pay. A complete description of the method is beyond the scope of this discussion.

Transmission service to conduct a wholesale power transaction is provided by MAPP, which administers the OASIS and provides transmission service over the MAPP Transmission tariff known as Schedule F. Schedule F allows a transmission customer to request service under a single region-wide tariff and gain access to the entire MAPP region. In administering the OASIS, MAPP uses an automated system that analyzes each transmission service request. The adequacy of the transmission system to support the transaction is analyzed and the transaction is either approved or denied depending on whether or not there is transmission capacity available. MAPP processes nearly 100,000 requests per year for transmission service. Of those requests approximately 13% of the wholesale energy transfer is denied. From the remaining service requests that are approved, about 2% of the scheduled wholesale energy is curtailed. Transmission customers are able to access the system and run a system impact calculator that indicates the likelihood of request approval before they submit an official request. Thus, many more transactions may be desired, but are never submitted, if the customer already has an indication the request will be denied.

Per the conditions of the MAPP/MISO merger, many of the MAPP functions have been assumed by MISO. MISO hired many of the former MAPP staff and continues to provide services from the former MAPP offices in St. Paul , Minnesota. The MAPP transmission tariff, Schedule F, is now only available on a monthly basis for a period of six consecutive months. At a certain point when enough MAPP members have joined MISO, Service Schedule F will no longer be available.

The adequacy and availability of the transmission facilities in Nebraska and the MAPP region is studied and evaluated on an on-going basis by the Transmission Planning Committee of MAPP. Every two years a report is issued, covering the next ten year period, which provides an assessment of the transmission system and recommends needed improvements. The last MAPP report was issued in November 2001. The study process is open to all MAPP members, as well as other interested parties, including state regulators. Because the MAPP region covers a wide area, the planning process is further divided into Sub-Regional Planning Groups (see Figure 4). Each of the sub-regions produces a report on the same time frame, and the results are rolled up into one comprehensive report for the MAPP region. The Nebraska sub-region includes parts of Kansas and Missouri. The lasts update for the Nebraska sub region was issued in April 2002. The results of the latest report indicate that the combined MAPP region has an export capability of about 4000 MW. Import capability into MAPP has not been studied because until recently there have been very few transmission limitations on importing power into the MAPP region. In addition, there has been excess generation capacity in MAPP and it has generally been low cost compared to the market. In general, the MAPP region has been a net exporter and the transactions have predominately been in the west-east and north-south direction. Market activity has been changing in recent years and the MAPP Transmission Planning Committee intends to conduct an import study in the near future. One of the difficulties encountered by the transmission planners in conducting these studies is that the planners need to have information about customer load growth and the location and size of new generation plants. Unfortunately, non-utility independent power producers are building many of the new generation plants as merchant plants, in states other than Nebraska. The independent power producers are very reluctant to disclose any of their plans about future power plant construction, claiming it is competitive information. Thus, the transmission planners do not have all the information they need to produce an accurate study.

As mentioned previously, the transmission system has limited capacity to provide for regional transactions. Transmission planners conduct system studies to determine exactly how much capacity is available and which areas of the transmission system are most critical or sensitive to providing wholesale transactions. The planners identify "constrained interfaces", sometimes referred to as flowgates, which are most critical and set limits on how much capacity these transmission facilities can reliably handle. Constrained interfaces may be a single transmission line or a group of lines in an area. In MAPP there are a number of constrained interfaces (see Figure 5 which shows some, but not all of the interfaces). All of the Nebraska constrained interfaces are shown in Figure 6, indicated by the curved lines. The direction of the curve indicates that the constrained interface is constrained in one direction only. For example, the Cooper-South interface is limited for transactions to the south only. Transactions moving to the north are not limited. The directions of the constrained interfaces support the statement that MAPP is generally exporting power in a north-south and west-east direction, and that imports into MAPP are not a problem.

Transmission Customers in MAPP can go to the OASIS web site and review all of the postings for available transmission capacity on the constrained interfaces. Postings are listed each day for the next 79 days, then each month for the next 36 months. In general, the near term (the next few days) will show limited capacity, but the long term will show much greater capacity. This reflects the earlier statement that much of the wholesale market activity is conducted in the short term, whereas not as much activity is conducted over the longer term.

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

6.0 RTO Characteristics and Functions

In Order 2000, FERC identified four characteristics and eight functions that a RTO must satisfy. Contained within these characteristics and functions are the real substance of a RTO's authority, responsibility and control.

6.1 Characteristics

6.1.1 Independence

Many industry participants have described this characteristic, independent governance, as the cornerstone for a successful RTO. The expectation is that the RTO will have a Board of Directors that is independent of any market participation, to avoid conflicts of interest. This means the board members cannot be employees or board members of any utility, generator, marketer, or any other entity that is a participant in the electric marketplace, nor have any financial interest in these entities, including stock ownership.

6.1.2 Scope and Regional Configuration

Until the July 12, 2001 orders, FERC had previously granted "conditional" approval to several RTO filings indicating they had satisfied this requirement. But FERC reversed itself with these orders and indicated that only four RTOs will meet its approval. FERC rejected the Southwest Power Pool RTO, along with other RTO filings, citing lack of regional scope as one of the reasons for the denial. The Southwest Power Pool is geographically the closest RTO to Nebraska to be denied by FERC. FERC has opined that these filings do not meet the "natural" wholesale markets without giving any clear direction as to how FERC determined where the boundaries lie for these natural markets. Since then FERC has again reversed itself and said that it has no set number of RTOs in mind. FERC's main focus under the SMD rulemaking is to assure that all RTOs use the same standard tariff and business practices so that it minimizes any seams issues between adjoining RTOs.

As events have played out, Nebraska transmission facilities will reside in two different RTOs, the MISO and whatever RTO forms in the west.

6.1.3 Operational Authority

FERC requires a RTO to be the NERC Security Coordinator, which entails monitoring the status of the transmission system and directing Control Area Operators what actions to take. In Nebraska, there are three Control Area Operators that encompass all of the transmission facilities that lie in the eastern interconnected system. NPPD, OPPD and LES each serve as a Control Area Operator. As a Control Area Operator each of these utilities must perform numerous functions to monitor the status of the electric system and take appropriate actions to remedy any problems that arise in their Control Area, and coordinate with the Regional Security Coordinator on problems that cannot be resolved by actions they take individually.

In the TRANSLink ITC proposal NPPD and OPPD will no longer be control area operators. They will continue to balance generation and load within their area. Instead TRANSLink will be operate one control area for the for MAPP members facilities. However, NPPD and OPPD will retain operational control under certain emergency conditions.

FERC has admitted that it is difficult to draw a precise line exactly what duties fall within this characteristic, but it is clear that FERC expects the RTO to have great latitude to control the operation of the transmission system when it comes to providing transmission service. FERC has even rejected the exclusion of the transmission owner from asserting operational control during emergencies in the New York RTO filing.

6.1.4 Short-Term Reliability

This characteristic entails the authority of the RTO to approve all interchange transactions between Control Area Operators, the authority to order redispatch of generation for reliability, and the authority to approve all transmission maintenance outage schedules.

FERC has stopped short of requiring the RTO to have direct physical control of the transmission system, but it has left the Control Area Operators of the transmission owners with almost no decision making discretion.

6.2 Functions

6.2.1 Tariff Administration and Design

In the July 12 orders, FERC has ruled that only the RTO can propose transmission rates for FERC's approval. ITCs will have to coordinate any transmission tariff proposal with the RTO and will not have unilateral ability to propose transmission rates to FERC.

In the TRANSLink Order, FERC ruled that TRANSLink cannot have its own transmission tariff. TRANSLink can instead have its own rate design under a MISO rate schedule.

6.2.2 Congestion Management

This function is a means to relieve the congestion which is occurring on the transmission system due to the tremendous increase in wholesale market transactions, without continually resorting to curtailing transactions after they have been scheduled. Thus far, no one proposal has gained widespread acceptance, but most proposals generally involved redispatching generation on a bid based system.

In the FERC SMD rulemaking, FERC has proposed that the entire industry adopt the locational marginal pricing method for pricing congestion. This method has been in use on the east coast in the PJM and New York ISOs. However, there is not widespread acceptance of this method elseswhere.

6.2.3 Parallel Path Flow

Parallel flows are the result of the interconnected nature of the electric system. Power flows over the entire network and utilities in one RTO may see significant system usage of their transmission system due to power schedules in another RTO. Currently, this issue has not adequately addressed in any RTO proposals. It is primarily a compensation issue.

6.2.4 Ancillary Services

The RTO must arrange for the provision of the necessary ancillary services, most of which are provided by the generators, for the transmission customers who do not wish to make their own arrangements.

In the FERC SMD rulemaking , FERC requires an ITP to establish an ancillary services market.

6.2.5 OASIS and Total Transmission Capability (TTC) and Available Transmission Capability (ATC)

FERC has ruled that only the RTO can control the OASIS and make the determination of TTC and ATC. The transmission owners must supply all of the necessary information to the RTO. However an ITC because it is independent from market participants can provide some of the functions that otherwise would be assigned to the RTO.

6.2.6 Market Monitoring

This function is one of oversight of the wholesale transactions taking place. The RTO is required to monitor and analyze the market to determine if any market abuse is taking place, report its findings to FERC and recommend any needed changes.

6.2.7 Planning and Expansion

The July 12 FERC orders have taken a further step in directing that the RTO shall have exclusive authority to conduct transmission studies and develop plans for expansion of the transmission system. The transmission owners can participate in the plans, but not control any of the outcomes.

The FERC SMD takes the planning function further and defines specific roles and obligations for load-serving entities, transmission owners, and state regulators.

6.2.8 Interregional Coordination

Initially this function was thought to be very important if the 13 some RTOs in development all would come to fruition. But since FERC has declared that only four RTOs are needed, this function takes on much less significance.

7.0 Other Issues

One other significant issue that stands as a potential impediment to participation in RTOs by some of the public power utilities in Nebraska is the restrictions placed on tax-exempt bonds by the IRS and the bond covenants of that debt. Those restrictions are currently being studied by the utilities, and further discussion will be included in the next draft of this report.

The other significant addition to the markets introduced by the FERC SMD Order is the requirement for day-ahead and real-time energy markets. FERC encourages customers to continue to use long term bilateral contracts to the extent they desire. FERC also is mandating the establishment of these spot markets. This will be a costly undertaking and one that can only be reasonably done over a large geographic area. While FERC has introduced the new term of ITP, it is hard to see how the ITP will not also be the RTO since many of these functions cannot reasonably be performed by a single utility.

8.0 Conclusions

To put it lightly the state of RTO development is in a state of flux and the timing of this report makes it impossible to predict what will transpire in the months ahead. At best, the report will serve to identify key issues that could significantly affect the way the electric transmission system in Nebraska is planned, operated and priced.

At this juncture the only organization that is a “viable” RTO for Nebraska utilities to participate in is the MISO. For transmission facilities in Nebraska that are part of the Western Interconnected System, there is no “viable” Western RTO at this time.

The Nebraska transmission system is adequate to serve Nebraska customers when system conditions are normal. However, under abnormal system conditions, such as the loss of major transmission lines or a large generation plant, Nebraska customers depend on the interconnected utilities in surrounding states and the generation reserve sharing pool to maintain reliability. Nebraska utilities contribute to the reliability of the region in a reciprocal manner.

The transmission system in Nebraska does experience significant usage due to the wholesale transactions occurring in the region. Reliability is maintained by setting capacity limits on the constrained interfaces, and curtailing transactions when system conditions approach those limits.

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

Figure 1

Proposed TRANSLink Footprint

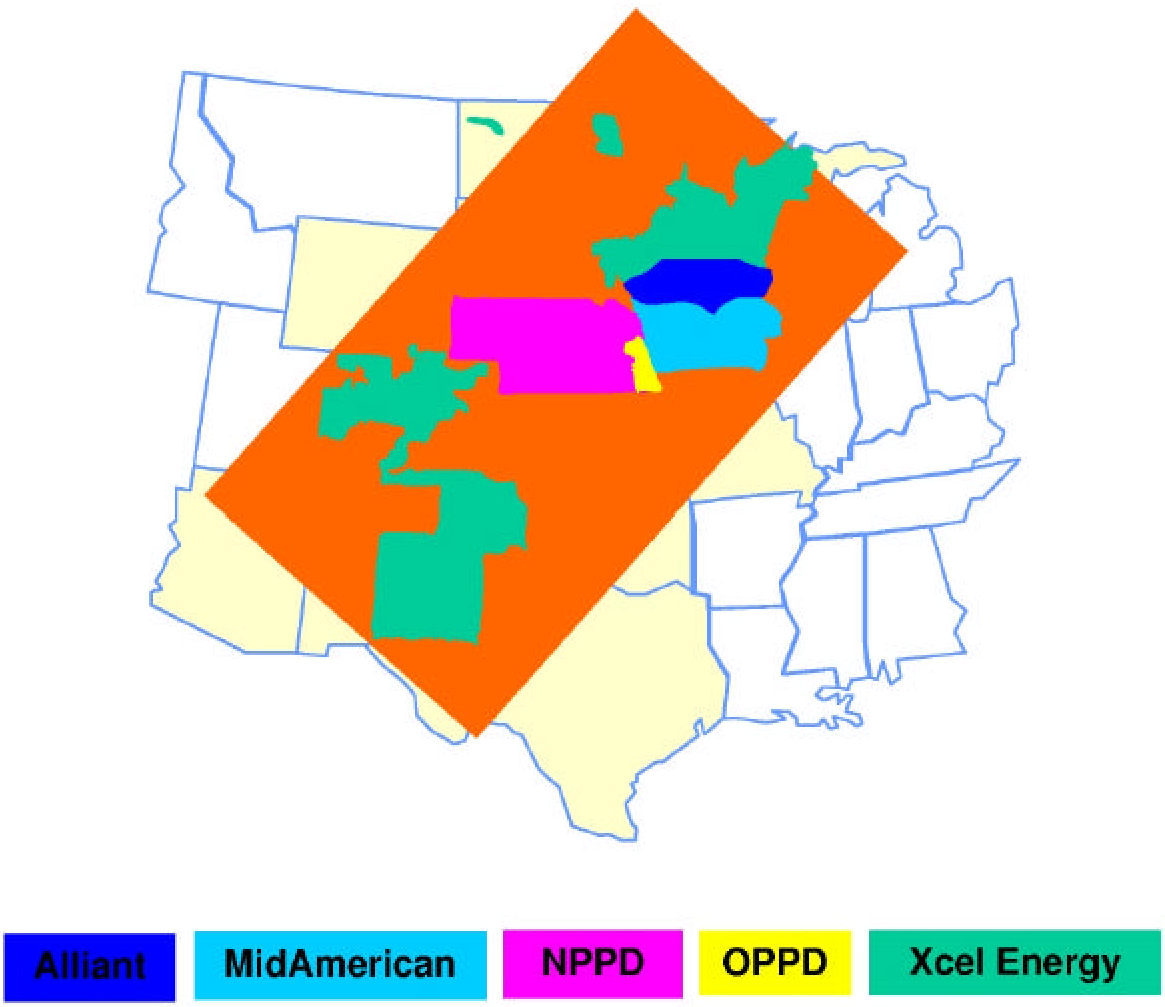


Figure 2

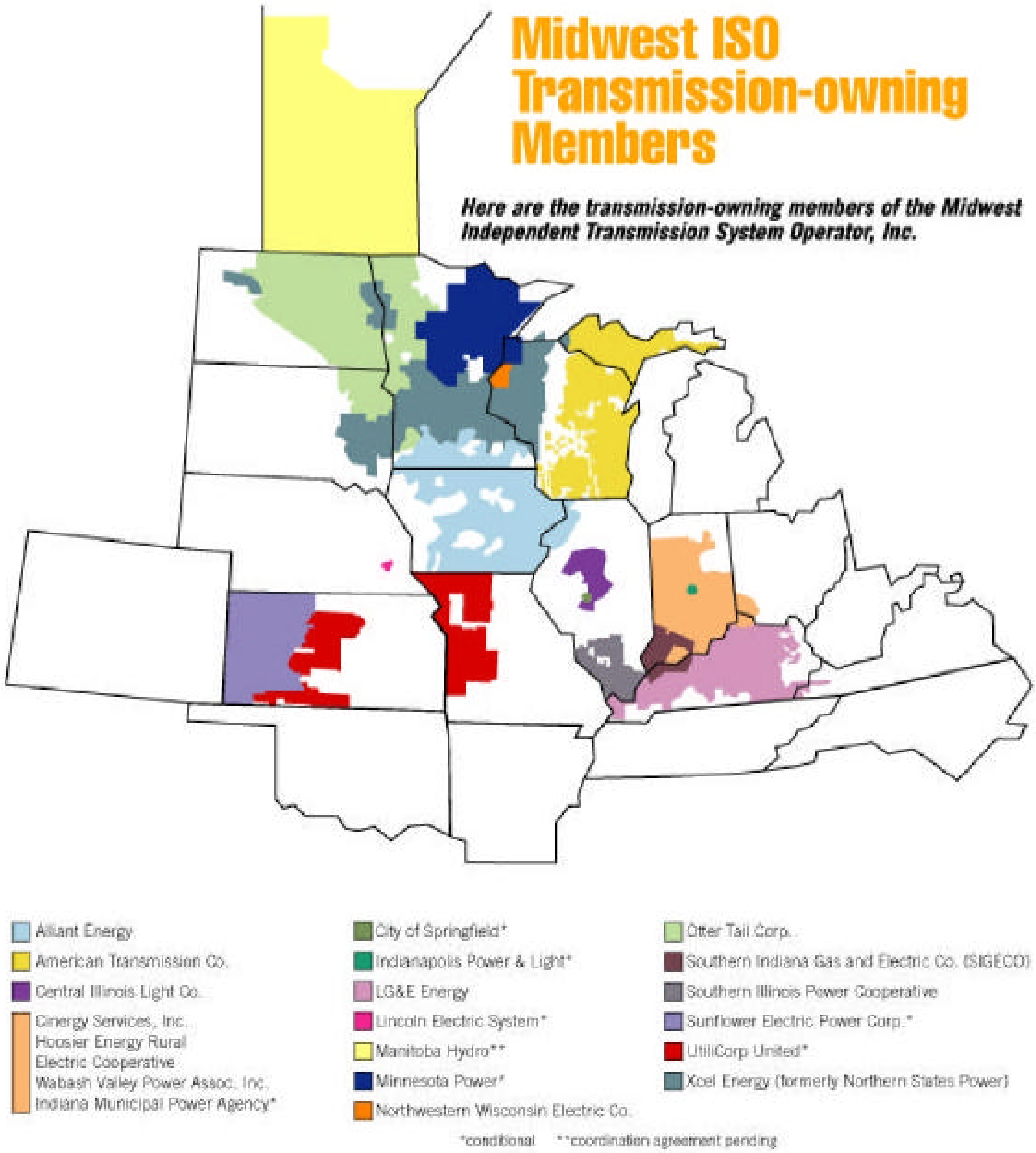

Midwest ISO Transmission-owning Members
Here are the transmission-owning members of the Midwest Independent Transmission System Operator, Inc.
Alliant Energy
American Transmission Co.
Central Illinois Light Co.
Cinergy Services, Inc.
Hoosier Energy Rural Electric Cooperative
Wabash Valley Power Assoc. Inc.
Indiana Municipal Power Agency*
City of Springfield*
Indianapolis Power & Light*
LG&E Energy
Lincoln Electric System*
Manitoba Hydro**
Minnesota Power*
Northwestern Wisconsin Electric Co.
Otter Tail Corp.
Southern Indiana Gas and Electric Co. (SIGECO)
Southern Illinois Power Cooperative
Sunflower Electric Power Corp.*
UtiliCorp United*
Xcel Energy (formerly Northern States Power)
*conditional **coordination agreement pending

Figure 3

Mid-Continent Area Power Pool

Figure 4

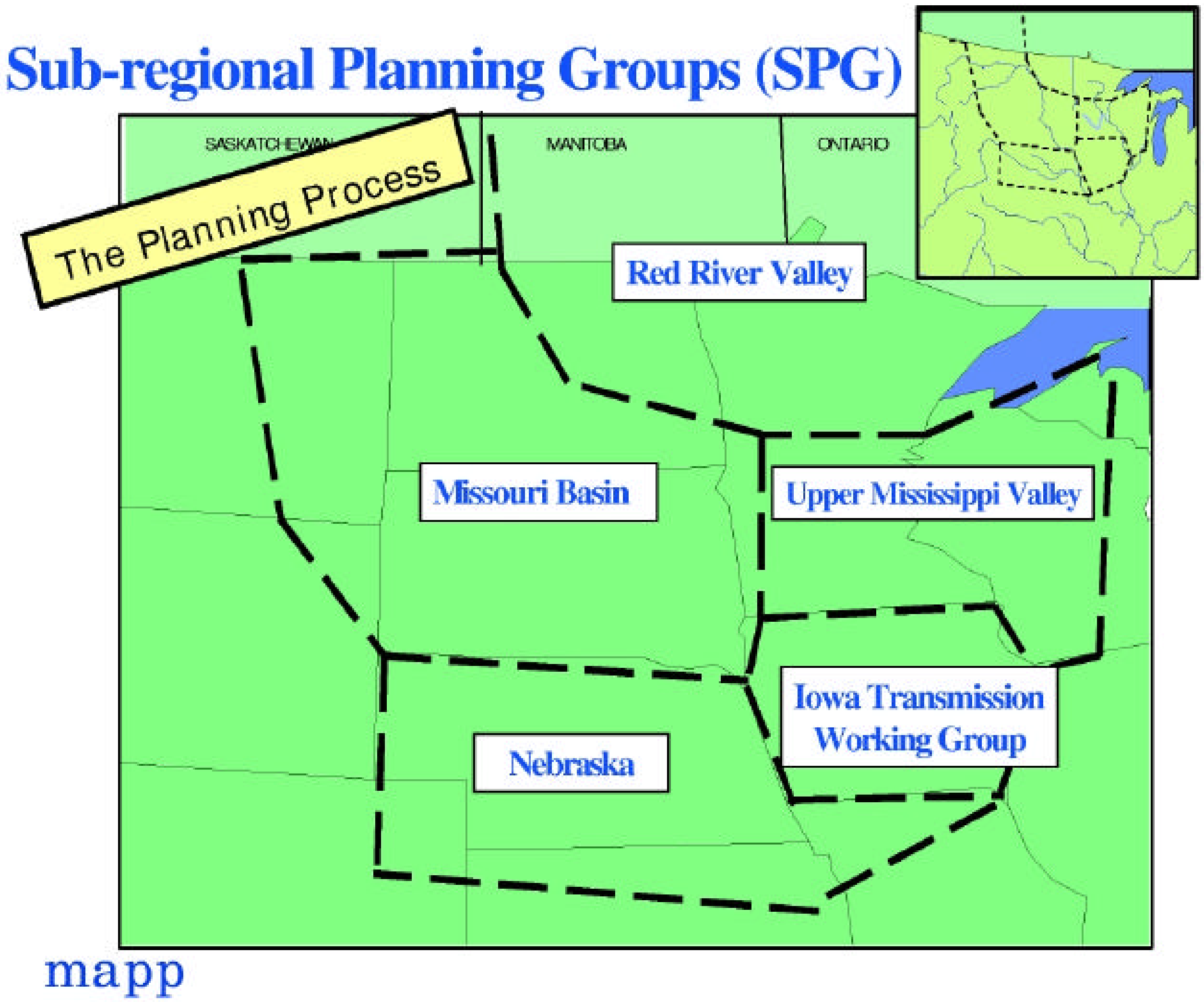

Sub-regional Planning Groups (SPG)
The Planning Process
SASKATCHEWAN
MANITOBA
ONTARIO
Red River Valley
Missouri Basin
Upper Mississippi Valley
Iowa Transmission Working Group
Nebraska
mapp

Figure 5

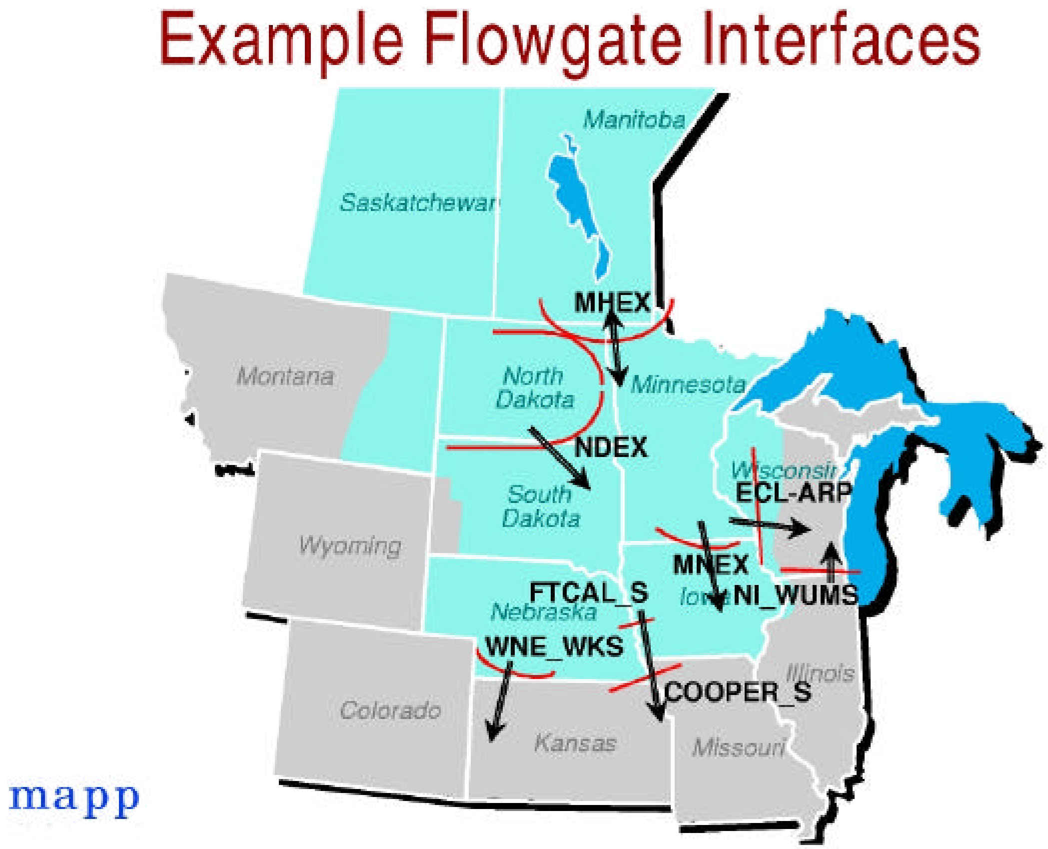
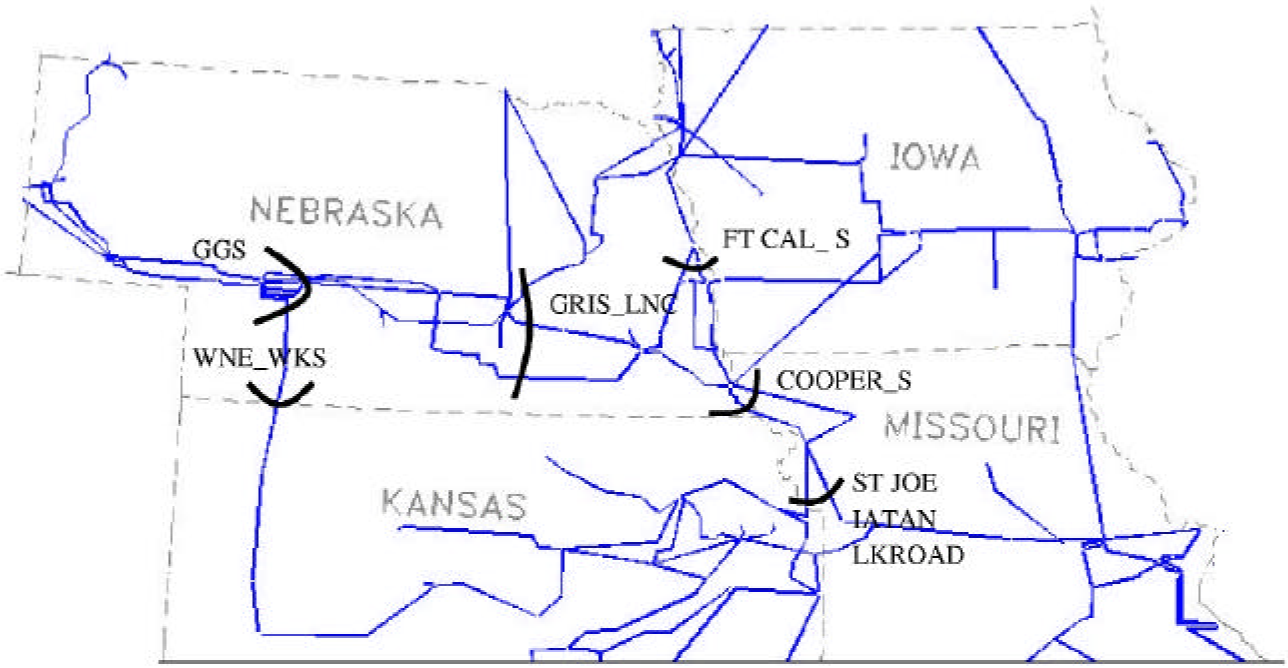

Example Flowgate Interfaces
Manitoba
Saskatchewan
MHEX
Montana
North Dakota
Minnesota
NDEX
South Dakota
Wisconsin
ECL-ARP
Wyoming
MNEX
FTCAL_S
Iowa
NI_WUMS
Nebraska
WNE_WKS
Illinois
COOPER_S
Colorado
Kansas
Missouri
mapp

Figure 6

NEBRASKA SUBREGIONAL PLANNING AREA



Chapter 2

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

1.0 Introduction

1.1 Groups' Purpose and Membership

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

Clint Johannes, Chairman	-	Nebraska Electric Generation & Transmission Cooperative, Inc. (NEG&T)
Bruce Abernethy	-	Lincoln Electric System (LES)
Deeno Boosalis	-	Omaha Public Power District (OPPD)
Barry Campbell	-	Nebraska Public Power District (NPPD)
Doug Erickson	-	The Energy Authority (TEA)
Kevin Gaden	-	Municipal Energy Agency of Nebraska (MEAN)
Burhl Gilpin	-	Grand Island Utilities
John Krajewski	-	MEAN
Derril Marshall	-	Fremont Utilities
Allen Meyer	-	Hastings Utilities
David Ried	-	OPPD

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

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

1.2 Approach

To accomplish the purpose described, the Group first defined the term "viable" using several alternate methodologies. Next the size of the region was determined. Since the Nebraska electric system is in two portions of the United States interconnected transmission grid, the region for each (eastern and western) was determined**.**

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>
> **3a**: 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 generic definition of a “viable market”, as described in [3 C(1)] above, shall be deemed as “having a reasonable chance of succeeding” financially.

2.2 FERC Definition

Analysis shows a "viable market" must be one in which no single utility, or group of utilities, is able to exercise "market power." The Federal Energy Regulatory Commission (FERC) established procedures for determining whether a proposed merger or settlement will impact certain regions or individual utilities and enhance the ability of certain utilities to control prices or exclude competition. This is known in the regulatory community as "market power." FERC provides the following definition: Market power exists if there are concerns with market concentration.

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

In determining the market concentration for available economic capacity, FERC looks at suppliers that can supply the product (wholesale capacity and energy) at a cost no greater than 5% above the competitive price. The concentration of suppliers that have available economic capacity and energy that can be supplied is less than the FERC-defined threshold for an "unconcentrated" market. FERC defines this using the Herfindahl-Hierschman Index (HHI), which is calculated by summing the squares of the market share of all competitors that can supply power at a price no greater than 5% above the competitive price. An HHI of less than 1,000 indicates an unconcentrated market. This analysis is often referred to as a "hub and spoke" test. The test is described in Section 2.3.

FERC's methodology for assessing market power has been evolving. Notably, FERC has taken steps to recognize the effect of transmission constraints on the exercise of market power. Initially, FERC began using variations to the traditional hub and spoke analysis that compensated for transmission constraints. This evolution has culminated in a new FERC order issued on November 20, 2001 entitled "ORDER ON TRIENNIAL MARKET POWER UPDATES AND ANNOUNCING NEW, INTERIM GENERATION MARKET POWER SCREEN AND MITIGATION POLICY (Docket No. ER96-2495-015, et al). The order introduced a new test for market power called the "Supply Margin Assessment" which laid out mitigation measures for companies failing the test and found a number of companies not in compliance with the order. A complete review of the new FERC tests and their impacts on this report are included in Section 4.1.1.3.

2.3 Basic Elements of Traditional FERC Market Power Analysis

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

Off-system energy sales data was calculated for utilities in a market region that is roughly defined as the Mid-Continent Area Power Pool plus one transmission tier. This raw data was attained from the 2000 Resource Data International (RDI) database. The results are shown on Exhibit II-1. This approach is different from the market index approach that is used in Issue #4 of this report. This is because the futures indices are only available for certain electric trading hubs. The "markets" or "hubs" represent specific transmission systems where the electricity can be obtained at the price listed on the specified index. However, it may not be possible to procure transmission from the hubs to Nebraska. Since available economic capacity is defined as "capacity not needed to serve a utility's native load obligations (including applicable reserve requirements)" and capacity is defined as "all of a utility's generating capacity", therefore, the available capacity should be the net difference between total capacity in the region and peak demand of the utilities serving the region, as calculated in Exhibit II-1.

One item that should be noted is the difference between Nebraska's supply cost and the indices. There is considerably less price volatility in Nebraska's customer-owned generation and long term purchase contracts than the hourly, daily, and monthly wholesale spot markets. This difference is due to the stability of the physical asset base and long-term contracts that provide less variability associated with fuel cost volatility, transmission access, and regional regulatory issues.

2.4 Definition of a Viable Market

Considering the factors described above, the following definition of a “viable market" is used for this report:

“A viable market is a market that has roughly the same number of competitive wholesale buyers and sellers that have adequate resources and transmission capabilities to serve the electric power needs of the defined region or market.”

There must be at least 10-15 sellers of roughly equivalent size and scope that can provide capacity and energy at rates competitive with prevailing market prices. A viable market also provides relevant real-time information to all market participants. A viable market also must be a sustainable market. Although there are various thoughts on this, there appears to be consensus that the recent wholesale market in the Western Interconnect is not sustainable from a price standpoint for the long-term at current retail rates and wholesale cost expectations.

3.0 Region Defined

3.1 East/West Interconnection Description

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

3.2 Nebraska’s Portion of Each Interconnect

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

3.3 Eastern Interconnection Defined

The Eastern Interconnection is defined as any generation and load that is synchronously connected to the grid that includes the entire eastern, southern and central United States and eastern Canada. Generally, this includes the states and provinces of North Dakota, South Dakota, Nebraska, Kansas, Oklahoma, a small portion of Texas and all states to the east as well as Saskatchewan and provinces to the east. However, there are a few locations, including the far western edge of South Dakota (divided at Rapid City) and everything located west of Sidney, Nebraska, that are not on the Eastern Interconnection. This includes almost all of the NERC reliability regions such as MAPP, MAIN, SPP, ECAR, NECC, FRCC, MAAC and SERC as defined in the glossary. The regions that specifically impact Nebraska include the MAPP region, the MAIN region, and the SPP region because some Nebraska utilities have contracted to receive or deliver power to those locations. (See Exhibit II-2)

3.4 ERCOT Interconnection

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

3.5 Western Interconnection Defined

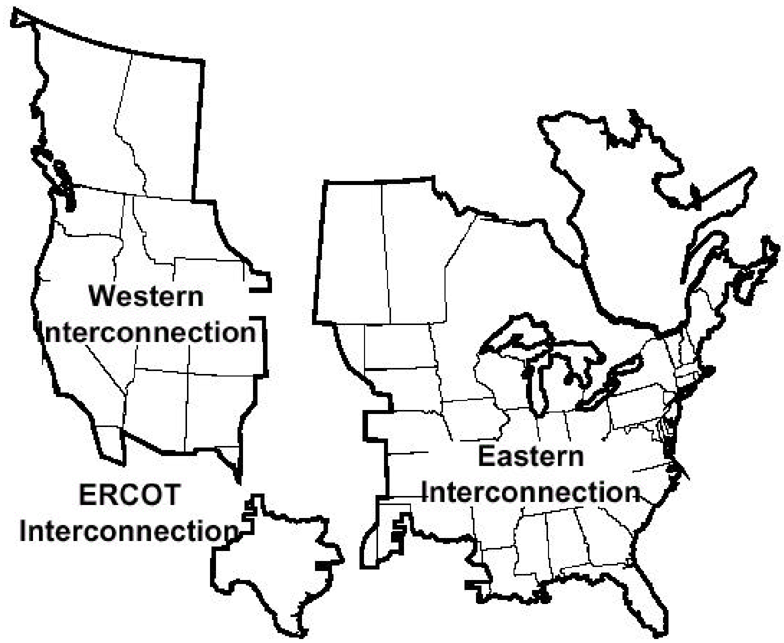
The Western Interconnection is defined as all load and resources that are synchronously connected with the reliability region of the Western Systems Coordinating Council (WSCC). States and provinces in this region include most of Montana, with the exception of a small part of eastern Montana that is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

Exhibit II-1

MARKET CONCENTRATION for AVAILABLE ECONOMIC CAPACITY CALCULATION TABLE

2000 Vintage Data	Number of Suppliers =	42		Number of Suppliers =	39	
	Maximum =	12.4%		Maximum	21.6%	
	HHI Calculation =	543.6		HHI Calculation =	942.7	
Utility Name	**Native Load Energy MWH**	**N L Energy % of Total**	**% Squared**	**Non-Requirements Wholesale Sales MWH**	**Non-Req. Whls Sales % of Total**	**% Squared**
Alliant West	2,018,094	0.7%	0.5	688,430	0.7%	0.5
Associated Electric Coop., Inc.	14,589,245	5.2%	26.7	4,016,813	4.2%	18.0
Basin Electric Power Coop	16,336,663	5.8%	33.5	12,450,877	13.1%	172.5
Black Hills Corp.	2,122,766	0.8%	0.6	684,378	0.7%	0.5
Colorado Springs Utilities	3,758,795	1.3%	1.8	113,588	0.1%	0.0
Columbia Water & Light Dept.	61,700	0.02%	0.0	8,282	0.0%	0.0
Cooperative Power Assoc.						
Dairyland Power Coop.	4,998,119	1.8%	3.1	677,069	0.7%	0.5
Empire District Electric Co.	2,700,657	1.0%	0.9	161,292	0.2%	0.0
Grand River Dam Authority	5,960,057	2.1%	4.5	479,492	0.5%	0.3
Great River Energy	10,109,464	3.6%	12.8	3,361,775	3.5%	12.6
Hutchinson Utilities Commission	113,748	0.04%	0.0	13,016	0.0%	0.0
IES Utilities, Inc.	9,964,231	3.5%	12.5	913,810	1.0%	0.9
Independence Power & Light Dept.	214,604	0.1%	0.0	31,821	0.0%	0.0
Interstate Power Co.	4,396,853	1.6%	2.4	592,375	0.6%	0.4
Kansas City Board of Public Utilities	2,574,410	0.9%	0.8			
Kansas City Power & Light Co.	14,951,919	5.3%	28.0	1,588,488	1.7%	2.8
Lincoln Electric System	1,285,629	0.5%	0.2	365,163	0.4%	0.1
Manitoba Hydro						
MidAmerican Energy Co.	20,807,804	7.4%	54.3	6,851,154	7.2%	52.2
Midwest Energy, Inc.	1,472	0.001%	0.0	59,464	0.1%	0.0
Minnesota Power & Light	6,938,196	2.5%	6.0	1,711,739	1.8%	3.3
Minnkota Power Coop., Inc.	1,663,033	0.6%	0.3	1,261,793	1.3%	1.8
Missouri Basin Municipal Power Agency						
Missouri Public Service						
Montana Dakota Utilities	2,331,188	0.8%	0.7	930,318	1.0%	1.0
Municipal Energy Agency of Nebraska	204,113	0.1%	0.0	429,069	0.5%	0.2
Muscatine Power & Water	1,359,113	0.5%	0.2	511,698	0.5%	0.3
Nebraska Public Power District	14,258,837	5.1%	25.5	8,534,269	9.0%	81.1
Northern States Power Co.	34,904,563	12.4%	152.9	6,500,442	6.9%	47.0
Northwestern Public Service Co.	1,566,537	0.6%	0.3	373,713	0.4%	0.2
Oklahoma Gas & Electric Co.	23,327,212	8.3%	68.3	256,358	0.3%	0.1
Oklahoma Municipal Power Authority	939,573	0.3%	0.1			
Omaha Public Power District	11,760,938	4.2%	17.4	4,135,753	4.4%	19.0
Otter Tail Power Co.	3,610,302	1.3%	1.6	1,494,241	1.6%	2.5
Pacificorp-East	11,007,517	3.9%	15.2	5,450,484	5.7%	33.1
Platte River Power Authority	3,239,346	1.1%	1.3	471,356	0.5%	0.2
PSC of Colorado - Eastern Colorado	21,641,254	7.7%	58.8	20,504,605	21.6%	467.9
Saskatchewan Power						
Southern Minnesota Municipal Power Agenc	2,583,216	0.9%	0.8	273,485	0.3%	0.1
Southwestern Power Administration	3,761,778	1.3%	1.8			
Springfield City Utilities	2,945,747	1.0%	1.1	446,359	0.5%	0.2
St. Joseph Light & Power Co.	1,255,293	0.4%	0.2	135,017	0.1%	0.0
Sunflower Electric Power Corp., Inc.	2,643,717	0.9%	0.9	864,834	0.9%	0.8
United Power Assoc.						
WAPA Billings East (UM-East)	4,206,211	1.5%	2.2	1,497,055	1.6%	2.5
WAPA Billings West (UM-West)						
WAPA Montrose (UC/LM)	4,251,175	1.5%	2.3	3,422,013	3.6%	13.0
West Plains, Colorado						
West Plains, Kansas						
Western Farmers Electric Coop.	4,955,977	1.8%	3.1	2,533,489	2.7%	7.1
Western Resources, Inc.						
TOTAL	**282,321,066**		**543.6**	**94,795,377**		**942.7**

Exhibit II-2



3.6 Reasons for Size of Region Used for this Report

The reason that was applied to the definition of Region, defined from a trader's experience, is a realistic distance that power can be expected to be imported or exported from Nebraska without realizing substantial risks on transmission availability or costs. It was decided that anything with additional wheeling becomes a reliability risk and higher cost that would drive the generation price to non-competitive levels. Although there may be isolated cases where power from SERC or the Tennessee Valley Authority (TVA) may be able to be delivered reliably to Nebraska, it is highly unlikely that power from the southern United States would be delivered reliably to Nebraska ratepayers during the peak time of the summer and winter periods.

For the purposes of this report, the Region is considered to be the area which Nebraska utilities would either import or export electricity. Based on the experience of the marketing staffs from the respective Nebraska member utilities, the size of the Region was defined as described below.

3.6.1 Eastern Region

For the purposes of this report, the Region will be the same that was used in last year's report. This would include all members of MAPP, and all utilities that are directly interconnected with a MAPP utility can use the MAPP Schedule F Transmission Tariff. This would encompass utilities located in the western portion of MAIN, which are primarily located in Illinois, Indiana, Wisconsin and Michigan that have the ability to interconnect directly with MAPP. For purposes of this analysis, we would include utilities that were no more than one transmission system away from a MAPP member transmission utility prior to establishment of MISO.

The other systems included are the northern SPP Region, which includes those utilities that are interconnected in Northern Kansas, such as Western Resources, Kansas City (Kansas) BPU, UtiliCorp United, and Sunflower Electric and Mid-West Electric in Western Kansas. With regard to Missouri, this Region would include most of the Western Missouri utilities such as Kansas City Power & Light (KCP&L), UtiliCorp United, Missouri Public Service and St. Joseph Light & Power (SJLP). The last two listed are subsidiaries of UtiliCorp United. This area is shown as the first map in Exhibit II-3.

This year, an alternative Market Region was considered. This region would have included utilities that are currently members of the Midwest Independent System Operator (MISO) or utilities that are likely to become members. This would have included all of MAPP plus one transmission tier, which is essentially the same definition as last year with the qualification that the MAPP area shrunk and the transmission tier got much larger with the introduction of MISO. The area would have encompassed members of the TRANSlink Independent Transmission Company (See Issue #1) that will ostensibly become part of MISO. The region described above is shown as the second map in

Exhibit II-3. This encompasses members in the areas of MAPP, MAIN, Northern portions of SPP, Western portions of ECAR and far Northwestern portions of SERC. This new region was considered because, by definition, a Regional Transmission Organization (RTO) will function as a single market.

After careful consideration and discussion with members of the Issue #1 (Regional Transmission Organization) Committee, it was decided to use the same Market Region as defined last year. The logic being that the Midwest Independent System Operator (MISO) has not yet been completely formed, nor are all the protocols and rules completely developed. The result is that Nebraska utilities and MISO do not currently function as a single market and may not do so for the foreseeable future. Perhaps in the future when MISO is completely formed and mechanisms are in place to deal with a number of transmission issues, including some considerable transmission constraints, this will be a viable Market Region. The committee will monitor this development.

3.6.2 Western Region

The size of the Region on the Western Interconnect was considered to be everything inside of WAPA's Rocky Mountain Region control area, which is headquartered in Loveland, Colorado. This region includes all of the panhandle of Nebraska (everything west of Sidney, Nebraska), including Scottsbluff, Gering, Mitchell, Morrill, Kimball, Lyman and many of the rural electric distributors, such as Chimney Rock PPD and Wyrulec Electric, which are served by Tri-State G&T; select areas of western Colorado, including the Craig Station (near Craig and Hayden, CO), and the Four-Corners region of New Mexico; the Mona region in eastern Utah, which is interconnected with many Utah municipal utilities as well as Pacificorp. Additionally, the Pacificorp transmission system, which is primarily western Montana, western Wyoming, western Utah, and all of Idaho, Washington and Oregon, is located within one transmission path of WAPA.

Exhibit II-3

Map 1 – MAPP and Utilities directly interconnected with MAPP before MISO

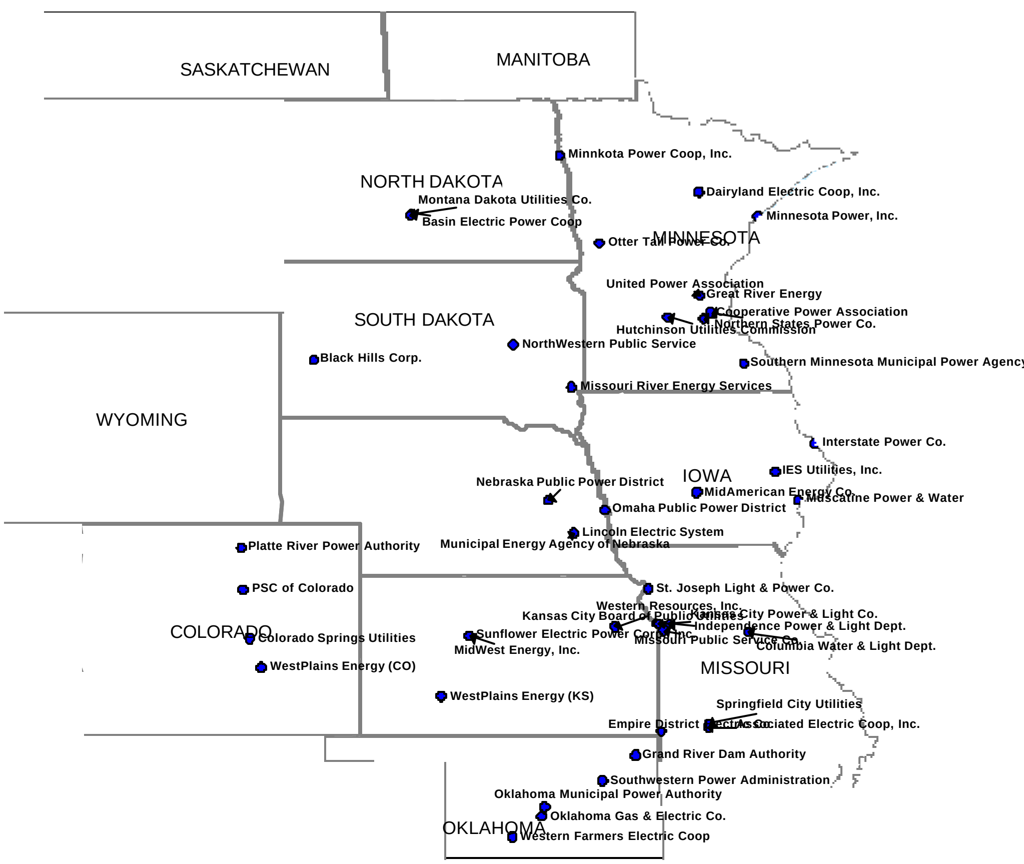
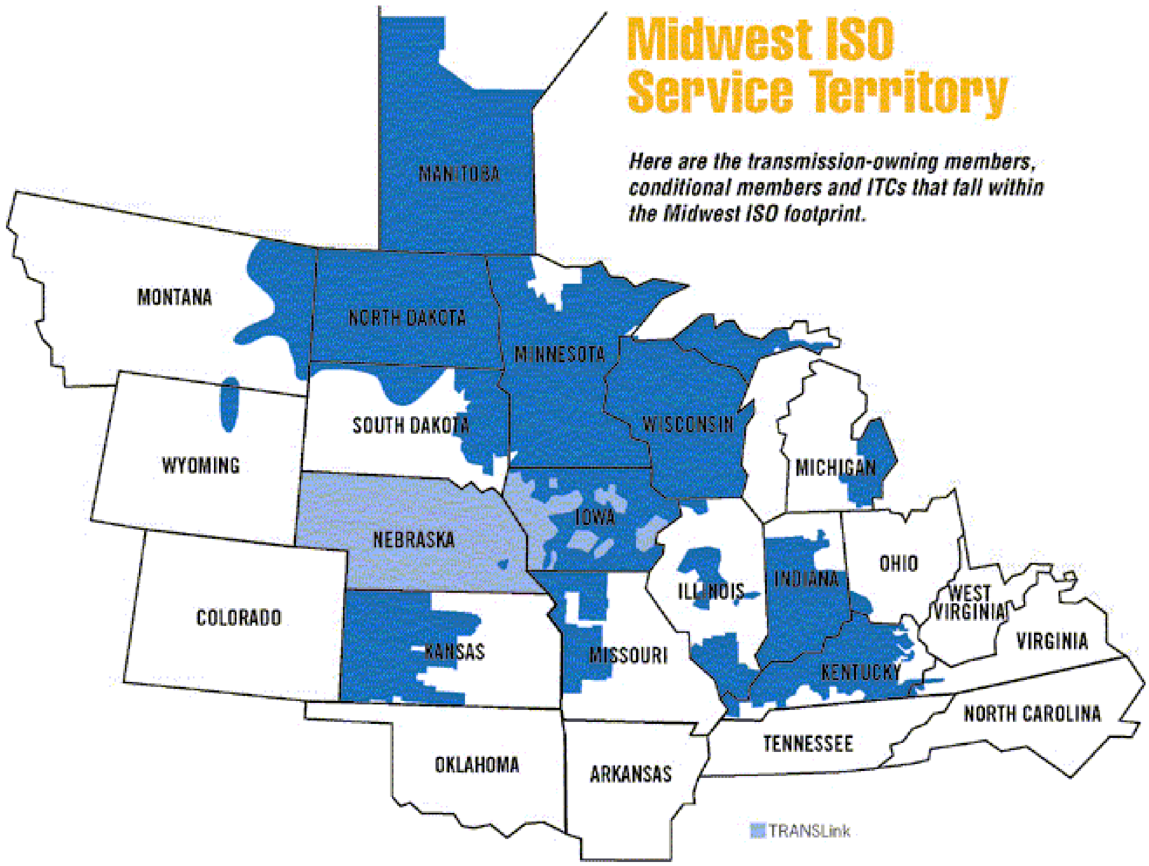


Exhibit II-3 (continued)

Map 2 – MISO service territory including TRANSlink Utilities

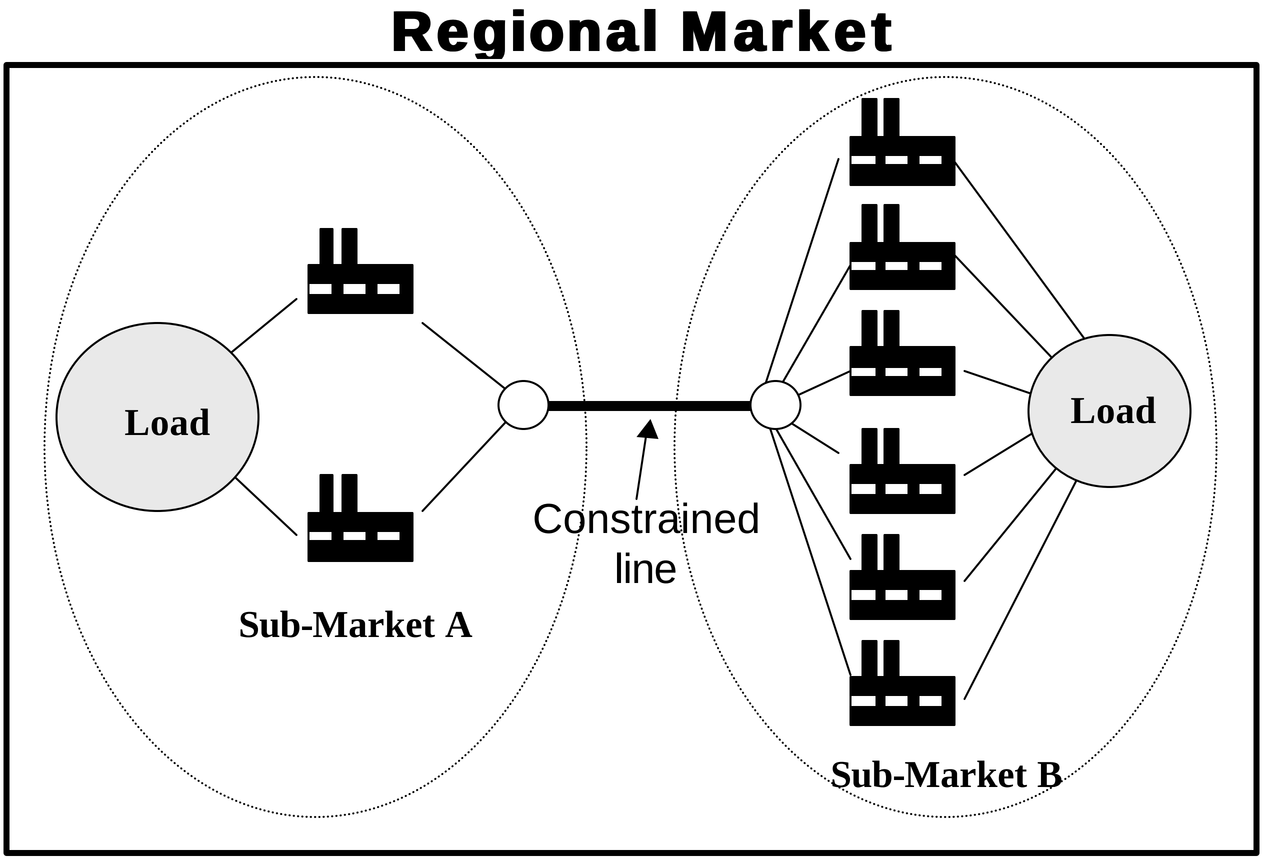


4.0 New FERC Methods for Assessing Market Power

4.1 Reasons for Instituting New Methods

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

Exhibit II-4



4.1.1 New Tests of Market Power

4.1.1.1 Modified "Hub and Spoke" Test

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

4.1.1.2 Electricity Market Models

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

4.1.1.3 Supply Margin Assessment

On November 20, 2001 FERC issued a new order entitled “ORDER ON TRIENNIAL MARKET POWER UPDATES AND ANNOUNCING NEW, INTERIM GENERATION MARKET POWER SCREEN AND MITIGATION POLICY (Docket No. ER96-2495-015, et al). The order introduced a new test for market power called the “Supply Margin Assessment” laid out mitigation measures for companies failing the test, and found a number of companies not in compliance with the order. The Supply Margin Assessment is designed to test for market power within a utility control area. A control area is defined as the area transcribed by an individual utility’s transmission system in which the utility has responsibility of balancing supply and demand of electricity and maintaining the stability of the system. FERC has stated that a utility has market power if the utility’s generation capacity in the control area is greater than the Supply Margin in the control area. The Supply Margin is defined as the total generation in excess of the peak load (reserve margin) in the area plus the total transmission capacity interconnected to the area. If a utility fails this test, FERC will judge the utility as having market power, unless the utility joins a Regional Transmission Organization (RTO). If the utility joins an RTO they are absolved of having market power by FERC. Ostensibly, this is because an RTO will have market monitoring capabilities and transmission congestion management protocols that will mitigate market power within the RTO. If a utility refuses to join an RTO, FERC has set out a number of mitigation measures including revoking the utilities ability to charge market-based rates for wholesale market transactions, as well as requiring that an independent third party operates the utility’s open access, real-time information system. With this order, FERC has migrated from the ‘hub and spoke’ method where it was relatively difficult to demonstrate market power to the Supply Margin Assessment where virtually every vertically integrated utility in the country will fail the test unless they join an RTO. In this regard, the order seemed designed to “encourage” all utilities to join RTO’s. In a dissent to the order, FERC commissioner, Linda K. Breathitt stated, “If forming RTO’s is the goal here, then we should be straightforward about that and do a rulemaking to mandate them, going through the front door and not the back door.” This FERC ruling has interesting consequences for the Conditions Certain of LB901. If one applies the FERC logic then Issue #1, “Nebraska being part of an RTO” and Issue #2 “Whether or not a viable wholesale market exists in a region which includes Nebraska” merges into one. In other words if Condition #1 is satisfied, Condition #2, by definition, will also be satisfied. If the TRANSLink ITC is accepted as part of the Midwest Independent System Operator (MISO), then the entire Eastern Region of Nebraska will be part of one RTO. By FERC’s definition, this entire region, which includes Nebraska, will therefore be free from market power.

5.0 Findings

5.1 Current Wholesale Market

5.1.1 Eastern Region

5.1.1.1 Number and Size of Sellers

There are currently 39 utilities in the market region identified in this report, with the largest single seller representing around 21% of the market as shown in Exhibit II-1. It is not unreasonable to conclude that since there are almost double the amount of buyers & sellers expected for an unconcentrated market and the highest percentage of off-system energy is around the 20% threshold, then the multitude of other buyers & sellers significantly contributes to the dilution of the market power effects of largest sellers.

5.1.1.2 Market Information

The market information that is used in the MAPP region is typically tracked on a daily basis from the sales and purchase information provided by area traders to regional and national news organizations, such as Reuters and Bloomberg. This data is reported in publications such as the 'Electric Power Daily' and BTU Daily. Other information used to track market information and market prices in the region is the Commonwealth Edison Hub, which is starting to become a fairly recognized trading point in the region. These are generally deliveries that are made to the Chicago metro region to serve electrical load. This trading point is named for the former Commonwealth Edison System that is now known as Exelon.

The Entergy price index is for a financially firm (includes Firm Liquidated Damages or FLD) energy product provided five 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, also FLD, is available under similar conditions at the Cinergy transmission system, which covers Central and South Indiana, Southwest Ohio, and North Kentucky.

5.1.1.3 Sustainability

The Eastern Region's wholesale market appears to be sustainable at current practice and market prices that either meet or exceed the expectations of those people who are trading in the marketplace. One concern is the issue of market power, since there are a small number of selling or purchasing entities in the Region. This may cause problems with the Group's definition from an available capacity standpoint and regarding an equitable balance between buyers and sellers.

5.1.2 Western Region

5.1.2.1 Number and Size of Sellers

The number and size of the sellers is significantly different in the Western Interconnect than they are in the Eastern Interconnect. As compared to the East, the West has fewer sellers and, therefore, greater market concentration. These include such parties as Public Service of Colorado (PSCo), Pacificorp and Pinnacle West, which was the former Arizona Public Service. In addition, there are many start-up marketers for subsidiaries of investor-owned utilities in the West. This includes Southern Companies' spin-off called Mirant, Idaho Power's spin-off called IdaCorp, and British Columbia Hydro's marketing arm called PowerEx. Many large marketers and investor-owned utilities from the far West continue to be very large players in the Region, such as Avista Energy and the Pacificorp marketing arm.

5.1.2.2 Market Information

In a typical year, the market information available from the Western Interconnect is similar to the data supplied in the Eastern Interconnect. In the past 12 months, the media has actively documented the hurdles faced by the Western Interconnect in their effort to meet load and capacity requirements, including the black-outs and very high purchase power costs that have occurred in California.

5.1.2.3 Sustainability

The Western Region's recent wholesale market does not appear to be sustainable considering current wholesale power market prices. Much of the higher prices and volatility has to do with a lack of available generating and transmission resources in the west.

6.0 Conclusion

6.1 Status of Viable Wholesale Market in the Eastern Region

The Eastern Interconnect wholesale market appears to be viable in that it has a large number of buyers and sellers. However, at times, it has limited access to reliable transmission access to either deliver into Nebraska loads or export from Nebraska generation, depending on system loading conditions. The market does appear to be viable since the number of buyers and sellers are adequate. Currently, transmission access is primarily available through the MAPP Schedule F Transmission Tariff that applies transmission reservation up to, but not exceeding, two years in duration. Anything beyond two years in duration must use the individual transmission provider's tariff approval, which may require some additional transmission studies by each party involved. However, any MAPP member tariff can also be used for service one year or longer. The presumption that the region will be served by the Midwest Independent System Operator, which will migrate to a standard transmission tariff, manage congestion and monitor the members for market power suggests that this viability will be maintained in the future. FERC's new "Supply Margin Assessment" order has, in fact, stated that, with utilities joining the RTO, there will be no market power as FERC defines it.

It is not unreasonable to conclude that, since there are almost double the amount of buyers & sellers expected for an unconcentrated market, and the highest percentages of off-system energy is approximately 20% out of these remaining buyers & sellers, then the multitude of other buyers & sellers significantly contributes to the dilution of any market power effects.

Since Nebraska's electricity supply is cost-based and customer-owned, there is considerably less volatility than that of the regional indices, which are based on the hourly, daily and monthly wholesale spot market.

If one applies the FERC logic then Issue #1, "Nebraska being part of an RTO" and Issue #2 "Whether or not a viable wholesale market exists in a region which includes Nebraska" merges into one. In other words if Condition #1 is satisfied, Condition #2, by definition, will also be satisfied. If the TRANSLink ITC is accepted as part of the Midwest Independent System Operator (MISO), then the entire Eastern Region of Nebraska will be part of one RTO. By FERC's definition, this entire region, which includes Nebraska, will therefore be free from market power.

6.2 Status of Viable Wholesale Market in the Western Region

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

There could be considerable economic implications to Nebraska utilities if large coal-fired generation units are unavailable, de-rated or off-line to western Nebraska utility members, which includes primarily MEAN which serves most of the municipals in western Nebraska, and Tri-State G&T in Westminster, Colorado, which serves all of the rural electrics in the panhandle of Nebraska.

Chapter Three

"To what extent retail rates have been unbundled in Nebraska"

1.0 Purpose

Technical Group #3, has been tasked with determining "To what extent retail rates have been unbundled in Nebraska." Although the group's purpose is to determine to what extent retail rates have been unbundled in Nebraska, it is also important to provide background and some insight into the possible impacts of the process on the consumers, utilities and other businesses in Nebraska.

The purpose of this document is not to debate the merits or problems with deregulation, but to identify the current status of unbundling in Nebraska and to give the reader a better understanding of the complexity and cost for the current infrastructure to unbundle. It is important to note that all the effects of retail competition are very hard to predict as each state that has moved to competition has different issues and concerns. The overall impact on Nebraska is also hard to predict, as it is the only state that has 100% consumer-owned electric utilities.

2.0 Team Members

Jay Anderson	Omaha Public Power District
Rich Andrysik	Lincoln Electric System
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Jim Gibney	Wahoo Utilities
Jamey Pankoke	Perennial Public Power District
Marv Rief	Nebraska Public Power District
Donna Starzec	Nebraska Public Power District

3.0 Introduction

3.1 What is Unbundling and Why Would Anyone Do It?

LB901 defines unbundling as "the separation of utility bills into the individual price components for which an electric supplier charges its retail customers, including, but not limited to, the separate charges for generation, transmission, and distribution of electricity."[1]

There are various reasons why utilities may unbundle electrical service. The most compelling and the main reason that a utility unbundles is due to state statute or regulatory rule as part of a comprehensive deregulation plan. "The unbundling of retail electricity related services is a means to achieve direct access between consumers and competitive electricity supply. The overall objective of direct access is to reduce the total cost of electricity to society. Unbundling is therefore a means to develop a framework to facilitate consumer choice such that the overall costs 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 rates, so consumers are not pushing for deregulation. However, some consumers are requesting unbundled billing information to compare the costs of individual components of their energy bill with those costs in their facilities in other states. This process on its own may cause other utilities in Nebraska to have to unbundle as customers may begin to ask for comparisons at the same level that they are receiving in other states.

4.0 How Electricity Related Services Could Be Unbundled

An excellent description of "How Electricity Related Services Could Be Unbundled" was included in a paper written by Dr. Artie Powell, a Utah Division of Public Utilities Economist, in May of 1998.

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[1] State of Nebraska, Legislature of Nebraska, Legislative Bill 901, (Lincoln, Nebraska, 2000) p.3.
[2] Dr. Artie Powell, Utah Division of Public Utilities position paper presented to Utah Public Service Commission, Unbundling Electricity-Related Services (Utah: 1998) p.1.

> "In the states that have unbundled retail electricity services or are in the process of unbundling retail electricity services, the following process generally occurs.
>
> By statute or regulatory rule, electricity customers are permitted to choose their electricity supplier by a specified date. Prior to that date, a process is initiated to identify distinct components of electric service. Following public comment and an order or rule identifying distinct components of electric service, the affected utility companies are then ordered to file the separate, unbundled costs associated with each service component as well as appropriate cost allocation methods. Following a formal hearing process, an order is then issued establishing tariffs for each distinct component of electric service. Generally, the resulting tariffs enable electric service providers, other than the incumbent provider, and consumers to engage in transactions for electric service.
>
> For many of these distinct electric services, the separate, stand-alone cost for providing the service has not previously been identified in the electric industry. Hence, the need for a technical hearing on direct cost and allocation of indirect cost to that service.
>
> This formal procedure, i.e., initial order or statute, industry filing, public comment, formal hearing, final order on tariffs, etc., was also used by the Federal Energy Regulatory Commission in establishing unbundled tariffs for wholesale and transmission electric services.
>
> This approach has also been used in the telecommunications industry. The federal telecommunications act ordered local telephone competition and delegated to the Federal Communication Commission the task of identifying "unbundled network elements" and establishing general pricing guidelines. It has then been the task of the state public service commissions to approve rates for unbundled network elements.
>
> In the gas industry, the retail unbundling process has generally been initiated by the regulated utilities, which file for approval of unbundled tariffs before the appropriate state regulatory body. This filing initiates a formal proceeding to identify service components and set rates.
>
> Utilities which are not subject to state regulation, are generally exempted from restructuring and unbundling requirements, at least initially. However, if they choose to participate in a competitive retail electricity market, then the restructuring and unbundling process is required.
>
> One common theme in state proceedings to date is the notion that unbundling is an evolutionary process that may not be resolved in the first go around. The issues are complicated, controversial and cost assignment to services governed by joint production decisions is difficult. Many states begin by identifying the principles and objectives of unbundling. Ultimately, accounting, cost-allocation, economics, and engineering details must be addressed and legal discussion ensues to define requirements for default service and obligation to serve."[3]

Utilities that have unbundled have grouped costs in a number of categories. The most basic are distribution, generation, and transmission. These are the distinct components that are then separated out on the customer's bill, and the cost associated with each particular component is shown. These and other unbundled categories used around the country are listed here:

Distribution Charge
Generation Charge
Transmission Charge
Customer Charge
Competitive Transition Charge
Meter Charge
Public Purpose Programs

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

Nuclear Decommissioning
Trust Transfer Amount
City Tax
State Tax
Franchise Fee
Stranded Cost
Delivery Charge

5.0 Consumer Information And Education

The unbundling process makes electricity bills more complex. To deal with the complexity the consumers need to be educated. Consumer information and education is critical in rolling out rate unbundling, or for that matter, any other precursor to retail competition. After all, if the end goal is to provide better service at lower costs to consumers, then it is imperative that consumers be knowledgeable in the choices they make in order to achieve that goal.

Most states have adopted provisions to inform electric consumers of the market changes and the options that will be available to them. In states already operating in some sort of deregulated environment, special emphasis was placed on residential and small business consumers with the idea they were the least knowledgeable about the components of their electric bills. If these classes of consumers are already the least knowledgeable about their electric bills in their current state, the risk is that they may be confused, or misled, by unbundled electric billing. Clearly, a well thought out consumer education effort will be necessary for any such unbundling effort to be successful.

Even though Nebraska may be able to learn from, or even copy, the processes and content of consumer education programs in states which have already undergone some sort of deregulation or restructuring, the cost of rate unbundling consumer education will still be substantial. Decisions on who will be responsible for this communication will need to be made, i.e., a state agency to provide consistent, impartial information; or mandate utilities to provide required content. Whichever path is chosen, the cost of consumer education regarding retail competition has been allowed to be recovered through transition charges.

6.0 Consumer Choices

As described above the overall purpose of unbundling is to allow the consumer to have the information necessary to choose which energy price is better for the consumer. The mere unbundling of utility bills is complex enough, but then add the complexity of marketing choices that competition often brings and the complexity reaches a new level. As the consumer compares offers from multiple energy service providers it may become apparent that the energy service providers have different offers based on what it costs them to serve the customer and the return that the company requires to stay in business. The consumer may wonder why this is and why the offers are different as they are both providing the same commodity.

A good example of this is the variety of pricing options that the long-distance phone companies have started to offer. One phone company may offer $0.10 per minute charges, but have a $5.00 minimum. Another company offers $0.14 per minute, but gives the consumer a check for $100.00. Yet another may offer free Internet service if you sign up for their plan of $0.20 per minute. Indeed the choices resulting from competition did not get easier, but there is more variety than there was before. Long distance service is one portion of this, as the consumer still has to pay for local phone service. This local service is usually offered by one company and the billing for this service has become more complex in its own right as there are various new charges on the bill that are broken out to inform the consumer.

7.0 Local Distribution Companies

Many people hear of deregulation and think that if it occurs their local utility will go away. The local utility may not exist in its current form; however, the lines that serve the consumers will still be the same lines. If Nebraska moves to retail competition there will be companies from outside of Nebraska that may offer electric services in the state. These energy service providers would be allowed to compete to sell energy as in most states that go to deregulation. The local distribution company that delivers electricity to your house would more than likely remain the same, as this is not a service that lends itself to competition. This is similar to your local telephone company to which you pay a monthly bill for local phone service. Because this service can not be economically offered by others (e.g. it doesn't make sense to have two or three separate companies running wires down the road to serve the same customers) a governing board often regulates what these companies can charge the consumer, as there is no competition.

8.0 Cost Allocation And Comparison

Unbundling exposes costs for each and every service the utility provides. Assuming that the costs are being generated for the reason of providing some type of service to the consumer, one could say the functional pieces of the utility that provide various services to the consumer are exposed. The transparency required for unbundling costs and services are really a double-edged sword. Although it will give more information, this information will not come for free. The information to functionally unbundle is often more detailed than most utilities are required to keep in the current environment.

There are 162 entities in Nebraska which own one or all of the three functional parts of the electric business: generation, transmission, and distribution systems. Although a majority of these entities operate distribution systems only, they bill generation, transmission, and distribution functions as one combined charge. While utilities generally classify expenses in a way that allows them to separate core functions, there are other parts of the business, such as support divisions of the company, that do not provide a direct service to the consumer, but support the other parts of the company. These costs will have to be allocated and reflected in each part of the unbundled rate to make sure that the entities recover all the costs of doing business.

Municipal power suppliers may encounter even more complexity than other types of utilities. There are 122 municipal electric utilities in Nebraska. Most of them are quite small, and provide a number of municipal services in addition to electricity. In many cases, water, sanitary sewer, solid waste collection, and natural gas service are billed along with electricity service. This creates billing congestion. It also places a burden on small communities' computer hardware, software, and accounting resources. There is only so much accounting and billing service a small community utility can affordably provide to its customers. In many cases throughout Nebraska, required unbundling of electric bills would place a heavy burden on many communities who have chosen to keep their billing methods simple and inexpensive.

8.1 Reallocation Of Costs Among Classes

Once costs are unbundled, costs between rate classes will be compared at a lower level than they are currently. This cost comparison may lead to challenges by customers in various classes. The process of unbundling, coupled with a competitive environment, will prompt utilities to reallocate some costs to different customer classes to accurately reflect the cost of service and eliminate cross subsidization.

9.0 Explicit And Implicit Costs

9.1 Transition Costs

There is no doubt that if deregulation is instituted in Nebraska, many utilities will incur significant expense to meet the requirement of unbundling. Utilities may be required to hire more personnel to maintain cost records; consumers will have more questions that will require more people to answer calls; and current billing systems will need to be changed to allow new billing formats. The cost for this process will have to be passed on to the consumer in some way as the current funding for these activities comes from the ratepayers.

9.2 Stranded Costs

Stranded costs represent investments made and obligations incurred by a utility in a fully regulated environment that will not be recoverable in a fully competitive environment. Stranded costs include stranded assets, stranded liabilities, and stranded benefits. At the current time, Nebraska still maintains low wholesale pricing, indicating a low likelihood of net stranded cost on a statewide basis. However, this is subject to change, as the amount of stranded costs depends on a variety of variable conditions such as wholesale power market price and the value of potential stranded assets. If stranded costs exist at the point where deregulation occurs, these costs will have to be addressed and applied in some reasonable manner to the consumer's bills as a separate line item or absorbed by the utility that incurred them (see Section 4.0).

10.0 Consumer Issues
10.1 Public Vs. Private
Locally rate-regulated public power utilities in Nebraska are governed by certain "sunshine" laws that make their operation and governance unique in the energy industry. Public power utilities are required to conduct their policy-making meetings in public. In Nebraska, city councils, boards of directors, or boards of public works are the norm, with all records open to the public. In a competitive environment the ability of competing energy service providers to access such information may provide them with a competitive advantage.

10.2 Consumer Information
There is some discussion whether or not public power utility customer records are indeed "public records." At issue is the question whether public record laws "trump" customers' right to privacy. In at least one recent major case, a state supreme court effectively ruled that the right to privacy of customers of public power utilities was less-important than the utilities' obligation to make known their names, addresses and telephone numbers.

> "The Supreme Court of Tennessee ruled that the municipal electric utility in Nashville must provide the local newspaper with a computerized list showing the names, addresses and telephone numbers of all its customers…In its November 16, 1998 ruling, the Supreme Court said the information constitutes a public record and must be provided to the newspaper, even if the utility has to write a special computer program to do this."[4]

If public power utilities, as a result of deregulation, were forced to share customer account databases with other energy service providers, this sharing may give competing energy service providers an unfair advantage in any future competitive environment, unless the other energy service providers were also required share their customer information. Moreover, such "public records," combined with unbundled billing data would enable "cherry-picking" -- selectively marketing to customers with certain attractive load characteristics. The incumbent utility would have little competitive advantage other than incumbency.

11.0 Uniform Business Practices
If deregulation were to occur in Nebraska many decisions will need to be addressed. Many of these issues are related to unbundling, but not in our direct area of focus for this report, "To what extent retail rates have been unbundled in Nebraska." As states have begun to move to deregulation many of these states have developed their own rules to govern business transactions. Nebraska would likely go through a similar process. In September, 1999, the Edison Electric Institute (EEI), Coalition for Uniform Business Rules (CUBR), National Energy Marketers Association (NEMA) and the Electric Power Supply Association (EPSA) announced a partnership to develop a "consensus driven set of uniform business practices (UBP) for competitive electricity markets."[5] The group released a two-volume set on uniform business practices in December 2000. Volume I offers "recommended guidelines" on a number of issues that arise in newly competitive retail energy markets. In particular, "Volume I addresses the issues of customer information, customer enrollment & switching, billing & payment processing, load profiling, supplier licensing, market participant interaction, disputes between the utility and the supplier, and customer inquiries."[6] Volume II addresses unbundled electricity metering. The main reason that this effort was undertaken is best stated in the December 7, 2000 news release from the Edison Electric Institute. According to Mike McGrath, Group Director of Customer and Energy Service for the Edison Electric Institute, "Uniform business transactions may help lower barriers to market entry, encourage new product lines, reduce utility distribution company system costs to accommodate retail access, and give customers more price and product benefits."[7] McGrath goes on to state

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[4] Public Power Weekly, 7 December 1998: No. 98-49

[5] "Energy Groups Join Forces to Develop Uniform Business Practices," Edison Electric Institute News Release, 29 September 1999: p.1.

[6] "Business Group Releases Final Report on Retail Energy Markets," Edison Electric Institute News Release, 7 December 2000: p.1.

[7] Ibid.

that, "The ultimate audience for this effort is the regulatory community that is working to develop market rules in their respective states."[8] "Regulators in New York, Virginia and several other states have already begun to consider the UBP report in their deliberations. By offering the views of the collaborative group on many difficult issues-including areas where the parties reach consensus- the UBP group hopes the report will facilitate the regulators' considerations of the issues."[9] As mentioned above, some of these issues are out of our preview and many of the issues that have been touched upon in this report are related to such business practices. These business practices will have a significant impact upon all participants if deregulation occurs and should be weighed in any deregulation effort.

12.0 Status In Nebraska
12.1 Survey Results

As stated in the LB901 text, Technical Group # 3 is to determine "To what extent retail rates have been unbundled in Nebraska." To accomplish this task the Group assembled a survey and mailed the survey out to 162 entities that retail electricity in Nebraska, according to Department of Energy[10]. Our Group received a response rate of 74.1% representing 97.4% of customers and 98.2% of total Mwh sales to ultimate consumers. The study basically found these main points:

--Only one utility has formally unbundled.

--The majority of utilities do not have unbundled cost of service studies.

--Half of the utilities' billing systems will accommodate unbundling.

--Over half of the utilities believe they have enough information to unbundle.

--70% of utilities stated that they would not unbundle unless mandated.

The detailed information from the surveys was included in the 2001 LB901Report.

13.0 Cost to Unbundle Electricity Bills in Nebraska
13.1 Introduction

For the 2002 report, Technical Group #3 was requested to estimate the cost that would be incurred if retail electricity bills were to be unbundled in Nebraska. The Group's main duty was to determine what the total cost for unbundling in Nebraska would be, should the Nebraska electric utility industry open to competition. As previously stated in the report, the costs associated with moving to retail competition are very hard to predict, because each state has a variety of different issues and concerns to be addressed. Because of such issues that are out of this Group's scope, the Group chose to produce this report to present information regarding the estimated costs for unbundling bills in Nebraska for informational presentation purposes only. It is not intended to estimate the total cost of deregulation.

Separating unbundling from deregulation is very complicated. Deregulation impacts the unbundling process, so when determining the costs to be included in unbundling, which is a small piece of the deregulation process, certain assumptions were made. Various items determined to be unbundling costs were obtained from the entities listed below under Cost Estimation Methodology. The entities completed a spreadsheet with the costs that would be incurred by them. The individual results were then accumulated into categories, and a statewide total cost to unbundle was estimated.

In states that deregulate, a statewide consumer education program is usually needed to communicate to the consumer a new billing process. Costs used in this analysis were determined by calling various states to get the actual costs they incurred. Again each state varied, due to the different issues involved, and the demographics in their particular

[8] Ibid.
[9] Ibid.
[10] Energy Information Administration, Department of Energy, "Table 17: Class of Ownership, Number of Ultimate Consumers, Revenue, Sales, and Average Revenue per Kilowatt-hour for All Sectors by State and Utility," (1999) (http://www.eia.doe.gov/cneaf/electricity/esr/esrt17p28.html).

state. The Group determined a per-customer cost of $1.36 (based on Pennsylvania's actual cost per customer) and applied it to the number of customers in Nebraska. Each public power entity will need to determine whether additional consumer education is needed in their area.

13.2 Cost Estimation Methodology

The cost estimates determined are highly speculative and subject to many assumptions. Because there is no state level 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 Group used information from the Nebraska Municipal Power Pool (NMPP).

Assumptions were made when determining the costs for municipalities. The Group assumed three major cost components, which were software, hardware, and rate case analysis/development. The costs were based on information received from NMPP. NMPP currently has a reasonably priced integrated business accounting and utility billing software program that has the ability to create unbundling bills. From NMPP's information, the Group then determined the software cost, and applied it to the total number of municipalities. This cost was based on NMPP's current price to purchase software, train employees, and install this software. The Group then assumed some of the municipalities would need to purchase new hardware before this software could be installed. The cost estimate used for the rate case analysis/development is based on prices received from NMPP for these services.

Once these costs were gathered, the costs were broken down into the various categories listed below.

Set-up Expense: The total one-time cost that would be incurred would be approximately $7 million for set-up expenses.

- Evaluation and planning of current system hardware and software
- New system hardware and software
- New System set-up and testing
- Program and testing of existing systems
- Cost for rate design
- Training costs

On-going Expense: The total cost incurred would be approximately $1 million annually.

- Additional bill printing expenses
- Call center questions

Statewide Consumer Education: The total cost to educate the consumers would be approximately $1 million for the State of Nebraska.

- Consumer education was based on the number of customers in Nebraska. The cost used in this analysis would vary considerably, based on the how much education the state of Nebraska would require. Each public power entity would also have to make a determination regarding how much education the entity feels is required to inform its customers about their new unbundled bills in their area.

13.3 Comparison to Other States

The cost to educate consumers can vary in each state. A representative from our Group called several public utility commissions to gather consumer education costs associated with states that have deregulated. Any additional dollars spent by utilities is not included.

The public utility commissions and the costs include: Illinois Commerce Commission - $1.0 million, Maine PUC – $1.3 million, Connecticut PUC $7.5 million, Michigan PUC $30 million, Texas PUC - $36 million, Pennsylvania PUC - $65 million, and California PUC - $82 million.

Each state varied considerably based on the different issues and concerns in their state. Some of the variables include factors such as a statewide network computer system, education, or stranded costs, while other states do not include these.

As stated, the report shows costs for unbundling only. The unbundling portion is only a small part of the total deregulation costs, evidenced by the magnitude of the costs associated with unbundling and consumer education in each state. The Group is not discrediting the deregulation process, but merely stating the magnitude of the costs associated with it.

States vary regarding how many line items to unbundle on the bill, and what costs should be in each line item. As illustrated in the 2001 report, among the states that have deregulated, there are differences in the bill presentation/level of unbundling. A determination of the level of unbundling for the state of Nebraska has currently not been made. However for purposes of this section, we assumed generation, transmission, distribution, a customer charge, and up to two other items would be included, i.e. probably no more than 5-6 line items.

13.4 Scope Considerations

Unbundling is usually part of a deregulation effort. Unbundling is only a small portion of the total deregulation costs incurred in each state. The statement below was included in the paper written by Dr. Artie Powell in which he explains the unbundling process. This statement was previously included in the report:

> "The process regarding unbundling occurs after a formal statue or regulatory rule, and electricity customers are permitted to choose their electricity supplier by a specified date. Prior to that date, a process is initiated to identify distinct components of electric service. Following public comment and an order or rule identifying distinct components of electric service, the affected utility companies are then ordered to file the separate, unbundled costs associated with each service component as well as an appropriate cost allocation method.
>
> One common theme in state proceedings to date is the notion that unbundling is an evolutionary process that may not be resolved in the first go around. The issues are complicated, controversial, and cost assignment to services governed by joint production decision is difficult. Many states begin by identifying the principles and objectives of unbundling. Ultimately, accounting, cost-allocation, economics, and engineering details must be addressed and legal discussion ensues to define requirements for default service and obligation to serve."[1]

There are many factors outside the scope of the Group, some of which would include: (See Section 14.0 for a detailed explanation.)

- Dynamic data exchange
- Qualified suppliers
- Public Utilities Commission vs. Nebraska Power Review Board
- Competitive services
- Provider of last resort
- Universal service

13.5 Conclusion Regarding Unbundling Costs

There are many major issues that are out of the scope of Technical Group #3 and that will need to be addressed in the deregulation process. These issues will impact the final cost to unbundle bills in Nebraska. Resolution of such issues cannot be made by this Group, but are essential to estimating the final overall costs of unbundling.

These unbundling cost estimates are presented for informational purposes only, and further analysis would be needed should deregulation occur. A total deregulation effort would cost much more that the unbundling costs shown here.

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

14.0 Scope Consideration Descriptions

14.1 Dynamic Data Exchange

Communication system that allows data to be shared between companies. (example: local telephone carrier allowing billing usage information to be shared with a long distance carrier)

14.2 Qualified Suppliers

Each supplier must be certified by the State before they are allowed to transact business.

14.3 Public Utility Commission vs. Nebraska Power Review Board vs. Local Boards

Currently each public power entity, town, and co-operative agency has their own central rate making authority.

14.4 Competitive Services

Usually in states that deregulate, suppliers are allowed to compete for business. Companies are allowed to bid specific services that were previously provided by the incumbent utility. (example: meter reading services)

14.5 Provider of Last Resort (POLR)

A provider of last resort is a "back-up" utility provider that can provide your electric service. Consumers have the right to choose the supplier of their choice. If a consumer does not choose a supplier, or a chosen supplier denies service, electricity will be supplied by a local utility supplier.

14.6 Universal Service

Ensuring that everyone has access to enough electricity to meet their needs and that it is available at affordable rates that are just and reasonable for all residents of the State.

15.0 Description for Each Cost Breakdown for Unbundling

15.1 Initial Costs

15.1.1 Evaluation and Planning

This would consist of the time and cost involved to evaluate and plan for an option that would allow the entity to produce unbundled bills. The options to plan and evaluate would be:

- Program current system: This would be the time and cost involved in determining if the current system is capable of unbundling.

- Upgrade to a new version of software from existing vendor: This would be the time and cost involved to determine if purchasing a new version of software from the current vendor will meet the unbundling needs.

- Purchase new software: This would be the time and cost included in selecting new software that would be needed to meet the requirements for unbundling.

- Make the changes necessary to an existing system capable of unbundling.

15.1.2 New System Software or Upgrades

This would be the actual cost to purchase new or upgrade software for the unbundling process.

15.1.3 Hardware

New hardware may be required for unbundling. This would include the cost to purchase equipment such as computers, printers, etc.

15.1.4 System Setup and Testing

These costs would include the time and expense to install, test, and implement the changes to the existing or new software system.

15.1.5 Program Existing System

If the choice was made to upgrade the existing system, how many hours and what cost would it be for individuals to program the current system? Because unbundling requires items to be broken out separately on customer bills, additional lines will be needed to print on the bills. Therefore, what would be the total cost to make these changes?

15.1.6 Testing of Software/Hardware

Once all the rates are implemented, what would be the cost involved in testing the new or existing software or hardware that was purchased for unbundling?

15.1.7 Rate Design

This would include employee payroll costs, consultants, and any other expenses required for unbundling the rates. Also include any cost associated with testing to make sure the new rates recover desired revenue.

15.1.8 Training Costs

15.1.8.1 Entity Training

Call Center Training/Customer Service Training: Cost to train the Call Center personnel and Customer Service representatives to answer customer questions regarding unbundling.

Estimated Cost for "Consumer Education": This would include TV and radio advertising, newspaper ads, billboards, and any other type of advertising used to educate consumers regarding unbundling. This would also include the cost to produce, print, and distribute the brochures about unbundling. The cost would depend on the number of customers in each public power entity, and the type of brochure produced.

15.2 On-going Expenses

15.2.1 Bill Print Additional Pages

Additional pages will be required to print the customer's invoice with unbundling charges broken out. Some customers will have many more pages than before unbundling was implemented. Some public power entities previously printed bills on small post cards, and because of the additional printing associated with unbundling, they may be required to print on a larger invoice. This will be an additional expense each month in supplies, such as paper, postage, and toner.

15.2.2 Call Center Questions

Customers will have many questions about unbundling charges on their bills on an ongoing basis. This cost should include the additional time each month to answer unbundling related questions.

15.2.3 CIS Annual Maintenance

This is an estimate for the annual maintenance for the Customer Information System required for unbundling.

15.3 Statewide Consumer Education

This would be the cost for a total statewide education program for Nebraska (we obtained the estimated costs based on information from other deregulated states). The $1.36 estimated cost per customer was based on information received from Pennsylvania and applied to the number of customers in each public power entity in Nebraska.

Chapter 4

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

1.0 Introduction
1.1 Purpose and Group Membership

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

Clint Johannes (Chair)	-	Nebraska Electric Generation & Transmission Cooperative, Inc. (NEG&T)
Bruce Abernethy	-	Lincoln Electric System (LES)
Deeno Boosalis		Omaha Public Power District (OPPD)
Doug Erickson	-	The Energy Authority (TEA)
Kevin Gaden	-	Municipal Energy Agency of Nebraska (MEAN)
David Ried	-	OPPD
Barry Campbell	-	Nebraska Public Power District (NPPD)
John Krajewski	-	MEAN
Derril Marshall	-	Fremont Utilities
Allen Meyer	-	Hastings Utilities
Burhl Gilpin		Grand Island Utilities

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

1.2 Approach

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

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

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

2.0 Wholesale Market Terminology

2.1 Market Product Definitions

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

The “ Monthly Forward Price” of an asset is the price established today with a non-exchange traded bilateral contract, for delivery of the asset on a designated future date at a specified location (“hub” or “market”). The “Monthly Futures Price” is a contract associated with a particular “hub” or “market” for future delivery of a commodity, exchange traded (physical delivery is possible, but not required).

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

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

2.2 Comparison Concepts

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

2.3 Physical Product Definitions

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

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

2.4 Market Product Time Period

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

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

2.5 Market Product Categories

The market also divides its products into categories that are defined by guaranteed and non-guaranteed availability. If the market guarantees availability it is called "firm." This "firmness" is either backed up by a pro-rata cost share of physical capability (either cost of new capacity or fixed cost of existing capacity), or the promise of money – FLD to compensate for possible additional costs to procure energy. If the customer will accept non-guaranteed availability conditions, then the price of this "non-firm" product is usually lower because the customer is sharing the risk of availability with the market, and does not need to compensate the market for guaranteed physical capability. It should be noted that these blocks of power are provided at a fixed amount, 100% of the time within the time periods, and is termed a "100% Load Factor" product. Few end-use customers require this amount of power all the time; however, the market product is priced as such since the current market price index mechanisms do not account for varying customer load patterns. For example, within a period of a year, a typical residential customer has a lower need for electrical power, as demonstrated with a "load factor" of less than 50%, whereas a commercial customer, such as a grocery store would typically be between 50 & 75%. Industrial customers load factors typically range in 60% - 95%, depending on the type of production process involved. However, on the other end of the scale, an irrigation customer may only have a load factor of 10-20%, because of the limited amount of time within a year the energy is required.

2.6 Market Price and Production Cost Difference

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

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

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

2.7 Market Price Volatility and Production Cost Stability

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

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

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

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

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

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

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

2.8 Market Product Price

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

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

2.9 Transmission Cost & Loss Considerations

As described in the 2002 documentation update for Technical Issue 2, the Midwest Independent System Operator (MISO) transmission region covers a larger geographical area than the previous Mid-continent Area Power Pool (MAPP) transmission region, thereby increasing the physical delivery costs & losses associated with moving market-priced electricity products to the customers within the state of Nebraska. Currently, electricity traders are experiencing as much as 17% in delivery losses, which add similar percentages to the price of a market product. Also, the standard market transmission tariffs associated with delivering these market products from external regions to Nebraska customers can add an additional $4 to $ 6 per 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" are provided in the attached Appendix 4-A. The "reserves", the long-term "obligation to serve", and "Ancillary Services" should be accounted for in the comparison methodology for market prices and Nebraska costs.

2.14 Load Factor Considerations

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

3.0 Market Product Pricing & Nebraska Production Cost Comparison Methodology

3.1 Alternative Comparison Methods

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

(1) Send out a Request for Proposal (RFP) on electricity products to serve customers on the exact same basis as currently served,

(2) Purchase a regional electricity price application model from a vendor to determine an estimated market value,

(3) Develop a fixed and variable cost allocation tool to determine Nebraska's "cost to provide" electricity that is on an equivalent basis with market products that have price indices and are publicly available, independent and credible.

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

(1) The RFP could be perceived by the market as a price discovery process only, so the respondents may not provide "real" bids, or the prices offered may be extremely low initially just to gain market entry. This implies that the prices would not be truly reflective of market value, and the process involved would be extremely time-consuming and labor-intensive to develop the RFP, let the bids, and evaluate the bids on an equitable basis just for price comparison purposes,

(2) Purchasing a regional electricity price application model from a vendor would be cost prohibitive with an estimated cost of up to $300,000 depending on level of detail and service provided, also the set-up and training required to determine equivalent electricity products could be labor-intensive,

(3) The self-developed tool approach allows for all of the Nebraska power systems to have input on how the model should work to equitably compare costs and prices; fixed and variable cost allocations can be determined by each utility on the same basis as a market product for appropriate matching; the contract-sensitive data remains confidential; the modeling can be applied quickly and efficiently for each utility and then consolidated easily for a single state-wide result; the costs are minimal, and there is Nebraska utility acceptance of process and results.

3.2 Comparison Modeling Tool Detail

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

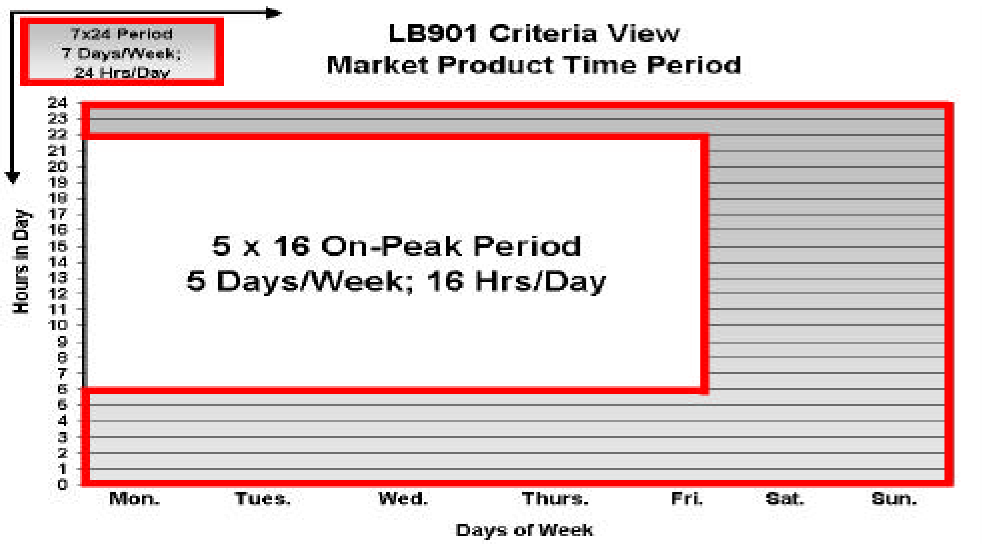
(1) Determine the total annual production revenue requirements for all the Nebraska utilities' power resources,

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

(3) Break down the total cost to serve (as determined in (2) above) to an hourly basis to determine a cost per hour to serve each utility's load based on an hourly load shape for each year (typically 8760 hours per year), which is accomplished by appropriately allocating the fixed and variable costs on a per hour basis to each utility's load that each utility is obligated to serve by weighting the costs on a MWH per year or market price basis, by time period (Peak and Off-peak), calculating an hourly $/MWH cost to serve load in each of the 8760 hours of the year,

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

Exhibit IV -1


LB901 Criteria View
Market Product Time Period
7x24 Period
7 Days/Week;
24 Hrs/Day
5 x 16 On-Peak Period
5 Days/Week; 16 Hrs/Day
Hours in Day
24
23
22
21
20
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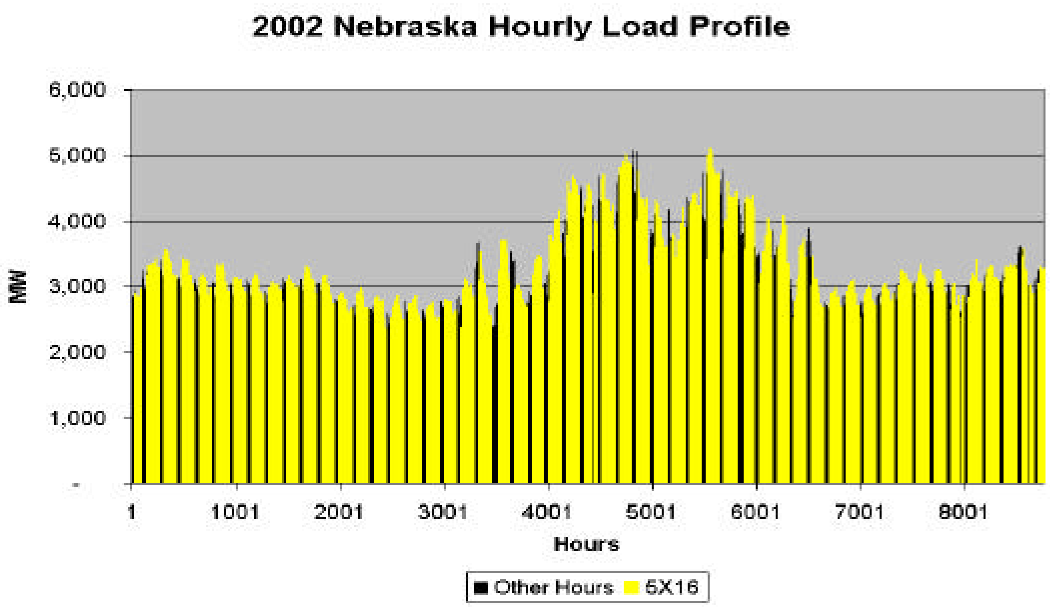
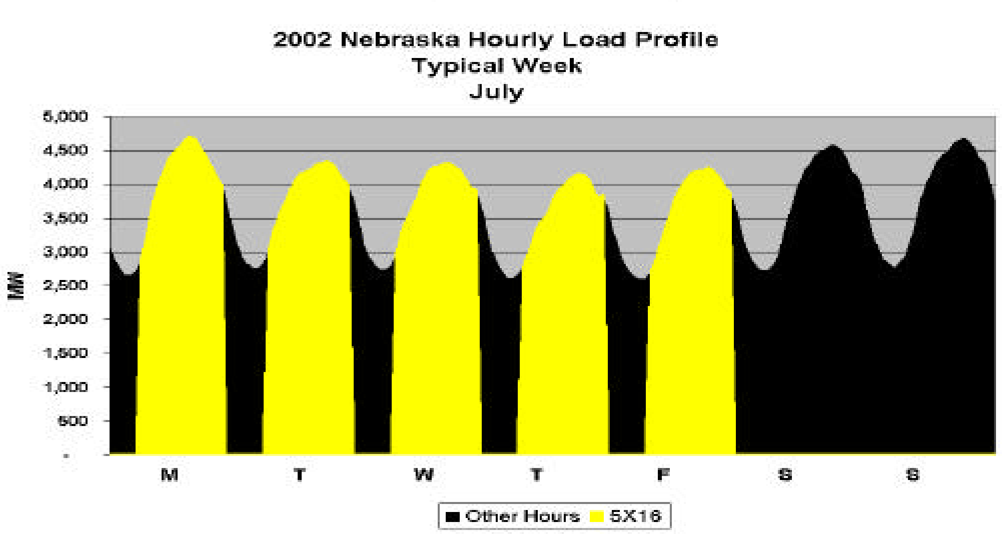
Mon.
Tues.
Wed.
Thurs.
Fri.
Sat.
Sun.
Days of Week


2002 Nebraska Hourly Load Profile
MW
6,000
5,000
4,000
3,000
2,000
1,000
-
1
1001
2001
3001
4001
5001
6001
7001
8001
Hours
Other Hours
5X16


2002 Nebraska Hourly Load Profile
Typical Week
July
MW
5,000
4,500
4,000
3,500
3,000
2,500
2,000
1,500
1,000
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M
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Other Hours
5X16

3.3 Comparison Modeling Tool Application

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

(1) Costs and prices were compared on a total annual amount calculated per month for an equivalent 100% load factor, 5 x 16 market product since there were a multitude of market price indices available for this type of product,

(2) Both "average" and "median" monthly market price history were calculated based on the daily price settlement indices utilizing the raw data from 'Platt's Global Energy - Power Markets Week - Price Index Database' as the detailed source,

(3) The market indices chosen to best represent a potential product availability for Nebraska customers located at the particular "market" or "hub" but not delivered to the customer, were "MAPP" (as available), "Cinergy," "Entergy," and "ComEd"; ("MAPP" history is available, but because of limited trading, or an "illiquid" market, no future pricing index currently exists); also, for physical resource comparison purposes, assuming customers built their own resources to serve their own load, various new generation unit types (peaking, intermediate & baseload) were priced & calculated, based on market cost allocation methods, then compared,

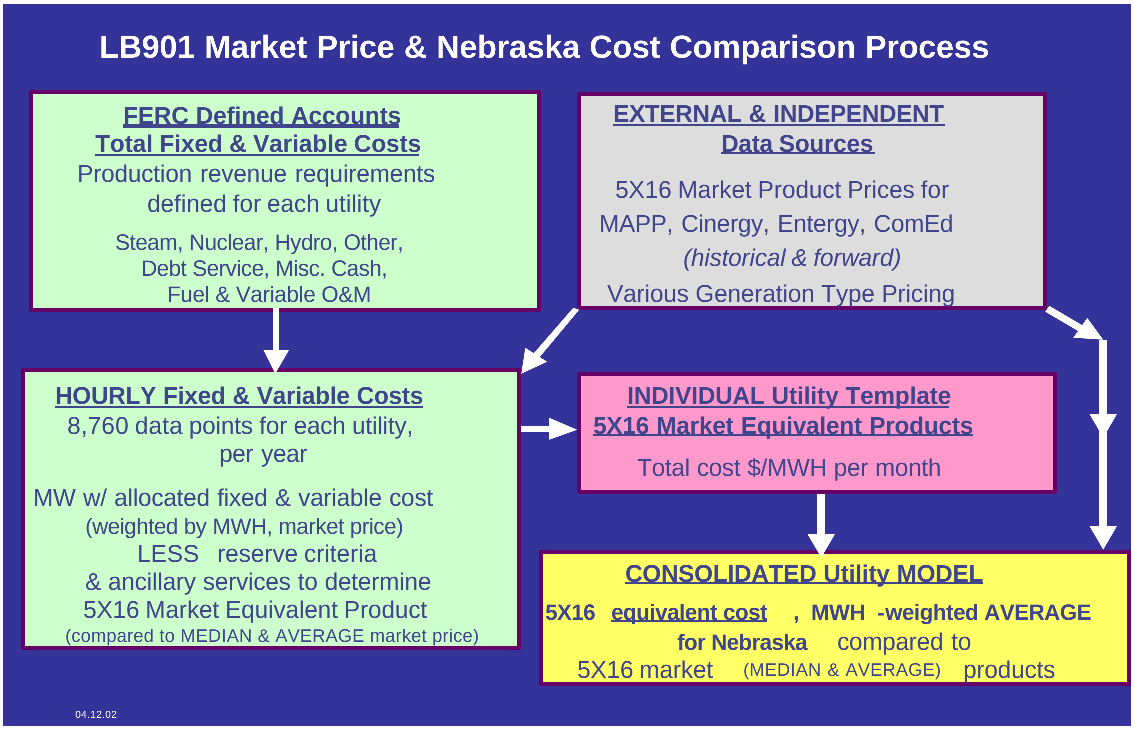
(4) Two different methods of allocating the fixed costs of existing power resources for each utility were modeled in order to provide a range of possibilities in cost allocations for discussion to determine how most utilities would allocate fixed costs; these two methods were (a) January thru December monthly MWH-weighted, and (b) January thru December monthly market price-weighted; also, Ancillary Services, Planning Reserves, and Additional Capacity hedging values from existing utility price were subtracted from the utility costs in order to determine an appropriate market product price comparison,

(5) For the study period, an anomaly occurred in 2000 when winter prices (specifically December) were higher than summer prices. It was recommended to "force" the fixed cost allocation when considering market price weighting of fixed costs to the summer because the single winter season of 2000 / 2001 was considered "unusual" and not typical of market pricing patterns. In March 2002, it was noted that actual January 2001 market prices were the highest prices in 2001, so the detailed market price comparison tool was updated to include the user-option of "forcing" the actual fixed cost allocations (for the market-price weighting of fixed costs portion only) into the summer months (June, July, August) so that a single winter season price anomaly would not corrupt the overall comparison results. Also, for the Peaking unit only, the user has an option to compare Peaking unit costs when the market price warrants dispatching this type of resource (the market price is either equal to or higher than the Peaking unit cost).

(6) The cost to serve Nebraska customers from Nebraska power systems was then compared to the cost to serve Nebraska customers from the market, calculated on an annual MWH-weighted basis from which a percentage of market price was calculated to quantify differences between Nebraska power systems and available market product pricing on a rolling average basis for 1999 - 2002 (3 years of history and 1 year of future pricing); annual price volatility (fluctuation) comparisons were also performed.

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

Exhibit IV-2



4.0 Results of Modeling Tool Comparisons

4.1 Time-period Utilized

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

For 2002 modeling comparison purposes the time period of 1999 through 2002 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 1999-2002, with 2002 being the estimated year for both market pricing & production costs.

- Incorporating the future year 2003 into the modeling introduces another layer of "assumptions" & "speculation" that may reduce the credibility of an agreed upon modeling process that provides reasonable conclusions.

- Market pricing is changing on a month-to-month basis and comparing too early may provide a false signal of difference between market price and expected production costs both on a price & volatility basis. For example, the May 2001 price for an August 2001 market product was approximately $83/MWh; in June 2001 the price for the same August 2001 market product was approximately $55/MWh. With this price volatility just two months out, greater price swings can be expected 12 to 18 months out.

- Historical weighting reflects actual market prices & actual production costs which are more credible & accurate than projections or expectations. The four-year rolling average allows for anomalies & unusual fluctuations in both the market price & production costs to be smoothed out for more reasonable comparison purposes.

- Need to be cautious that legislative action is not triggered on projections or expectations which are subject to larger errors (e.g., California), but on actual experience and estimations that have a higher confidence of accuracy (e.g., just one year).

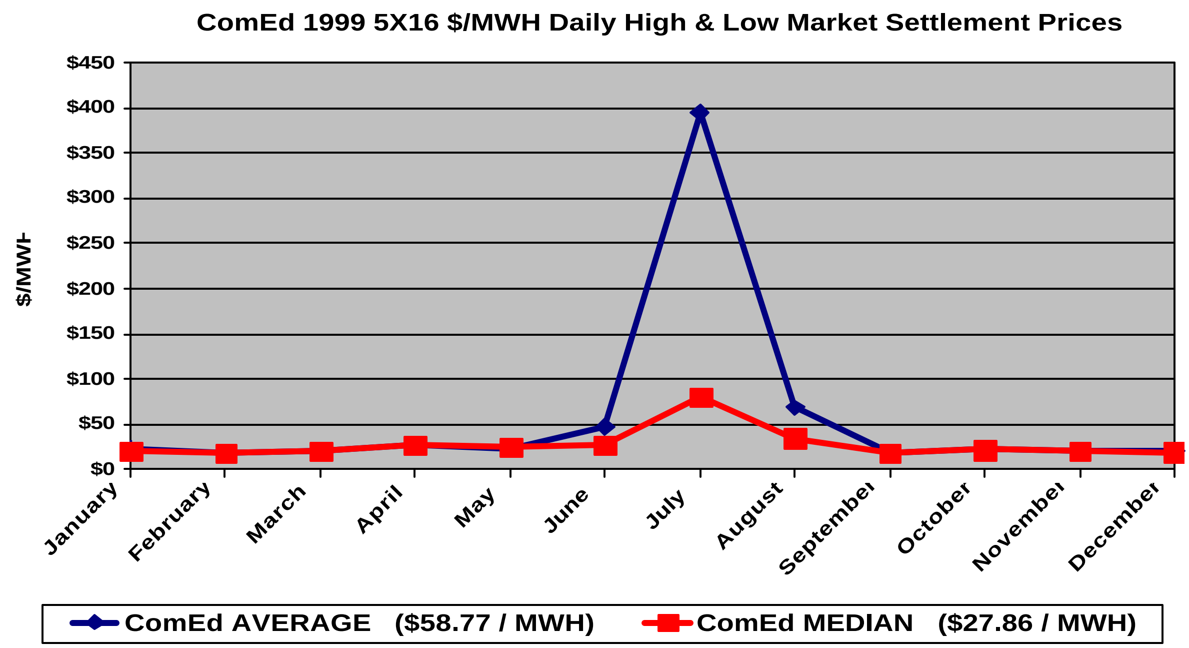
4.2 Sensitivity Cases Analyzed

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

4.3 Median Market Pricing

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

Exhibit IV-3



4.4 MegaWatt-Hour (MWH) Weighted Fixed Cost Allocations

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

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

4.5 Other Cost Allocation Issues

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

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

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

4.6 Results Based on Median Market Product Pricing Indices and Applying MWH-Weighted Fixed Cost Allocations to Nebraska Production Costs for 1999 through 2002.

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 1999 through 2002. As shown in the table, on an equivalent basis, Nebraska production costs consistently rank below the market product indices even with nuclear unit outage and high market purchase price production cost anomalies throughout the study period. Also included, is a LB901 historical study period comparison describing the four-year rolling average results for the various study periods completed. Differences in study period results are to be expected since market prices will fluctuate more than Nebraska Production costs as described in Section 2.7, so the differentials between them will also tend to fluctuate, as supported by the price volatility calculations provided.

Exhibit IV-4

TABLE DESCRIBING NEBRASKA PRODUCTION COSTS

PERCENTAGE BELOW AVERAGE MARKET PRICING

Year	MWH - Weighted Fixed Cost Allocations	Market Price - Weighted Fixed Cost Allocations
1999	52.7%	53.6%
2000	28.1%	28.1%
2001	31.3%	31.3%
2002	13.0%	13.1%
Straight Average	31.3%	31.5%
Four Year Average (MWH-weighted)	**32.4%**	**32.9%**

PERCENTAGE BELOW MEDIAN MARKET PRICING

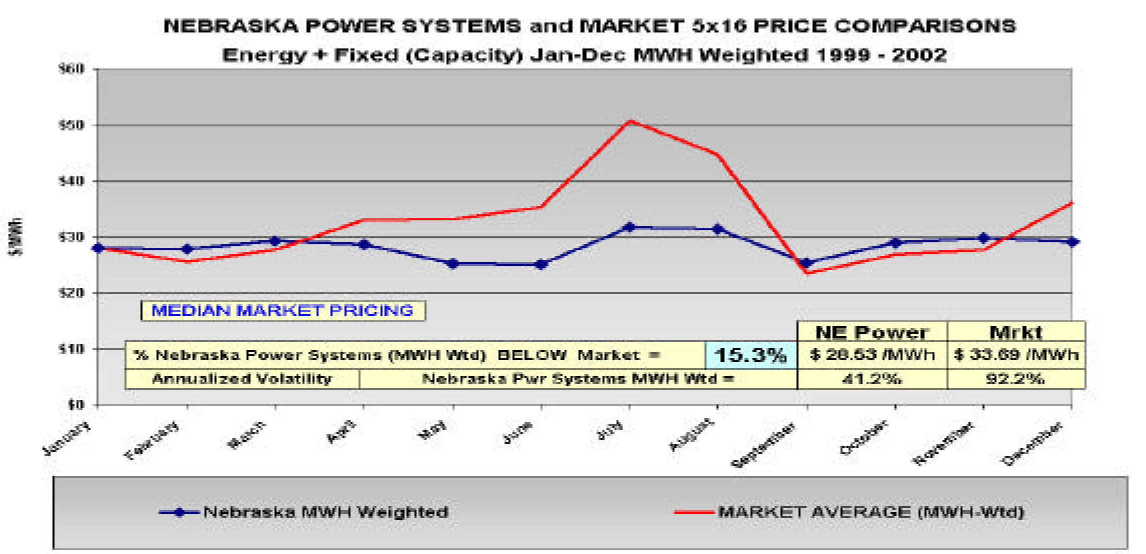
Year	MWH - Weighted Fixed Cost Allocations	Market Price - Weighted Fixed Cost Allocations
1999	1.9%	3.8%
2000	24.2%	24.1%
2001	31.8%	31.8%
2002	11.9%	12.3%
Straight Average	17.5%	18.0%
Four Year Average (MWH-weighted)	**15.3%**	**16.3%**

HISTORICAL LB901 STUDY PERIOD COMPARISON

Study Period Years	% Nebraska Systems Below Market	Nebraska Cost Annualized Volatility	Market Price Annualized Volatility
1998 - 2001	**18.6%**	**34.4%**	**84.5%**
1999 - 2002	**15.3%**	**41.2%**	**92.2%**

Exhibit IV-5 portrays a graph that depicts on a monthly basis for the four-year study period (1999-2002) a comparison of median market product pricing indices to Nebraska production costs with MWH-weighted fixed cost allocations applied. As shown in the graph, on an equivalent basis, Nebraska production costs protect consumers from potential market price volatility while being below market by approximately 15%. The market price volatility represents a measure of the rate of price uncertainty over time and is typically measured by determining a standard deviation over a specific period. In the results provided below, the "Annualized Volatility Calculations" block compares the rate of price uncertainty for the market product per year ("annual" basis) to the rate of price uncertainty for Nebraska production costs. The calculation demonstrates how well Nebraska production costs protect Nebraska customers from the relative uncertainties of market price changes by indicating an annualized price volatility measure of 41%, which is less than one half of the market product price volatility of 92% for the same type of electricity product over the same period.

Exhibit IV-5



5x16 Price $/MWH Comparisons	1999 - 2002	LB 901 "Condition-Certain" Criteria	
	Statewide		
	4 Year AVERAGE		
CONSOLIDATED MODEL VERSION for INFORMATION AGGREGATION			
MEDIAN MARKET PRICING			
		NE Power	Mrkt
% Nebraska Power Systems (MWH Wtd) BELOW Market =	15.3%	$ 28.53 /MWh	$ 33.69 /MWh
% Nebraska Power Systems (MRKT Wtd) BELOW Market =	16.3%	$ 28.21 /MWh	$ 33.69 /MWh
Annualized Volatility	Nebraska Pwr Systems MWH Wtd =	41.2%	92.2%
Annualized Volatility	Nebraska Pwr Systems MRKT Wtd =	80.1%	92.2%

5x16 Price $/MWH Comparisons	1999 - 2002	LB 901 "Condition-Certain" Criteria	
	Statewide		
	4 Year AVERAGE		
CONSOLIDATED MODEL VERSION for INFORMATION AGGREGATION			
AVERAGE MARKET PRICING			
		NE Power	Mrkt
% Nebraska Power Systems (MWH Wtd) BELOW Market =	32.4%	$ 28.53 /MWh	$ 42.20 /MWh
% Nebraska Power Systems (MRKT Wtd) BELOW Market =	32.9%	$ 28.31 /MWh	$ 42.20 /MWh
Annualized Volatility	Nebraska Pwr Systems MWH Wtd =	41.2%	166.2%
Annualized Volatility	Nebraska Pwr Systems MRKT Wtd =	109.0%	166.2%

For comparison purposes, Exhibit IV-6 is provided to describe the detail associated with the 2002 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

AVERAGE 5X16 $/MWH Daily Settlements for 2002

	HISTORICAL				FORWARD INDICES (as of May 1, 2002)							
	January	February	March	April	May	June	July	August	September	October	November	December
MAPP	20.71	21.14	25.09	28.38	34.48	36.76	54.01	55.33	29.61	29.41	29.81	31.79
Comed	20.16	20.67	23.29	28.52	31.50	37.70	50.33	50.33	30.25	28.80	28.80	28.80
Cinergy	19.81	20.83	23.32	28.48	33.00	37.88	50.50	50.50	29.03	28.75	28.75	28.75
Entergy	19.48	20.82	26.11	31.23	34.38	39.38	50.38	50.38	29.50	30.25	30.25	30.25
MAPP CALC	104.5%	101.7%	103.5%	96.5%								

MEDIAN 5X16 $/MWH Daily Settlements for 2002

	HISTORICAL				FORWARD INDICES (as of May 1, 2002)							
	January	February	March	April	May	June	July	August	September	October	November	December
MAPP	20.00	20.51	23.44	26.25	35.32	38.45	54.64	52.33	25.86	29.24	29.86	31.64
Comed	19.34	20.16	22.62	26.09	31.50	37.70	50.33	50.33	30.25	28.80	28.80	28.80
Cinergy	18.48	20.14	22.87	26.06	33.00	37.88	50.50	50.50	29.03	28.75	28.75	28.75
Entergy	18.99	20.11	26.01	29.73	34.38	39.38	50.38	50.38	29.50	30.25	30.25	30.25
MAPP CALC	105.6%	101.6%	98.3%	96.2%								

MAPP Capacity Price $/kW-yr for 2002 =	17.00			
Peaking Unit real levelized $/MWH for 2002 =	40.54	@ 85% CF and Fuel of $3.00/ mmBTU	66.43	@ 10% CF
Combined Cycle real levelized $/MWH for 2002 =	32.40	@ 85% CF and Fuel of $3.00/ mmBTU		
Baseload Coal real levelized $/MWH for 2002 =	29.31	@ 85% CF and Fuel of $0.75/ mmBTU		

(All generation units EXclude transmission cost adders)

FORWARD PRICES FOR MAY THRU DECEMBER BASED ON INTERCONTINENTAL EXCHANGE May 1, 2002 @ 6:52 am

These results for the 1999 – 2002 study period are slightly lower than the results for the previous period, 1998 – 2001, due mostly to the downward trend of market prices driven by lower natural gas prices and increased generation, as well as a slight increase in Nebraska Production costs. However, the price volatility associated with Nebraska Production costs remains stable compared to market price, providing a fairly consistent, less volatile, cost expectation for Nebraska's Ratepayers.

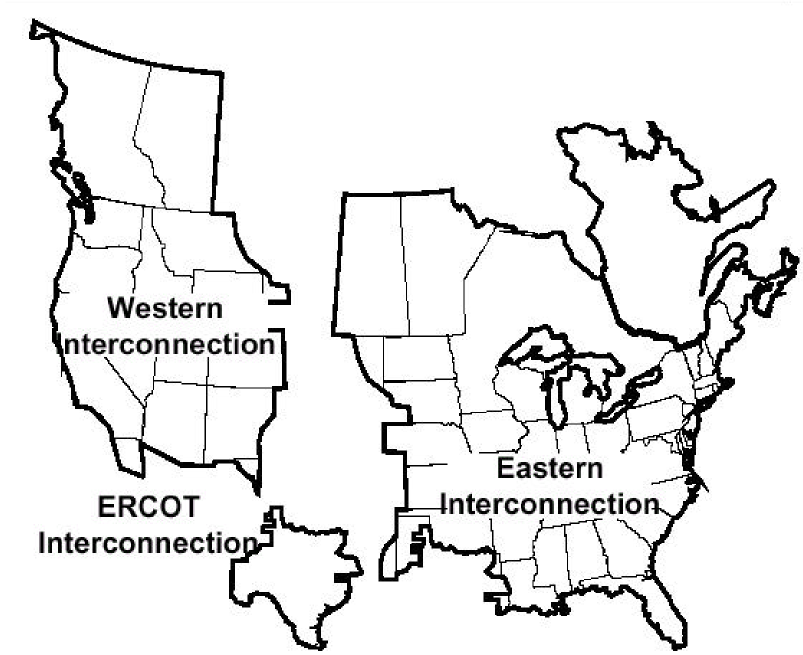
5.0 Expected Differences Eastern Region to Western Region

5.1 North American Electrical Interconnection

The majority of the electric systems in North America are comprised of three Interconnections as shown on Exhibit IV-7 and described below:

> Eastern Interconnection - the largest Interconnection covers an area from Quebec and the Maritimes to Florida and the Gulf Coast in the East and from Saskatchewan to eastern New Mexico in the West. It has HVDC connections to the Western and ERCOT Interconnections.
>
> Western Interconnection - second largest Interconnection extends from Alberta and British Columbia in the North to Baja California Norte, Mexico, and Arizona and New Mexico in the south. It has several HVDC connections to the Eastern Interconnection.
>
> ERCOT Interconnection – includes most of the electric systems in Texas with two HVDC connections to the Eastern Interconnection.

Exhibit IV-7



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 (584,503 MW compared to 135,186 MW) and generation (671,364 MW as compared to 166,269 MW). The interconnection DC tie capability between the Eastern and Western Interconnection is 1,080 MW. Source: (NERC Reliability Assessment, October 2001). Nebraska's projected growth rate is approximately 1.8% and the current summer peak is approximately 5700 MW.

The Western Systems Coordinating Council's (WSCC) outlook regarding the reliability of the Western Interconnection is comprised of four sub-regions – Northwest Power Pool Area, Rocky Mountain Power Area, Arizona-New Mexico-Southern Nevada Power Area, and California-Mexico Power Area. A resource assessment on a region-wide basis is not considered appropriate because of transmission constraints. This also explains the marketing limitations in the region due to the lack of firm transmission to facilitate such transactions and the limited interconnection tie capability to the Eastern Interconnection.

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

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

The Mid-Continent Area Power Pool (MAPP) encompasses the Nebraska load and generation in the Eastern Interconnection. The demand forecast is for a projected demand growth of 1.9% per year through the 2010 period. Generation reserve margins in MAPP are projected to decline from 20% in 2001 to 15% in 2005. The majority of generation serving Nebraska is located in Nebraska.

In making this market comparison of Eastern to Western Interconnections, the market drivers have to be considered as well as the relationship of Nebraska's electrical capacity requirements associated with each interconnection. The market price drivers that influence the market differences include generation regulatory requirements, generation fuel type, fuel cost, generation availability/dependability, load demand, weather, and transmission availability.
The current Nebraska total capacity requirements include approximately 98% of the total residing within the Eastern Interconnection and 2% residing within the Western Interconnection. The Eastern and Western Interconnections are separate systems other than the relatively small amount of DC tie transfer capability between the systems.

5.3 Western Region Market Compared to Eastern Region Market

5.3.1 "Markets" or "Hubs"

The Eastern Interconnection "market" indices or "hubs" used for the Nebraska market in the Eastern Region (as defined in Issue #2 Section III-F) 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 (as defined in Issue 2 Section III-F).

5.3.2 Volatility and Price Comparison

The price fluctuation or volatility in the Eastern Region market has overall been significantly higher than the volatility for the Western Region market. This is primarily due to the extreme price levels in the Eastern Region markets during the summer of 1999. Looking at the price levels only for 2000 through 2002 however, shows a higher volatility in the Western Region for this time frame than in the Eastern Region.

While volatility has been greater overall for the Eastern Region, the average $/MWh price of the Western Region has averaged 67% higher than prices for the Eastern Region for the 1999 through 2002 time period (1-1-99 through 3-1-02). This is due to the significantly higher average price level for the Western Region since May 2000, despite the extreme price action seen in the Eastern Region during the summers of 1999. Market price levels for both the Eastern and Western Regions have decreased in recent months.

5.3.3 California Influence

The California market is beyond the Region, as defined in the report; however, the California market did influence the overall market. This could be seen in terms of an immediate psychological influence on the overall market as well as a direct influence on Nebraska and the market in terms of increased credit risk when dealing with power suppliers that operated in the California market as well as the Eastern and Western Regions. Some regulatory changes have occurred already as a result of the California deregulation experience such as price caps for the Western Interconnection.

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; MEAN serves some western Nebraska municipals; 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. However, the purchased wholesale power from the Western Region is currently trending higher than that of power purchased in the Eastern Region.

5.4.2 Stability

It is difficult to predict what Nebraska’s cost of production will be in the future. However, Nebraska should generally be in a stable position through the 2003 time period. There is adequate generation to meet the load requirements per the NERC Reliability Assessment. Recent market prices in the Western Region have trended higher and been more volatile than the Eastern Region; therefore Western Nebraska does have more exposure to the market during periods that normal generation supply is unavailable due to planned or forced outages.

6.0 Conclusions

The challenge for Technical Group #4 was to develop an equitable comparison between the credible indices that were identified and the product provided by Nebraska electric utilities to their customer-owners. The product that Nebraska providers sell is a firm, total electrical requirements product, available 24 hours a day, 7 days a week, in quantities that usually 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 15% lower than the equivalent wholesale “median” market price based on the period 1999 – 2002 (three years actual, one year projected), and weighted based on MWH. Based on the “average” market price, Nebraska production costs are approximately 32% lower than the “average” market price.

These results for the 1999 – 2002 study period are slightly lower than the results for the previous period, 1998 – 2001, due mostly to the downward trend of market prices driven by lower gas prices and increased generation, as well as a slight increase in Nebraska Production costs. However, the price volatility associated with Nebraska Production costs remains stable compared to market price, providing a fairly consistent, less volatile, cost expectation for Nebraska’s Ratepayers.

The “median” market price comparison, approximately 15% lower than the market price, compares favorably with retail rate comparisons. The Energy Information Administration (EIA) annually compiles data from the Form EIA-861 for approximately 3,300 public and investor-owned electric utilities including active power marketers and other energy service providers. The most current data for 2000 shows that Nebraska’s average retail rate of 5.31 cents/kWh is approximately 22% lower than the national average retail rate of 6.78 cents/kWh.

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

Appendix IV-A – ANCILLARY SERVICES DEFINITIONS

SCHEDULE 1.

Scheduling, System Control and Dispatch Service (FERC Acct. 561)

This service is required to schedule the movement of power through, out of, within, or into a Control Area. This service can be provided only by the operator of the Control Area in which the transmission facilities used for transmission service are located. Scheduling, System Control and Dispatch Service is to be provided directly by Service Provider (if Service Provider is the Control Area operator) or indirectly by Service Provider making arrangements with the Control Area operator that performs this service for Service Provider's Transmission System. The Transmission Customer must purchase this service from Service Provider or the Control Area operator. The charges for Scheduling, System Control and Dispatch Service are to be based on set rates. To the extent the Control Area operator performs this service for Service Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to Service Provider by that Control Area operator.

SCHEDULE 2.

Reactive Supply and Voltage Control from Generation Sources Service

In order to maintain transmission voltages on Service Providers' transmission facilities within acceptable limits, generation facilities (in the Control Area where Service Providers' transmission facilities are located) are operated to produce (or absorb) reactive power. Thus. Reactive Supply and Voltage Control from Generation Sources Service must be provided for each transaction on Service Providers' transmission facilities. The amount of Reactive Supply and Voltage Control from Generation Sources Service that must be supplied with respect to the Transmission Customer's transaction will be determined based on the reactive power support necessary to maintain transmission voltages within limits that are generally accepted in the region and consistently adhered to by Service Provider.

Reactive Supply and Voltage Control from Generation Sources Service is to be provided directly by Service Provider making arrangements with the Control Area operator that performs this service for Service Providers' Transmission System. The Transmission Customer must purchase this service from Service Provider or the Control Area operator. The charges for such service are to be based on set rates. To the extent the Control Area operator performs this service for Service Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to Service Provider by the Control Area operator.

SCHEDULE 3.

Regulation and Frequency Response Service

Regulation and Frequency Response Service is necessary to provide for the continuous balancing of resources (generation and interchange) with load and for maintaining scheduled Interconnection frequency at sixty cycles per second (60 Hz). Regulation and Frequency Response Service is accomplished by committing on-line generation whose output is raised or lowered (predominantly through the use of automatic generating control equipment) as necessary to follow the moment-by-moment changes in load. The obligation to maintain this balance between resources and load lies with Service Provider (or the Control Area operator that performs this function for Service Provider). Service Provider must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from Service Provider or make alternative comparable arrangements to satisfy its Regulation and Frequency Response Service obligation. The amount of and charges for Regulation and Frequency Response Service are to be based on set rates. To the extent the Control Area operator performs this service for Service Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to Service Provider by that Control Area operator.

SCHEDULE 4.

Energy Imbalance Service

Energy Imbalance Service is provided when a difference occurs between the scheduled and the actual delivery of energy to a load located within a Control Area over a single hour. Service Provider must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from Service Provider or make alternative comparable arrangements to satisfy its Energy Imbalance Service obligation. To the extent the Control Area operator performs this service for Service Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to Service Provider by that Control Area operator.

Service Provider shall establish a deviation band of the scheduled transaction to be applied hourly to any energy imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s).

SCHEDULE 5.

Operating Reserve – Spinning Reserve Service

Spinning Reserve Service is needed to serve load immediately in the event of a system contingency. Spinning Reserve Service may be provided by generating units that are on-line and loaded at less than maximum output. Service Provider must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from Service Provider or make alternative comparable arrangements to satisfy its Spinning reserve Service obligation. The amount of and charges for spinning Reserve Service are to be based on set rates. To the extent the Control Area operator performs this service for Service Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to Service Provider by that Control Area operator.

SCHEDULE 6.

Operating Reserve – Supplemental Reserve Service

Supplemental Reserve Service is needed to serve load in the event of a system contingency; however, it is not available immediately to serve load but rather within a short period of time. Supplemental Reserve Service may be provided by generating units that are on-line, but unloaded by quick-start generation, or by interruptible load. Service Provider must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from Service Provider or make alternative comparable arrangements to satisfy its Supplemental Reserve Service obligation. The amount of and charges for Supplemental Reserve Service are to be based on set rates. To the extent the Control Area operator performs this service for Service Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to Service Provider by that Control Area operator

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.[1]

2.0 Team Members

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

3.0 Introduction

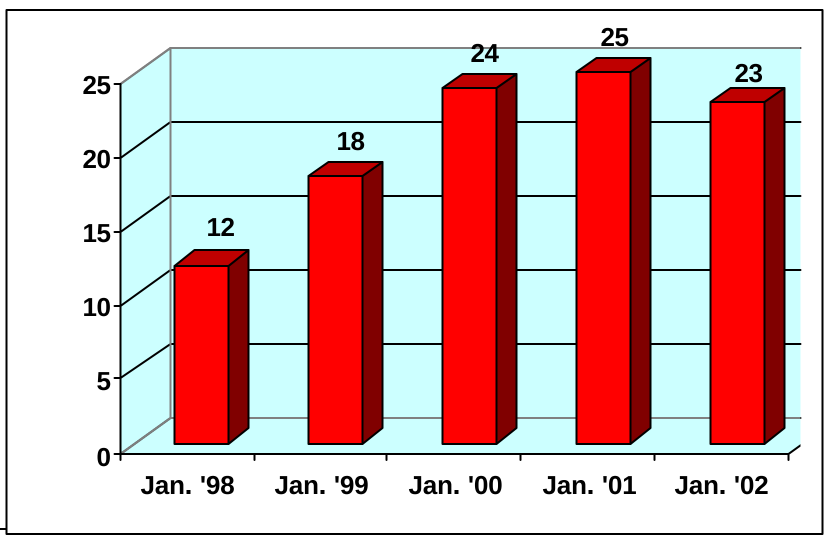
3.1 Deregulation Overview

Proponents of deregulation argue that competitive markets are more efficient than government regulated economic activities. Professor Willis Emmon's recent book on deregulation and privatization states: "Deregulation is a broad concept that encompasses easing or eliminating government restrictions in three major areas: a firm's freedom of entry into a market, its freedom of action within a market, and its profitability (maximum or minimum) within the market."[2] One of the biggest public policy challenges in achieving successful deregulation is the creation of truly competitive markets. The LR 455 Phase II Report, December 1999, analyzed the driving forces of retail electric deregulation and discussed the impacts of deregulating other industries in Nebraska such as airlines and telecommunications. See pp.8-16. As the Report clearly pointed out, in Nebraska "competitive markets" often bypass rural or sparsely populated areas, especially when the deregulating industry is capital intensive such as airlines, railroads, and telecommunications.

Skepticism about the consumer benefits of electric deregulation in Nebraska, along with Nebraska's competitive energy costs, were two key factors leading to the "condition certain" approach recommended in the LR 455 Phase II Report and adopted in LB 901 (2000).

Retail deregulation gained considerable popularity between the late 1990s and January 2001 with 25 state legislatures or regulatory agencies committing to various forms of retail customer choice. This trend reversed by January 2002 when only 23 states were considering such action. See Exhibit V-1.

Exhibit V-1
Number of States Moving to Implement Retail Competition
5-Year Trend

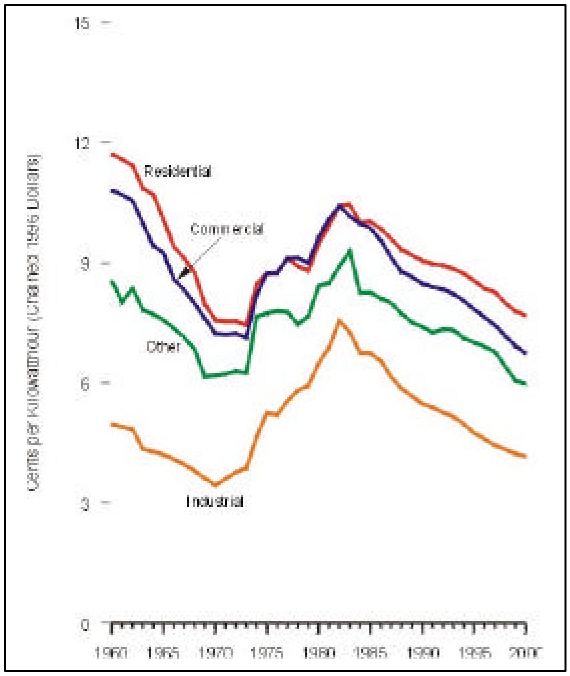


[1] This report reflects deregulation developments through August 20, 2002.
[2] Willis Emmons, *The Evolving Bargain*, "Strategic Implications of Deregulation and Privatization," 2000: p. 2.

However, developments which began during the summer of 2000 in California, Washington, Montana, New York and certain other states have created significant questions about the benefits of retail choice and have resulted in delays or repeals of retail choice in six states.

In inflation-adjusted terms, all sector prices for electricity fell steeply in the 1960s, reversed course around 1970 to rise sharply through the early 1980s, and then returned to a pattern of rapid decline. Over the decades, industrial consumers paid the lowest rates for electricity; residential customers usually paid the highest prices. By 2000, all sectors paid lower rates than they had in 1960. See Exhibit V-2.

Exhibit V-2
Retail Prices of Electricity by Sector



4.0 Status of Retail Competition in Selected States

"To be number one in the nation today isn't saying very much with all the retail markets effectively closed."[3]

In 2001a number of state legislatures decided to re-think the merits of electricity retail competition. Within a six-month period, six states took legislative action to postpone the implementation of retail choice.

4.1 Significant Legislative Actions Affecting the Implementation of Retail Choice

- Arkansas – Legislation was enacted in February 2001 to delay implementation of retail choice until October 2003 or later.
- Montana – Legislation enacted in May 2001 (HB 474) that delays until 2007 the date when consumers would be <u>required</u> to shop for alternative providers.
- Nevada – Legislation enacted in April 2001 repeals prior retail choice legislation and halts the sale of utility generation assets.
- New Mexico – Legislation signed in March 2001 to delay the implementation of retail choice until 2007.
- Oklahoma – Legislation enacted in May 2001 (SB 440) to repeal prior retail choice legislation. Task force created to study restructuring prior to further action.
- Oregon – Legislation enacted in July 2001 delaying the implementation of retail choice until March 2002.

[3] George Spencer, Publisher of *Restructuring Today* commenting on the relative "success" of Pennsylvania's retail competition scheme. June 22, 2001.

A number of internet web sites contain comprehensive state-by-state summaries of the status of electric retail competition. The sites provide the status of restructuring legislation and regulation and details on the structure of the approach taken. However, because much of the recent regulatory and legislative activity on electricity restructuring has been to delay and/or repeal prior initiatives toward retail competition, none of these web sites was completely up to date as of the drafting of this report. Despite the many limitations of these sites regarding timeliness and accuracy, one can find useful information on the status of restructuring.

American Public Power Association
www.appanet.org/legislativeregulatory/staterestructuring/index.cfm

Edison Electric Institute
www.eei.org/issues/comp_reg

C.H. Guernsey & Company
www.chguernsey-econ.com/restructuringlinks.html

National Association of Regulatory Utility Commissioners
www.naruc.whatsup.net

National Rural Electric Cooperative Association
www.nreca.org/leg_reg

US Department of Energy (Energy Information Administration)
www.eia.doe.gov/cneaf/electricity/chg_str/tab5rev.html

William Spratley Associates
www.spratley.com

The following pages contain a brief summary of the status and implementation of retail competition in several states. Some of these states have attempted a retail competition regimen for a number of years while others are just now beginning to implement retail competition legislation. It is important to understand that in no state was a vibrant competitive retail electricity market found. The dearth of competition is particularly pronounced in the residential sector. In the general case, the states that have "implemented" retail choice have done so on paper only with very few customers actually switching suppliers and very few suppliers actually marketing to customers. Pennsylvania was initially an exception, but has seen considerable decline in retail marketers.

On a national basis, average retail electricity prices have been trending downward since the mid-1980s due to improved power plant efficiencies and generally declining fuel costs, among other factors.

4.1.1 Arizona

Arizona is a classic example of how the implementation of retail competition initially produced a flurry of activity, which ultimately has reverted to the status quo. Pursuant to legislation enacted in 1998, the Arizona Corporation Commission promulgated regulations to implement retail choice. The legislation called for choice for all customers by December 31, 2000. Salt River Project, one of the largest public power electric utilities in the United States was included in the choice requirement with all customers eligible to choose by June 1, 2000.

Competitive suppliers are required to be certified by the Arizona Corporation Commission and a number of them completed the certification process. The retail choice legislation contained a number of important consumer safeguards. For example, the incumbent utility must be the supplier of last resort and serve all customers who did not exercise their option to switch. Pursuant to law, customer account information is deemed proprietary and cannot be released without the written consent of the customer. A customer cannot have his/her supplier switched without a written authorization and the law also contains prohibitions of certain abusive marketing practices.

Although the legal framework for retail competition is in place, there is virtually no retail competition in Arizona. None of the certified competitive suppliers are attempting to market to residential customers and the few commercial and industrial customers that initially switched suppliers have now returned to the incumbent utility. The electricity crisis in California has had a chilling effect on consumer interest in retail competition in Arizona and many other states.

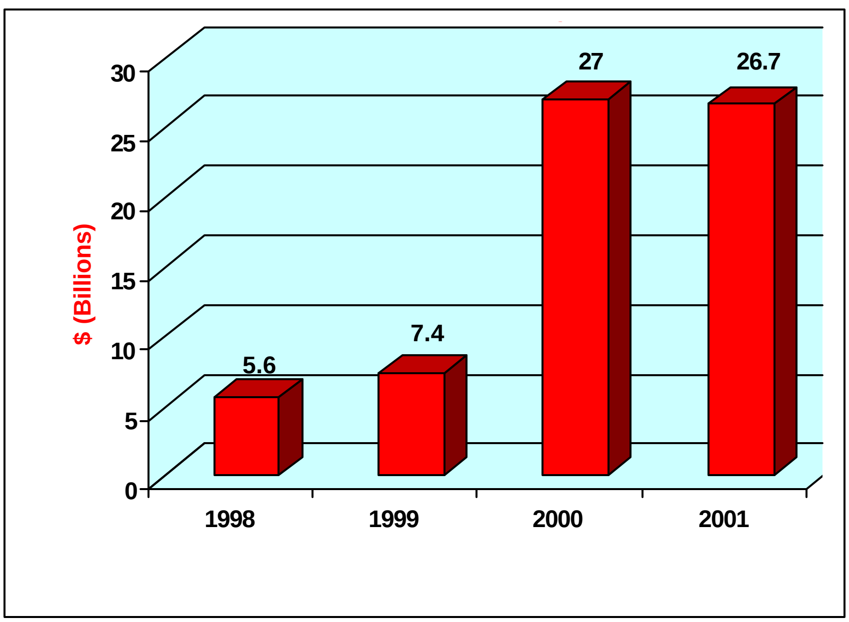
4.1.2 California

The current negative reaction toward retail customer choice has been accelerated by California's flawed efforts to implement retail competition. California had electric rates among the highest in the nation when it passed retail choice legislation in 1996 (A.B. 1890). On September 26, 1996, California Governor Pete Wilson signed A.B. 1890 into law and ushered in one of the most expensive lessons in the annals of public policy making. The law which became effective in 1998 required the state's three major investor-owned utilities to participate, but allowed public power entities which comprise about 30% of California's market to opt out, which they all did. Over the course of the past year, politicians across the political spectrum at every level of government have been attempting to craft an exit strategy from what is widely regarded as an economic disaster for the state.

Under the California model, investor-owned electric utilities were required to divest their ownership in fossil-fueled generation assets and then to purchase power supply from the California Power Exchange. The price for supply was set by a day-ahead auction. In addition, electric utility transmission operations were transferred to a newly created independent system operator (ISO).

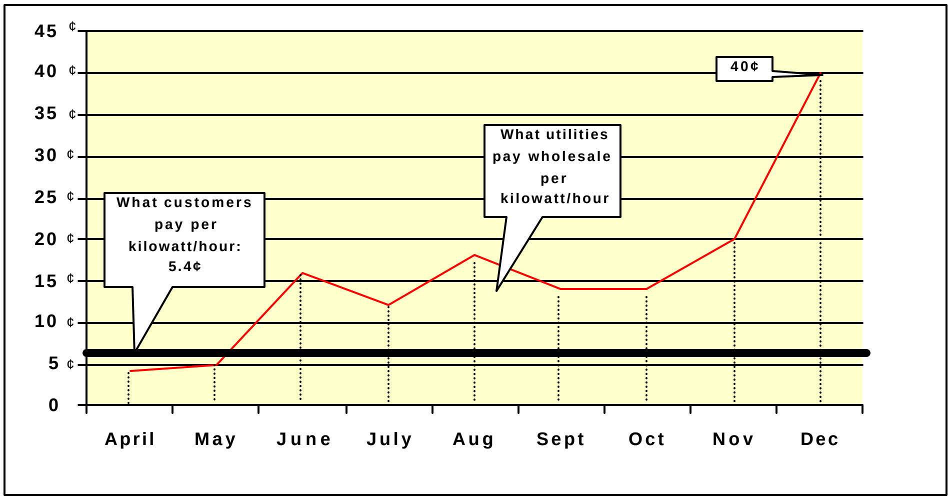
Initially, customers received a modest reduction from rates that were in effect during 1996. Retail rates were then fixed for a period of time while the utilities were allowed to collect transition charges to cover stranded investments. However, the utilities were forced to purchase power on the wholesale markets at auction prices and then sell at retail at fixed prices. The disconnect between the two prices became extreme during 2000 leaving the incumbent electric utilities billions of dollars short. See Exhibit V-3.

Exhibit V-3
Cost of Wholesale Electricity for California



The state's largest investor-owned utility, Pacific Gas and Electric, is now in bankruptcy reorganization and the two other major electric companies are also seriously stressed financially. See Exhibit V-4. Retail rate increases exceeding 50% have been approved.

Exhibit V-4
Pacific Gas & Electric 2000



The overwhelming number of customers who initially switched energy suppliers returned to the incumbent utilities during the peak of the wholesale energy-pricing crisis. See Exhibit V-5.

On March 21, 2002 the California PUC took the long anticipated step of suspending the direct access program effective back to September 20, 2001. At the time of the suspension, the California Department of Water Resources (DWR) was -- pursuant to legislative mandate -- purchasing electricity at wholesale on behalf of the customers of the three major California investor-owned utilities. In its order, the PUC reasoned that, "the suspension of the ability to acquire direct access service will provide DWR with a stable customer base from which to recover the cost of power it has purchased and continues to purchase."[4]

The order announced a remarkable shift in philosophy on the part of the PUC that had long championed the merits of customer choice and market efficiency. The order noted that customers will face high energy costs over the next few years and that, "Under these circumstances, customers might be tempted to switch from utility bundled service to electric service providers in order to avoid some of the impact of higher rates and take advantage of lower spot market prices. It is not in the public interest to permit such behavior."[5]

The order that was issued on a 3-2 vote was accompanied by a stinging dissent from PUC Commissioners Henry Duque and Richard Bilas who observed that, "Something else is going on here. We think that the DWR does not want direct access because if the public is presented with alternatives, it will make DWR's purchasing mistakes abundantly clear. Indeed, retaining direct access as a way to send price signals to consumers may be the only way to place pressure on DWR to make more prudent purchases."[6]

In February 2002, the California PUC filed what is known as a "Section 206" complaint with the Federal Energy Regulatory Commission (FERC) against certain sellers of long-term power contracts to the state. The Federal Power Act requires that the FERC ensure that all wholesale power contracts are "just and reasonable". The PUC's complaint alleges that a significant number of wholesale power contracts entered into by the state were at prices some $21 billion in excess of what could be considered "just and reasonable" and that the state was forced to procure enormous amounts of electricity under conditions of extreme market power.

Recent disclosures in the Enron bankruptcy matter have given new ammunition to California's claims. Internal Enron memos discuss a variety of bogus energy trading strategies including artificially increasing the demand for transmission capacity that resulted in excess payments back to Enron. Senator Dianne Feinstein (D-CA) sent a letter to Attorney General John Ashcroft asking for a criminal investigation of Enron for actions she believes constitute

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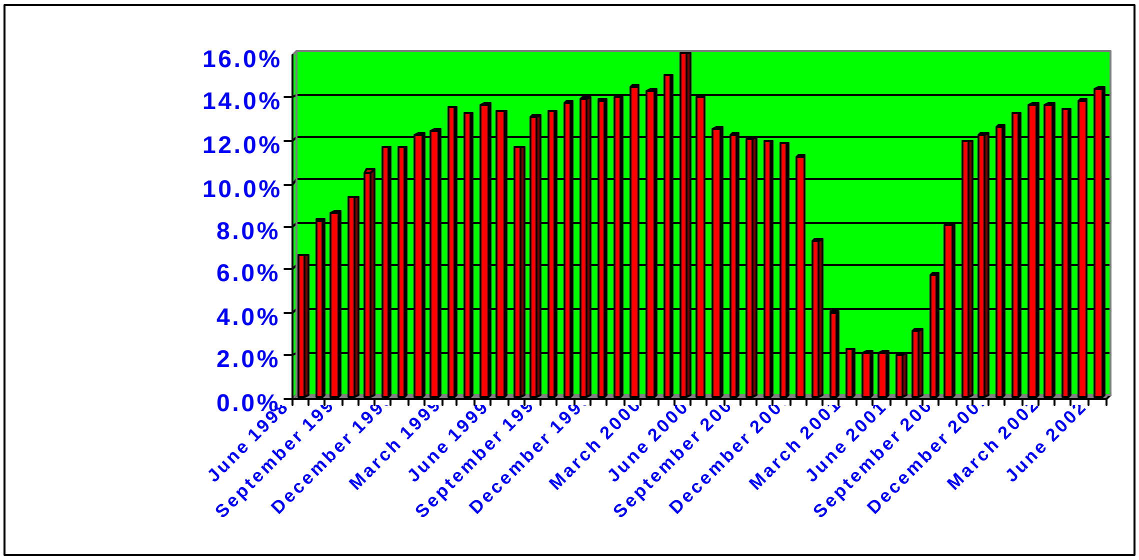
[4] Decision 01-09-060, September 20, 2001, page 4.
[5] IBID at page 6.
[6] IBID at page 15.

fraud. Senator Barbara Boxer (D-CA) pressed for Senate hearing on the matter and said that she hoped that Enron officials would "be sitting in a dark cell some day for what they did."[7]

Exhibit V-5
Direct Access Load as a Percentage of California Investor-Owned Electric Utility Total kWh Load



4.1.3 Montana

In April 1997, The Montana Electric Utility Industry Restructuring and Consumer Choice Act, (SB 390), was signed into law. In addition to addressing many policy issues related to electric industry restructuring, the Act required each major utility to file a transition plan with the Commission one year prior to the implementation of retail choice.

Montana Power Company's (MPC) transition plan was approved in July 1998, and their pilot program began in July 1999. Pacificorp's transition plan was submitted in July 1997 and their pilot program started July 1998 for five of their large industrial customers. Pacificorp's plan allowed residential customers to choose their retail supplier beginning January 1999.

Early experience with retail choice proved to be disappointing with very few customers switching suppliers. On October 27, 2000, the Montana PSC made the following observations in response to problems with Montana's retail deregulation:

- While market activity within some customer segments has been greater than in others, to date the percentage of all MPC customers who have moved to choice is less than 5/10ths of a percent.
- 23 of Montana's 25 rural electric cooperatives have opted not to restructure or offer retail choice. Only one competitive supplier is offering real alternative electricity supply products to MPC's residential and small business customers and that supplier recently informed its customers they will be returned to MPC service because market prices are above regulated, rate moratorium prices.
- The Northwest Power Planning Council suggests that the demand-supply imbalance contributing to higher wholesale prices will likely persist for several years.
- The Federal Energy Regulatory Commission has yet to fully implement its goal of open, independent, regional electricity transmission systems, which are prerequisites for workable wholesale and retail electricity supply markets.

[7] "California Officials Want Energy Refunds, Extension of Price Caps"; San Jose Mercury News; May 8, 2002.

- Given the current and projected wholesale market prices, it is unlikely that competitive suppliers will be able to offer electricity to the majority of MPC's retail customers at prices below rate-moratorium prices, which suggests it is very likely that electricity supply markets will not be workably competitive on July 1, 2002.

In May of 2001, HB 474 was signed into law, significantly altering the existing restructuring legislation, and extending the transition period to full retail choice until July 1, 2007. HB 474 allows customers being served by alternative suppliers to switch to the default supplier providing that the customer does not resell the electricity. The PSC is directed to adopt a mechanism to ensure the default supplier may fully recover electricity supply costs in rates.

In a May 14, 2002 article by PSC Commissioner Bob Rowe, the author notes that it was assumed that when the State of Montana restructured its power industry, almost all small customers would have chosen their own supplier by Summer 2002. In fact, Rowe states, "only a handful of residential customers have selected a competitive supplier and no competitive suppliers are actively marketing to them at this time."[8]

During 2001, the State's largest electric utility, Montana Power Company, was in a period of transition out of the electricity business and announced its intentions to sell off all energy related interests and re-focus the company into a telecommunications provider. The company's common stock, which was once highly favored on Wall Street, fell from $60 per share in mid-2000 to less than $3 per share in early 2002 In March 2002, the name "Montana Power" faded into history when the electric utility assets of the company were purchased by NorthWestern Energy Company based in South Dakota. The telecommunications assets were transformed into Touch America.

4.1.4 Pennsylvania

Pennsylvania is often cited as the one state where retail competition exists in a meaningful way. The Electric Generation Customer Choice and Competition Act, was passed by the legislature in November 1996 and signed by the Governor on December 2, 1996. The bill required that retail access be phased-in over three periods starting in 1999. According to the Act, at least one third of the peak load of each customer class would be eligible for retail choice on January 1, 1999. In addition, the Commission interpreted the Act such that 66% of the peak load of each customer class would be eligible for retail choice by January 2, 1999, and 100% by January 2, 2000.

The Pennsylvania Office of Consumer Advocate offers the data set forth below on the percentage of customers who have switched from the incumbent suppliers as of April of 1999, 2000, 2001, and 2002. While the percentage of customers who have switched appears impressive in comparison to the lack of switching elsewhere in the country, it is clear that of the seven Pennsylvania markets, retail competition is occurring in a meaningful way in only two markets. Indeed in the other five markets, the percentage of customers who have switched has generally been less today than it was three years ago. See Exhibit V-6.

Exhibit V-6

Percentage Switched As of April 1999

	Residential	Commercial	Industrial	Total
Allegheny Power	**1.4**	**4.8**	**35.4**	**1.8**
Duquesne Light	**13.1**	**12.1**	**13.4**	**13.0**
GPU Energy	**3.8**	**13.0**	**28.4**	**5.0**
PECO Energy	**12.8**	**21.87**	**55.87**	**13.78**
Penn Power	**6.2**	**6.8**	**28.1**	**6.3**
PPL	**2.0**	**10.2**	**9.4**	**3.0**
UGI	**4.3**	**1.7**	**0**	**3.8**

[8] "Public Service Commission Considers 'Default Supply Portfolio' ", Bob Rowe, May 14, 2002

Percentage Switched As of April 2000

	Residential	Commercial	Industrial	Total
Allegheny Power	1.1	6.2	23.6	1.8
Duquesne Light	25.5	16.7	16.4	24.6
GPU Energy	4.99	15.02	32.04	6.31
PECO Energy	15.26	29.73	62.34	16.78
Penn Power	6.3	10.7	34.7	6.8
PPL	2.4	14.5	11.8	3.9
UGI	3.9	1.7	0	3.6

Percentage Switched As of April 2001

	Residential	Commercial	Industrial	Total
Allegheny Power	0.40	1.60	8.70	0.50
Duquesne Light	33.40	13.90	17.30	31.40
GPU Energy	3.90	8.30	13.30	4.50
PECO Energy	34.10	27.50	32.80	33.50
Penn Power	6.30	6.70	19.60	6.30
PPL	1.60	10.30	5.80	2.60
UGI	3.10	1.00	0	2.90

Percentage Switched As of April 2002

	Residential	Commercial	Industrial	Total
Allegheny Power	0.2	.1	0.0	0.2
Duquesne Light	29.5	17.90	23.5	28.3
GPU Energy	0.4	.30	1.4	0.4
PECO Energy	25.4	5.80	2.3	23.4
Penn Power	1.0	0.4	2.6	0.9
PPL	0.2	1.4	1.6	0.3
UGI	0.2	0.3	0	0.2

Another measure of the deterioration of retail choice in Pennsylvania can be seen in the following two graphs that show the number of megawatts of energy sold by competitive providers. Exhibit V-7 shows the energy sold by competitive providers to all customers and Exhibit V-8 shows the quantity of energy sold by competitive providers to industrial customers. In both instances, the more recent sales are considerably below that of three years ago.

According to statistics published by the Energy Association of Pennsylvania, the state generates well over 33,000 megawatts of energy per year -- about 5% of the total US capacity. Pennsylvania is second only to Texas in the amount of electric energy generated. Thus, as shown in the graphs, the quantity of energy sold by competitive providers is not a substantial factor in the total state market.

Exhibit V-7
Total Customer Load (MW) Served by Alternative Suppliers in Pennsylvania

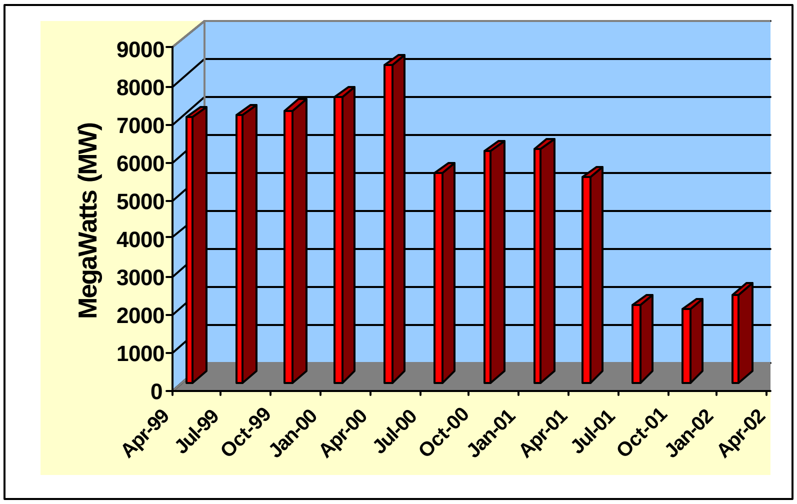
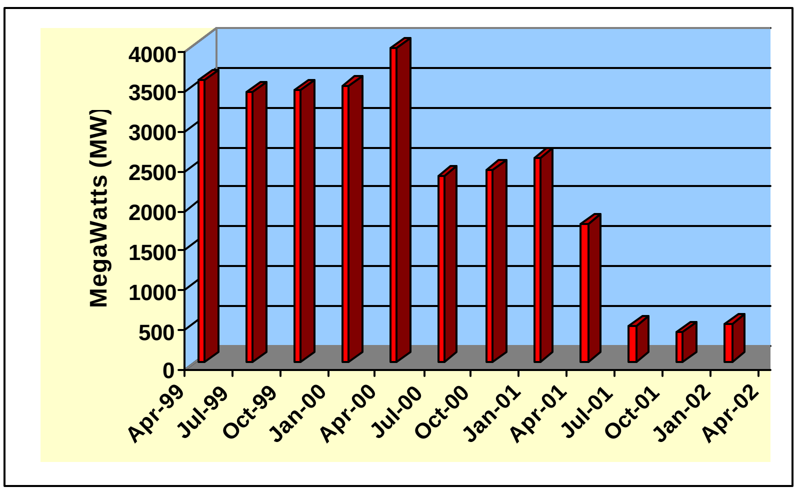


Exhibit V-8
Total Industrial Load (MW) Served by Alternative Suppliers in Pennsylvania



Pennsylvania's retail market is also experiencing other difficulties. In December 2001, the Pennsylvania Office of Consumer Advocate announced that about 800 former customers of "Utility.com" would be receiving approximately $50,000 in refunds. Refunds of about $70,000 had previously been distributed to 1,000 former "Utility.com" customers. "Utility.com" was an electric generation supplier located in Eneryville California that did business primarily over the internet until it abruptly stopped serving customers and went out of business.

Pennsylvania, like many jurisdictions, has experienced some initial reduction in retail electric rates. However, rates have recently been increasing.

4.1.5 New York

The State of New York took a different path to implement retail competition. They accomplished the matter via regulatory ruling rather than through legislation. New York has phased in retail choice by way of a series of settlements with the individual investor-owned utilities in the state with choice for all customers as of July 1, 2001.

The New York Times recently reported on June 1, 2001, that the rates for Consolidated Edison Company, "the highest in the continental United States before deregulation, have risen significantly, up almost 40 percent from two years ago. Just yesterday, the managers of the state's power grid predicted that peak summer rates could rise an additional 22 percent by 2003. The energy plan that President Bush issued last month lumps New York with California among the states with the nation's most severe energy supply problems. A host of critics, from former commission staffers to business lobbyists to consumer advocates, say that deregulation in New York has gone awry."

To date, there is little evidence of much customer switching particularly among residential and small commercial customers.

4.1.6 Connecticut

Pursuant to legislation enacted in April 1998, retail choice started in Connecticut in July 2000. Customers who choose the standard offer rates will get bill reductions of at least 10% below the rates in effect on December 31, 1996. A "systems benefits charge" is incorporated into the distribution charge collected by the incumbent utilities covering consumer education, dislocated utility worker programs, low income energy conservation, nuclear decommissioning, and funds for the development of renewable energy resources.

Incumbent utility companies were entitled to stranded cost recovery provided they divested themselves of non-nuclear generating assets by January 1, 2000. Divestiture did occur and stranded costs are now being recovered through a securitization process.

All electric suppliers must disclose their generation mix that must include a minimum of supply from renewable resources. This minimum increases over time.

Customers can change suppliers once every 12 months without charge or more often with a switching charge imposed. The retail choice rules also provide for anti-slamming provisions.

Although retail choice has technically been in effect since July 2000, the concept remains more theory than reality as most suppliers have shown little interest in the Connecticut market.

4.1.7 New Hampshire

In May 1996, pursuant to state legislation, New Hampshire launched a retail competition pilot program in anticipation of statewide retail competition. Nearly three dozen marketers entered the pilot and spent millions vying for 3% of the state's customers. Cash incentives, bird feeders, and free evergreen trees were given away in an effort to win customers. One by one the marketers withdrew from the pilot. Enron, pulled out of the pilot after spending millions to attract 770 residential customers in the City of Peterborough.[9] As they withdrew, Enron explained, "It doesn't make economic sense for us to hang on to our (new) customers."

The state's largest electric utility, Public Service Company of New Hampshire, then filed a legal challenge against the implementation of statewide retail competition claiming that the program would impair the firm's financial viability. The case lingered for several years in State and Federal courts until September 2000 when a final settlement was reached between the company and the public utility commission providing for certain rate reductions and the implementation of retail competition.

Further legal complications ensued but have now been resolved. Retail competition was scheduled to begin in April 2001. Then the state legislature intervened and delayed the start until 2004.

[9] "Enron Pulls Out of New Hampshire Retail Pilot," Megawatt Daily, September 22, 1998.

4.1.8 Vermont

The Vermont electric "market" operates with traditional rate base rate-of-return regulation. The Public Service Board entered an order on January 14, 2000 to investigate "the establishment of specific retail access policies and procedures that would be applicable to the companies should they voluntarily open their service territories to retail choice." This docket builds on earlier (1999) filings of the companies that outlines proposals to restructure the industry in Vermont. In February of 2002, the Vermont Public Service Board halted its investigation into retail competition stating that significant changes and uncertainty in the wholesale market for electricity make conditions inappropriate for the implementation of retail choice in Vermont for a few years.

Various legislative proposals in Vermont have not mandated the implementation of retail choice.

In October 2000, the State held a conference to publicly air issues associated with retail competition. The conference featured case studies of retail competition schemes in California, Pennsylvania and Massachusetts.

4.1.9 Maine

The Maine legislature enacted a law in May 1997 providing that retail competition would commence in March 2000. Unbundled bills were provided to customers starting in 1999 and divestiture of generation assets was required by March 2000. The law requires that all supplies include a 30% renewable resource portfolio (inclusive of hydro). In 1999, the Maine legislature appropriated $1.6 million for a consumer education program.

Rising oil and natural gas prices are driving up the cost of electricity for industrial and large commercial customers while small business and residential customers are currently protected from higher prices under a two-year freeze. Trade press reports indicate that there has been very little residential customer switching in Maine thus far. A significant percentage of industrial customers have switched.

4.1.10 Rhode Island

Pursuant to state legislation, Rhode Island implemented retail choice effective July 1, 1997 for large industrial customers and July 1, 1998 for all customers. The state often boasts that it was the first to offer retail choice for its customers. Narragansett Electric Company had significant stranded costs that are being spread over a 12-year transition period through a customer surcharge. Demand-side management and renewable resource programs are being funded via a second surcharge.

From all accounts, retail choice in Rhode Island has been a failure. The only company competing for residential customers, Sunshine Energy (a subsidiary of FP&L Energy Services) withdrew from the market well over 2 years ago.

When retail choice was first offered, a number of large industrial customers banded together in a group known as The Energy Council of Rhode Island. These customers abandoned the incumbent utility and signed on with competitor Select Energy of Connecticut. When the one-year contract expired, Select Energy declined to renew it and the customers were forced to return to the incumbent (Narragansett). Narragansett agreed to take back the customers but only at a rate known as the "last resort rate" which is in excess of the standard offer rate being charged to all other industrial customers.

Rhode Island PUC member Kate Racine was quoted as saying that, "I think we are being very fair in allowing them back on at these rates" to which the industrial group responded, "The pioneers are getting punished in Rhode Island. It will be quite a while before we will see anyone leaving the standard offer."[10]

4.1.11 Massachusetts

On March 1, 1998, the state of Massachusetts implemented what was described as the nation's most progressive reform of traditional regulation of the electric utility industry. The plan called for immediate full retail choice for all customers and a 10% reduction in residential rates to be followed in September 1999 with an additional 5%

[10] "R.I. Industrials Run From Restructuring," Electricity Daily, June 23, 2000.

reduction. The plan provided for recovery of "prudently incurred" utility stranded costs and included special charges for public benefit programs including energy efficiency and development of renewable energy resources. When the largest power marketers shunned the residential market and other features of the new deregulation law came under closer scrutiny, a ballot initiative campaign was launched in an effort to repeal the new law. The utilities in the state raised and spent about $8.5 million for the campaign and successfully defeated the measure.

As in virtually all states with retail choice programs, public power entities in Massachusetts were exempt from the retail choice mandate provided that they did not provide retail service outside their service territories.

By year-end 2000, regulators in Massachusetts approved significant rate increases for all customers receiving service under so-called "standard-offer" service. Provisions in the state's retail choice law allow utilities to pass along to customers the costs associated with unusual fluctuations in the energy markets.

By most accounts, retail choice in Massachusetts exists on paper only with few customers or alternative power suppliers participating.

5.0 Recent Adopters of Retail Choice

5.1 Ohio

Pursuant to legislation enacted in 1999, Ohio commenced retail choice as of January 1, 2001. Industry newsletter, *Restructuring Today*, noted on May 17, 2001, that "not much is happening". The newsletter interviewed Cinergy chief executive officer James Rogers who speculated that it would be years before a truly competitive market emerges, "because people for 50 years have been buying from their local utility."

In late 2000, MidAmerican Energy became the first company to become registered as a certified competitive supplier in the Cincinnati Gas and Electric territory in southwest Ohio. A MidAmerican Energy press release dated November 27, 2000, stated that, "MidAmerican will compete in Ohio not only on price, but also on the basis of exceptional customer service." MidAmerican established an office in Beachwood, Ohio and is currently contacting customers throughout the state. Little is publicly known about the success of this venture.

The web site of the Ohio Public Utility Commission provides a link to a study conducted by the Center for Research and Public Policy. The study summarizes a survey conducted during April-June 2000 that finds that…

- 38.2% of residential consumers and 53.8% of business consumers report hearing or reading about electric competition in Ohio.

- Utilities in Ohio receive positive ratings among residential and business consumers on "reliable service" -- 89.1% and 83.6% respectively.

- Large majorities of residential and business consumers (86.3% and 85.4% respectively) report having great or some confidence that service will continue uninterrupted in a new, competitive market. Still nearly 10% of each market segment has little or no confidence that service will continue uninterrupted.

- "Lower price" was perceived by both residential consumers (74.2%) and business consumers (76.0%) as the leading advantage to competition.

- The leading disadvantages to competition among residential consumers were slamming, marketing calls, higher prices, and lower reliability levels.

5.2 Illinois

Pursuant to legislation enacted in 1997, Illinois has begun to transition to customer choice. As of December 31, 2000 all non-residential customers have the option to select their energy supplier. Residential customers were given the retail choice option as of May 1, 2002.

Because customer choice is so new in the state, there is little data to show how the law is working. However, the law requires the Illinois Commerce Commission to file an annual report to the legislature on the implementation of retail choice and the most recent report filed in April 2002 offers some sobering views on how retail choice is faring to date.

Below are a few key excerpts from that report:

The trends in the rate of customer switching and other quantitative measures of retail activity that were apparent in 2000 largely continued into 2001. The Commission continues to find signs of retail electric market growth in the service territories of the three largest utilities in the state. In the Commonwealth Edison ("ComEd") service territory, a relatively large and growing number of customers have switched from ComEd's basic bundled service to delivery services, continuing a growth pattern that began as soon as the market opened to electric customers in October 1999. By the end of 2001, over 18,000 ComEd customers had switched either to alternative supplier or to the Power Purchase Option ("PPO"), a market-based service that is available only to the customers of the utilities that assess transition charges. Customer switching is nearing or has surpassed the 1,000 customer mark in the service territories of AmerenCIPS and Illinois Power, the two other utilities that charge transition fees and thus offer the PPO as an alternative to bundled service.

However, customer switching is still negligible or non-existent in the service territories of the state's smaller utilities. After two and one-half years of the availability of delivery services, there are few signs that customers in those service areas will have supply options other than the bundled service offering provided by the utilities when the restructuring law was enacted in late 1997.

The Commission explained in its 2001 report that growth in the retail market is dependent on the competitiveness of the wholesale market. There are indications, however, that the wholesale market is not yet capable of supporting a competitive retail market. One sign of a lack of a vibrant wholesale market is that about half of the power supplied to delivery services customers is being sold to suppliers by the incumbent utilities through the PPO rather than by independent producers. There are few signs at present that this situation will change in the near future.

While 18 suppliers are entitled to sell power and energy, only nine suppliers were active in 2001 (that is, actually made electricity sales). With one exception, each of these suppliers is either an Illinois utility or an affiliate of an Illinois gas and/or electric utility.

The Commission expects a slow start for the opening of the residential market in most areas of the State. One measure of the interest level among suppliers towards the residential market is the number of residential ARES applications. As of April 1, the Commission has not received any applications for certification to serve residential customers. However, as the Commission has received informal interest about certification requirements, including several suppliers not currently serving in the Illinois market, the Commission is hopeful that applications will be forthcoming in the near future.

To date, the restructuring law has provided significant consumer benefits through mandated reductions in residential bundled rates and a commercial and industrial customer rate freeze. In addition, some customers have been able to achieve savings by switching to delivery services, obtaining their electric supply either from the PPO or from Retail Electric Suppliers. While these are tangible benefits of the restructuring law, the rate freeze and mandated rate reductions end on January 1, 2005. The energy component of bundled service rates, as well as the price of energy to delivery services customers, will then be determined by the potentially volatile electricity wholesale market.

The development of robust wholesale competition would clearly be the ideal solution to the potential problems ahead. However, there is no guarantee that robust wholesale competition will develop in Illinois by January 2005. Unreasonably high wholesale electricity prices, attributable to the market power of sellers, may prevail as long-term contracts expire.

5.3 Texas

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

Following are the key provisions of the new law:

- Freezes electric rates for investor-owned electric utilities in Texas through 2001.
- Prohibits large utilities from lowering their rates for residential and small commercial customers before 2005, or until 40 percent of their customers are served by competitors.
- Exempts electric cooperatives and city-owned electric companies from customer choice unless their governing boards decide to open their markets to competition.
- Allows customers the choice of using renewable energy (wind and solar power) for example.
- Requires older electric generators to meet current environmental rules by 2003 or be shut down.
- Creates a fund to pay for lower rates for low-income families and property tax losses for affected school districts.
- Provides for automatic enrollment of qualified low-income families in low-income assistance programs.
- Prohibits disconnection of service for nonpayment during periods of extreme weather.
- Allows customers to receive one bill for their electric service in an easy-to-read format and understandable language.
- Creates a Do Not Call list for customers who do not wish to be called by telemarketers on behalf of electric service providers.
- Provides customer protection against discrimination, against being billed for unauthorized charges (cramming), against unauthorized change of service provider (slamming) and other unfair, misleading and deceptive practices.

Texas has noted it is considerably different than California in its approach to retail deregulation. Generation capacity has been expanded within the state, so it does not rely on imports of electricity. With an expected peak demand of 67,000 megawatts, statewide capacity this summer is at 83,000 MW which provides a 24 percent reserve margin according to a June 20, 2001, news release from the Public Utility Commission of Texas. However, transmission investment has not kept up with generation expansion. Also, more than 45 percent of the generation is gas fired, leading to some concerns about future volatility in gas prices.

The jury is still out on the State of Texas Electrical Deregulation. After a brief pilot program last summer to test the waters nearly the entire state of Texas was struck with electrical deregulation on January 1st of this year and a 6.5% decrease in rates. Little detail or the actual numbers of customers switching providers have been provided in the articles reviewed. TXU does indicate they have done minimal switching. Most of the articles searched on the internet were written prior to the January 1st deregulation date and were speculative in nature.

Deregulation of retail sales of electricity in southeast Texas will be delayed until 2003 due to the lack of a regional transmission organization (RTO). Investor utilities serving southeast Texas did not draw competition during the pilot program. With an RTO there are hopes to get out-of-state competitors to ship electricity into southeast Texas. Also in northwestern and southwestern Texas, deregulation has also been delayed because those areas are not ready (no information was given as to why).

Under the Texas deregulation program, electric utilities were divided into three areas: retail, power generation and transmission and distribution. Any investor-owned companies that wish to enter the retail market must create an affiliate company. To ensure deregulation, the Texas Public Utilities Commission created a price-to-beat for investor-owned affiliates that will remain in place until 2005 or until 40% of customers switch to another retail company.

Uninterested Consumers/Program Glitches

Despite aggressive promotional campaigns (billboards, TV, radio ads, direct mail), the average Texas consumer still isn't convinced there is much value in switching providers. Interest is not much higher among commercial and industrial companies. Household surveys taken show that a large majority indicates no plans to switch. The tough sell for electrical deregulation for some can be traced to past telephone deregulation which left some homeowners without phone service for a week or more. For the fear of blackouts some did not participate in the pilot deregulation program, with only 39% of those eligible households participating.

Startup delays, lag (sometimes months) in switching customers to new providers, and computer problems at the Electric Reliability Council of Texas (ERCOT) in the pilot program have contributed to this consumer reluctance to switch providers. Also some major providers in the pilot program have since left the market. There have been comparisons drawn to the deregulation of the telephone market of past which showed a pattern of initial competition, followed by reduced prices, higher levels of innovation and subsequent market consolidation.

The aftermath of the California troubles and bankruptcy of Enron Corporation have also cast a shadow over deregulation. Recent disclosures of trading irregularities at Dynegy and Reliant have also created further doubts in consumers' minds.

The real battleground for incumbent utilities appears to be large industrial and commercial accounts. It appears that a monopolistic or duopolistic market scenario will be maintained for consumer accounts over the near term and a more fragmented market will emerge for commercial and industrial accounts.

Positive Comments
On the positive side in contrast to California, Texas has plenty of power plants to supply power. Texas deregulation law also allows incumbent utilities to raise rates twice a year when natural gas rates change, shielding them from bankruptcy when power prices skyrocket. ERCOT's chief executive officer, Tom Noel, expects to be tinkering on the system for several years to fine-tune the final product. Texas PUC say they are encouraged and the market is in a transition phase. The head of TXU, chairman Erle Nye, still supports deregulation and predicts it will benefit Texas through lower electric rates and better service. He continues to say he is disappointed with the snags that are occurring and the trial pilot program should have been given more time and also deregulation phased in more slowly.

Continued Unrest
Recently there have been calls by a member of the state legislative committee overseeing deregulation for the resignation of ERCOT's Tom Noel, for technical difficulties that continue to dog Texas deregulation. TXU recently announced that as many as 150,000 customers have gone without bills for several months and many municipalities report hundreds of thousands in lost savings because of billing problems.

ERCOT Chairman Jack Hawks recently stepped down because he does not have the confidence of all key constituents due to criticism from state legislators and others for failing to quickly correct customer switching and other problems.

On June 18, impatient state lawmakers gave notice they were losing patience and prepared to start fixing persistent problems in the state's deregulated market. They further ordered the PUC to step in and supervise election of a new ERCOT Stakeholders board.

Until the switching process is smoothed out consumers will continue to resist deregulation as they see no positive value in changing providers. Only time will tell the complete story.

6.0 Reconsideration of Retail Choice

6.1 Nevada

In 1997 the Nevada legislature enacted legislation calling for the implementation of retail choice. Additional legislation was enacted in 1999 delaying the onset of such competition until March 1, 2000 unless a determination was made that a later date was necessary to protect the public interest.

In 2001, Assembly Bill No. 369 was enacted that effectively repealed the implementation of retail choice. The preamble of the repeal legislation provides insight into the view of the state legislature on this question. Here are some excerpts from the preamble of the repeal legislation.

Several of the major industries in this state are particularly dependent upon electricity. Under present market conditions in the electric industry, comprehensive and effective regulation of electric utilities in this state is vital to the economy of this state and is essential to protect the health, safety and welfare of the residents of this state. Until present market conditions have changed and adequate mechanisms have been developed to allow this state to adjust its comprehensive regulation of electric utilities in Nevada, this state has a compelling interest in continuing its comprehensive regulation of electric utilities to protect the consumers in this state, to safeguard the economy of this state and to ensure that the electric utilities in this state provide adequate and reliable electric service at just and reasonable prices.

In recent years, the western United States has experienced a severe and ongoing crisis in the electric industry marked by critical shortages in the supply of electricity and extreme volatility in the price of electricity in the wholesale and retail markets. The severe and ongoing crisis in the electric industry in the western United States is both an immediate threat and a continuing danger to the economy of this state and to the health, safety and welfare of the residents of this state.

Until the severe and ongoing crisis in the electric industry in the western United States has sufficiently abated, this state must maintain its comprehensive regulation over electric utilities and its traditionally broad jurisdiction and control over electric generation assets to promote stability and predictability in the electric industry, to foster confidence in the financial markets, to ensure that consumers have adequate and reliable electric service and to protect the public from unjust and unreasonable utility rates.

6.2 Arkansas

The Arkansas General Assembly enacted retail choice legislation in 1999 and amended it during the 2001 session. The amended bill postpones the start of retail competition in Arkansas from Jan. 1, 2002, until at least October 2003 and no later than October 2005. Spurred by concerns over deregulation issues in California, the Arkansas Public Service Commission (APSC) called a collaborative meeting in October 2000 of staff, investor-owned utilities, electric co-operatives, the attorney general, municipalities and industrial customers to examine the future of retail open access. The amended legislation was the final result.

Below is an overview of the key provisions of Arkansas' amended restructuring plan.

6.2.1 Customer Choice

- Retail competition may begin as soon as Oct. 1, 2003 or it may be delayed by the APSC in one-year increments until Oct. 1, 2005.
- Investor-owned utilities and retail electric co-ops will participate in retail open access. Municipally owned utilities may opt in, but must open their markets to competition if they choose to do so.
- Customers who do not affirmatively choose an alternate supplier will stay with the utility's affiliated energy service supplier (ESP).

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

6.2.2 Customer Protections/Reliability

- The Arkansas PSC is working with various stakeholder groups to adopt consumer protection rules on a range of consumer issues.
- The Arkansas PSC will license and register suppliers.

6.2.3 Rate Freeze

- Incumbent utilities have an obligation to provide default service, at frozen rates for a set time period.

6.2.4 Market Structure/Market Power

- Act 1556 requires functional unbundling of generation, transmission and distribution/customer service business activities.
- All utilities and affiliate ESPs were required to file a market power study no later than January 2001. Accordingly, Southwestern Electric Power Company (AEP -SWEPCO) filed its market power study in November 2000. Pending analysis of these reports, the following may be required:
    - price caps.
    - asset separation.
    - auctioning of default customers and
    - as a last resort, divestiture of power plants.
- Companies must file a code of conduct with the APSC that is consistent with the Arkansas affiliate rules to prevent utilities from unfairly favoring their affiliates or harming competitors.

6.2.5 Stranded Cost Recovery

- Stranded costs may be recovered, but in order to do so, utilities must use all reasonable mitigation measures.

6.2.6 Other Key Provisions

- Bill production and issuance, credit and collections and call center functions related to bill production and issuance and credit and collections have been deemed competitive services.
- Utilities may recover all reasonable costs directly incurred by the transition to competition for three years following the start of retail competition. Default service rates cannot be increased to recover transition costs.

6.3 Oklahoma

Under the state's 1997 law, retail access was scheduled to begin on July 1, 2002, pending passage of a more detailed restructuring implementation law. A restructuring implementation bill failed in the 2000 legislature and higher energy prices in the region and broad public awareness of the California energy situation made passage of implementation legislation a political impossibility for now. In the 2001 session of the legislature, a bill was enacted (SB 440) and has now been signed by Governor Keating which contains the following primary features:

- To delay implementation of retail competition until restructuring can be studied further,
- To require passage of enabling legislation to restart restructuring,
- To establish a study group to examine the state's transmission infrastructure and restructuring and
- To create tax credits to subsidize electricity produced by new renewable resources.

The legislation, as an emergency bill, became effective immediately upon its June 4 enactment.

6.3.1 Conditions for Starting Retail Competition

While the measure does not specify a date when retail competition may be implemented, it does set general milestones that must be passed before retail competition can begin. Retail access can not be implemented in Oklahoma until:

1. The final report of the Advisory Committee is completed, which must be done by Dec. 31, 2002; and
2. "Electric restructuring enabling legislation is adopted by the Legislature and signed by the Governor."

Reauthorizing restructuring probably would be required even though SB 440 does not revoke any restructuring-related provisions of the 1997 law except the July 1, 2002, start date.

6.3.2 Restructuring Advisory Committee

The law directs the Electric Restructuring Advisory Committee to:

- Study the current status of the state's electric transmission system as well as the study conducted by the Southwest Power Pool to identify potential points of congestion and suggested future transmission expansion including their financial impacts;
- Examine the electric issues report submitted to the legislature on Oct. 1, 1999;
- Analyze the operational characteristics and control systems of the current electric industry transmission infrastructure in the state;

- Solicit comments from consumers;
- Review any proposed federal legislation that may affect the state's electric industry;
- Examine how to encourage further development of "zero-emission electric generation facilities";
- Identify "management and control practices adopted by other states" for implementing restructuring and recommend those practices that may be of public benefit in Oklahoma; and
- Identify any other issues "relevant and necessary for the Advisory Committee to carry out its duties."

The nine member Advisory Committee will be in place until January 2005, unless terminated earlier by a majority of its members.
The interim report on transmission issues must be completed by Dec. 31, 2001. The final restructuring report must be adopted by a majority of the committee and be delivered to the governor and the legislative leadership by Dec. 31, 2002.

6.3.3 Renewables Tax Credit

SB 440 establishes a new tax credit for tax years beginning on or after January 1, 2002, to offset the tax liability for a taxpayer's production and sale of electricity generated by eligible zero-emission facilities in the state. Eligible generation is a new renewable resource with a production capacity of 50 megawatts or larger using wind, moving water, sun or geothermal energy, and which resource is placed in operation after the effective date of SB 440. The credit is applied as a subsidy over 10 years on a declining scale.

6.4 Florida

In November of 2001, Governor Jeb Bush's 2020 Study Commission issued a final report calling for the state to transition to a competitive wholesale electric market. However, the Commission recommended that the retail electric market remain regulated.

6.5 Louisiana

The Louisiana Public Service Commission issued an order in December of 2001 that reaffirmed their earlier conclusions that retail competition in Louisiana, which is a low cost state, would not be in the public interest for any class of retail customer.[11] The Commission stated it's responsibility was to ensure ratepayers receive electric service at the lowest reasonable cost and that "retail competition in the electric industry has not achieved the success predicted by its proponents in any state where it has been implemented…".

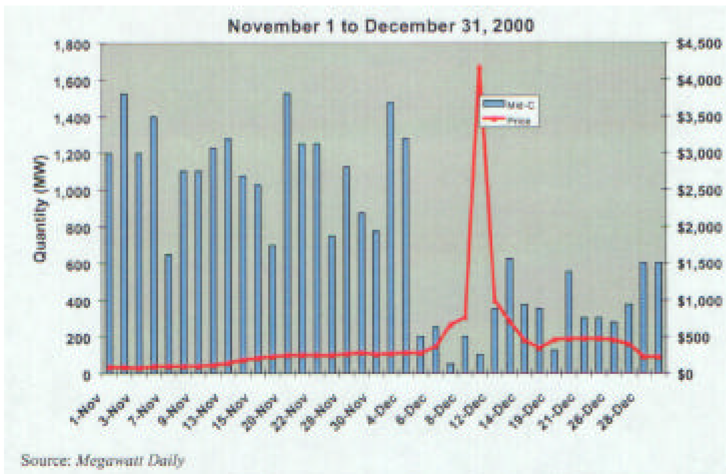
The Commission began its study of retail competition in 1995. In 1997, the Commission's staff issued a report stating that retail competition might be in the public interest, depending on a number of factors and further studies. Upon further study, in 1999 the Commission staff concluded that retail competition was not in the public interest at that time. They stated it was unlikely to result in lower electric rates for Louisiana consumers. However, the Commission directed their staff to prepare a comprehensive plan for a transition to competition. In January of 2001 the staff submitted their plan for competition under which only industrial customers with average loads greater than 5 MW would be able to choose alternative suppliers. In its order of December 4, 2001 declining to pursue retail competition, the Commission directed staff to continue to monitor retail competition in neighboring states like Texas and developments at the federal level and report back annually.

7.0 Regional Impacts

The crisis in California affected the price of wholesale energy throughout the entire western grid that includes California, Oregon, Washington, Montana, Nevada, Idaho, Utah, Colorado, Wyoming, New Mexico, and Arizona (a small portion of far western Nebraska is also in the western grid). Volatile wholesale electric markets resulting, in part, from poorly implemented retail deregulation can have tremendous impacts on the price of electricity in states that have formally rejected retail choice. For example in Washington, which has not implemented retail choice, prices briefly reached several thousand dollars per megawatt-hour (MWH) in the wholesale market in December 2000 [see Exhibit V-9] and were averaging approximately $300/MWH through the first five months of 2001.

[11] Louisiana Public Service Commission, *in Re: Analysis of Competitive Implications, Ex Parte;* Docket Nos. U-21453, U-20925 (SC), U-22092 (SC) - (Sub-docket A) - B, (December 4, 2001).

Exhibit V-9
Price and Quantity at Mid Columbia Day-Ahead On-Peak Power



For a comparison to 1990's prices, see Exhibit V-10.

Exhibit V-10
Average Cost of Power Purchases by Utilities 1990-1999
($/MWH)

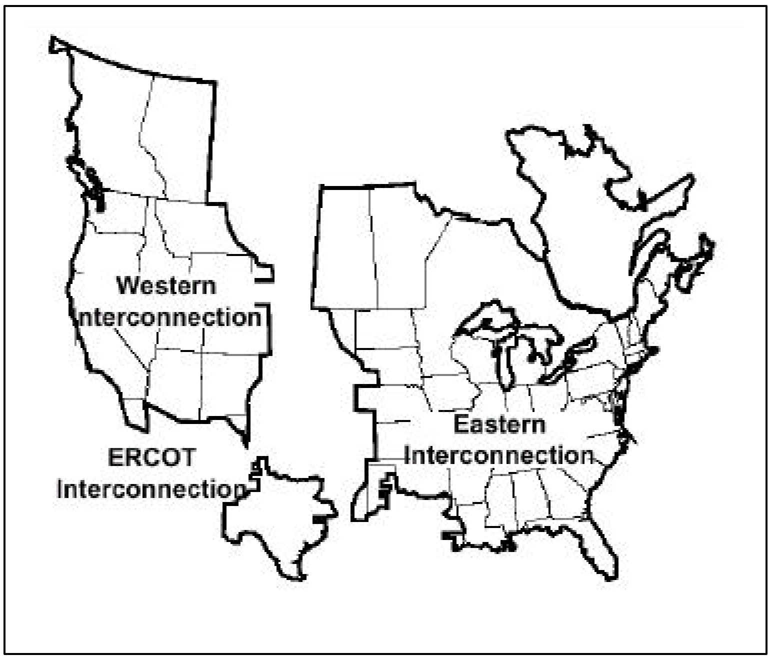
	WSCC Subregion				
Year	**Arizona**	**California**	**Northwest**	**Rockies**	**Total**
1990	**$38**	**$53**	**$20**	**$28**	**$38**
1991	**$36**	**$52**	**$20**	**$30**	**$37**
1992	**$38**	**$57**	**$22**	**$32**	**$40**
1993	**$36**	**$58**	**$25**	**$31**	**$41**
1994	**$37**	**$61**	**$27**	**$36**	**$42**
1995	**$35**	**$57**	**$25**	**$35**	**$40**
1996	**$32**	**$54**	**$29**	**$34**	**$36**
1997	**$31**	**$50**	**$24**	**$35**	**$33**
1998	**$30**	**$55**	**$29**	**$36**	**$36**
1999	**$27**	**$45**	**$31**	**$30**	**$35**

Source: Resource Data International, PowerDat Database, January, 2001.

ExhibitV-11 below shows the three transmission interconnections in the lower 48 states and Canada.

Exhibit V-11

Three Transmission Interconnects



Each grid is essentially self-contained and there is only limited transfer capability between grids. Thus, surplus supplies or low generating costs in one grid are generally not transferable to another. Furthermore, the nation's electric transmission grid was primarily built by individual utilities to move electricity from generation facilities to distribution facilities. Following the Northeast blackout on November 9, 1965, in which 30 million people lost power, electric utilities formed the North American Electric Reliability Council (NERC). Greater emphasis was placed on interconnecting the transmission of individual utilities to improve regional reliability by providing emergency power among utilities through the creation of ten regional power pools. In some regions such as the Mid-Continent Area Power Pool (MAPP) in which Nebraska is located, there were also increased wholesale sales between utilities, but nothing approaching the level experienced in the past few years. The transmission grid was not designed to facilitate massive transfers of wholesale energy across large regions.

8.0 Consideration of Retail Choice by Neighboring States

The six states that border Nebraska have all considered revisions to their laws for the purpose of implementing a retail choice regime – all six states have rejected such a move. In general these states, either through regulatory or legislative action, have concluded that the conditions for a successful implementation of retail choice are not yet present and that moving to choice is not in the best interests of customers in their state at this time.

8.1 Colorado

During 1998, the Colorado Legislature enacted Senate Bill 98-0152 that established the Colorado Electric Advisory Panel. The legislation called for the panel to make recommendations regarding the feasibility and desirability of implementing a retail choice regime in the state. The engineering/consulting firm of Stone and Webster was engaged to analyze the energy and economic modeling issues associated with the issue.

The Stone and Webster report concluded that, "restructuring the electric industry in Colorado will likely lead to an increase in retail electricity rates throughout the state. This finding holds for the current customers of all utilities, for all but one customer class (irrigation customers), for all years, for all regulatory cases considered, and for all scenarios considered."[12]

On November 1, 1999 the Advisory Panel issued its final report. Of the 29 members on the panel, 17 voted that retail choice was not in the best interests of the State while 12 members voted in favor of pursuing deregulation.

The study notes that, "In summary we believe restructuring of the retail electric industry is not in the best interest of all Colorado consumers and the State as a whole for the following reasons:

- Colorado's electric rates are relatively low. States that have actually implemented retail restructuring have almost always been high cost states. Significantly different issues arise when low cost states like Colorado consider adopting retail restructuring of the electric industry.
- The Panel's consultant, Stone & Webster, which has conducted the only thorough study to date of retail restructuring impacts specific to Colorado, found that under every tested scenario, rates, on an average basis, were likely to go up—as much as 29% more than under the existing system over a twenty (20) year period—if retail restructuring were implemented.
- The predicted rate impacts will be disproportionate with low income, fixed income, rural, residential, and small business consumers suffering rate increases greater than the Stone & Webster projections, i.e., if large commercial and industrial consumers see decreases, then other consumers will see even greater increases than those projected."[13]

8.2 Iowa

The Iowa State legislature devoted considerable time debating the merits of retail choice. During the 1999 and 2000 sessions of the legislature, retail choice legislation was the focus of attention. The Des Moines Register reported on April 12, 2000, that the state's two largest investor-owned utilities (Mid-American Energy and Alliant Energy) spent over $200,000 on lobbyists in an attempt to advance legislation.

Mid-American Energy launched a retail choice pilot program in Council Bluffs. The intent of the pilot was to demonstrate that multiple energy suppliers and marketers would seek to serve residential and small commercial customers if given the opportunity to do so. After a year or more of considerable effort, not a single competing firm entered the pilot. The Iowa Utilities Board terminated the pilot at mid-year 2000.

On March 2000 the Iowa legislature concluded its consideration of retail choice for the session and failed to advance a bill to the Governor.

8.3 Kansas

In April 1996, the Kansas Legislature enacted House Bill No. 2600 that created a Legislative Task Force to study electric retail competition. The Task Force engaged the services of the McFadden Consulting Group of Arvada, Colorado and Resource Data International of Boulder, Colorado to conduct a study of the subject. The study found that, "Many experts believe restructuring of the electric utility industry will provide economic benefit to consumers. Our analysis in this report supports that conclusion for the customers in Kansas." The report further found that, "Competition is more effective than regulation at maintaining discipline in the marketplace" and that, "On an average statewide basis, prices in a deregulated market will be lower than in a regulated environment."[14]

[12] Report to the Colorado Electric Advisory panel prepared by Stone & Webster, July 1999, p. ES-2
[13] Final report of the Colorado Electricity Advisory Panel, November 1, 1999, p. 3 (Executive Summary)
[14] "An Analysis of the Impacts of Retail Wheeling on the State of Kansas"; McFadden Consulting Group, August 18, 1997, see Executive Summary.

That same year (1997) the Kansas Corporation Commission received a report prepared at its request by the National Regulatory Research Institute (NRRI) that reached similar conclusions by noting that, "retail competition should effectuate a more consumer-responsive, efficient electric power industry in Kansas. Consumers should see lower prices and the availability of additional electric services. The pertinent questions attending retail competition are not 'if' but 'how' and 'when'." The NRRI study took issue with an earlier study conducted by the Docking Institute for being "overly gloomy" in its assessment of retail choice. According to NRRI, the Docking Institute study incorrectly depicted retail choice as taking wealth away from rural areas and redistributing it to urban areas. The NRRI concluded that, "Taking everything into account, the best strategy for Kansas would be, in the shortest time possible, to pass legislation that would open up the state's retail markets to competition."

The NRRI conclusions were premised on the notion that, "Kansas cannot be characterized as a low-cost state for which under open markets, electricity prices would rise toward the regional average. Electricity prices in Kansas are currently above those in surrounding states."[15]

A third study released in 1997 also added fuel to the push for retail choice in Kansas. A report issued by the Hugo Wall School of Urban and Public Affairs of Wichita State University found that all customers would benefit from retail choice but cautioned that, "Industrial customers are likely to be the major beneficiaries of a price-fixed competitive marketplace because of the electricity-intensive nature of their operations."[16]

Notwithstanding the urging of retail choice proponents, the Kansas State Legislature has not enacted retail choice legislation.

8.4 Missouri

The Missouri Public Service Commission appointed 35 individuals to serve on the Retail Electric Competition Task Force in its Order of May 23, 1997. The Task Force was charged with preparing comprehensive reports to the Commission, based upon thorough investigation and study of retail wheeling of electricity and related issues, that recommend how Missouri should implement retail electric competition in the event that legislation is enacted which authorizes it.

On May 1, 1998 the task force submitted its report and concluded that, "the introduction of retail competition should proceed only if it can be shown to benefit all classes of consumers and should be implemented consistent with this goal. Regulation must continue for services that are not subject to full and fair competition. The appropriate regulatory authority must manage the transition to full and fair competition by monitoring market conduct, addressing any anti–competitive practices and mitigating market power."[17]

The report detailed a number of consumer safeguards that should be in place in the event that the Missouri legislature advanced a bill implementing retail choice. A number of bills were introduced in recent years but the political climate has not been conducive to passage. Thus Missouri, like the other states in the region, is taking a wait-and-see attitude toward retail competition.

8.5 South Dakota

There has been only minimal interest in retail choice in South Dakota. In 1999 the Business Research Bureau of the University of South Dakota published a study on electricity restructuring and the impact on electric cooperatives. The study concluded that under retail choice, "South Dakota rural electric cooperative residential customer's billings are projected to increase and their large industrial customer's billings are projected to decrease."[18]

[15] "An Assessment of Retail Competition in Kansas' Electric Power Industry"; National Regulatory Research Institute, September 1997, see Executive Summary.
[16] "The Impact of Retail Wheeling on Municipal Electric Utilities in Kansas."
[17] Report of the Retail Electric Competition Task Force, May 1, 1998, p. 28
[18] "Electricity Pricing in a Restructured Electric Power Industry", Business Research Bureau, University of South Dakota, January 14, 1999, see Executive Summary

In light of the highly rural nature of the South Dakota market and the relatively low cost of power, there has been no substantial legislative interest in pursuing retail choice.

8.6 Wyoming

On May 14, 1996, the Wyoming Public Service Commission hosted a Stakeholders Dialogue and Collaborative on Electric Restructuring Issues in Casper, Wyoming. Because the idea of electric industry restructuring is complex, the Commission established six subcommittees to comment on the broad issues of electric restructuring in Wyoming. The process eventually resulted in the development of a white paper on the concept of retail choice in Wyoming. The paper did not result in firm conclusions one way or the other on the desirability of retail choice but rather was a comprehensive discussion of the many policy issues associated with such a policy move.[19]

The white paper recommended a study of the economic impacts of restructuring and subsequently hired Black and Veatch to conduct the work. This study, issued in September 1997, predicted only small benefits from retail choice.[20]

There has been only minimal legislative interest in retail choice and no legislation has been enacted on the subject.

9.0 Federal Issues

Considerable discussions about electricity deregulation began during the 105th Congress (1997-98) and continue today. There has been no significant Federal legislation passed to date; however, energy bills have passed both the House and the Senate and are currently being discussed in conference. See discussion below.

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

Congress has been also dealing with electricity reliability issues. In 2000, Slade Gorton, (R-WA) introduced S.2071 ‘The Electric Reliability Act’. It passed the full Senate, but failed to gather enough support in the House prior to the conclusion of the 106th Congressional Legislative session last year. Reliability problems have increased with the changing roles of industry participants.

In the House of Representatives, national energy policy legislation (H.R. 4) was introduced on July 27, 2001 and was passed on August 2, 2001. S.517 was brought directly to the Senate floor without committee debate and passed on April 25, 2002, after weeks of robust debate.

H.R.4, Securing America's Future Energy Act, contains important provisions impacting public power electric utilities including: energy efficiency program reauthorization and funding, weatherization assistance program authorization and funding, taking the Nuclear Waste Fund off budget to remove artificial spending limits, reauthorization (for a 10-year period) of the Renewable Energy Production Incentive (REPI) Program, clean coal technology funding, authorizes funding for the DOE's Nuclear Energy Plant Optimization Program, and some private use tax relief for public power. Provisions also would allow for oil and gas drilling on a portion of the Arctic Wildlife Refuge.

S.517, the Senate bill, is significantly different from H.R. 4. S.517 has three basic goals:

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[19] “White Paper on Electric Utility Industry Restructuring Issues”, November 12, 1996, Wyoming Public Service Commission.

[20] Study of the Potential Economic Impacts of Electric Restructuring on the State of Wyoming, Black and Veatch, September 1999, see Executive Summary

- Promote fuel diversity and renewable energy
- Improve efficient transmission and use of energy in industry, automobiles, buildings, and appliances
- Protect environment and begin addressing global climate issues

Some of the more specific issues include:

- Federal vs. State Jurisdiction
- Reliability
- Mergers
- Market Transparency
- Market-Based Rate Authority
- Renewable Portfolio Standard (RPS)
- Federal Purchase Requirement
- Pilot Program
- PURPA Reform
- PUHCA Repeal
- Pricing
- Hydro Re-licensing
- Price Anderson Act
- Renewable Energy Production Incentives (REPI)
- Clean Coal Incentives
- Private Use Tax Rules
- Climate Change

Whether compromise legislation can be agreed to should be known by October, 2002. Depending on its final form, this legislation could dramatically impact the electric industry throughout the nation.

9.1 Bush Administration National Energy Policy Recommendations

On May 17, 2001 the Bush Administration National Energy Policy Development Group released its Final Report of Recommendations for a comprehensive national energy policy. While a total of 105 specific policy recommendations were included in a total of eight separate chapters, the following bullet points summarize some of the recommendations potentially impacting the electric power industry:

- The U.S. Environmental Protection Agency (EPA) should be directed to work with legislators to introduce multi-pollutant legislation that significantly reduces and caps emissions of sulfur dioxide, nitrogen oxides and mercury from electric power generators. Included should be:
  - Mandatory reduction targets
  - Phased in reductions
  - Provisions to allow utilities make modifications to their plants without fear of litigation
  - Market-based incentives
- The Office of Science and Technology and the President's Council of Science and Technology should make energy efficiency recommendations.
- The Secretary of Energy should promote energy efficiency and analyze the research and development programs in place relative to energy efficiency then make recommendations for future budget. These recommendations should include provisions for private partnerships.
- The Secretary of Energy should improve energy efficiency of appliances.
- Federal agencies should take measures to improve energy efficiency, especially those in areas with energy shortages

- Directs the Secretary of Energy to propose comprehensive electricity legislation.
- PUHCA should be repealed and PURPA should be reformed.
- FERC should be encouraged to use its existing statutory authority to promote competition.
- $2 billion over the next 10 years should be devoted to clean coal technology. The research and development tax credit should be permanently extended.
- Nuclear energy should become a major component of our national energy policy. Licensing of reactors should be responsible but less stringent. EPA should be directed to study the Air Quality benefits of nuclear power and the Price-Anderson Act should be renewed.
- Exploration of advanced nuclear fuel technologies should be revisited.
- The licensing process for hydropower should be more efficient.
- Access to federal lands should be re-evaluated in order to increase biomass, solar and wind-based energy.
- The report supports a $39.2 million increase in DOE's supply account for research and development of renewable energy sources.
- Tax credits should be offered for new landfill methane projects, biomass projects and wind technologies. Residential solar energy property should be encouraged with a 15% tax credit – maximum $2,000. The ethanol excise tax exception should be continued.
- EPA should develop an industry partnership that encourages and rewards companies for buying renewable energy. The partnership should also make renewable energy more accessible for companies.
- $1.2 billion of bid bonuses for the responsible leasing of ANWR should be allocated for research and development of renewable energy sources.
- Next generation technologies such as hydrogen and fusion should be developed.
- FERC should improve reliability of the interstate transmission system.
- Appropriate agencies should remove current constraints on the interstate transmission grid. The Secretary of Energy should complete a report by December 31, 2001 that explores a national energy grid.
- FERC, the Secretary of Interior and the State of Alaska should work with Canada to and other interested parties to expedite the construction of a natural gas pipeline to the lower 48 states.
- EPA should review existing enforcement actions for New Source Review and present a report to the President within 90 days. The Attorney General should review the enforcement actions to ensure that they are consistent with the Clear Air Act.

9.2 FERC

The Federal Energy Regulatory Commission (FERC) regulates wholesale power sales and transmission transactions of jurisdictional utilities (investor-owned utilities, not public power, cooperatives, or federal utilities). Following passage of the Energy Policy Act of 1992, FERC has played a major role in developing regulatory policies designed to promote wholesale electric competition through open access transmission and through the creation of new regional transmission entities. Nebraska's electric utilities are non-jurisdictional. However, several transmission-owning utilities in Nebraska have voluntarily pursued arrangements to participate in FERC-approved transmission organizations.

On June 18, 2001 the Federal Energy Regulatory Commission voted unanimously to extend wholesale price controls over California spot market sales as well as spot market sales in the entire 11-state Western System Coordinating Council. For sales during Stage 1, 2, or 3 emergencies in California, prices would be capped at the highest cost generation delivered to the market. During non-emergency time periods, the prices are capped at 85% of the highest cost generation that was in effect during the most recent Stage 1 reserve deficiency period called by the California Independent System Operator. FERC purports to subject public power systems to these measures as a condition of access to the grid. The order is being challenged by several public power entities from California. One of the key issues for Nebraska will be whether FERC's current lack of authority over public power transmission and rates can be altered without federal legislation, if at all.

On July 12, 2001, FERC issued orders, the purpose of which is to create four regional transmission organizations. FERC's orders mandate action designed to create Southeast and Northeast RTOs. The orders do not require immediate action for the Midwest or West RTOs. See FERC Dockets RTO 01-99-000 and RTO 01-100-000. FERC's ability to make that happen and how Nebraska's public power, cooperative and federal transmission facilities might be voluntarily integrated in the process remain as open questions.

10.0 Conclusions

The establishment of the "condition-certain" approach in LB 901 has proven to be a wise policy decision by the State of Nebraska. This approach recognized the necessity of conditioning retail choice upon the establishment of adequate regional wholesale energy markets and adequate transmission networks, among other issues. Several of the states which opened retail electricity markets or were scheduled to do so on a "date certain" basis have retrenched and are now paying far greater attention to the need to establish viable regional wholesale markets prior to further implementing retail choice.

The following summarizes the conclusions of the report of Technical Group No. 5.

- Rates in retail choice states have been reduced primarily through regulatory mandates and capped during transition periods
- Wholesale prices have increased throughout most of the nation but declined significantly in June 2001 across the western United States
- Marketers have withdrawn or scaled back in many states with retail choice programs
- Few customers have switched suppliers in most retail choice states (and many of them have returned to incumbent utility)
- California/West Coast Energy Crisis has slowed national interest in retail choice
- Retail choice has taken a back seat to energy supply and other wholesale issues at the federal level
- Promises of wholesale or retail competition driving down energy prices have been generally unfulfilled thus far
- Retail choice is still alive and continues to evolve
- Must get wholesale markets right prior to implementing retail choice legislation
- Adequate power supply and reserves are crucial
- Adequate transmission is crucial
- Increased stability of fuel prices is needed for retail choice programs to function properly
- Better customer response to wholesale price signals are needed
- Development of a comprehensive energy policy has gained significant attention in Congress and the Bush Administration, but details are far from decided due, in part, to narrow political majorities
- FERC is actively involved in developing and addressing the transition to a more competitive wholesale market

GLOSSARY

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

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

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

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

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

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

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

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

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

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

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

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

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

Contract Path: The most direct physical transmission tie between two interconnected entities. When utility systems interchange power, the transfer is presumed to occur over the contract path 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.

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

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

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

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

FRCC: Florida Reliability Coordinating Council

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

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

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

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

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

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

LES: Lincoln Electric System

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

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

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

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

LR 455: Legislative Resolution 455 was a three- year review of the electric industry in Nebraska, commissioned by the Nebraska State Legislature in1997, that recommended and formed the basic premise of the "Condition Certain" approach to electric deregulation in Nebraska.

MAAC: Mid-Atlantic Area Council

MAIN: MidAmerican Interconnected Network

MAPP: See Mid-Continent Area Power Pool

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.

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.

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

SERC: Southeastern Electricity Reliability Council.

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

SPP: Southwest Power Pool.

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.

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