ANNUAL REPORT-2008
MONITORING OF
"CONDITIONS CERTAIN" ISSUES
IN NEB. REV. STAT. § 70-1003(6)
(Formerly referred to as Legislative Bill 901)

OCTOBER 2008

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INTRODUCTION

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

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

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

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

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

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

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

NAME		REPRESENTING
Fred Bellum	-	American Association of Retired Persons
Tim Burke	-	Omaha Public Power District
Marvin Fishler	-	Irrigation Customer
Gary Hedman	-	Southern Public Power District
Jay Holmquist	-	Nebraska Rural Electric Association
Clint Johannes	-	Nebraska Electric Generation & Transmission Cooperative
Eric Hixon	-	Central Nebraska Public Power & Irrigation
Gary Mader	-	Grand Island Utilities
Derril Marshall	-	Fremont Utilities
John McClure	-	Nebraska Public Power District
Dave Mazour	-	Tri-State Generation and Transmission Association, Inc.
Dan Mechtenberg	-	Aquila
Bruce Pontow	-	Nebraska Electric Generation & Transmission Cooperative
Virginia Bigelow	-	Nebraska League of Women Voters
Nancy Packard	-	Nebraska League of Women Voters
Frank Reida	-	Residential Customer
Marvin Schultes	-	Hastings Utilities
Adam Smith	-	Industrial Customer
J. Gary Stauffer	-	Municipal Energy Agency of Nebraska
Kurt Stradley	-	Lincoln Electric System
Neal Suess	-	Loup River Public Power District
Tim Texel	-	Nebraska Power Review Board (NPRB)

The NPRB retained PAPE CONSULTING SERVICES as the Coordinating Consultant for the report periods of 2001 through 2005. RON MORTENSEN, P.E., became the Coordinating Consultant for reports beginning with the 2006 report. The Consultant is responsible for coordinating the activities and meetings of both the Technical and Review Groups, and for assembling the annual report. The first Annual Report was issued in October 2001, with subsequent reports issued in October 2002, 2003, 2004, 2005, 2006 and 2007.

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

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

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

This 2008 report is the eighth report following up on the five "Conditions Certain" issues identified in LB 901 (2000). All eight reports are similar in format and content in order to carry background information forward for new readers. Changes to the report reflect changing conditions and results.

EXECUTIVE SUMMARY

The five Conditions Certain issues identified in § 70-1003(6) were assigned to five separate Technical Groups. This Executive Summary includes an overall summary and the specific new findings and conclusions of those Technical Groups, that are incorporated in the 2008 Update, as well as the findings and conclusions from the prior years' reports.

A significant new item considered by the Conditions Certain study process in 2008 is the plan for Nebraska utilities to join the Southwest Power Pool in early 2009. Chapters One and Two of this report discuss those changes.

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

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

The overall results of the 2008 conditions certain report indicate that all three conditions have not been met, as indicated by the following:

- Viability of a regional transmission organization and adequate transmission exist in Nebraska or a region that includes Nebraska:
    - A viable regional transmission organization will exist upon completion of membership of Nebraska transmission owners in the Southwest Power Pool scheduled for April 1, 2009
    - Adequate transmission will exist in the region to make transactions sought by utilities and marketers when developed through the Southwest Power Pool Transmission Expansion Planning process which will include Nebraska upon membership in the Southwest Power Pool
    - This condition is expected to be met in early 2009
- A viable wholesale market in a region including Nebraska:
    - A reasonably efficient and workable wholesale market exists in the Southwest Power Pool market which will include Nebraska.
    - This condition is expected to be met in early 2009.
- Wholesale electricity prices in the region must be comparable or competitive with Nebraska prices:
    - Nebraska prices for the 2005-2008 study period are approximately 44 percent below the regional market
    - Regional bulk market prices are significantly non-competitive
    - This condition has not been met.

Other conditions certain in this report include the extent that retail rates have been unbundled and any other information the board believes to be beneficial to the Governor, the Legislature, and Nebraska's citizens when considering whether retail electric competition would be beneficial, such as, but not limited to, an update on deregulation activities in other states and an update on federal deregulation legislation. Several significant items should be mentioned:

- There has been no significant unbundling of retail rates in Nebraska.
- In other states, customers served by regulated retail markets have generally experienced smaller electric rate increases than customers served by "competitive" retail markets and the expectation of wholesale and retail competition driving down prices has not taken place.
- The most current data for 2006 shows that Nebraska's average retail rate of 6.07 cents/kWh is approximately 32 % lower than the national average retail rate of 8.90 cents/kWh. Preliminary data for 2007 indicate a continuing of this ranking compared to national averages.
- Nebraska ranks second in lowest rates compared to states contiguous with Nebraska.

SUMMARIES OF CHAPTERS FOR 2008 REPORT

Summary of Issue 1

After six years of uncertainty about the future viability of MAPP as a regional transmission organization, MAPP members began leaving MAPP to join the Midwest ISO. Nebraska utilities have determined that the best interests of their customers are served by withdrawing from MAPP membership and joining SPP.

The SPP was organized in 1941 and Nebraska Power Company, the predecessor to Omaha Public Power District, was a charter member. SPP has a long-standing tradition of member driven decision making, which fits well with the public power model in Nebraska. SPP is a FERC-approved RTO and in direct response to the question before this group, SPP is a viable regional transmission organization.

SPP will provide all of the regional transmission services that the Nebraska utilities previously obtained through its membership in MAPP and MRO, including reliability coordination service, regional transmission tariff service, generation reserve sharing, regional transmission expansion planning, seams management, and NERC reliability council participation. In addition, the SPP energy imbalance market will provide a new opportunity for sales into and purchases from the SPP market that are expected to result in substantial cost savings for the Nebraska utilities.

The second part of the question before this group of whether adequate transmission exists in Nebraska or in a region that includes Nebraska will be addressed through the Nebraska utilities participation in the SPP Transmission Expansion Planning (STEP) process. Nebraska utilities have continued to expand their transmission systems in Nebraska such that there is adequate transmission in Nebraska to serve new load growth and deliver new generation resources to our customers. Adequate regional transmission to reduce transmission congestion to facilitate economic transactions in the wholesale energy market or to interconnect large scale development of renewable energy resources such as wind will be addressed in the SPP STEP process. New transmission projects will be identified and cost allocations will be determined in an effort to improve the transfer capability of the regional transmission system

Summary of Issue 2

The tests for market power were conducted for both the SPP RTO and MISO RTO. The results show a split decision. The final conclusion is that a reasonably efficient and workable wholesale market exists in the SPP market area but not in the MISO area.

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

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

Summary of Issue 3

No change from the 2007 report. These are the results that were gathered over the past years. Technical Group #3 will continue to review the status of unbundling in Nebraska, and report the results as needed.

Summary of Issue 4

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

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

The results of the comparison between the market product indices and the Nebraska production costs show that Nebraska production costs are approximately 44 % lower than the equivalent wholesale “median” market price based on the period 2005-2008 (three years actual, one year projected), and weighted based on MWH. Based on the “average” market price, Nebraska production costs are approximately 44% lower than the “average” market price.

These results for the 2005-2008 study show a widening gap between the Nebraska production costs and the market, due mostly to the upward trend of market prices driven by higher natural gas prices. Nebraska utilities do not have as high a concentration of natural gas-fired units when compared to the entire electric industry. The price volatility associated with Nebraska production costs remains stable compared to market price, providing a fairly consistent, less volatile, cost expectation for Nebraska’s ratepayers.

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

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

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

The "median" market price comparison, approximately 39% lower than the market price, compares favorably with retail rate comparisons. The Energy Information Administration (EIA) annually compiles data from the Form EIA-861 for approximately 3,300 public and investor-owned electric utilities including active power marketers and other energy service providers.

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.

Summary of Issue 5

- Costly natural gas is becoming an increasingly important fuel source for electricity generation now producing approximately 20% of the Nation's electricity.
- Natural gas sets the market price for electricity in several retail and wholesale markets.
- Promises of wholesale or retail competition driving down energy prices have not occurred.
- Competitive wholesale markets are a necessary precedent to successfully implementing retail choice.
- Adequate power supply, reserves, and infrastructure are crucial, including the proper mix of generation resources.
- Elimination of the "obligation to serve" is a contributing factor to the reduction of generation reserve margins.
- Customers served by regulated retail markets have generally experienced lower electric rate increases than customers served by "competitive" retail markets.

Chapter 1

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

1.0 Purpose & Team Members

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

Team Members

Paul Malone	–	Nebraska Public Power District
Dan Dahlgren	–	Omaha Public Power District
John Krajewski	–	Municipal Energy Agency of Nebraska
Bruce Merrill	–	Lincoln Electric System

2.0 Summary - Participation in the Southwest Power Pool (SPP)

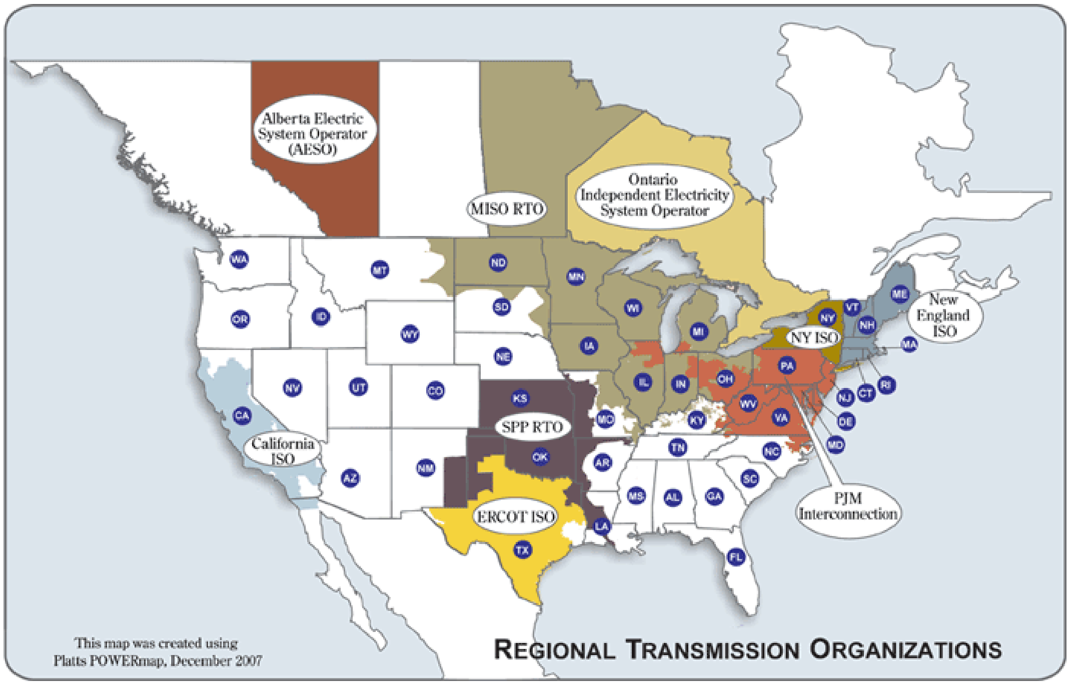
After an extensive evaluation of the options for participation in a regional transmission organization, the Nebraska utilities have determined that the best interests of their customers are served by joining SPP. NPPD, OPPD, and LES have all signed the SPP membership agreement, subject to acceptance by the Federal Energy Regulatory Commission (FERC) of certain provisions required to recognize the unique status of public power utilities under Nebraska state law. MEAN is also planning to join SPP once it receives it's Board approval. SPP is expected to file the membership agreement changes at FERC in October 2008. A second FERC filing is planned for November 2008, which is required, to include the Nebraska utilities' transmission facilities under the SPP tariff.

The Nebraska utilities have provided withdrawal notices to the various regional organizations they are currently participants in, including the Mid-Continent Area Power Pool (MAPP), the Midwest Contingency Reserve Sharing Group, and the Midwest Reliability Organization (MRO). A detailed transition plan has been developed for all of the SPP services with a planned start date of April 1, 2009.

3.0 Evaluation of Regional Transmission Organization Participation Options

Shown below is a map of the FERC- approved Regional Transmission Organizations (RTOs). The two RTOs which border Nebraska, the Midwest ISO and SPP, provide the required transmission services, although their respective market structure and governance vary considerably.

Regional Transmission Organizations

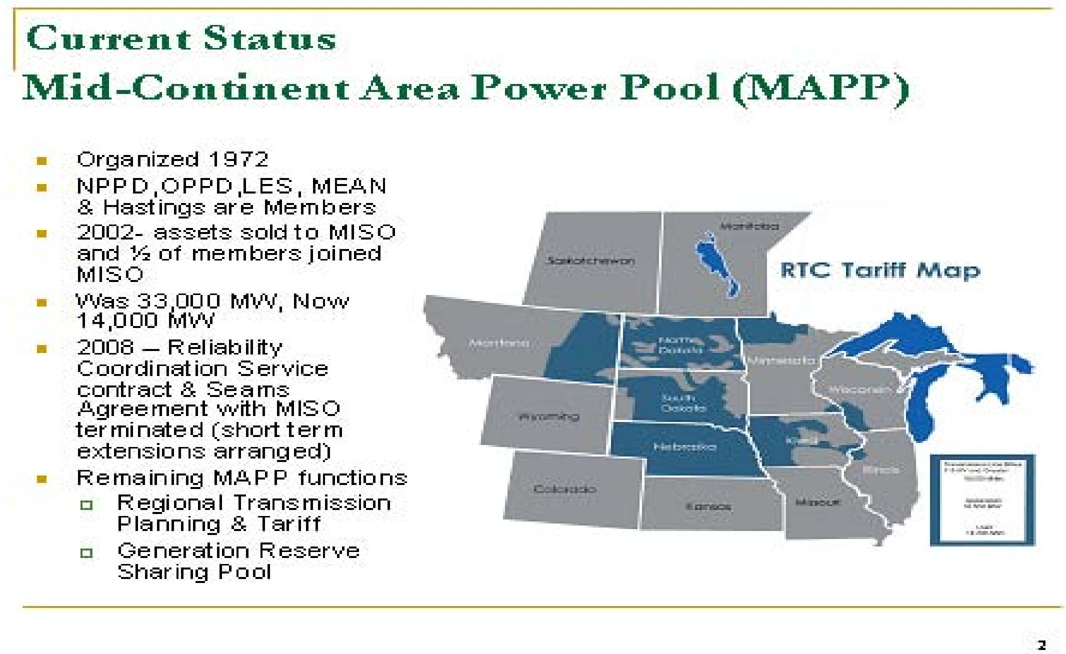


3.1 Status of MAPP

The Nebraska utilities, including NPPD, OPPD, LES, MEAN and the City of Hastings are currently members of MAPP, some having been founding members of that organization in 1972. MAPP has provided many regional transmission services, such as regional transmission tariff service and regional transmission planning, but MAPP has never been a FERC-approved RTO. To become an RTO, FERC requires the organization to meet a number of criteria, including governance by an independent board of directors and operational control of the transmission facilities under a single region-wide transmission tariff. A number of years ago, the MAPP members voted to not re-organize MAPP to qualify as an RTO. Instead, the MAPP members chose to retain the organizational structure whereby governance is controlled by member representatives and the MAPP regional transmission tariff provides limited service.

In 2002, approximately one-half of the MAPP members chose to withdraw their transmission facilities from MAPP and join the Midwest ISO, which is a FERC-approved RTO. At that same time, the MAPP members voted to sell the MAPP assets to the Midwest ISO and execute service agreements with the Midwest ISO to provide regional transmission services to the remaining MAPP members for a period of six years. It was thought that the remaining MAPP members would eventually participate in the Midwest ISO or some other type of regional entity, and the six years would provide a period to make that determination. Since

2002 some of the remaining MAPP members have joined the Midwest ISO. The figure below depicts the geographic area remaining in the MAPP region. Originally the MAPP region included approximately 33,000 MW of load in all or parts of North Dakota, South Dakota, Montana, Nebraska, Iowa, Minnesota, Wisconsin, and the Canadian province of Manitoba. Currently, the load served by the remaining members is approximately 14,000 MW, and the geographic area has been greatly reduced.



In February 2008, the Transmission Service Agreement between MAPP and the Midwest ISO, under which the Midwest ISO provided Reliability Coordination Service and Transmission Tariff Administration Service, terminated. In addition, the Seams Operating Agreement (SOA), which provides for coordination of transmission service and transmission congestion management, between the Midwest ISO region and MAPP region, terminated at that same date.

In late 2007, in recognition that the service agreements with the Midwest ISO would be terminating, the MAPP members began working with the Midwest ISO on alternatives for participation in the Midwest ISO. Knowing that it would take some time to develop the participation proposal and have it accepted by FERC, the Midwest ISO agreed to temporarily extend the above service agreements to ensure continued regional services were available.

3.2 Midwest ISO Participation Options

In March 2008, the Midwest ISO filed a proposal at FERC for approval. The proposal included three options for the MAPP members to participate in the Midwest ISO under Module F of its transmission tariff. The first option, Part I of Module F, provides for Reliability Coordination Service, which is a mandatory service requirement for utilities that operate as a North American Electric Reliability Corporation (NERC) certified Balancing Authority. NPPD, OPPD, and LES are the only Balancing Authorities in Nebraska.

Reliability Coordinators monitor a wide geographic area of the bulk electric system and their role is to ensure reliable operations of the system and prevent system disturbances from causing cascading outages.

The second option, Part II of Module F, provides for seams management which is designed to manage transmission congestion between the Midwest ISO and the MAPP members.

The third option, Part III of Module F, is an entirely new service which would allow the MAPP member to participate in the Midwest ISO energy market, but unlike the existing Midwest ISO members, the MAPP member taking this service would retain its own transmission tariff and operational control of its transmission facilities.

In a June 2008 Order, FERC approved Parts I and II, but did not act on Part III, indicating that Part III raised broad policy questions because the MAPP members would be allowed to participate in the Midwest ISO energy markets, but would not be subject to all of the other requirements of the Midwest ISO tariff, most notably the requirement to share in the regional transmission expansion planning and cost allocation process. FERC invited interested parties to file comments on Part III and has announced that it will hold a technical conference in November 2008 to consider the issues.

In the fall of 2007, the Nebraska utilities (NPPD, OPPD, LES, and MEAN) independently engaged a consultant to perform an economic analysis of participation in the Midwest ISO. The analysis consisted of numerous market simulations of the generation production cost modeling, and comparing whether Nebraska utilities would see any economic benefits by participation in the Midwest ISO energy markets. The Nebraska utilities also met with the Midwest ISO management on a number of occasions to more fully explore the issues concerning participation.

3.3 SPP Participation Option

Because the Nebraska utilities border the SPP region and their transmission facilities are interconnected with members of SPP, it was decided that SPP should also be evaluated as an option for participation in a RTO. A similar economic analysis was performed for SPP participation concurrently with the Midwest ISO evaluation. Below is a map of the SPP region.

Southwest Power Pool (SPP)

- Organized 1941
- 13 Transmission Owning Members
- 43,000 MW Summer
- Regional Transmission Tariff
- Regional Transmission Planning & Generator Interconnection Studies
- Reliability Coordination
- Generation Reserve Sharing Pool
- Energy Imbalance Market
- Seams Agreement with MISO
- NERC Reliability Council

6

The SPP energy market is not as comprehensive or complex as the Midwest ISO energy market. The Midwest ISO energy market includes a bid-based Day Ahead and Real Time market, which includes Financial Transmission Rights. In addition, the Midwest ISO is preparing to implement an Ancillary Services Market, which will provide bid-based operating reserves. By comparison, the SPP energy market only provides a next hour Energy Imbalance market. To simply this comparison, all load and generation must be placed under the bid-based Midwest ISO energy markets, and all wholesale prices are determined using the locational marginal pricing methodology, whereas in SPP only the next hour energy imbalance is priced using the locational marginal pricing methodology. To put this in perspective, 100% of the energy pricing is determined by the Midwest ISO energy market, and only about 8% of the energy in SPP is priced. The remaining 92% of the energy is priced by the utility serving the load. In the case of the Nebraska utilities, this means 92% of the energy will be provided by our own generation resources to serve our customers, and will be priced as it always has been, on a cost of service basis.

Even though the energy markets of the Midwest ISO and SPP are structured quite differently, the economic analysis using generation production cost modeling was performed in the same manner so that there would be comparability in the outcomes.

The conclusions of the independent economic analysis indicated that each of the Nebraska utilities would realize a significant financial benefit for their customers from participation in SPP compared to the Midwest ISO. The reasons that SPP is more economically favorable include:

- Higher off-peak market prices in SPP. As a net seller of its excess generation in the wholesale market, the Nebraska utilities expect to receive additional revenue for their market sales.
- Lower administrative costs in SPP.
- Revenue sharing for Point to Point Transmission Service.
- Reduced planning and operating reserves.
- Lower charges for electrical losses.

Based on the positive outcome of the economic analysis, the Nebraska utilities initiated a series of meetings beginning in late 2007 with SPP management to investigate the possibilities for participation in SPP as a member or through contracted services.

Qualitative issues of participation in SPP were also examined and found to be favorable. Some of those issues include:

- Nebraska utility Boards retain all current authority
- Nebraska utilities maintain their non-jurisdictional FERC status
- SPP governance structure allows for members participation in policy decisions. While SPP has an independent Board of Directors, there is a Members Committee that votes on all issues prior to the Board's final consideration, which allows the Board to be fully informed of the members positions.
- The SPP region is similar in size to the original MAPP region, and similar in nature to the load density characteristics of Nebraska.
- The SPP transmission tariff provides access to the regional wholesale electric market in SPP and also provides for transmission service to other regions.
- The Nebraska utilities' transmission facilities will become part of the SPP seams agreement it has had with the Midwest ISO to manage transmission congestion.
- Nebraska utilities maintain control of their generation to serve native load, and only bid excess energy into the energy imbalance market.
- Nebraska utilities will be part of the SPP Transmission Expansion Planning process, which includes a cost-sharing mechanism for transmission improvements to meet reliability criteria.

The quantitative economic and qualitative issues evaluation culminated in the execution of a Memorandum of Understanding (MOU) in May 2008 between SPP, NPPD, OPPD, and LES indicating their intent to pursue membership in SPP and negotiate the necessary agreements. MEAN was not a signatory to the MOU because it does not own transmission facilities to place under the SPP tariff, but nevertheless MEAN has participated in the discussions with SPP. Work began on a transition plan and teams were formed representing each of the Nebraska utilities and SPP to develop detailed project management tasks to accomplish their respective assignments. The transition teams identified include:

- Reliability Coordination Service – all real-time transmission system data from the Nebraska utilities must be transmitted electronically to SPP.
- Market Integration – all of the generators and load must be incorporated into the SPP models and various market registration documents must be completed.
- Transmission Policy – The transmission revenue requirements of the Nebraska utilities must be submitted to SPP along with a listing of transmission facilities and agreements which will be grandfathered. This information is required for inclusion in the SPP tariff filing at FERC.
- Transmission Tariff Administration – all transmission system information needed for processing transmission service requests under the SPP tariff must be incorporated into the SPP models.

- Transmission Planning – all transmission modeling data of the Nebraska system must be included in the SPP transmission planning process.
- NERC Reliability Council – The Nebraska utilities need to transfer their participation from the MRO to SPP for compliance with NERC reliability standards.
- Training – The Nebraska control center operators will train on the SPP operations procedures and SPP operators will learn the specifics of the Nebraska transmission system.

As mentioned in Section 2.0, SPP has approved the changes to the SPP governing documents, including the Bylaws, Membership Agreement, and Tariff to meet the legal requirements of the Nebraska utilities under State law. A FERC filing will be made in October 2008, with approval by FERC expected in December 2008, assuming there are no contentious issues. A second FERC filing is planned for November 2008, which is required to place the Nebraska utilities' transmission facilities under the SPP tariff. Approval of that filing is expected by January 2009. The planned start date for participation in SPP is April 1, 2009.

4.0 Conclusions

After six years of uncertainty about the future viability of MAPP as a regional transmission organization, MAPP members began leaving MAPP to join the Midwest ISO. The Nebraska utilities have determined that the best interests of their customers are served by withdrawing from MAPP membership and joining SPP.

SPP is a FERC-approved RTO and in direct response to the question before this group, SPP is a viable regional transmission organization. SPP has a long-standing tradition of member driven decision making, having been organized in 1941, which fits well with the public power model in Nebraska.

SPP will provide all of the regional transmission services that the Nebraska utilities previously obtained through its membership in MAPP and MRO, including reliability coordination service, regional transmission tariff service, generation reserve sharing, regional transmission expansion planning, seams management, and NERC reliability council participation. In addition, the SPP energy imbalance market will provide a new opportunity for sales into and purchases from the SPP market that are expected to result in substantial cost savings for the Nebraska utilities.

The second part of the question before this group of whether adequate transmission exists in Nebraska or in a region that includes Nebraska will be addressed through the Nebraska utilities participation in the SPP Transmission Expansion Planning (STEP) process. Nebraska utilities have continued to expand their transmission systems in Nebraska such that there is adequate transmission in Nebraska to serve new load growth and deliver new generation resources to our customers. Adequate regional transmission to reduce transmission congestion to facilitate economic transactions in the wholesale energy market or to interconnect large scale development of renewable energy resources such as wind will be addressed in the SPP STEP process. New transmission projects will be identified and cost allocations will be determined in an effort to improve the transfer capability of the regional transmission system.

The Nebraska utilities' decision to join SPP is one that is expected to provide a long-term solution to the question of participation in a regional transmission organization.

Chapter 2

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

1.0 Introduction

1.1 Purpose and Membership

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

Clint Johannes (Chair)	-	NE Electric Generation & Transmission Cooperative
Deeno Boosalis	-	Omaha Public Power District
Jim Fehr	-	Nebraska Public Power District
Dennis Florom	-	Lincoln Electric System
Kevin Gaden	-	Municipal Energy Agency of Nebraska
Derril Marshall	-	Fremont Utilities
Allen Meyer	-	Hastings Utilities
Jon Sunneberg	-	Nebraska Public Power District

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

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

1.2 Approach

To accomplish the purpose described, the Group first defined the meaning of the term "viable" and the alternative methodologies for testing the viability of a market. This definition and the evolution of standard tests for market viability are outlined in Section 2. Next the regional markets that include Nebraska were defined. Nebraska is somewhat unique in that it transcends two major transmission grids in the U.S.; the Eastern Interconnection and the Western Interconnection. Therefore, Nebraska has two separate and distinct regional electricity markets. Both of these markets are defined in Section 3.

2.0 Viable Wholesale Market Definition

2.1 Economic Logic

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

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

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

2.2 FERC Definition and Tests for Market Power

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

2.2.1 Horizontal Market Power

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

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

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

A broader test of market concentration is the Herfindahl-Hierschman Index (HHI). This test is calculated by summing the squares of the market shares of all competitors in a given market. An HHI of 1,000 or less indicates an unconcentrated market while an HHI of over 1,800 indicates a concentrated market. A score of 1,000 to 1,800 shows a modestly concentrated market.

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

2.2.2 Vertical Market Power

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

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

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

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

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

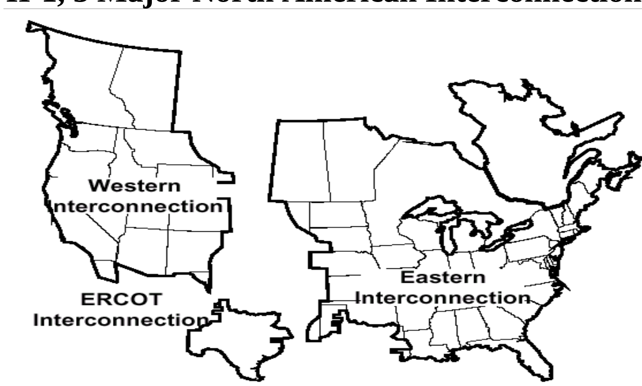
3.0 Market Region Defined

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

3.1.1 Major Transmission Interconnections in North America

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

Exhibit II-1, 3 Major North American Interconnections

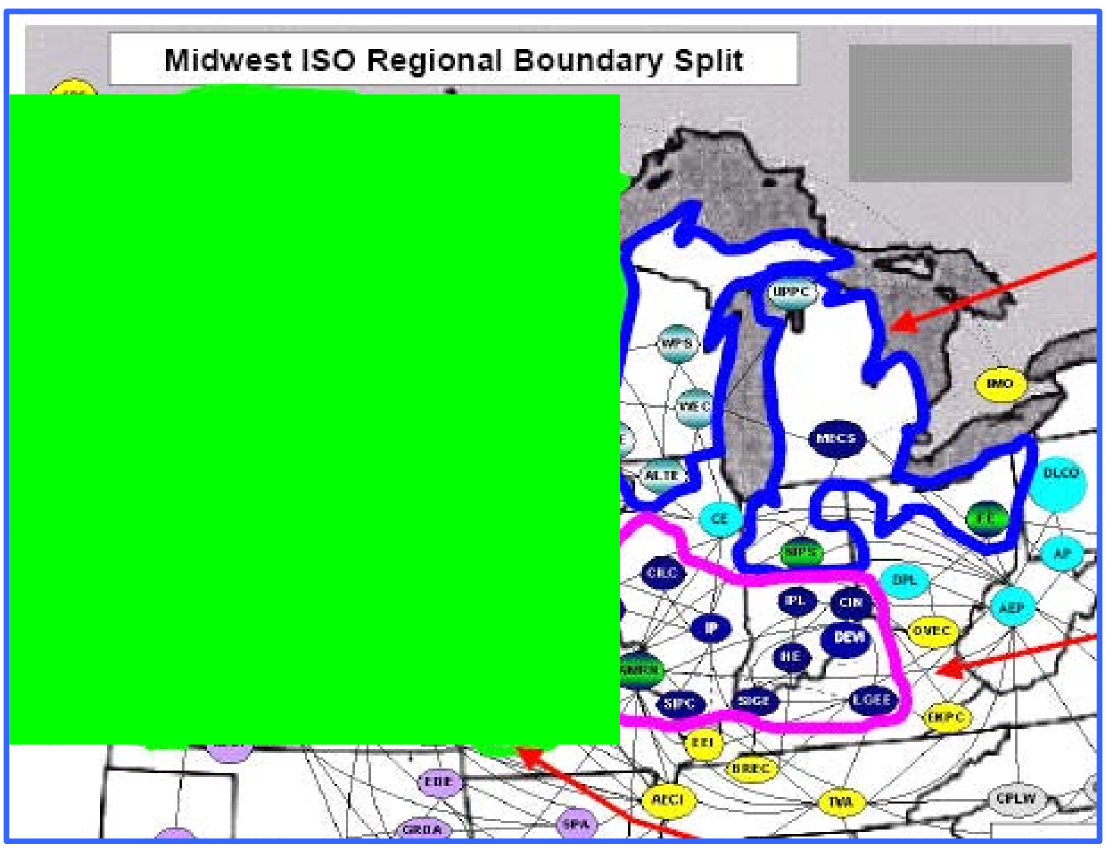


3.1.2 The Wholesale Electricity Region that includes Nebraska

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

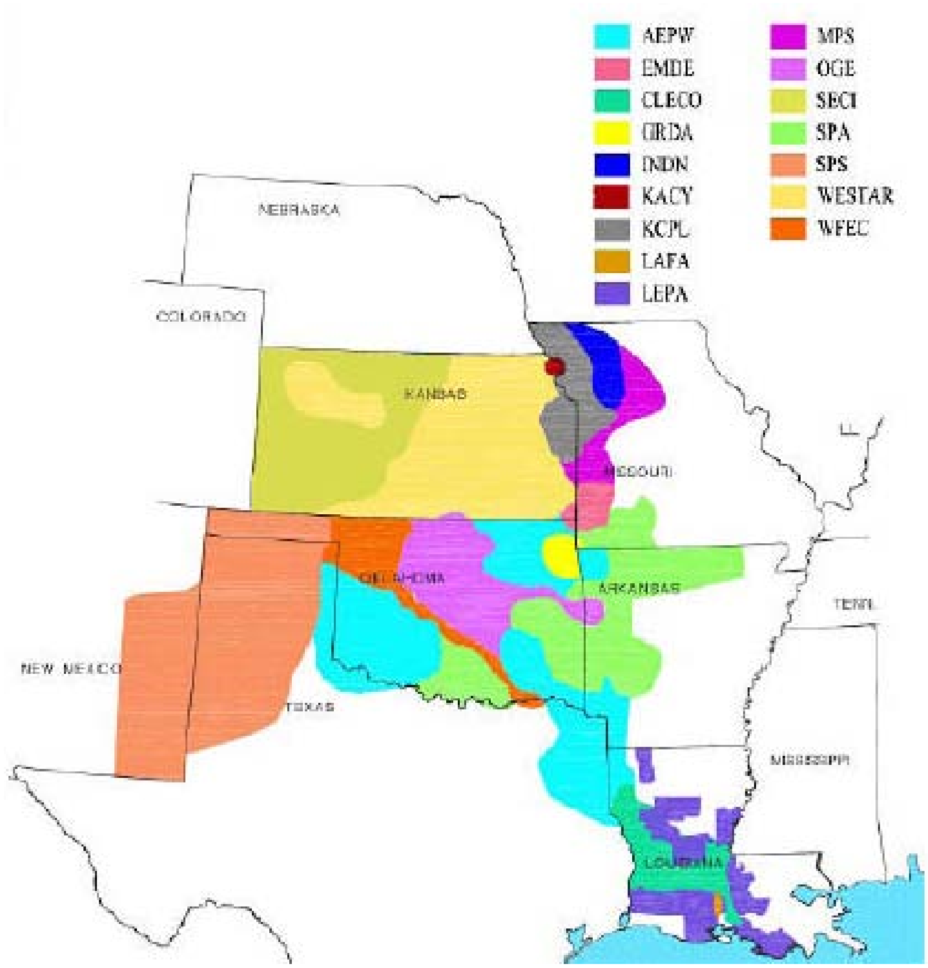
Since 1972, OPPD, NPPD, MEAN and Hastings Utilities have been members of the Mid-Continent Area Power Pool (MAPP) which offered Generation Reserve Sharing and a regional tariff. In 2002, the assets of MAPP were sold to the Midwest Independent System Operator (MISO), a large RTO. At that time about half the members of MAPP joined MISO. As part of the agreement, MISO provided MAPP with reliability coordination services, transmission tariff administration and transmission congestion management. This allowed the remaining MAPP members to continue wholesale market operations. During this period of time, the MISO geographical area (including MAPP) was used to define the regional wholesale electricity market for past versions this report. This regional area is shown in Exhibit II-2 including all of the areas outlined in different colors as well as the green shaded area which is the MISO West sub-region.

Exhibit II-2, MISO Footprint



In 2008, MISO terminated the reliability coordination and transmission congestion management services with MAPP. It became incumbent upon the remaining MAPP members to join a regional RTO. The members entered into negotiations with MISO and a second RTO called the Southwest Power Pool (SPP). The geographical footprint of SPP is shown in Exhibit II-3 below.

Exhibit II-3, SPP Footprint



On May 16, 2008, NPPD, OPPD and LES signed a Memorandum of Understanding to join the SPP RTO contingent upon FERC approval and execution of related agreements. Given that this agreement is still pending, Technical Group #2 decided to include a market power analysis of both the MISO and SPP RTO regions as part of this report.

4.0 Information sources used for this Report

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

The reports used in this year's report are:

- SPP 2007 State of the Market Report, compiled by Boston Pacific Company, Inc. of Washington DC, and published June 2008
- MISO 2007 State of the Market Report, compiled by Potomac Economics, Inc. of Washington DC, and published April 24, 2008

5.0 2008 Market Power Analysis for MISO and SPP

5.1 Horizontal Market Power Tests

The 2007 calculations for market share (top 3 participants), market share (top participant) and the Herfindahl-Hierschman Index (HHI) are shown for both the SPP and MISO. In addition, the calculation for the MISO West sub-region is also shown. The MISO West sub-region footprint is shown in Exhibit II-2 as the green shaded area. The reason that MISO chose to divide its analysis into sub-regions is due to the sheer size of the MISO footprint. This acknowledges that MISO does not behave as a single market but rather is characterized by three sub-markets also outlined in Exhibit II-2. Therefore, we compare the SPP region with the MISO West sub-region in this analysis.

Exhibit II-4, Comparative Horizontal Market Power Measures

	SPP	MISO West	MISO
Market Share Top 3 Participants	47%	73%	27%
Market Share Top Participant	18%	41%	10%
HHI	1,103	2,310	512

The analysis demonstrates that the MISO West sub-region is more concentrated than the SPP region. The MISO West market share for the top three participants is nearly three fourths of the entire market compared to about half in the SPP region. Similarly, the market share of the top participant is 41% in MISO West compared to 18% for SPP. The SPP market share is below the 20% threshold used as an indicator of market power. The *SPP State of the Market Report* when referencing that no participant has over 20% of the market share stated *"Again, this is another indicator that the EIS Market is a competitive market."*

The HHI measure of 1,103 for SPP is very close to the 1,000 mark which is used as the gauge in determining unconcentrated market. The HHI for MISO West is nearly twice that amount at 2,310. This is well above the 1,800 mark that is indicative of a highly concentrated market. The *SPP State of the Market Report* stated, "*The HHIs also indicate a competitive market.*"

The *MISO State of the Market Report* concludes *"The report indicates that concentration is low for the overall Midwest ISO area, but moderate in the Central and East areas and high in the West and WUMS areas."*

5.2 Vertical Market Power Tests

The MISO Independent Market Monitor conducted a pivotal supplier test to identify the presence of vertical market power in the MISO area. This test is described in Section 2.2.2 of this report.

Pivotal Suppliers are generators that are essential to meeting load or reserve requirements in an area that becomes transmission constrained during times of high electricity demand. During those times the pivotal supplier can withhold offering power to the market in order to drive up prices. In MISO, 58% of all constraints have a pivotal supplier, this rises to 62% in the highly constrained upper Michigan area. The *MISO State of the Market Report* concludes, *"Based on these results, we find substantial local market power exists."*

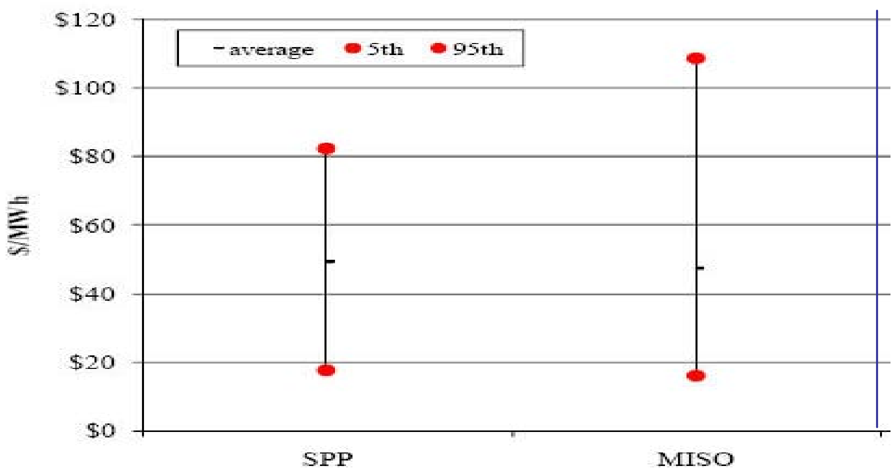
The SPP Independent Market Monitor conducted a Price Cap test also described in Section 2.2.2. SPP has a price cap that is put into effect only in areas where the transmission system becomes congested. It is applicable only to generation resources that can materially change the congestion in the area. Finally, the price cap is set at the variable cost of a new peaking power plant (the lowest cost generation that the competitive market would provide) with the fixed costs spread over the estimated hours of congestion for affected area. An analysis of the SPP Price Cap was conducted to determine how often a price offer is accepted near the SPP Price Cap. According to the *SPP State of the Market Report, "if price offers are seldom accepted near the SPP Cap, then we believe this indicates prices are comfortably below this one measure of a competitive price level."* The results of the test indicated that in 2007 offers within 5% if the price cap were accepted less than two hundredths of one percent of all resource intervals. The *SPP State of the Market Report* concluded, *"The bottom line is that price offers were almost never accepted near the SPP Cap."*

Finally, the SPP Independent Market Monitor conducted a Price Volatility test. Exhibit II-5 shows a comparison of the average price, maximum price and volatility of prices in the SPP and MISO markets. The average prices in both markets are similar, but the maximum price in MISO is much higher as is the overall volatility of prices in market. This concept is also verified in Exhibit II-6 which shows the average price as well as price in the 5th percentile (low) as well as the 95th percentile (high) for both SPP and MISO. If one accepts the major assumption in this test, that large swings in prices over short periods of time are associated with vertical market power, this shows that MISO exhibits higher vertical market power than the SPP market.

Exhibit II-5, Comparative Prices of SPP and MISO

Comparative Prices SPP and MISO ($/Mwh)			
	Average Price	Maximum Price	Volatility
SPP	$49.18	$386.16	48%
MISO	$47.37	$622.63	69%

Exhibit II-6, Comparative Prices of SPP and MISO



6.0 Conclusion

6.1 Status of Viable Midwest Wholesale Market in the Eastern Region

The tests for market power were conducted for both the SPP RTO and MISO RTO. The results show a split decision. The final conclusion is that a reasonably efficient and workable wholesale market exists in the SPP market area but not in MISO area.

6.2 Status of Viable Midwest Wholesale Market in the Western Region

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

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

Chapter 3

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

1.0 Purpose

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

2.0 Status of Unbundling in Nebraska

There were no new developments regarding unbundling for the Group to address in 2005, 2006 and 2007. In 2004, all the electric utilities in Nebraska were surveyed to determine their current unbundling status. The results of that survey are shown in Section 5.0 Survey Results.

3.0 Team Members

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

4.0 Introduction

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

There are various reasons why utilities may unbundle electrical service. The most compelling and the main reason that a utility unbundles is due to state statute or regulatory rule as part of a comprehensive deregulation plan. "The unbundling of retail electricity related services is a means to achieve direct access between consumers and competitive electricity supply. The overall objective of direct access is to reduce the total cost of electricity to society. Unbundling is therefore a means to develop a framework to facilitate consumer choice such that the overall cost of electricity to society is reduced."[2]

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

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

rates, so consumers are not pushing for deregulation. However, some commercial and industrial consumers are requesting unbundled billing information to compare the costs of individual components of their energy bill with those costs in their facilities in other states. This process on its own may cause other utilities in Nebraska to have to unbundle as customers may begin to ask for comparisons at the same level that they are receiving in other states.

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

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

5.0 Survey Results

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

 # OF RESPONSES

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

 # OF ELECTRICAL CUSTOMERS REPRESENTED

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

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

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

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

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

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

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

Q2A. - WILL YOUR CURRENT BILLING SYSTEM ACCOMMODATE UNBUNDLING?

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

Q2B. - IF YOU ANSWERED "NO" TO QUESTION "2A," ARE YOU PLANNING TO CHANGE SYSTEMS TO ACCOMMODATE UNBUNDLING OR ARE YOU CONSIDERING THIS ISSUE IN THE PURCHASE OF ANY NEW BILLING SYSTEM?

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

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

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

6.0 Estimated Unbundling Costs

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

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

The technical group estimated the cost for only unbundling in Nebraska to be approximately $9 million. This would include an estimated one-time cost of approximately $8 million. The on-going cost per year would be approximately $1 million. A statewide consumer education program would be needed to communicate to the consumer a new billing process, so consumer education on a statewide basis was included in these estimated costs. The estimated cost per customer was based on other deregulated states. The technical group used a $1.36 average cost per customer (which was based on the information received from Pennsylvania), and then applied this cost to the number of customers in each public power entity in Nebraska.

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

7.0 Conclusion

These are the results that were gathered over the past years. Technical Group #3 will continue to review the status of unbundling in Nebraska, and report the results as needed. There may be activity in the area of privately owned generation that might require limited unbundling and Technical Group #3 may look in to those activities.

Chapter 4

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

1.0 Introduction

1.1 Purpose and Group Membership

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

Team members

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

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

1.2 Approach

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

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

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

2.0 Wholesale Market Terminology

2.1 Market Product Definitions

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

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

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

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

2.2 Comparison Concepts

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

2.3 Physical Product Definitions

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

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

2.4 Market Product Time Period

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

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

2.5 Market Product Categories

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

2.6 Market Price and Production Cost Difference

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

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

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

2.7 Market Price Volatility and Production Cost Stability

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

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

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

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

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

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

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

2.8 Market Product Price

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

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

2.9 Transmission Cost and Loss Considerations

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

2.10 Nebraska Production Cost

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

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

2.11 Long-term “Obligation to Serve” Considerations

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

2.12 Various Generation Unit Types Serving Load

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

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

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

2.13 Ancillary Services Component

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

2.14 Load Factor Considerations

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

3.0 Market Product Pricing and Nebraska Production Cost Comparison Methodology

3.1 Alternative Comparison Methods

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

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

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

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

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

(1) The RFP could be perceived by the market as a price discovery process only, so the respondents may not provide “real” bids, or the prices offered may be extremely low initially just to gain market entry. This implies that the prices would not be truly reflective of market value, and the process involved would be extremely time-

consuming and labor-intensive to develop the RFP, let the bids, and evaluate the bids on an equitable basis just for price comparison purposes,

(2) Purchasing a regional electricity price application model from a vendor would be cost prohibitive, with an estimated cost of up to $150,000 depending on level of detail and service provided. Also, the set-up and training required to determine equivalent electricity products could be labor-intensive,

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

3.2 Comparison Modeling Tool Detail

To develop a modeling tool that separates the various components of Nebraska power system costs to match the available market product indices requires clearly defining these costs. Therefore, since the available market price indices are for products located at specific transmission systems outside of the state, 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,

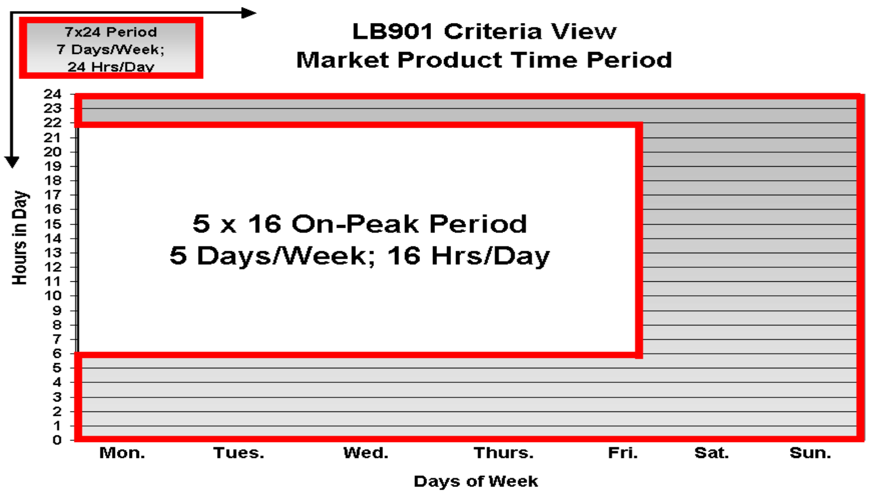
(2) Apply a consistent set of fixed and variable production cost accounts based on Federal Energy Regulatory Commission (FERC) accounting definitions to calculate the production cost to serve load,

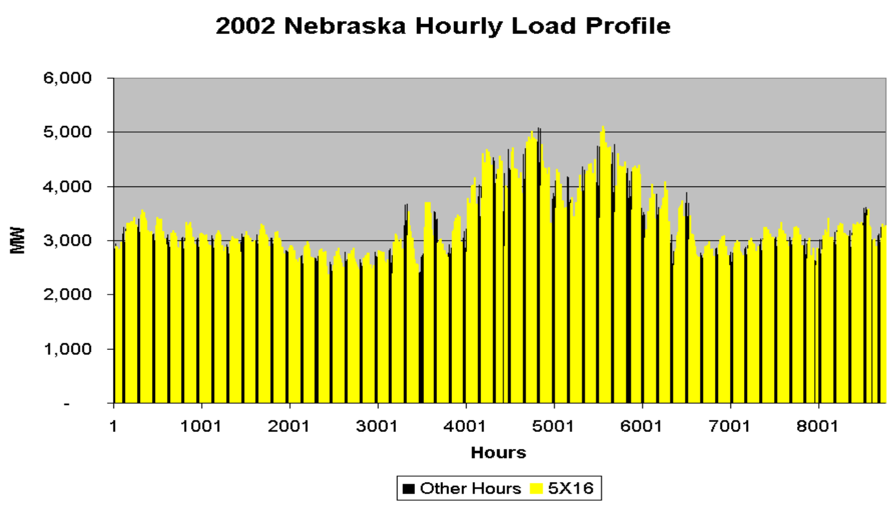
(3) Break down the total cost to serve (as determined in (2) above) to an hourly basis to determine a cost per hour to serve each utility's load based on an hourly load shape for each year (typically 8,760 hours per year), which is accomplished by appropriately allocating the fixed and variable costs on a per hour basis to each utility's load that each utility is obligated to serve by weighting the costs on a MWH per year or market price basis, by time period (Peak and Off-peak), calculating an hourly $/MWH cost to serve load in each of the 8,760 hours of the year,

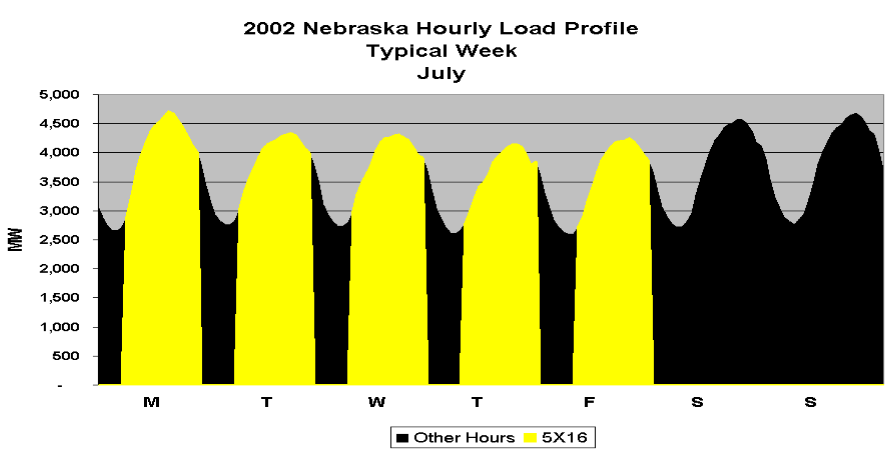
(4) Since the costs have been calculated on a $/MWH basis for each hour (as determined in (3) above), sum the hourly fixed cost and variable cost, less any obligation adders such as reserves, "obligation to serve" values and ancillary services, and adjust the load factors to match available market product indices which are on a 5 X 16 basis (5 days per week – Monday thru Friday, 16 hours per day). Exhibit IV-1 below

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

Exhibit IV-1







3.3 Comparison Modeling Tool Application

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

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

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

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

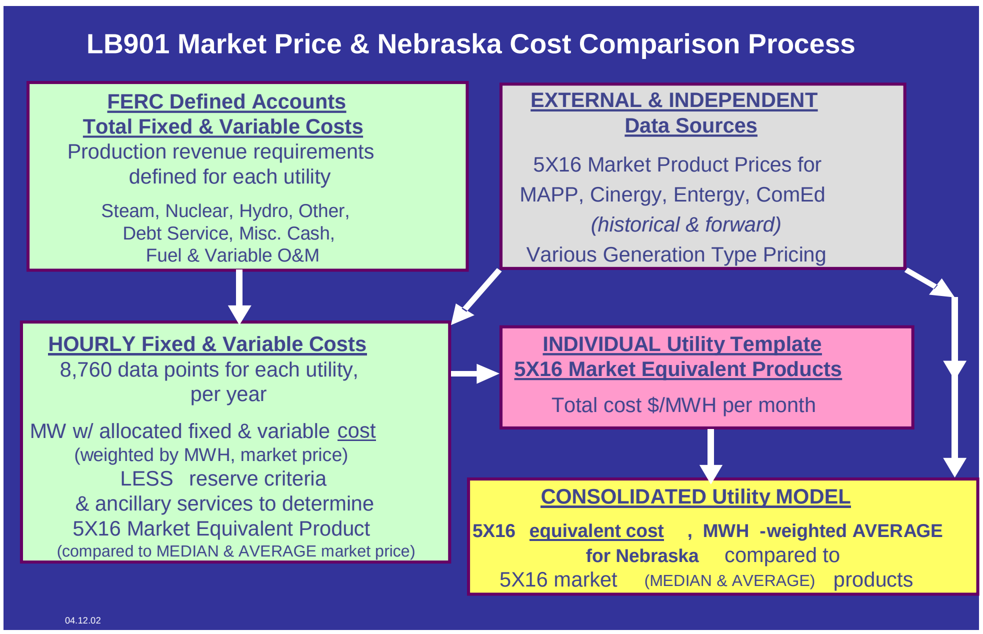
(3) Two different methods of allocating the fixed costs of existing power resources for each utility were modeled in order to provide a range of possibilities in cost allocations for discussion to determine how most utilities would allocate fixed costs; these two methods were (a) January thru December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

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

(5) The cost to serve Nebraska customers from Nebraska power systems was then compared to the cost to serve Nebraska customers from the market, calculated on an annual MWH-weighted basis from which a percentage of market price was calculated to quantify differences between Nebraska power systems and available market product pricing on a rolling average basis for 2002-2005 (3 years of history and 1 year of future pricing); annual price volatility (fluctuation) comparisons were also performed.

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

Exhibit IV-2



4.0 Results of Modeling Tool Comparisons

4.1 Time-period Utilized

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

For 2008 modeling comparison purposes, the time period of 2005 through 2008 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 2005-2008 with 2008 being the estimated year for both market pricing and production costs.

- Incorporating the future year 2008 into the modeling introduces another layer of “assumptions” and “speculation” that may reduce the credibility of an agreed upon modeling process that provides reasonable conclusions.

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

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

- Need to be cautious that legislative action is not triggered on projections or expectations which are subject to larger errors (as happened in California), but on actual experience and estimations that have a higher confidence of accuracy (such as a four-year rolling average).

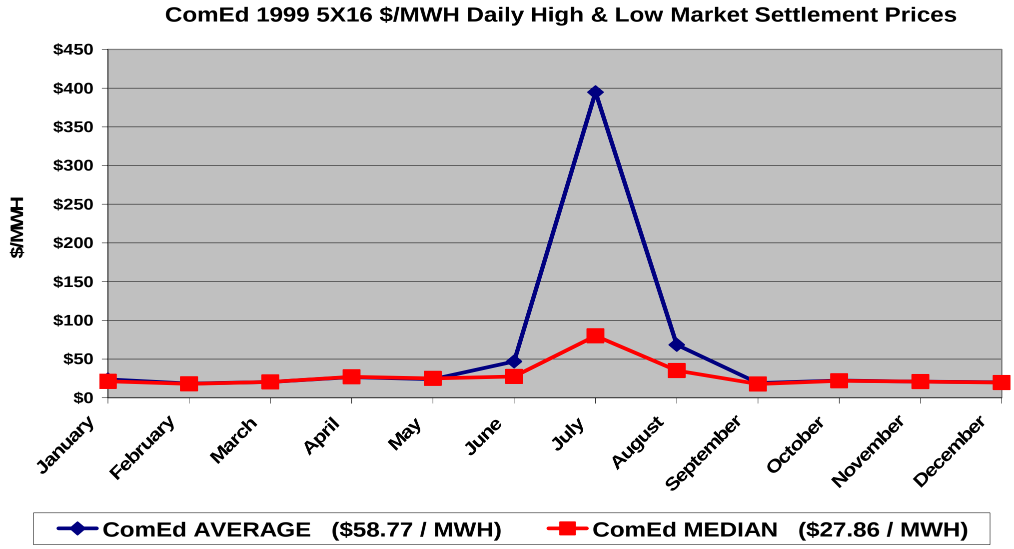
4.2 Sensitivity Cases Analyzed

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

4.3 Median Market Pricing

Exhibit IV-3 on the following page shows two distributions for 5 X 16 monthly market prices in the ComEd market for 1999 based on high and low daily settlement prices. One is based on the “average” of the daily high and low settlement prices, and the other is based on the “median” of the daily high and low settlement prices. The “average” represents the summation of all the prices divided by the number of prices, whereas the “median” is the middle number of the price after sorting from low to high. The “median” is considered more “typical” since it is not biased or skewed by a single high number, whereas the “average” can be biased or skewed by a single high number. Therefore, to avoid inherent biasing of the Nebraska cost comparisons to a higher market price (possibly driven by one or two high numbers), median market pricing was chosen as the better market criteria to compare and set the threshold for Nebraska costs.

Exhibit IV-3



4.4 MegaWatt-Hour (MWH) Weighted Fixed Cost Allocations

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

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

4.5 Other Cost Allocation Issues

As discussed in Sections 2.7 through 2.14 earlier in this chapter, there are other cost allocation issues that could be considered for equitable comparison purposes. For 2002, the modeling tool initially developed in 2001, was updated and enhanced to include user options to incorporate transmission cost adders that reflect the additional cost of actually delivering a market product to the Nebraska system (both losses and tariffs). Although this flexibility is built into the modeling tool, the 2005 overall comparison results are based on these values being set to zero so that an equitable comparison to last year's results can be made and any market bias perception is eliminated. A model user option to include an "obligation to serve" value was also incorporated, but, again, this option was set to zero for the same reasons described above.

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

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

4.6 Value of Long-term Obligation to Serve

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

A market-based electricity product provider does not share this same responsibility; hence, there is downward pressure on the price for the market–based electricity product as compared to local providers. This actual value is difficult to quantify since this is a subjective criteria that may be different for each customer depending on individual risk tolerance for price changes. Four different analytical approaches were developed and modeled for the 2003 Report. The results were included in Section 4.8 of the 2003 Report. The analyses indicated that the value of the long-term obligation to serve was in the \$3-\$5/MWH range for a 5x16 product. These results are for subjective consideration only, and are not specifically accounted for in the 2002-2005 Nebraska production cost comparison to market pricing.

4.7 Results Based on Median Market Product Pricing Indices and Applying MWh-Weighted Fixed Cost Allocations to Nebraska Production Costs for 2005 through 2008.

Exhibit IV-4 provides a tabulation of the results comparing median market product pricing indices and applying MWH-weighted fixed cost allocations to Nebraska production costs for 2005 through 2008. As shown in the table, on an equivalent basis, Nebraska production costs consistently rank below the market product throughout the study period. Seven (7) LB901 historical study period comparisons are also included, describing the four-year rolling average results for the various study periods completed. A main driver of the gap between Nebraska production and market prices appears to be natural gas prices. Refer to Exhibit IV-4a. Nebraska utilities do not have as high of concentration of natural gas-fired units when compared to the entire electric industry.

Exhibit IV-4

COMPARISON TABLE for NEBRASKA PRODUCTION COSTS

PERCENTAGE BELOW MEDIAN MARKET PRICING

Year	MWh - Weighted Fixed Cost Allocations	Market Price - Weighted Fixed Cost Allocations
2005	53.5%	53.0%
2006	32.0%	32.7%
2007	40.0%	40.2%
2008	48.1%	48.0%
Straight Average	43.4%	43.5%
Four Year Average (MWh-weighted)	43.7%	43.8%

HISTORICAL LB901 STUDY PERIOD COMPARISON

Study Period Years	% Nebraska Systems Below Market	Nebraska Cost Annualized Volatility	Nebraska Cost Monthly Std Dev	Market Price Annualized Volatility	Market Price Monthly Std Dev
1998-2001	18.6%	34.4%		84.5%	
1999-2002	15.3%	41.2%		92.2%	
2000-2003	18.1%	43.4%		62.4%	
2001-2004	20.8%	49.5%		45.6%	
2002-2005	28.3%	35.8%	$1.97/MWh	34.2%	$3.29/MWh
2003-2006	39.6%	32.0%	$2.17/MWh	34.3%	$5.68/MWh
2004-2007	41.3%	25.5%	$1.77/MWh	29.0%	$5.98/MWh
2005-2008	43.7%	30.9%	$2.39/MWh	33.9%	$7.10/MWh

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

Exhibit IV-4a

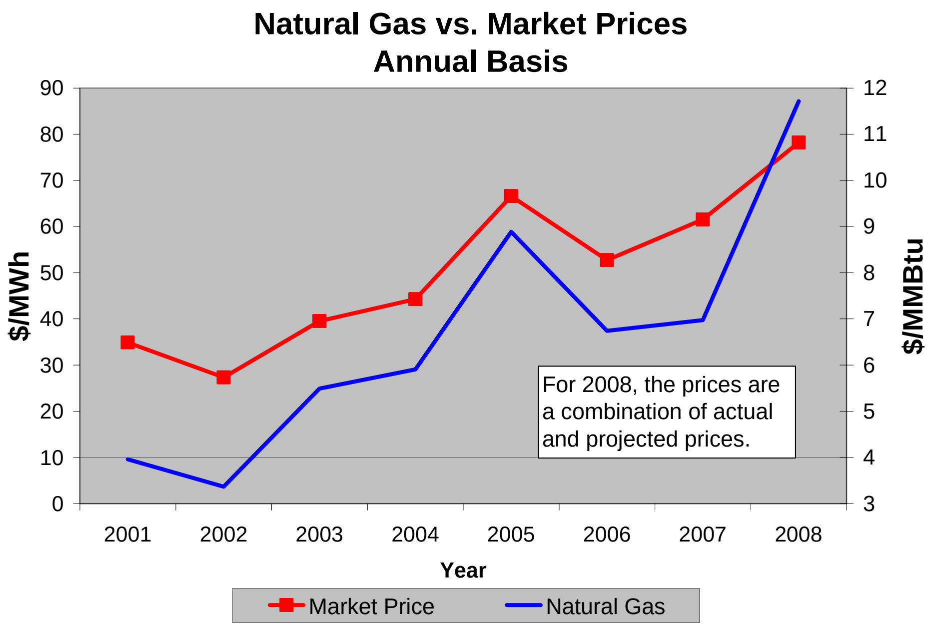
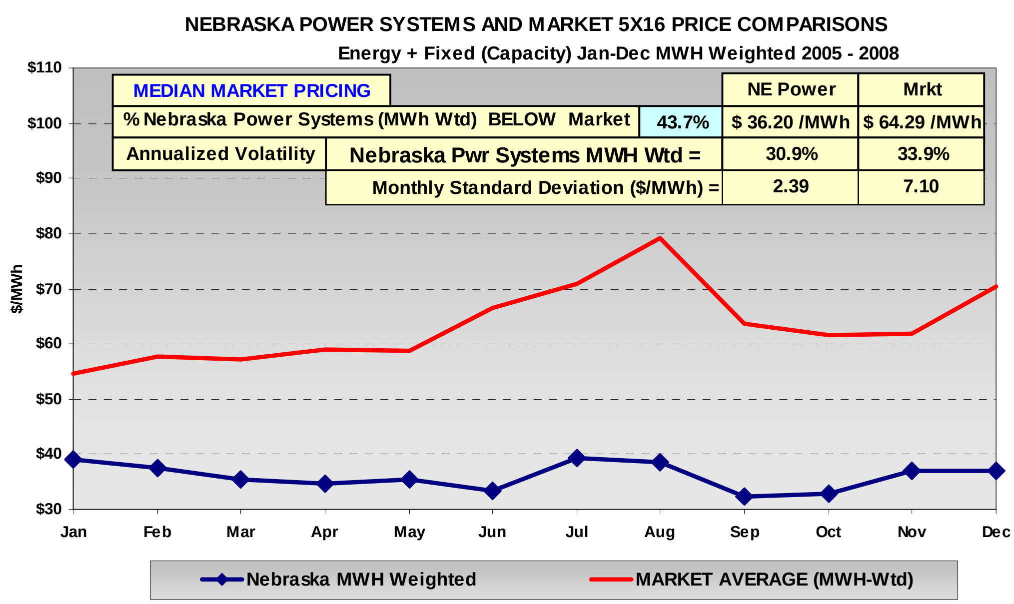


Exhibit IV-5 provides a monthly comparison for the four-year study period (2005-2008) between the median market product pricing indices to Nebraska production costs. In every month, Nebraska production costs are lower. The calculated volatility is slightly lower for Nebraska production and the market. Even though the annualized volatility is approximately the same, the standard deviation for the Nebraska Power Systems is $4-5/MWh less than the market.

Exhibit IV-5



For comparison purposes, Exhibit IV-6 is provided to describe the detail associated with the 2008 market prices and physical generation resource costs, as applied in this year's model.

Exhibit IV-6

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

= Manual Entry
= Calculated Value
= Special Calculation
= Automatic Link

AVERAGE 5X16 $/MWH Daily Settlements for 2008

	Historical			FORWARD INDICES (as of March - 2008)								
	January	February	March	April	May	June	July	August	September	October	November	December
MAPP	68.38	73.87	77.61	69.00	73.00	81.00	92.75	92.75	80.00	72.00	73.00	82.00
NI	64.17	67.69	71.43	67.00	72.50	82.00	99.00	99.00	74.75	74.50	71.75	74.00
Cinergy	65.02	68.61	70.20	68.00	74.00	84.50	101.00	101.00	77.50	74.50	72.00	74.50
Entergy	63.35	67.24	72.59	73.00	72.50	82.15	97.50	98.50	84.15	77.40	78.15	84.95
MAPP CALC	106.5%	108.9%	108.7%	99.5%	100.0%	97.7%	93.5%	93.2%	101.5%	95.4%	98.7%	105.4%

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

MEDIAN 5X16 $/MWH Daily Settlements for 2008

	Historical			FORWARD INDICES (as of March - 2008)								
	January	February	March	April	May	June	July	August	September	October	November	December
MAPP	72.13	77.50	77.50	68.02	73.15	80.51	89.87	89.37	80.52	70.30	73.49	81.77
NI	65.13	68.50	69.25	67.32	72.24	80.55	93.31	93.53	75.18	72.07	71.92	74.91
Cinergy	67.38	70.25	68.25	67.02	72.32	83.64	95.26	97.25	77.62	72.43	73.02	73.63
Entergy	66.95	68.00	72.00	72.56	72.77	82.92	94.67	93.51	83.23	74.31	80.13	83.73
MAPP CALC	108.5%	112.5%	111.0%	98.6%	101.0%	97.7%	95.2%	94.3%	102.3%	96.4%	98.0%	105.6%

MAPP Capacity Only Price $/kW-yr for 2008 = 15.00

85

New Peaking Unit $/MWH for 2008 = 130 @ 85% CF and Fuel of $8.0/ mmBTU — 171 @ 10% CF

New Combined Cycle $/MWH for 2008 = 76 @ 85% CF and Fuel of $8.0/ mmBTU

New Baseload Coal $/MWH for 2008 = 49 @ 85% CF and Fuel of $0.88/ mmBTU

(All generation units EXclude transmission cost adders)

The results for the 2005 - 2008 study period show the continuing gap between the Nebraska production costs and the market. A major reason for this gap is the high natural gas price.

5.0 Expected Differences Eastern Region to Western Region

5.1 North American Electrical Interconnections

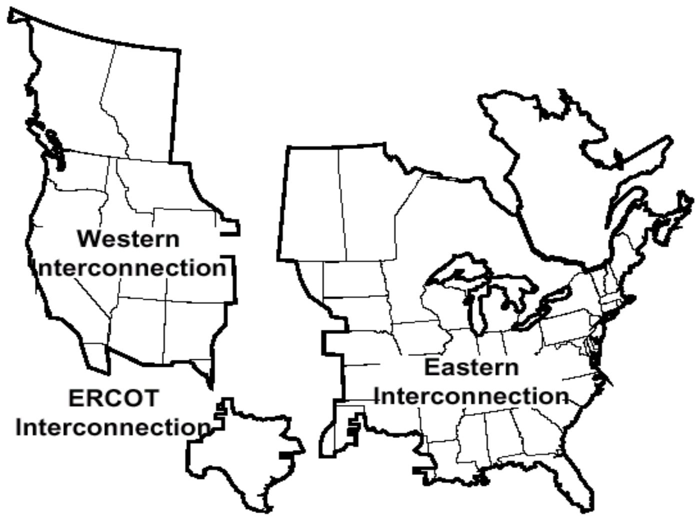
The majority of the electric systems in North America are comprised of three Interconnections as shown on Exhibit IV-8 and described below:

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

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

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

Exhibit IV-8



5.2 Eastern Interconnection and Western Interconnection Generation Supply and Demand

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

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

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

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

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

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

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

5.3 Western Region Market Compared to Eastern Region Market

5.3.1 "Markets" or "Hubs"

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

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

5.3.2 Volatility and Price Comparison

The price levels for 2003 through 2006 show a higher volatility in the Western Region for this time frame than in the Eastern Region, although the most volatile time period was in 2000. This fluctuation of volatility has decreased to where both regions are currently seeing similar volatility.

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

5.4 Nebraska Production Costs

5.4.1 Western Nebraska versus Eastern Nebraska Costs

Power costs in Nebraska reflect the cost of power primarily generated from within Nebraska. However, WAPA is a partial requirements wholesaler to a number of Nebraska utilities; Tri-State of Westminster, Colorado, serves rural systems in western Nebraska; and LES and MEAN receive some power from the Laramie River Station in Wyoming.

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

5.4.2 Stability

It is difficult to predict what Nebraska's cost of production will be in the future. However, Nebraska should generally be in a stable position through the 2007 time period. There is adequate generation to meet the load requirements per the NERC Reliability Assessment. Recent market prices in the Western Region have trended higher and been more volatile than the Eastern Region; therefore, Western Nebraska does have more exposure to the market during periods that normal generation supply is unavailable due to planned or forced outages.

6.0 Conclusions

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

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

The results of the comparison between the market product indices and the Nebraska production costs show that Nebraska production costs are approximately 44 % lower than the equivalent wholesale "median" market price based on the period 2005-2008 (three years actual, one year projected), and weighted based on MWH. Based on the "average" market price, Nebraska production costs are approximately 44% lower than the "average" market price.

These results for the 2005-2008 study show a widening gap between the Nebraska production costs and the market, due mostly to the upward trend of market prices driven by higher natural gas prices. Nebraska utilities do not have as high of concentration of natural gas-fired units when compared to the entire electric industry. The price volatility associated with Nebraska Production costs remains stable compared to market price, providing a fairly consistent, less volatile, cost expectation for Nebraska's ratepayers.

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

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

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

The "median" market price comparison, approximately 44% 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.

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

Chapter 5

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

1.0 Purpose

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

2.0 Team Members

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

3.0 Introduction and Deregulation Overview

No state has enacted retail choice legislation since 2000 and several states have scaled back or repealed retail choice initiatives. For example, in 2007, Virginia passed legislation eliminating future retail competition for all customers except industrial customers with 5 MW or greater loads. State retail electric markets have gained considerable attention in the past few years due to significant increases in retail electricity prices. Escalating and volatile fuel prices are a key driver, but do not fully explain all the cost increases. Some state retail choice programs are either struggling or inactive. As noted in a previous report, on September 1, 2004, the State Corporation Commission of Virginia issued a press release describing the findings of its fourth annual report on retail choice in Virginia. The press release notes *"that the electricity supply industry continues to struggle following price run-ups, disclosures of accounting and data improprieties, creditworthiness issues and volatile fuel prices, particularly natural gas."* The press release concludes *"that Virginia is not the exception when it comes to the lack of competitive activity for electricity supply service. In other states with retail choice, energy markets are generally inactive with few customers able to purchase power at a price lower than their traditional utility company."*

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

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

Not all states agree with this assessment. In the Report to the 80th Texas Legislature, Scope of Competition in Electric Markets in Texas dated January, 2007, the Texas PUC concluded without any data that *"it is likely that residential customers are paying lower rates than would have been produced through regulation."* (pg. 61).

Several states have faced significant challenges with retail choice as rate caps were removed as part of retail restructuring programs. Pennsylvania is one of the last states transitioning from retail rate caps to market-based pricing. On September 11, 2008, the Consumer Advocate of Pennsylvania offered the following comments to that state's Public Utility Commission. "*Electricity generation prices remain capped for the majority of Pennsylvania consumers, but the expiration of rate caps looms at the end of 2009 and 2010, and both my Office and the Commission have prepared estimates of what types of increases might occur when capped rates are replaced with market-based rates. As the Commission well knows, it is not unreasonable to expect overall rate increases of 50% to 60% or more for residential customers of some of our electric utilities that currently have relatively low generation rates, such as Met Ed, Penelec, and Allegheny (West Penn).*

4.0 Texas

Because of the national significance of the public policy choices adopted in Texas, the material below contains background on the Texas retail electric program and the status of the program efforts.

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

Following are the key provisions of the Texas law:

- Froze electric rates for investor-owned electric utilities in Texas through 2001.
- Prohibits large utilities from lowering their rates for residential and small commercial customers before 2005, or until 40% of their customers are served by competitors.
- Exempts electric cooperatives and municipally-owned electric companies from customer choice unless their governing boards decide to open their markets to competition.
- Allows customers the choice of using renewable energy (wind and solar power for example).
- Requires older electric generators to meet current environmental rules by 2003 or be shut down.
- Creates a fund to pay for lower rates for low-income families in low-income families in low-income assistance programs.
- Prohibits disconnection of service for nonpayment during periods of extreme weather.
- Allow customers to receive one bill for their electric service in an easy-to-read format and understandable language.
- Creates a Do Not Call list for customers who do not wish to be called by telemarketers on behalf of electric providers.

- Provides customer protection against discrimination, against being billed for unauthorized charges (cramming), against unauthorized change of service provider (slamming) and other unfair, misleading and deceptive practices.

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

Under the Texas deregulation program, electric utilities were divided into three areas: retail, power generation and transmission and distribution. Any investor-owned companies that wish to enter the retail market must create an affiliate company. To ensure deregulation, the Texas Public Utilities Commission created a price-to-beat for investor-owned affiliates that was to remain in place until 2005 or until 40% of customers switched to another retail company. In September of 2004, the price-to-beat in the five distribution areas ranged from 10.9 to 13.0¢/kWh with the average residential at 11.7¢. Price-to-beat rates have increased significantly since January 2002. For summer 2008, representative residential price offerings are set forth below and range from approximately 12¢/kwh to more than 20¢/kwh (See Attachment A).

Below is a comparison of average retail electric revenue per kWh in Nebraska, which has not adopted retail choice, and three states that have choice. For preliminary 2007 data for all states, see attachments B through F. For an illustrative map, see Attachment G.

Source: U.S. Energy Information Administration – www.eia.doe.gov

* 2007 #'s are preliminary

Average Price/kWh

	Nebraska	Texas	Illinois	Pennsylvania	U.S. Average
1996	5.32¢	6.16¢	7.69¢	7.96¢	6.86¢
1997	5.30¢	6.17¢	7.71¢	7.99¢	6.85¢
1998	5.30¢	6.07¢	7.46¢	7.86¢	6.74¢
1999	5.31¢	6.04¢	6.98¢	7.67¢	6.64¢
2000	5.31¢	6.49¢	6.94¢	7.65¢	6.81¢
2001	5.39¢	7.38¢	6.90¢	8.01¢	7.29¢
2002	5.55¢	6.62¢	6.97¢	8.01¢	7.20¢
2003	5.64¢	7.50¢	6.88¢	7.98¢	7.44¢
2004	5.70¢	7.95¢	6.80¢	8.00¢	7.61¢
2005	5.82¢	9.11¢	6.97¢	8.27¢	8.14¢
2006	6.07¢	10.34¢	7.07¢	8.68¢	8.90¢
2007*	6.21¢	10.27¢	8.56¢	9.07¢	9.14¢

5.0 Pennsylvania

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

Number & Percentage of Customers Served By An Alternative Supplier
As of 7/1/2008

	Residential		**Commercial**		**Industrial**		**Total**	
Allegheny Power	0	0%	0	0%	0	0%	0	0%
Duquesne Light	115,269	22%	10,204	16.8%	559	46.5%	126,032	21.5%
MetEd/Penelec	0	0%	1	0%	3	0.7%	4	0%
PECO Energy	3,506	.2%	24,458	15.7%	2	.1%	27,966	1.8%
Penn Power	12,407	8.37%	2,155	10.3%	143	63%	14,705	8.7%
PPL	0	0%	23	0%	7	0.2%	30	0%
UGI	0	0%	0	0%	0	0%	0	0%
TOTAL	**131,182**		**36,841**		**714**		**168,737**	

Pennsylvania Office of Consumer Advocate 7/25/07

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

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

Testimony of Sonny Popowsky, Consumer Advocate of Pennsylvania, before PA House Consumer Affairs Committee

6.0 Illinois

The Utility Reform Legislation passed late in 1997. The enactment of The Electric Service Customer Choice and Rate Relief Act of 1997 (HB 362) was phased in over an eight-year transition period that would allow utility customers to gradually switch to other suppliers. The intention of the eight-year transition was to "allow" Commonwealth Edison and the state's other expensive electric companies to streamline operations, lower costs and prepare for a competitive electricity market. The Illinois Commerce Commission (ICC) is responsible for overseeing the transition of the competition into the electric industry.

In exchange for the extended phase-in of competition, residential customers received an upfront rate decrease of 15%. In the first year of the new law, Commonwealth Edison changed top management, put up all of their fossil-fuel power plants for sale and shut down the largest nuclear plant ever retired in the United States. Illinois Power Company announced it would sell or close its only nuclear plant and the four other smaller electric utilities in the state were purchased by larger out of state companies.

The mandatory transition period ended January 1, 2007. Illinois lifted its rate caps at that time and now there is talk of reinstating the rate cap because of the major rate increases. Legislation was introduced and passed to avert a crisis. However, a rate relief package of nearly $1 billion was provided by investor-owned utilities.

7.0 National Rate Comparison

Nebraska remains one of the lowest cost states for electricity ranking 5th lowest overall based on 2007 preliminary data from the Energy Information Administration, See Attachments B-F for national and regional comparisons.

8.0 Conclusions

- Costly natural gas is becoming an increasingly important fuel source for electricity generation, now producing approximately 20% of the Nation's electricity.
- Natural gas sets the market price for electricity in several retail and wholesale markets.
- Promises of wholesale or retail competition driving down energy prices have not occurred.
- Competitive wholesale markets are a necessary precedent to successfully implementing retail choice.
- Adequate power supply, reserves, and infrastructure are crucial, including the proper mix of generation resources.
- Elimination of the "obligation to serve" is a contributing factor to the reduction of generation reserve margins.
- Customers served by regulated retail markets have generally experienced lower electric rate increases than customers served by "competitive" retail markets.

Attachment A
Public Utility Commission of Texas – Retail Electric Service Rate Comparisons – July 2008 bill comparison – Pages V-8 through V-17

Attachments B - F
EIA 2007 retail rate comparisons for all states

Attachments G
EIA 2006 average electricity costs by states provided for further information.

Public Utility Commission of Texas - Competitive Markets Division
Retail Electric Service Rate Comparisons
July 2008 Bill Comparison
Average Annual Rate (Cents per KWH)

TDU Service Area		Average Monthly Usage			
Oncor Electric Delivery	Retail Electric Provider	500 kWh	1000 kWh	1500 kWh	2000 kWh
	AMIGO ENERGY				
	100% Renewable	17.71	16.90	16.90	16.90
	Deep Discount	25.00	24.19	24.19	24.19
	Online Offer, Twelve-Month Commitment	16.21	15.40	15.40	15.40
	Truly Fixed, Twelve-Month Commitment	17.21	16.40	16.40	16.40
	CIRRO ENERGY				
	Smart Lock 12	16.89	15.65	15.18	15.10
	Smart Pass 12	16.49	15.25	14.78	14.70
	Smart Pass 24	16.79	15.55	15.08	15.00
	COMMERCE ENERGY				
	Clear Choice Renewable	15.60	15.60	15.60	15.60
	Sure Choice All-In	15.10	15.10	15.10	15.10
	Sure Choice Variable	20.39	19.90	19.73	19.65
	DIRECT ENERGY	15.60	15.10	14.93	14.85
	DYNOWATT	22.79	22.30	22.13	22.05
	Go Green Variable	23.38	22.89	22.72	22.64
	Twelve-Month Cost Control	14.89	14.40	14.23	14.15
	Twelve-Month Go Green	15.44	14.95	14.78	14.70
	FIRST CHOICE POWER				
	Simply Better Convenience	23.59	23.10	22.93	22.85
	Simply Better Earth Saver	20.49	20.00	19.83	19.75
	Simply Better Price	19.69	19.20	19.03	18.95

TEXAS CHOICE

Public Utility Commission of Texas - Competitive Markets Division
Retail Electric Service Rate Comparisons
July 2008 Bill Comparison
Average Annual Rate (Cents per KWH)

TDU Service Area		Average Monthly Usage			
Oncor Electric Delivery	Retail Electric Provider	500 kWh	1000 kWh	1500 kWh	2000 kWh
	GEXA ENERGY	16.88	15.90	15.58	15.42
	Green	17.38	16.40	16.08	15.92
	Green 12	17.38	16.40	16.08	15.92
	Guaranteed	17.18	16.20	15.88	15.72
	GREEN MOUNTAIN ENERGY				
	100% Wind	18.59	17.93	17.71	17.60
	Pollution Free	16.90	16.30	16.10	16.00
	Pollution Free Reliable Rate	16.50	16.50	16.50	16.50
	RELIANT ENERGY				
	Flex	16.50	16.00	15.83	15.75
	Flex 100% Texas Wind	18.10	17.60	17.43	17.35
	Rate Reduction 24	17.20	16.70	16.53	16.45
	STARTEX POWER	21.08	20.50	20.50	20.50
	Seasonal Savings Twelve-Month	14.78	14.20	14.20	14.20
	TXU ENERGY				
	PowerStart	18.59	17.74	17.33	17.12
	SureValue 24	18.19	17.35	16.94	16.74
	Texas Choice 24	16.69	15.92	15.54	15.36

TEXAS ELECTRIC CHOICE

Public Utility Commission of Texas - Competitive Markets Division
Retail Electric Service Rate Comparisons
July 2008 Bill Comparison
Average Annual Rate (Cents per KWH)

TDU Service Area		Average Monthly Usage			
CenterPoint Energy Houston Electric	Retail Electric Provider	500 kWh	1000 kWh	1500 kWh	2000 kWh
	AMIGO ENERGY				
	100% Renewable	19.71	18.90	18.90	18.90
	Deep Discount	25.50	24.69	24.69	24.69
	Online Offer, Twelve-Month Commitment	18.63	17.81	17.81	17.81
	Truly Fixed, Twelve-Month Commitment	19.21	18.40	18.40	18.40
	CIRRO ENERGY				
	Smart Lock 12	17.99	16.85	16.48	16.35
	Smart Pass 12	19.76	18.62	18.25	18.12
	COMMERCE ENERGY				
	Clear Choice Renewable	17.60	17.60	17.60	17.60
	Sure Choice All-In	17.00	17.00	17.00	17.00
	Sure Choice Variable	22.59	22.10	21.93	21.85
	DIRECT ENERGY	17.50	17.00	16.83	16.75
	DYNOWATT	22.79	22.30	22.13	22.05
	Go Green Variable	23.38	22.89	22.72	22.64
	Twelve-Month Cost Control	16.19	15.70	15.53	15.45
	Twelve-Month Go Green	16.74	16.25	16.08	16.00

Public Utility Commission of Texas - Competitive Markets Division
Retail Electric Service Rate Comparisons
July 2008 Bill Comparison
Average Annual Rate (Cents per KWH)

TDU Service Area		Average Monthly Usage			
CenterPoint Energy Houston Electric	Retail Electric Provider	500 kWh	1000 kWh	1500 kWh	2000 kWh
	FIRST CHOICE POWER				
	Simply Better Convenience	26.49	26.00	25.83	25.75
	Simply Better Earth Saver	22.19	21.70	21.53	21.45
	Simply Better Price	21.39	20.90	20.73	20.65
	GEXA ENERGY	17.76	16.90	16.61	16.46
	Green	18.36	17.50	17.21	17.06
	Green 12	18.56	17.70	17.41	17.26
	Guaranteed	17.76	16.90	16.61	16.46
	GREEN MOUNTAIN ENERGY				
	100% Wind	20.35	19.69	19.48	19.37
	Pollution Free	18.50	17.90	17.71	17.61
	Pollution Free Reliable Rate	18.20	18.20	18.20	18.20
	RELIANT ENERGY				
	Flex	17.60	17.10	16.93	16.85
	Flex 100% Texas Wind	19.40	18.90	18.73	18.65
	Rate Reduction 24	20.90	20.40	20.23	20.15
	STARTEX POWER	21.08	20.50	20.50	20.50
	Seasonal Savings Twelve-Month	15.78	15.20	15.20	15.20
	TXU ENERGY				
	Freedom	16.21	16.90	16.84	16.76
	Resident's Choice	17.06	17.31	17.64	17.92

TEXAS ELECTRIC CHOICE

Public Utility Commission of Texas - Competitive Markets Division
Retail Electric Service Rate Comparisons
July 2008 Bill Comparison
Average Annual Rate (Cents per KWH)

TDU Service Area		Average Monthly Usage			
Texas - New Mexico Power	Retail Electric Provider	500 kWh	1000 kWh	1500 kWh	2000 kWh
	AMIGO ENERGY				
	100% Renewable	17.83	16.90	16.90	16.90
	Deep Discount	25.32	24.39	24.39	24.39
	Online Offer, Twelve-Month Commitment	16.83	15.91	15.91	15.91
	Truly Fixed, Twelve-Month Commitment	17.33	16.40	16.40	16.40
	CIRRO ENERGY				
	Smart Pass 12	16.67	15.68	15.23	15.19
	COMMERCE ENERGY				
	Clear Choice Renewable	17.20	17.20	17.20	17.20
	Sure Choice All-In	16.60	16.60	16.60	16.60
	Sure Choice Variable	22.29	21.80	21.63	21.55
	DYNOWATT	22.79	22.30	22.13	22.05
	Go Green Variable	23.38	22.89	22.72	22.64
	Twelve-Month Cost Control	15.89	15.40	15.23	15.15
	Twelve-Month Go Green	16.44	15.95	15.78	15.70
	FIRST CHOICE POWER				
	Simply Better Convenience	21.61	22.33	22.59	22.72
	Simply Better Earth Saver	20.99	20.50	20.33	20.25
	Simply Better Price	20.19	19.70	19.53	19.45

TEXAS ELECTRIC CHOICE

Public Utility Commission of Texas - Competitive Markets Division
Retail Electric Service Rate Comparisons
July 2008 Bill Comparison
Average Annual Rate (Cents per KWH)

TDU Service Area		Average Monthly Usage			
Texas – New Mexico Power	Retail Electric Provider	500 kWh	1000 kWh	1500 kWh	2000 kWh
	GEXA ENERGY				
	Green	16.77	15.90	15.61	15.47
	Green 12	17.17	16.30	16.01	15.87
	Guaranteed	17.17	16.30	16.01	15.87
		16.57	15.70	15.41	15.27
	GREEN MOUNTAIN ENERGY				
	100% Wind	18.58	17.93	17.71	17.60
	Pollution Free	16.89	16.30	16.10	16.00
	Pollution Free Reliable Rate	16.50	16.50	16.50	16.50
	RELIANT ENERGY				
	Flex	18.40	17.90	17.73	17.65
	Flex 100% Texas Wind	19.00	18.50	18.33	18.25
	Rate Reduction 24	19.50	19.00	18.83	18.75
	STARTEX POWER	21.17	20.50	20.50	20.50
	Seasonal Savings Twelve-Month	15.27	14.60	14.60	14.60
	TXU ENERGY				
	Freedom	15.33	16.08	16.34	16.48
	Resident's Choice	16.36	16.54	16.91	17.18

TEXAS ELECTRIC CHOICE

Public Utility Commission of Texas - Competitive Markets Division
Retail Electric Service Rate Comparisons
July 2008 Bill Comparison
Average Annual Rate (Cents per KWH)

TDU Service Area		Average Monthly Usage			
AEP Texas Central	Retail Electric Provider	500 kWh	1000 kWh	1500 kWh	2000 kWh
	AMIGO ENERGY				
	100% Renewable	19.11	18.30	18.30	18.30
	Deep Discount	25.20	24.39	24.39	24.39
	Online Offer, Twelve-Month Commitment	17.71	16.90	16.90	16.90
	Truly Fixed, Twelve-Month Commitment	18.51	17.70	17.70	17.70
	CIRRO ENERGY				
	Smart Pass 12	19.99	18.57	18.04	17.93
	COMMERCE ENERGY				
	Clear Choice Renewable	17.10	17.10	17.10	17.10
	Sure Choice All-In	16.60	16.60	16.60	16.60
	Sure Choice Variable	22.49	22.00	21.83	21.75
	CPL RETAIL ENERGY	19.06	18.43	18.22	18.11
	DYNOWATT	22.79	22.30	22.13	22.05
	Go Green Variable	23.38	22.89	22.72	22.64
	Twelve-Month Cost Control	16.99	16.50	16.33	16.25
	Twelve-Month Go Green	17.54	17.05	16.88	16.80
	FIRST CHOICE POWER				
	Simply Better Convenience	28.29	27.80	27.63	27.55
	Simply Better Earth Saver	22.69	22.20	22.03	21.95
	Simply Better Price	21.89	21.40	21.23	21.15

Public Utility Commission of Texas - Competitive Markets Division
Retail Electric Service Rate Comparisons
July 2008 Bill Comparison
Average Annual Rate (Cents per KWH)

TDU Service Area		Average Monthly Usage			
AEP Texas Central	Retail Electric Provider	500 kWh	1000 kWh	1500 kWh	2000 kWh
	GEXA ENERGY	17.56	16.40	16.20	15.83
	Green	18.66	17.50	17.12	16.93
	Green 12	19.06	17.90	17.52	17.33
	Guaranteed	18.46	17.30	16.92	16.73
	GREEN MOUNTAIN ENERGY				
	100% Wind	20.34	19.69	19.47	19.36
	Pollution Free	18.49	17.90	17.70	17.60
	Pollution Free Reliable Rate	18.40	18.40	18.40	18.40
	RELIANT ENERGY				
	Flex	19.00	18.50	18.33	18.25
	Flex 100% Texas Wind	19.60	19.10	18.93	18.85
	Rate Reduction 24	21.30	20.80	20.63	20.55
	STARTEX POWER	23.38	22.80	22.80	22.80
	Seasonal Savings Twelve-Month	16.48	15.90	15.90	15.90
	TXU ENERGY				
	Freedom	17.40	16.95	16.84	16.78
	Resident's Choice	17.36	17.55	17.93	18.22

Public Utility Commission of Texas - Competitive Markets Division
Retail Electric Service Rate Comparisons
July 2008 Bill Comparison
Average Annual Rate (Cents per KWH)

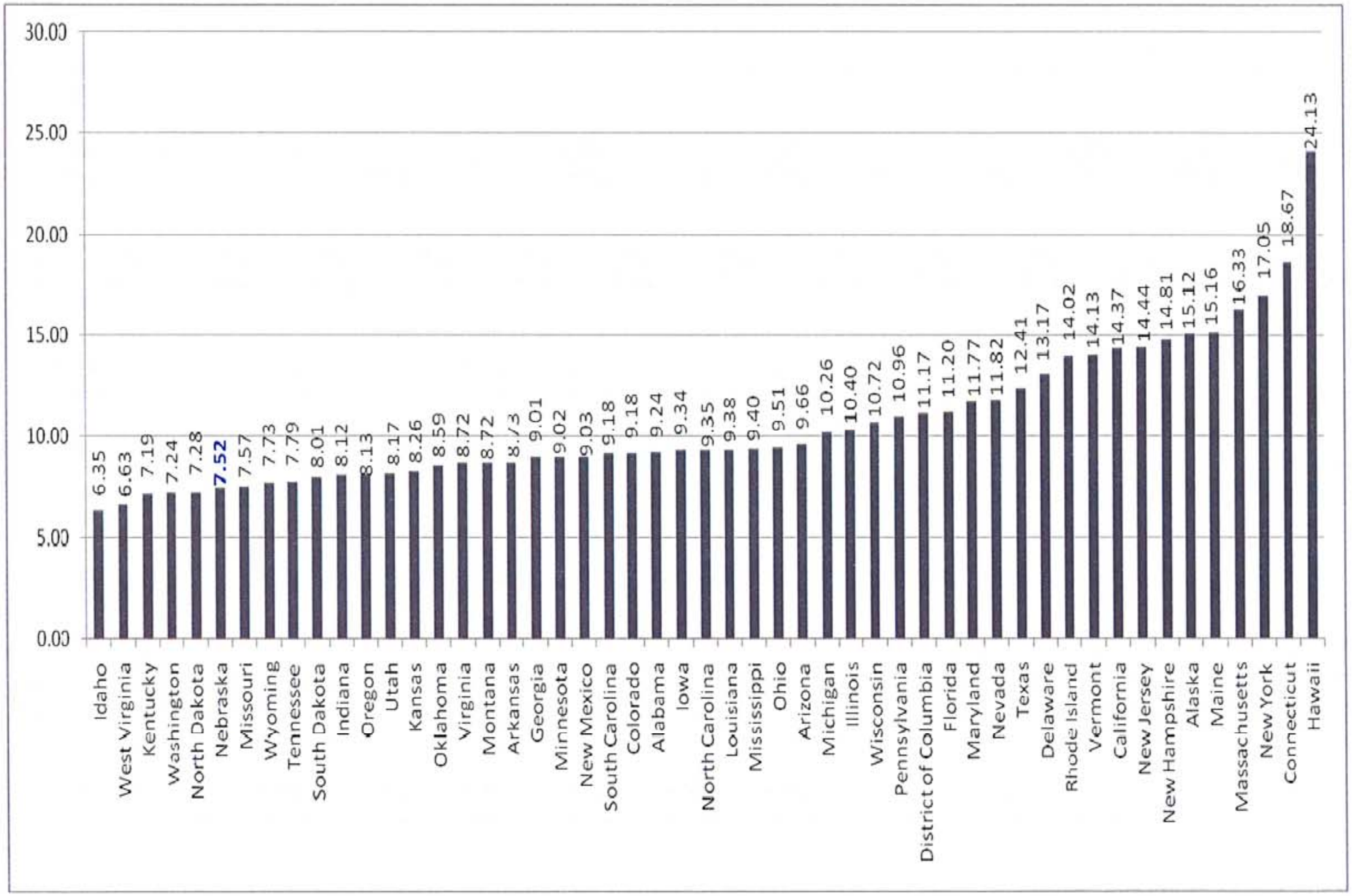
TDU Service Area		Average Monthly Usage			
AEP Texas North	Retail Electric Provider	500 kWh	1000 kWh	1500 kWh	2000 kWh
	AMIGO ENERGY				
	100% Renewable	16.71	15.90	15.90	15.90
	Deep Discount	25.20	24.39	24.39	24.39
	Online Offer, Twelve-Month Commitment	14.73	13.92	13.92	13.92
	Truly Fixed, Twelve-Month Commitment	16.31	15.50	15.50	15.50
	CIRRO ENERGY				
	Smart Pass 12	15.82	14.25	13.68	13.54
	COMMERCE ENERGY				
	Clear Choice Renewable	13.10	13.10	13.10	13.10
	Sure Choice All-In	12.60	12.60	12.60	12.60
	Sure Choice Variable	19.99	19.50	19.33	19.25
	DYNOWATT	22.79	22.30	22.13	22.05
	Go Green Variable	23.38	22.89	22.72	22.64
	Twelve-Month Cost Control	13.79	13.30	13.13	13.05
	Twelve-Month Go Green	14.34	13.85	13.68	13.60
	FIRST CHOICE POWER				
	Simply Better Convenience	24.69	24.20	24.03	23.95
	Simply Better Earth Saver	20.39	19.90	19.73	19.65
	Simply Better Price	19.59	19.10	18.93	18.85

TEXAS ELECTRIC CHOICE

Public Utility Commission of Texas - Competitive Markets Division
Retail Electric Service Rate Comparisons
July 2008 Bill Comparison
Average Annual Rate (Cents per KWH)

TDU Service Area		Average Monthly Usage			
AEP Texas North	Retail Electric Provider	500 kWh	1000 kWh	1500 kWh	2000 kWh
	GEXA ENERGY	15.91	14.61	14.17	13.95
	Green	16.19	14.90	14.46	14.25
	Green 12	16.19	14.90	14.46	14.25
	Guaranteed	15.79	14.50	14.06	13.85
	GREEN MOUNTAIN ENERGY				
	100% Wind	18.04	17.39	17.17	17.06
	Pollution Free	16.40	15.80	15.61	15.51
	Pollution Free Reliable Rate	16.50	16.50	16.50	16.50
	RELIANT ENERGY				
	Flex	15.90	15.40	15.23	15.15
	Flex 100% Texas Wind	16.50	16.00	15.83	15.75
	Rate Reduction 24	16.60	16.10	15.93	15.85
	STARTEX POWER	21.08	20.50	20.50	20.50
	Seasonal Savings Twelve-Month	13.18	12.60	12.60	12.60
	TXU ENERGY				
	Freedom	15.96	15.62	15.53	15.49
	Resident's Choice	15.33	15.55	15.85	16.10
	WTU RETAIL ENERGY	15.98	15.44	15.26	15.17

2007 Residential Average Retail Price of Electricity

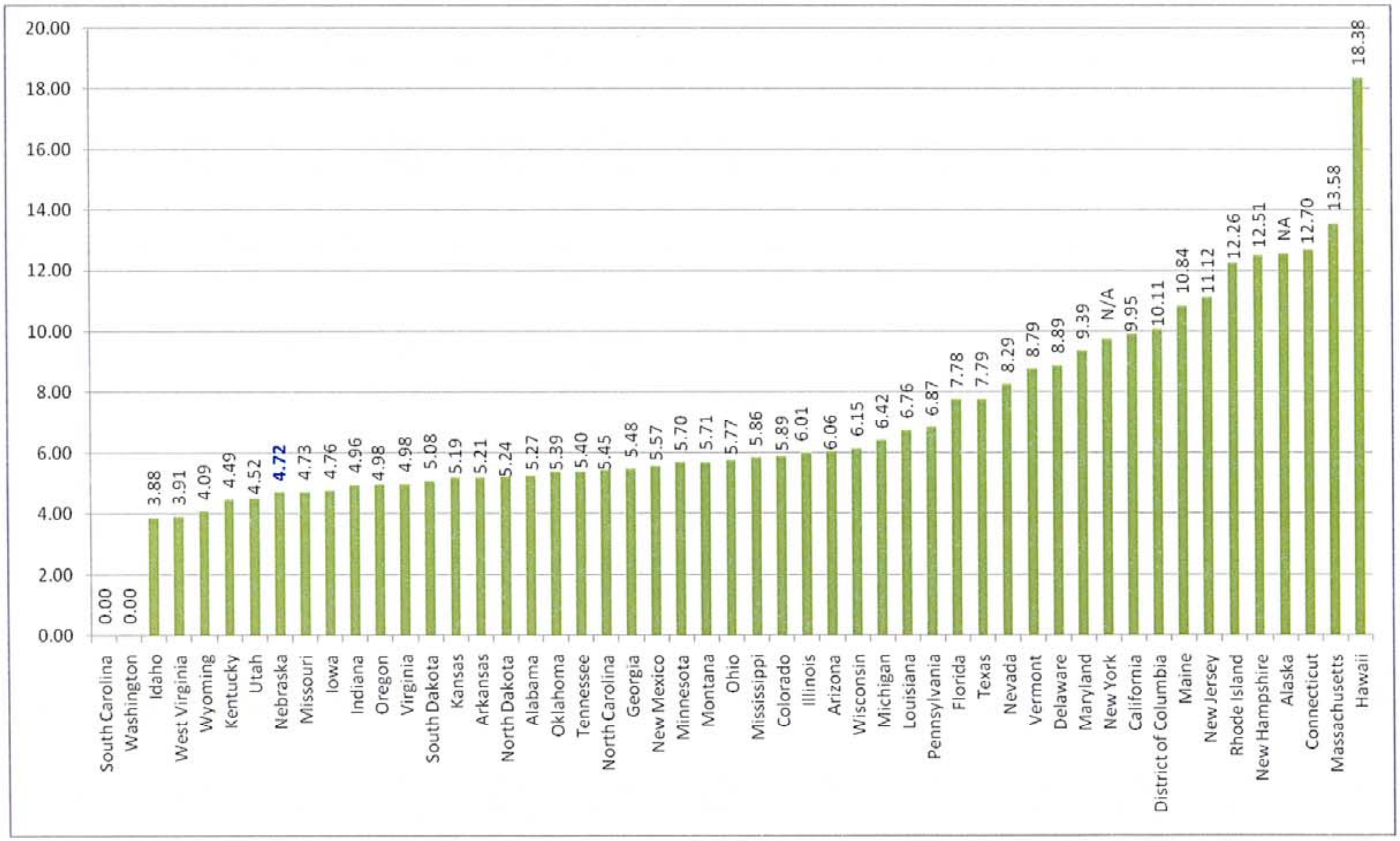


www.eia.gov Energy Information Administration/Electric Power Monthly March 2008 *Table 5.6.B*

20

ATTACHMENT C

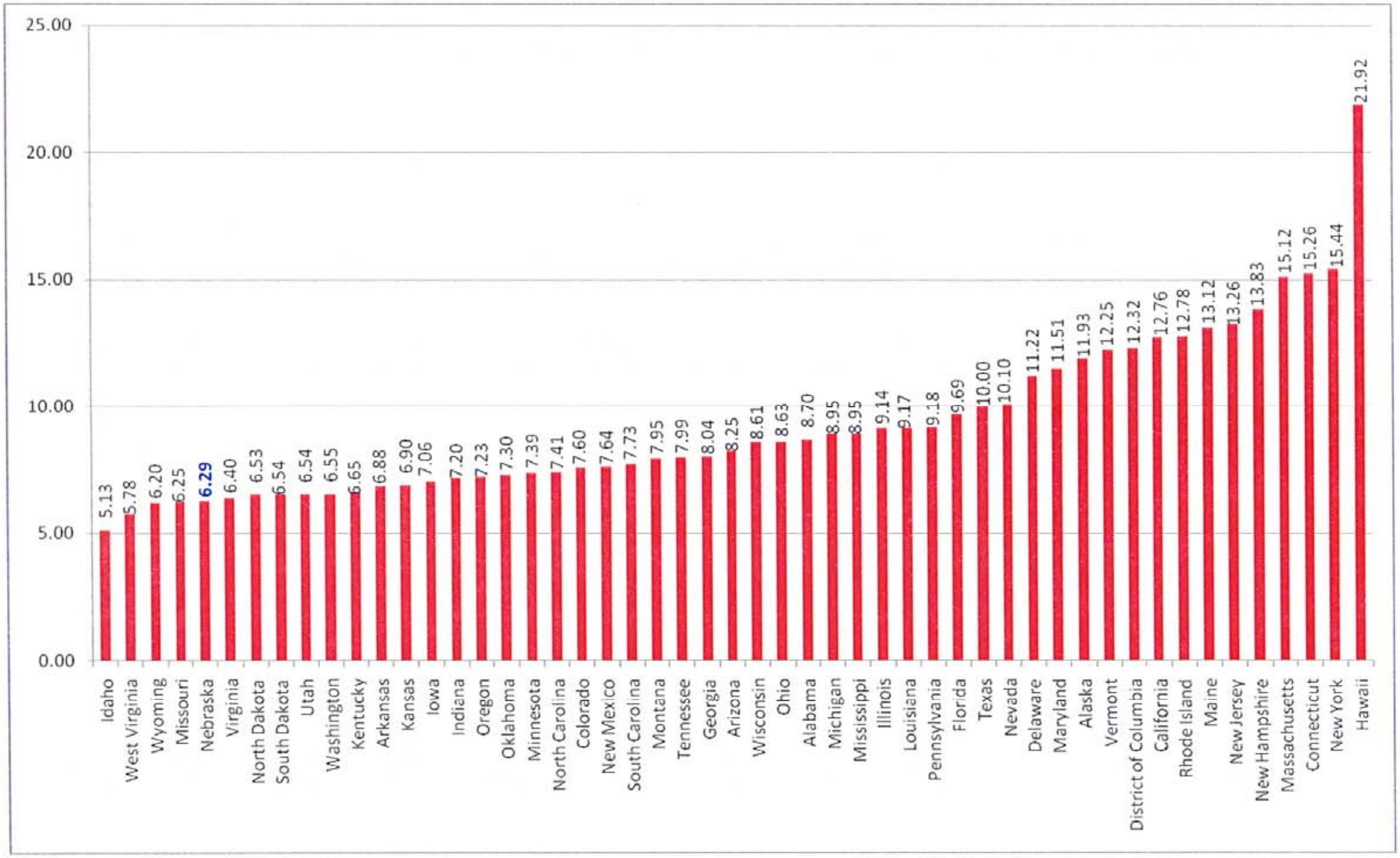
2007 *Industrial* Average Retail Price of Electricity



www.eia.gov Energy Information Administration/Electric Power Monthly March 2008 *Table 5.6.B*

21

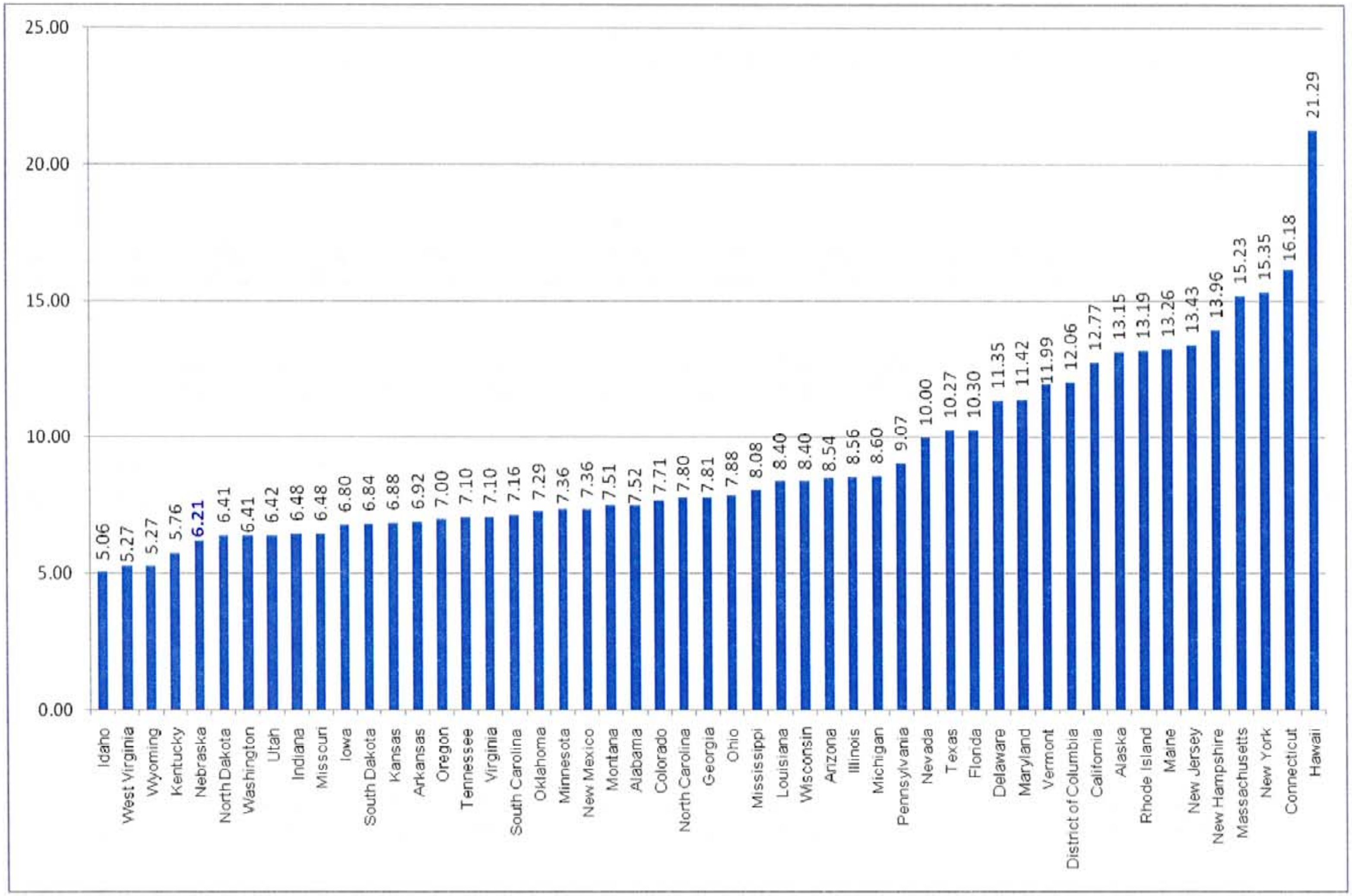
2007 *Commercial* Average Retail Price of Electricity



www.eia.gov Energy Information Administration/Electric Power Monthly March 2008 *Table 5.6.B*

22

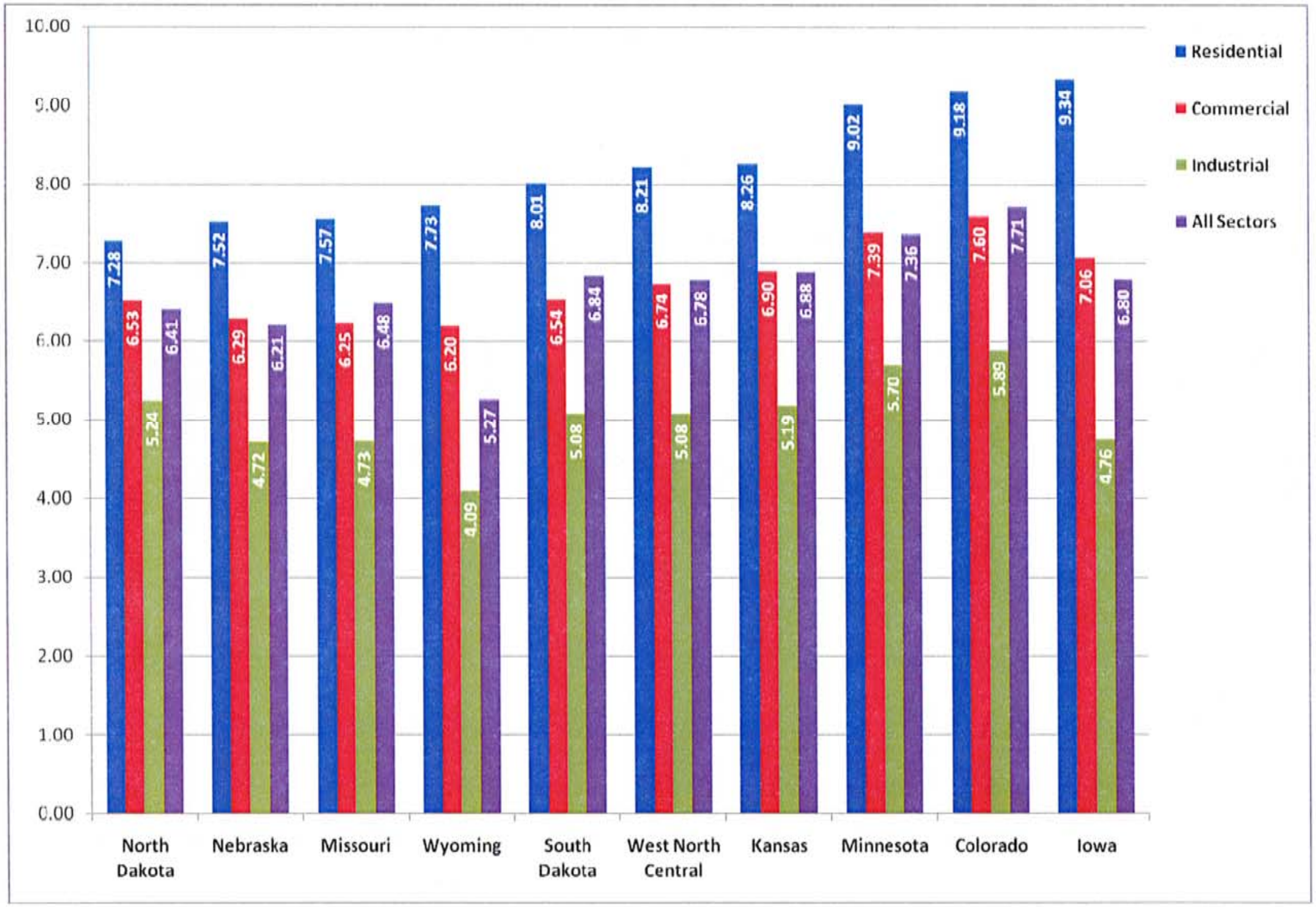
2007 *All Sectors* Average Retail Price of Electricity



www.eia.gov Energy Information Administration/Electric Power Monthly March 2008 *Table 5.6.B*

2007 *West North Central Region*

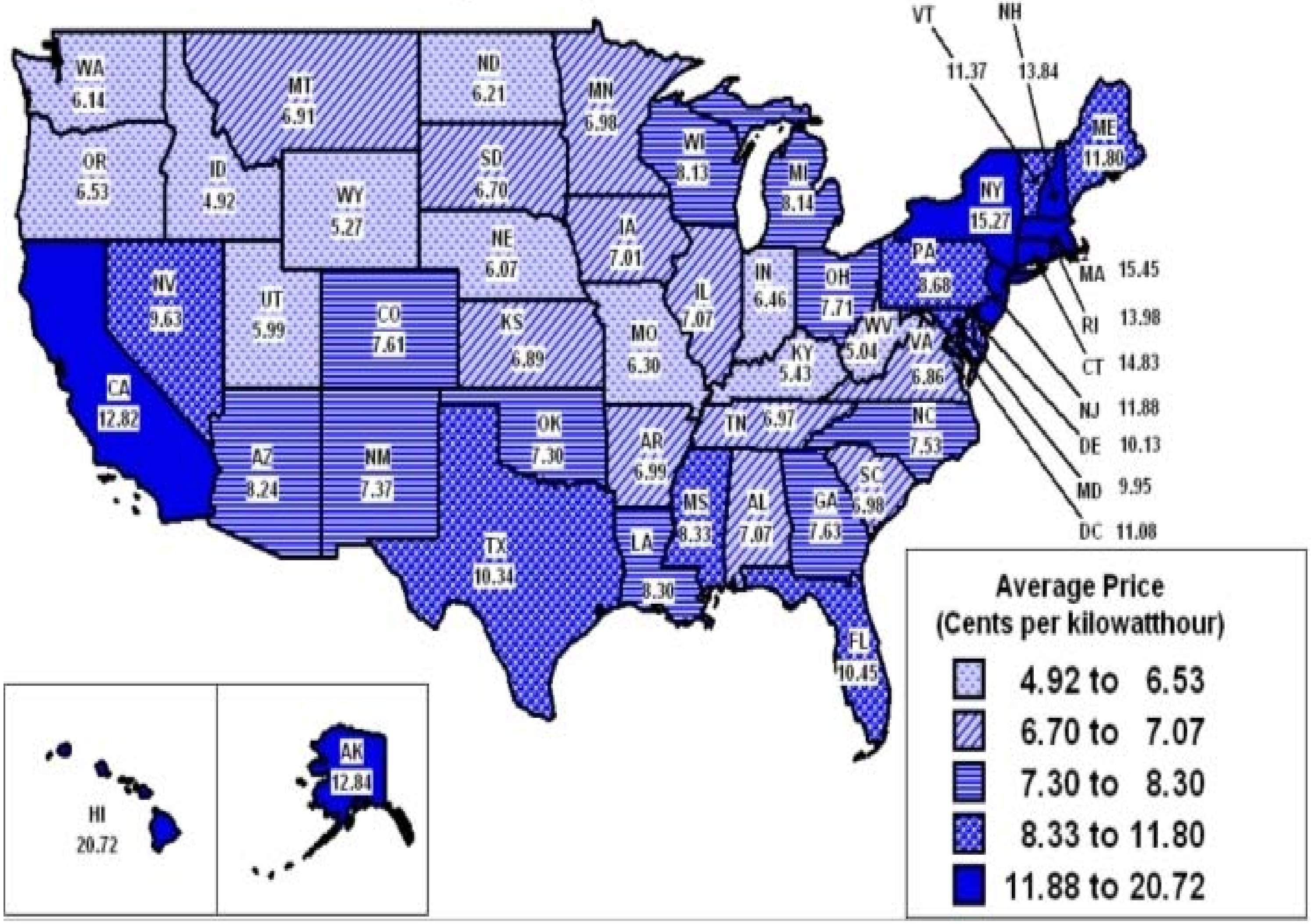
Average Retail Price of Electricity



www.eia.gov Energy Information Administration/Electric Power Monthly March 2008 *Table 5.6.B* 24

Attachment G
2006 Energy Information Agency

U.S. Total Average Price per kilowatthour is 8.90 Cents



GLOSSARY

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

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

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

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

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

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

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

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

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

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

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

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

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

Contract Path: The most direct physical transmission tie between two interconnected entities. When utility systems interchange power, the transfer is presumed to occur over the contract path not withstanding the fact that power flow in the network will distribute in accordance with network flow conditions.

Control Area: An electric system or systems, bounded by interconnection metering and telemetry, capable of controlling generation to maintain its interchange schedule with other control areas and contributing to frequency regulation of the interconnection.

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

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

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

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

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

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

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

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

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

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

ECAR: East Central Area Reliability Coordination Agreement.

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

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

ERCOT: The Electric Reliability Council of Texas.

FERC: Federal Energy Regulatory Commission

FTR: Future Transmission Right

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

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

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

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

FRCC: Florida Reliability Coordinating Council

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

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

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

Grid: A system of interconnected power lines and generators that is managed so that the generators are dispatched as needed to meet the electrical demands.

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

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

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

LES: Lincoln Electric System

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

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

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

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

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

MAAC: Mid-Atlantic Area Council

MAIN: MidAmerican Interconnected Network

MAPP: Mid-Continent Area Power Pool

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

Megawatt [MW]: One million watts

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

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

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

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

MISO – Midwest ISO

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

MTEP-3: Midwest Transmission Expansion Plan

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

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

NPCC: Northeast Power Coordinating Council

NPPD: Nebraska Public Power District

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

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

OPPD: Omaha Public Power District.

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

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

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

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

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

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

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

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

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

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

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

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

RTO – Regional Transmission Organization

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

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

SERC: Southeastern Electricity Reliability Council.

Service Schedule F: MAPP's open access transmission tariff

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

SPP: Southwest Power Pool.

SMA: Supply Market Assessment (FERC concept)

SMD: Standard Market Design (FERC concept)

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

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

TLR: MAPP transmission loading relief procedures

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

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

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

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

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

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

WAPA: Western Area Power Administration

Summary of Individual Chapters for previous study years

Issue #1 (Chapter 1)
SUMMARY OF 2007 REPORT

- Viability of the MAPP region is less certain than in previous years
- MISO market participation options need to be evaluated carefully
- Participation in SPP may be an option
- Adequate transmission exists in Nebraska to deliver generation to load but:
  - Parallel flows from the market cause increased congestion
  - Regional transmission cannot support all of the potential wholesale market transactions

SUMMARY OF 2006 REPORT – In summary, MAPP does currently serve Nebraska utilities as a viable regional transmission organization. Its continued viability beyond 2008 is uncertain, but a new organization, MCSG, is under development to replace MAPP as the regional transmission organization.

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

SUMMARY OF 2005 REPORT - President Bush signed the Energy Policy Act into law on August 8, 2005. The FERC chairman has indicated that FERC intends to take a new direction in its role to ensure that competitive wholesale electric markets are free of discriminatory practices. As a result, Nebraska's public power utilities anticipate that they will have many new requirements to meet in the coming years. See Issue # 5 (Chapter 5) for an overview of the implications for public power utilities of the Energy Policy Act.

The utility membership in the two RTO's that adjoin Nebraska has solidified to some extent, and it does not appear that the geographical boundaries of the two entities will be changing in the near future. Nebraska utilities continue to remain members of MAPP, and although the geographical footprint of MAPP has shrunk as several members left to join the Midwest ISO, the generation reserve sharing pool has remained the same as the original MAPP membership. Another consideration in the boundary issues is that the footprint of the Midwest Reliability Organization includes all of the original MAPP members, a number of Midwest ISO members, and two Canadian providences. Because of the differing boundaries for transmission service, generation reserve sharing and Regional Reliability Councils, several seams agreements have been executed which require significant data exchange between the regions. The Nebraska utilities have concluded that continued membership in MAPP provides the most cost effective solution for participation in a regional transmission organization. FERC is no longer pursuing mandatory participation in an RTO that meets all of its requirements, so MAPP can continue to function as a regional transmission organization, providing access to the regional wholesale energy markets under its regional transmission tariff.

While the electric industry continues to change under FERC direction and enactment of federal legislation, the end point is no clearer at this time. Therefore, the conclusion remains unchanged from last year's report that there is no economically viable FERC-approved RTO for Nebraska utilities to participate in.

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

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

The TRANSLink project was officially terminated in November 2003.

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

SUMMARY OF 2003 REPORT - The August 14, 2003 blackout, the most wide-ranging in U. S. electric history, will cause a significant review of the nation's transmission infrastructure and the organizational entities controlling it. Congressional hearings have been scheduled and a joint U. S. and Canadian Task Force have been appointed to investigate the blackout. Many are calling for passage of the long debated federal energy legislation. How this will impact the continued development of Regional Transmission Organizations (RTOs) remains to be seen. The Midwest ISO has indicated that it will be reevaluating the timing for the start-up of its energy markets, and will make a recommendation to its Board of Directors in September. Progress on the development of TRANSLink has been slowed due to the lack of state regulatory commission approvals, and as a result the TRANSLink participants are reevaluating their options for continued development of TRANSLink. In light of the pending investigations of the blackout, and uncertainty about federal legislation which may be enacted, it seems prudent for Nebraska utilities to wait until such time as more is known so they can make an informed decision before proceeding to join a RTO. At this time there is not a RTO that has been shown to be economically, technically and operational viable. There is adequate transmission capacity in Nebraska to deliver the generation output of plants in Nebraska to the Nebraska customer load, but there is not sufficient capacity to support all of the wholesale power transactions that are requested in the region.

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

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

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

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

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

However, in a series of orders issued on July 12, 2001 FERC reversed its course and now suggests that only four RTOs should be formed, one in the Northeast, Southeast, Midwest and West. This change in direction by FERC has caused considerable confusion in the industry. As a result, this Issue is in a state of flux. At this juncture the only organization that has the potential to become a viable RTO for Nebraska utilities to participate in is the

Midwest ISO (MISO), assuming FERC decides that MISO is to become the Midwest RTO it envisions. This report will serve to identify key issues that could significantly affect the way the electric transmission system in Nebraska is planned, operated and priced.

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

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

Issue #2 (Chapter 2)
SUMMARY OF 2007 REPORT - The traditional test of market power, the hub and spoke test, demonstrated that two out of the three regions in the wholesale market that includes Nebraska, experienced market power. The newly approved FERC market power screens of individual utilities indicate that nearly all of the area utilities not belonging to an RTO have market power. The final conclusion is that a reasonably efficient and workable wholesale market does exist in the Midwest region, but it cannot be judged as being free from market power given the new FERC rules.

SUMMARY OF 2006 REPORT - Eastern Region: The traditional test of market power, the hub and spoke test, demonstrated that two out of the three regions in the wholesale market that includes Nebraska, experienced market power. The newly approved FERC market power screens of individual utilities indicate that nearly all of the area utilities not belonging to an RTO have market power. Additionally, new proposed FERC rulemakings that will review the validity of these screens for identifying market power as well as a review of the initial orders responsible for the deregulation of the wholesale market suggest that FERC is very concerned about the effectiveness of these rulemakings in detecting market power. Finally, a draft report to Congress states that the market for long-term wholesale power is illiquid and represents a deficiency in the market. The final conclusion is that a reasonably efficient and workable wholesale market does exist in the Midwest region, but it cannot be judged as being free from market power given the new FERC rules.

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

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

SUMMARY OF 2005 REPORT - Since the initiation of the Generation Market Screen and Mitigation Policy in April 2005, 21 independent or utility holding companies (representing 48 operating companies) submitted market power screens as part of the FERC Review. Of the 48 utilities, 11 have unconditionally passed the market screens. They are free to continue selling wholesale energy at market-based rates. Most of these utilities are members of "qualifying" RTOs. Four of the 48 utilities submitting tests were asked to revise their filings because of missing information, while the remaining 33 utilities who failed one or more screens were ordered to refile a Delivered Price Test or additional information demonstrating lack of market power, a plan for mitigating market power, or an acceptance of cost-based rates within 60 days. As of this writing, of the 33 utilities that failed the screens, 18 utilities have not yet submitted a filing for the order, 8 utilities have filed plans accepting cost-based rates, and 7 utilities filed additional tests and information to FERC in an effort to demonstrate a lack of market power. In the Midwest, there have been numerous filing with mixed results. Some of the screens have been accepted by FERC, some utilities have accepted cost-based rates, while others will have to submit additional information to FERC.

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

SUMMARY OF 2004 REPORT-The new information gathered for this year's analysis is sending mixed and ambiguous signals regarding market power in the Midwest portion of the Eastern Interconnect. On one hand, "traditional" tests of market power used by FERC suggest that this market has a large number of buyers and sellers and appears to be viable. A defined process for accessing wholesale transmission is available through MAPP, utilizing

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

There are considerable capacity shortfalls and transmission interconnection 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 is 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 and T in Westminster, Colorado which serves all of the rural electrics in the panhandle of Nebraska.

ISSUE # 3 (Chapter 3)
SUMMARY OF 2007 REPORT – There were no new developments.

SUMMARY OF 2006 REPORT - There were no new developments in 2006. Technical Group #3 will continue to review the status of unbundling in Nebraska, and report the results as needed. During the study year 2007, there may be activity in the area of privately owned generation that might require limited unbundling and Technical Group #3 may look in to those activities.

SUMMARY OF 2005 REPORT-There were no new developments in 2005 for Technical Group #3 to address.

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

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

These results are almost identical to the 2001 survey results.

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

SUMMARY OF 2002 REPORT - For this year's report, this Technical Group was requested to estimate the cost that would be incurred if retail electric bills were to be unbundled in Nebraska. The cost associated with moving to retail competition is hard to estimate because of the different issues and concerns to be addressed. Unbundling of retail bills is 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.

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

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

Issue #4 (Chapter 4)
SUMMARY OF 2007 REPORT - The results of the comparison between the market product indices and the Nebraska production costs show that Nebraska production costs are approximately 39% lower than the equivalent wholesale "median" market price based on the period 2003-2006 (three years actual, one year projected), and weighted based on MWH. Based on the "average" market price, Nebraska production costs are approximately 39% lower than the "average" market price.

SUMMARY OF 2006 REPORT - The challenge for Technical Group #4 was to develop an equitable comparison between the credible indices that were identified and the product provided by Nebraska electric utilities to their customer-owners. The product that Nebraska providers sell is a firm, total electrical requirements product, available 24 hours a day, 7 days a week, in quantities that vary hourly, weekly, monthly, seasonally, and annually. This obligation to serve includes both existing and new customers. The typical index described in the previous sections provides a price for a fixed hourly quantity of energy, possibly with a premium for financial firmness, but with no obligations on the part of the seller beyond the current month or, in the case of daily indices, beyond that day. The typical index is not a comparable product to that provided by a Nebraska utility to its customers.

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

The results of the comparison between the market product indices and the Nebraska production costs show that Nebraska production costs are approximately 39% lower than the equivalent wholesale “median” market price based on the period 2003-2006 (three years actual, one year projected) and weighted based on MWH. Based on the “average” market price, Nebraska production costs are approximately 39% lower than the “average” market price.

These results for the 2003-2006 study show a widening gap between the Nebraska production costs and the market, due mostly to the upward trend of market prices driven by higher natural gas prices. Nebraska utilities do not have as high of concentration of natural gas-fired units when compared to the entire electric industry. The price volatility associated with Nebraska Production costs remains stable compared to market price, providing a fairly consistent, less volatile, cost expectation for Nebraska’s ratepayers.

In addition, the results of an analyses performed in 2003 that applied four different approaches to determining the value of the long-term obligation to serve that is provided by Nebraska utilities appears to be in the $3 – 5 / MWH range, and this is added value that Nebraska utilities provide customers over and above market products. Currently, electricity traders are experiencing as much as 17% in delivery losses (equivalent to approximately $5 / MWH), which add to the price of a market product. Also, the standard market transmission tariffs associated with delivering these market products from external regions to Nebraska customers can add an additional $4 – 6 / MWH to the market product price

SUMMARY OF 2005 REPORT - In 2005, Technical Group # 4 was again focused on the task of making “a comparison of Nebraska’s wholesale electricity prices to the prices in the region”. This involved using the same fixed and variable cost allocation tool that was used in prior years’ comparisons. The results of this year’s comparisons between the market product indices and the Nebraska production costs show that Nebraska production costs are approximately 28% lower than the equivalent “median” market price based on the period 2002-2005 (three years actual and one year estimated) and weighted based on MWH. These results compare to the prior period results for 2001-2004 of 21%. The results for 2002-2005 show a widening gap between the Nebraska production costs and the market, due mostly to the upward trend of market prices driven by higher natural prices. Nebraska utilities do not have as high of concentration of natural gas-fired units when compared to the entire electric industry. The “median” market price comparison compares favorably with rate comparisons. The Energy Information Administration annually compiles data from the Form EIA-861 for approximately 3,300 public and investor-owned electric utilities including active power marketers and other energy service providers. The most current data for 2003 shows that Nebraska’s average retail rate of 5.40 cents/kWh is approximately 26% lower than the national average retail rate of 7.26 cents/kWh. The price volatility associated with Nebraska production costs remain stable compared to market price, providing a fairly consistent, less volatile, cost expectation for Nebraska's ratepayers.

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

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

SUMMARY OF 2003 REPORT -Technical Group # 4 utilized the same fixed and variable cost allocation tool in 2003 that was used in the prior two reports. The results of this years comparisons between the market product indices and the Nebraska production costs show that Nebraska production costs are approximately 18% lower than the equivalent wholesale "median" market price based on the period 2000-2003 (three years actual and one year estimated) and weighted based on MWH. These results are slightly better than the 15% results for the prior period 1999-2002 due primarily to the upward trend of market prices driven by higher natural gas prices and stable generation. The price volatility associated with Nebraska production costs remains stable compared to market price, providing a fairly consistent, less volatile, cost expectation for Nebraska's ratepayers. The "median" market prices compare favorably with retail rate comparisons. The Energy Information

Administration (EIA) annually compiles data from Form EIA-861 for approximately 3,300 public and investor-owned electric utilities including active power marketers and other energy service providers. The most current data for 2001 shows that Nebraska's average retail rate of 5.39 cents/kWh is approximately 26 % below the national average of 7.32 cents/kWh.

The Nebraska power system product is based on a long-term "obligation to serve" that is not inherent in market-based electricity products. Typically, there is a thirty to forty year obligation stemming from the commitment to build various physical generation unit types to provide stability in power resources that is derived from having "iron in the ground", and limited dependence on the market. This translates to a long-term commitment to providing physical resources that meet or exceed Nebraska's power systems "obligation to serve". A market-based electricity product provider does not share this same responsibility; hence, there is downward pressure on the price for the market-based electricity product as compared to local providers. This actual value is difficult to quantify since this is a subjective criteria that may be different for each customer depending on individual risk tolerance for price changes. Four different analytical approaches were developed and modeled to establish the value of the long-term "obligation to serve". The results of the four different analyses indicate that it appears reasonable that the value of the long-term obligation to serve is in the \$3-\$5/MWH range for a 5 X 16 peaking type product. These results are presented for subjective consideration only, and are not specifically accounted for in the 2000-2003 Nebraska production cost comparison to market pricing.

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

The results of this 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.

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

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

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

Issue #5 (Chapter 5)

- The cost of gas is becoming an increasingly important fuel source for electricity generation, now producing approximately 20 percent of Nation's electricity.

- Texas is producing approximately 50 percent of its electricity with natural gas.

- Natural gas sets the market price for electricity in several retail and wholesale markets.

- Promises of wholesale or retail competition driving down energy prices have not occurred.

- Competitive wholesale markets are a necessary precedent to successfully implementing retail choice.

- Adequate power supply, reserves and infrastructure are crucial.

- Elimination of the "obligation to serve" is a contributing factor to the reduction of generation reserve margins.

- Customers served by regulated retail markets have generally experienced lower electric rate increases than customers served by "competitive" retail markets..

SUMMARY OF 2006 REPORT

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

SUMMARY OF 2005 REPORT - The development of retail choice across the nation showed very little progress in the last year. On September 1, 2005 the Virginia Corporation Commission issued it's fifth annual report on retail choice in the state noting that retail competition in Virginia has not led to prices lower than would have been charged under traditional regulation, and offered that "It appears that, from the data so far, most retail customers (especially residential) in restructured states where the transitional period has ended and the price is now based on the wholesale market, are seeing prices increase faster than in the non-structured states or states still in transition with a price cap. At best, at this point in time, no discernable overall benefit to retail consumers can be seen from restructuring".

Texas continues to receive attention as the most successful retail choice state. The process in Texas began in 1999 with legislation, and retail choice for all customers on January 1, 2002 at which time retail rates were reduced by 6%. Generally, retail choice participation in Texas is growing. During the period 2004 thru March 2005, residential participation has grown from just over 14% to 21.6%, and small industrial and commercial participation has increased from 19% to 28.9%. This equates to about 22.5% of the residential load, and 60% of the small industrial and commercial load. Over 65% of the large industrial loads have switched to non-affiliated retail electric suppliers.

On August 8, 2005, President Bush signed into law national energy policy legislation. Some of the major elements of this legislation were the repeal of a long-standing law, the Public Utility Holding Company Act, and reform of the Public Utility Regulatory Policies Act of 1978. In addition, a provision known as "FERC Lite" will allow limited expansion of FERC jurisdiction over public power to promote wholesale power markets. Public power would provide transmission services at non-rate terms and conditions that are comparable to what they provide to themselves. No FERC ratemaking authority over public power was included. Other elements of the new law that could impact public power include: Service Obligation/Native Load Protection, Uniform Refund Authority, Participant Funded Transmission, Transmission Reliability Standards, Transmission Siting Authority, Renewable Energy Production Incentive, and Clean Energy Bonds.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

In a January 2003 report, the Texas PUC detailed the status and progress of retail competition after one full year of implementation. The PUC estimates that retail customers have saved over $1.5 billion in electricity costs during the first year, and low-income customers have received almost $70 million in discounts through the System Benefit Fund through October 2002. In all areas open to competition, there are multiple retail electric providers, with as many as ten offering residential service in some areas. The PUC indicated that the competitive market is small but growing. There have been some problems in the Texas market. New Power was one of the more aggressive marketers in Texas. After signing up 78,000 customers, it filed for bankruptcy in June 2002. Technical problems have delayed bills and blocked some switching requests. A far more serious problem emerged in March 2003 when a surge in wholesale power prices indicated evidence of market manipulation, prompting a Texas PUC official to state that some regulation of the merchant energy business may be needed.

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

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

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

In Montana very few residential customers have selected a competitive supplier and no competitive suppliers are currently marketing to them. Montana Power Company faded into history when its 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 its 2001 report that growth in the retail market is dependent on the competitiveness of the wholesale market, but there are indications that the wholesale market is not yet capable of supporting a competitive retail market.

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

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

The Louisiana Public Service Commission issued an order in December 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 is not convinced there is much value in switching providers, and interest is not much higher among commercial and industrial customers. Startup delays, lag in switching customers to new suppliers and computer problems have contributed to customer reluctance to switch providers. Texas Utilities recently announced that as many as 150,000 customers have gone without power bills for several months and many municipalities report hundreds of thousands in lost savings because of billing problems. The aftermath of the California troubles and the bankruptcy of Enron have cast a shadow over deregulation. Recent disclosures of trading irregularities at Dynegy and Reliant have also created further doubts in consumer's minds. Texas has plenty of power plants to supply power, and Texas incumbent utilities can raise rates twice a year when natural gas prices change, shielding them from bankruptcy when power prices skyrocket. Until the switching process is smoothed out, consumers will continue to resist deregulation as they see no positive value in changing providers.

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

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

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

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

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

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