Chapter 1

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

1.0 Purpose

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

2.0 Team Members

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3.0 Summary

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

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

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

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

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

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

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

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

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

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

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

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

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

4.0 Background

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

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

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

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

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

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

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

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

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

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

5.0 Current Status of Transmission Adequacy and Availability

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

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

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

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

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

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

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

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

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

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

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

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

6.0 RTO Characteristics and Functions

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

6.1 Characteristics

6.1.1 Independence

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

6.1.2 Scope and Regional Configuration

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

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

6.1.3 Operational Authority

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

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

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

6.1.4 Short-Term Reliability

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

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

6.2 Functions

6.2.1 Tariff Administration and Design

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

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

6.2.2 Congestion Management

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

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

6.2.3 Parallel Path Flow

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

6.2.4 Ancillary Services

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

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

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

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

6.2.6 Market Monitoring

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

6.2.7 Planning and Expansion

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

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

6.2.8 Interregional Coordination

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

7.0 Other Issues

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

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

8.0 Conclusions

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

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

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

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

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

Figure 1

Proposed TRANSLink Footprint

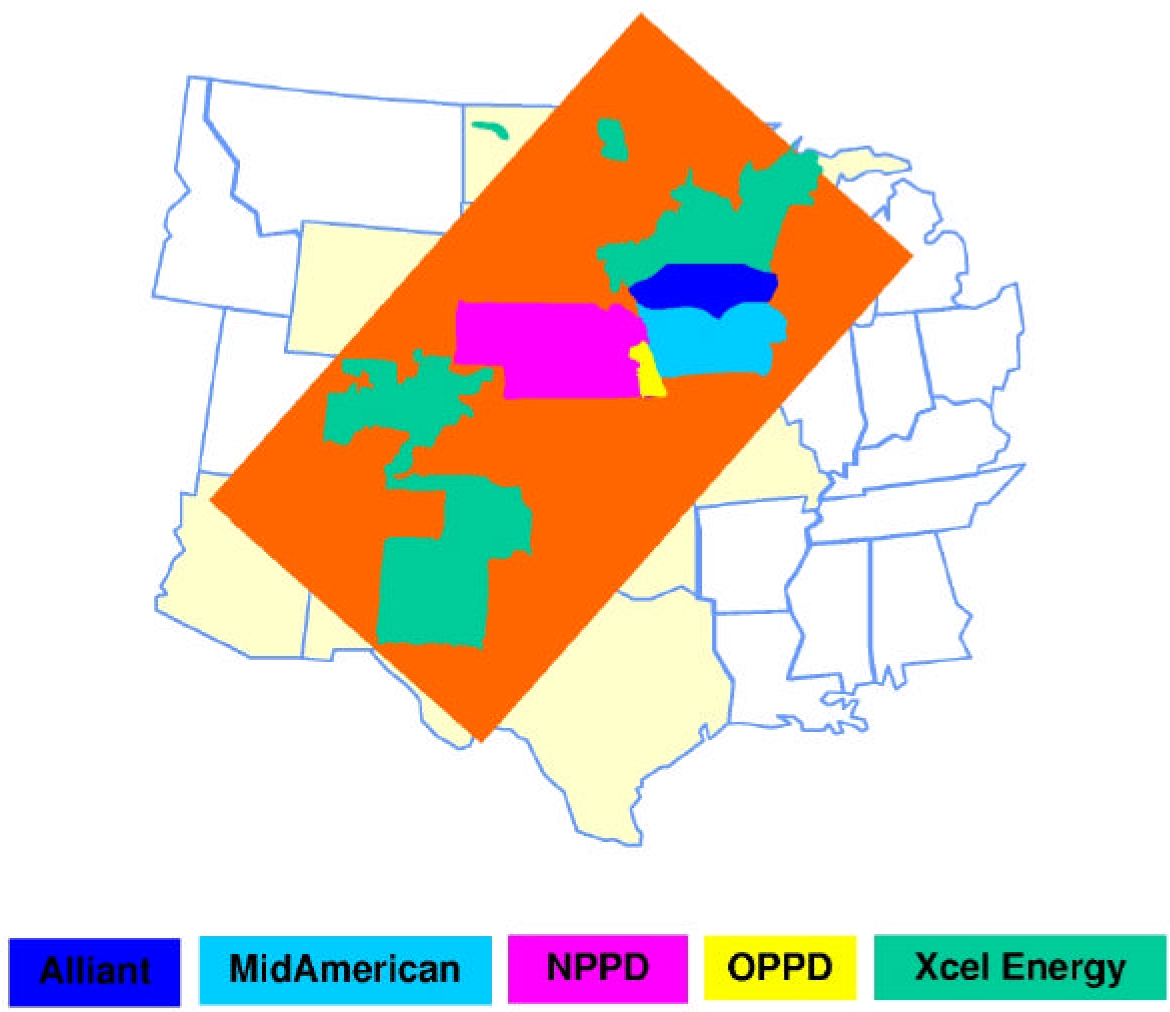

Figure 2

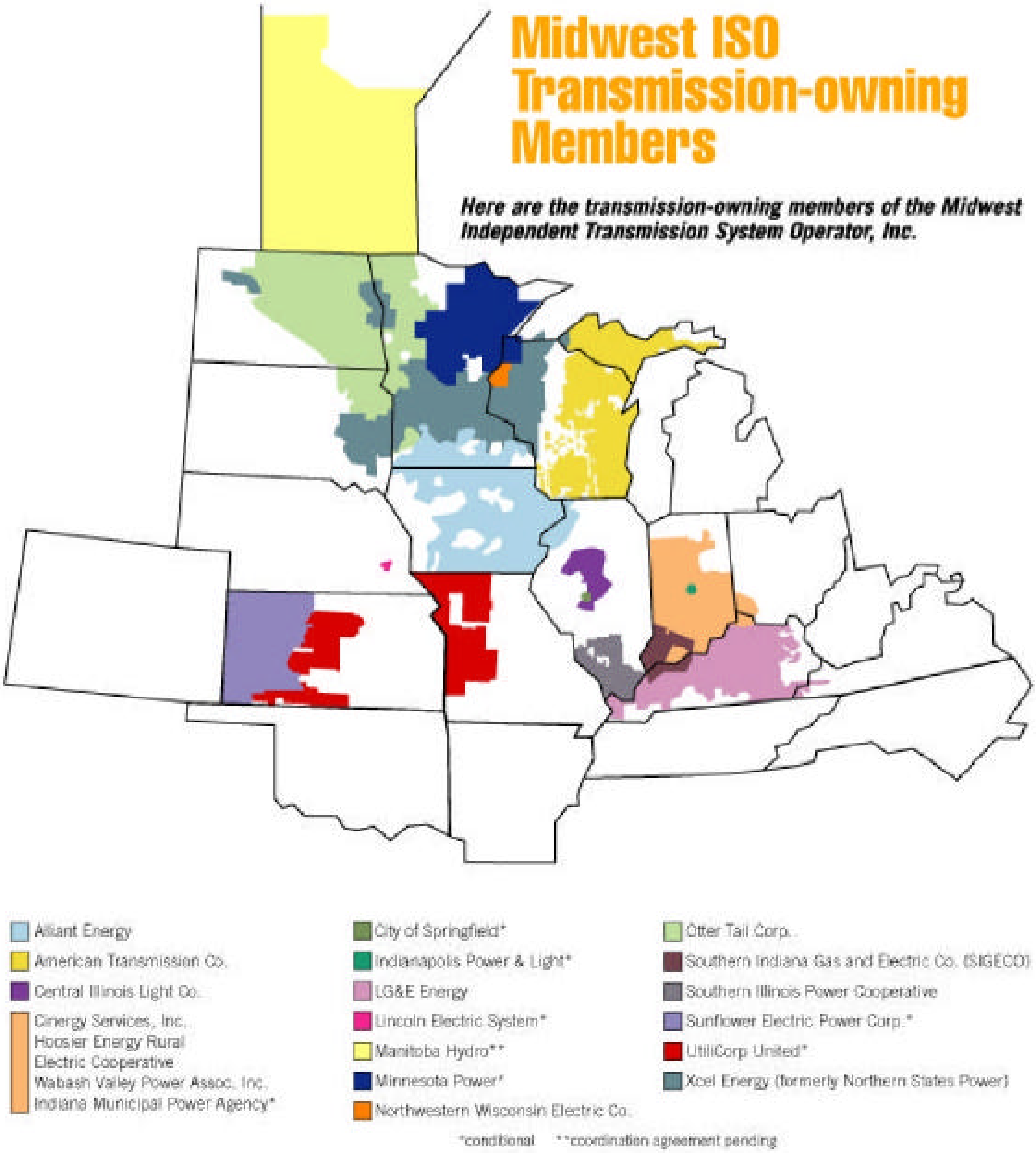
Midwest ISO Transmission-owning Members
Here are the transmission-owning members of the Midwest Independent Transmission System Operator, Inc.
Alliant Energy
American Transmission Co.
Central Illinois Light Co.
Cinergy Services, Inc.
Hoosier Energy Rural Electric Cooperative
Wabash Valley Power Assoc.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

Figure 3

Mid-Continent Area Power Pool

Figure 4

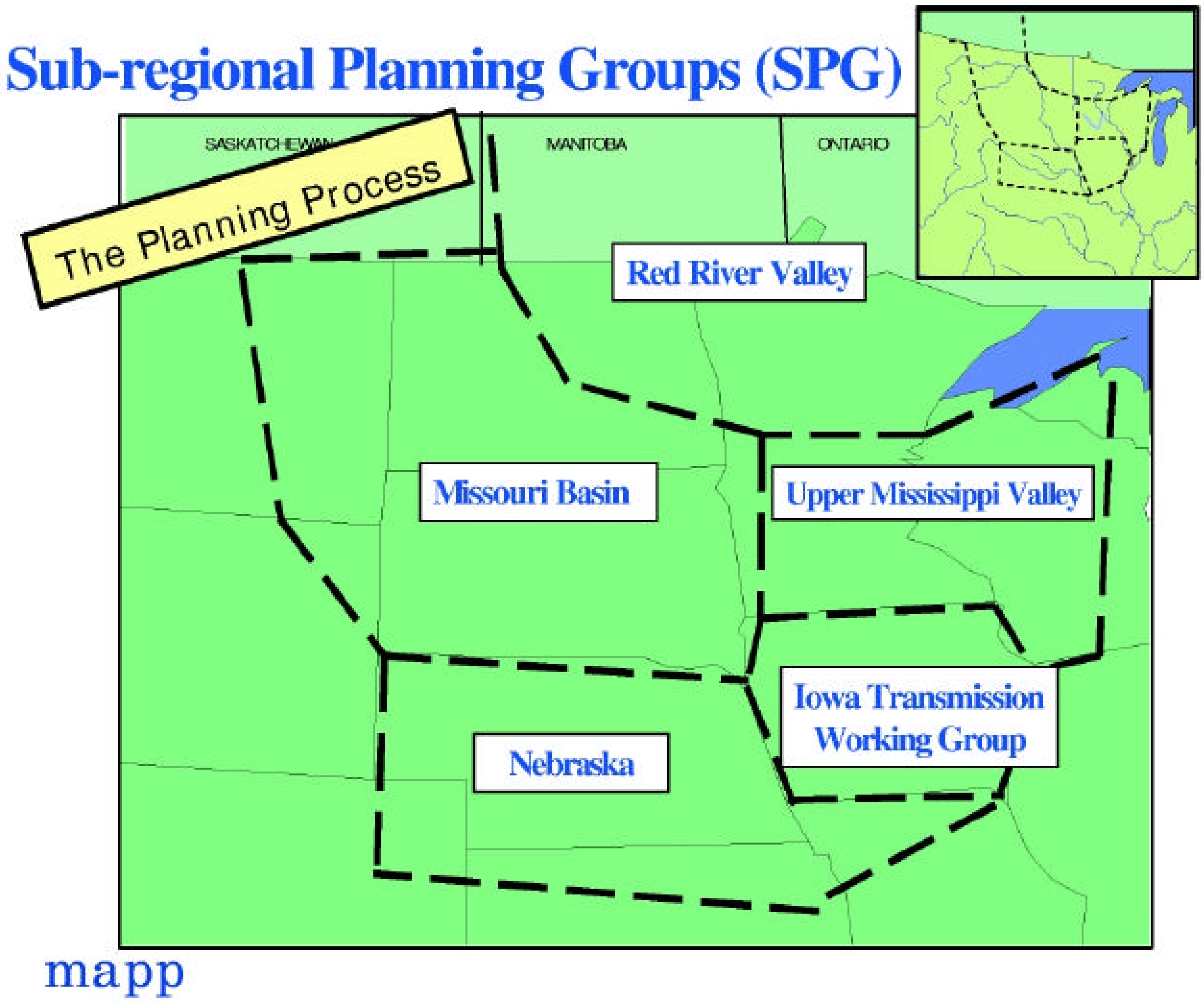
Sub-regional Planning Groups (SPG)
The Planning Process
SASKATCHEWAN
MANITOBA
ONTARIO
Red River Valley
Missouri Basin
Upper Mississippi Valley
Iowa Transmission Working Group
Nebraska
mapp

Figure 5

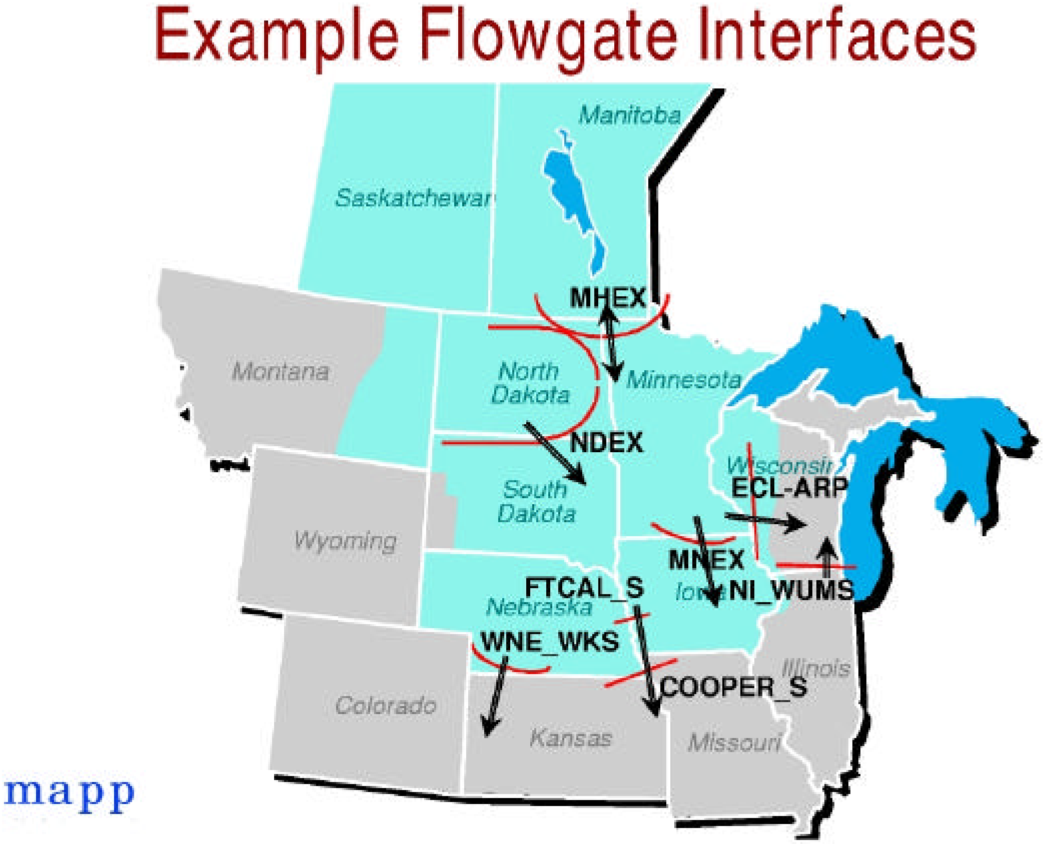
Example Flowgate Interfaces
Manitoba
Saskatchewan
MHEX
Montana
North Dakota
Minnesota
NDEX
Wisconsin
ECL-ARP
South Dakota
Wyoming
MNEX
FTCAL_S
Iowa
NI_WUMS
Nebraska
WNE_WKS
Illinois
COOPER_S
Colorado
Kansas
Missouri
mapp

Figure 6

NEBRASKA SUBREGIONAL PLANNING AREA