Chapter 2

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

Introduction

1.1 Groups' Purpose and Membership

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

Team Members

Clint Johannes (Chair)	-	Nebraska Electric G&T Cooperative Inc. (NEG&T)
Deeno Boosalis	-	Omaha Public Power District (OPPD)
Jim Fehr	-	Nebraska Public Power District (NPPD)
Dennis Florom	-	Lincoln Electric System (LES)
Kevin Gaden	-	Municipal Energy Agency of Nebraska (MEAN)
Burhl Gilpin	-	Grand Island Utilities
John Krajewski	-	MEAN
Derril Marshall	-	Fremont Utilities
Allen Meyer	-	Hastings Utilities
Jon Sunneberg	-	NPPD

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

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

1.2 Approach

To accomplish the purpose described, the group first defined the meaning of the term “viable” and the alternative methodologies for testing the viability of a market. This definition and the evolution of standard tests for market viability are outlined in Section 2. Next the regional markets that include Nebraska were defined. Nebraska is somewhat unique in that it transcends two major transmissions grids in the U.S., the Eastern Interconnection and the Western Interconnection. Therefore Nebraska has two separate and distinct regional electricity markets. Both of these markets are defined in Section 3. The general approach for completing this year’s report is different than previous years. This is because the Federal

Energy Regulatory Commission's (FERC) thinking has evolved significantly since the initial LB901 report. Experience that FERC has gained in regulating emerging wholesale markets has provided valuable lessons learned which they have applied by trying new tests and techniques. Technical Group #2 has endeavored to follow these changes and modify our approach to reflect the FERC's latest thinking. In the past, Technical Group #2 conducted FERC's standard test of market viability using data obtained by the group. Two factors have changed this approach. First, the data used for conducting this analysis is no longer available to the group. Second, FERC has proposed that Regional Transmission Organizations (RTO) assume the responsibility of testing for market viability in the regions they serve. Conducting annual market viability tests is one of these responsibilities. The Midwest Independent System Operator (MISO) is the approved RTO for the Midwest region. In May 2003 they published their first *State of the Market Report.* The analysis included all the current and prospective utility members of MISO. Therefore the major transmission owning utilities in Nebraska are included. Since the MISO report is the definitive analysis for "whether or not a viable electricity market exists for the region which includes Nebraska it became the primary source for past Technical Group #2 reports.

2.0 Viable Wholesale Market Definition

2.1 Economic Logic

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

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

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

2.2 Evolution of FERC Definition and Tests for Market Power

A "viable market" must be one in which no single utility, or group of utilities, is able to exercise "market power." The standard test for market power is called the "Hub and Spoke" test. It was first used by FERC to assess the impacts of electric utility mergers on market concentration as set out in FERC Order 592, Merger Policy Assessment. This has been considered the "official" test of market power since FERC started using it in 1996. It has been the basis of this report since the inception of LB901. This test is described and presented in Section 2.3. The appropriate size of the region used in the conduct of this test is defined in Section 3.

As wholesale electric markets matured and market power became a prevalent issue, FERC acknowledged that the Hub and Spoke test alone was not sufficient to detect all market power. Notably, FERC has recognized the effect of transmission constraints on the exercise of market power. Initially, FERC began using variations to the traditional hub and spoke analysis that compensated for transmission constraints. This culminated in a FERC order issued on November 20, 2001 entitled "ORDER ON TRIENNIAL MARKET POWER UPDATES AND ANNOUNCING NEW, INTERIM GENERATION MARKET POWER SCREEN AND MITIGATION POLICY (Docket No. ER96-2495-015, et al.)." This order proposed a new standard test called "Supply Margin Assessment." A moratorium on this test was initiated soon after it was released because of political opposition. A complete review of the new FERC tests and the specific reasons for using them are discussed in Section 4.

On April 14, 2004 FERC released the ORDER ON REHEARING AND MODIFYING INTERIM GENERATION MARKET POWER ANALYSIS AND MITIGATION POLICY (Docket No. ER96-2495-016 et al.). This order adopts two new screens to assess generation market power and proposed new measures for mitigating market power in the future. The new screens were intended to replace the Supply Margin Assessment (SMA) generation market power analysis proposed in November of 2001 but suspended shortly thereafter. The new order was released after several rounds of comments and a technical conference examining the issues surrounding the SMA. The new interim generation market power order is presented in Section 4.1.1.4.

The "Standard Market Design" Notice of Proposed Rulemaking (Docket RM01-12-000) was issued July 31, 2002. This rulemaking along with a FERC Whitepaper clarifying certain issues introduced in the rulemaking (Issued April 28, 2003) is known by the abbreviation "SMD." The SMD is a very far-reaching and prescriptive outline of how Regional Transmission Organizations (RTO) should be organized and how they should operate. SMD proposes that RTO's assume the function of *Market Monitoring and Market Power Mitigation.* This includes the responsibility to constantly watch for the abuse of market power and also grants authority to implement defined corrective actions when market power is detected. As it is anticipated by FERC that all utilities will eventually belong to an RTO, every utility in the country will be subject to this oversight. A review of the *Market Monitoring and Market Power Mitigation* responsibilities as outlined in the SMD is shown in Section 5. The proposed rules will set out prescribed tests for market power but also gives considerable leeway to each RTO in devising new tests they believe are appropriate for their region. The RTO will be required to periodically report on the status of market power in their region. The assumption is that RTO's are uniquely qualified to assess market power in the region they serve. RTO's are independent. They will run the regional spot market and operate the transmission system, therefore they will have all the operational data required to run the appropriate tests. RTO's will also have the transmission and market models, the budget and the expertise to conduct market power analyses. In July, 2005 FERC officially removed SMD from consideration as a rulemaking because of controversy over the far-reaching powers afforded to FERC through the RTO's. This is a moot point, however, as the voluntary RTO's that have been established, have generally followed the guidelines set out in the SMD proposed rulemaking and whitepaper. Furthermore, FERC has developed other means to persuade utilities to voluntarily join RTO's as outlined in Section 4.1.1.4.

2.3 Basic Elements of Traditional FERC "Hub and Spoke" Market Power Analysis

The Federal Energy Regulatory Commission (FERC) established procedures for determining whether a proposed merger or settlement will impact certain regions or individual utilities, and enhance the ability of certain utilities to control prices or exclude competition. This is known in the regulatory community as "market power." FERC provides the following definition: Market power exists if there are concerns with market concentration.

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

In determining the market concentration for available economic capacity, FERC looks at suppliers that can supply the product (wholesale capacity and energy) at a cost no greater than 5% above the competitive price. The concentration of suppliers that have available economic capacity and energy that can be supplied is less than the FERC-defined threshold for an "unconcentrated" market. FERC defines this using the Herfindahl-Hierschman Index (HHI), which is calculated by summing the squares of the market share of all competitors that can supply power at a price no greater than 5% above the competitive price. An HHI of less than 1,000 indicates an unconcentrated market while an HHI of over 1,800 indicates a concentrated market.

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

For every year that this report has been completed, Technical Group #2 has conducted the Hub and Spoke test by calculating the HHI index using public domain data. After 2003, the data necessary to conduct this test was not publicly available. Fortunately, MISO calculates the HHI as part of their *State of the Market Report.* This analysis was conducted for the entire MISO reliability region as well as sub-regions of MISO corresponding to the reliability areas that are represented in MISO. These sub-regions represent logical groupings of transmission interconnections for the purpose of monitoring reliability. The MISO area and sub-regions are shown in Exhibit II-1. The HHI statistic calculated for the entire MISO region, as shown in Exhibit II-2, was 548 for 2005. Even though the concentration has been trending upward over the last couple of years, this still suggests the entire MISO area is a very unconcentrated market as the statistic is well below 1,000. This is because the larger the area, the more suppliers, the smaller the HHI. In this case the HHI is misleading because the entire MISO area does not behave as one big market; rather it is divided into sub markets because of transmission constraints. For instance, the West region (including Nebraska) and the East region show HHI statistics of 2,397 and 2,072 respectively. This indicates that these sub-markets are fairly concentrated and hold the potential for exercising market power.

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

Exhibit II-1

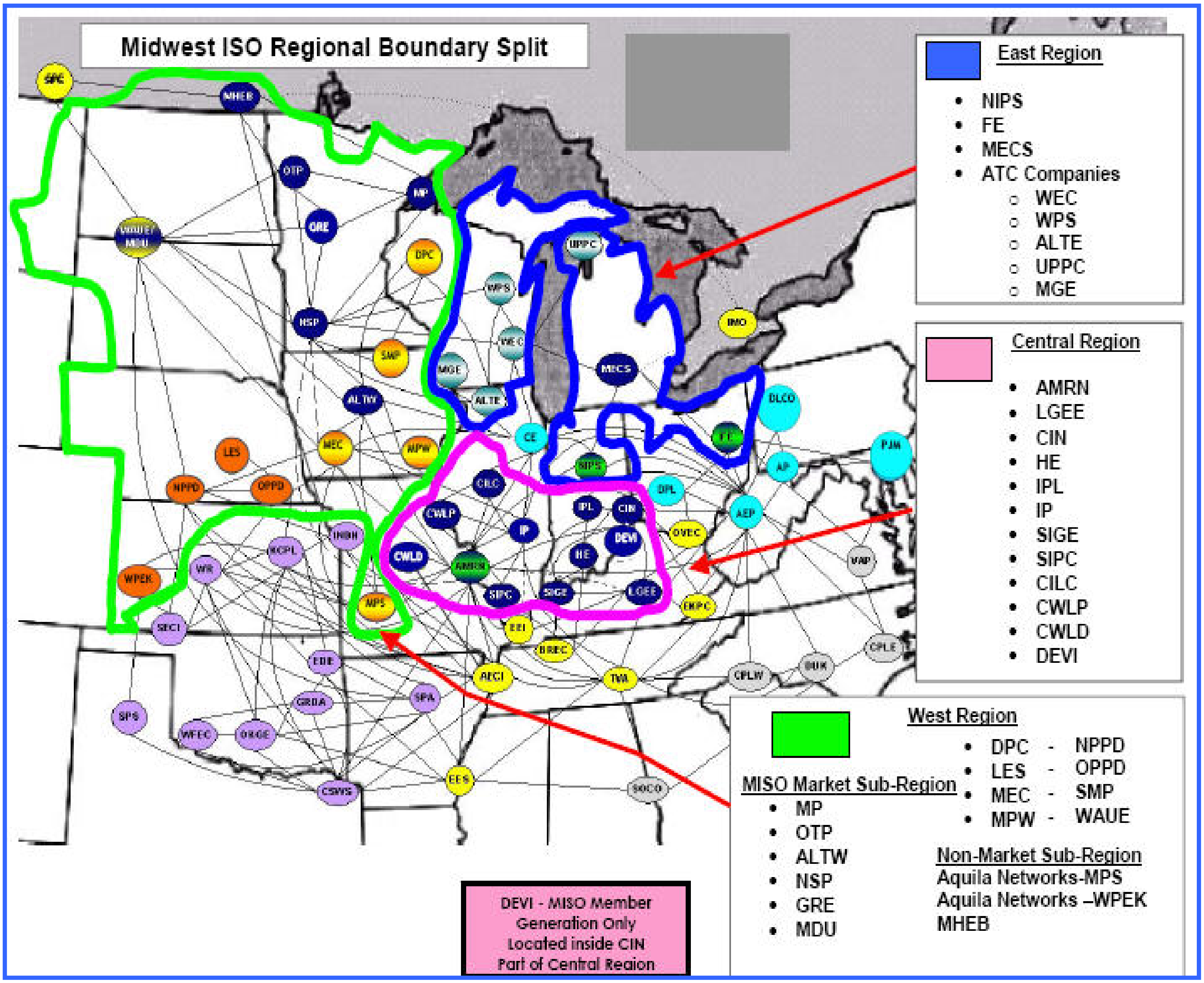
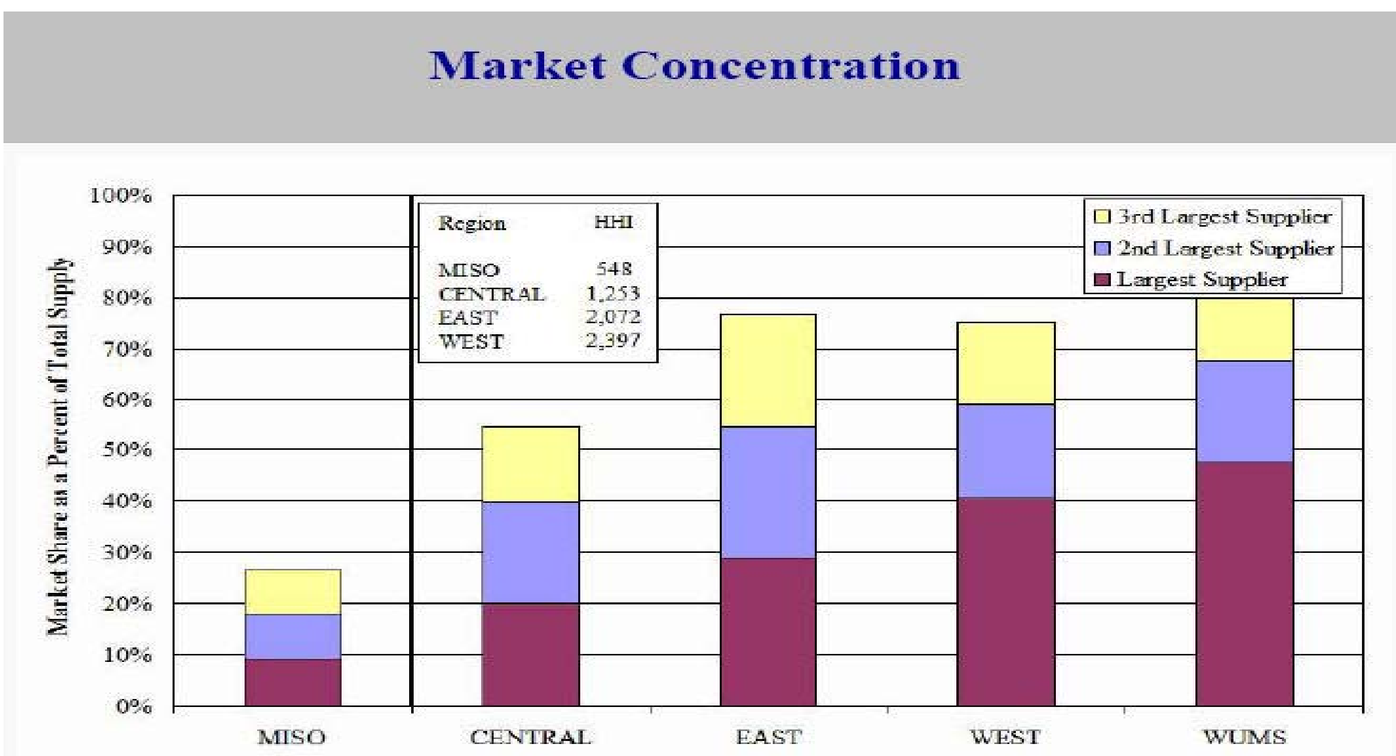


Exhibit II-2

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

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

Exhibit II-3



3.0 Region Defined

3.1 East/West Interconnection Description

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

3.2 Nebraska's Portion of Each Interconnect

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

3.3 Eastern Interconnection Defined

The Eastern Interconnection is defined as any generation and load that is synchronously connected to the grid that includes the entire eastern, southern and central United States and eastern Canada. Generally, this includes the states and provinces of North Dakota, South Dakota, Nebraska, Kansas, Oklahoma, a small portion of Texas and all states to the east as well as Saskatchewan and provinces to the east. However, there are a few locations including the far western edge of South Dakota (divided at Rapid City) and everything located west of Sidney, Nebraska, that are not on the Eastern Interconnection. This includes most all of NERC reliability regions such as MAPP, MAIN, SPP, ECAR, NECC, FRCC, MAAC and SERC as defined in the glossary. The regions that specifically impact Nebraska include the MAPP region, the MAIN region and the SPP region because some Nebraska utilities have contracted to receive or deliver power to those locations. (See Exhibit II-3)

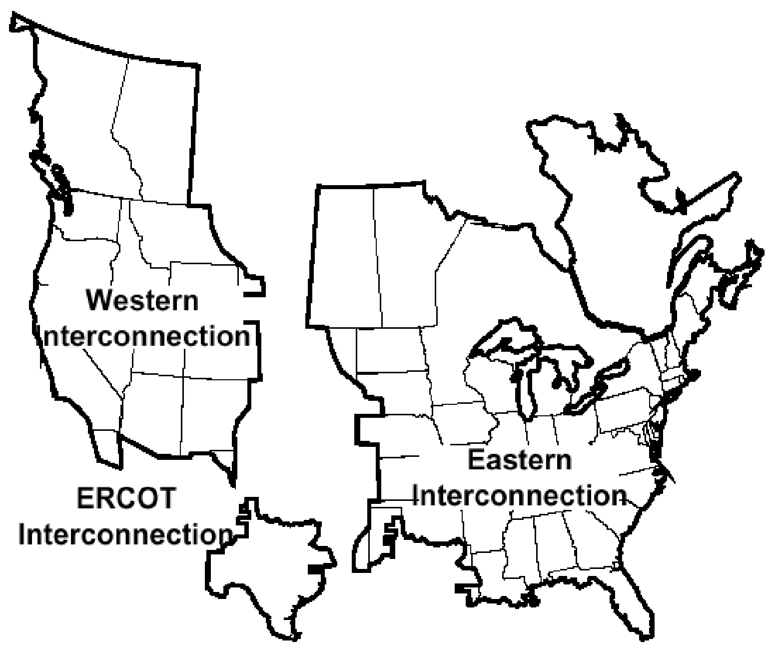
3.4 ERCOT Interconnection

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

3.5 Western Interconnection Defined

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

Exhibit II-4



3.6 Comparison of Region to that in Technical Group #1

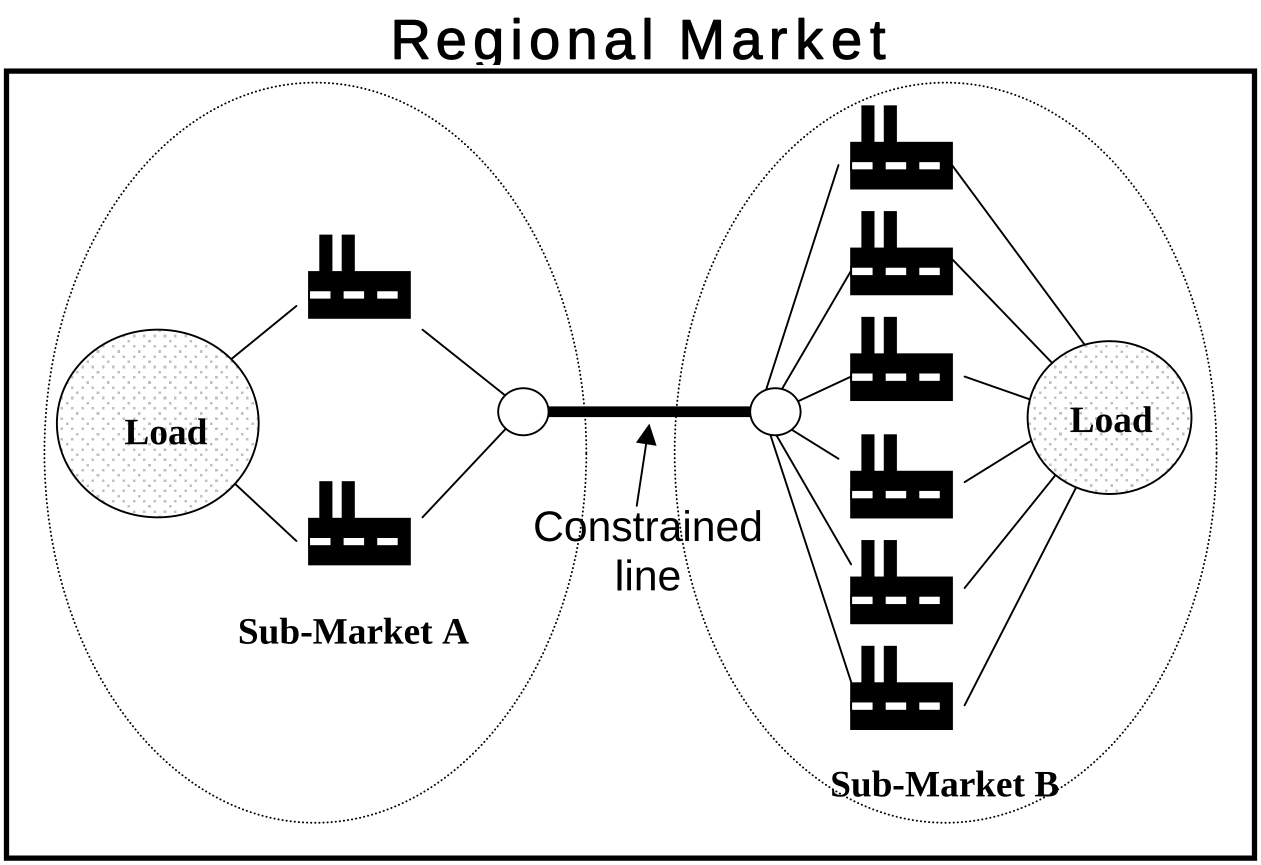
Technical Group #1 was assigned to review the viability of the transmission in the region including Nebraska. The regional definition of Technical Group #1 is essentially the same as the definition used in this report.

4.0 New FERC Methods for Assessing Market Power

4.1 Reasons for Instituting New Methods

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

Exhibit II-5



4.1.1 New Tests of Market Power

4.1.1.1 Modified "Hub and Spoke" Test

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

4.1.1.2 Electricity Market Models

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

4.1.1.3 Supply Margin Assessment

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

4.1.1.4 Interim Generation Market Screen and Mitigation Policy

On April 14, 2004 FERC released the ORDER ON REHEARING AND MODIFYING INTERIM GENERATION MARKET POWER ANALYSIS AND MITIGATION POLICY (Docket No. ER96-2495-016 et al.). This order adopts two new screens to assess generation market power and proposed new measures for mitigating market power in the future. The new screens were intended to replace the Supply Margin Assessment (SMA) generation market power analysis proposed in November of 2001, but suspended shortly thereafter. The two new screens are called the "Pivotal Supplier Analysis" and the "Market Share Analysis". Both tests attempt to take into account some of the objections to the SMA such as adjusting for native load and contract obligations when assessing market power.

If a utility fails to pass either screen there is a "rebuttable presumption of market power". This means that the utility can request to submit additional analyses to FERC demonstrating an absence of market power or waive that right and accept the mitigation measures outlined in the order. The additional analysis would include, among others, the "Delivered Price Test".

AEP, Southern Company and Entergy, (the original utilities involved in the SMA controversy) were ordered to file the results of the new tests by June 13, 2004. All other jurisdictional utilities currently possessing market-based rate authority would have to file test results according to schedule published by FERC.

4.1.1.4.1 Relevant Market Area for Interim Generation Market Screens

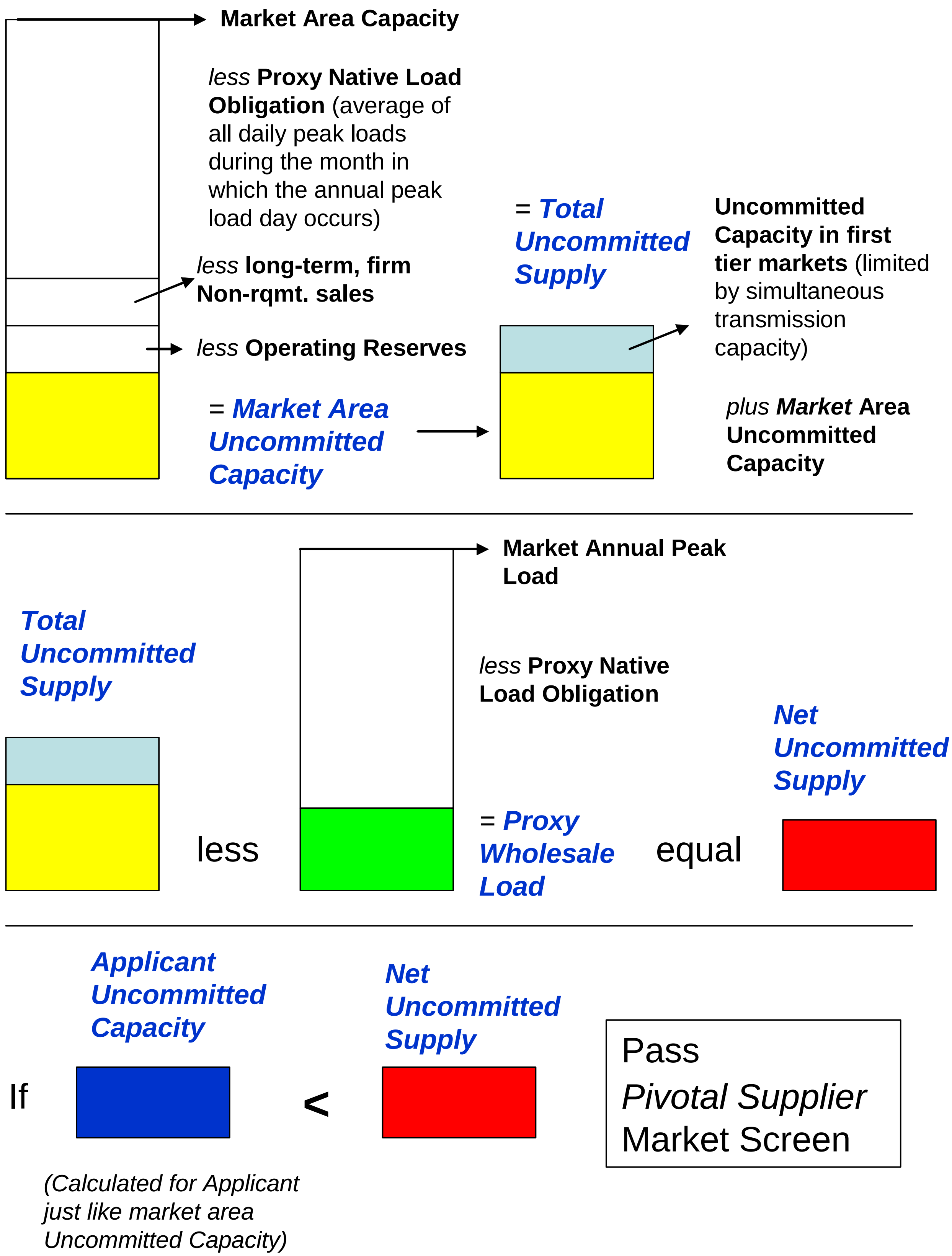
The relevant market area used when conducting the two market screens has a profound effect on the results of the test. The greater the size of the relevant market area the less likely the applicant will be found to possess market power. For utilities belonging to an RTO, the entire geographic region under the RTO will be considered the relevant market area, provided the RTO has a sufficient market structure and a single energy market. The rehearing order stated that this would include PJM, ISO-NE, NYISO and CAISO, but would not include MISO or SPP because neither performs single central commitment and dispatch at this time. For all utilities that do not belong to a qualified RTO, the control area in which they operate would be the relevant market area.

4.1.1.4.2 "Pivotal Supplier" Market Screen

The Pivotal Suppler Analysis seeks to determine if the applicant utility has the ability to manipulate market prices by unilaterally withholding generation from the market during peak period conditions. If the applicant's generation is absolutely essential to meeting peak wholesale market demands of the relevant market area (control area), the applicant will fail the screen. Exhibit II-5, shows how the Pivotal Supplier screen is calculated.

Exhibit II-6

Pivotal Supplier Market Screen

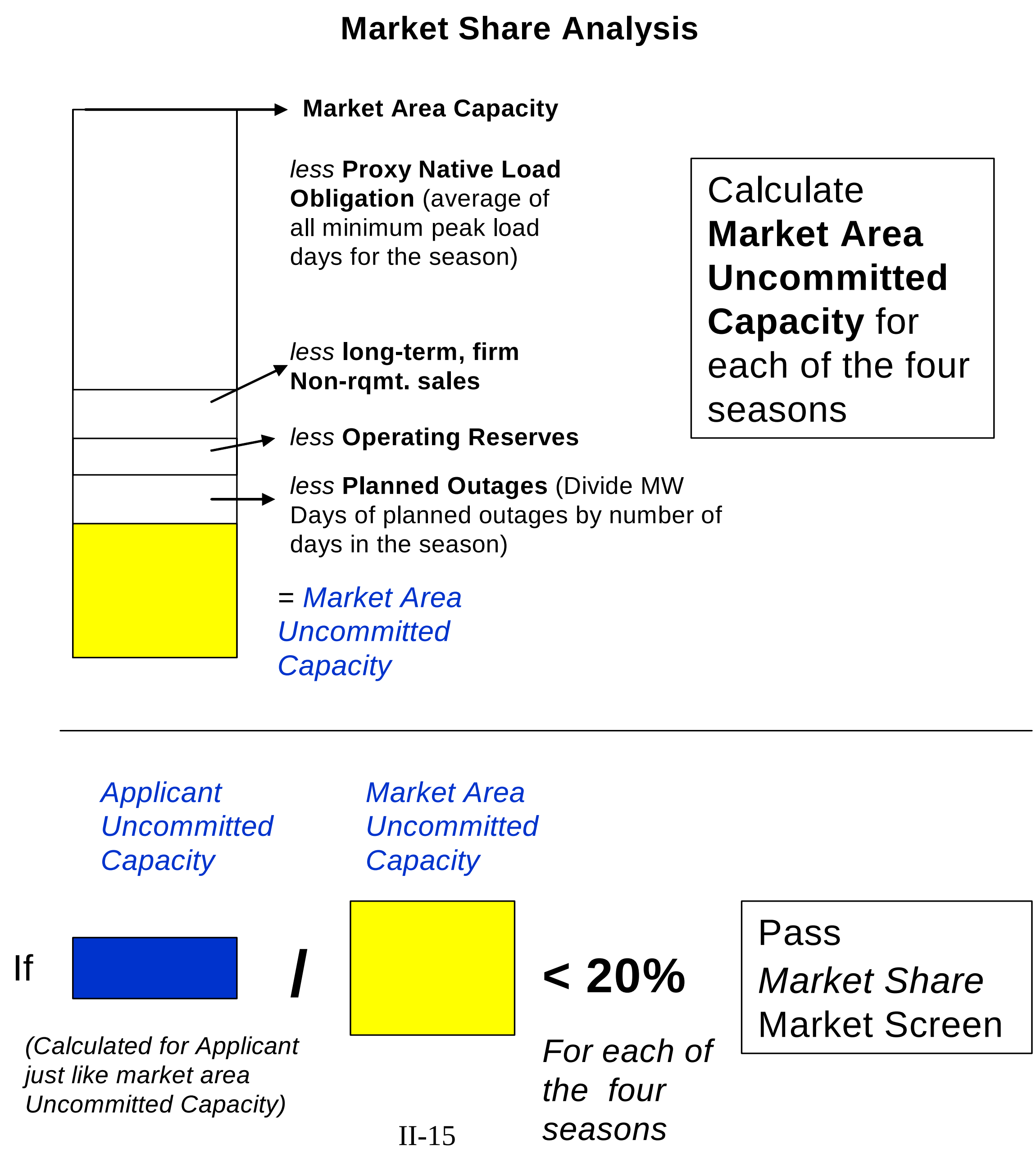


As shown in Exhibit II-5, if the applicant's uncommitted capacity is less than the uncommitted capacity offered by all other competitors than it will not be required (or pivotal) in satisfying all of the wholesale market demands in the area. On the other hand if the applicant's uncommitted capacity is more than that of all other suppliers to the area, the applicant's uncommitted capacity would be essential in meeting the wholesale demands. In that case the applicant could effectively withhold generation and unilaterally raise prices for electricity.

4.1.1.4.3 "Market Share" Market Screen

The Market Share Analysis considers the percentage of total uncommitted generation that is owned or controlled by the applicant during each of the four seasons of the year. If the applicant has more than 20% of the total market it is considered to have market power. Where the pivotal supplier analysis tests for market power under specific peak conditions, the market share analysis is a general test of market power attributed to sheer size.

Exhibit II-7



The calculation for the "Market Share" test is shown in Exhibit II-6. Note that the definition of Uncommitted Capacity changes under this test. The native load obligation used to calculate the Uncommitted Capacity is defined as the minimum peak load day for the season. This focuses the test on the off-peak market. The Uncommitted Capacity is also adjusted for planned generation outages that generally occur during non-peaking times.

4.1.1.4.4 "Delivered Price" Market Screen

The Delivered Price Analysis can be submitted (along with other specialized tests) if the applicant fails the first two market screens. The delivered price test is similar to the first two tests, except that the price at which the capacity can be delivered is taken into consideration. For example, an applicant may have a high market share of uncommitted capacity relative to total uncommitted capacity. However, if the applicant can prove that the capacity cannot be delivered at competitive prices (i.e. it is high cost) they would be incapable of realizing market share. This capacity can be effectively eliminated from the market power calculations.

4.1.1.4.5 Mitigation Measures

If an applicant fails the first two market screens and fails to prove a lack of market power with subsequent analysis or chooses not to submit such analysis, they will be required to implement measures to mitigate their market power. An applicant may propose mitigation measures tailored to their particular circumstance. If FERC finds these remedies inadequate, it will rescind the applicants market-based rate authority and order cost-based rates. The cost-based rates for mitigation are shown in Exhibit II-7.

Exhibit II-8

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

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

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

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

Alliant filed its market screens before MISO became a qualifying RTO and failed the screens for their control area. After MISO became a qualifying RTO in April 2004, the tests were recalculated using the entire MISO area as the relevant market. This allowed Alliant to pass the market power screens.
Aquila, Inc. failed screens for Missouri Public Service and West Plains and were deemed to have market power. Aquila submitted to cost mitigation for wholesale sales.
Mid-American failed screens for the Mid-American control area and must submit to cost mitigation. In addition FERC has also conducted investigations into the improper administration of the Open Access Transmission Tariff (OATT), unreasonably denying transmission access to utilities requesting it and erecting artificial barriers of entry for competing utilities. FERC found these allegations to be true and required Mid-American to turn over tariff administration and transmission operation to an independent third party operator to guarantee unbiased service.

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

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

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

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

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

Exhibit II-9

Midwest Results of FERC Market Power Proceedings

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

4.1.1.4.7 FERC Notice of Proposed Rulemaking on Market-based rates

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

4.1.1.4.8 Implications for Public Power

As non-jurisdictional utilities, public power is not directly impacted by this order. The Large Public Power Council in an opinion paper stated "…members are not generally required to perform the tests and make filings with FERC. However, they could be asked to provide proprietary information to be used in the preparation of the market power analysis for neighboring jurisdictional utilities. They could also be 'dragged into' the mitigation phase where a jurisdictional utility argues that mitigating their market power would place them at a disadvantage relative to neighboring non-jurisdictional utilities (this argument has already been made in a rehearing requests) or that non jurisdictional participation in an RTO is an essential part of the required mitigation."

Indirectly, Public Power could see some near-term impacts. If a number of jurisdictional utilities fail the market screens and are required to sell at cost-based prices, this may dampen wholesale electric prices, notably during peak periods when excess demand would normally drive prices above marginal costs. This would be positive for net buyers and the market and negative for net sellers.

The longer-term consequences may be more profound. It would difficult for any vertically integrated utility with control area responsibilities to pass both market screens without being a member of an RTO. This rehearing order is clearly intended as a strong incentive for jurisdictional utilities to join RTO's expeditiously. Non-jurisdictional utilities are probably on the radar screen. As more jurisdictional utilities join RTO's, public power will become more isolated. RTO's may began to implement reciprocity conditions for sale into the RTO market. Eventually, public power may have to join an RTO or sell into the wholesale market at cost-based rates.

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

5.1 FERC Notice of Proposed Rulemaking on Open Access Transmission Tariffs

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

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

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

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

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

6.0 Conclusion

6.1 Status of Viable Midwest Wholesale Market in the Eastern Region

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

6.2 Status of Viable Midwest Wholesale Market in the Western Region

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

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