ISSUE DATE: July 26, 2000

DOCKET NO. E-999/CI-99-1261

ORDER ADOPTING BOUNDARY GUIDELINES FOR DISTINGUISHING TRANSMISSION FROM GENERATION AND DISTRIBUTION ASSETS

BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

Gregory Scott	Chair
Edward A. Garvey	Commissioner
Joel Jacobs	Commissioner
Marshall Johnson	Commissioner
LeRoy Koppendrayer	Commissioner

In the Matter of a Proceeding to Develop Statewide Jurisdictional Boundary Guidelines for Functionally Separating Interstate Transmission from Generation and Local Distribution Functions

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PROCEDURAL HISTORY

On July 23, 1999, Minnesota Power (MP) filed a request that the Commission establish guidelines for determining the functional boundaries between an electric utility's transmission and generation functions, and between its transmission and distribution functions. In the Matter of Developing Statewide Jurisdictional Boundary Guidelines for Functionally Separating Interstate Transmission from Generation and Local Distribution Functions, Docket No. E-015/M-99-1002.

On September 3, 1999, the Commission issued its ORDER CLOSING DOCKET AND INITIATING PROCEDURES FOR DEVELOPING GUIDELINES. In that order, the Commission concluded that the resolution of various issues – including competitive proceedings, cost separation dockets, rate cases, and valuations for asset transfers – would depend upon a proper determination of which assets contribute to the generation, transmission and distributions functions, respectively. The Commission initiated the current docket for the exploration of this issue.

On October 4, November 3, and December 3, 1999, parties filed comments.

On February 25 and March 17, 2000, the Commission convened technical conferences. The Minnesota Department of Commerce (the Department) filed a report on the technical conferences on April 27.

The Commission received further comments by May 17, 2000, and further reply comments by May 30, 2000. The Minnesota Chamber of Commerce filed comments on June 12. All commentors ask the Commission to adopt some form of guidelines.

On June 28, 2000, Dairyland Power Cooperative, the Department, Great River Energy, MP, Northern States Power (NSP), Otter Tail Power Company, Reliant Energy/Minnegasco, and Wisconsin Public Service Corporation reached consensus on which guidelines and appendices to recommend for Commission adoption.

The matter came before the Commission later that same day. No party spoke in opposition to the consensus guidelines.

FINDINGS AND CONCLUSIONS

I. Background

The traditional electricity utility provides at least three services: generation, transmission, and distribution. The precise definition of these services is a matter of some dispute. Generally, generation consists of creating different electrical charges at different points, and establishing a circuit through which a current would flow between these points; the current could then be harnessed to do work. Generally, transmission consists of extending the circuit over relatively long distances at relatively high voltage for subsequent distribution. Generally, distribution consists of extending the circuit over relatively short distances at relatively low voltage for consumption.[1] The price a customer pays for electricity reflects the cost of providing each of these services.

Historically, an electric utility would serve customers by bundling these services together. The price for electricity was designed to reflect the aggregate cost of the three services. In such an economic environment, there was little need to designate how much of a given type of plant was used to perform each type of service individually.

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[1]For greater rigor, see the Federal Energy Regulatory Commission's Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Docket No. RM94-7-001; Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities, Docket No. RM95-8-000, 75 FERC 61,080, ORDER NO. 888 FINAL RULE, FERC Stats. & Regs. ¶ 32,514 at 33,145 (April 24, 1996)(Order 888). For example, that order establishes the following seven "factors" indicating when an asset provides a distribution function:

(1) Local distribution facilities are normally in close proximity to retail customers.
(2) Local distribution facilities are primarily radial in character.
(3) Power flows into local distribution systems; it rarely, if ever, flows out.
(4) When power enters a local distribution system, it is not reconsigned or transported to some other market.
(5) Power entering a local distribution system is consumed in a comparatively restricted geographical area.
(6) Meters are based at the transmission/local distribution interface to measure flows into the local distribution system.
(7) Local distribution systems will be of reduced voltage.

See also In the Matter of the Informal Filing and Request for Technical Conference by Northern States Power Company Regarding Electric Cost-Separation Methods, Docket No. E-002/M-98-1878, Office of Administrative Hearing's Summary of Proceedings (April 14, 1999).

The advent of restructuring in the electricity industry is changing this environment.[2] Today a wholesale customer may receive power generated by one party, transmitted by another party and distributed by a third party. Thus, all parties may benefit from knowing with greater precision which assets are used for a utility's transmission services, distinct from the assets used for a utility's generation services or distribution services. General guidelines may facilitate restructuring by indicating how the various components of the system would be classified.

More specifically, on December 20, 1999, the Federal Energy Regulatory Commission (FERC) issued its Order No. 2000[3] encouraging electric utilities to delegate control over interstate transmission facilities to "regional transmission organizations." This order places at issue the question of which facilities constitute transmission facilities, as distinguished from generation or distribution facilities.

II. Commission analysis

The Commission concludes that the issues raised by MP in this docket warrant Commission action. These issues are not of slight or transitory significance. To the contrary, they have been raised in a number of Commission dockets, including –

- Docket No. E,G-999/CI-98-1759 In the Matter of an Investigation into the Continuation of Demand-Side Management Financial Incentives for Gas and Electric Utilities (Office of Attorney General's June 16, 1999 comments that conservation measures can best be evaluated when compared to an accurate measure of generation, transmission and distribution costs),

- In the Matter of the Informal Filing and Request for Technical Conference by Northern States Power Company Regarding Electric Cost-Separation Methods, Docket No. E-002/M-98-1878 (seeking method to distinguish the costs of generation, transmission and distribution),

- In the Matter of an Investigation into Gas and Electric Utility Unbundling/Retail Choice/Restructuring, Docket No. E,G-999/CI-99-687 (exploring giving customers choices to buy generation, transmission and distribution services separately),

- In the Matter of Developing Statewide Jurisdictional Boundary Guidelines for Functionally Separating Interstate Transmission from Generation and Local Distribution Functions, Docket No. E-015/M-99-1002 (the docket prompting the current docket), and

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[2] A detailed summary of the changing dynamics of the electricity industry appears in Order 888, Section III ("Background").

[3] Regional Transmission Organizations, Docket No. RM99-2-000, FINAL RULE, 89 FERC ¶ 61,285 (December 20, 1999).

- In the Matter of NSP Petition to Transfer Functional Control of Certain Transmission Facilities to the Midwest Independent System Operator, Docket No. E-002/M-00-257 (NSP's filing to transfer control of transmission facilities to the Midwest Independent System Operator (MISO), as encouraged by the FERC's Order No. 888).[4]

Given the centrality of these issues, and the broad agreement among industry participants on the proposed guidelines for addressing these issues, the Commission will approve the proposed guidelines. The guidelines have the advantage of providing a uniform, state-wide framework for analyzing asset separation issues, while providing for individualized application to various utilities. The guidelines shall be used wherever issues of identifying the assets involved in generation, transmission or distribution arise, and in particular in Docket No. E-002/M-00-257 noted above.

ORDER

1. The Commission adopts the attached guidelines, together with Appendices A and B, for the purpose of determining the functional boundaries between the transmission and generation functions, and between the transmission and distribution functions. The Commission directs parties to use the guidelines and appendices in all future proceedings involving functional unbundling and other relevant proceedings.

2. This Order shall become effective immediately.

BY ORDER OF THE COMMISSION

Burl W. Haar
Executive Secretary

(S E A L)

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[4]The issue of functional separations also arises in Docket No. E, G-002/PA-99-1031 In the Matter of the Application of Northern States Power Company for Approval to Merge with New Century Energies, Inc., and the resulting Docket No. E-002/M-00-791 In the Matter of NSP Petition to Display Unbundled Generation Costs on Customer Bills. Lacking a resolution to these separation issues, the parties to Docket E,G-002/PA-99-1031 stipulated to a formula for estimating generation costs based on existing data. As such, the guidelines resulting from this docket need not apply to those dockets.

Boundary Guidelines for Functionally Separating Transmission from Generation and Distribution Functions

1. Lines with voltage of more than 50 kV are considered transmission assets unless demonstrated to be distribution assets after applications of relevant factors. Lines with voltage of 50 kV or less are distribution assets unless demonstrated to be transmission assets after application of relevant factors. See Appendix A regarding "relevant factors." When load flow analysis is used to demonstrate the functional use of assets, it shall be done in conformance with Appendix B.

2. When all connecting lines and/or transformers are classified as transmission assets, then the substation should also be classified as 100 percent transmission. Likewise, when all connecting lines and/or transformers are classified as distribution assets, then the substation should also be classified as 100 percent distribution. The equipment in combination substations should be classified by functionality; the common facilities should be classified based on the primary function of the substation. The "primary function of the substation" is determined by the purpose for which the substation was built (e.g., if to serve a local distribution system, it is distribution) or the primary electrical function served by the substation equipment, not by comparing the costs of the equipment as classified by functionality.

3. Distribution substations and feeders that are shared by neighboring distribution utilities and not subject to federal open access requirements are distribution assets.

4. Radial generation outlet lines, step-up transformers, transformer-protection equipment, breakers installed to protect generation and not needed to clear transmission or distribution system faults, station auxiliary transformers, and related metering and telemetering equipment are generation assets. In generation to transmission substations, one-half of the shared breakers in a breaker-and-a-half protection scheme are generation assets.

5. Direct-current (DC) lines: A DC line is to be considered a transmission asset if it is available for open access use and is posted on the OASIS (Open Access Same-Time Information System). The connected generating station should be responsible for the firm DC transmission service necessary to transmit the full operating capability of the generating station to the alternating-current transmission system. A DC line is to be considered a generating station outlet (generation asset) if the line is not posted on the OASIS.

6. Generation facilities that are physically located on the transmission system and used exclusively for transmission system reliability (black start) purposes are transmission assets. Generation facilities that are physically located within generation plants are generation assets, except that generators located within a generation plant that are under the operational control of the transmission system operator and are dedicated exclusively to black starting the transmission grid are transmission assets.

7. Equipment used to protect the transmission system such as breakers and line relay panels, are transmission assets. Step-down transformers interconnecting transmission and distribution facilities, and their associated protection equipment (including high-side disconnection devices), are distribution assets. In transmission-to-distribution substations, distribution is responsible for one-half of the shared breakers in a breaker-and-a-half protection scheme.

8. Capacitors shall be classified the same as the facilities to which they are connected. For instance, capacitors shall be included as transmission facilities only to the extent that they are electrically located on transmission facilities and serve a transmission function.

Appendix A

“Relevant Factors"

While not all the following are appropriate for use in every case, the following are “relevant factors” which may help in making exception to the general classification provided in Guideline No.1.

Transmission v. Distribution tests

- configuration of equipment
- equipment characteristics
- use or customer
- how is it operated
- how was it planned

1. How does the FERC 7-factor test apply and what is the result of its application?

2. Is the facility installed only for the purpose of serving a particular “customer” (either generation or distribution)?

3. Does the facility serve wholesale load or other grouped load (e.g. retail load pockets), either in a looped or radial configuration?

4. Was it designed to serve single phase load?

5. Was it jointly planned to meet load-serving needs of more than one utility? Are there contractual relationships designating its use?

6. What are the anticipated future uses of the facility? Is it planned to be looped?

7. Does the facility interconnect two or more utilities?

8. Who operates the line? Who performs maintenance and emergency repair? How is it operated on a normal and contingent basis?

9. What requirements does the facility meet under NESC design and maintenance codes?

10. What is the dominant functionality of the facility? If it is used for one purpose (e.g., transmission) most of the time, than it could be classified to that purpose.

Appendix B

Load Flow Tests

Load-flow analysis may be used to determine the effect of simulated transactions on various facilities if done in conformance with the following guidance:

Models

Models from the current series of planning models approved by the MAPP Model Building Working Group, or successor organization, shall be used. Models within the series that represent the time period closest to the present shall be used. It is acceptable to add facilities that are not included in the standard model if the purpose is to analyze the facilities' function for Unbundling. All changes to the model, such as facility characteristics, configuration, or load and generation levels shall be reported. An explanation of the rationale for the changes shall be provided. Facility performance under different load or through flow levels should be considered in the model selection process.

Transaction Simulation

Transactions of at least 10 MW, but less than 200 MW shall be simulated. No transaction should be so large that it distorts the solution results. A single source and sink generator shall be used. The source and sink generators selected shall be technically capable of providing this function and should be selected using criteria including whether they are likely to economically participate in such a transaction. The source and sink must be located off the transmission system being analyzed and of sufficient electrical distance from the facilities being analyzed to produce valid results. Multiple transactions may be simulated to determine a facility's function. The transactions simulated shall be described in detail.

Solution Technique

The specific solution technique used and any manual adjustments, such as changes to phase shifting transformers, DC lines or switched shunts shall be reported. Any change in facility configuration performed to represent the expected post-contingent operating condition described in the Evaluation Criteria section shall be reported.

Evaluation Criteria

The effect of a transaction shall be measured by its Outage Transfer Distribution Factor (OTDF) on the monitored element. Facilities may be re-configured before solving the load-flow to reflect the expected post-contingent operating configuration. The configuration adjustment could be due to either automatic control action or operating procedures. Items included in the subsystem description, the list of monitored elements, and the list of contingencies tested shall be reported. To be considered a Transmission facility, the OTDF impact on the monitored, in-service, facility must be greater than the specified threshold value. The threshold value may be increased for higher voltage facilities, but must always be at least three percent. The actual OTDF threshold(s) used shall be reported. The rationale for any differences between the OTDF threshold values used in the MAPP region for the Transmission Loading Relief procedure and those used for Unbundling shall be reported.