MIDAMERICAN ENERGY COMPANY

Technical Report for Delineation of Transmission and Local Distribution Facilities

Issued on June 7, 2011

Introduction

In its Order No. 888, in the context of determining how to classify electrical facilities as distribution and transmission for rate-making purposes, the Federal Energy Regulatory Commission ("FERC") recognized that a "bright line" between state and federal rate-making jurisdiction is difficult to draw.[1] To provide a consistent approach, it adopted a "seven-factor test"[2] with seven indicators of local distribution that are to be used to functionally delineate state and federal jurisdictional boundaries. FERC defers to determinations of state commissions applying the seven-factor test to classify transmission and local distribution facilities, provided the following seven indicators making up the seven-factor test are applied:[3]

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 on 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.[4]

In 1998, MidAmerican prepared a Technical Report for Delineation of Transmission and Local Distribution Facilities using the seven factor test to delineate MidAmerican facilities into transmission and local distribution ("1998 Report"). Upon application of the test, all facilities at 69 kV and below were determined to have local distribution characteristics, along with several radial 161 kV lines, several relatively short urban-center 161 kV lines and two urban-center 345-161 kV transformers. The delineation of substations was determined from the classification of line and transformer facilities connecting to each substation. All other MidAmerican facilities above 100 kV were determined to not have local distribution characteristics and therefore classified as transmission. Both the Iowa Utilities Board and the Illinois Commerce Commission recommended MidAmerican's delineation to FERC. In turn, FERC deferred to the action of the state commissions.[5]

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[1] *Promoting Wholesale Competition through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, 75 FERC ¶ 61,080 (1996), pp. 435-436

[2] Id. at pp. 401-402

[3] Id. at pp. 437-438

[4] Id. at pp. 401-402

[5] *Re: MidAmerican Energy Company*, Docket No. SPU-98-12, Order Recommending Delineation of Transmission and Local Distribution Facilities, 193 P.U.R.4th 555, 1999 WL 632816 (Iowa U.B. 1999); *MidAmerican Energy Company*,

In approving MidAmerican's delineation, both the state commissions and FERC recognized that the delineation was subject to change. FERC stated that if any facilities, regardless of their original nominal classification, proved to be used to provide transmission service to wholesale purchasers, they could become reclassified. FERC also noted its deference would not affect a separate determination of what facilities must be under the operational control of a regional transmission organization. The Iowa Utilities Board also retained jurisdiction to recommend different delineations if there were changes in facts and circumstances.

On September 1, 2009, MidAmerican integrated its electric transmission system with the Midwest Independent Transmission System Operator, Inc. ("Midwest ISO"). The transmission system committed to the operation of the Midwest ISO consists of all networked transmission facilities above 100 kV and all networked transformers where the two highest voltages exceed 100 kV.[6] As a result of integration, MidAmerican began the process of reclassifying, for accounting purposes only, its facilities with voltages at or exceeding the Midwest ISO threshold. In 2009, in FERC Docket AC10-9, FERC approved the reclassification of the non-radial urban-center 161 kV lines and related substation facilities from distribution to transmission. In 2010, in FERC Docket AC10-142, FERC approved the reclassification of a number of 161 kV substations as combination transmission and local distribution substations, with the 161 kV portions of those substations being reclassified as transmission. The result of both of these filings is to align the accounting classification of the 161 kV facilities classified as transmission with the functional control classifications of the Midwest ISO.

Considerable changes have occurred in the operation of the MidAmerican electrical system and in the industry since 1998, including such changes as:

1. The development of regional transmission organizations.

Docket No. 98-0816, 1999 WL 33915318 (Ill.C.C. 1999); *MidAmerican Energy Company*, Docket Nos. ER99-3887-000 and EL99-92-000, Order Approving Classifications, 90 FERC ¶ 61,105 (2000).

[6] Section I.P of the Agreement of Transmission Facilities Owners to Organize the Midwest Independent Transmission System Operator, Inc., a Delaware Non-Stock corporation; Midwest ISO FERC Electric Tariff First Revised Service Agreement No. 1

2. Substantial changes in generation affecting the MidAmerican transmission footprint including the construction of a number of new natural gas fired generating plants (including MidAmerican Greater Des Moines Energy Center), the addition of several coal plants (including MidAmerican's Walter Scott Unit No. 4), the construction of many new wind farms (with most at locations which have not previously had any local generation) and the construction of substantial new transmission lines.

3. MidAmerican's integration into the Midwest ISO, resulting in the former MidAmerican balancing authority area being integrated into the multi-state Midwest ISO balancing authority area.

4. The migration of many portions of the Mid-Continent Power Pool ("MAPP") into the Midwest ISO, the migration of the Nebraska entities to the Southwest Power Pool, and the termination of the MAPP regional transmission tariff.

This report applies the seven indicators to review the classification of 69 kV and 34.5 kV facilities considering current conditions. Since the 1998 Report, MidAmerican, as well as other utilities and municipals interconnected with MidAmerican, have participated in the Midwest ISO real time and day ahead energy markets. As a result, the generation across the market footprint is used to efficiently serve the load in the market footprint. As a result, the MidAmerican system sees increased transfers in support of the market. As a result, MidAmerican networked facilities at 69 kV and above serve a broader area.

System Description

At the end of 2010, MidAmerican served a total of 726,872 electric retail customers with 638,091 of those customers located in Iowa, 84,336 in Illinois and 4,445 in South Dakota. MidAmerican owns and operates electric system facilities at nominal voltage of 345 kV, 161 kV, 69 kV, 34.5 kV, 13.8 kV, 13.2 kV and 12.47 kV and below. In some cases in this report, facilities at 13.8 kV, 13.2 kV, and 12.47 kV are collectively referred to as "13 kV facilities". There are approximately 1,180 miles of 345 kV lines, 1,439 miles of 161 kV lines, 1,904 miles of 69 kV lines and 86 miles of 34.5 kV lines comprising the MidAmerican electrical system. MidAmerican's facilities are located predominately in the state of Iowa. In Iowa, MidAmerican has approximately 1,093 miles of 345 kV lines; 1,316 miles of 161 kV lines; 1,758 miles of 69 kV lines; and 86 miles of 34.5 kV lines. In Illinois, MidAmerican has approximately 63 miles of

345 kV lines, 123 miles of 161 kV lines, and 129 miles of 69 kV lines. In South Dakota, MidAmerican has approximately 17 miles of 69 kV lines. In Missouri, MidAmerican has approximately 24 miles of 345 kV lines.

MidAmerican has 345-161 kV substations, 161 kV-lower voltage substations, 69 kV-lower voltage substations, as well of a number of substations with other voltages.

Seven Factor Test Analysis

This analysis is of MidAmerican's 345 kV, 161 kV, 69 kV and 34.5 kV and below facilities. The seven factors are used in determining whether these facilities are considered local distribution versus transmission.

Factor 1: Local distribution facilities are normally in close proximity to retail customers.

MidAmerican uses facilities with a single phase rating of 7,200 volts, 7,620 volts or 7,967 volts and a three phase rating of 12,470, 13,200 and 13,800 volts nominal to serve retail customer load. Also, there are small pockets of 2,400 volt (single phase) and 4,160 volt (three phase) nominal rated facilities which serve some retail customer load. These primary facilities connect to transformers which supply utilization voltage (120-240 volt, 120-208 volt or 277-480 volt) to the customers. The low side of these transformers feed cables which typically run from the street to the customer's switchgear or breaker panel. These cables are often 50 feet to 200 feet long with an estimated average length of approximately 120 feet. This system layout means that these facilities are on average within an estimated 120 feet of the retail customer. Since these facilities directly serve retail customers through service transformers, the primary facilities from 13.8 kV and below are local distribution facilities and are in close proximity to the retail customer.

There are relatively few 34.5 kV facilities on the MidAmerican system: 86 miles of 34.5 kV lines between only sixteen substations with 161 to 69 to 34.5 kV, 69 to 34.5 kV, 34.5 to 13 kV, or 34.5 to 4 kV transformations. (This is excluding wind farms where 34.5 kV collector systems are used between wind turbine service transformers and step-up transformers to transmission voltages. These collector circuits are considered generation facilities.) The 34.5 kV facilities make up a small portion of the MidAmerican system as a result of upgrades of 34.5 kV facilities to higher voltages or retirements due to the need to meet new system conditions such as increasing load while meeting system planning criteria. The remaining 34.5 kV facilities are in rural areas so the 34.5 kV lines are relatively long. Appendix 1, Page 1 shows that the average length of 34.5 kV lines is approximately 6.6 miles. A 34.5 kV line between two substations that have 34.5-13 kV transformation will have sections (between two poles) that are electrically very close to retail customers near the substation, while other sections will be a significant distance

from the substation/retail customers. The estimated average electrical distance between the 34.5 kV line sections in this case is 1.7 miles. If the 34.5 kV line connects to one substation that has a 34.5-13 kV transformation and the other end to a 34.5 kV switching station with no 34.5-13 kV transformation, the estimated average electrical distance is 3.3 miles.

The 69 kV system consists of substations with 161-69 kV transformation, 69 kV lines between such substations and 69-13 kV substations. There are approximately 1,375 miles of networked 69 kV lines. In this report, the term "networked" refers to lines that are ultimately connected to substations or other lines in such a way that power at any given time can flow in different directions on the lines depending on load levels, system conditions and generation dispatch. Appendix 2, Pages 1-7 shows that the average line length of networked 69 kV between substations containing 69 kV facilities is approximately 4.9 miles; therefore, the estimated average electrical distance from the 69 kV facilities and the retail customer is 1.2 to 2.4 miles.

The 161 kV system consists of substations with 345-161 kV transformation, 161 kV lines between such substations and 161-13 kV substations. There are approximately 1,411 miles of networked 161 kV lines. Appendix 2, Pages 8-11 shows that the average line length of networked 161 kV between substations containing 161 kV facilities is approximately 8.7 miles; therefore, the estimated average electrical distance from the 161 kV facilities and the retail customer is 2.2 to 4.4 miles.

The 345 kV system consists of 345 kV lines and substations. There are approximately 1,173 miles of networked 345 kV lines. Appendix 2, Page 12 shows that the average line length of networked 345 kV between substations containing 345 kV facilities is approximately 27.9 miles; therefore, the estimated average electrical distance from the 345 kV facilities and the retail customer is 7 to 14 miles.

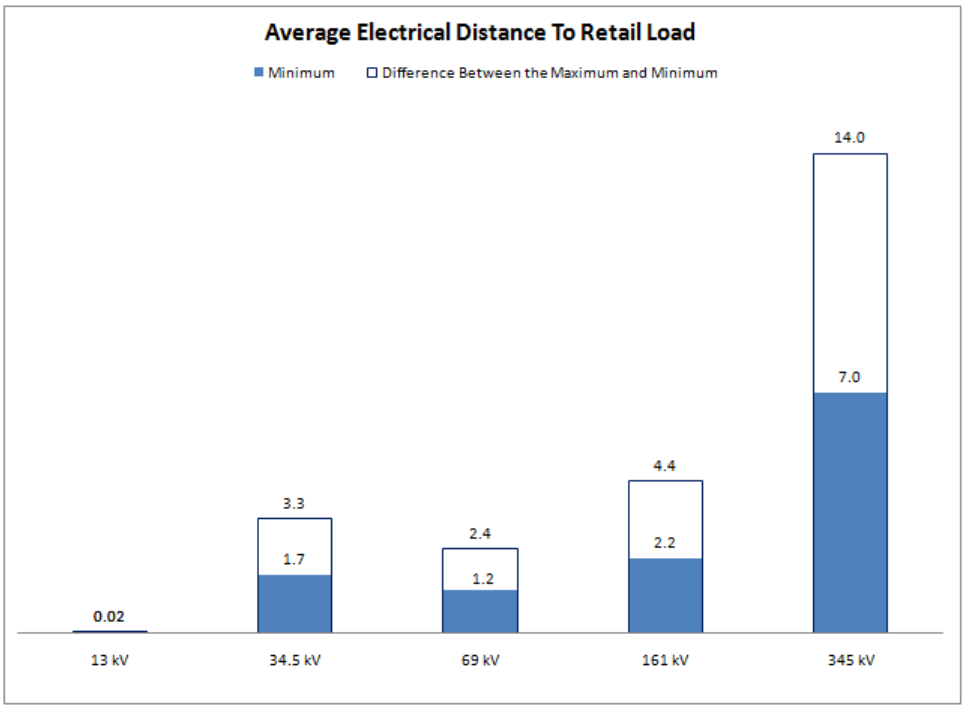

Figure 1: Average Electrical Distance to Retail Load

Figure 1 shows the average electrical distances from the 13 kV, 34.5 kV, 69 kV, 161 kV and 345 kV to retail load. The estimated average electrical distances of 1.7 to 3.3 miles for 34.5 kV, 1.2 to 2.4 miles for 69 kV, 2.2 to 4.4 miles for 161 kV and 7 to 14 miles for 345 kV are substantially greater than the estimated average distance of 120 feet from the retail customer to the primary local distribution facility at 13 kV and below. As compared to the 13 kV and below, the 34.5 kV and above facilities are not in close proximity to the retail customers.

If this factor alone is considered, MidAmerican 34.5 kV and above facilities would be categorized as transmission while 13 kV and below facilities would be categorized as local distribution.

Factor 2: Local distribution facilities are primarily radial in character.

MidAmerican operates approximately 26,650 miles of single phase primary lines and 9,350 miles of three phase primary lines at 13 kV and below. It is estimated that 99 percent of these lines are operated radially, with only a few facilities in large downtown areas operated networked. In this context, the term "radial" refers to lines that are ultimately connected to a single source of power such that power flows in one direction from the source to the load. Given that nearly all 13 kV and below facilities are operated radially, MidAmerican 13 kV and below facilities are considered to be operated radially in this report and therefore, considered local distribution facilities.

MidAmerican has approximately 86 miles (all) of its 34.5 kV lines, 529 miles of 69 kV lines, 29 miles of 161 kV lines and 7 miles of 345 kV lines operated radially (see Appendix 1) and are used to support 345 kV, 161 kV, 69 kV or 34.5 kV to 13 kV or lower local distribution substations. These radial 34.5 kV and above lines feed local distribution substations that serve retail customer load and do not support the bulk electric system. If only Factor 2 is considered, they would be categorized as local distribution facilities.

The approximately 1,375 miles of MidAmerican's networked 69 kV lines may serve 69-13 kV substations and may also support the bulk electric system as they provide parallel paths for power flow across the system. The approximately 1,411 miles and 1,173 miles of MidAmerican's networked 161 kV and 345 kV lines serve 345-161 kV, 161-69 kV and 161-13 kV substations and provide paths for power to flow across the system. These facilities are not radial in character and if only Factor 2 is considered, they would be categorized as transmission.

If Factor 2 alone is considered, all MidAmerican 69 kV and above networked facilities would be categorized as transmission, and all 345 kV, 161 kV and 69 kV radial facilities and all 34.5 kV and below facilities would be categorized as local distribution.

Factor 3: Power flows into local distribution systems; it rarely, if ever, flows out.

In the 1998 Report analysis, the MidAmerican 69 kV system was tested against this factor by monitoring flows on MidAmerican's 161-69 kV transformers under system normal conditions, and single contingency conditions on the greater than 100 kV system. In this study, a similar test is applied given considerable changes in conditions on the MidAmerican system and in the industry as noted in the introduction.

A transmission line's participation in the flows from an outaged transmission line is measured by the incremental change in the non-outaged facility's flow. Based on the principle of superposition, incremental changes in the power flow on a transmission line due to an outage on another transmission line reflect power flowing across the transmission system.

To perform this test, a list of transmission system contingencies was prepared, which included all lines and transformers[7] operated at 34.5 kV and above in the MidAmerican area (includes lines operated at 34.5 kV and above owned by Cedar Falls and Atlantic), the ITC Midwest area (includes lines operated at 34.5 kV and above owned by Central Iowa Power Cooperative), the Muscatine Power & Water area, and the Iowa zone of the WAPA area (includes lines operated at 34.5 kV and above owned by Corn Belt Power Cooperative). Power flow software was then used to identify the outage distribution factor for each MidAmerican line operated at 34.5 kV or

[7] A transformer was included in the contingency analysis only if it contained two windings operated at voltages greater than 34.5 kV.

higher during each outage of a line or transformer included in this contingency set. The outage distribution factor is defined as the percentage of flow from the outaged facility that appears as additional flow on the monitored facility during the contingency condition. For example if a 161 kV line was carrying 200 MW in the base case of all transmission lines in service and the 69 kV facility in question experiences an increase in loading of 10 MW for the outage of that 161 kV line, the outage distribution factor of the 69 kV line for this outage would be 10/200, or 5%. The outage distribution factor for a given line will vary based on its configuration (radial or networked) and its electrical proximity to the outaged element.

In this analysis, a total of 545 MidAmerican lines operated at 34.5 kV and above were monitored, and a total of 2,247 contingencies were evaluated. Appendix 3 shows the maximum outage distribution factor for each networked MidAmerican line operated at 69 kV and higher (note there are no networked MidAmerican lines operated at 34.5 kV). Appendix 4 shows the maximum outage distribution factor for each radial MidAmerican line operated at 34.5 kV and higher. Table 1 provides a summary of the results.

Table 1. Summary of Outage Distribution Factors on MidAmerican high voltage lines

Description	**Average Outage Distribution Factor**
MidAmerican Networked 69 kV lines (263 lines)	55.04%
MidAmerican Networked 161 kV lines (154 lines)	66.43%
MidAmerican Networked 345 kV lines (39 lines)	61.49%
MidAmerican Radial 34.5 kV lines (10 lines)	0%
MidAmerican Radial 69 kV lines (72 lines)	0%
MidAmerican Radial 161 kV lines (6 lines)	0%
MidAmerican Radial 345 kV lines (1 line)	0%

The networked facilities operated at 69 kV and higher are shown to play a significant role in transporting power during contingency conditions, while the 69 kV and above facilities operated radially and the 34.5 kV and below (operated radially) play no role in transporting power during contingency conditions. Table 1 supports the conclusion that the networked facilities operated at 69 kV and higher perform a transmission function while the 69 kV and above operated radially and 34.5 kV and below lines perform only a local distribution function. During transmission outages, the flow from the outaged element is diverted to other transmission facilities and the original power transport across the system is maintained. A local distribution facility is not impacted by outages on transmission facilities. Figure 2 graphically displays the average maximum outage distribution factor for MidAmerican networked facilities by voltage range.

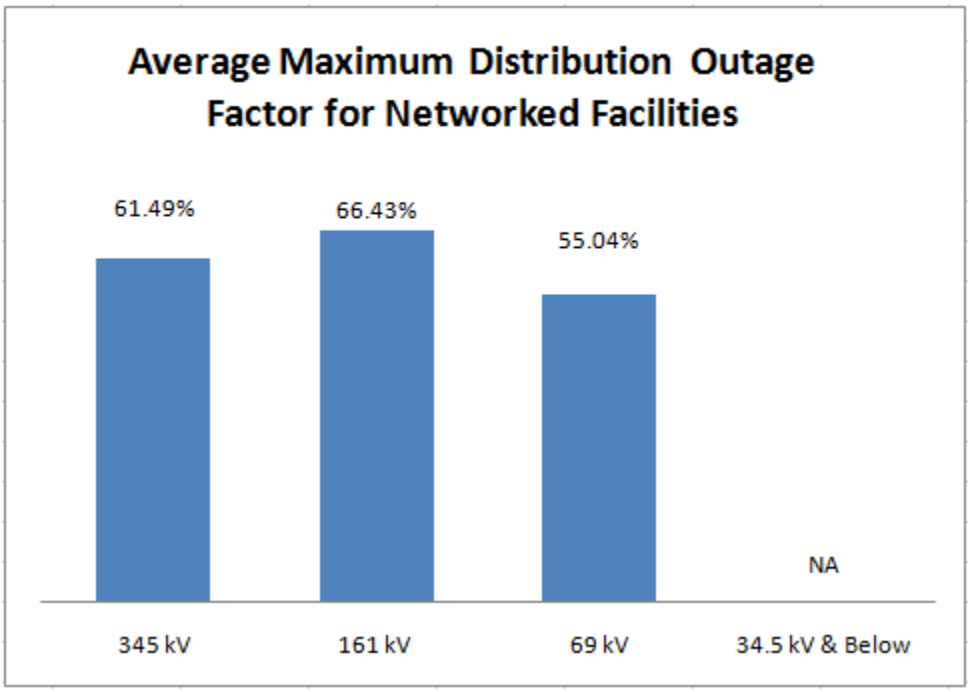

Figure 2: Average Maximum Outage Distribution Factor by Voltage Level for Networked Facilities

If this factor alone is considered, the MidAmerican 345 kV, 161 kV, and 69 kV networked facilities would be categorized as transmission and the 345 kV, 161 kV, 69 kV and 34.5 kV and below facilities operated radially would be categorized as local distribution.

Factor 4: When power enters a local distribution system, it is not reconsigned or transported on to some other market.

Since the 1998 Report, MidAmerican, as well as other utilities and municipals interconnected with MidAmerican, have joined the Midwest ISO. This allows load and generation from these entities to participate with other loads and generation in the multi-state market of the Midwest ISO. As a result of this market interaction, the MidAmerican system sees increased transfers as it supports market flow.

In Factor 3 it was demonstrated that flows on MidAmerican's networked facilities participate in the transportation of power. This fact can be further evaluated by considering flows on MidAmerican's tie lines. A review of the 2010 series of Midwest Reliability Organization ("MRO") power flow models shows a total of 116 tie-lines from the MidAmerican area to adjacent areas, of which 70 are tie-lines operated at 69 kV. Of the 70 tie-lines operated at 69 kV, 39 are networked 69 kV lines owned or partially owned by MidAmerican. The remaining 69 kV tie-lines are either owned by others or are operated radially. Of the 46 tie-lines operated at voltages greater than or equal to 100 kV, 31 are networked facilities owned or partially owned by MidAmerican; the remaining such tie-lines are owned by others. Of the 31 MidAmerican tie-lines operated at voltages greater than 100 kV, 19 are operated at 161 kV and 12 are operated at 345 kV.

When considering power transfers between markets and across the MidAmerican area in a power flow program, the sum of the tie-line flows will tend to net out such power transfers between markets. For example, if there is a 1,000 MW transfer from the west to the east across the MidAmerican area, the tie-line flow into the MidAmerican area in the west will be on the order of +1,000 MW and the tie-line flow into the MidAmerican area in the east will be on the order of -1,000 MW. When the tie-line flows into the MidAmerican system are summed up and therefore netted out, then the power transfer into the MidAmerican area is estimated as being on the order of 0 MW, which does not accurately capture the power transfers between markets. The sum of tie-line flow absolute values will tend to overestimate power transfers between markets and across the MidAmerican area. Using the previous example at a 1,000 MW transfer from the west to the east across the MidAmerican area, power flowing into the MidAmerican system on tie-lines in the west has an absolute value of +1,000 MW. The power flowing into of the MidAmerican system on tie-lines in the east has an absolute value on the order of +1,000 MW so the sum of the absolute value of flows on the tie-lines is on the order of +2,000. Therefore the average of the net and the absolute values is more appropriate when considering power transfers between markets and across the MidAmerican area

Appendix 5 provides the flows on the 39 MidAmerican networked tie-lines operated at 69 kV, 19 MidAmerican networked tie-lines operated at 161 kV and 12 MidAmerican networked tie-lines operated at 345 kV in four power flow models of the 2011 seasons (spring light load, summer peak, summer off-peak and winter peak) representing a range of load levels. Tables 2-4 summarize the results in Appendix 5 for net tie-line power flow and absolute tie-line power flow for tie lines operated at 69 kV, 161 kV and 345 kV respectively. The last column of Tables 2-4 provides the averages of the net and absolute values.

Table 2. Summary of Seasonal Flows on MidAmerican 69 kV tie lines

Model	**Total Interchange on 39 MidAmerican Networked Tie Lines Operated at 69 kV**		
	Net (MW)	**Absolute Value (MW)**	**Average of Net and Absolute Value (MW)**
2011 Spring Light Load	63.3	280.1	171.7
2011 Summer Peak	-61.0	497.0	218.0
2011 Summer off-peak	15.8	370.4	193.1
2011 Winter peak	16.2	487.8	252.0

Table 2 illustrates that as an aggregate group, the 69 kV facilities play an important role in transporting power to other markets. There is substantial flow on the 69 kV networked tie lines, supporting the designation of the 69 kV networked facilities as transmission.

Table 3. Summary of Seasonal Flows on MidAmerican 161 kV tie lines

Model	**Total Interchange on 19 MidAmerican Networked Tie Lines Operated at 161 kV**		
	Net (MW)	**Absolute Value (MW)**	**Average of Net and Absolute Value (MW)**
2011 Spring Light Load	187.3	471.9	329.6
2011 Summer Peak	-60.2	937.6	438.7
2011 Summer off-peak	45.8	782.8	414.3
2011 Winter peak	-88.5	732.5	322.0

Table 3 illustrates that as an aggregate group, the 161 kV facilities play an important role in transporting power to other markets. There is substantial flow on the 161 kV networked tie lines, supporting the designation of the 161 kV networked facilities as transmission.

Table 4. Summary of Seasonal Flows on MidAmerican 345 kV tie lines

Model	Total Interchange on 12 MidAmerican Networked Tie Lines Operated at 345 kV		
	Net (MW)	Absolute Value (MW)	Average of Net and Absolute Value (MW)
2011 Spring Light Load	-499.2	1713.6	607.2
2011 Summer Peak	21.6	2800.6	1411.1
2011 Summer off-peak	-263.3	2642.9	1189.8
2011 Winter peak	-174.4	2786.6	1306.1

Table 4 illustrates that as an aggregate group, the 345 kV facilities play an important role in transporting power to other markets. There is substantial flow on the 345 kV networked tie lines, supporting the designation of the 345 kV networked facilities as transmission.

If this factor alone is considered, the MidAmerican 69 kV and above networked facilities would be categorized as transmission, while the 69 kV and above facilities operated radially and the 34.5 kV and below facilities would be categorized as local distribution.

Factor 5: Power entering a local distribution system is consumed in a comparatively restricted geographical area.

Factors 3 and 4 support the contention that power entering the networked portion of the MidAmerican 69 kV and above system is not wholly consumed in a comparatively restricted geographical area. During contingencies some of the power originally flowing on higher voltage facilities is transported across the 69 kV and above network and back to the higher voltage system (Factor 3), while some of it is transported to other systems (Factor 4). As a parallel path to higher voltage lines, the MidAmerican networked 69 kV and above system provides an alternate route to transmit power, and these facilities are not utilized solely for the consumption of power by end-users in comparatively restricted geographical areas. As a system which transports power to other systems, the MidAmerican networked 69 kV and above facilities are not solely for the consumption of power by end users in comparatively restricted geographical areas.

If this factor alone is considered, the MidAmerican 69 kV and above networked facilities would be categorized as transmission while the 69 kV and above facilities operated radially and the 34.5 kV and below facilities would be categorized as local distribution.

Factor 6: Meters are based at the transmission/local distribution interface to measure flows into the local distribution system

Supervisory Control and Data Acquisition ("SCADA") equipment has been installed throughout the MidAmerican system at various system voltage levels and locations to monitor electric system power flows on a near real-time basis. Other parameters are collected, including reactive power and voltage quantities. The SCADA information is transmitted from various locations and collected at one location, MidAmerican's Des Moines Control Center. SCADA quantities are used to monitor power flows into 34.5 kV and below transformers since 161 kV and 69 kV line flows are measured at the substation busses that feed the transformers that step down to 34.5 kV and below. Revenue accuracy metering is located at ownership boundaries with wholesale customers and with other interconnected utilities.

If this factor alone is considered, the MidAmerican 69 kV and above facilities would be categorized as transmission while the 34.5 kV and below facilities would be categorized as local distribution.

Factor 7: Local distribution systems will be of reduced voltage

Most of the facilities 69 kV and above are networked. Operation of a networked system is different from the operation of a radial system. In a networked system, it is generally true that facilities continue to be energized when a breaker or switch opens; while in a radial system, it is generally true that facilities are de-energized when a breaker or switch opens. Therefore, more time is spent restoring service to customers served from radial facilities than networked facilities. In this manner, radial 345 kV, 161 kV and 69 kV facilities operate similarly to 13 kV and below facilities. The operation of the networked 345 kV, 161 kV and 69 kV facilities differs from the operation of radial 345 kV, 161 kV and 69 kV and 34.5 kV and below facilities. Further, the 34.5 kV and below facilities are a transformation away from 69 kV and higher voltage facilities.

Therefore, 345 kV, 161 kV and 69 kV radial facilities are operated differently and 34.5 kV facilities are of reduced voltage and are operated differently as compared to networked 69 kV and higher voltage facilities. If this factor alone is considered, the MidAmerican networked 69 kV and above facilities would be categorized as transmission while the 345 kV, 161 kV, 69 kV and 34.5 kV (all) and below facilities that are operated radially would be categorized as local distribution.

7-Factor Test Conclusions

The above seven factors are used for determining whether MidAmerican's 345 kV, 161 kV, 69 kV, 34.5 kV, 13 kV and below facilities should be considered local distribution or transmission. Each factor does not necessarily have equal weight when determining which facilities are local distribution and transmission. However, if the factors predominately indicate that sections of MidAmerican's system are local distribution (or transmission), then these sections can logically

be concluded to be local distribution (or transmission). Table 5 shows a summary of the results of the seven factor test.

Table 5: Summary of Seven Factor Test

Voltage	Factor 1	Factor 2	Factor 3	Factor 4	Factor 5	Factor 6	Factor 7
13 kV & Below	D	D	D	D	D	D	D
34.5 kV	T	D	D	D	D	D	D
69 kV Radial	T	D	D	D	D	T	D
69 kV Networked	T	T	T	T	T	T	T
161 kV Radial	T	D	D	D	D	T	D
161 kV Networked	T	T	T	T	T	T	T
345 kV Radial	T	D	D	D	D	T	D
345 kV Networked	T	T	T	T	T	T	T

It is concluded that MidAmerican's 69 kV and above networked facilities should be categorized as transmission while 69 kV and above facilities operated radially and 34.5 kV and below facilities should be categorized as local distribution.

Accounting Considerations

The effect of MidAmerican's two accounting reclassifications noted above (FERC Docket Nos. AC10-9 and AC10-142) is that the plant accounts associated with all of MidAmerican's non-radial 161 kV and 345 kV lines (i.e., facilities that are presently subject to the functional control of the Midwest ISO) are accounted for in transmission accounts on MidAmerican's books. As a result of the inclusion of these facilities in transmission plant accounts, MidAmerican recovers their costs in its transmission rates calculated pursuant to the Midwest ISO tariff. In order for amounts associated with MidAmerican's re-delineated 69 kV facilities to receive similar accounting and ratemaking treatment, accounting changes are needed. A new set of mass plant accounts will be developed to reclassify 69 kV line plant amounts between transmission and distribution plant accounts, and accounting entries reflect these changes relative to existing plant. Unlike 161 kV and 345 kV transmission lines, 69 kV line facilities (poles, conductor, insulators, etc.) are not accounted for in discrete plant accounts for each line. Rather, the 69 kV line facilities are accounted for in mass plant accounts. Such mass plant accounts do not contain information concerning which particular facilities are located on which particular line.

Due to the unavailability of individual 69 kV line plant accounting data, the mass plant accounts are allocated on the basis of the ratio of 69 kV line miles classified as transmission to the plant account balance as determined in this report. Using this calculation, a set of 69 kV transmission mass plant accounts will be developed. There is a total of 1,905 miles of 69 kV lines. Of that total, 1,375 miles are networked 69 kV lines. Therefore, the percentage of networked 69 kV line miles is approximately 72% and the radial line miles are approximately 28%. The amounts of 69

kV line in each state will be allocated proportional to the total 34.5 kV and 69 kV line miles in that state.

Using the ratio of networked 69 kV line miles to total 69 kV line miles to allocate 69 kV line mass plant accounts is valid because the proportions of both 69 kV line investments and book values are comparable (on a dollars per mile basis) when radial and networked lines are compared. It is also appropriate to use a ratio of the total mass plant accounts in this manner because MidAmerican's 69 kV line design practices do not differentiate between whether the line being constructed or modified is radial or networked. Thus, the types of poles and conductor used on a line are determined by other factors, not whether the line is operated networked or radial.

New investments in 69 kV lines following the development of the second set of mass plant accounts will be accounted for based on the classification of the line being modified or constructed. New lines would be accounted for in either the transmission or distribution mass plant account depending on whether the line being constructed is networked or radial. Likewise, modifications to existing lines would be accounted for in this same manner.

Substation Delineations

The 1998 Report utilized an approach for classifying substation facilities based on the classification of the transmission lines connecting to the substation. Under that approach, a 161 kV substation had to have at least three transmission lines connecting to it in order for the substation to be a candidate for a combination transmission and distribution substation[8]. As stated previously, accounting reclassifications were made in 2009 and 2010 to align 161 kV substation facilities with the facilities under the Midwest ISO's functional control.

Given that many of MidAmerican's 69 kV lines have been concluded to be performing a transmission function, it is necessary to establish procedures for classifying 69 kV substations connecting to such lines. There are approximately 100 substations at a voltage of 69 kV which are candidates for becoming combination substations based on the networked operation of the 69 kV lines connecting to the substation.

It is a significant effort to account for combination substations as opposed to substations classified as 100% distribution. This additional effort stems from the complexity of accounting to both transmission and distribution accounts for new capital projects at substations with both types of facilities. Adding to the complexity, field operations personnel performing work in combination substations must separately keep track of time and expenses incurred. As a result of these concerns, it is not practical to develop combination substations accounting information for each 69 kV substation which could qualify.

[8] *Re MidAmerican Energy Company,* 193 P.U.R.4th 555, 1999 WL 632816 (Iowa U.B.)

A reasonable way to reduce the number of new combination substations required is to utilize the "three or more" approach that was originally applied to the 161 kV substations. Under this approach, a 69 kV substation is a candidate to become a combination substation only if at least three networked 69 kV lines or at least two networked 69 kV lines and one 69 kV capacitor connect to the substation. In the aggregate, using this approach will add approximately 20 additional combination substations to the existing total. In contrast, if every potential 69 kV substation (having at least 2 networked 69 kV lines connecting to the substation) were to be re-delineated as a combination substation without regard to the "three or more" rule, approximately 90 additional combination substations would be added to the total.

Due to the additional initial effort and the ongoing complexity of accounting for costs of many more combination substations, the "three or more" rule has been implemented in this re-delineation when determining which 69 kV substations to re-classify as combination substations. To the extent accounting procedures allow for more streamlined cost accounting approaches in the future, the utilization of the "three or more" rule may be changed.

The determination of which specific facilities in new combination and revised delineation combination substations are allocated to transmission accounts versus distribution accounts follows a similar approach as used in the 1998 study to delineate transmission and local distribution substation costs. Namely:

1. Transmission facilities include 161-69 kV transformers, 161-69 kV transformer breakers, networked 69 kV facilities including station dead-end structures, station bus, station bus supports and bus structures, 69 kV line breakers, 69 kV line switches, 69 kV switches used for isolation of line circuit breakers, line protective relays, 69 kV instrument transformers (used for line protective relaying and metering) and disturbance monitoring equipment. Transmission facilities also include shunt 69 kV capacitors. 345-161 kV transformers and associated equipment remain in transmission accounts.

2. Common facilities are those facilities serving a common purpose between transmission and local distribution. Such common facilities include substation land, rock, fence, control buildings, station batteries, station grounding systems, station service transformers and communications equipment. Common facilities in networked 69 kV substations are allocated to transmission and distribution accounts by pro-rating based on the original cost of the transmission and distribution facilities in the substation.

3. Distribution facilities are those facilities within networked 69 kV substations which are operated radial to the 69 kV networked system and include 69-13 kV transformers, 69-4 kV transformers, transformer 69 kV breakers and/or circuit switchers, transformer 69 kV switches, transformer protective relaying, transformer metering, 13 kV facilities and 4 kV facilities. In addition, the portion of the common facilities which are not allocated to transmission accounts will remain in distribution accounts.

Future Changes to Classifications

Transmission and local distribution facility classifications are subject to change. Classifications may change as the system changes in its characteristics as has been observed since the 1998 Report.