MidAmerican Energy Company

Reliability Planning Criteria for 69 kV

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Issued by: Dehn Stevens, Director
System Planning and Services

1.0 SCOPE

This document defines the criteria to be used in assessing the reliability of MidAmerican Energy Company's (MidAmerican's) 69 kV System.

2.0 GENERAL

Reliability assessments of the MidAmerican 69 kV System are performed to identify areas of the system where the reliability criteria are not expected to be met. Reliability assessments are also performed to evaluate impacts of interconnections of new generation, transmission, or loads on the MidAmerican 69 kV System[1]. In the reliability assessments, contingencies are analyzed for reliability criteria violations including thermal overloads, low voltage, high voltage, transient instability, voltage instability and cascading outages. In addition, circuit breaker interrupting capability, delivery point reliability, voltage flicker, and harmonics are analyzed. These 69 kV criteria provide a description of acceptable 69 kV performance or the allowable 69 kV limits that must be met for events that occur on the 69 kV system.

3.0 PURPOSE

The purpose of these 69 kV reliability planning criteria, henceforth "Criteria", is to provide a basis for the planning, design and operation of MidAmerican's 69 kV system (including transformers with a 69 kV secondary winding) in the interest of its customers, communities served, and owners in a consistent, reliable, and economic manner. It is intended that these Criteria conform to the appropriate industry reliability standards and the applicable rules and regulations of the Federal Energy Regulatory Commission (FERC) and other regulatory bodies having jurisdiction.

These Criteria are subject to review and change at any time to conform to changes in the appropriate industry reliability standards and the applicable rule and regulation changes in the future.

4.0 SYSTEM PLANNING PERFORMANCE STANDARDS

A. System Performance Criteria

The MidAmerican 69 kV System shall be planned, designed, and constructed so that the network can be operated to supply projected customer demands and projected firm transmission service at all demand levels over the range of forecast system demands, under the contingency conditions defined in Table 1 (see Appendix for Table 1) without exceeding stability limits, applicable thermal and voltage limits (see Table 2 in the Appendix for steady-state voltage criteria), applicable limits to loss of demand or

[1] Reliability assessments of the MidAmerican 69 kV system are performed, as appropriate, for interconnections to the MidAmerican system or neighboring systems. Also, the seams between MidAmerican and neighboring systems are investigated for impacts of MidAmerican and neighboring-system contingencies.

curtailed firm transfer, and without resulting in cascading outages, uncontrolled separation, or instability. The 69 kV System shall also be planned to include sufficient Reactive Power resources to meet system performance criteria.

Planned system adjustments such as transmission configuration changes and redispatch of generation are allowed if such adjustments are executable within the time duration applicable to facility ratings. System readjustments are subject to the notes provided in Table 1, Section 5.0, and other requirements of the MRO Reliability Standards. The system shall be planned, designed, and constructed to prevent subsynchronous resonance issues, harmonic issues, voltage flicker issues, generator shaft torsional issues, and over dutied fault interrupting device conditions. System assessments shall be conducted annually to demonstrate that the system meets the latest Criteria and, as necessary, to evaluate impacts of material changes in generation, transmission, or loads on the MidAmerican 69 kV System.

B. Steady-State Voltage Criteria

The steady-state voltage provided to customers must comply with ANSI Standard C84.1 (see Reference C). This standard defines two voltage ranges within which the customer's voltage must be maintained. Range A covers voltages for which the system is designed to provide under normal conditions. The occurrence of service voltages outside this range should be infrequent. Range B covers voltages outside of Range A that necessarily result from practical design and operating conditions on supply or user systems, but which are to be limited in extent, frequency, and duration. Corrective measures are to be taken within a reasonable time to bring voltages back within Range A.

The devices and techniques used to maintain voltages within ranges A and B vary from case to case. The voltages listed in Table 2 of the Appendix are those needed to provide voltages to users within the required ranges and shall apply to the MidAmerican 69 kV System. Note the major assumptions and considerations listed below the table.

Reliability assessments of the MidAmerican 69 kV System shall include evaluation of system voltages in a manner designed to:

- typically represent the minimum voltage conditions, for example, evaluation at summer peak load. Cases are to be adjusted to reflect generation resource dispatch that is expected to typically represent the voltage limit being evaluated and with appropriate representation of the MW and MVAR loads including those of generating stations, as appropriate.
- typically represent the maximum voltage conditions, for example, using a spring light load case with wind farms connected to the MidAmerican system operating with no real power output, collector circuit MVAR charging represented, and with the wind farm voltage control, if any, simulated.

C. Transient Voltage Criteria

Generator Bus Transient Voltage Limits shall adhere to the high voltage duration curve and low voltage duration curve in Attachment 2 of NERC PRC-024.

Load Bus Transient Over Voltage Limits (the period after the disturbance has occurred but not including the fault duration), maximum short-term AC voltage are: 1.6 per unit voltage from 0.01 to and including 0.04 seconds; 1.2 per unit voltage from 0.04 to and including 0.5 seconds; 1.1 per unit voltage from 0.5 to and including 5 seconds; and 1.05 per unit voltage for greater than 5 seconds.[2] These voltage limits also apply to buses without loads and generators.

Load Bus Transient Low Voltage Recovery Limits are as follows: voltage may be less than 0.7 per unit voltage from 0 to 2 seconds after fault clearing. Voltage shall remain above 0.7 per unit from 2 to 20 seconds after fault clearing. Voltage shall recover to 0.9 per unit 20 seconds after fault clearing.[3]

The Load Bus Transient Over Voltage and Load Bus Transient Low Voltage Recovery Limits are illustrated in Figure 1 below:

[2] Exception: Contingencies resulting in an 'isolated bus' connected to a radial transmission line or transformer. For example, at a three terminal ring bus substation with three transmission lines a prior outage of one line followed by a fault on a second line can result in only one line remaining in-service. Such a configuration can result in voltages outside of criteria at the remaining in-service terminal, the 'isolated bus'.

[3] Exception: Contingencies resulting in 'reverse power' configurations where load connected to ≥100 kV buses is being served radially through one or more transformers (e.g. 161-69 kV) from the underlying 69 kV system.

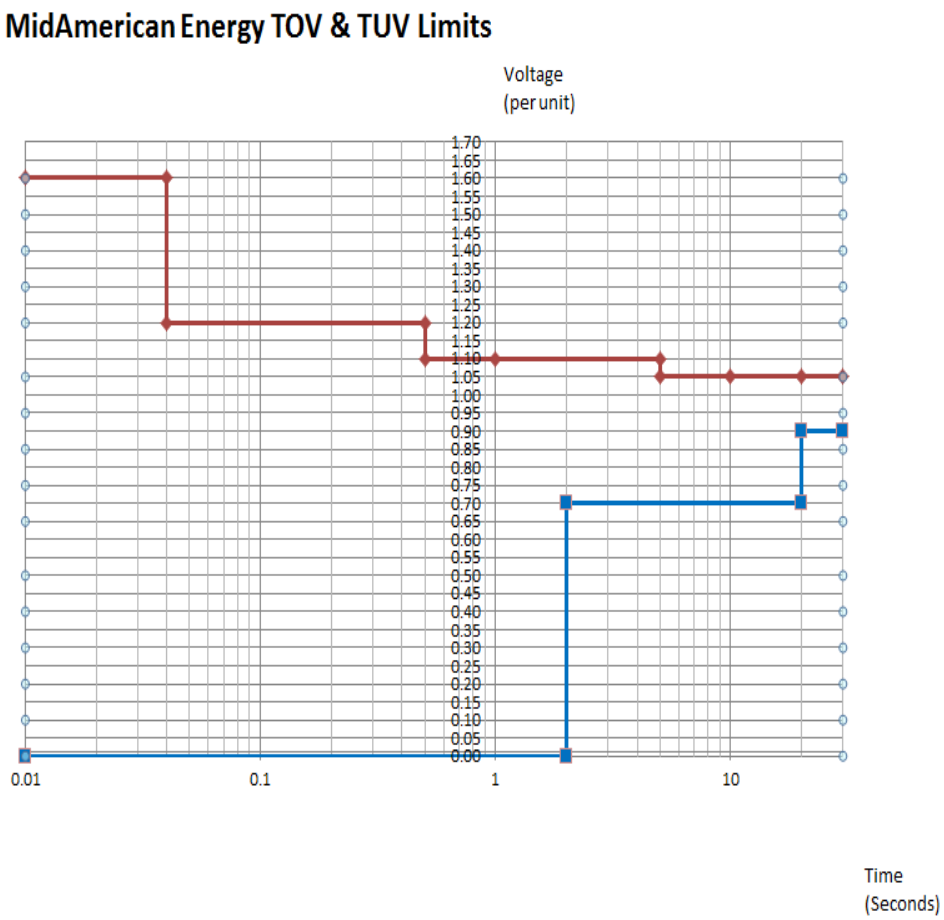

Figure 1 Transient Voltage Limits

D. Voltage Stability

The MidAmerican 69 kV System shall be planned, designed and constructed to provide sufficient reactive capacity and voltage control facilities at all demand levels and committed Total Transfer Capability[4] levels to satisfy the reactive requirements and to ensure performance defined in Planning Events of Table 1. The system shall be planned so that there is sufficient margin between the normal operating point and the collapse point for voltage stability to allow for a reliable system.

Voltage stability studies shall be performed to demonstrate that there is sufficient margin between the normal operating point and the collapse point. The studies shall include voltage versus power transfer or system demand (P-V curve). Sufficient margin is maintained by operating at or below P_{limit}. P_{limit} is determined by developing P-V curves for those buses that have the largest contribution to voltage instability due to the most limiting

[4] See the definition at Glossary of Terms Used in NERC Reliability Standards.

disturbance as defined in Planning Event Category P1 in Table 1. P_{limit} is calculated as the lesser of:

- (0.9) * P_{crit} where P_{crit} is defined as the maximum power transfer or system demand (nose of P-V curve) or
- the maximum power transfer or system demand before a bus voltage falls below 0.9 per unit (shown below in Figure 2 as point "a"), or
- the Total Transfer Capability or system demand which does not result in a post-contingency voltage violation.

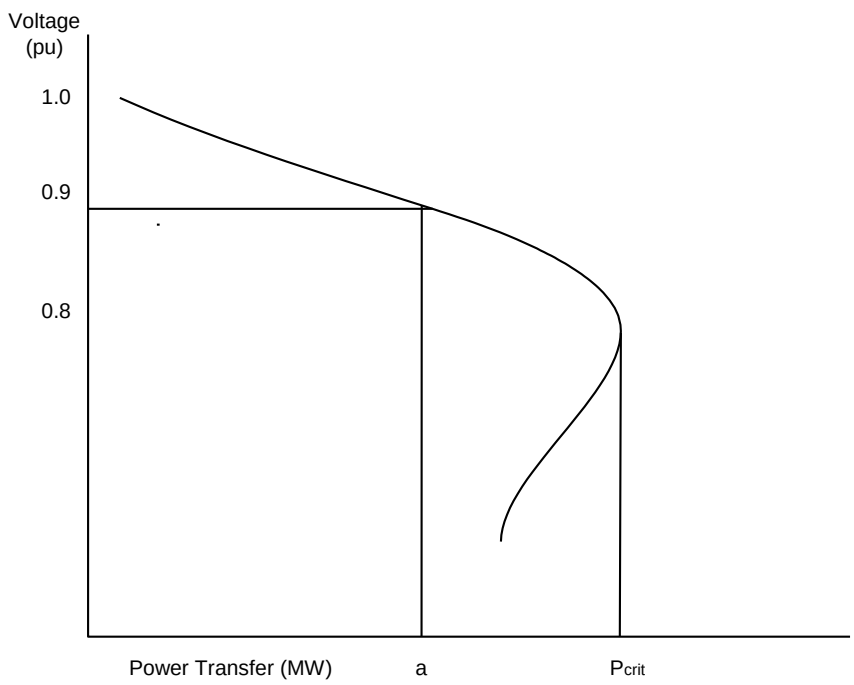

Figure 2 P-V Curve

E. System Frequency

Facilities must be planned to maintain system frequency between the thresholds plotted in Figure 3, including a 10% reliability margin for both time and frequency, for all events defined in Table 1 in the Appendix. The overfrequency thresholds plotted in Figure 3 reflect the most restrictive performance curve from either PRC-006 or PRC-024. The underfrequency thresholds plotted in Figure 3 reflect the most restrictive performance curve from either PRC-024 or MidAmerican's underfrequency load shedding (UFLS) plan used to comply with PRC-006. MidAmerican's UFLS plan must not be designed to initiate the tripping of load if system frequency is between the thresholds plotted in Figure 3. Furthermore, generators interconnected to the MidAmerican transmission system must be designed to remain connected to the system if system frequency is

between the thresholds plotted in Figure 3. Therefore, by maintaining system frequency between the thresholds plotted in Figure 3, facilities are planned in such a manner to avoid non-consequential loss of load, as required by footnote 12 to Table 1 in TPL-001-4, and unintended generation tripping.

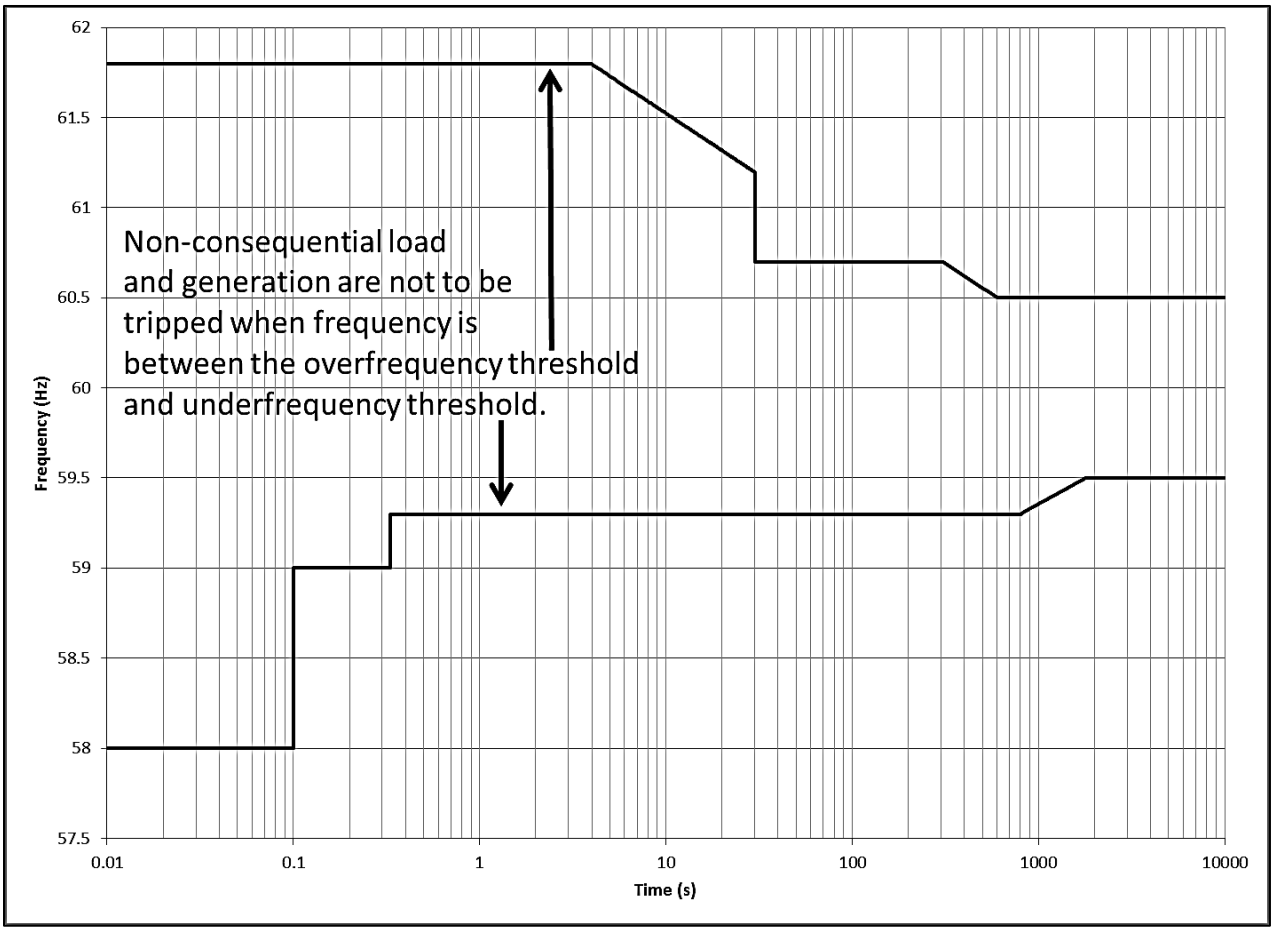

Figure 3: Planning Thresholds for System Frequency

1. $t \leq 0.1\ s$
2. $0.1\ s < t \leq 0.33\ s$
3. $0.33\ s < t \leq 4.0\ s$
4. $4.0\ s < t \leq 30.0\ s$
5. $30.0\ s < t \leq 300\ s$
6. $300\ s < t \leq 600\ s$
7. $600\ s < t \leq 800\ s$
8. $800\ s < t \leq 1800\ s$
9. $t > 1800\ s$

1. $58\ Hz < f < 61.8\ Hz$
2. $59\ Hz < f < 61.8\ Hz$
3. $59.3\ Hz < f < 61.8\ Hz$
4. $59.3\ Hz < f < -0.686 \log_{10}(t) + 62.21\ Hz$
5. $59.3\ Hz < f < 60.7\ Hz$
6. $59.3\ Hz < f < \frac{-(\log_{10}(t)+90.935)}{1.45713}\ Hz$
7. $59.3\ Hz < f < 60.5\ Hz$
8. $\frac{\log_{10}(t)+100.116}{1.7373}\ Hz < f < 60.5\ Hz$
9. $59.5\ Hz < f < 60.5\ Hz$

F. Disturbance Performance Requirements

The MidAmerican 69 kV System shall be planned, designed and constructed to meet the disturbance performance requirements set forth in Table 1 in the Appendix as modified by the MEC Note 3 which provides the definition for Cascading, MEC Note 4 which states the minimum damping ratio (ζ) of each mode present in an electrical response must be greater than 0.03, and MEC Note 5 where a one-cycle safety margin must be added to the actual or planned fault clearing time.

5.0 MITIGATION ALTERNATIVES TO MEET RELIABILITY CRITERIA

When system simulations indicate an inability of the 69 kV System to meet the performance requirements of Table 1, the deficiencies must be resolved by a mitigation plan. Below is a summary of the available mitigation alternatives for each event category defined in Table 1. It should be noted that operating guides may be written for any type of system readjustment included in Table 1. This section is intended to add additional explanation of Table 1 and explain how it is implemented. This section is intended on being consistent or more stringent than Table 1.

A. 69 kV Planning Event Category P0 criteria violations

Facility loadings exceeding facility normal ratings as provided in Reference D or bus voltages lower than the “Continuous Minimum Voltage” and higher than the “Maximum Voltage” as defined in Table 2 require physical upgrades to meet system performance requirements under 69 kV Category P0 conditions.

B. 69 kV Planning Events P1, P2, P4, and P7 criteria violations

69 kV Planning Events P1, P2, P4, and P7 studied at peak, shoulder, off-peak, and light load conditions resulting in facility loading above emergency ratings, bus voltages below the applicable "1 Hour Emergency Minimum Voltage"[5] defined in Table 2, or bus voltages above the "Maximum Voltage"[6] defined in Table 2, require physical upgrades to meet system performance requirements. Manual readjustment during and after the contingency cannot be used to resolve the criteria violations.

69 kV Planning Events P1, P2, P4, and P7 studied at peak, shoulder, off-peak, and light load conditions resulting in facility loading between normal and emergency ratings as provided in Reference D or causing bus voltages above the applicable "1 Hour Emergency Minimum Voltage" but below the applicable "Continuous Minimum Voltage" defined in Table 2 may rely on manual adjustment in an operating guide to reduce the facility loading to the facility normal rating and to increase bus voltages to the applicable "Continuous Minimum Voltage" defined in Table 2. This is provided the readjustments do not result in load shedding, do not cause additional thermal or voltage violations, and meet the requirements of Section 5.0 F. and G. A physical upgrade is required if manual readjustment is not capable of implementation within the applicable facility emergency rating duration or within the 1 hour voltage readjustment period.

[5] Exception: Contingencies resulting in 'reverse power' configurations where load connected to ≥100 kV buses is being served radially through one or more transformers (e.g. 161-69 kV) from the underlying 69 kV system.

[6] Exception: Contingencies resulting in an 'isolated bus' connected to a radial transmission line or transformer. For example, at a three terminal ring bus substation with three transmission lines a breaker failure can result in two of the lines being outaged and only one line remaining in-service. Such a configuration can result in voltages outside of criteria at the remaining in-service terminal, the 'isolated bus'.

C. 69 kV Planning Event P5 criteria violations

69 kV Planning Event P5 contingencies studied at peak, shoulder, off-peak, and light load conditions resulting in 69 kV facility loadings above normal ratings, 69 kV bus voltages below the applicable "Continuous Minimum Voltage"[7] defined in Table 2, or 69 kV bus voltages above the "Maximum Voltage"[8] defined in Table 2 do not require physical upgrades or an operating guide describing manual system adjustments unless analysis indicates the possibility of cascading 69 kV outages that cause:

- a ≥ 100 kV facility to exceed its normal rating
- a ≥ 100 kV bus voltage to drop below the applicable "Continuous Minimum Voltage"[7]
- a ≥ 100 kV and above bus voltage to exceed the applicable "Maximum Voltage"[8]

[7] Exception: Contingencies resulting in 'reverse power' configurations where load connected to ≥100 kV buses is being served radially through one or more transformers (e.g. 161-69 kV) from the underlying 69 kV system.
[8] Exception: Contingencies resulting in an 'isolated bus' connected to a radial transmission line or transformer. For example, at a three terminal ring bus substation with three transmission lines a prior outage of one line followed by a fault on a second line can result in only one line remaining in-service. Such a configuration can result in voltages outside of criteria at the remaining in-service terminal, the 'isolated bus'.

D. 69 kV Planning Event P3 and P6 (N-1-1) criteria violations

An operating guide with manual readjustment may be used after the first contingency of a 69 kV Planning Event Category P3 or P6 (N-1-1) event to prevent reliability criteria violations following the second contingency of the N-1-1 event. The operating guide used between the first and second contingency must keep facility loadings after the second contingency of the N-1-1 event below their emergency ratings and bus voltages after the second contingency of the N-1-1 event between the applicable "1 Hour Emergency Minimum Voltage"[9] and "Maximum Voltage"[10] as defined in Table 2.

An operating guide with manual readjustment may also be used after the second contingency of the 69 kV Planning Event Category P3 and P6 event, if the second contingency of the event results in:

- facility loadings between normal and emergency ratings
- bus voltages between the applicable "1 Hour Emergency Minimum Voltage"[7] and the "Continuous Minimum Voltage"[9] defined in Table 2, or
- bus voltages between the applicable "Continuous Minimum Voltage" and the "Maximum Voltage"[10] defined in Table 2.

However, any such operating guide is subject to the requirements in Section 5.0 F. and G., and must reduce facility loadings to the facility normal ratings and increase bus voltages to the applicable "Continuous Minimum Voltage" defined in Table 2. Such operating guides must be able to return facility loadings and bus voltages to acceptable levels within the applicable facility emergency rating duration or within the 1 hour voltage readjustment period.

- System Operating Limitation

  If analysis indicates that after the second contingency of a P3 or P6 Planning Event, facility loadings are between 100% and 125% of their emergency ratings, then the allowable readjustment period between the first and second contingency is no more than 2 hours.

  After the second contingency of the P3 or P6 Planning Event, the allowable system readjustment period is no more than the applicable emergency rating duration for thermal constraints, and up to 1 hour for voltage constraints.

[9] Exception: Contingencies resulting in 'reverse power' configurations where load connected to ≥100 kV buses is being served radially through one or more transformers (e.g. 161-69 kV) from the underlying 69 kV system.
[10] Exception: Contingencies resulting in an 'isolated bus' connected to a radial transmission line or transformer. For example, at a three terminal ring bus substation with three transmission lines a prior outage of one line followed by a fault on a second line can result in only one line remaining in-service. Such a configuration can result in voltages outside of criteria at the remaining in-service terminal, the 'isolated bus'.

- Significant Overload Limitation

  If analysis indicates that after the second contingency of a P3 or P6 Planning Event, facility loadings exceed 125% of their emergency ratings, then the allowable readjustment period between the first and second contingency is no more than 60 minutes.

  After the second contingency of the P3 or P6 Planning Event, the allowable system readjustment period is no more than the applicable emergency rating duration for thermal constraints, and up to 1 hour for voltage constraints.

A physical upgrade is required for P3 and P6 Planning Events if an operating guide cannot be used in accordance with the provisions of 5.0 D., 5.0 F., or 5.0 G.

E. Maintenance Outages (Planning Event PM69 in Table 1) criteria violations.

PM69 maintenance outages defined in Table 1 will only be studied at shoulder or light load conditions with local wind generation dispatched at no more than 40% of nameplate.

An operating guide with manual readjustment may be used after the first contingency of a Planning Event Category PM69 event to prevent reliability criteria violations following the second contingency of the PM69 event. The operating guide used between the first and second contingency must keep facility loadings after the second contingency of the PM69 event below their emergency ratings and bus voltages after the second contingency of the PM69 event between the applicable "1 Hour Emergency Minimum Voltage"[11] and "Maximum Voltage"[12] defined in Table 2.

An operating guide with manual readjustment may also be used after the second contingency of the PM69 event if the second contingency of the event results in:

- facility loadings between normal and emergency ratings
- bus voltages between the applicable "1 Hour Emergency Minimum Voltage"[11] and the "Continuous Minimum Voltage" defined in Table 2, or
- bus voltages between the applicable "Continuous Minimum Voltage" and the "Maximum Voltage"[12] defined in Table 2.

However, any such operating guide is subject to the requirements in Section 5.0 F. and G., and must reduce facility loadings to the facility normal ratings and increase bus voltages to the applicable "Continuous Minimum Voltage defined in Table 2. Such operating guides must be able to return facility loadings and bus voltages to acceptable levels within the applicable facility emergency rating duration or within the 1 hour voltage readjustment period.

A physical upgrade is required for a PM69 event if an operating guide cannot be used in accordance with the appropriate provisions of Section 5.0 E, 5.0 F, or 5.0 G. A 10 year transition period from January 1, 2015 is allowed for identified physical upgrades.

[11] Exception: Contingencies resulting in 'reverse power' configurations where load connected to ≥100 kV buses is being served radially through one or more transformers (e.g. 161-69 kV) from the underlying 69 kV system.
[12] Exception: Contingencies resulting in an 'isolated bus' connected to a radial transmission line or transformer. For example, at a three terminal ring bus substation with three transmission lines a prior outage of one line followed by a fault on a second line can result in only one line remaining in-service. Such a configuration can result in voltages outside of criteria at the remaining in-service terminal, the 'isolated bus'.

F. General Requirements of Operating Guides

An operating guide, when available as a mitigation solution, may include generation redispatch (according to the requirements of Section 5.0 E. and F.), capacitor and reactor switching including those switched by automated controls, LTCs including those with automatic controls or under operator control, controlled HVDC power flow, and/or other system reconfiguration (such as transmission and transformer tripping or switching) assuming that such reconfiguration does not result in load shedding and does not cause additional thermal or voltage violations.

In situations where there is a firm commitment to proceed with a physical upgrade to mitigate the criteria violation and a temporary operating guide is needed as a bridge, the following unusual measures will be allowed:

- a temporary short-time duration emergency limit provided the limit is consistent with the time required to complete the necessary operating steps to return to normal time duration limits,
- a temporary operating configuration (e.g. operating a ring-bus breaker as normally open) assuming that the temporary operating configuration can be reasonably accommodated and does not cause load shedding, violation of thermal ratings or bus voltages, or significant operational issues, or
- as a last resort, the temporary operating guide may include controlled load shedding after the first contingency[13]. Last resort means that no temporary measure other than non-consequential load dropping can be taken to mitigate violations until a more permanent Corrective Action Plan can be adopted. For example, if facilities are being considered for retirement that cause the violations then such retirement must be delayed until a Corrective Action Plan such as an operating guide that does not require non-consequential load dropping is adopted or a system improvement is completed and put in-service.

Approved operating guides will be re-evaluated on a regular basis to confirm the continued ability to meet the performance requirements of Tables 1 and 2 through implementation of the operating guide. This includes a requirement that additional thermal or voltage violations not be created through implementation of the operating guide.

G. Generation Redispatch Limitations

In many cases, MISO Market Generation is not efficient in resolving 69 kV issues. MISO evaluates the potential of MISO Market Generation to resolve 69 kV issues on a case by case basis. MISO's criteria with regard to the limitations of MISO Market Generation to relieve particular 69 kV constraints shall be represented in 69 kV system assessments.

[13] It should be noted that Table 1 provides specific limitations to non-consequential load dropping for certain outage events. See Footnote 12 in Table 1.

H. Supplemental Protection Schemes (SUPPS)

A SUPPS is an automatic control scheme designed to alleviate overloads on monitored facilities below 100 kV for N-1-1 contingencies. Each SUPPS monitors a 69 kV facility, such as a 161-69 kV transformer or a 69 kV line. When loading on the monitored facility exceeds specified levels, the SUPPS reduces local generation to alleviate overloading of the monitored facility. Typically, SUPPS generation re-dispatch controls are implemented in the two following stages:

- Stage 1: Curtail generator output to pre-determined level if loading on the monitored element approaches or exceeds its normal rating
- Stage 2: Trip a pre-determined amount of generation if loading on the monitored element approaches or exceeds its emergency rating

For reliability reasons, Remedial Action Schemes at 100 kV and above are limited to certain situations as described in the MidAmerican Energy Company Reliability Planning Criteria for 100 kV and above. In a similar way, for reliability reasons, MidAmerican limits the application to SUPPS to certain situations as described in the following:

- SUPPS may only be used as mitigation for issues on facilities below 100 kV for N-1-1 contingencies.
- SUPPS may only monitor conditions on facilities below 100 kV.
- SUPPS may only be used if, in MidAmerican's sole judgment, improvements to resolve the identified violations are not practical.

In order to minimize the risk of the SUPPS failing to operate (when required to maintain system reliability), all SUPPS installed subsequent to the effective date of this Criteria must be designed using design redundancy similar to what NERC and the MRO require of an RAS. This means the SUPPS must be designed such that a single component failure will not prevent the SUPPS from operating when required to maintain system reliability. This means that the SUPPS should be designed considering redundant logic devices, redundant control outputs, redundant communication channels, and separate Voltage Transformer secondaries in order to meet the single component failure requirement.

6.0 SHORT CIRCUIT CRITERIA

When the short circuit analysis portion of the 69 kV reliability assessment is conducted, the analysis shall be used to determine whether circuit breakers have interrupting capability for faults that they will be expected to interrupt using the system short circuit model with any planned generation and transmission facilities in service which could impact the study area.

Short circuit currents are evaluated in accordance with industry standards as specified in American National Standards report ANSI C37.5 for breakers rated on the total current (asymmetrical) basis and IEEE Standard report C37.010 for breakers rated on a symmetrical current basis.

In general, fault current levels must be within specified momentary and/or interrupting ratings of circuit breakers for studies made with all facilities in service, and with generators and synchronous motors represented by their appropriate (usually sub-transient saturated) reactances. For any circuit breaker which is shown to have a short-circuit duty that exceeds its interrupting ratings, Corrective Action Plans will be developed. Corrective action plans may include breaker replacement, system reconfiguration or operating guides.

7.0 RELIABILITY CRITERIA FOR DELIVERY POINTS TO LOAD

The 69 kV system operated in a radial configuration is generally designed to provide cost effective service to customers without the improved reliability that having a loop would provide. Considerations and situations that can determine the need for a system upgrade from a radial configuration to a looped configuration with a normally open or normally closed tie include, but are not limited to:

- Customers willing to fund the conversion to increase reliability
- Significantly increasing load
- Effects of a large-scale outage
- Expected outage exposure, in load amount and hours at risk
- Estimated time to repair an outage
- Prevention of thermal overload or low-voltage situations
- Projected future system performance
- Economics

The benefits of converting a long-distance radial system to a looped system may not justify the expense to the ratepayer. In such situations, state utility commissions may provide advice as to how to proceed, and how (and when) to fund the expansion.

Three times annual net revenue of a new load in Iowa, Illinois, or South Dakota must equal or exceed the cost of new facilities for the addition of the second source to be considered justified.[14]

Three times the expected annual net revenue of an existing load in Iowa, Illinois, or South Dakota must equal or exceed the cost of new facilities for the addition of a second source plus the book value of existing facilities for the addition of the second source to be considered justified.[5]

[14] Consistent with MidAmerican's retail tariff and/or the administrative code for that state.

8.0 VOLTAGE FLICKER CRITERIA

Figure 4 provides MidAmerican's allowable fluctuations in supply voltage which is based upon industry guidelines and standards. MidAmerican utilizes the International Electrotechnical Commission (IEC) method in setting allowable voltage flicker levels for the MidAmerican system taking into account all flicker causing sources. The allowable voltage flicker limit for an individual customer is set to 3% for intact system conditions. For new projects, the allowable voltage flicker limit is set to 5% for single 69 kV and above element outage conditions. Arc furnaces must demonstrate through rigorous time-domain simulations that MidAmerican's performance requirements for voltage flicker levels will not be violated. Figure 4, as well as, industry information on arc furnaces will be considered in determining acceptable voltage flicker levels on a case by case basis for arc furnaces.

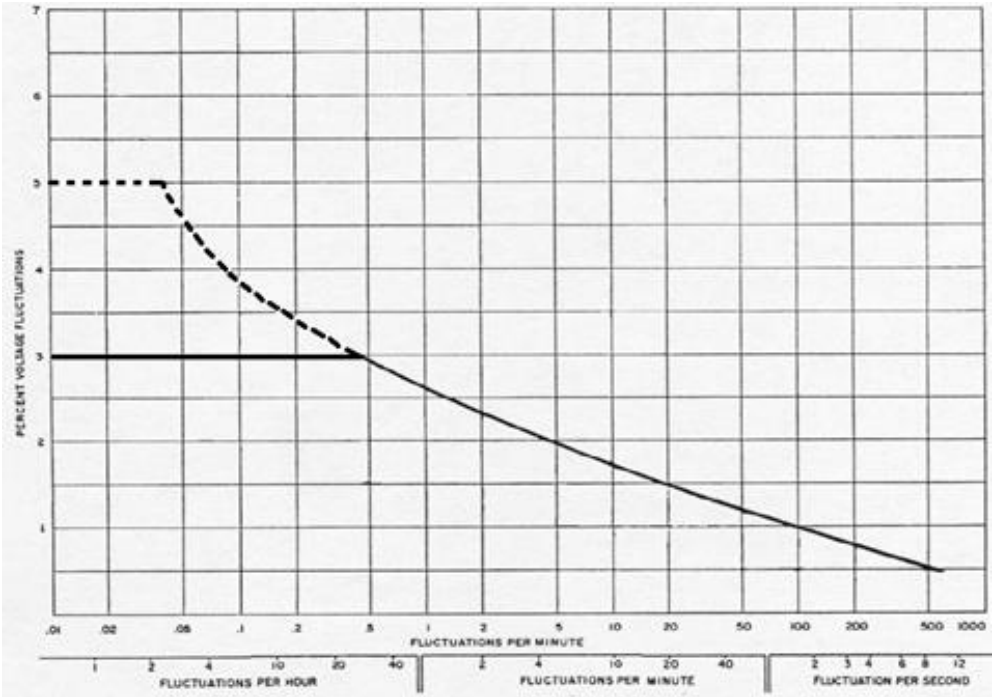

Figure 4 Allowable Voltage Flicker Curves
(Solid Line-System Intact & Dashed Line-Outage Conditions)

9.0 HARMONIC DISTORTION LEVEL CRITERIA

MidAmerican's harmonic distortion level criteria as provided in Tables 3 and 4 are intended to provide for allowable harmonic injection from individual customers so as not to degrade the performance of the equipment of other customers, cause abnormal heating in the MidAmerican's facilities, cause metering errors, or cause objectionable interference in communication facilities. Harmonic levels shall be monitored at customer locations where harmonic levels have or may exceed specified limits.

MidAmerican's allowable harmonic limits are those of IEEE 519- IEEE Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems. MidAmerican's harmonic distortion limits focus on harmonics at either the point of common coupling (PCC), which is the point between the customer that is the harmonics source and other customers, the point of metering, or the point of interference (POI). The POI is a point that both MidAmerican and the customer can either access for direct measurement of the harmonic indices meaningful to both or estimate the harmonic indices through mutually agreed upon methods. The MidAmerican criteria is designed with the goal of reducing the harmonic effects at any point in the entire system by establishing limits on certain harmonic indices (currents and voltages) at either the PCC, a point of metering or a POI.

Nominal Voltage	**Individual Voltage Distortion (%)**	**Total Voltage Distortion THD (%)**
69 kV and below	3.0	5.0

Table 3 Voltage Distortion Limits[15]

Maximum Harmonic Current Distortion in Percent of I_L
Individual Harmonic Order (Odd Harmonics)

I_{sc}/I_L	$3 \leq h < 11$	$11 \leq h < 17$	$17 \leq h < 23$	$23 \leq h < 35$	$35 \leq h \leq 50$	TDD
<20 [16]	4.0	2.0	1.5	0.6	0.3	5.0
$20 \leq x < 50$	7.0	3.5	2.5	1.0	0.5	8.0
$50 \leq x < 100$	10.0	4.5	4.0	1.5	0.7	12.0
$100 \leq x < 1000$	12.0	5.5	5.0	2.0	1.0	15.0
≥ 1000	15.0	7.0	6.0	2.5	1.4	20.0

Table 4 - Current Distortion Limits for Systems 120 V through 69 kV [17,18,19]

[15] Table 1, IEEE 519-2014, IEEE Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems, page 6.
[16] All power generation equipment is limited to these values regardless of actual I_{sc}/I_L.
[17] Table 2, IEEE 519-2014, page 7.
[18] Even harmonics are limited to 25 % of the odd harmonic limits in the tables. Current distortions that result in a direct current offset, e.g. half wave converters, are not allowed.
[19] h = order of harmonic; I_{sc} = maximum short-circuit current at either the PCC, the metering point, or the POI; I_L = maximum demand load current (fundamental frequency component) at either the PCC, the metering point or the POI; TDD = the total root-sum-square harmonic current distortion, in percent of the maximum demand load current (15 or 30 min demand) at the PCC, the metering point, or the POI.

10.0 69 KV FACILITY RATING METHODOLOGY

MidAmerican's 69 kV Facility Ratings Methodology shall be used to establish and communicate MidAmerican's facility ratings for the 69 kV System.

11.0 DOCUMENT CONFLICTS

If there are conflicts in this document, the more stringent provision takes priority.

12.0 CONCLUSIONS

This document presents the criteria for planning the MidAmerican 69 kV System. The purpose of these criteria is to provide a basis for system simulations and associated assessments needed periodically to ensure that reliable systems are developed in time to meet specified performance requirements, and continue to be modified or upgraded as necessary to meet present and future system needs.

13.0 REFERENCES (USE LATEST REVISION)

A. American National Standards Institute (ANSI) C37.010—Application Guide for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis

B. ANSI C37.5—Guide for Calculation of Fault Currents for Application of AC High-Voltage Circuit Breakers Rated on a Total Current Basis

C. ANSI Standard C84.1—Electric Power Systems and Equipment-Voltage Ratings

D. MidAmerican Energy Company 69 kV Facility Ratings Methodology

E. NERC Glossary of Terms

F. Electric Utility Engineering Reference Book, Volume 3, pg. 347, ABB Power Systems Inc., February 1989.

G. IEEE 519 – IEEE Recommended Practices and requirements for Harmonic Control in Electrical Power Systems.

H. International Electrotechnical Commission (IEC), "IEC 1000 Electromagnetic compatibility (EMC) – Part 3: Limits – Section VII: Limitation of voltage fluctuations and flicker for equipment connected to medium and high voltage power supply systems – technical report type II", Project number 1000-3-7

I. IEC, "Disturbances in supply systems caused by household appliances and similar electrical equipment, Part 3: Voltage fluctuations", Publication 555-3

J. NERC TPL-001-4 - Transmission System Planning Performance Requirements.

Table 1 – Steady State & Stability Performance Planning Events

Steady State & Stability:

a. The System shall remain stable. Cascading and uncontrolled islanding shall not occur. MEC Note 3

b. Consequential Load Loss as well as generation loss is acceptable as a consequence of any event excluding P0.

c. Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event.

d. Simulate Normal Clearing unless otherwise specified.

e. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

Steady State Only:

f. Applicable Facility Ratings shall not be exceeded. MEC Note 1

g. System steady state voltages and post-Contingency voltage deviations shall be within acceptable limits.

h. Planning event P0 is applicable to steady state only.

i. The response of voltage sensitive Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements.

Stability Only:

j. Transient voltage response shall be within acceptable limits.

Category	Initial Condition	Event [1, MEC Note 2]	Fault Type [2]	Event Voltage Level Studied	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P0 No Contingency	Normal System	None	N/A	N/A	EHV, HV	No	No
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5 MEC Note 6] 4. Shunt Device [6]	3Ø	≥ 69 kV	EHV, HV, non-BES	No[9]	No[12]
		5. Single Pole of a DC line	SLG				
P2 Single Contingency	Normal System	1. Opening of a line section w/o a fault [7]	N/A	≥ 69 kV	EHV, HV, non-BES	No[9]	No[12]
		2. Bus Section Fault	SLG	≥ 100 kV	EHV	No[9]	No
					HV	Yes	Yes
		3. Internal Breaker Fault [8] (non-Bus-tie Breaker)	SLG		EHV	No[9]	No
					HV	Yes	Yes
		4. Internal Breaker Fault (Bus-tie Breaker) [8]	SLG		EHV, HV	Yes	Yes

Category	Initial Condition	Event [1, MEC Note 2]	Fault Type [2]	Event Voltage Level Studied	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P3 Multiple Contingency	Loss of generator unit (POI ≥ 69 kV) followed by System adjustments[9]	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5 MEC Note 6] 4. Shunt Device [6]	3Ø	≥ 69 kV	EHV, HV, non-BES	No[9]	No[12]
		5. Single pole of a DC line	SLG				
P4 Multiple Contingency *(Fault plus stuck breaker[10])*	Normal System	Loss of multiple elements caused by a stuck breaker [10](non-Bus-tie Breaker) attempting to clear a Fault on one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6] 5. Bus Section	SLG	≥ 100 kV	EHV	No[9]	No
					HV	Yes	Yes
		6. Loss of multiple elements caused by a stuck breaker[10] (Bus-tie Breaker) attempting to clear a Fault on the associated bus	SLG		EHV, HV	Yes	Yes
P5 Multiple Contingency *(Fault plus relay failure to operate)*	Normal System	Delayed Fault Clearing due to the failure of a non-redundant relay[13] protecting the Faulted element to operate as designed, for one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6] 5. Bus Section	SLG	≥ 100 kV	EHV	No[9]	No
					HV	Yes	Yes

Category	Initial Condition	Event [1, MEC Note 2]	Fault Type [2]	Event Voltage Level Studied	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P6 Multiple Contingency *(Two overlapping singles)*	Loss of one of the following (≥ 100 kV) followed by System adjustments.[9] 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device[6] 4. Single pole of a DC line	Loss of one of the following: 1. Transmission Circuit 2. Transformer [5 MEC Note 6] 3. Shunt Device [6]	3Ø	≥ 100 kV	EHV, HV, non-BES	Yes	Yes
		4. Single pole of a DC line	SLG				
P7 Multiple Contingency *(Common Structure)*	Normal System	The loss of: 1. Any two adjacent (vertically or horizontally) circuits on common structure [11] 2. Loss of a bipolar DC line	SLG	≥ 100 kV	EHV, HV	Yes	Yes
PM69 Multiple Contingency *(Maintenance Outage + P1 Event)*	Prior outage of one of the following at load levels at which maintenance outages are typically taken, such as shoulder and light load conditions followed by System adjustments.[9] 1. Opening of a line section w/o a fault [7] (≥ 69 kV) 2. Transmission Circuit (≥ 69 kV) 3. Transformer [5] (≥ 69 kV) 4. Shunt Device [6] (≥ 69 kV)	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5 MEC Note 6] 4. Shunt Device [6]	3Ø	≥ 69 kV	EHV, HV, non-BES	Yes	Yes
		5. Single pole of a DC line	SLG				

Table 1 – Steady State & Stability Performance Extreme Events

Steady State & Stability

For all extreme events evaluated [MEC Notes 2 and 4]:

a. Simulate the removal of all elements that Protection Systems and automatic controls are expected to disconnect for each Contingency.

b. Simulate Normal Clearing unless otherwise specified. [MEC Note 5]

Steady State

1. Loss of a single generator, Transmission Circuit, single pole of a DC Line, shunt device, or transformer forced out of service followed by another single generator, Transmission Circuit, single pole of a different DC Line, shunt device, or transformer forced out of service prior to System adjustments.
2. Local area events affecting the Transmission System such as:
    a. Loss of a tower line with three or more circuits.[11]
    b. Loss of all Transmission lines on a common Right-of-Way[11].
    c. Loss of a switching station or substation (loss of one voltage level plus transformers).
    d. Loss of all generating units at a generating station.
    e. Loss of a large Load or major Load center.
3. Wide area events affecting the Transmission System based on System topology such as:
    a. Loss of two generating stations resulting from conditions such as:
        i. Loss of a large gas pipeline into a region or multiple regions that have significant gas-fired generation.
        ii. Loss of the use of a large body of water as the cooling source for generation.
        iii. Wildfires.
        iv. Severe weather, e.g., hurricanes, tornadoes, etc.
        v. A successful cyber-attack.
        vi. Shutdown of a nuclear power plant(s) and related facilities for a day or more for common causes such as problems with similarly designed plants.
    b. Other events based upon operating experience that may result in wide area disturbances.

Stability

1. With an initial condition of a single generator, Transmission circuit, single pole of a DC line, shunt device, or transformer forced out of service, apply a 3Ø fault on another single generator, Transmission circuit, single pole of a different DC line, shunt device, or transformer prior to System adjustments.
2. Local or wide area events affecting the Transmission System such as:
    a. 3Ø fault on generator with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
    b. 3Ø fault on Transmission circuit with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
    c. 3Ø fault on transformer with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
    d. 3Ø fault on bus section with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
    e. 3Ø internal breaker fault.
    f. Other events based upon operating experience, such as consideration of initiating events that experience suggests may result in wide area disturbances

Table 1 – Steady State & Stability Performance Footnotes (Planning Events and Extreme Events)
1. If the event analyzed involves elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Firm Transmission Service and Non-Consequential Load Loss. 2. Unless specified otherwise, simulate Normal Clearing of faults. Single line to ground (SLG) or three-phase (3Ø) are the fault types that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria. 3. Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV, high voltage (HV) Facilities defined as 100 kV to 300kV, and non-BES Facilities defined as less than 100 kV. The designation of EHV, HV, and non-BES is used to distinguish between stated performance criteria allowances for interruption of Firm Transmission Service and Non-Consequential Load Loss. 4. Curtailment of Conditional Firm Transmission Service is allowed when the conditions and/or events being studied formed the basis for the Conditional Firm Transmission Service. 5. For non-generator step up transformer outage events, the reference voltage, as used in footnote 1, applies to the low-side winding (excluding tertiary windings). For generator and Generator Step Up transformer outage events, the reference voltage applies to the primary connected voltage (high-side of the Generator Step Up transformer). Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers. 6. Requirements which are applicable to shunt devices also apply to FACTS devices that are connected to ground. 7. Opening one end of a line section without a fault on a normally networked Transmission circuit such that the line is possibly serving Load radial from a single source point. 8. An internal breaker fault means a breaker failing internally, thus creating a System fault which must be cleared by protection on both sides of the breaker. 9. An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Firm Transmission Service following Contingency events. Curtailment of Firm Transmission Service is allowed both as a System adjustment (as identified in the column entitled 'Initial Condition') and a corrective action when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in any Non-Consequential Load Loss. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources should be considered. 10. A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) or an independent pole tripping (IPT) breaker, only one pole is assumed to remain closed. A stuck breaker results in Delayed Fault Clearing. 11. Excludes circuits that share a common structure (Planning event P7, Extreme event steady state 2a) or common Right-of-Way (Extreme event, steady state 2b) for 1 mile or less. 12. An objective of the planning process is to minimize the likelihood and magnitude of Non-Consequential Load Loss following planning events. In limited circumstances, Non-Consequential Load Loss may be needed throughout the planning horizon to ensure that performance requirements are met. However, when Non-Consequential Load Loss is utilized under footnote 12 within the Near-Term Transmission Planning Horizon to address performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss meets the conditions shown in Attachment 1. In no case can the planned Non-Consequential Load Loss under footnote 12 exceed 75 MW. 13. Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32, & 67), and tripping (#86, & 94).

Table 1 – Steady State & Stability Performance Footnotes (Planning Events and Extreme Events)

MEC Notes:

1. Applicable rating refers to the applicable normal and emergency facility thermal rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable ratings may include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All ratings must be established consistent with applicable industry standards addressing facility ratings. MidAmerican's ratings are provided in Reference D and voltage limits in Table 2 of the Appendix.
2. Only those Planning Events and Extreme Events that are expected to produce more severe System Impacts must be identified and evaluated for system performance.
3. Cascading in steady state analysis is based, in part, upon the MISO default and is as follows:
   a. Four or more ≥ 100 kV elements trip due to excessive loading, power swings, or abnormal system voltages in planning simulations where tripping is not due to primary or backup protection to clear faults or due to the expected operation of a RAS.
   b. One or more ≥ 100 kV elements trip due to excessive loading, power swings, or abnormal system voltages where tripping is not due to primary or backup protection to clear faults or due to the expected operation of a RAS and load loss due to tripping of these elements exceeds 1,000 MW. This load loss does not include consequential load loss due to elements that trip to clear the fault, either as primary or backup protection, load loss due to expected operation of a RAS or firm load shed performed in accordance with the NERC TPL Standards.
   c. Elements are defined as transmission lines, transformers, and generators. A group consisting of all elements within a protective zone is considered a single element. For example, a three-terminal line is a single element. By itself, a shunt device is not an element.
   d. Tripping is assumed to occur at load levels of 125% or higher of the highest emergency rating unless the facility's relay load limits have been reviewed and a different value is applicable.
   e. Tripping of below 100 kV elements will be reviewed to determine if such tripping impacts ≥ 100 kV elements.
4. The minimum damping ratio (ζ) of each mode present in an electrical response must be greater than 0.03.
5. A one-cycle safety margin must be added to the actual or planned fault clearing time.
6. Includes faults on distribution transformers serving radial load that interconnect at 100 kV and above.

Table 2. 69 kV Steady-State Bus Voltage Levels

Contingency Event from Table 1	Bus Type	Minimum Voltage (p.u.)[2, 4]		Maximum Voltage (p.u.) [1, 4]
		Continuous	1 Hour Emergency	
P0	Transmission	0.950	0.950	1.050
	Generation POI [3]	1.000	1.000	1.050
P1 **P2.1**	Transmission	0.950	0.930	1.050
	Generation POI [3]	1.000	0.950	1.050
P2.2 – P2.4 **P3** **P4** **P5** **P6** **P7** **PM**	Transmission	0.930	0.900	1.050
	Generation POI [3]	0.950	0.950	1.050

1. Temporary excursions beyond the "Maximum Voltage" may be caused by abnormal system conditions; however, these shall be limited in extent, frequency, and duration.

2. After the Contingency Event, bus voltages may drop to the applicable "1 Hour Emergency Minimum Voltage" but must be restorable to the applicable "Continuous Minimum Voltage" level within one hour after the Contingency Event. System adjustments that may be used to restore voltage include adjustment of transformer load tap changers, switching of capacitor banks and/or reactors, opening of lines or transformers that do not result in the loss of demand, dispatch of quick-start generation, and redispatch of already on-line generation.

3. Generators interconnecting at 69 kV are issued a target voltage and a tolerance band for the point of interconnection (POI) bus. Generators interconnecting at 69 kV that cannot physically regulate voltage at the POI bus may be issued a power factor schedule and the applicable transmission bus voltage limits will apply at the POI bus. Generation POI bus voltages must be met at POI buses where interconnected generation is on-line and able to regulate the POI bus voltage.

4. Power flow voltage results in p.u. should be rounded to the nearest thousandths place.