

7. Transmission and Distribution

Highlights

- *Ameren Missouri will construct two of the five transmission projects that have been approved by the Midcontinent Independent System Operator (MISO) Board of Directors in Missouri for completion before 2019.*
- *New high-efficiency distribution line transformers may provide cost-effective energy savings beyond new efficiency standards.*
- *Ameren Missouri views the Smart Grid as more of a direction than a destination; this is evidenced by our continuous infusion of technology into the electric grid over the past 30 years – with plenty of work yet to be done.*

Ameren Missouri is continuously maintaining or replacing aging infrastructure in order to meet its obligation to provide safe and adequate service and to endeavor to meet its customers' reliability expectations. Rapid growth during the 1960s and 70s due to a housing boom and the advent of air conditioning resulted in a replacement of the previous vintage infrastructure and an even larger new system. As growth has slowed over time the infrastructure has not experienced optimal turnover. This lack of asset turnover means our existing grid is heavily populated with 40-60-year-old equipment that is at risk of failure, obsolete, and inefficient compared to modern equipment. Ameren Missouri has proactively begun to address this issue, and plans to make certain investments to replace its aging grid infrastructure so that it can continue to provide safe and adequate service. In doing so, Ameren Missouri will, consistent with available capital, incorporate cost-effective advanced technologies on an opportunistic basis that provide enhanced energy services and mitigate future obsolescence.¹

However, Ameren Missouri faces significant challenges in this area. Specifically, the regulatory framework that is currently in effect in Missouri discourages investment at the level needed to replace and modernize this infrastructure on an optimal timeline. Regulatory lag, which prevents electric utilities from recovering depreciation expense or return from the time a capital investment is placed in service until it can be included in rates, provides a persistent disincentive for electric utilities to invest at any level above that which is required to provide the safe and adequate service the law requires that it provide to its customers. To solve this problem, a solution must be found that removes the current disincentives that discourage Missouri's electric utilities from making beneficial investments in the electric grid.

¹ EO-2017-0073 1.N

Finding such a solution is important because as customer expectations continue to increase and as technological advances afford customers more service options, the role of the electric grid as the foundation for electric service is becoming increasingly important. As noted above, Ameren Missouri's transmission and distribution lines, substations and transformers that connect customers to generation sources and that allow transactions in the electric markets, including the MISO and bilateral markets are reaching the end of their lives, must be replaced and upgraded as needed to facilitate more reliable, multi-directional power flows enabled by greater adoption of distributed energy resources and battery storage in the future. To meet these increasing expectations, electric transmission and distribution facilities would need to be modernized to incorporate smart grid technologies which will enable more efficient operation of the distribution grid and more rapid recovery from outages. In addition, electric facilities will need to be modified as necessary to take advantage of service options that technological advances are providing to customers every day. In short, to meet increasing customer expectation and to capitalize on technological advances that present opportunities to enhance service, the electric grid will need to be adapted. That adaptation will require significant capital that, today, electric utilities are discouraged to invest. Examples of the Ameren Missouri's significant capital needs include the fact that approximately half of Ameren Missouri's substations are over 40 years old and nearing the end of their lives, and the fact that Ameren Missouri's underground network in downtown St. Louis relies on some facilities which are up to 100 years old.²

Ameren Missouri has evaluated a range of transmission and distribution options as part of an End-to-End Efficiency Study performed with the assistance of Electric Power Research Institute (EPRI). The study helped identify some promising opportunities including reactive power optimization and high-efficiency transformers. Many of the conclusions from the EPRI study were based on generic data and therefore need further analysis.

A total of five transmission projects have been approved by the MISO Board of Directors for construction in Missouri for completion before 2019. Ameren Missouri will construct two of these projects. The projects will address future reliability issues and provide for continued safe and reliable service to customers.

² EO-2017-0073 1.M

7.1 Transmission

7.1.1 Existing System³

Ameren Missouri owns and operates a 2,970 mile transmission system that operates at voltages from 345 kV to 138 kV. The system is composed of the following equipment:

- 1,297 miles of 138 kV transmission circuits
- 718 miles of 161 kV transmission circuits
- 955 miles of 345 kV transmission circuits
- 18 extra high voltage substations with a maximum voltage of 345 kV
- 38 substations with a maximum voltage of 161 kV
- 62 substations with a maximum voltage of 138 kV⁴

7.1.2 Regional Transmission Organization Planning⁵

Ameren Missouri contracts with Ameren Services to provide transmission services including operations, planning, engineering, construction, and administrative services.

Since 2004, Ameren Missouri has been a member of the Midcontinent Independent System Operator (prior to April 26, 2013 it was called the Midwest Independent Transmission System Operator), or MISO, a Regional Transmission Organization (RTO). MISO was approved as the nation's first RTO in 2001 and is an independent nonprofit organization that supports the delivery of wholesale electricity and operates energy and capacity markets in 15 U.S. states and the Canadian province of Manitoba.

A key responsibility of the MISO is the development of the annual MISO Transmission Expansion Plan (MTEP). Ameren Missouri is an active participant in the MISO MTEP development process. Participation in the MISO MTEP process is the method by which Ameren Missouri's transmission plan is incorporated into the annual MTEP document. The overall planning process can be described as a combination of "Bottom-Up" projects identified in the individual MISO Transmission Owners transmission plans which address issues more local in nature and are driven by the need to safely and reliably provide service to customers, and projects identified during MISO's "Top-Down" studies, which address issues more regional in nature and provide economic benefits or address public policy mandates or goals.⁶

³ 4 CSR 240-22.045(1)

⁴ All substation numbers are based on 2016 FERC Form 1 data.

⁵ 4 CSR 240-22.045(3)

⁶ 4 CSR 240-22.045(3)(B)1

Through these MTEP related activities, Ameren Missouri works with MISO, adjacent RTOs and Transmission Planning Regions, adjacent MISO Transmission Owners and stakeholders to promote a robust and beneficial transmission system throughout the Midwest region. Ameren Missouri's participation helps ensure that opportunities for system expansion that would provide benefits to Ameren Missouri customers are thoroughly examined. This combination of Bottom-Up and Top-Down planning helps insure all issues are addressed in an effective and efficient manner.⁷

Guidance is provided to MISO on the assumptions, inputs, and system models that are used to perform the various analyses of the overall MISO transmission system. Ameren Missouri's participation in the MTEP development process includes: review of MISO and stakeholder developed material, comments and feedback, and working to insure the projects approved in the MTEP are in the interests of the Ameren Missouri customers. Ameren Missouri is regularly represented by attendance and participation in the MISO stakeholder organizations which are key components of the MTEP development process including the:

- Planning Advisory Committee (PAC) – The PAC provides input to the MISO planning staff related to the process, adequacy, integrity and fairness of the MISO wide transmission expansion plan.
- Planning Subcommittee (PSC) – The PSC provides advice, guidance, and recommendations to MISO staff with the goal of enabling MISO to efficiently and timely execute its planning responsibilities, as set forth in the MISO Tariff, MISO/Transmission Owner Agreement, FERC Orders applicable to planning and other applicable documents.
- Interconnection Process Task Force (IPTF) – The IPTF has the goal of reducing study time and increasing certainty associated with new requests to connect to the transmission grid within MISO
- Sub-regional Planning Meetings (SPM) – The SPMs are hosted by MISO in accordance with FERC Order 890, to encourage an open and transparent planning process. Stakeholders are encouraged to participate in discussions of planning issues and proposals on a more local basis and discuss projects, issues and concepts that are potentially driving the need for new transmission expansions.
- Loss Of Load Expectation Working Group (LOLEWG) – The LOLEWG works with MISO staff to perform Loss of Load Expectation (LOLE) analysis that calculates the congestion free Planning Reserve Margin (PRM) requirements as defined in the Module E-1 of the Tariff.

⁷ 4 CSR 240-22.045(3)(B)1; 4 CSR 240-22.045(3)(B)2; 4 CSR 240-22.045(3)(B)3

- Regional Expansion Criteria and Benefits Working Group (RECBWG) – The RECBWG is a forum for stakeholders to provide input in the various processes used in the MISO tariff to allocate the cost of transmission system upgrades and improvements to the appropriate beneficiaries.
- Interregional Meetings – Numerous meetings are held each year with PJM RTO, SPP RTO and the SERTP Planning Region to discuss, evaluate and consider interregional transmission issues and identify opportunities for transmission expansion, consistent with the respective RTO’s regional planning processes.
- Other Committees, Task Forces and Working Groups as appropriate.

The result of the MTEP process is a compilation of transmission projects that are needed to address system reliability requirements, improve market efficiency, and/or provide specific system benefits as delineated in the MISO Tariff. The MTEP identifies solutions to meet regional transmission needs and to create value opportunities through the implementation of a comprehensive planning approach.

Each MTEP document is identified by the year in which it was completed. Appendix A of each MTEP lists and briefly describes the transmission projects that have been evaluated, determined to be needed and subsequently approved by the MISO Board of Directors (BOD). The MTEP15 document is the culmination of more than 18 months of collaboration between MISO planning staff, MISO Transmission Owners, and stakeholders. Each MTEP cycle focuses upon identifying system issues and improvement opportunities, developing alternatives for consideration, evaluating those options to determine the most effective solutions and finally identifying the preferred solution. As described in more detail in the MISO Tariff, the primary purposes of the MTEP process are to identify transmission projects that:

- Ensure the transmission system supports the customer’s needs in a continued safe and reliable manner.
- Provide economic benefits such as increased market efficiency and resultant overall lower energy cost.
- Facilitate public policy objectives such as integrating renewable energy resources.
- Address other issues or goals identified through the stakeholder process.

The interconnection of new generation resources to the transmission system under MISO’s control is also an important part of the overall transmission planning effort. Ameren Missouri actively participates in regional generation interconnection studies for proposed generation interconnections inside and outside of the Ameren Missouri area. Participation in these transmission studies ensures that they are performed on a consistent basis and that the proposed connections and any system upgrades needed

on the Ameren Missouri transmission system are properly integrated and scheduled to maintain system reliability.

With the approval of MTEP15, a total of five transmission projects have been approved by the MISO Board of Directors for construction in Missouri before 2019. A summary of the projects is shown in the table below. Table 7.1 also includes the proportion of transmission service charges arising from the projects that Ameren MO Load is expected to pay.⁸ The costs of these projects are not impacted by whether the project is constructed by Ameren Missouri or an affiliate.

Table 7.1 MTEP Transmission Projects in Missouri - Summary

Transmission Projects with a Portion in Missouri in MTEP15 or Prior MTEPs in Service in Late 2016 or Not Yet in Service			
Project Type	Number of Projects	Estimated Total Project Cost (\$Million)	Estimated Percentage of Transmission Service Charges Arising From the Projects to be Paid by Ameren Missouri Load
Baseline Reliability or Reliability/Other Projects Not Cost Shared	2	34	100%
MVPs 7, 8, & 9	3	1050.6	Approximately 8.7%

A brief description of the five transmission projects can be found in Appendix A.⁹

A key component of fulfilling Ameren Missouri's obligation of continuing to provide safe and adequate service is the identification of potential future needed transmission upgrades. A list of projects that are under consideration by Ameren and MISO and that are located totally or partially in Missouri is provided in Appendix A in Table 7A.2.

Current and previous transmission system expansion plans can be found on MISO's website:

<https://www.misoenergy.org/Planning/TransmissionExpansionPlanning/Pages/TransmissionExpansionPlanning.aspx>¹⁰

⁸ 4 CSR 240-22.045(3)(A)4

⁹ 4 CSR 240-22.045(6)

¹⁰ 4 CSR 240-22.045(3)(C)

Revenue Credits from Previously Constructed Regional Transmission Upgrades¹¹

Regional transmission upgrades, such as Multi-Value Projects (MVP) and Market Efficiency Projects, are eligible for cost sharing under Attachment GG or MM of the MISO Tariff. Ameren Missouri does not have any Multi-Value or Market Efficiency projects which result in revenue credits. However, Ameren Missouri does have four Baseline Reliability Projects that were approved for regional cost sharing under a prior version of Attachment GG. The fourth project completed in 2016 (Lutesville-Northwest Cape) was included in Schedule 26 rates in June 2017. Ameren Missouri expects approximately \$12.8 million of Schedule 26 revenue in 2017 increasing to \$16.2 million in 2018 when Lutesville-Northwest Cape will be in rates for all 12 months. It should be noted that over 90% of Ameren Missouri's Attachment GG revenue requirement will be allocated to the AMMO pricing zone. Therefore, when Ameren Missouri Schedule 26 revenues increase in 2017 and 2018, there will be a corresponding increase in Schedule 26 charges that Ameren Missouri must pay.

7.1.3 Ameren Missouri Transmission Planning¹²

Ameren Missouri's transmission strategy is centered upon meeting the evolving needs of its customers and Ameren Missouri's commitment to provide them safe and adequate service and to endeavor to meet their increasing reliability expectations. Each year the Ameren Missouri transmission system is thoroughly examined and studied to verify it will continue to provide Missouri customers with reliable and adequate service through compliance with all applicable North American Electric Reliability Corporation (NERC) standards as well as Ameren's Transmission Planning Criteria and Guidelines.

The studies identify potential system conditions where reduced reliability may occur in the future. Additional studies are then performed to evaluate all practical alternatives to determine what, where and when system upgrades are required to address the future reliability concern. This annual review identifies any transmission system reinforcements necessary to provide reliable and safe service in response to changing system conditions. These studies consider the effects of overall system load growth, the adequacy of the supply to new and existing substations to meet local load, the expected power flows on the bulk electric system (BES) and the resulting impacts on the reliability of the Ameren Missouri transmission system.

In order to successfully achieve the goal of a safe and reliable transmission system, Ameren Missouri participates in a multitude of transmission planning activities including:

- MISO Transmission Expansion Plan (MTEP) development

¹¹ 4 CSR 240-22.045(3)(A)5

¹² 4 CSR 240-22.045(3)(B)1; 4 CSR 240-22.045(3)(B)2; 4 CSR 240-22.045(3)(B)3; 4 CSR 240-22.045(3)(B)4

- MISO regional generation interconnection studies
- NERC reliability standards development,
- Participation in SERC regional planning and assessment activities,

This high level of involvement affords the opportunity to supply comments and provide input to these many transmission planning processes which supports the goal of maintaining a reliable and safe transmission system which will meet the current and future needs of our Missouri customers.

As part of the Ameren Missouri Transmission Planning Process the ability of transmission system improvements to reduce transmission system losses is considered. A major aspect of Ameren Missouri's focus of providing continued safe and adequate service to our customers and to meet their reliability expectations is maintaining transmission equipment and replacing aging infrastructure when it approaches the end of its operational life. The Ameren Missouri area experienced rapid economic growth and substantial investment in transmission infrastructure during the 1960s and 70s. Considerable portions of the transmission system are now over forty years old and are reaching the end of their operational life with a commensurate increased risk of failure and higher maintenance expense. The existing equipment is also less efficient than comparable modern equipment. Ameren Missouri is working to address the most critical issues by making targeted investments to replace its aging grid infrastructure to maintain system reliability, consistent with available capital.

7.1.4 Avoided Transmission Cost Calculation Methodology¹³

The methodology that was used during the development of the previous Integrated Resource Plan was again used in the 2017 Plan. Avoided transmission costs are based upon integrated system effects and are difficult to quantify, as opposed to energy and capacity costs where there are markets that provide specific prices. As part of integration modeling, Ameren Missouri estimated the MW impacts of DSM programs and a corresponding reduction in transmission capital expenditures.

The first step is to identify the transmission projects that are related to serving customer load and their associated cost. An estimated generic marginal cost of system transmission capacity is then calculated and adjusted by applying the following factors:

- Usage Growth-Related Factor - This factor captures the effect that some of the transmission projects cannot be deferred by DSM because they are not driven by usage growth but rather by load relocating to different areas with Ameren Missouri. This causes a local load increase but not a net system load increase.

¹³ 4 CSR 240-22.045(2); 4 CSR 240-22.045(3)(A)3

- Location-specific Factor/Deferrable Factor - This factor accounts for the fact that Ameren analyzes the transmission system in aggregate and it is not possible to determine with certainty which load increase will be deferred by DSM programs. DSM programs are not being designed to avoid or offset specific transmission projects; therefore it is not possible to identify the specific transmission projects which would be deferred.
- Condition/Reliability Replacement Factor - This factor approximates the effect that projects constructed to serve increased load will result in turnover of transmission assets. If Ameren Missouri does not upgrade or replace transmission equipment because of DSM, then Ameren Missouri will be required to spend additional funds on maintenance or reliability projects that would have been avoided if the older equipment had been replaced with new equipment as part of the project that was deferred. For example, choosing 70% for this factor says that for every \$1 saved from DSM, \$0.30 is needed to support the equipment that would have been replaced with new equipment.

The results of the analysis are provided in Chapter 7 - Appendix A.

7.1.5 Transmission Impacts of Potential Ameren Missouri Generation Resource Additions/Retirements & Power Purchases/Sales¹⁴

As part of the determination of the proper combination of resources needed to serve the Ameren Missouri load, the size and location of potential future generation resources are estimated. Transmission's role in this process is to assess the transmission system enhancements necessary to safely and reliably deliver the energy from these potential future resources.

Table 7.2 provides a high level assessment of interconnection costs for the listed potential future generation resources. These estimates may be impacted by other new resources connecting to the grid, revisions to resource timing, new transmission projects and other factors.

¹⁴ 4 CSR 240-22.040(3); 4 CSR 240-22.040(3)(A); 4 CSR 240-22.045(1)(B); 4 CSR 240-22.045(1)(C); 4 CSR 240-22.045(3)(D); EO-2017-0073 1.D

Table 7.2 Transmission Project Costs for New Generation **

Resource	Cost of Needed Transmission Upgrades (2016\$)	Approximate Cost to Ameren Missouri Customers (2016\$)
Combined Cycle - Lutesville	600 MW	\$2.63 Million
Simple Cycle - Lutesville	700 MW	\$2.63 Million
Pumped Hydro - Church Mountain	600 MW	\$107.31 Million
Nuclear - Callaway	1100 MW	\$661.88 Million

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As part of the determination of the proper combination of resources needed to serve the Ameren Missouri load, the need for continued operation of existing resources is examined. Transmission's role in this process is to determine the overall impact of retiring existing generation resources on the transmission system and identify any system upgrades necessary to maintain safe and adequate service after the resource is no longer available. Table 7.3 contains the results of a high level assessment of the cost to Ameren Missouri customers of transmission system upgrades needed to provide continued safe and adequate service if the indicated Ameren Missouri generators retire within the planning period. These estimates may be impacted by new resources connecting to the grid, revision of the shutdown timeframe, new transmission projects and other factors.

Table 7.3 Estimated Transmission Project Costs for Retirements at End of Useful Life **

Generating Station	Cost of Needed Transmission Upgrades (2016\$)
Meramec	\$77 Million
Rush Island	\$97 Million
Sioux	\$341 Million
Labadie 1&2	\$97 Million
Labadie 3&4	\$94 Million

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Note: Changing the timing of retirements could alter the allocation of the above costs.

The Ameren Missouri transmission system was also examined to determine if additional transmission system upgrades would be justified to facilitate power purchases and sales by Ameren Missouri. The analysis indicates an Ameren Missouri import or export capability of 1200 MW, which exceeds the 300 MW import or export minimum requirements. For IRP analysis purposes, Ameren Missouri has used a limit of 300 MW as the maximum allowed shortfall of resources to load and reserve requirements.

Because resources would be added to prevent a shortfall greater than 300 MW this represents the minimum import capability requirement to ensure reliable operation of the system. The transmission system analysis indicates no additional transmission system upgrades are justified based upon this requirement.¹⁵

Transmission Impacts due to New Generation Resource Connections within the MISO Footprint or Point-to-Point Transfers of Energy within the MISO Footprint to Ameren Missouri

Ameren Missouri participates in regional generation interconnection studies for proposed generation interconnections inside the MISO footprint. Participation in these activities ensures that the studies are performed on a consistent basis and that the proposed connections are integrated into the Ameren Missouri system to maintain system reliability. Power flow, short-circuit, and stability analyses are performed to evaluate the system impacts of the requested interconnections. If system deficiencies are identified in the connection and system impact studies, additional studies are performed to refine the limitations and develop alternative solutions.

New Generation Resources - Future generation resources within the MISO footprint seeking to connect to the transmission system will be subject to the interconnection requirements described in the MISO Tariff and applicable MISO Business Practice Manuals. In order to interconnect to the transmission system, the resource owner must provide project details including location, resource size, type of service requested, when it wants to connect, etc. After this information has been received, the impacted Transmission Owner and MISO will perform the system study and analysis necessary to determine the transmission upgrades needed to safely and reliably interconnect the generation resource to the transmission system.

Point to Point Transactions - The MISO Tariff and applicable MISO Business Practice Manuals describe the process by which transmission service requests can be made to have firm point-to-point transmission service within the MISO footprint. The entity requesting service would provide details including: source and delivery locations, quantity of energy to be transmitted, timing and duration of delivery, etc. After this information has been received, the impacted Transmission Owner(s) and MISO will perform the system study and analysis necessary to determine the transmission upgrades needed to safely and reliably support the requested transmission service. The transmission upgrades needed to support a transmission service request will not be determined until the completion of the system study and analysis. The MISO Tariff and MISO Business Practice Manuals that are in effect at the time when the point-to-point

¹⁵ 4 CSR 240-22.040(3)(B)

transmission service request is submitted will describe the process by which Financial Transmission Rights (FTRs) are allocated and can be obtained by entities.

The total cost of any necessary transmission upgrades cannot be determined until a resource interconnection request and/or a transmission service request has been submitted to MISO via the process described in the MISO Tariff and applicable Business Practice Manuals and the necessary transmission system studies have been performed. The result of the studies will identify the transmission system upgrades necessary to safely and reliably fulfill the transmission service request or generation interconnection request. The studies will include a description of the needed transmission system reinforcements, their location, in service date and estimated total cost. Therefore the cost of any needed system upgrades will not be known until the system study and analysis is complete.

Transmission Impacts due to New Generation Resources outside the MISO Footprint Connecting to the MISO Transmission System or Point-to-Point Transfers of Energy from Outside the MISO Footprint to Ameren Missouri

Ameren Missouri participates in generation interconnection studies for proposed generation interconnections from generators located outside of the MISO footprint. Participation in these activities ensures that the studies are performed on a consistent basis and that the proposed connections are integrated into the Ameren Missouri system to maintain system reliability. Power flow, short-circuit, and stability analyses are performed to evaluate the system impacts of the requested interconnections. If system deficiencies are identified in the connection and system impact studies, additional studies are performed to refine the limitations and develop alternative solutions.

New Generation Resources - Future generation resources external to the MISO footprint seeking to connect to the transmission system within the MISO footprint will be subject to the interconnection requirements described in the MISO Tariff and applicable MISO Business Practice Manuals. In order to interconnect to the transmission system, the resource owner must provide project details including location, resource size, type of service requested, when it wants to connect, etc. After this information has been received, the impacted Transmission Owner and MISO will perform the system study and analysis necessary to determine the transmission upgrades needed to safely and reliably interconnect the generation resource to the transmission system. The transmission upgrades needed to physically interconnect a generator source within the RTO footprint will not be determined until the completion of the system study and analysis.

Point to Point Transactions - The MISO Tariff and applicable MISO Business Practice Manuals describe the process by which transmission service requests can be made to have firm point-to-point transmission service into the MISO footprint from a generation resource located outside the MISO footprint. The entity requesting service would provide details including: source and delivery locations, quantity of energy to be transmitted, timing and duration of delivery, etc. After this information has been received, the impacted TO(s) and MISO will perform the system study and analysis necessary to determine the transmission upgrades needed to safely and reliably support the requested transmission service. The transmission upgrades needed to support a transmission service request will not be determined until the completion of the system study and analysis. The MISO Tariff and MISO Business Practice Manuals that are in effect at the time when the point-to-point transmission service request is submitted will describe the process by which Financial Transmission Rights (FTRs) are allocated and can be obtained by entities.

The total cost of any necessary transmission upgrades cannot be determined until a resource interconnection request and/or a transmission service request has been submitted to MISO via the process described in the MISO Tariff and applicable Business Practice Manuals and the necessary transmission system studies have been performed. The results of the studies will identify the transmission system upgrades necessary to safely and reliably fulfill the transmission service request or generation interconnection request. The studies will include a description of the needed transmission system reinforcements, their location, in service date and estimated total cost. Therefore the cost of any needed system upgrades will not be known until the system study and analysis is complete.

7.1.6 Cost Allocation Assumptions for Modeling¹⁶

The MISO Tariff allocates 100% of the BRP revenue requirements to the local zone where the project is located. The MVP revenue requirements are collected under MISO Tariff Schedule 26-A, which is charged to Monthly Net Actual Energy Withdrawals, Export Schedules, and Through Schedules. MISO estimated charges include the MVPs approved in December 2011 by the MISO Board of Directors. No additional MVPs are currently being planned as part of the MISO MTEP process. Overall, Ameren Missouri expects approximately 8.7% of the MVP costs to be assigned to its customers.

¹⁶ 4 CSR 240-22.045(3)(A)4

7.1.7 Advanced Transmission System Technologies¹⁷

Ameren Missouri views the concept of Smart Grid as an ongoing process rather than a final condition. There has been a steady growth in the development of new advanced transmission system technologies that surpass the capabilities of currently installed equipment. Ameren Missouri's vision is to use advanced technologies as tools in the ongoing pursuit of service reliability, operating efficiency, asset optimization, and a secure energy delivery infrastructure consistent with available capital. Ameren Missouri's current focus on advanced transmission system technologies is driven by the benefits associated with these technologies.

Advanced technologies are examined and considered for implementation in association with the MISO and as part of the MTEP development process and the Ameren Missouri transmission planning and operating activities. Three of the major advanced transmission technologies that have been implemented are briefly described below:

- Synchrophasor (Phasor Measurement Unit - PMU) technology deployment
Ameren Missouri has completed a project with MISO under a DOE grant to increase the number of PMU installations in the Ameren Missouri system. Under the DOE grants, Ameren Missouri installed these high speed time-synchronized monitoring devices at Labadie, Meramec, and Sioux Power Plants, and Montgomery, Kelso, Loose Creek, and Overton transmission substations. These devices capture high-resolution voltage, current, and frequency data and send the information to a central data gathering facility that is maintained by MISO. Combined PMU measurements will provide a precise, comprehensive view of the entire interconnection and enable advanced monitoring and analysis to identify changes in grid conditions, including the amount and nature of stress on the system. PMU data will feed applications that allow grid operators to understand real-time grid conditions; see early evidence of changing conditions and emerging grid problems; and better diagnose, implement and evaluate remedial actions to protect system reliability. Ameren's recently upgraded Energy Management System (EMS) has the capability to integrate PMU data with conventional Remote Terminal Unit (RTU) Supervisory Control and Data Acquisition (SCADA) data for more robust display and analysis. The EMS State Estimator is currently utilizing the data for operational analysis and displays are currently being built to provide PMU data visually to the Transmission Operators. This information is also vital for the development and eventual implementation of

¹⁷ 4 CSR 240-22.045(3)(A)2; 4 CSR 240-22.045(3)(A)4; 4 CSR 240-22.045(3)(B);
4 CSR 240-22.045(1)(D); 4 CSR 240-22.045(4)(A); 4 CSR 240-22.045(4)(C); 4 CSR 240-22.045(4)(D);
4 CSR 240-22.045(4)(E)1; 4 CSR 240-22.070(1)(B)

predictive software systems to identify potential areas of system weakness before an incident actually occurs.

- Installation of Fiber Optic Ground Wires (OPGW) on all new or rebuilt transmission circuits.

On transmission line projects, Ameren Missouri is installing OPGW in place of standard steel or aluminum ground wire. OPGW combines the functions of providing a protective ground and a high speed communications path. A typical OPGW cable consists of a tubular structure with one or more optical fibers in it which is then surrounded by layers of steel or aluminum wire. The OPGW cable is installed between the tops of transmission line structures where the steel or aluminum wire connects the adjacent towers to earth ground and shields the transmission line conductors from lightning strikes. The optical fiber communications path has several advantages over traditional metal wire technology including immunity from outside electrical interference (caused by power transmission lines or lightning) and cross-talk from communications on parallel circuits. These advantages make OPGW an ideal choice for Ameren Missouri to use to provide a high-speed voice and data communications path for modern digital protective relay systems, which improve generator and transient system stability. Ameren Missouri also specifies additional optical fibers be included within the cable for future use by new advanced technologies. The OPGW installation will replace the telephone company's legacy 4-wire copper communication systems, which are being phased out by the telecommunication companies and are expected to be retired in 2021.

- Purchase and installation of high efficiency EHV transformers¹⁸

Ameren Missouri routinely specifies EHV transformers with a higher efficiency than the transformers most commonly purchased by other utilities throughout the US. Ameren Missouri's transformer specifications require the purchase of EHV transformers with very high no-load loss efficiency. As documented in the 2014 ABB report provided in Appendix B, the EHV transformers that Ameren Missouri would purchase in the future will be significantly more efficient than those that other utilities typically purchase. Ameren Missouri's EHV transformer overvoltage operating requirements and monetary loss evaluation value drive a very high no-load loss efficiency. The economic factors that drive the monetary load-loss evaluation value would have to more than triple before a 5% improvement in load-losses would be achieved. As indicated in the report, a 20% increase in purchase price would only gain a 0.0484% increase in

¹⁸ 4 CSR 240-22.045(1)(A)

efficiency. Ameren has continued discussions with suppliers to review the potential of purchasing transformers with even lower losses, but transformer costs have not changed significantly since 2014, and there have not been any developments in material or design that would change the evaluation.

In a past study conducted in collaboration with EPRI, Ameren Missouri identified eight types of transmission efficiency or loss reduction measures: 1) Reconductoring / Bundling Phase Conductor, 2) Shield Wire Segmentation, 3) Voltage Upgrade of AC lines, 4) Coordinated Voltage Control, 5) Energy-Efficient Transformer, 6) Power Flow Control, 7) Insulation Losses, and 8) Conversion from AC to DC

Two of these measures passed the qualitative screening: Reconductoring / Bundling Phase Conductor, and Shield Wire Segmentation. Ameren Missouri considers each application as part of the normal planning and engineering process for new or rebuilt lines.¹⁹

7.1.8 Ameren Missouri Affiliates Relationship²⁰

Ameren Missouri's focus is upon continuing to provide safe and adequate service to its customers. Ameren Missouri has prioritized its capital investments to address local issues including: improvements to its aging distribution and transmission infrastructure and energy centers, accomplish mandated environmental investments, implement mandated transmission upgrades (e.g., for NERC compliance), and to comply with other state and federal mandates (such as the Missouri RES). These kinds of investments must be made to deliver safe and adequate service to Ameren Missouri's customers.

In MTEP11, the MISO approved a portfolio of 17 MVPs, which stretch across the Midwest portion of the MISO footprint. This set of MVPs are premised on the integration of local and regional needs into a transmission solution that, when combined with the existing transmission system, provides the least cost delivered energy to customers. Specific projects were included in the portfolio based upon their benefits to the regional transmission system.

A section of this MVP portfolio will traverse a portion of the Ameren Missouri territory. These transmission projects are identified in MTEP11 as MVPs 7, 8 and 9.

An Ameren Missouri affiliate, Ameren Transmission Company of Illinois (ATXI), has received a Certificate of Convenience and Necessity (CCN) to build a portion of one MVP project in Missouri and had received a CCN for the rest of that MVP and a portion of another one, subject to satisfaction of certain conditions relating to county assents. As the result of a Missouri Court of Appeals decision concluding that the earlier CCN

¹⁹ 4 CSR 240-22.045(1)(A)

²⁰ 4 CSR 240-22.045(3)(B)5; 4 CSR 240-22.045(5)

was invalid because it was issued before county assents were obtained, the CCN for the second project was vacated. ATXI has now obtained all required county assents and has a new application for a CCN pending before the Commission. Ameren Missouri does not plan to construct these kinds of regional projects because it is in the best interests of its Missouri customers that it invests its limited capital only in generation, distribution and transmission investments needed to provide safe and adequate service to its load including the transmission improvements needed to connect an Ameren Missouri generating unit to the grid. Because of its limited capital, Ameren Missouri has concluded that it should not invest in other transmission projects, such as MVPs because investing in regional transmission would undermine Ameren Missouri's ability to deliver safe and adequate service. The building of the MVPs by ATXI will not impact the cost of the project relative to construction by Ameren Missouri.

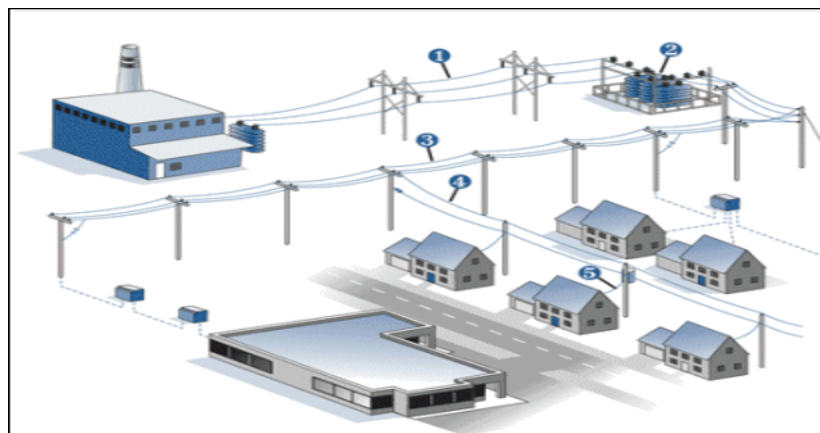
7.2 Distribution

7.2.1 Existing System²¹

Ameren Missouri delivers electricity to approximately 1.2 million customers across central and eastern Missouri, including the greater St. Louis area, through distribution system power lines that operate at voltage levels ranging from 2,400 volts (V) through 69,000 V. Ameren Missouri has 33,000 circuit miles of electric distribution lines, which move electricity into the 63 counties and more than 500 communities where businesses operate and people live.

Approximately 70% of Ameren Missouri's distribution system operates at 12,470 V, 12% operates at 4,160 V and 11% operates at 34,500 V. The remainder operates at other nominal voltage levels. (See Figure 7.1 for further information.)

Figure 7.1 Power Flow



²¹ 4 CSR 240-22.045(1)

Here's how the power flows from a power plant to an electric customer:

- 1 Electricity travels from the power plant over high-voltage transmission lines.
- 2 At a substation, the electricity's voltage is lowered so that it can travel over the distribution system.
- 3 Main distribution power lines, typically 3-phase circuits, bring electricity into communities.
- 4 Local distribution power lines serve neighborhoods and individual customers.
- 5 Service drops carry electricity from pole-mounted or pad-mounted transformers - which lowers the voltage again - to customer premises.

Much of the distribution system in rural areas is supplied via single substations operating in radial configurations. Long distribution feeders are usually required to serve multiple isolated communities. Long feeders are usually equipped with automatic reclosers to interrupt fault currents and isolate damaged sections, thereby restoring service to upstream portions of the feeder. Where possible, normally open tie switches are installed in downstream sections of feeders to provide emergency service from another source during upstream forced outages. The company installs capacitors and/or voltage regulators, as necessary, to counteract voltage drop and maintain proper voltage levels along lengthy circuits.

A more interconnected distribution system is justified to serve densely populated urban areas. Although substations operate in radial configurations, two or more supply circuits are normally available on the primary side of substation transformers. Each customer is served by a single power source at any given time, but the company can re-configure the interconnected system to maintain service to customers via alternate sources when portions of the system must be de-energized to perform maintenance or complete repairs. Although voltage levels tend to be less of an issue in closely coupled, interconnected systems, the company does employ capacitors to maintain power factor within prescribed limits.

Finally, a portion of the distribution system is networked, which means customers are continuously connected to more than one source. Examples include the 208Y/120 V underground distribution network in downtown St. Louis and the 69 kV network that supplies communities throughout central Missouri, including Jefferson City, Kirksville, Moberly and Montgomery City. Networked systems offer the advantage of supplying customers from more than one source, so they are not as susceptible to a total loss of power; but, since the system is networked, disturbances in the distribution system tend to affect a larger number of customers. Automatic isolation of faulted equipment and control of power flow in networked systems are more difficult than in radial systems.

For these and other reasons, the company employs networked systems on a limited basis in Missouri.

Ameren Missouri's distribution system includes both overhead and underground power lines at the low and medium voltage distribution levels. Underground lines (22% of the total) are more aesthetically pleasing and less vulnerable to weather-caused damage, but they take longer to repair upon failure and are significantly more expensive to install and replace.

Ameren Missouri's distribution system adequately fulfills its fundamental objective of providing service to all customers under peak load conditions. In addition, the vast majority of the system can adequately serve peak load under single contingency conditions. Over the past three years, Ameren Missouri's System Average Interruption Frequency Index (SAIFI) has outperformed the company's target value (SAIFI is below the 2016 target value of 0.80).

7.2.2 System Inspection²²

Ameren Missouri assesses the age and condition of distribution system equipment with regular inspection, testing and equipment replacement programs, as described below.

Circuit and Device Inspections

Ameren Missouri inspects distribution circuits (4,160 V to 69,000 V) at least every four years in urban areas and six years in rural areas, in compliance with Missouri PSC Rule 4 CSR 240-23.020, to protect public and worker safety and to proactively address problems that could diminish system reliability. The program includes follow-up actions required to address noted deficiencies. Inspections include all overhead and underground hardware, equipment and attachments, including poles. Infrared inspections are performed on overhead facilities, underground-fed transformers and switchgear to detect any abnormalities in equipment. Wooden poles are treated every 12 years as appropriate for purposes of life extension. Inspectors may also measure impedance of the static-protected grounding system. Radio-controlled capacitors, reclosers, and sectionalizers are inspected on a 4-year or 6-year cycle in conjunction with circuit inspections. Locally controlled capacitors, voltage regulators, and sectionalizers are tested or inspected on an annual or bi-annual basis. Any inoperable capacitor cells are repaired or replaced, helping to ensure optimal power factor system-wide. Ameren Missouri also replaces a number of transformers each year with higher efficiency units when corrosion, oil leaks or other visually detectable issues occur.

²² 4 CSR 240-22.045(1)(A)

Underground Cable Replacements

Sections of single phase or three phase direct buried cable are replaced with upgraded cable in conduit (typically by direct boring) following failure. This program replaces cable at the end of its useful life, providing the benefits of improved reliability while lessening operational costs and saving customers from disruptive service interruptions.

Substation Asset Management

Ameren Missouri schedules substation maintenance to maximize reliability of equipment, and selectively performs various diagnostic tests to obtain meaningful data to predict and prevent failures. Many tests, such as infra-red scanning to detect abnormal equipment heating, can be performed with the equipment in-service. Corrective maintenance is scheduled largely on the basis of diagnostic data, with the intent of restoring equipment to full functionality. When it is no longer practical to make repairs, old equipment is replaced by new with an emphasis on system automation, efficiency and reduction of losses.

Conversion of Dusk-to-Dawn and Municipal Street Lighting

Ameren Missouri implemented a five-year plan to replace all bracket mounted HID fixtures with more efficient LED fixtures. The company continues to monitor the development of both post-top and directional LED fixtures for potential application on the Ameren Missouri system.

7.2.3 System Planning²³

Ameren Missouri assesses system capacity, efficiency and losses through seasonal distribution system planning studies.

Annual Load Analysis and System Planning Process

Ameren Missouri records summer and winter peak load conditions (power, power factor, phase balance and voltage levels) at bulk and distribution substations. Distribution loads are temperature-corrected to represent 1-in-10 year maximum values using multipliers derived from statistical analyses of historic load data for several types of area load characteristics. Temperature adjustments for bulk substations are derived from historical temperature vs. loading profile curves for each particular bulk substation.

Engineers also calculate bulk substation loads using a power flow computer model that simulates the electric power delivery system. Using temperature-corrected distribution substation loads and current equipment ratings as inputs, the software calculates bulk substation loads. These are compared to temperature-corrected values and used to evaluate what, if any, diversity factors apply at each bulk substation.

²³ 4 CSR 240-22.045(1)(A)

After verifying the validity of the system model, engineers conduct seasonal planning studies of winter and summer peak conditions, evaluating worst case single-contingency failure scenarios for all bulk substations, 34,500 V and 69,000 V circuits, distribution substations, and distribution circuits. These studies pinpoint system limitations and enable engineers to identify upgrades required to maintain adequate system capacity. The evaluation of distribution system losses and maintenance of adequate system voltage levels are included in these analyses.

Planning system upgrades to withstand single-contingency outage conditions ensures that load levels will remain within circuit capabilities for such events. Under normal conditions (the majority of the time) individual circuit elements operate at lower load levels with correspondingly lower losses.

An integral part of the entire load analysis process is the establishment of equipment ratings and/or loading limits. Ameren Missouri evaluates transformer and conductor losses as part of the methodology used to establish distribution equipment ratings.

Distribution System Engineering Analyses

The Transformer Load Management (TLM) System relates customers to the distribution transformers serving them, allowing Ameren Missouri to predict transformer peak demand and apparent power from the customers' total monthly energy usages. Ameren Missouri uses this information to analyze distribution circuits and to reduce distribution losses through the more efficient loading of transformers. Additionally, customer meters are automatically read during peak load periods to confirm the transformer peak demands calculated with the TLM system.

Synergi Electric software by Det Norske Veritas – Germanischer Lloyd (DNV GL) and PSS/E software by Siemens PTI are used to analyze distribution circuits, ensuring reliable, safe, and efficient operation of the distribution system. Synergi or PSS/E is used for: load estimation, power flow analysis, protective device coordination, fault current calculation, voltage flicker, phase balancing, and capacitor placement. Both software systems allow engineers to analyze existing, alternate, or proposed configurations for over/under voltages/currents, line losses, appropriate conductor sizing, and optimal capacitor placement.

SCADA (Supervisory Control and Data Acquisition) is used to remotely monitor and control the electric distribution system. Engineers use SCADA data to ensure that system models properly reflect real distribution system conditions, therefore enabling better planning of future system development.

Capital Project Evaluation²⁴

Ameren Missouri assesses the feasibility and cost effectiveness of potential system expansion and modernization projects on an ongoing basis, and invests in these projects consistent with available capital. Both conventional and advanced technologies are regularly considered. Due to recent trends in load growth, the majority of approved projects in recent years have focused on system reliability improvement and modernization, as opposed to capacity increase. Potential capital projects are identified by various operating, engineering and planning personnel. All bulk substation, subtransmission feeder and distribution substation projects are reviewed by Distribution System Planning prior to consideration for funding. Distribution feeder and customer service projects are reviewed by Service Division and Distribution Operations staff prior to consideration for funding.

Capital projects are considered to be mandatory if they are required by PSC or government regulations, result from court cases, are necessary to meet minimum obligations to serve, or address imminent public or employee safety concerns. Funding priorities for projects which are not mandatory are based on cost/benefit and risk assessments. Key to this evaluation is a reliability based prioritization metric called the Service Availability Cost Factor (SACF) - a calculated index that facilitates ranking projects on a common cost/benefit basis. In its simplest form, SACF represents the cost per unit risk where risk is measured as customer load in kVA multiplied by hours of outage. By giving preference to projects with the best cost/benefit ratios (lowest SACF scores), Ameren Missouri ensures that system capacity and reliability will be enhanced as fully as possible through proper prioritization of capital investments.

Cost/benefit evaluations for three common types of projects are outlined below:

1. Substation Overload

A single-unit substation serves load that peaks above the unit's normal rating. Considering the shape of the load curve, the unit serves 400,000 kVA-hrs above its rating, on an annual basis. Load served above a unit's rating is considered to be at risk of experiencing rotating service interruptions. The cost of replacing the transformer with a larger unit is estimated to be \$1M. The cost/benefit ratio for this project would be $\$1\text{M} / 400,000 \text{ kVA-hrs} = \$2.50 / \text{kVA-hr}$.

2. Redundant Supply Circuit

A single-unit substation is loaded to 12 MVA under summer peak conditions. The substation is served by an overhead circuit with an average forced outage rate of 6 hrs/yr. Ameren applies forced outage weighting factors which increase

²⁴ 4 CSR 240-22.045(4)(C); 4 CSR 240-22.045(4)(D); 4 CSR 240-22.045(4)(D)1;
4 CSR 240-22.045(4)(D)2; 4 CSR 240-22.045(4)(E); 4 CSR 240-22.045(4)(E)1

with higher load and/or longer duration. The weighting factor for this example is 2.0. Assuming an outage occurs during summer peak, a weighted total of 144,000 kVA-hrs are considered to be at risk of forced outage, due to the supply circuit. A second 34.5 kV supply can be built from an independent source for a total cost of \$1,250,000, thereby reducing outage time to that required for automated switching at the substation. The cost/benefit ratio for this project would be $\$1,250,000 / 144,000 \text{ kVA-hrs} = \$8.68 / \text{kVA-hr}$

3. Smart Grid Feeder Automation

Two independent 12.47 kV feeders serve adjacent areas. Both feeders serve peak loads of 8 MVA (distributed evenly along their lengths), with average forced outage rates of 8 hrs/yr. The forced outage weighting factor for this example is 1.5. Two (normally closed) reclosers can be installed at the mid-points of the feeders and a third (normally open) recloser can be installed as a tie between the ends of the feeders, for a total cost of \$225,000. Advanced technology reclosers will be employed and programmed to work as an automatic transfer system, such that a fault in any one section of a feeder can be isolated and service can be automatically restored to the remainder of the feeder. This project will alleviate a weighted total of 96,000 kVA-hrs at risk. The cost/benefit ratio for this project would be $\$225,000 / 96,000 \text{ kVA-hrs} = \$2.35 / \text{kVA-hr}$.

7.2.4 Peak Demand Reduction via Voltage Control²⁵

For over 20 years, Ameren Missouri has had the ability to reduce demand at selected distribution substations by reducing load tap changer (LTC) voltage setpoints at the time of peak system demand. The actual load reduction achieved in this manner depends upon the magnitude and voltage sensitivity of the affected electrical loads. Peak demand shaving through voltage reduction has been limited to short durations during emergency situations and can sometimes play a role in deferring electrical system capacity enhancement projects.

Estimating demand reduction due to voltage control begins with identifying substations with appropriate LTC equipment. Ameren Missouri has identified 260 substations capable of implementing voltage control. The magnitude of potential demand reduction has been estimated based on substation demand data gathered from July 2008 through June 2009, a test year used to support weather normalization modeling.

It is estimated that 70% of the summer distribution system peak demand, or approximately 5,400 MW, is served by substations with voltage control capability. Although higher levels of voltage reduction are possible, this study assumed voltage

²⁵ 4 CSR 240-22.045(1)(A); 4 CSR 240-22.045(1)(D)

reduction would be limited to 2.5%. Based on Ameren Missouri experience, load decreases by approximately 0.84% for every 1% reduction in voltage. Furthermore, experience indicates not all LTC equipment responds when signaled to reduce voltage. It is assumed that 90% of the equipment will respond properly. On this basis, Ameren Missouri can achieve approximately 100MW of demand reduction via voltage control at the time of system peak. However, Ameren Missouri has determined that voltage reduction should not be included in its capacity position since there are no provisions in MISO tariff for a load serving entity to include voltage reduction to modify its coincident peak demand or to register it as a demand response resource.

7.2.5 System Efficiency²⁶

Ameren Missouri regularly pursues opportunities to improve distribution system efficiency, subject to capital availability, through ongoing activities and projects, including those listed below:

Periodic System Loss Study

Ameren Missouri evaluates the efficiency of its overall electric delivery system on a periodic basis by performing a comprehensive loss study. Losses in each portion of the system are calculated under peak load conditions using the computer software noted previously. Loss data from these evaluations are used in ongoing system planning activities and as supporting information for Rate Case Filings.

System Upgrade and Expansion Projects

By their nature, many types of energy delivery upgrade and expansion projects improve system efficiency by reducing load current, I²R losses, or both. Examples of such projects include:

- Constructing new circuits or rebuilding existing circuits that make use of higher operating voltages, as in the conversion of power lines from 4 kV to 12 kV or the migration toward 138kV-fed distribution substations
- Constructing new circuits or rebuilding existing circuits with larger conductors
- Reconnecting single phase loads on three phase circuits to achieve balanced system phase currents
- Upgrading existing substations or strategically placing new substations to serve areas with increasing load density; and
- Reconfiguring distribution feeders as appropriate when connecting new customers

²⁶ 4 CSR 240-22.045(1)(A)

Reactive Power (VAR) Optimization

Customer loads consume real power (measured in watts), however AC power systems also require reactive power (measured in volt-amperes-reactive, or VARs) to deliver energy. Delivering VARs consumes distribution circuit capacity and can create undesirable levels of voltage drop. Ameren Missouri installs capacitor banks to maintain overall power factor near unity, thereby releasing as much system capacity as practical. Maintaining a power factor near unity reduces the current flows through the system that are necessary to satisfy its real power requirements. This in turn lowers line losses (I^2R losses) and reduces conductor heating, ultimately helping to prolong equipment life.

Because the amount of reactive power that customers need varies with load, a controlled but variable source of VARs enables optimal system performance. Ameren Missouri employs automatic and remotely controlled capacitor banks to stabilize system voltage as loads are cycled on and off. As recommended in the 2009 Ameren Missouri End-to-End Efficiency Study, performed with assistance from EPRI, Ameren Missouri has increased its focus on optimizing reactive power flow within the distribution system. To replace obsolete equipment and improve capacitor bank control capabilities, the company has budgeted to install a fleet of 2300 new capacitor bank controllers. This change-out will be completed in phases, with removed controllers providing spare parts for remaining obsolete equipment. Installation of new controllers began in 2011 and approximately 1450 were installed by the end of 2016. The remaining units are scheduled for installation over the next 5 – 10 years. These new controls replace aging equipment and improve system performance, power factor and distribution system efficiency.

Loss-Evaluated Distribution Transformer Purchasing

Ameren Corporation currently purchases transformers based on Total Cost of Ownership (TCO), including acquisition cost plus the evaluated cost of no-load and load losses, capitalized over a 30-year life. By purchasing high-efficiency distribution transformers that meet the US Department of Energy efficiency requirements, Ameren will gradually reduce total circuit losses in a cost-effective manner. Ameren Missouri conservatively projects an annual demand savings of 0.11 MW and an annual energy savings of 817 MWh's from replacing ~8,500 transformers, yearly.

Ameren evaluates the option to purchase high-efficiency, amorphous core transformers as they become available in volumes required. Although amorphous core transformers presently carry an additional purchase premium, the corresponding reduction of no-load losses can lead to a favorable TCO and an improvement in system efficiency to the long-term advantage of rate payers.

7.2.6 Distributed Generation

Ameren Missouri does have an interest in distributed generation (DG) as a means of deferring distribution system expansion projects. One example is the Ameren owned and operated Maryland Heights Energy Center, a landfill gas project in St. Louis County. This project includes 3 x 5 MW combustion turbine-generator sets, operating on landfill gas. The project feeds into the local 34.5 kV distribution system and is capable of producing maximum output of 15 MW.

Potential projects are analyzed on a case-by-case basis; however, the scope of candidates tends to be small. At this time, Ameren Missouri is evaluating the potential installation of photovoltaic generating capacity at a number of locations. Factors that influence the evaluation of potential DG installations include noise and/or emissions ordinances, operational complexities associated with fuel availability, equipment maintenance, and the fact that traditional system expansion projects usually provide secondary benefits like improving reliability which offset the benefits of installing DG.

Ameren generally cannot dispatch customer-owned DG, so this type of resource is not included when performing load analysis and system improvement evaluations. Chapter 8 explores distributed generation as a demand-side resource.

7.2.7 Advanced Distribution System Technologies²⁷

Ameren Missouri has adopted a Smart Grid Strategy to transform our electric grid to create a secure, reliable and more efficient infrastructure enabling customers' use of "energy smart" technologies. The company intends to implement plans that are consistent with a corporate goal of serving 75% of appropriate Ameren customers with a multi-layered penetration of smart technologies, subject to capital availability.

There have been many technological, operational and societal benefits identified in association with the US Department of Energy's vision for the Smart Grid. Ameren Missouri's Smart Grid vision focuses on the continued pursuit of service reliability, operating efficiency and asset optimization, and on building a secure, robust energy delivery infrastructure as a means of enabling other Smart Grid elements. Among these elements are emerging technologies owned and operated by customers who are motivated by the prospect of becoming more active participants in energy-related decisions.

Ameren Missouri views the Smart Grid as the infusion of technology – communications technology, automation technology, and end-device intelligence – into the otherwise passive system of poles, wires, cables, transformers, switches and meters comprising

²⁷ 4 CSR 240-22.045(1)(A); 4 CSR 240-22.045(1)(D); 4 CSR 240-22.070(1)(B)

the electric infrastructure. From a practical standpoint, capabilities like communicating with end devices, controlling them remotely, configuring them to operate automatically, receiving reports back on what they did, and the central control and back office systems necessary to integrate and support these functions, all represent features of an intelligent grid.

Ameren Missouri considers the Smart Grid to be more of a direction than a destination. Given the digital nature of the technology being referenced by the term and the frequency with which it turns over relative to the more robust hardware it attempts to automate, the Smart Grid will never represent a discrete state of existence that, once arrived at, signals the end of the effort. Simply put – in the same way that few people will ever have their “last” cell phone or their “last” personal computer, the electric grid will likely never achieve what can be considered a “final state” of automation or intelligence.

Ameren Missouri’s current activities in electric infrastructure technology are driven by deliberate and intended benefits associated with its adoption of the Smart Grid. These intended outcomes are summarized below:

Reliability Improvement – Deploy smart technologies across the energy delivery infrastructure in order to improve electric service reliability for Missouri customers.

Efficiency, Optimization and Integration – Improve the operating efficiency and asset optimization of the energy delivery infrastructure and further integrate Ameren’s existing Smart Grid applications, allowing for the flexibility, scalability, and extensibility of these and future applications.

Customer Enablement and Use of Technology – Provide the necessary resources to both prepare the electric grid for emerging customer technologies and enable motivated electric customers in Missouri to make use of those technologies and become more active participants in energy decisions.

Ameren Missouri sees its communication role as one of leading its employees, customers, regulators, and other stakeholders to a greater understanding of Smart Grid concepts, applications, and potential benefits, as well as Ameren Missouri’s specific plans for the future. Internally, Ameren Missouri fosters an environment of continuous learning for leaders and subject matter experts around Smart Grid topics through its participation in pilot installations and research projects, its participation with other utilities and industry groups on the development of Smart Grid concepts and standards, and the engagement of external consultants and industry experts. Additionally, there will be opportunities to partner with property developers and large customers in active demonstrations that showcase Ameren Missouri’s Smart Grid applications.

7.2.8 Ameren Missouri's Smart Grid Plan²⁸

Various aspects of Ameren Missouri's Smart Grid Plan are discussed below, but enabling all is the availability of enhanced digital control and communication capabilities. The basic function of power delivery systems is not changing; we still need generators, transformers, overhead and underground circuits, switches, circuit breakers, fuses, etc. New is the ability to better sense system conditions, evaluate the health of system equipment, and employ either local or remote control schemes via high-speed 2-way digital communications technology. Advanced equipment, offering this type of control and communication capability, is replacing older types of less advanced equipment. Some replacements are programmatic on a set schedule, while others are implemented as equipment is replaced due to age or failure. Several types of conventional equipment and their advanced technology replacements are outlined below. This list is representative of present options, but certainly does not include every advanced technology item available today or in the future.

<u>Conventional Equipment</u>	<u>Advanced Technology Equipment</u>
Solid Blade Manual Switch	Remote Control Switch with SCADA communication and current/voltage monitors or Electronic Recloser
Oil Type Recloser	Electronic Recloser with SCADA communication and current/voltage monitors and fault location capability
Faulted Circuit Indicator	Faulted Circuit Indicator with SCADA communication
Capacitor Control (Time / Temp / 1-way comm.)	Local/Remote Capacitor Control with 2-way comm. and current, voltage, kVA and status monitors
Underground Manual Switch	Padmount Switch with SCADA communication and current/voltage monitors and fault location capability
Network Protector	Advanced Network Protectors with SCADA comm. and current/voltage/load and equipment condition monitoring capability
Electromechanical Relays	Microprocessor Based Relays with SCADA comm. and current/voltage/load/fault impedance/equipment condition monitoring/etc. capability
Transformer Bushing Tests	Online Bushing Power Factor Monitoring
Transformer Oil Tests	Online Transformer Oil Monitoring
Circuit Breaker Timing Tests	Online Breaker Timing and Contact Wear Monitoring

²⁸ 4 CSR 240-22.045(1)(D); 4 CSR 240-22.045(4)(B); 4 CSR 240-22.045(4)(E)1

Automated Switching Applications

Ameren Missouri's design strategy for the (34.5 & 69 kV) subtransmission system includes providing redundant service to distribution substations with load in excess of 10 MVA. Substations with loads below 10 MVA typically employ radial configurations with single supplies. When load exceeds 10 MVA, a second supply with automatic high-side transfer equipment is typically installed. As load approaches 15 MVA, a second (larger) substation transformer and automatic low side transfer capability usually is added. As load approaches 20 MVA, the first transformer is normally replaced with a unit equal in rating to the second transformer and the transfer scheme is upgraded to an automatic high/low selective scheme. In densely populated areas, redundant subtransmission circuits are typically available at each substation; but, redundant circuits are not always available at all substations in less populated areas. In such locations, redundant subtransmission supplies are typically provided via automated switching devices in nearby circuits and a radial supply circuit is extended to the substation in question. Ameren focuses on minimizing the length and exposure associated with such radial supply circuits until further development achieves full redundancy at the substation.

Whether a line switch or part of a substation, Ameren Missouri employs modern, SCADA-controlled, automatic smart switching devices in order to limit the time and effort required to execute switching actions. Substation transfer schemes are always designed for automatic operation, while line switches may be designed for automatic or remote control operation, depending upon the circumstances involved. Conventional manual switches are only employed in less critical locations, where they are not involved in automated service restoration. In recent years, several existing manual switches have been upgraded to remote control capability or replaced by new SCADA-controlled equipment. Up to 200 automated line switches could be required in addition to the 306 already in service to fully deploy on this strategy over the next 10-15 years.

Ameren Missouri's strategy for automating 12kV distribution circuits is to install SCADA-equipped smart switching devices (at least one bisecting the feeder backbone and at least one tying the downstream section to a different feeder) to limit the load dropped due to a single line contingency to roughly half the feeder's peak load. Although this is a general design objective, it can only be implemented in those cases where the existing circuit topology supports the restoration of unfaulted line sections to a different feeder. Up to 1,600 automated switches could be required in addition to the 305 already in service to fully deploy on this strategy over the next 20-25 years.

Ameren Missouri plans to deploy 12kV smart switching strategies annually by circuit, substation, or group of adjacent substations as appropriate, according to the greatest combined customer density and potential reliability improvement for the cost. Substation and circuit candidates for switching solutions are identified through the standard annual contingency analysis studies conducted, as well as through periodic

reliability reports of worst-performing feeders, worst performing high customer-density substations, etc.

Funding for automated switching applications is approved for specific projects and programmatic efforts on an annual basis. Although such investments are very important, they are not considered to be mandatory and do compete with other non-mandatory projects for capital funding. As noted in section 7.2.3, capital funding for non-mandatory electric distribution projects is allocated based on cost/benefit and risk assessments for each competing project. This approach provides the greatest benefit to customers for the available capital funding in each budget year.

Smart Substation Technologies

For many years Ameren Missouri has been building substations that are considered “smart” by today’s standards. As a means of ushering in the next generation of substation intelligence in the industry, Ameren Missouri has adopted Smart Substation Design Guidelines to incorporate combinations of the following features into the standard design of capital projects:

- water and dissolved gas content monitoring
- fault detection and location monitoring
- switchgear circuit breaker timing and contact wear monitoring
- circuit breaker trip coil failure monitoring
- multi-function temperature sensing

These projects include the construction or re-build of entire substations as well as the installation or replacement of substation transformers. Additionally, mobile substation transformer and switchgear purchases going forward will feature a combination of these types of sensors.

Industry data indicates that over the long term, the capture and trending of substation transformer diagnostic sensor data can reduce substation outage events due to unforeseen transformer failures and extend the average operating lives of these large assets. The premium for the sensing technology involved is less than 5% over all construction scenarios. Ameren Missouri plans to install this sensor technology on substation transformers over time as an integral part of its capital substation projects going forward, including those undertaken for reasons of load growth, reliability upgrade, or condition-based maintenance.

Multi-Layered Network Architecture

Currently several isolated and overlapping networks are operating today in support of AMR meters, radio-controlled line capacitors, substation SCADA and automated switching, none of which is sufficient for the long-term expansion and widespread use of intelligent end devices. It’s anticipated that more capacity will be required for ultimate

end device populations in the tens of thousands, and more speed could be required to support large file transfers from remote diagnostic sensors in substations.

In response to this Ameren Missouri has developed and is deploying a multi-layered network architecture intended to support existing smart applications and enable future applications – a Wide Area Network (WAN) backbone for backhauling large amounts of field application data, Local Area Networks (LANs) for aggregating intelligent end device data (typically at substation locations), and Field Area Networks (FANs) for supporting communication with field end-devices beyond and downstream from the substation.

Ameren Missouri is developing a WAN that leverages various industry-proven transport systems such as fiber, digital microwave, and common carrier leased services, and likely features a mix of private and non-shared public infrastructure of either a wired or wireless nature. WAN infrastructure additions over time will focus on the connection of substations and other key network entry points, the delivery of information to the control center(s), and the application of necessary security layers throughout the network architecture.

Ameren Missouri is deploying LAN technology over time at substations as their specific locations are identified as effective aggregation points for planned feeder deployments of intelligent end devices like automated line switches, capacitors and regulators. Since these devices are being deployed on the distribution system by circuit or substation, the already owned or leased substation site becomes the preferred choice for this aggregation. Targeting these deployments at “smart” substation sites also allows for communications consolidation and maximizing the impact of the LAN infrastructure investment.

In some areas of the Ameren Missouri service territory the FAN will feature a radio frequency (RF) mesh network that is both self-organizing and self-optimizing, dynamically routing data communications amongst a diverse set of paths that wirelessly interconnect multiple end devices. In other areas, the FAN will feature a more traditional point-to-multipoint RF network or a cellular-based alternative, depending on the application and its inherent reliability and latency requirements. Ameren Missouri plans to adopt the use of intelligent end devices with open architectures as endorsed by National Institute of Science and Technology (NIST) standards, regardless of the smart applications involved and the other technology choices made.

Advanced Distribution Management System (ADMS)

Ameren Missouri has implemented an Advanced Distribution Management System (ADMS) as a means of providing an integrated suite of software applications with which to manage the electric distribution system. It is a highly integrated system of applications that provides distribution system operators a common user interface with

which to monitor and control the distribution system on a daily basis. It not only replaced existing applications like outage management, switching orders, and Supervisory Control and Data Acquisition (SCADA), it features new applications such as dynamic circuit modeling, switching and restoration simulations, and a distribution system dashboard.

ADMS is foundational to future Ameren Missouri Smart Grid planning since it enables advanced applications that rely on the integration of functions formerly separate and distinct. In addition, ADMS allows for growth and scalability that is not feasible on the legacy platforms and provides the flexibility to add and integrate future applications. Ameren Missouri went live on the new ADMS platform during 2014.

Supervisory Control and Data Acquisition

Ameren Missouri's strategy for substation supervisory control and data acquisition is to programmatically introduce remote load monitoring at existing substations lacking such capability, for purposes of improving daily operations and facilitating the long-term planning of substation assets. Remote outage detection and supervisory control features will be introduced at existing substations lacking such capability on an opportunistic basis in association with other capital projects.

Ameren Missouri's 30+ years of experience in this area has shown that continuously updated load information on substation components can defer or eliminate previously justified capital projects, quickly identifies unforeseen overloads, releases capacity by allowing for daily operation closer to margin, and greatly enhances outage restoration activities. Remote metering also enables automatic transfer capability in smart switching applications and enables feeder level optimization via phase balancing and the operation of line capacitors. Supervisory control of switching devices further enhances operations by allowing for real-time outage notification and immediate intervention by dispatchers in restoration scenarios.

Of Ameren Missouri's 660 distribution substations, there are approximately 190 without remote metering capability. Ameren Missouri's plan is to upgrade a prescribed number of these substations annually on a programmed basis according to the preferences of operating and circuit planning entities, and align these upgrades as appropriate with smart switching and smart capacitor deployments that are planned on associated feeders.

There are approximately 250 Ameren Missouri distribution substations without outage detection and supervisory control capability. Ameren Missouri's plan is to convert these substations opportunistically over time as other capital projects are undertaken to replace their switching devices. Ameren is also funding the programmatic addition of

metering and SCADA capabilities at some of these substations, which are not scheduled for other upgrade projects in the foreseeable future.

Capacitor Control

Smart line capacitor operation has helped Ameren Missouri maintain a consistent 98% distribution system power factor over the last twenty years. However, the capacitor control technology available today allows for feeder level efficiencies and degrees of optimization that were never before possible. The use of "smart" capacitor controls not only helps achieve these levels of efficiency and optimization, but also more effectively controls customer end-use voltages, and more reliably supports the reactive requirements of the transmission system. Ameren Missouri's intent is to leverage new ADMS system capabilities to integrate substation load monitoring with "smart" line capacitor operation for the first time in order to achieve these goals.

Ameren Missouri's first step as part of this automation strategy is the deployment of the next generation of "smart capacitor" technology on the distribution and subtransmission systems. Ameren Missouri will leverage the need to replace the existing 25-year old line capacitor control system in operation today in the St. Louis metro area for this deployment. To this end, 2,300 capacitor controls will be upgraded over the next 5 – 10 years due to the unavailability of legacy controls and the fact that no other hardware replacements are necessary as part of these upgrades.

Additionally, Ameren Missouri will be installing "smart" capacitors in place of the remaining 1,100 non-fixed units in the service territory. This deployment will take place over time by circuit, substation, or group of adjacent substations, coincident with the deployment of automated switches in order to maximize the benefits associated with the communications investment.

Meter Infrastructure and Data²⁹

Ameren Missouri currently reads 1.2 million electric and 130 thousand gas meters with a one way Automated Meter Reading (AMR) RF system. The system delivers daily meter information (daily usage, meter flags and outage detection). It is also capable of delivering demand, TOU and interval meter data for a small proportion of the meters; however, it does not have the bandwidth and cannot be upgraded to support the large amount of data needed to provide interval readings for all of the Ameren Missouri meters. The system was installed between 1995 and 2000. The AMR modules in the meters are projected to have a 15-20 year life. Due to the age of these systems, Ameren Missouri is currently evaluating options to replace the AMR system in Missouri.

²⁹ EO-2017-0073 1.B; EO-2017-0073 1.P

If a modern Automated Meter Infrastructure (AMI) system replaced the existing AMR system, it would ultimately benefit Ameren Missouri customers by providing such things as demand response, dynamic pricing, remote disconnect/reconnect, customer prepay, and other benefits that would improve customer choice. It would also benefit Ameren Missouri customers by enabling the collection of interval data for all customers, which could be presented to customers via a web portal on a next day basis. The AMI system would allow customers more detailed insights into their energy usage which could help modify their energy usage behavior. Furthermore, an AMI system is expected to allow for improvements in field work efficiency and customer outage duration through improved detection of meter problems, improved theft detection, improved outage detection, and improved customer voltage information that cannot be obtained using current communication technology.

Ameren Missouri has been investigating different meter reading options including evaluation of the costs and benefits of a system-wide implementation of AMI. The analysis indicates that there would be benefits from the implementation of an AMI system for Ameren Missouri.

The decision to proceed with an AMI system implementation is dependent on several factors including: the continued operational performance of the AMR system, the results of needed regulatory reforms in Missouri, and the availability of capital for Ameren Missouri projects. While the AMR system is ending its useful life, the timing of when Ameren Missouri will move forward with an AMI project has not yet been determined. Generally, the project will take 2 years to design and build the Information Technology infrastructure and meters could then be deployed as capital is available. The project is expected to cost approximately \$430M. The most recent economic analysis is provided in the workpapers.

To keep costs low to our customers, Ameren Missouri's policy is to allow only one revenue meter per electrical supply service to the premise. In cases where customers would like real time energy information, Ameren Missouri offers a meter option that provides an interface to the customer's energy management system. Ameren Missouri currently has approximately 800 large commercial and industrial customers utilizing this option.

In cases where a customer desires sub-metering on the load side of our revenue meter, the customer engages an electrical contractor to perform this work at the customer's expense. The revenue metering has traditionally been the division point between the electric utility ownership and the customer ownership of the electrical supply system. The customer's electric system is under the jurisdiction of electrical contractors and the local electrical inspection authorities, and is guided by the National Electrical Code (NEC).

Emerging Customer Technologies

Ameren Missouri continually follows the advancements and industry trends associated with emerging customer-owned products and technologies, especially as they influence the planning around their eventual penetration on Ameren's distribution system – these include electric vehicles, micro-grids, small-scale distributed generation and energy storage.

Ameren Missouri has taken a particularly focused interest in the emergence of electric vehicles and is actively engaged in opportunities for contributing to the region's overall preparedness. Ameren Missouri has studied the potential penetration of electric vehicles in the service territory and the resultant impact of vehicle charging on the distribution system. We have identified and fully developed the business model associated with electric vehicles, the ownership and operation of public charging stations, and the possible rate structures associated with charging these vehicles at home, at work, and on merchant properties.

Ameren Missouri has participated as a corporate member of the St. Louis Regional Clean Cities Plug-In Readiness Task Force as a means of following the discussions around being plug-in ready and identifying possible community partnering opportunities for technology promotion. Internally, Ameren Missouri has taken delivery of several PHEV bucket trucks and several battery electric and plug-in hybrid electric sedans. These activities were pursued as a means of self-education and preparation for the energy advisor role Ameren Missouri has assumed in this area with inquiring customers. Ameren Missouri proactively installed charging stations at its corporate headquarters and several operating centers to support its growing electric fleet and early-adopting employees. We have also communicated a distinct interest in getting directly involved with the deployment of charging stations for public use along medium and long distance corridors.

7.2.9 Advanced Technology Investment Strategy³⁰

As discussed in Section 7.2.3, Ameren Missouri assesses the feasibility and cost effectiveness of potential system expansion and modernization capital projects on an ongoing basis. Both conventional and advanced technologies are regularly considered, with advanced technologies applied where they offer significant reliability or operational advantages, subject to capital availability. Conventional technologies are applied where there is no appreciable advantage offered by employing more expensive advanced technology. Most projects include a mix of conventional and advanced technology equipment.

³⁰ 4 CSR 240-22.045(4)(B); 4 CSR 240-22.045(4)(C); 4 CSR 240-22.045(4)(D)

Ameren Missouri updates its 5-year capital budget plan on an annual basis. Individual capital projects are submitted for consideration and are approved or deferred, based on cost/benefit and critical risk assessments. Through this annual budget development process, Ameren ensures that system capacity and reliability will be enhanced as fully and cost effectively as possible through proper prioritization of capital investments.

In addition to individual capital projects, Ameren Missouri implements several types of advanced technology equipment on programmatic bases. Specific examples are discussed below:

- **Substation Equipment Monitors** - Ameren Missouri has adopted Smart Substation Design Guidelines to incorporate transformer water & dissolved gas content monitors, fault detection & location monitors, switchgear circuit breaker timing & contact wear monitors, circuit breaker trip coil failure monitors and multi-function temperature sensing monitors into the standard design of substation capital projects. Of Ameren Missouri's 660 distribution substations, approximately 190 are without remote metering capability. Approximately 250 distribution substations are without outage detection and supervisory control capability. Ameren Missouri plans to upgrade these facilities opportunistically over time as substation capital projects are undertaken. This is an on-going investment strategy whose costs are incorporated into individual capital projects.
- **Reduced Loss Transformers** - Ameren Missouri purchases substation and distribution line transformers on a Total Cost of Ownership basis, optimizing the combined purchase + evaluated loss cost. By purchasing high-efficiency distribution line transformers that meet the US Department of Energy efficiency requirements, Ameren will gradually reduce total circuit losses in a cost-effective manner. Ameren Missouri conservatively projects an annual demand savings of 0.11 MW and an annual energy savings of 817 MWh's from replacing approximately 8500 distribution line transformers yearly. Replacement of distribution line transformers is an on-going investment strategy which is budgeted annually, based on anticipated transformer usage.
- **Faulted Circuit Indicators (FCI)** – Ameren Missouri installs conventional FCI equipment at key locations in distribution circuits to reduce customer interruption durations by assisting in the identification of fault locations. Self-powered, SCADA-equipped FCI modules are installed at key locations in subtransmission circuits to provide similar benefits on a larger scale. Ameren plans to install between 100 and 150 sets of smart FCI's per year over the next 5 – 10 years. Specific locations are identified on an annual basis to address distribution system operational concerns. This is an on-going investment strategy which is budgeted annually, based on business needs and priorities.

- **Automated Subtransmission Switching Equipment** – Ameren Missouri employs SCADA-equipped smart switching devices at substations and key locations on subtransmission circuits to reduce the time and effort required to execute switching actions. 306 smart switches are presently in-service and another 200 are expected to be installed over the next 10-15 years. Specific locations are identified on an annual basis to address distribution system operational concerns. This is an on-going investment strategy which is budgeted annually, based on business needs and priorities.
- **Automated Distribution Switching Equipment** – Ameren Missouri employs SCADA-equipped smart switching devices to sectionalize 12kV distribution feeders and tie unfaulted sections to neighboring feeders to facilitate emergency outage recovery. 305 switching devices have been installed to date and another 1600 devices are expected to be installed over the next 20-25 years. Specific locations are identified on an annual basis to address distribution system operational concerns. This is an on-going investment strategy which is budgeted annually, based on business needs and priorities.
- **Capacitor Control Equipment** - Ameren Missouri has begun to deploy a new “smart capacitor” control scheme on its distribution and subtransmission systems. This upgrade is driven by the obsolescence of existing control equipment, but will enable the company to maintain a consistent 98% power factor while facilitating feeder level control optimization that was never before possible. To this end, 2300 voltage or load controlled capacitors will be upgraded over the next 5 – 10 years and an additional 1100 seasonally switched banks will be upgraded beyond that date. Specific capacitor bank upgrades are scheduled on an annual basis to replace failed equipment and address distribution system operational concerns. This is an on-going investment strategy which is budgeted annually, based on business needs and priorities.

7.3 Compliance References

4 CSR 240-22.040(3) 9

4 CSR 240-22.040(3)(A) 9

4 CSR 240-22.040(3)(B) 11

4 CSR 240-22.045(1) 3, 17

4 CSR 240-22.045(1)(A) 15, 16, 19, 20, 24, 26

4 CSR 240-22.045(1)(B) 9

4 CSR 240-22.045(1)(C) 9

4 CSR 240-22.045(1)(D) 14, 23, 26, 28

4 CSR 240-22.045(2) 8

4 CSR 240-22.045(3)(A)2 14

4 CSR 240-22.045(3)(A)3 8

4 CSR 240-22.045(3)(A)4 6, 13, 14

4 CSR 240-22.045(3)(A)5 7

4 CSR 240-22.045(3)(B) 14

4 CSR 240-22.045(3)(B)1 3, 4, 7

4 CSR 240-22.045(3)(B)2 4, 7

4 CSR 240-22.045(3)(B)3 4, 7

4 CSR 240-22.045(3)(B)4 7

4 CSR 240-22.045(3)(B)5 16

4 CSR 240-22.045(3)(C) 6

4 CSR 240-22.045(3)(D) 9

4 CSR 240-22.045(4)(A) 14

4 CSR 240-22.045(4)(B) 28, 35

4 CSR 240-22.045(4)(C) 14, 22, 35

4 CSR 240-22.045(4)(D) 14, 22, 35

4 CSR 240-22.045(4)(D)1 22

4 CSR 240-22.045(4)(D)2 22

4 CSR 240-22.045(4)(E) 22

4 CSR 240-22.045(4)(E)1 14, 22, 28

4 CSR 240-22.045(5) 16

4 CSR 240-22.045(6) 6

4 CSR 240-22.070(1)(B) 14, 26

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