EVERGY METRO

TRANSMISSION AND DISTRIBUTION ANALYSIS

INTEGRATED RESOURCE PLAN

4 CSR 240-22.045

APRIL 2021

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VOLUME 4.5: TRANSMISSION AND DISTRIBUTION ANALYSIS

HIGHLIGHTS

- Evergy's transmission losses as a percent of peak load served are low relative to the SPP footprint as a whole.
- SPP did not identify any economic projects in the Evergy Metro footprint during its 2020 Integrated Transmission Planning (ITP) process.
- SPP identified six reliability projects in the Evergy Metro footprint through its 2020 ITP process, all of which are breaker replacements due to the short circuit portion of the study with a need date of 6/1/2022.

PURPOSE: This rule specifies the minimum standards for the scope and level of detail required for transmission and distribution network analysis and reporting.

SECTION 1: ADEQUACY OF THE TRANSMISSION AND DISTRIBUTION NETWORKS

(1) The electric utility shall describe and document its consideration of the adequacy of the transmission and distribution networks in fulfilling the fundamental planning objective set out in 4 CSR 240-22.010. Each utility shall consider, at a minimum, improvements to the transmission and distribution networks that—

1.1 <u>OPPORTUNITIES TO REDUCE TRANSMISSION POWER AND ENERGY LOSSES</u>

(A) Reduce transmission power and energy losses. Opportunities to reduce transmission network losses are among the supply-side resources evaluated pursuant to 4 CSR 240-22.040(3). The utility shall assess the age, condition, and efficiency level of existing transmission and distribution facilities and shall analyze the feasibility and cost-effectiveness of transmission and distribution network loss-reduction measures. This provision shall not be construed to require a detailed line-by-line analysis of the transmission and distribution systems, but is intended to require the utility to identify and analyze opportunities for efficiency improvements in a manner that is consistent with the analysis of other supply-side resource options;

Electrical losses in a transmission line are primarily dependent on the specific characteristics of the line (conductor type, line length, etc.) and the amount of power flowing (I^2R) on the transmission line. Evergy uses 161 kV transmission lines (approximately 1,000 miles) for the majority of its load serving substations and many of Evergy's existing 161 kV transmission lines use a single 1192 ACSR conductor per phase on H-frame wood structures, which provides a normal line rating of 316 MVA and an emergency rating of 356 MVA for summer conditions. For increased transmission capability and lower line losses, Evergy Transmission Engineering recommends two different line designs depending on location: two

795 ACSR conductors per phase on H-frame wood if the line is located in a rural area or single 1192 ACSS on steel structures if the line is located in an urban area. The bundled 795 ACSR design provides a normal line rating of 501 MVA and an emergency rating of 563 MVA for summer conditions and the single 1192 ACSS provides a normal and emergency line rating of 591 MVA for summer conditions. The updated conductor reduces the line's electrical resistance and results in reduced transmission losses. Transmission Engineering estimated the cost to rebuild a transmission line at $1.6 million per mile in rural areas and $1.85 million per mile in urban areas.

In order to "analyze the feasibility and cost-effectiveness of transmission network loss-reduction measures", Evergy Transmission Planning staff analyzed the costs and loss reductions associated with rebuilding five of Evergy Metro's most heavily loaded 161kV transmission lines. This analysis involved calculating new impedances values for the five transmission lines converted to the preferred conductor based on location and performing a loadflow analysis to determine the level of loss reduction for the rebuilt lines. Results of this analysis for 2021 is in Table 1 below.

Table 1: Cost Analysis for 161kV Transmission Line Loss Reduction

Current Line Information						
161kV Transmission Line		Line Length	Impedance			
From	TO	MILE	R (pu)	X (pu)	B (pu)	
Salisbury	Norton	22.23	0.01022	0.06574	0.03239	
West Gardner	BNSF	2.60	0.00081	0.00709	0.00409	
Moonlight	BNSF	3.43	0.00114	0.01007	0.00575	
Leeds	Winchester Junction North	3.80	0.00130	0.01080	0.00570	
Hawthorn	Birmingham	3.30	0.00190	0.00970	0.00470	
			EM Losses (MW)			49.7
Rebuild Line Information						
161kV Transmission Line		Line Length	Impedance			
From	TO	MILE	R (pu)	X (pu)	B (pu)	
Salisbury	Norton	22.23	0.00507	0.04585	0.04606	
West Gardner	BNSF	2.60	0.00059	0.00536	0.00539	
Moonlight	BNSF	3.43	0.00103	0.00984	0.00510	
Leeds	Winchester Junction North	3.80	0.00087	0.00784	0.00787	
Hawthorn	Birmingham	3.30	0.00075	0.00681	0.00684	
			Total Cost			$57,433,500.00
			EM Losses (MW)			48.2
			Loss Reduction (MW)			1.5
			Loss Reduction (kW)			1500
			Cost Per kW			$38,289.00

The average cost of loss reduction per kW for these five transmission lines is $38,289/kW. Clearly, transmission loss reduction is not cost effective for Evergy when compared to the cost of new supply side resources. This is mainly due to the fact that Evergy already has a relatively low loss transmission system.

The Evergy transmission system is a relatively low loss network due to good line design, concentration of load, and the distribution of its generation resources throughout its service territory. As shown in Table 2, Evergy's projected transmission loss as a percent of peak load served for 2021 summer peak load conditions is only 1.5%. The comparative value for the rest of the Southwest Power Pool (SPP) is 2.4%.

Table 2: SPP 2021 Transmission Losses by Area

Area	Load MW	Loss MW	% Loss
652	4,441.4	222.5	5.0%
640	3,737.2	137.5	3.7%
534	1,265.5	43.0	3.4%
515	616.1	20.9	3.4%
531	402.3	13.0	3.2%
526	6,550.9	187.7	2.9%
544	1,099.3	29.2	2.7%
536	6,138.9	146.2	2.4%
525	1,754.0	36.9	2.1%
524	6,762.5	137.4	2.0%
520	10,474.7	207.5	2.0%
Evergy Metro & Missouri West Combined	5,860.2	85.7	1.5%
645	2,883.3	33.3	1.2%
523	1,468.6	16.7	1.1%
650	772.3	8.4	1.1%
546	756.4	8.1	1.1%
545	296.4	3.1	1.0%
659	283.9	1.2	0.4%
542	547.8	2.2	0.4%
527	315.9	0.6	0.2%
SPP	56,427.5	1341.0	2.4%

1.1.1 DISTRIBUTION SYSTEM OVERVIEW

The various Evergy planning groups (Supply, Transmission, and Distribution) assimilates a broad set of engineering inputs to determine how the company will invest in improving the respective systems to meet ongoing load growth, system reliability, operational efficiency and asset optimization needs. The Distribution Planning group analyzes data, identifies patterns, develops electrical models representative of the Evergy distribution system, and performs studies to understand and prioritize system improvement needs.

The Evergy Missouri service area consists of three general types of areas: a predominantly developed urban core, suburban areas in the territory fringes, and a rural area. The inner urban core can be characterized by high utilization of its distribution assets and its aging infrastructure. Reliability risk in this area is addressed by installing replacement or contingency infrastructure and infrastructure inspections as noted in Section 1.1.2.4 (Conditions). The distribution system, over many decades, has been built by adding only enough capacity to serve immediate load requirements. These types of problems have been categorized as condition or contingency. Specific recognizable projects like new River Market duct banks, decommission of Grand Avenue substation, and the Navy, Charlotte and Grand Avenue West substation expansion projects are good examples of this type of investment.

In contrast, the suburban areas of the Evergy System require the build-out of the distribution system due to the development of open land. The highest load growth is seen on the fringe, demanding investments to serve emerging electrical loads – largely a capacity issue. New circuits require expanding substation breaker positions and circuits must be effectively tied together to allow for contingency switching and to disperse the load across a larger number of circuits. Many investments like this have been made in recent years, especially around the Birmingham and Waldron substations.

The rural areas have the most widespread infrastructure components and have the fewest or most limited emergency ties, where any load manipulation can cause large disturbances to customers' voltage. Distribution Planning carefully examines these systems to ensure customer voltages are within tolerance, a process that demands high-quality mapping and device load data. With so many widespread components, acquiring data was one of the greatest challenges in these areas.

However, load data acquisition is improving with the deployment of Current Fault Circuit Indicators (CFCI).

The Distribution Planning group is tasked with elevating the highest priority and highest-risk projects to a point where investments are made earlier than those with lower priorities and risk profiles. Many years of constant review have provided the group with a robust set of criteria within which these problems are evaluated, and process improvements continue to be made to further analyze how to build out the distribution system to assure cost-effectiveness.

Furthermore, the Long-Term Planning component handled by Distribution Planning assures strategic long-term investments are made. Solutions are selected based upon how well they fit into an area-plan and not just the cost-effectiveness for the immediate need. Between the robust planning criteria and the strategic long-term vision, Distribution Planning will continue to construct the distribution system capable of serving tomorrow's needs by making appropriate investments when they are needed.

In the inner-urban core of Kansas City, the long-term vision involves installing replacement substation assets in new locations to strategically phase-out deteriorated underground components, improve reliability, and provide additional area capacity. Components nearing the end of their useful life can then be abandoned, removed, or rebuilt, and the company will have an upgraded distribution system better suited to reliably serve the inner-urban core of Kansas City well into the future. The Charlotte substation was placed into service in 2018 and duct bank projects directly exiting Charlotte substation was also completed. Rebuilding Northeast Substation, installing new duct bank projects to replace aging infrastructure and increasing substation transformation at Troost Substation have been budgeted in the five-year plan and have components critical to the long-term strategy over the next twenty years.

On the suburban fringe, Distribution Planning plots growth patterns to identify substation sites well ahead of the need. On the northern edge of the metro area, several substation sites have already been purchased in anticipation of future load growth. Distribution Planning constantly reviews the build-out of the distribution system on the suburban fringe as development in Kansas City continues to expand north, south, and east of the current metro area.

The rural areas of the service territory are envisioned to one day have entirely remotely-received load and condition data – a completely automated system. Today, load information is difficult to obtain and costly for field load checks during peak periods. Strategic and timely decisions can better be made with abundant characteristic data for the components being studied. Efforts are underway to systematically bring all rural components up to metro-area data acquisition standards. A specific example of these efforts is the deployment of Current Fault Circuit Indicators (CFCI).

It is the goal of Distribution Planning to assure that every investment optimizes capital spend and balances risk, meets current and future needs, and is built strategically when and where they are needed. Many tools and a great deal of information is processed and analyzed to develop these strategic plans.

1.1.2 ANNUAL SCOPE OF WORK

Throughout each year, Distribution Planning prepares several system studies to determine weaknesses or risks to reliability and to assess the overall adequacy of our distribution system. Much of the work focuses on increasing reliability and prioritizing work based upon cost, scope, impact, and effectiveness. This work is centered around five (5) specific areas: capacity, contingency, voltage, condition and compliance. The table below illustrates the various deliverables associated with each focus area:

Table 3: Distribution Planning - Annual Scope of Work

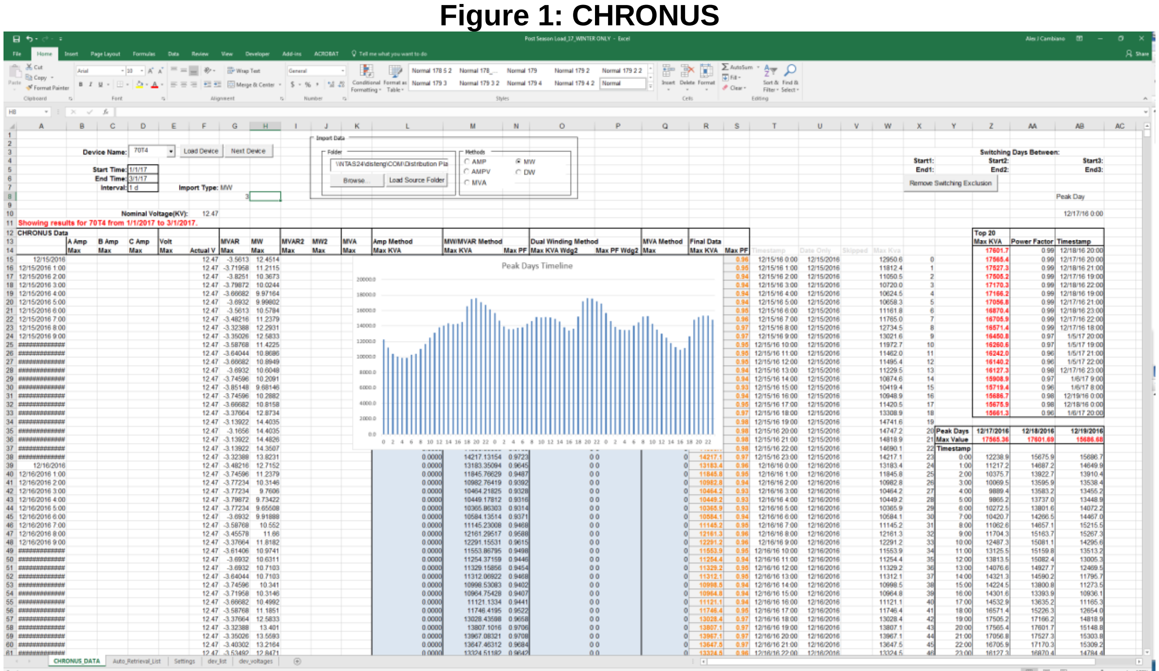
Category	Study Name	Deliverable
Capacity	Load Preservation, 5-Year System Expansion-Load, Peak Load Study, 15-Year Forecast, Circuit Rating Study	Black Start Plan, Budgetary Recommendations, Distribution Load Book, Forecasted Substation Loads, Circuit Rating utilized for Operational Guidance
Contingency	5-Year System Expansion-Contingency, N-1 Contingency, N-1 Transformer Contingency, Fault Location Isolation Service Restoration (FLISR)	Budgetary Recommendations, Circuit Contingency Plan, Transformer Contingency Plan, Grid Modernization
Voltage & Losses	Phase Balancing, Voltage Drop, System Efficiency Studies, Capacitor, Voltage Regulation	Load-Swap Recommendations, Voltage Management Schemes, System Loss Studies, Capacitor Installations, Substation Tap Settings
Condition	Worst Performing Circuits, Circuit Review, Short Circuit, Other Reviews	Budgetary Recommendations, Grid Modernization, Customer-Required Special Studies
Compliance	MO/KS Load Split, EIA 861 Annual Circuit Count	Non-metered Power flow Across State lines, Circuit Count for Voltages 35 kV & below

To complete this identified scope of work, Distribution Planning engineers utilize a variety of tools that make use of the device loads and system schematics as input. There are several tools currently in use at Evergy, Inc. to collect and process this information.

<u>Historian/Network Manager</u>

The new Energy Management System (EMS) was placed in-service in 2016. With this product, Evergy, INC. also utilizes the CHRONUS data archive tool, which now contains device loads and other historical system characteristics. Once all system components are merged into the new system, CHRONUS will be the primary archive for engineers to find and extract load and voltage history. The figure below provides a snapshot of the data extracted from CHRONUS.

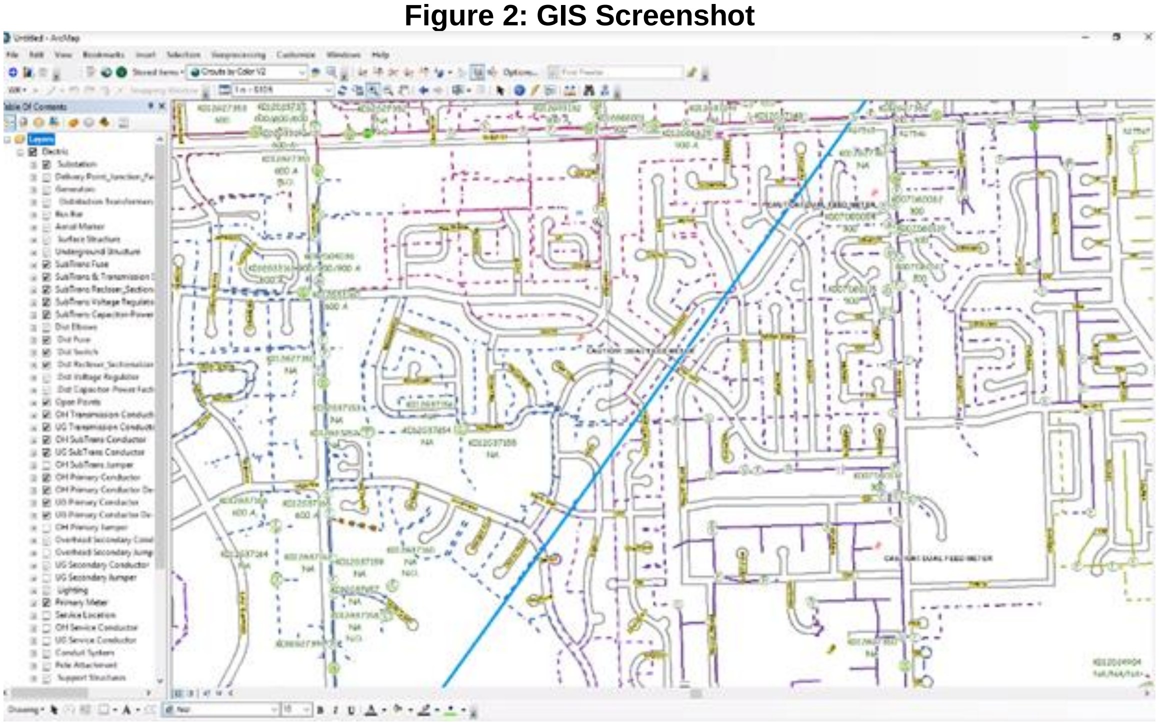
Figure 1: CHRONUS



Geographic Information System (GIS)

Evergy, INC. is upgrading from G/Technology to ESRI's GIS application. Although base operations and capabilities of G/Tech and ESRI are similar, the advanced functionality and mapping features in ESRI support greater integration across Evergy's software stack. The Distribution Planning engineers will use the GIS application to acquire model data for use in Synergi. Device characteristics and connectivity drive load-flow models in use by Distribution Planning engineers. The figure below provides a snapshot of GIS.

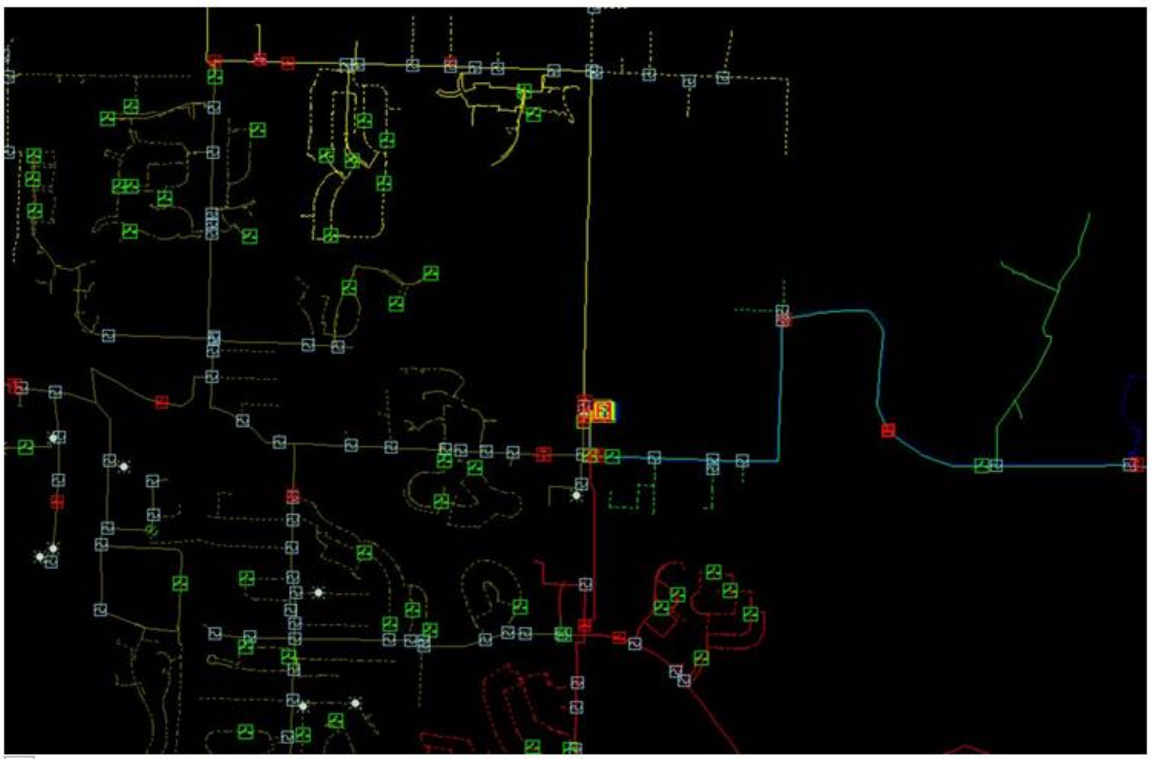
Figure 2: GIS Screenshot



Synergi

A multipurpose tool primarily used by engineers to analyze load flow characteristics of distribution feeders. Evergy also provides fault current information to customer's electrical contractors when performing arc-flash studies, a process which requires the use of Synergi. The figure below provides a snapshot of the Synergi software program.

Figure 3: Synergi Screenshot



1.1.2.1 Capacity Planning

Device loads, such as substation transformer and distribution circuit loads are collected annually from several remote-sensing sources. This load data is compared to previous years' loads and device maximum loading to determine how the load is changing over time and if any component is overloaded and in need of an upgrade. These types of problems are given a higher priority than others to assure continued reliability.

1.1.2.1.1 Circuit Rating Study

Using adjusted loads, Distribution Planning will determine ratings for each circuit. This study is done in several different ways depending on the configuration and style of the distribution components under review. The most complex of these studies deals with underground feeder cables within duct bank, which de-rate each other by mutual heating. Distribution Planning uses circuit loads to determine capacity ‘choke-points’ in order to rate the circuit. These ratings are provided to Operations to determine alarm setpoints and become an integral part of the N-1 Contingency Study. These ratings are also compared with native device loads to determine where normal-load capacity expansions are needed, leading to budget recommendations.

Figure 4: Screenshot from Cable De-rating Program

Description	Duct Bank from M.H. 2312 East to M.H. 2313		
Rows	6	**# of Positions**	
Columns	2	10	
Ambient	22		
Earth Rho	90		

Position	Circuit	load factor	running load	vertical	horiz.	Nom Ckt Voltage	Duct Type	Cable Type
1	1561	0.67	204	77.8	5.6	13	4.5"-Fibre	1-400 KCM-3C PILC
2	7472	0.67	35	77.8	12.9	13	4.5"-Fibre	1-400 KCM-3C PILC
3	1574	0.67	201	70.5	5.6	13	4.5"-Fibre	1-750 KCM-3C PILC
4	1511	0.67	123	70.5	12.9	13	4.5"-Fibre	1-750 KCM-3C PILC
5	1743	0.67	185	63.2	5.6	13	4.5"-Fibre	1-750 KCM-3C PILC
7	1567	0.67	109	55.9	5.6	13	4.5"-Fibre	1-750 KCM-3C PILC
9	7432	0.67	228	48.6	5.6	13	4.5"-Fibre	1-750 KCM-3C PILC
10	1522	0.67	178	48.6	12.9	13	4.5"-Fibre	1-750 KCM-3C PILC
11	1523	0.67	180	41.3	5.6	13	4.5"-Fibre	1-750 KCM-3C PILC
12	1512	0.67	195	41.3	12.9	13	4.5"-Fibre	1-750 KCM-3C PILC

Circuit	Load (A)	Oper. Temp.	Norm. Amp.	Norm. MVA	Emerg. Amp.	Emerg. MVA
1561	204	50.6	380	8.68	428	9.78
7472	35	37.8	369	8.44	418	9.55
1574	201	45.1	522	11.93	575	13.15
1511	123	40.6	520	11.88	575	13.15
1743	185	44.0	522	11.94	575	13.15
1567	109	40.3	522	11.93	575	13.15
7432	228	45.7	536	12.26	575	13.15
1522	178	42.4	533	12.19	575	13.15
1523	180	41.0	544	12.44	575	13.15
1512	195	41.7	546	12.47	575	13.15

1.1.2.2 Contingency Planning

Contingency Planning is similar to Capacity Planning in its view of loads compared to device capacity but deals in an N-1 contingency setting. Evergy. designs its system to withstand a failure of any one component at a given time. It is the responsibility of Distribution Planning Engineers to determine system weaknesses which do not comply with this and to make the necessary changes to allow emergency switching to restore power without overloading backup devices. These issues have a secondary priority in the budgetary process.

1.1.2.2.1 N-1 Contingency

The annual contingency study will provide the earliest indication of system improvement needs. It is more likely wire upgrades will be needed in the case of feeder or transformer loss, rather than there being simply too much native load on a single feeder or substation transformer. For Distribution Planning, the N-1 Contingency Study is a very systematic and complex process due to the magnitude of the individual distribution system circuit components. Synergi is the primary software tool in use to determine the load flow across a circuit. Distribution Planning engineers divide circuits into segments of load and establish switching orders for restoration in the case of a feeder or substation transformer loss. Using GIS models and load data, Synergi determines how that load is dispersed across the circuit by allocating the load based on the by-phase connected KVA on each circuit.

Three complex inputs into one N-1 Contingency Study using a highly technical software program yields effective results determining where system improvement is needed. By using the Synergi model to rearrange configuration of circuitry, Distribution Planning can detect where mapping errors exist, where low voltage can be problematic, and where wire sizes can limit how the distribution system is operated. Contingency Planning is an intensely complex process taking significant engineering time to determine system weaknesses for a given planning year. The study is completed every year for loss of every distribution feeder and substation transformer.

These weaknesses are identified and analyzed to determine the impact to system reliability and are ranked against each other correspondingly. This ranking, energy efficiency impacts, reliability and customer impact risks, and the project cost determine whether a system improvement is constructed or not. Distribution Planning therefore must not only identify the weakness but provide some budgetary estimation and project description. It also becomes the responsibility of Distribution Planning to thoroughly communicate why a project exists throughout the company, until it becomes part of the approved budget and is handed-off to a design engineer for sponsorship.

1.1.2.3 Distribution Voltage

At the customer-end of any given line, distribution voltage must be maintained within specific tolerances. It is the responsibility of Distribution Planning to assure system-level issues do not adversely affect the voltage received by Evergy, INC. customers. To do this, GIS models are used in a load-flow program called Synergi to simulate voltage levels in the field. In addition to supplying adequate voltage levels to our customers, we also strive to maintain an efficient low-loss distribution system. Several examples of this are the annual load balancing efforts and capacitor studies to optimize voltage levels and reduce system losses.

1.1.2.3.1 Loss Studies

Another method of analyzing overall system efficiency is through the performance of system loss studies. These are done periodically, and the information gathered is used by Planning Engineering as well as in rate case filings. The most recent system loss study was performed by Siemens in June 2018. A complete copy of this study, "Electric Loss Study for Test Year 2016 for the KCP&L and GMO Systems", can be found in Appendix 4.5.D.

1.1.2.3.2 Evergy Green Circuits Analysis

Another example of Evergy's efforts to improve overall circuit efficiency and reduce system losses was a study commissioned by Evergy and completed by EPRI (Electric Power Research Institute). This study analyzed various loss reduction options such as phase balancing, capacitor controls, reconductoring, and/or voltage optimization. The information gathered by this study has been used by Planning Engineering to optimize their approach to circuit construction, configuration and operation. A complete copy of this study, "Evergy Green Circuits Analysis Study", can be found in Appendix 4.5.E.

1.1.2.3.3 Distribution Transformer Efficiency Analysis

Currently, Evergy, INC. purchases transformers based on the Total Ownership Cost (TOC), which includes the transformer purchase price as well as the cost of the no-load and load-losses associated with each transformer, capitalized over a 30-year expected transformer life. Transformer manufacturers are required to follow Department of Energy (DOE) transformer efficiency standards and those standards are one factor they consider when optimizing transformers, along with variables related to our specific system. The most recent update to the DOE's efficiency standards were made in 2016.

1.1.2.4 <u>Condition</u>

Another important focus area for Distribution Planning Engineering deals with component conditions and their effect on reliability as it relates to capacity, contingency, voltage and overall system efficiency. Ongoing strategic planning to maintain reliability must account for device degradation over time, and planning engineers look for cost-effective replacement or maintenance opportunities where they coincide with capacity expansion plans. By working with the Asset Management group to determine the best course of action, these replacements in some cases are combined into Distribution Planning's capacity expansion projects – an increase in project scope from the normal course of action. System expansion to proactively replace degraded system components can be a more cost-effective solution than the "run-to-failure" strategy.

1.1.2.4.1 <u>URD Cable Replacement Programs</u>

Currently, there are two cable replacement programs in existence at Evergy: 1) Proactive Cable Replacement, and 2) Reactive Cable Replacement.

The Proactive Cable Replacement/Rehabilitation program targets Underground Residential Distribution (URD) primary cable loops and laterals that are shown to have elevated risk of failure based on engineering analysis. Cable failure data is collected on an ongoing basis and compiled to show area results and trends. The analysis of this data helps prioritize the areas that are selected for our proactive programs.

The Reactive Cable Replacement program addresses service reliability issues associated with URD primary cable. Evergy collects condition history and performs lifecycle analysis on failed cables.

1.1.2.4.2 <u>Cable Assessment Program</u>

In the Cable Assessment Program, the insulation properties of individual cable segments are evaluated using a partial discharge test which evaluates the cable's integrity. Based on the results of these tests, a decision is made on which cable segments to replace.

1.1.2.4.3 Worst Performing Circuit Analysis

The High Outage Count Customer Program, also known as the "Worst Performing Circuits" Program, is a circuit-based program addressing service reliability issues associated with customers experiencing abnormally high outage counts. Evergy identifies high outage count customers, investigates their outage events, and develops solutions to improve their circuit reliability. The Company uses the definition found in the MPSC reliability rule, 4 CSR 240-23.010 (6) to identify the top five percent (5%) worst performing circuits and to prioritize work needed to improve their reliability.

Analyzing annual outage management system records and field ultrasound inspection results assist in understanding root causes and the ensuing remedial action required to mitigate future incidents. The top ranked five percent (5%) high outage count customer circuits are analyzed annually to ensure reliability improvements are being achieved.

1.1.2.4.4 Pole Replacement and Reinforcement Program

The Distribution Pole Replacement/Reinforcement Program addresses reliability issues associated with the condition of distribution poles. Evergy annually conducts a ground-line inspection of the system to determine if there is a need to replace or reinforce distribution poles. The evaluation includes an examination for indications of decay and/or fungi at or below ground level, hollowness, and shell rot. When a pole is identified for replacement or reinforcement, the Company uses an independent contractor who is an expert in pole evaluation, maintenance, and repair, to prioritize and coordinate pole maintenance or replacement. The work is prioritized based on greatest risk to safety and impact to customer reliability.

1.1.2.4.5 <u>Lateral Improvement Program</u>

The Lateral Improvement Program addresses system-wide distribution reliability performance. Evergy conducts analysis to identify unfavorable reliability metrics. The systematic approach used determines root causes of irregular system component performances—such as pole or cross-arm failure, cutouts, arrester malfunction, grounding issues, undetected equipment vandalism and/or other undetected damage, among others. Detailed condition assessments and risk-modeling are used to formulate solutions concentrated on specific reliability issues. Projects are prioritized based on the magnitude and impact of customer outage.

1.1.2.4.6 <u>Proactive Retirement of 50 MVA Substation Transformers</u>

The Asset Management group has also proactively undertaken a study to assess Evergy's fleet of 50 MVA dual-secondary winding transformers, determine their risk of failure, and develop a retirement/replacement program. The condition of each transformer is primarily based upon dissolved gas analysis taken from annual transformer oil sampling. Evergy utilizes a transformer analysis package that categorizes each transformer as a category 1, 2, 3, or 4, with category 4 being the worst condition. This program reduces the overall operational risk associated with transformers that are identified as being at a higher risk for failure.

1.2 <u>ASSESMENT OF INTERCONNECTING NEW FACILITIES</u>

(B) Interconnect new generation facilities. The utility shall assess the need to construct transmission facilities to interconnect any new generation pursuant to 4 CSR 240-22.040(3) and shall reflect those transmission facilities in the cost benefit analyses of the resource options;

Any Evergy generation resource addition that would impact transmission level (>60 kV) flows would have to proceed through the Southwest Power Pool (SPP) Generation Interconnection process before it could be interconnected to the transmission system. The Interconnection process as detailed in SPP's Federal Energy Regulatory Commission (FERC) approved transmission tariff provisions allows customers detailed transmission studies and interconnection estimates for connecting to and using Evergy's transmission system. The resource addition would also have to go through the SPP Aggregate Facility Study process to obtain firm transmission service for delivery of generation to load.

1.3 ASSESSMENT OF TRANSMISSION UPGRADES FOR POWER PURCHASES

(C) Facilitate power purchases or sales. The utility shall assess the transmission upgrades needed to purchase or sell pursuant to 4 CSR 240-22.040(3). An estimate of the portion of costs of these upgrades that are allocated to the utility shall be reflected in the analysis of preliminary supply-side candidate resource options; and

Evergy is member of the Southwest Power Pool (SPP), a Regional Transmission Organization (RTO) mandated by the Federal Energy Regulatory Commission to ensure reliable supplies of power, adequate transmission infrastructure, and competitive wholesale prices of electricity. As a member of SPP, Evergy participates in the regional transmission expansion plan processes of the RTO, including requesting firm transmission service through the Aggregate Facility Study (AFS) process, which evaluates the transmission upgrades necessary for delivery of power purchases.

1.4 ASSESSMENT OF TRANSMISSION OR DISTRIBUTION IMPROVEMENTS WITH RESPECT TO COST EFFECTIVENESS OR DSM OR SUPPLY-SIDE RESOURCES

(D) Incorporate advanced transmission and distribution network technologies affecting supply-side resources or demand-side resources. The utility shall assess transmission and distribution improvements that may become available during the planning horizon that facilitate or expand the availability and cost effectiveness of demand-side resources or supply-side resources. The costs and capabilities of these advanced transmission

and distribution technologies shall be reflected in the analyses of each resource option.

1.4.1 CAPACITOR AUTOMATION EFFORTS

Evergy is operating its MO Metro capacitor automation program over a 4G cellular system. Although Evergy has upgraded 52% of its capacitor control fleet, we are constantly reviewing additional controller and capacitor upgrades.

Control upgrades allow for:

- Remote engineering and control
- Enhanced data availability
- Better internal diagnostics

The business case for automated capacitors includes:

- Enhancements considered when upgrading legacy capacitor locations:
  - Voltage Override
  - Neutral Sensing
  - Limiting number of switching operations per day
  - Ability to change setpoints remotely
  - Ability to obtain power quality data for improved customer service
- Enhancement of safety for Evergy workers
  - Five-minute time delay in control for a close after an open
  - One-minute timer for close after faceplate control operation
- Reduction of O&M Costs
  - Limiting number of capacitor patrols due to near real time data
  - Limiting number of customer voltage complaints
  - Potentially extending life of existing capacitor switches
- Improved Distribution and Transmission Power Factor
  - Enhance System Stability
  - Enhance system volt/VAr response
  - Increase system efficiency
- Enabling component in advanced voltage management schemes

1.4.2 VOLTAGE MANAGEMENT PROGRAM

Evergy is working on a territory wide voltage management program under our STP initiative. Although being vetted throughout the STP process, the voltage management program will likely have consideration for the following voltage augmentation schemes:

- Peak Demand Management
- Conservation Voltage Reduction
- Volt-VAR Optimization
- Energy Efficiency

As the review process continues, main components of our evaluation will be as follows:

- Assessment of impact on intelligent grid assets e.g. capacitors, voltage regulators, Load Tap Changers (LTCs), etc…
- Circuit, substation and system voltage management
- Improved process for adjusting intelligent grid asset set points
- Remote control of intelligent grid assets
- Functional and business impact of each voltage management scheme

This project will involve replacing electromechanical and non-communicating intelligent grid devices. These new devices will support standard industry specifications.

SECTION 2: AVOIDED TRANSMISSION AND DISTRIBUTION COST

(2) Avoided Transmission and Distribution Cost. The utility shall develop, describe, and document an avoided transmission capacity cost and an avoided distribution capacity cost. The avoided transmission and distribution capacity costs are components of the avoided demand cost pursuant to 4 CSR 240-22.050(5)(A).

The Evergy transmission projects included in the SPP regional planning processes for reliability improvement or economic benefits would not be impacted by the implementation of DSM (Demand Side Management) programs. Therefore, the only avoided cost for transmission facilities are the transmission equipment additions associated with distribution facility expansions.

2.1 IMPACT OF DSM ON DISTRIBUTION EXPANSION

As in the 2012 IRP submittal, Evergy INC. made assumptions regarding planned system expansion projects in areas that are designated as “growth areas” versus areas designated as “established areas”. Again, targeting was focused on capital projects associated within established areas since targeted DSM (Demand Side Management) programs were unlikely to be able to delay the need to expand substations on the fringe of metro-area growth because these areas contained significant “green space” with large areas that remain undeveloped.

Distribution Planning’s annual review of 15-year load projections revealed the fact that loads for these “established areas” continue to flatten and more commonly, decline, which has eliminated the need for expansion projects in these areas. It seems reasonable that as load growth has fallen off in the established areas, that efficiencies gained by replacing older heating/cooling units, lighting, and other older appliances, would begin to significantly impact peak loads for these areas. In the 2012 IRP submittal, the Gladstone, Claycomo, and Chouteau substations were identified as substations located in established areas where a system expansion project might be needed at some point in the future, making these a viable candidate for targeted DSM programs. However, a review of the most recent 15-year projections identifies the Gladstone and Chouteau substations to be in modest to significant load decline through year 2035, with total substation loads dropping from as little as 2% at Gladstone to as much as 17% at Choteau substation.

Currently, Evergy INC. has not identified any specific capital projects located within any established areas that can be specifically targeted for DSM programs. Areas that have been identified as established areas either have sufficient capacity available to absorb the limited growth or are in load decline. These areas will continue to be monitored by Distribution Planning to determine if future opportunities for targeted DSM might become available. Should economic conditions improve, and/or significant redevelopment occurs in these established areas, opportunities to target DSM programs to delay or eliminate the cost to expand capacities for these areas may again exist.

SECTION 3: ANALYSIS OF TRANSMISSION NETWORK PERTAINENT TO A RESOURCE ACQUISITION STRATEGY

(3) Transmission Analysis. The utility shall compile information and perform analyses of the transmission networks pertinent to the selection of a resource acquisition strategy. The utility and the Regional Transmission Organization (RTO) to which it belongs both participate in the process for planning transmission upgrades.

3.1 TRANSMISSION ASSESSMENTS

(A) The utility shall provide, and describe and document, its—

3.1.1 TRANSMISSION ASSESSMENT FOR CONGESTION UPGRADES

1. Assessment of the cost and timing of transmission upgrades to reduce congestion and/or losses, to interconnect generation, to facilitate power purchases and sales, and to otherwise maintain a viable transmission network;

SPP's Integrated Transmission Planning Process (ITP) is an annual planning cycle that assesses near- and long-term economic and reliability transmission needs. The ITP produces a ten-year transmission expansion plan each year, combining near-term, ten-year, and North American Electric Reliability Corporation transmission planning (TPL-001-4) compliance assessments into one study. A 20-year assessment is performed once every five years unless otherwise directed by the SPP Board of Directors. The ITP process seeks to target a reasonable balance between long-term transmission investments and congestion costs to customers.

The 2020 Integrated Transmission Plan looked ahead 10 years to ensure the SPP region could deliver energy reliably and economically, facilitate public policy objectives, seek solutions with neighboring regions and maximize benefits to end-use customers. Three distinct scenarios were considered to account for variations in system conditions over ten years. These scenarios considered requirements to support firm deliverability of capacity for reliability while exploring rapidly evolving technology that may influence the transmission system and energy industry. The scenarios included varied wind projections, utility-scale and distributed solar, energy storage resources, generation retirements and electric vehicles. Ultimately, the analysis resulted in the approval of a portfolio of 54 transmission projects across the SPP region at a cost of approximately $532 million. Evergy received six transmission projects as a result of the 2020 ITP study – all of which consisted of breaker replacements identified in the short circuit portion of the ITP study. The need dates for the projects are 6/1/2022.

3.1.2 <u>TRANSMISSION ASSESSMENT FOR ADVANCE TECHNOLOGIES</u>

2. Assessment of transmission upgrades to incorporate advanced technologies;

Three distinct scenarios were considered during Southwest Power Pool's 2020 Integrated Transmission Planning process. These scenarios considered requirements to support firm deliverability of capacity for reliability while exploring rapidly evolving technology that may influence the transmission system and energy industry. The scenarios included varied wind projections, utility-scale and distributed solar, energy storage resources, generation retirements and electric vehicles. Transmission upgrades were selected based on their ability to meet the varied needs identified in all scenarios.

3.1.3 <u>AVOIDED TRANSMISSION COST ESTIMATE</u>

3. Estimate of avoided transmission costs; 22.045 Transmission and Distribution Analysis,

The Evergy transmission projects included in the SPP regional planning processes for reliability improvement or economic benefits would not be impacted by the implementation of DSM programs. Therefore, the only avoided cost for transmission facilities are the transmission equipment additions associated with distribution facility expansions.

3.1.4 REGIONAL TRANSMISSION UPGRADE ESTIMATE

4. Estimate of the portion and amount of costs of proposed regional transmission upgrades that would be allocated to the utility, and if such costs may differ due to plans for the construction of facilities by an affiliate of the utility instead of the utility itself, then an estimate, by upgrade, of this cost difference;

Table 4 below shows the SPP projected annual transmission revenue requirement allocated to Evergy Metro for regional transmission upgrades.

Table 4: SPP Projected ATRR Allocated to Evergy Metro

Year	Projected Region-Wide Revenue Requirement	Allocated to the EMe Zone	Allocation to the EMe Native System Load
2021	$548,344,441	$43,469,134	$37,745,632
2022	$552,236,015	$43,529,216	$37,797,803
2023	$514,206,103	$40,143,815	$34,858,152
2024	$502,467,850	$39,209,036	$34,046,453
2025	$487,979,700	$38,070,022	$33,057,411
2026	$472,887,797	$36,886,167	$32,029,432
2027	$457,679,255	$35,693,648	$30,993,930
2028	$442,122,062	$34,475,235	$29,935,943
2029	$426,540,049	$33,254,979	$28,876,356

The region-wide revenue requirement includes amounts for projects owned by Transource Missouri. Transource Missouri is a wholly-owned subsidiary of Transource Energy, LLC, which is a joint venture between transmission holding company subsidiaries of Evergy and American Electric Power ("AEP"). Evergy owns 13.5 percent of Transource Energy and AEP owns the other 86.5 percent.

3.1.5 REVENUE CREDITS ESTIMATE

5. Estimate of any revenue credits the utility will receive in the future for previously built or planned regional transmission upgrades; and

Table 5 below shows the region-wide 2021 revenue requirement for the SPP-directed projects owned by Evergy.

Table 5: Region-Wide Revenue Requirements for SPP Projects Owned by Evergy

Evergy Metro SPP-Directed Projects	2021 Region-Wide Revenue Requirement
Projects with NTCs issued prior to June 19, 2010	
Tomahawk-Bendix Reconductor	$33,385
West Gardner Autotransformer	$162,739
Stilwell-Antioch Reconductor	$71,541
Antioch-Oxford Reconductor	$48,167
Antioch-Oxford Reconductor Switches	$0
Reconductor Craig-College -161kV Line	$14,921
Mayview -Line Terminal Equipment to 600A	$0
South Waverly Capacity Bank	$21,745
Craig Sub 161 kV Capacitor Bank	$56,010
Westar Energy - Reservation	$3,428
Total	$411,936
Projects with NTCs issued after June 19, 2010	
Swissvale-Stilwell Tap at W. Gardner	$382,793
Loma Vista E.-Winchester Jct -161kV	$6,876
W. Gardner Line Terminals	$54,162
Total	$443,831
Projects with a Need Date after October 1 ,2015	
Craig 161 kV Breaker	$1,209
Midtown 161 kV Breakers	$24,671
Southtown 161 kV Breakers	$3,490
Iatan Stranger 345kV Voltage Conversion	$246,049
Northeast-Charlotte-Crosstown -161kV Reactor	$8,776
Stilwell Relaying	$3,728
Brookridge-Overland Park 161kV Term Upgrades	$25,724
Sub - Olathe - Switzer 161kV Ckt1 Terminal Upgrades	$31,140
Total	$344,787
Total Evergy Metro SPP-Directed Projects	$1,200,554

3.1.6 TIMING OF NEEDED RESOURCES ESTIMATE

6. Estimate of the timing of needed transmission and distribution resources and any transmission resources being planned by the RTO primarily for economic reasons that may impact the alternative resource plans of the utility.

The SPP 2020 ITP portfolio did not contain any economic projects in the Evergy Metro service territory, thus there are no transmission resources planned by the RTO that would impact the alternative resource plans of Evergy.

3.2 USE OF RTO TRANSMISSION EXPANSION PLAN

(B) The utility may use the RTO transmission expansion plan in its consideration of the factors set out in subsection (3)(A) if all of the following conditions are satisfied:

See response to Section 3.1.1 above for description of SPP RTO transmission expansion planning processes.

3.2.1 UTILITY PARTICIPATION IN RTO TRANSMISSION PLAN

1. The utility actively participates in the development of the RTO transmission plan;

Evergy actively participates in the development of SPP transmission expansion plans through a number of related activities. These include participation in the Model Development Working Group (MDWG), the Transmission Working Group (TWG) and regional transmission expansion workshops

Participation in the MDWG involves reviewing and updating the transmission planning models used for regional transmission expansion analysis. This includes adding Evergy transmission projects into the planning models and providing a substation level load forecast for the seasonal and future years planning models. The expected generation dispatch required to meet Evergy load requirements is also included in these models. These models form the basis for the reliability analysis needed to identify future transmission projects to maintain reliable service and reduce transmission congestion.

The Transmission Working Group (TWG) is responsible for planning criteria to evaluate transmission additions, seasonal Available Transfer Capability (ATC) calculations, seasonal flowgate ratings, oversight of coordinated planning efforts, and oversight of transmission contingency evaluations. The TWG works with individual transmission owners on issues of coordinated planning and North American Electric Reliability Corporation (NERC) and SPP compliance. The TWG coordinates the calculation of the ATC for commerce maintaining regional reliability, while ensuring study procedures and criteria are updated to meet the regional needs of SPP, in cooperation with governing regulatory entities. The TWG is responsible for publication of seasonal and future reliability assessment studies on the transmission system of the SPP region. The TWG works closely with the Economic Studies Working Group (ESWG) to develop the scope documents used to direct the analysis and studies performed for the ITP process.

SPP hosts ITP workshops annually to get stakeholder input to the transmission planning process and provide analysis results for stakeholder review. The workshops allow SPP stakeholders to provide input on assumptions for economic analysis and review identified needs and proposed solutions selected by SPP. Evergy proposes projects through SPP's FERC Order No. 1000 process, reviews selected transmission projects in its area and coordinates with SPP regarding details within its area that may affect proposed solutions. In other instances, Evergy offers an operating guide to mitigate a transmission problem and avoid new transmission construction.

3.2.2 <u>ANNUAL REVIEW OF RTO EXPANSION PLANS</u>

2. The utility reviews the RTO transmission overall expansion plans each year to assess whether the RTO transmission expansion plans, in the

judgment of the utility decision makers, are in the interests of the utility's Missouri customers;

Evergy reviews transmission projects in its area, coordinates with SPP regarding details within its area that may affect proposed solutions, or requests restudy for projects that it believes are not required. Evergy planning personnel participate throughout the year within the planning process providing insight and review of the transmission plans. In some instances, Evergy may be able to offer an operating guide to mitigate a transmission problem and avoid or delay new transmission construction. Also, Evergy personnel participate in the overall approval of RTO expansion plans through the SPP approval process within the Markets and Operation Policy Committee and Members Committee.

3.2.3 ANNUAL REVIEW OF SERVICE TERRITORY EXPANSION PLAN

3. The utility reviews the portion of RTO transmission expansion plans each year within its service territory to assess whether the RTO transmission expansion plans pertaining to projects that are partially- or fully-driven by economic considerations (i.e., projects that are not solely or primarily based on reliability considerations), in the judgment of the utility decision-makers, are in the interests of the utility's Missouri customers;

Evergy reviews transmission plans and projects within its service territory that develop through the SPP RTO transmission expansion plan. Many are zonal projects providing additional obligations to serve or meet specific planning and bulk electric reliability criteria. For region-wide project sets identified through the SPP Integrated Transmission Planning process, projects meet a wide range of needs including reduced production costs, reduced congestion, reduced system losses and base reliability needs.

3.2.4 DOCUMENTATION AND DESCRIPTION OF ANNUAL REVIEW OF RTO OVERALL AND UTILITY-SPECIFIC EXPANSION PLANS

4. The utility documents and describes its review and assessment of the RTO overall and utility-specific transmission expansion plans; and

Evergy reviews transmission projects in its area and coordinates with SPP regarding details within its area that may affect proposed solutions or requests restudy for projects that it believes are not required. Evergy planning personnel participate throughout the year within the planning process providing insight and review of the transmission plans. In some instances, Evergy may be able to offer an operating guide to mitigate a transmission problem and avoid or delay new transmission construction. Also, Evergy personnel participate in the overall approval of RTO expansion plans through the SPP approval process within the Markets and Operation Policy Committee and Members Committee.

3.2.5 AFFILIATE BUILD TRANSMISSION PROJECT DISCUSSION

5. If any affiliate of the utility intends to build transmission within the utility's service territory where the project(s) are partially- or fully-driven by economic considerations, then the utility shall explain why such affiliate built transmission is in the best interest of the utility's Missouri customers and describe and document the analysis performed by the utility to determine whether such affiliate-built transmission is in the interest of the utility's Missouri customers.

Transource Energy, LLC ("Transource"), a joint venture between Evergy and American Electric Power ("AEP"), was created to build and invest in transmission infrastructure. Transource will pursue competitive transmission projects in the SPP region, the MISO and PJM regions, and potentially other regions in the future. Evergy owns 13.5 percent of Transource and AEP owns the other 86.5 percent of Transource.

At this point, it is Evergy's intent to pursue, develop, construct, and own through its interest in Transource – rather than through Evergy Metro and/or Evergy Missouri West – any future regional and inter-regional transmission projects subject to regional cost allocation. While it is premature to determine the specific impact on the regionally allocated costs resulting from constructing projects within Transource, it is anticipated that the partnership between Evergy and AEP will provide for a financially strong, cost-competitive, and technically-proficient transmission development entity. The scale, execution experience, and engineering expertise that Transource expects to be able to bring to the projects should provide benefits to customers through lower construction costs, better access to capital, and operational efficiencies.

3.3 RTO EXPANSION PLAN INFORMATION

(C) The utility shall provide copies of the RTO expansion plans, its assessment of the plans, and any supplemental information developed by the utility to fulfill the requirements in subsection (3)(B) of this rule.

The following SPP regional transmission planning reports are provided as attachments to this report.

2020 SPP Integrated Transmission Planning Assessment Report

2021 SPP Transmission Expansion Plan Report

2021 SPP Transmission Expansion Plan Report Appendix 1

The 2020 SPP Integrated Transmission Planning Assessment is described in Section 3.1.1 above. The 2021 SPP Transmission Expansion Plan (STEP) Report and Project List summarize 2020 activities that impact future development of the SPP transmission grid. Six distinct areas of transmission planning are discussed in this report: Transmission Services, Generation Interconnection, Integrated Transmission Planning, High Priority Studies, Sponsored Upgrades, and Interregional Coordination.

3.4 TRANSMISSION UPGRADES REPORT

(D) The utility shall provide a report for consideration in 4 CSR 240-22.040(3) that identifies the physical transmission upgrades needed to interconnect generation, facilitate power purchases and sales, and otherwise maintain a viable transmission network, including:

3.4.1 TRANSMISSION UPGRADES REPORT – PHYSICAL INTERCONNECTION WITHIN RTO

1. A list of the transmission upgrades needed to physically interconnect a generation source within the RTO footprint;

It is not possible to provide a specific list of transmission upgrades needed to physically interconnect a generation resource within the SPP footprint. Any generation interconnection request within the SPP must proceed through the generation interconnection process as defined by the SPP transmission tariff. That process will examine the specific location proposed for generator interconnection and develop the necessary transmission upgrades needed at that location.

3.4.2 TRANSMISSION UPGRADES REPORT – DELIVERABILITY ENHANCEMENT WITHIN RTO

2. A list of the transmission upgrades needed to enhance deliverability from a point of delivery within the RTO including requirements for firm transmission service from the point of delivery to the utility's load and requirements for financial transmission rights from a point of delivery within the RTO to the utility's load;

In the SPP, requests for firm transmission service are processed through the Aggregate Facility Study (AFS) process. The AFS process is performed two times per year by collectively analyzing specific transmission service requests, including those associated with generation interconnection requests, across the entire SPP footprint. These service reservations are modeled based on control area to control area transfers. The transmission system is assessed with these potential service requests and, where needed, transmission improvements are identified that would enable the service to occur without standard or criteria violations. All transmission customers are allocated cost responsibility for portions of the various upgrades needed to deliver all of the transmission service requests. Transmission customers may adjust their conditions following the posting of the preliminary results if their initial conditions were not met; otherwise, the request will be considered withdrawn. This is an iterative process until all conditions are met. The remaining transmission customers with service requests in the process agree to the projects needed to deliver the remaining transmission service and share the resulting upgrade costs. Those remaining upgrade projects are included in the next SPP transmission expansion plan process.

Because of the iterative nature of the Aggregate Facility Study process it is not possible to identify specific transmission upgrades needed to deliver energy from a resource in the RTO footprint to Evergy until the process for a specific transmission service request has been completed.

3.4.3 TRANSMISSION UPGRADES REPORT – PHYSICAL INTERCONNECTION OUTSIDE RTO

3. A list of transmission upgrades needed to physically interconnect a generation source located outside the RTO footprint;

It is not possible to develop a list of specific upgrades needed to interconnect a generation resource located outside the SPP without actually making a generation interconnection request at a specific location.

3.4.4 <u>TRANSMISSION UPGRADES REPORT – DELIVERABILITY ENHANCEMENT OUTSIDE RTO</u>

4. A list of the transmission upgrades needed to enhance deliverability from a generator located outside the RTO including requirements for firm transmission service to a point of delivery within the RTO footprint and requirements for financial transmission rights to a point of delivery within the RTO footprint;

It is not possible to develop a list of specific upgrades needed to deliver capacity and energy from a generation resource located outside the SPP without actually making a generation interconnection request and an associated transmission service request at a specific location.

3.4.5 <u>TRANSMISSION UPGRADES REPORT – ESTIMATE OF TOTAL COST</u>

5. The estimated total cost of each transmission upgrade; and

A list of Evergy Metro transmission projects included in the 2021 SPP Transmission Expansion Plan (STEP) is shown below in Table 6.

Table 6: Evergy Metro Transmission Upgrades 2021 SPP STEP

Transmission Project	Cost Estimate	Project Type	Need Date
Increase rating of Nashua transformer to 650/715 MVA.	$12,600,000	ITP20	1/1/2033
Install new 2-ohm line reactor at Northeast substation on the 161 kV line from Northeast to Charlotte to Crosstown.	$204,681	Economic	1/1/2018
Replace 1 breaker at Craig 161 kV with 63 kA breakers	$291,361	Regional Reliability	6/1/2021
Replace 2 breakers at Leeds 161 kV with 40 kA breakers	$502,440	Regional Reliability	6/1/2021
Replace 2 breakers at Midtown 161 kV with 40 kA breakers	$363,914	Regional Reliability	6/1/2021
Replace 4 breakers at Southtown 161 kV with 40 kA breakers	$1,004,980	Regional Reliability	6/1/2021
Replace three breakers at the Northeast 161 kV station with 63 kA breakers	$887,479	Regional Reliability	6/1/2022
Replace 1 breaker at the Stilwell 161 kV station with a 63 kA breaker	$566,485	Regional Reliability	6/1/2022
Replace 1 breaker at the Leeds 161 kV station with a 40 kA breaker	$566,485	Regional Reliability	6/1/2022
Replace 1 breaker at the Shawnee Mission 161 kV station with a 40 kA breaker	$566,485	Regional Reliability	6/1/2022
Replace 1 breaker at the Southtown 161 kV station with a 40 kA breaker	$566,485	Regional Reliability	6/1/2022
Replace 2 breakers at the Craig 161 kV station with a 63 kA breakers	$1,132,970	Regional Reliability	6/1/2022

Total estimated construction cost for these transmission upgrades is $19,253,765. However, SPP has not yet issued a Notification to Construct, which directs project owners to begin construction on specific projects, for the first project listed.

3.4.6 TRANSMISSION UPGRADES REPORT – COST ESTIMATES

6. The estimated fraction of the total cost and amount of each transmission upgrade allocated to the utility.

A list of Evergy transmission projects included in the 2021 SPP STEP and the portion of their estimated cost allocated to Evergy Metro is shown below in Table 7.

Table 7: Transmission Upgrade Cost Allocated to Evergy

Transmission Project	Cost Estimate	% Allocated to Evergy Metro	Evergy Metro $
Increase rating of Nashua transformer to 650/715 MVA.	$12,600,000	68.8%	$8,668,800
Install new 2-ohm line reactor at Northeast substation on the 161 kV line from Northeast to Charlotte to Crosstown.	$204,681	68.8%	$140,821
Replace 1 breaker at Craig 161 kV with 63 kA breakers	$291,361	68.8%	$200,456
Replace 2 breakers at Leeds 161 kV with 40 kA breakers	$502,440	68.8%	$345,679
Replace 2 breakers at Midtown 161 kV with 40 kA breakers	$363,914	68.8%	$250,373
Replace 4 breakers at Southtown 161 kV with 40 kA breakers	$1,004,980	68.8%	$691,426
Replace three breakers at the Northeast 161 kV station with 63 kA breakers	$887,479	68.8%	$610,586
Replace 1 breaker at the Stilwell 161 kV station with a 63 kA breaker	$566,485	68.8%	$389,742
Replace 1 breaker at the Leeds 161 kV station with a 40 kA breaker	$566,485	68.8%	$389,742
Replace 1 breaker at the Shawnee Mission 161 kV station with a 40 kA breaker	$566,485	68.8%	$389,742
Replace 1 breaker at the Southtown 161 kV station with a 40 kA breaker	$566,485	68.8%	$389,742
Replace 2 breakers at the Craig 161 kV station with a 63 kA breakers	$1,132,970	68.8%	$779,483

SECTION 4: ADVANCED TECHNOLOGY ANALYSIS

(4) Analysis Required for Transmission and Distribution Network Investments to Incorporate Advanced Technologies.

4.1 TRANSMISSION UPGRADES FOR ADVANCED TRANSMISSION TECHNOLOGIES

(A) The utility shall develop, and describe and document, plans for transmission upgrades to incorporate advanced transmission technologies as necessary to optimize the investment in the advanced technologies for transmission facilities owned by the utility. The utility may use the RTO transmission expansion plan in its consideration of advanced transmission technologies if all of the conditions in paragraphs (3)(B)1. Through (3)(B)3. are satisfied.

Evergy will use advanced technologies such as Hybrid Structure Design, Solid Dielectric Cables, and Fiber Optic Shield Wire where applicable in transmission upgrades included in the SPP regional transmission expansion plan.

4.2 DISTRIBUTION UPGRADES FOR ADVANCED DISTRIBUTION TECHNOLOGIES

(B) The utility shall develop, and describe and document, plans for distribution network upgrades as necessary to optimize its investment in advanced distribution technologies.

The STP includes a grid modernization program to invest in technology supporting advancement in distribution operation. The STP focuses on expanding automated grid operation through schemes like FLISR (Fault Location Isolation and Supply Restoration), VVO (Volt-VAR Optimization) and FLA (Fault Location Analysis) under our ADMX program. ADMX is an Evergy branded, architecture-based approach to ADMS that will capitalize on innovation, flexibility and adaptability.

ADMX's key benefit is the ability to execute each automated grid operation mode as makes sense for our business and asset deployment.

4.3 OPTIMIZATION OF INVESTMENT IN ADVANCED TRANSMISSION AND DISTRIBUTION TECHNOLOGIES

(C) The utility shall describe and document its optimization of investment in advanced transmission and distribution technologies based on an analysis of—

4.3.1 OPTIMIZATION OF INVESTMENT – TOTAL COSTS AND BENEFITS

1. ***Total costs and benefits, including:***

4.3.1.1 Distribution Analysis

Evergy has not yet performed a comprehensive analysis to optimize investments in advanced distribution technologies.

Under the STP, Evergy will be completing an analysis on each ADMX module. The analysis will consider upfront and ongoing costs, licensing requirements, required field installations and overall system performance to support our STP operational goals.

In addition to the analysis completed under STP, certain voltage management schemes like peak demand management, will be modeled in Evergy's IRP process.

Each of the technologies are assessed for cost/benefit vs. alternative investments on an as needed basis. Many grid automation applications, intelligent grid assets and newer technologies are initially tested through a pilot project before wide-scale deployment. Pilots are prudent in order to verify correct operation and maintain an environment that is flexible.

4.3.2 <u>OPTIMIZATION OF INVESTMENT – COST OF ADVANCED GRID INVESTMENTS</u>

A. Costs of the advanced grid investments;

4.3.2.1 <u>Distribution</u>

Refer to comments in Section 4.3.1.1

4.3.3 <u>OPTIMIZATION OF INVESTMENT – COST OF NON-ADVANCED GRID INVESTMENTS</u>

B. Costs of the non-advanced grid investments;

4.3.3.1 <u>Distribution</u>

Refer to comments in Section 4.3.1.1

4.3.4 <u>OPTIMIZATION OF INVESTMENT – REDUCTION OF RESOURCE COSTS</u>

C. Reduced resource costs through enhanced demand response resources and enhanced integration of customer-owned generation resources; and

4.3.4.1 <u>Distribution</u>

Refer to comments in Section 4.3.1.1

4.3.5 <u>OPTIMIZATION OF INVESTMENT – REDUCTION OF SUPPLY-SIDE COSTS</u>

D. Reduced supply-side production costs;

4.3.5.1 <u>Distribution</u>

Refer to comments in Section 4.3.1.1

4.4 <u>COST EFFECTIVENESS OF INVESTMENT IN ADVANCED TRANSMISSION AND DISTRIBUTION TECHNOLOGIES</u>

2. Cost effectiveness, including

4.4.1 COST EFFECTIVENESS – INCREMENTAL COSTS ADVANCED GRID TECHNOLOGIES VS NON-ADVANCED GRID TECHNOLOGIES

A. The monetary values of all incremental costs of the energy resources and delivery system based on advanced grid technologies relative to the costs of the energy resources and delivery system based on non-advanced grid technologies;

4.4.1.1 Distribution

Refer to comments in Section 4.3.1.1

4.4.2 COST EFFECTIVENESS – INCREMENTAL BENEFITS ADVANCED GRID TECHNOLOGIES VS NON-ADVANCED GRID TECHNOLOGIES

B. The monetary values of all incremental benefits of the energy resources and delivery system based on advanced grid technologies relative to the costs and benefits of the energy resources and delivery system based on non-advanced grid technologies; and

4.4.2.1 Distribution

Refer to comments in Section 4.3.1.1

4.4.3 OPTIMIZATION OF INVESTMENT – NON-MONETARY FACTORS

C. Additional non-monetary factors considered by the utility;

4.4.3.1 Distribution

Refer to comments in Section 4.3.1.1

4.4.4 OPTIMIZATION OF INVESTMENT – SOCIETAL BENEFIT

4.4.4.1 3. Societal benefit, including:

4.4.4.2 Societal Benefit – Consumer Choice

A. More consumer power choices;

4.4.4.2.1 Distribution

Refer to comments in Section 4.3.1.1

4.4.4.3 Societal Benefit – Existing Resource Improvement

B. Improved utilization of existing resources;

4.4.4.3.1 Distribution

4.4.4.4 Refer to comments in Section 4.3.1.1

4.4.4.5 Societal Benefit – Price Signal Cost Reduction

C. Opportunity to reduce cost in response to price signals;

4.4.4.5.1 Distribution

Refer to comments in Section 4.3.1.1

4.4.4.6 Societal Benefit –

D. Opportunity to reduce environmental impact in response to environmental signals; Environmental Impact

4.4.4.6.1 Distribution

Refer to comments in Section 4.3.1.1

4.4.5 OPTIMIZATION OF INVESTMENT – OTHER UTILITY-IDENTIFIED FACTORS

4. Any other factors identified by the utility; and

4.4.5.1.1 Distribution

Refer to comments in Section 4.3.1.1

4.4.6 OPTIMIZATION OF INVESTMENT –OTHER NON-UTILITY IDENTIFIED FACTORS

5. Any other factors identified in the special contemporary issues process pursuant to 4 CSR 240-22.080(4) or the stakeholder group process pursuant to 4 CSR 240-22.080(5).

4.4.6.1 Distribution

Refer to comments in Section 4.3.1.1

4.5 NON-ADVANCED TRANSMISSION AND DISTRIBUTION INCLUSION

(D) Before the utility includes non-advanced transmission and distribution grid technologies in its triennial compliance filing or annual update filing, the utility shall—

4.5.1 NON-ADVANCED TRANSMISSION AND DISTRIBUTION REQUIRED ANALYSIS

1. Conduct an analysis which demonstrates that investment in each non-advanced transmission and distribution upgrade is more beneficial to consumers than an investment in the equivalent upgrade incorporating advanced grid technologies. The utility may rely on a generic analysis as long as it verifies its applicability; and

4.5.1.1 Distribution

Evergy is not proposing any new non-advanced distribution grid technologies or programs in this triennial IRP compliance filing.

Evergy understands that prior to including new non-advanced distribution grid technologies in future IRP filings, Evergy will conduct, describe, and document an analysis which demonstrates that investment in each non-advanced distribution upgrade is more beneficial to consumers than an investment in the equivalent upgrade incorporating advanced grid technologies. Evergy further understands that we may present a generic analysis as long as we verify its applicability.

4.5.2 NON-ADVANCED TRANSMISSION AND DISTRIBUTION ANALYSIS DOCUMENTATION

2. Describe and document the analysis.

4.5.2.1 Distribution

Refer to comments in Section 4.5.1.1

4.6 ADVANCED TRANSMISSION AND DISTRIBUTION REQUIRED COST-BENEFIT ANALYSIS

(E) The utility shall develop, describe, and document the utility's cost benefit analysis and implementation of advanced grid technologies to include:

4.6.1.1 Distribution

Under the STP, Evergy will be completing an analysis on each ADMX module. The analysis will consider upfront and ongoing costs, licensing requirements, required field installations and overall system performance to support our STP operational goals.

In addition to the analysis completed under STP, certain voltage management schemes like peak demand management, will be modeled in Evergy's IRP process.

Each of the technologies are assessed for cost/benefit vs. alternative investments on an as needed basis. Many grid automation applications, intelligent grid assets and newer technologies are initially tested through a pilot project before wide-scale deployment. Pilots are prudent in order to verify correct operation and maintain an environment that is flexible.

4.6.2 ADVANCED GRID TECHNOLOGIES UTILITY'S EFFORTS DESCRIPTION

1. A description of the utility's efforts at incorporating advanced grid technologies into its transmission and distribution networks;

4.6.2.1 Distribution

Historical Advanced Grid Technology Deployments

The distribution grid in place at Evergy today is substantially "smart" having benefited from decades of power engineering expertise and adoption of relevant technology enhancements. The existing systems already execute a variety of sophisticated system operations and protection functions. Much of the automation has been accomplished through embedding incremental technological advancements into Evergy's asset and construction standards. The following sections describe many of the advanced distribution technologies that have and are currently being implemented at Evergy.

SmartGrid Demonstration Project

Evergy's SmartGrid Demonstration Project deployed an end-to-end SmartGrid (within Kansas City, MO) that provided a wide array of technologies and components. These were grouped into five (5) major sectors: Smart Distribution, Smart Metering, Interoperability and Security, Smart End-Use and Smart Generation. The DOE portion of the project was completed in 2015, with decommissioning of immature technologies through mid-2016. The final report was filed with the DOE in 2016. Please reference Evergy Smart Grid Project for additional details.

4.6.3 DISTRIBUTION ADVANCED GRID TECHNOLOGIES IMPACT DESCRIPTION

2. A description of the impact of the implementation of distribution advanced grid technologies on the selection of a resource acquisition strategy; and

Evergy will be taking steps under STP to implement various modules under our ADMX plan. The main near-term focuses are on automated switching and voltage management schemes. These schemes will execute automation engines like Fault Location Isolation and Supply Restoration (FLISR) and peak demand management. In addition to these automation engines, upgraded SCADA applications will be implemented to coincide with the automation schemes enabling components of advanced grid technologies.

Complete project timelines are still being developed in coordination with our RFP process with FLISR and peak demand management schemes tentatively scheduled to be in moderately rolled out in late 2023.

SECTION 5: UTILITY AFFILIATION

(5) The electric utility shall identify and describe any affiliate or other relationship with transmission planning, designing, engineering, building, and/or construction management companies that impact or may be impacted by the electric utility. Any description and documentation requirements in sections (1) through (4) also apply to any affiliate transmission planning, designing, engineering, building, and/or construction management company or other transmission planning, designing, engineering, building, and/or construction management company currently participating in transmission works or transmission projects for and/or with the electric utility.

Transource Energy, LLC ("Transource"), a joint venture between Evergy and American Electric Power ("AEP"), was created to build and invest in transmission infrastructure. Transource will pursue competitive transmission projects in the SPP region, the MISO and PJM regions, and potentially other regions in the future. Evergy owns 13.5 percent of Transource and AEP owns the other 86.5 percent of Transource.

At this point, it is Evergy's intent to pursue, develop, construct, and own through its interest in Transource – rather than through Evergy Metro and/or Evergy Missouri West – any future regional and inter-regional transmission projects subject to regional cost allocation. While it is premature to determine the specific impact on the regionally allocated costs resulting from constructing projects within Transource, it is anticipated that the partnership between Evergy and AEP will provide for a financially-strong, cost-competitive, and technically-proficient transmission development entity. The scale, execution experience, and engineering expertise that Transource expects to be able to bring to the projects should provide benefits to customers through lower construction costs, better access to capital, and operational efficiencies.

SECTION 6: FUTURE TRANSMISSION PROJECTS

(6) The electric utility shall identify and describe any transmission projects under consideration by an RTO for the electric utility's service territory.

SPP is scheduled to complete another ITP assessment in 2021, but projects are not yet under consideration.