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VOLUME 4.5

TRANSMISSION AND DISTRIBUTION ANALYSIS

THE EMPIRE DISTRICT ELECTRIC COMPANY

4 CSR 240-22.045

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HIGHLY CONFIDENTIAL

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TRANSMISSION AND DISTRIBUTION ANALYSIS

4 CSR 240-22.045 Transmission and Distribution Analysis

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 Opportunities to Reduce Transmission Power and Energy Losses

(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 directly dependent on the amount of current flowing on the line in question as well as the specific characteristics of the line (conductor type, line length, etc.). Empire uses a combination of 161-kV, 69-kV, and 34.5-kV transmission lines for serving its respective substations. The majority of Empire's 161-kV transmission infrastructure utilizes H-frame structures with a 795 ACSR type conductor. The associated summer A and B ratings are 290 and 341 MVA, respectively. If/When a particular line segment studied is found to have become overloaded; Empire evaluates the possibility of bundling conductors on the structures. In doing so, the losses on the bundled circuit are now halved, due to the reduced impedance characteristics. The flow on each of the conductors is reduced thereby reducing the direct losses on the conductor. The process of bundling a conductor also doubles the capacity of the chosen conductor. The resultant summer A and B ratings for 795 ACSR are 579 and 682 MVA, respectively.

In evaluating Empire's transmission system losses, approximately 13.5 MW of a total of 31.8 MW is accounted for on the 161-kV system. This is primarily due to the topography of Empire's service territory mainly consisting of rural loads. The aforementioned topography does not necessitate the need to serve dense load pockets with much larger conductor types than 795 ACSR, such as 1192 ACSR used in urban load environments; however, Empire's topography necessitates longer distances to be reconductored/bundled once a line segment is identified as a required upgrade. An example of such would be Empire's 161-kV line connecting Tipton Ford #292 to Monett #383 Substations. This specific line is approximately 29 miles in length. A general cost comparative analysis of reconductoring the line requiring a rebuild versus bundling the conductor for minimal structural change-outs of the line yields is shown in *Table 4.5-1.*

Configuration	**R**	**X**	**B**	**Losses in 52015 SP Model (in MW)**	**Difference (in MW)**
795 ACSR	0.0131	0.0856	0.0422	1.07	
2-795 ACSR	0.0065	0.0428	0.0211	1.06	0.01
2-566 ACSR	0.0093	0.0617	0.0585	1.09	0.02
Estimated cost to reconductor/bundle entire circuit:				$18,850,000	
Average cost per kW of loss reduction:				2-795 ACSR	$188,500
				2-556 ACSR	$94,250
Ratio of Avoided Transmission Costs (@ $61.44 / kW):				2-795 ACSR	3,068 : 1
				2-556 ACSR	1,534 : 1

Table 4.5-1 - Comparative Costs of Reconductoring versus Conductor Bundling of 161-kV Line

If dual bundled 795 ACSR or dual bundled 556 ACSR were chosen as a loss reduction option, the cost for this specific line is $188,500/kW and $94,250/kW, respectively. As related to the avoided transmission costs, the ratios are 3,068 and 1,534, respectively. These ratios exhibit the cost ineffectiveness of transmission loss reduction.

Empire's system losses (in MWs) represent approximately 0.02 percent of the losses evident in the projected 2015 summer peak model of the entire SPP footprint. When compared to like-configured systems (i.e., comparable size and topography), Empire's system losses are of negligible difference to that of the comparative averages, as shown in *Table 4.5-2.*

Area	Load (MW)	Losses (MW)	% Loss
523	1,092	22.5	2.0%
525	1,550	49.92	3.2%
534	1,366	36.45	2.7%
540	2,022	28.81	1.4%
Empire	1,170	32.19	2.7%
Averages	1,440	33.97	2.4%

Table 4.5-2 - Empire's System Losses

With respect to the distribution level, Empire has taken measures to standardize their construction efforts in stocking commonly used conductors within the industry. One example is the evaluation and subsequent restricted use of redundant conductor types. 4/0 ACSR was a commonly used conductor in past installations alongside 336 ACSR. The structural requirements are much the same for either conductor type, however, the ampacity of 336 ACSR as compared to 4/0 was 519 and 366 amps, respectively (per Southwire's Overhead Conductor Manual, 2nd Edition). Not only were gains had in the ampacity of the likened conductors, but also loss gains made. *Table 4.5-3* provides a comparison of these conductors.

	Ohm / mi at 75 C	Ampacity (amps)
4/0 ACSR	0.5999	366
336 ACSR	0.3298	519

Table 4.5-3 - Comparison of Conductors of Interest

In standardizing to a 336 ACSR conductor versus the previously used 4/0 ACSR, line losses were reduced while the capacity of the wires increased. In doing so, capital projects on the distribution level are able to be delayed, more readily available switching paths are gained, and system flexibility increased.

1.1.1 Distribution System Overview

Empire has a single planning group tasked with transmission and distribution planning efforts. This planning group analyzes data, develops electrical models representative of the Empire distribution system, and performs associated power flow studies to assess and prioritize system improvement needs as system dynamics dictate. Empire maintains distribution voltages of 25-kV, 12.47-kV, and 4.16-kV three-phase as well as a mixture of open wye (dual-phase) and single-phase feeders. These feeders are composed of an assortment of conductor types and configurations.

The majority of the Empire distribution system mirrors that of a rural area co-op. Many of Empire's distribution feeders are long in length and have a distributed load profile. The average total distribution feeder exposure length within the Empire footprint is approximately 11 miles. This distance encompasses the total circuitry length (i.e., all trunk lines, taps, radials, etc.). The average length of overhead three phase of all Empire distribution circuits is 7.21 miles. The highest density loads are located in the Joplin and Branson areas. The rural areas have the most widespread infrastructure components and have the fewest or most limited emergency ties, where minute load manipulation can cause large disturbances to customers' voltage. The limited availability of switching paths is the largest factor in restoration efforts as well as feeder relief. The Empire distribution system is configured as a radial fed system under normal operating conditions. Empire maintains three auto throw schemes in different parts of the system (Joplin and Branson in Missouri, and Welch, Oklahoma) where alternate switching paths with available capacity are readily available. These type systems have limited applicability due to the typical Empire distribution circuit being rural in character.

Expansion of the distribution network occurs in load pockets of expansive development (i.e., subdivision expansion, large industrial customer development on greenfield sites, etc.). System expansion typically occurs on a smaller scale in magnitude; however, with the addition of these types of incremental load additions, the existing infrastructure is impacted more heavily due to the voltage profile drastically changing from the application of spot load(s) applied to the circuit. Empire constantly evaluates possible economic development projects and their associative impacts on the available distribution feeders, power transformers, and existing customer voltage profiles so as to determine what specific large scale upgrades are needed for a specific project of interest.

Empire's planning department also maintains distribution feeder models. Empire has migrated to new distribution evaluation software and currently integrating the available mapping resources to better model the distribution systems. The new model will allow for detailed evaluations as data becomes available so that as expansion occurs and load reconfigures, projects may be identified and prioritized accordingly.

1.1.2 Annual Scope of Work

Throughout each year, Empire's planning department prepares a number of system studies to determine weaknesses or risks and to assess the overall adequacy of their distribution system. The majority of the work focuses on increasing reliability and prioritizing work based upon cost, scope, impact, and effectiveness. This work encompasses four specific areas which include capacity, contingency, voltage, and condition. Empire uses a variety of tools to conduct these types of evaluations, including software such as Google Earth Pro, CYME International's Power Engineering Solutions, and GTI geospatial analysis and viewing.

Figure 4.5-1 provides a screenshot from Google Earth Pro.

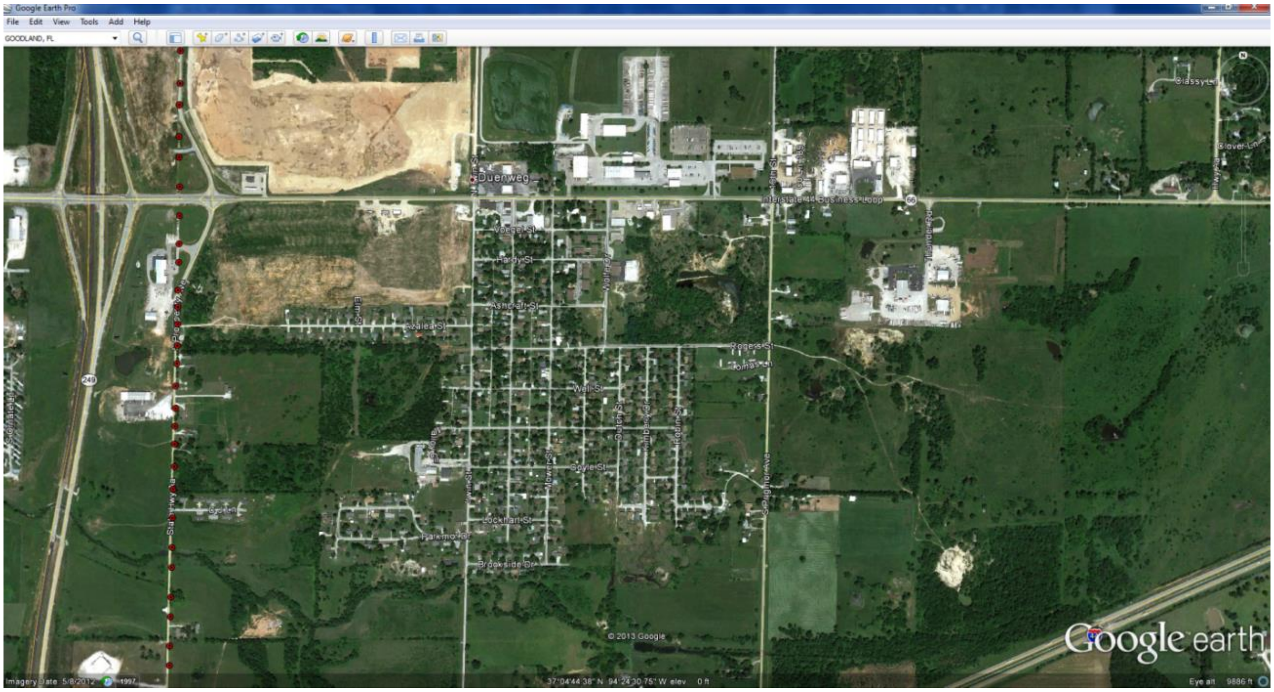

Figure 4.5-1 - Google Earth Pro Screenshot

Empire has merged the mapping system topology with Google Earth which allows for detailed mapping of associated feeders to be studied as well as allows for ready review of proximity to alternate switching paths. Allowing for a view of the topography and attempting to head off any construction hindrances has proven effective on past projects. Projects imposed over the Google Earth snapshots allow those with a vested interest in the job to gain further knowledge of the scope of work to be done.

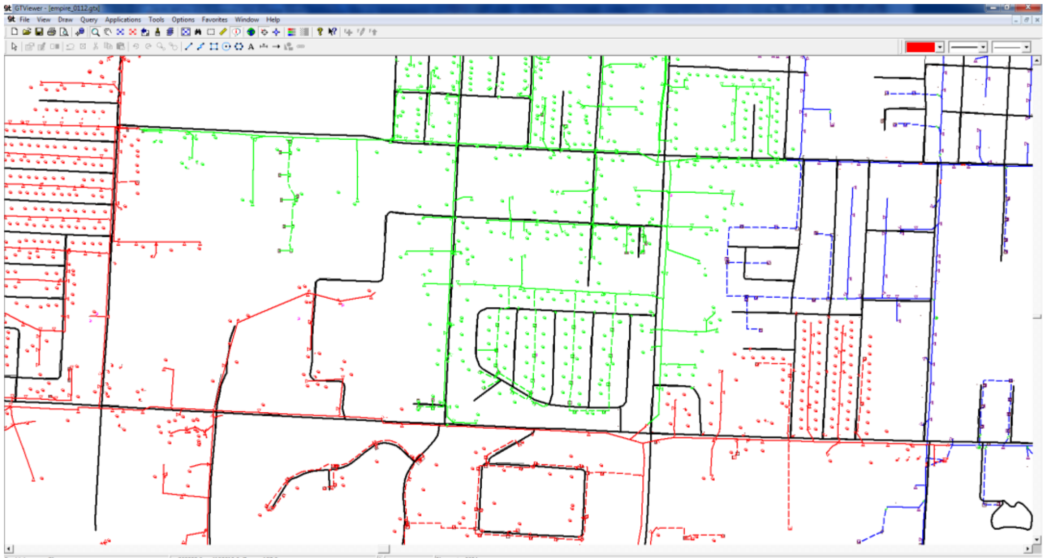

Figure 4.5-2 - GTViewer Screenshot

Figure 4.5-2 provides a screenshot from GTI's GTViewer. This software allows engineers to acquire model data for use in distribution analysis software, CYMDIST. GTI's software device characteristics and connectivity drive load-flow models in use by Empire's planning department. In the near horizon, Empire will attempt to merge all planning software platforms so that real time data and analysis will be available to users. In doing so, real time models will be a realization thereby allowing for an exhaustive review, should the need arise.

Figure 4.5-3 below provides a screenshot from CYM Distribution System Analysis.

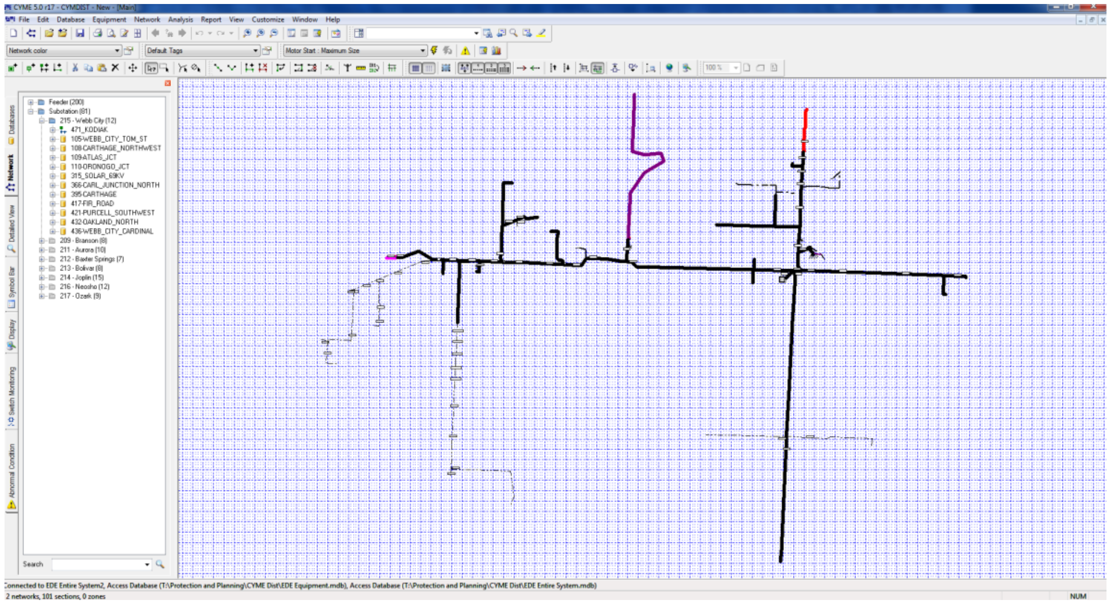

Figure 4.5-3 - CYMDIST Screenshot

CYMDIST is a multipurpose tool primarily used by engineers to analyze load-flow characteristics of distribution feeders. Empire's planning department also provides fault current information to customer's electrical contractors when performing arc-flash studies, a process which requires the use of CYMDIST.

1.1.2.1 Capacity Planning

Substation transformer and distribution circuit loads are collected annually, with the primary sources being monthly metering data and seasonal station checks. This load data is compiled into a database that can be parsed into different seasons, definite dates, specific months, or years' worth of data for analysis. The data is also compared to the maximum capacity available at the service transformer to determine overloads evident in past scenarios or present system configurations. These types of overloads are higher in priority due to the severity and long lead time mitigations available.

Figure 4.5-4 is an example of substation trending over multiple years in the multiple seasons.

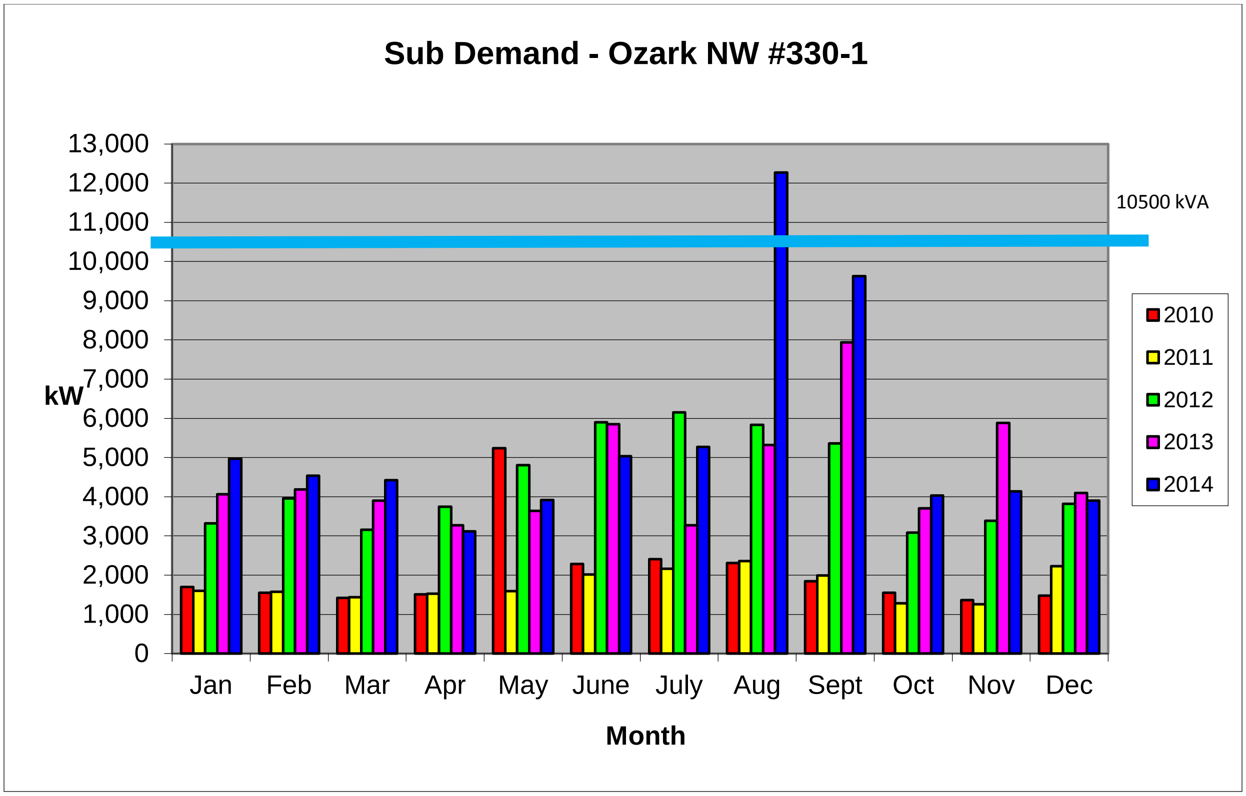

Figure 4.5-4 - Substation Trending Over Multiple Years During Peak Load Switching

A screenshot of the Microsoft® Access metering database compiled for seasonal, annual, or definite time interval(s) is shown in *Figure 4.5-5*.

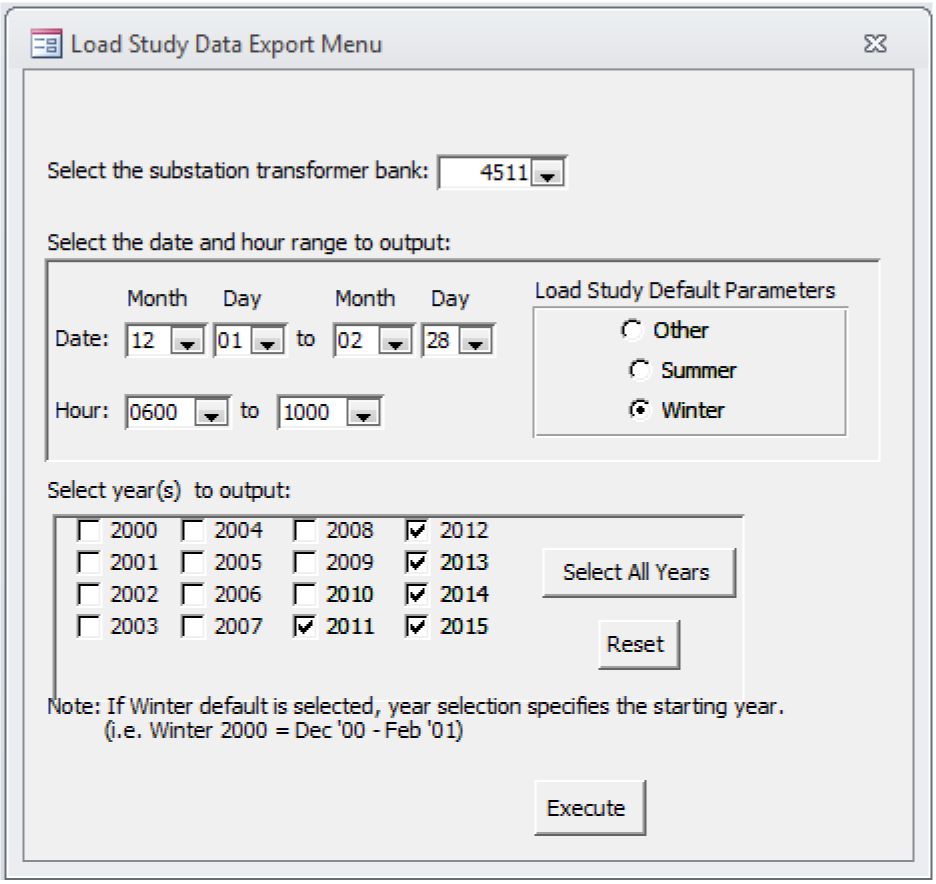

Figure 4.5-5 - Metering Data Compiled For Seasonal, Annual, or Definite Time Interval(s)

1.1.2.2 Contingency Planning

Transmission and distribution system planning includes consideration of contingencies and their impact on the systems as they may change under varying conditions. As the graph above shows, switching arrangements are reflected in our system load database. By inclusion of this type contingency event (above example represented loss of station transformer) allows for a representative model for evaluation in subsequent capital improvement project weighting. Projects are then scoped appropriately to allow for contingency switching events and redundancy of adequate capacity.

1.1.2.2.1 Distribution Contingency Evaluation

From distribution studies performed throughout a given year, Empire's planning department determines what switching paths are available during a contingency event. Examples of these types of studies include evaluation of substation transformer loading (as in the graph above) to determine available capacity present on a substation of interest, splitting trunk lines and their effects on voltage profiles on a given feeder, and phase loading imbalance due to the topography changes made during switching adjustments. These studies allow for the engineering department to make informed decisions on available transfer capabilities on specific feeders. Once weaknesses are identified and analyzed, the resulting system impacts can be ranked against other results for determining capital budget project priority. Ultimately, this ranking, energy efficiency impacts, reliability and customer impact risks, and the project cost are used to determine whether or not a system improvement is implemented. The Empire planning department identifies the weaknesses and provides budgetary estimation and project description in conjunction with Empire Line Design department. It also becomes the responsibility of the planning department to thoroughly communicate the justifications for projects to the vested departments internal to Empire.

1.1.2.2.2 Transmission Contingency Evaluation

Empire conducts transmission system performance studies as required by the NERC TPL-001, TPL-002, TPL-003, and TPL-004 standards, soon to be replaced by TPL-001-4. These studies are provided as supplements to the SPP TPL Compliance Report. Studies include evaluations of base case (N-0), N-1 (meeting the N-1 criteria within the Empire system footprint), multiple contingencies (Type C), and extreme contingency scenarios (Type D), as defined in Table 1 of the NERC Transmission Planning Standards.

1. Base Case - All Facilities In-Service: The studies are conducted on an annual basis incorporating both near-term and long-term planning horizons. The models used in the study process have an initial condition of normal operating procedures in place, have all projected firm transfers modeled, are performed over a range of forecasted demand levels for selected demand levels, and include existing and planned facilities as well as reactive power resources to

ensure that adequate reactive resources are available. Once these studies are conducted, mitigation techniques are ascertained to fulfill the performance requirements of the TPL-001 standard.

2. N-1 - Loss of a Single Element:

   a. The studies are conducted on an annual basis incorporating both near-term and long-term planning horizons. The models used in the study process have an initial condition of normal operating procedures in place, have all projected firm transfers modeled, are performed over a range of forecasted demand levels for selected demand levels, and include existing and planned facilities as well as reactive power resources to ensure that adequate reactive resources are available. Once these studies are conducted, mitigation techniques are ascertained to fulfill the performance requirements of the TPL-002 standard. The power flow models evaluated were created from the SPP 2011 Model Development Working Group (MDWG) B2 Final MOD Base Case series.

   b. The N-1 contingency analysis was run for each of the seasonal models from the 2011 series cases with varying system demands including winter, spring, summer, and fall. Alongside the TPL compliance report's automatically selected contingencies, an internal review of all N-1 contingencies within the Empire footprint was performed. The rationale used in choosing the contingencies studied included all single elements as defined in SPP Criteria 12 within the Empire footprint along with the effects of outaged tie lines with neighboring entities.

3. Multiple Contingencies - Loss of Two or More Elements:

   a. The studies are conducted on an annual basis incorporating both near-term and long-term planning horizons. The models used in the study process have an initial condition of normal operating procedures in place, have all projected firm transfers modeled, are performed over a range of forecasted demand levels for selected demand levels, and include existing and planned facilities as well as reactive power resources to ensure that adequate reactive resources are available. The power flow models evaluated were created from the SPP 2011 MDWG B2 Final MOD Base Case series. The multiple contingency analyses were run for each of the seasonal models from the 2011 series case with varying system demands including winter, spring, summer, and fall. Alongside the TPL compliance report's automatically selected contingencies, an internal review of Type C contingencies within the Empire footprint was performed. Once these studies are conducted, mitigation techniques are ascertained to fulfill the performance requirements of the TPL-003 standard.

b. The conditions evaluated which conform to Type C contingencies include loss of two or more elements (normal clearing, manual system adjustments between events), bus section faults, double circuit tower lines, and breaker to breaker sectional outages. The resultant thermal and voltage overloads were then evaluated in an effort to mitigate wherever possible with minimal loss of demand and curtailment of firm transfers. In satisfying the requirements of TPL-003, Empire does not employ a rating rational on the severity of specific contingency scenarios. Empire reviews the aforementioned applicable contingencies as defined in Table 1, Type C. In an effort to encompass the worst case scenario outages, the bus outages were included in the Type C contingencies but are also applicable to Type D contingencies. Bus section outages have been shown to be the most effectual outages on the Empire system, due to the number of outaged elements associated with individual simulations. The outages which involve single-line-to-ground or three-phase faults were not evaluated for stability purposes. The rationale for this omission hinged on three factors: no substantial system changes directly relating to stability were made to the Empire system, a previous stability study (the 2006 System Facilities Study) showed no Empire stability-related issues, and no stability issues were evident in the previous SPP TPL compliance reports.

4. Extreme Event (Multiple Elements) Contingency: The studies are conducted on an annual basis incorporating both near-term and long-term planning horizons. The models used in the study process have an initial condition of normal operating procedures in place, have all projected firm transfers modeled, are performed over a range of forecasted demand levels for selected demand levels, and include existing and planned facilities as well as reactive power resources to ensure that adequate reactive resources are available. Once these studies are conducted, mitigation techniques are ascertained to fulfill the performance requirements of the TPL-004 standard. The power flow models evaluated were created from the SPP 2011 MDWG B2 Final MOD Base Case series. The multiple contingency analyses were run for each of the seasonal models from the 2011 series case with varying system demands including winter, spring, summer, and fall. Alongside the TPL compliance report's automatically selected contingencies, an internal review using the rationale of all applicable contingencies which conform to Table 1, Type D within the Empire footprint was performed. These include loss of a tower line with three or more circuits, all circuits on common right-of-way, substation (one voltage level plus transformer), and the loss of all generating units at a station. The resultant thermal and voltage overloads are then evaluated in an effort to mitigate wherever possible, with minimal loss of demand and curtailment of firm transfers. In satisfying the requirements of TPL-004, Empire does not employ a rating rational on the severity of specific contingency scenarios, but

rather reviews contingencies applicable to Empire as defined in Table 1, Type D. Contingencies that are not applicable to Empire's footprint were not evaluated including Type D contingencies involving special protection systems, load centers, and switching stations.

1.1.2.2.3 Worst Performing Circuit Analysis

To improve the performance of the circuits, Empire adopted a corrective action plan that includes the following activities:

1. Empire employees perform a "walk-through" of the worst performing circuit, collecting engineering data to support the following coordination study and sectionalizing program. Items are noted and corrected as part of the corrective action plan. Upon walk-through completion, a coordination study of the circuit occurs. The coordination study evaluates protective equipment settings and application to ensure each protective device properly operates with other upstream and downstream protective equipment. Additional sectionalizing is then added to the circuit to reduce the number of customers experiencing an outage, in the event an outage occurs, thus increasing reliability to other customers on the circuit. Faulted circuit indicators are also added to the circuit to reduce restoration time and shorten customer outage duration. In addition to the coordination study and sectionalizing program, any vegetation-related issues identified are scheduled to be cleared for each circuit.

1.2 Assessment of Interconnecting New Facilities

(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;

Empire is required to meet the interconnection needs of transmission customers for connection to, and use of, the Empire transmission system. The Federal Energy Regulatory Commission (FERC)-approved transmission tariffs provide procedures for detailed transmission studies and interconnection estimates for connecting to and using Empire's transmission system. Empire's planning department provides a range of transmission costs for various sites of interest on defined projects and identifies potential transmission limitations with the inclusion of projects of interest. Any Empire generation resource addition that would impact transmission level flows is required to proceed through the Southwest Power Pool (SPP) Generation Interconnection (GI) process before it can be interconnected to the transmission system. Every resource addition would also have to be included in the SPP Aggregate Facility Study (AFS) process to obtain firm transmission service for delivery of generation to load. The SPP Definitive Interconnection System Impact Study for Generation Interconnection Requests (DISIS-2015-001) is provided for reference in Appendix 4.5A.

An example of this process is the addition of Empire's Riverton Unit 12 with the inclusion of future expansion to a combined cycle configuration. Once this additional resource had been submitted for study in the GI and AFS processes the resultant upgrades were identified and evaluated for feasibility and cost effectiveness. Building on the previous system impact study, the most recent Generation Addition study by way of expanded capacity was the additional capacity realized during the construction of the combined cycle addition to Riverton Unit 12. The initial filing for firm transmission service accounted to an assumed 250MW of capacity, nine years prior to the actual construction of the recovery unit. Now that actual testing data is available for the generator to be energized, Empire was able to gain an additional 35MW of gross capacity during seasonal operations; therefore this additional capacity required a system impact study to ensure deliverability of the additional capacity. The SPP Interconnection Facilities Study for Generator Interconnection Request (GEN-2014-028) is attached for reference.

This process is further illustrated in *Figure 4.5-6*, which provides approximate Generation Interconnection data for wind projects taken from the SPP Generation Interconnect Queue as of February 2015. Note that no wind projects were planned to be located within Empire's electric service territory in southwest Missouri.

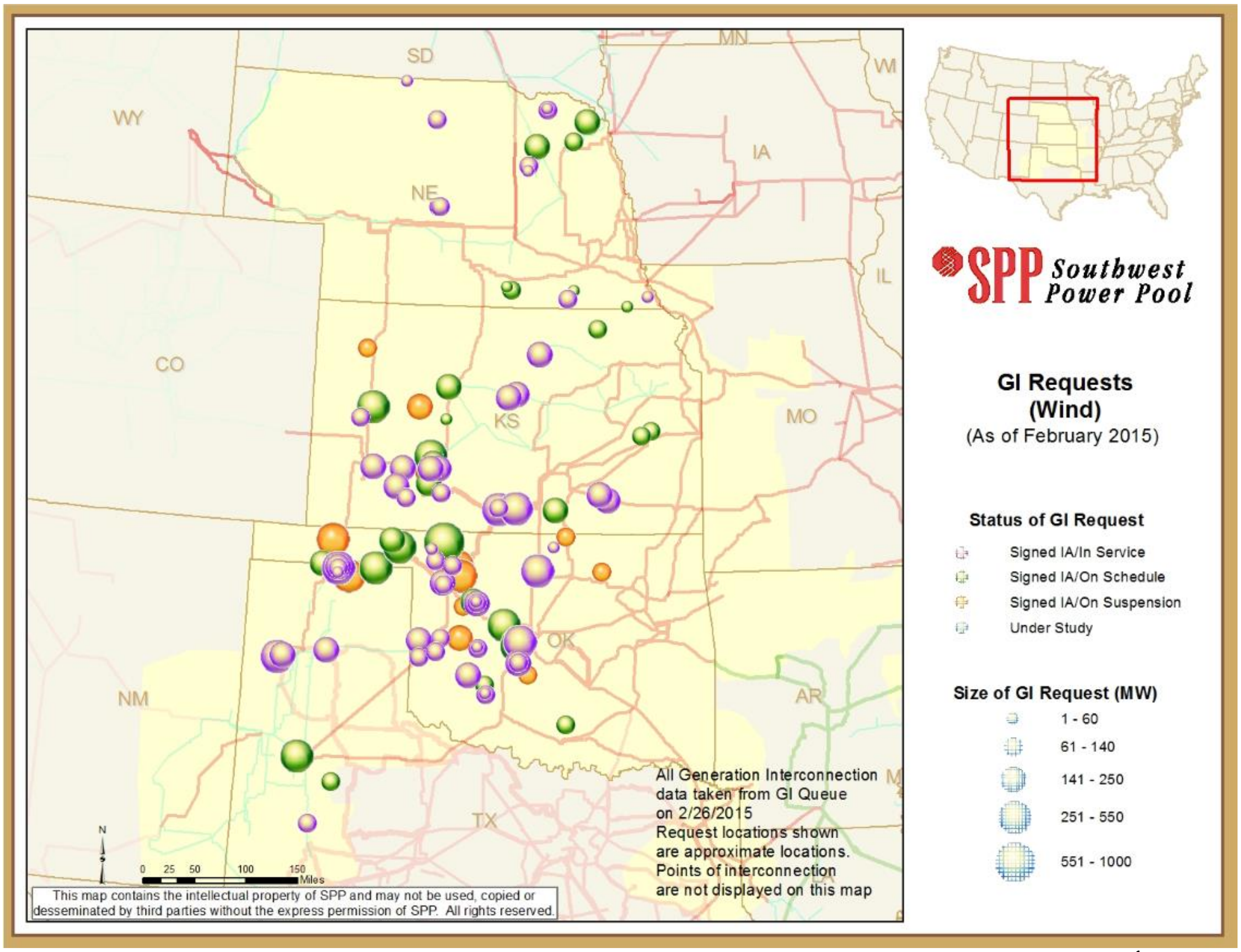

Figure 4.5-6 - SPP 2015 Generation Interconnection Requests for Wind Projects[1]

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

All Empire transmission planning is performed in conjunction with SPP, the Regional Transmission Organization (RTO) to which Empire belongs. Empire's affiliation with SPP began during World War II; when SPP was initially formed. FERC empowers RTOs to assure power

[1] Source: "Intro to SPP" slideshow from the Fast Facts section of SPP's website (http://www.spp.org/Documents/31587/20151001%20Intro%20to%20SPP-October%202015.pdf) as of October 2015, on page 86

supply reliability, transmission infrastructure adequacy, and competitive wholesale electricity prices through the North American Electric Reliability Corporation (NERC). In turn, SPP oversees enforcement and development of NERC reliability standards within its footprint; which spans across 14 states. Empire fully participates in SPP's regional transmission expansion planning processes. SPP conducted two expansion plan processes: the Balanced Portfolio (June 2009) and the Priority Projects (April 2010). Regardless of whether or not Empire adds supply resources or contracts for sales, the unique and specific costs of the Balanced Portfolio and Priority Projects are allocated throughout SPP. Therefore, no costs for Empire's allocation of the costs for the Balanced Portfolio and Priority Projects have been included in the analyses of preliminary supply-side resource options in this plan.

The Balanced Portfolio was a SPP strategic initiative to develop economic-based transmission upgrades that benefit the SPP region while allocating costs to utilities in the region. Balanced Portfolio projects have included 345-kV transmission upgrades to obtain potential savings that exceed project costs. Such upgrades are intended to reduce congestion on the SPP transmission system, and thereby reduce generation production costs. Other benefits include increased reliability and lower required reserve margins, deferment of other reliability upgrades, and environmental benefits from more efficient operation of generating assets and increased renewable resource production. SPP's analysis of the Balanced Portfolio concluded that these projects would provide an average benefit of $1.66/month per customer for a corresponding cost of $0.88/month per customer. Seven transmission projects for a total initial estimated engineering and construction cost of approximately $692 million were included in the Balanced Portfolio, as shown in *Figure 4.5-7*.

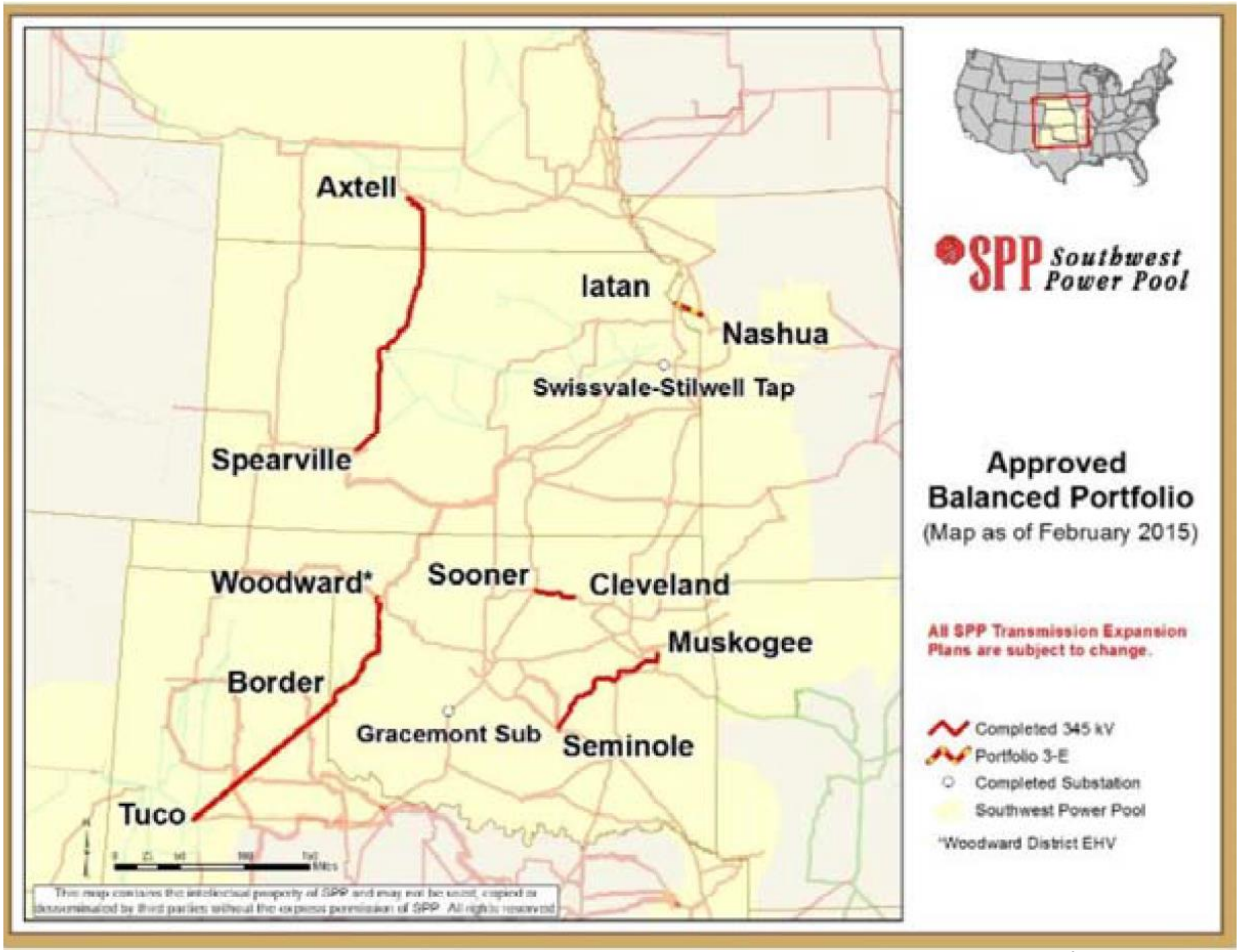

Figure 4.5-7 - SPP Approved Balanced Portfolio Transmission Projects[2]

The SPP Balanced Portfolio Report is provided for reference in Appendix 4.5B.

The purpose of SPP's Priority Projects plan was to identify, evaluate, and recommend transmission projects that could improve regional production costs, reduce grid congestion, enable large-scale renewable resources (primarily wind), improve the GI and AFS processes, and better integrate SPP's east and west regions. Six transmission projects with an approximate total cost of $1.1 billion were recommended for construction in the Priority Projects process providing a variety of benefits to the region. These Priority Projects will reduce transmission

[2] Source: "Intro to SPP" slideshow from the Fast Facts section of SPP's website (http://www.spp.org/Documents/31587/20151001%20Intro%20to%20SPP-October%202015.pdf) as of October 2015, on page 72

congestion, while improving the AFS process by creating additional transfer capability and increasing the ability to transfer power in an eastward direction to facilitate wind power.

The SPP Priority Projects Phase II Final Report is provided for reference in Appendix 4.5C.

The current study in progress at SPP is the Integrated Transmission Plan (ITP). There are three subsets of this particular study: ITP 20-Year (ITP20), ITP 10-Year (ITP10), and ITP Near-Term (ITPNT). Empire is an active participant in each of these studies and maintains a voting membership in each of the respective working groups.

The ITP is a three-year study process which assesses SPP's regional transmission needs in the long- and near-term with the intention of creating a cost-effective, flexible, and robust transmission network that will improve access to the region's diverse generating resources. Along with highway/byway cost allocation methodology, the ITP process, as embodied in SPP Attachment O and approved by FERC in July 2010, promotes transmission investment that will meet reliability, economic, and public policy needs. This report documents analysis of the ITP process which focused on the 20-year horizon with an objective of planning for SPP's long-term regional needs. ITP development was driven by the Synergistic Planning Project Team (SPPT), which was created by the SPP Board of Directors to address gaps and conflicts in all of SPP's transmission planning processes including Generation Interconnection and transmission service. ITP's purpose is to develop a holistic, proactive approach to planning that optimizes individual processes and positions SPP to respond to national energy priorities. ITP is based on SPPT's planning principles which emphasize the need to develop a transmission backbone large enough in both scale and geography to provide flexibility for meeting SPP's future needs.

ITP20 looks into the future 20 years as required by Open Access Transmission Tariff (OATT) Attachment O, Section III - 3. ITP20 is an expansion of the annual SPP Transmission Plan (STEP), which is the 10-year transmission expansion plan that began in 2006. SPP has had two previous EHV plans which similarly provide a look into the future that helps form near-term plans.

Projects identified in ITP20 provide benefits to the region across multiple futures and create flexibility for SPP to meet future needs. ITP effort has been driven by numerous interactions with stakeholders and with significant support from the Economic Studies Working Group (ESWG) and Transmission Working Group (TWG). Empire participates and maintains voting membership in both working groups. ITP20 differs from earlier EHV plans in the level of detail and effort that has gone into its preparation. The SPP 2013 Integrated Transmission Plan 20-Year Assessment Report is provided for reference in Appendix 4.5G.

The second phase of the ITP study process included ITP10 and ITPNT assessments performed under the requirements of OATT Attachment O, Section III. The study process for ITP10 utilized a diverse array of power system and economic analysis tools to evaluate 100-kV and above facility projects that satisfy needs such as:

1. Resolving potential criteria violations
2. Mitigating known or foreseen congestion
3. Improving access to markets
4. Staging transmission expansion
5. Improving interconnections

The recommended portfolio included projects ranging from comprehensive regional solutions to local reliability upgrades that address expected reliability, economic, and policy needs of the studied 10-year horizon. Two distinct futures were considered to account for possible variations in system conditions over the assessment's 10-year horizon. The SPP 2015 Integrated Transmission Plan 10-Year Assessment Report is provided for reference in Appendix 4.5F.

The most recent iteration of the ITPNT was approved by the TWG in December of 2014. ITPNT analyzes SPP's immediate regional transmission needs. ITPNT goals are to preserve grid reliability, in compliance with NERC reliability standards and individual transmission owner planning requirements, and efficiently bridge SPP's 10- and 20-year plans that meet public policy objectives and provide access to more economic energy sources. ITPNT assesses:

1. Near-term regional upgrades required to maintain reliability in accordance with NERC reliability standards and SPP criteria

2. Near-term zonal upgrades required to maintain reliability in accordance with more stringent individual transmission owner planning criteria

3. Coordinated projects with neighboring transmission providers

The SPP 2015 Integrated Transmission Plan Near-Term Assessment Report is provided for reference in Appendix 4.5E.

Empire participates with non-SPP members (e.g., Associated Electric Cooperative, Incorporated (AECI)) to examine potential mutually beneficial projects. One recent example is Empire's participation in the AECI-SPP Joint Study. The AECI-SPP Joint Study is a recurring study that involves impacted SPP members in the southeastern portion of SPP's footprint along with neighboring seams companies. The scope of the studies involve identifying forecasted issues on seams parties' footprints and studying proposed projects to acquire mutually beneficial results. This type of study allows for conversation to flow between SPP members and non-members so that interconnections, mitigation techniques, and cost sharing projects can be vetted by both sides of ownership. Collaboration shares the burden and pairs common goals with collective and impactful results. Empire not only provides possible projects for study, but also internally studies presented projects. Empire does this to determine whether a proposed project could mutually benefit Empire and AECI exclusive of other southeastern SPP members' lack of interest or benefit. Empire also participates in AECI's Long Range Plan meetings, most recently hosted by Empire in October 2015, to assess other proposed tie line projects between Empire and AECI.

1.4 Assessment of Transmission or Distribution Improvements with Respect to Cost Effectiveness of 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 Dynamic Voltage Conservation – Demand Response

By implementing advanced communicating capacitor bank controllers, voltage monitors, voltage regulators, faulted circuit indicators (FCI), and integrated load tap changers (LTC) at the substation transformers with a communications network and central logic controller, a more uniform and specified voltage profile can be maintained along the entire length of distribution primaries. Additionally, these technologies may better accommodate changes in reactive power demands and enable voltage conservation options. This is commonly referred to as Dynamic Voltage Conservation (DVC). This functionality may be enacted as a demand reduction measure during periods of extremely high load to lessen impacts on distribution system assets and reduce peak power purchases.

1.4.2 Conservation Voltage Reduction

Similar to DVC, conservation voltage reduction (CVR) consists of the exact same actions and utilizes the same assets to reduce voltage on applied circuits. However, the objective is to safely reduce voltage all the time rather than only during periods of high load. This may reduce immediate impacts to system assets and reduce fuel consumption. However it will also reduce overall kWh delivered to customers.

1.4.3 Energy Storage

Electricity can be stored as chemical or mechanical energy and used later by consumers, utilities, or grid operators. In distributed applications, energy storage technologies most likely utilize inverter-based electrical interfaces that can produce real and reactive power. Depending on the capacity and stored energy of these devices, they can provide the following economic, reliability, and environmental benefits for demand-side resources and/or supply-side resources:

- Optimized Generator Operation – The ability to respond to changes in load would enable grid operators to dispatch a more efficient mix of generation that could be optimized to reduce cost, including the cost associated with polluting emissions. Electricity storage can be used to absorb generator output as electrical load decreases, allowing the generators to remain in their optimum operating zone. The stored electricity could then be used later so that dispatching additional, less efficient generation could be avoided. The storage can have the effect of smoothing the load curve that the generation fleet must meet. This benefit includes two components: (1) avoided generator start-up costs and (2) improved performance due to improved heat rate efficiency and load shaving.
- Reduced Ancillary Services Cost – Ancillary services including spinning reserve and frequency regulation can be provided by energy storage resources. The reserve margin is a required capacity above the peak demand that must be available. If peak demand is reduced, reserve margin would be reduced.
- Reduced Congestion Cost – Distributed energy resources provide energy closer to the end use, so less electricity must be passed through the T&D lines, which reduces congestion.
- Reduced Electricity Losses – By managing peak feeder loads with electricity storage, peak feeder losses, which are higher than at non-peak times, would be reduced.
- Reduced Electricity Costs – Electricity storage can be used to reduce the cost of electricity, particularly during times when the price of "grid power" is very high. A consumer or the owner of an enabled distributed energy resource realizes savings on his electricity bill.

- Deferred Generation Capacity Investments – Electricity storage can be used to reduce the amount of central station generation required during peak times. This would tend to improve the overall load profile and allow a more efficient mix of generation resources to be dispatched. This can save utilities money on their generation costs.
- Deferred Transmission Capacity Investments – Utilities build transmission with capacity sufficient to serve the maximum amount of load that planning forecasts indicate. The trouble is, this capacity is only required for very short periods each year, when demand peaks. Providing stored energy capacity closer to the load reduces the power flow on transmission lines, potentially avoiding or deferring capacity upgrades. This may be particularly effective during peak load periods.
- Deferred Distribution Capacity Investments – Electricity storage can also be used to relieve load on overloaded stations and feeders, potentially extending the time before upgrades or additions are required.

1.4.4 Communication Network

Implementing fiber backhaul network, transmission/substation SCADA, distribution SCADA, fixed metering network, and/or distribution field network can help to ensure that the transmission and distribution grid are reliably supported by a secure communication network. A secure network enables all components of the grid to communicate effectively and is protected from cyber-attacks. The network should be robust and support the ability to monitor and control time-sensitive grid operations, including frequency and voltage; dispatch generation; analyze and diagnose threats to grid operations; fortify resilience by providing feedback that enables self-healing of disturbances on the grid; and evaluate data from sensors. This support enables the grid to further enhance its overall ability to utilize demand-side resources.

SECTION 2 AVOIDED TRANSMISSION AND DISTRIBUTION COST

(2) voided 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).

2.1 Avoided Transmission Capacity Cost

The SPP AFS process encompasses the petition of transmission service and the associated impacts on the existing transmission infrastructure or planned projects meeting specified interconnection agreements and/or having been issued a Notice To Construct (NTC) by SPP during the appropriate study process. All generation requests must be vetted through the SPP AFS process to obtain firm transmission service for delivery of generation to load. In doing so, Empire is able to evaluate the impacts either purchasing generation, adding generation onsite, adding generation offsite, or other applicable generation resource impacts upon the SPP transmission system through the multiple iterative processes of the AFS. As the proposed generation resources profiles are updated in the applicable study, Empire evaluates the most cost effective means to address their needed generation resources to meet forecasted load demand. Thus, the AFS study process reveals the transmission component of avoided demand cost.

The AFS study process is dynamic in nature. Locational differences of the requested resources, the available transmission in the immediate area of the resource, and the competing resources requests each affect the resultant cost of any given generation resource request. As competing requests are vetted by their respective companies, requests are withdrawn from the applicable AFS study. This again changes the AFS study portfolio. In the most recent AFS, Empire was able to determine its respective avoided transmission, avoided costs by averaging past years' AFS Engineering and Construction (E&C) costs as compared to the requested MW resources. The total costs were divided by the summation of requested resources to determine an average cost per kilowatt value. The values and the associated studied years are shown in *Table 4.5-4*.

Study Year	Total E&C Cost(s) Weighted to 2015 $'s	MW's in study	2015 $/kW
2008	$82,293,660	3,336	$25
2009	$43,784,634	2,777	$16
2010	$126,693,249	2,424	$52
2011	$748,555,032	3,936	$190
2012	$113,223,203	3,581	$32
2013	$9,965,576	961	$10
2014	$16,521,286	1,556	$11
Totals	$1,141,036,641	18,571	$61

Table 4.5-4 - Comparison of AFS Results

Thus the extrapolated cost per kilowatt for each subsequent year is shown in *Table 4.5-5:*

No.	Year	$/kW-Year	Levelized Cost $/kW-Year
1	2015	$61.44	$6.18
2	2016	$62.98	$6.33
3	2017	$64.55	$6.49
4	2018	$66.17	$6.65
5	2019	$67.82	$6.82
6	2020	$69.52	$6.99
7	2021	$71.25	$7.17
8	2022	$73.04	$7.34
9	2023	$74.86	$7.53
10	2024	$76.73	$7.72
11	2025	$78.65	$7.91
12	2026	$80.62	$8.11
13	2027	$82.63	$8.31
14	2028	$84.70	$8.52
15	2029	$86.82	$8.73
16	2030	$88.99	$8.95
17	2031	$91.21	$9.17
18	2032	$93.49	$9.40
19	2033	$95.83	$9.64
20	2034	$98.22	$9.88
21	2035	$100.68	$10.13

Table 4.5-5 - Total Annual AFS E&C Costs as Transmission - Avoided Demand Costs

The dynamic nature of the transmission costs is clearly evident. Each year's requests have differing impacts on the transmission service costs.

SECTION 3 ANALYSIS OF TRANSMISSION NETWORK PERTINENT 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;

Empire's participation with SPP was previously addressed in Section 1.3 regarding assessment of transmission upgrades for power purchases. Empire also utilizes SPP's ITP process to assess the need for, cost of, 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 along with other SPP members and affiliates.

The SPP ITP process is used to determine transmission requirements for maintaining electric reliability and for providing both near- and long-term economic benefits to SPP members and affiliates. The RTO region includes all or parts of Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, and Wyoming. The SPP ITP process identifies transmission expansion projects and prioritizes their schedules in order to maintain a reliable and cost-effective transmission network with improved access to SPP's diverse resources including wind energy. Wind energy development has fluctuated in recent years with variations in federal subsidization, but has dominated new generating capacity additions in SPP for several years.

The SPP ITP process is an iterative, multiple-horizon transmission planning process that has improved transmission planning across the SPP region. By integrating the transmission planning process across member utilities in 14 contiguous states, SPP promotes more rigorous and complete planning throughout a large area that improves the reliability of each utility and SPP as a whole. The result of this integrated planning process is the development of lowest-cost transmission solutions to anticipate and respond to constantly changing loads, environmental and regulatory requirements, and grid anatomy; while meeting evolving reliability criteria.

The current ITP process includes ITP20, ITP10, ITPNT assessments of transmission requirements to meet load growth and other potential developments. The 2013 ITP20 process examined high-voltage transmission needs at voltages above 300-kV, and included state-by-state requirements for renewable energy over time. ITP20 evaluated potential impacts of a 20-percent federal Renewable Electricity Standard (RES), a $36/ton carbon constraint, an additional 10 GW of exported wind, investment in Demand Side Management and Smart Grid technology, and a joint SPP/MISO future. ITP20 projected renewable energy generation of 10 GW without a federal RES, and 16.5 GW with a federal RES. The ITP20 Consolidated Portfolio included 436 miles of transmission lines and installation of six 345-kV step-down transformers. Implementation of ITP20 results was estimated in 2013 to have a total cost of $560 million (net present value revenue requirement of $845 million), and is expected to provide net benefits of approximately $1.5 billion over the life of the projects.

A value-based planning approach is used for the ITP10 assessment to analyze the transmission system over a 10-year horizon. In the ITP10 process, economic and reliability analyses develop solutions for issues identified on the system for voltages of 100-kV and above. The ITP10 process included all statutory/regulatory renewable mandates and goals, which resulted in 11.5 GW of renewable resources modeled in SPP. ITP10 also considered a future with a decrease in existing base load generation capacity. The recommended ITP10 portfolio consisted of projects for potential reliability, economy, and/or policy requirements with an estimated total E&C cost of $273 million in 2015, and a net present value revenue requirement of $334 million. These projects were predicted to generate net benefits of approximately $1.4 billion over their life under a future that contains 10.3 GW of wind capacity expected to be contracted by SPP members.

The near-term assessment is performed annually and will identify more immediate potential problems using NERC reliability standards, SPP criteria, and local planning criteria. Reliability upgrades at all transmission voltages are developed to address both regional reliability needs and identify necessary reliability upgrades for approval and construction. For the 2015 ITPNT, SPP performed reliability analyses that identified potential bulk power system problems across three scenarios. The first scenario contained projected transmission transfers between legacy SPP Balancing Authority (BA) and generation dispatch on the system. The second scenario maximized all applicable long-term firm transmission service with its required generation dispatch. The third was a Consolidated Balancing Authority (CBA) scenario that showed the needs on SPP's transmission system that resulted from Security Constrained Unit Commitment and Security Constrained Economic Dispatch. SPP provided results of these scenarios to transmission owners and stakeholders to develop solutions. SPP staff identified and presented their recommended solutions for potential reliability violations during planning summits for member and stakeholder review. The result was a list of solutions, necessary at 69-kV and above to ensure near-term reliability in the SPP region, which included 183 miles of new and rebuilt/reconductored transmission lines and eight new transformers. E&C cost estimates for the needed reliability projects totaled $248.2 million for upgrades that will receive an NTC. These upgrades solved 208 transmission overland and 64 voltage violations.

SPP created the Transmission Owner Selection Process (TOSP) in order to comply with FERC Order 1000. FERC Order 1000 requires the removal of federal right of first refusal (ROFR) for certain transmission projects under the SPP Tariff. Removal of federal right of first refusal allows for non-incumbent utilities to construct approved transmission facilities that meet SPP

Tariff criteria, these are known as Competitive Upgrades. SPP solicits proposals for Competitive Upgrades from Qualified Request for Proposal Participants utilizing the TOSP. Competitive Upgrades are submitted during a 30-day Detailed Project Proposal window and must address a need that was identified by SPP Staff during an ITP study.

Empire is very active in the interaction between SPP and its associated members. Empire participates by way of multiple working groups and various task forces. The following *Table 4.5-6* is a list of working groups/committees and task forces in which Empire participates.

SPP Stakeholder Committee/Task Force (Report to)	Position Type Voting/Monitoring
Members Committee (BOD)	Voting - Empire
Human Resources (BOD)	Voting - Empire
Strategic Planning Committee (BOD)	Monitoring
SPC Order 1000 Task Force	Monitoring
Membership (all members)	Monitoring
Finance Committee (BOD)	Monitoring
Governance Committee (BOD)	Monitoring
Market and Operating Policy Committee (full membership)	Voting - Empire
Transmission Working Group (MOPC)	Voting - Empire
Seams Steering Committee	Voting - VC
Seams Order 1000 Task Force	Voting - Empire
Model Development Working Group, reports to TWG	Voting, Chair - Empire
Economic Studies Working Group reports to MOPC (new)	Monitoring
Metrics Task Force (Reports to ESWG)	Voting -Empire
Business Practices Working Group (MOPC)	Voting - Empire
Balancing Authority Operating Committee - MOPC	Monitoring
CBA Technical Task Force	Voting - Empire
Members Compliance Group (ad hoc)	Monitoring
Regional Tariff Working Group (MOPC)	Voting - Empire
Market Working Group (MOPC)	Voting - Empire
Settlements Users Group	Monitoring
Project Cost Working Group	Monitoring
Change Working Group	Voting - Empire
Generation Working Group (MOPC)	Voting - Empire
Operations Reliability Working Group (MOPC)	Voting - Empire
Operations Training Working Group (MOPC)	Monitoring
Critical Infra-structure Protection Group - Cyber Security (MOPC)	Voting - Empire
System Protection and Control Working Group (MOPC)	Monitoring
SPP Regional State Committee	Monitoring
Cost Allocation Working Group (RSC)	Monitoring
Regional Cost Allocation (RCA) review task force	Voting - Empire
Regional Entity Trustees (RE)	Monitoring
Credit Practices Working Group	Monitoring
Process Improvement Task Force	Monitoring
Transmission Planning Improvement Task Force	Monitoring

Table 4.5-6 - Empire's SPP Participation

The following *Table 4.5-7* provides Empire management and staff individuals participating in various committees, studies, and groups at SPP.

SPP Stakeholder Committee / Task Force (Report to)	Empire Representative Existing
Members Committee (BOD)	Walters
Human Resources (BOD)	Walters
Strategic Planning Committee (BOD)	Baker
SPC Order 1000 Task Force	Open
Membership (all members)	Baker
Finance Committee (BOD)	Walters
Governance Committee (BOD)	Baker
Market and Operating Policy Committee (full membership)	McCord
Transmission Working Group (MOPC)	Morris
Seams Steering Committee	Gaines
Seams Order 1000 Task Force	Open
Model Development Working Group, reports to TWG	Morris
Economic Studies Working Group reports to MOPC (new)	King
Metrics Task Force (Reports to ESWG)	Open
Business Practices Working Group (MOPC)	McCord
Balancing Authority Operating Committee - MOPC	Pham
CBA Technical Task Force	Pham
Members Compliance Group (ad hoc)	Meyer
Regional Tariff Working Group (MOPC)	Doll
Market Working Group (MOPC)	McCord
Settlements Users Group	Tackett
Project Cost Working Group	Brown
Change Working Group	King
Generation Working Group (MOPC)	Houston
Operations Reliability Working Group (MOPC)	Pham
Operations Training Working Group (MOPC)	Kidwell
Critical Infra-structure Protection Group - Cyber Security (MOPC)	Long
System Protection and Control Working Group (MOPC)	Oswald/Morris
SPP Regional State Committee	Walters
Cost Allocation Working Group (RSC)	Baker
Regional Cost Allocation (RCA) review task force	Baker
Regional Entity Trustees (RE)	Baker/Meyer
Credit Practices Working Group	Ellis
Process Improvement Task Force	Doll

Table 4.5-7 - Current Empire Staff Assignments at SPP

3.1.2 Transmission Assessment for Advance Technologies

2. Assessment of transmission upgrades to incorporate advanced technologies;

Empire incorporates three main advanced technologies in its transmission system: All-dielectric self-supporting (ADSS) cable and/or optical ground wire (OPGW), microprocessor relaying, and automatic throw-over switching schemes on the 69-kV transmission system(s).

Empire currently employs the use of ADSS cable and has previously employed the use of OPGW for most or all of new shield wire installations. This gives not only superior lightning performance, due to the lower resistance of the OPGW compared to conventional galvanized steel strand shield wires but also provides a high capacity path for internal communications and system protection functions. The standard OPGW options provide either 48 or 144 single-mode fibers per shield wire, whereas ADSS incorporates 144 single-mode fibers allowing for not only presently needed communication paths for protection schemes but also allows for future implementation of further SCADA installation(s) and communication paths for backup/redundant relaying.

Empire utilizes microprocessor relaying for all new relaying installations. Substantial gains are found in the implementation of microprocessor relaying with respect to root cause analysis of fault events, as well as in protective coordination of transmission elements. With the use of microprocessor relaying, event recordings are able to be reviewed for possible misoperation as well as duplication of fault events to determine possible common fault locations. In conjunction with the aforementioned ADSS or OPGW, differential relaying on transmission elements are able to be implemented which result in a much more robust and increased speed of relay operation.

Empire has also implemented automatic throw-over switching schemes on the 69-kV transmission system(s) in attempts to reduce SAIDI and SAIFI. Due to their location on the transmission system, load taps on the 69-kV transmission system are dependent on remote relaying operations. If/When the remote relaying opens a transmission line segment, the load tap is de-energized. A solution is an automated throw-over scheme in which either side of the load tap of transmission is opened during a fault condition and tested to determine the faulted section. Once the faulted section is determined, the alternate section is then restored, thereby restoring power to the load tap. Empire incorporates microprocessor relaying in these schemes as well as ADSS cable (when applicable) so as to ensure fast response and robust protection.

In addition to the above technologies evaluated by Empire, the following comprises of a list of emerging technologies which Empire is currently evaluating for possible future implementation. Due to the infancy of some of the technologies, a complete system roll out will require further vetting so as to ensure the most cost effective and beneficial programs are installed. The associated costs are not available due to the pilot projects initiation; however the testing of technologies is ongoing on the Empire system. The technologies presently in review are as follows:

3.1.2.1 Fiber Optic Substation Data Network

3.1.2.1.1 Application

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3.1.2.1.2 Benefit

** **

3.1.2.1.3 Evaluation Results

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3.1.2.1.4 Implementation Plan

**

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3.1.2.1.5 Cost

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3.1.2.1.6 Justification

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3.1.2.1.7 Project Status

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Figure 4.5-8 - Joplin Multiple Ring ICON Proposed

3.1.2.2 Substation Data Archive, Server, and Database

3.1.2.2.1 Application

** **

3.1.2.2.2 Benefit

**

**

3.1.2.2.3 Evaluation Results

**

**

3.1.2.2.4 Implementation Plan

** **

3.1.2.2.5 Cost

** **

3.1.2.2.6 Justification

**

**

3.1.2.2.7 Project Status

** **

3.1.2.3 69-Kv Vacuum Circuit Breaker

3.1.2.3.1 Application

** **

3.1.2.3.2 Benefit

**

**

3.1.2.3.3 Evaluation Results

**

**

3.1.2.3.4 Implementation Plan

** **

3.1.2.3.5 Cost

**

**

3.1.2.3.6 Justification

**

**

3.1.2.3.7 Project Status

**

**

3.1.3 Avoided Transmission Cost Estimate

3. Estimate of avoided transmission costs;

Avoided transmission costs are discussed in Section 2 at Page 4.5-25. The results of the aforementioned estimation are provided in *Table 4.5-8* for convenience:

Study Year	Total E&C Cost(s) Weighted to 2015 $s	MWs in study	2015 $/Kw
2008	$82,293,660	3,336	$25
2009	$43,784,634	2,777	$16
2010	$126,693,249	2,424	$52
2011	$748,555,032	3,936	$190
2012	$113,223,203	3,581	$32
2013	$9,965,576	961	$10
2014	$16,521,286	1,556	$11
Totals	$1,141,036,641	18,571	$61

Table 4.5-8 - Comparison of AFS Results

The extrapolated cost per kilowatt for each subsequent year is shown in *Table 4.5-9*:

No.	Year	$/Kw-Year	Levelized Cost $/Kw-Year
1	2015	$61.44	$6.18
2	2016	$62.98	$6.33
3	2017	$64.55	$6.49
4	2018	$66.17	$6.65
5	2019	$67.82	$6.82
6	2020	$69.52	$6.99
7	2021	$71.25	$7.17
8	2022	$73.04	$7.34
9	2023	$74.86	$7.53
10	2024	$76.73	$7.72
11	2025	$78.65	$7.91
12	2026	$80.62	$8.11
13	2027	$82.63	$8.31
14	2028	$84.70	$8.52
15	2029	$86.82	$8.73
16	2030	$88.99	$8.95
17	2031	$91.21	$9.17
18	2032	$93.49	$9.40
19	2033	$95.83	$9.64
20	2034	$98.22	$9.88
21	2035	$100.68	$10.13

Table 4.5-9 - Total Annual AFS Cost Results as Transmission - Avoided Demand Costs

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;

The SPP Open Access Transmission Tariff (OATT) requires that a "Rate Impact Analysis" be performed for each Integrated Transmission Plan (ITP) per Attachment O: Transmission Planning Process, Section III: Integrated Transmission Planning Process, Sub-Section 8):

“8) Process to Analyze Transmission Alternatives for each Assessment:

The following shall be performed, at the appropriate time in the respective planning cycle, for the 20-Year Assessment, 10-Year Assessment and Near Term Assessment studies:…

f) The analysis described above shall take into consideration the following:

vi) The analysis shall assess the net impact of the transmission plan, developed in accordance with this Attachment O, on a typical residential customer within the SPP Region and on a $/kWh basis.”

The rate impact analysis process required to meet this 2015 ITPNT requirement was developed under the direction of the Regional State Committee in 2010-2011 by the Rate Impact Task Force (RITF). The RITF developed a methodology that allocated costs to specific rate classes in each SPP Pricing Zone (Zone).

The first step in this process is to estimate the zonal cost allocation of the Annual Transmission Revenue Requirement (ATRR). This cost allocated ATRR is calculated specifically for the ITPNT upgrades using the ATRR Forecast. The Forecast allocated 2015 ITPNT upgrade costs to the Zones using the Highway/Byway cost allocation method. This method allocates costs to the individual Zones and to the Region based on the voltage level of the upgrade. Transformer costs were allocated based on the low side voltage. Regional ATRRs are summed and allocated to the Zones based on their individual Load Ratio Share percentages.

Highway Byway Cost Allocation		
Voltage	**Regional**	**Zonal**
300-Kv and above	100%	0%
100-Kv - 299-Kv	33%	67%
Below 100-Kv	0%	100%

Table 4.5-10 - Highway Byway Cost Allocation

The following inputs and assumptions were required to generate the Forecast:

- Initial investment of each upgrade
    - New 2015 ITPNT upgrade investments modeled were $238 million in 2014 dollars
- Transmission Owner's estimated individual annual carrying charge percentage
- Voltage level of each upgrade
- In-service year of each upgrade
- 2.5 percent annual straight line rate base depreciation
- 2.5 percent construction price inflation applied to 2014 base year estimates
- Mid-year in-service convention

Empire presently does not have any projects identified in the ITPNT. The table below shows the dollar amount of new and modified projects of the 2015 ITPNT identified by state.

State	New NTC	Modified NTC
Arkansas	0	0
Kansas	65,079,071	0
Louisiana	3,979,734	0
Missouri	6,687,580	0
Nebraska	45,883,743	35,091,946
New Mexico	82,125,671	0
Oklahoma	38,994,767	0
Texas	29,517,730	0
Subtotals	**272,268,295**	**35,091,946**

Table 4.5-11 - 2015 ITPNT Projects by State

Empire will have costs associated with the other members' zonal and regional proposed projects as shown in the following allocation of upgrades with new NTCs and modified NTCs between upgrades needed for Regional Reliability and Zonal Reliability. Upgrades classified as Zonal Reliability are required to meet local planning criteria which is more stringent than SPP Criteria.

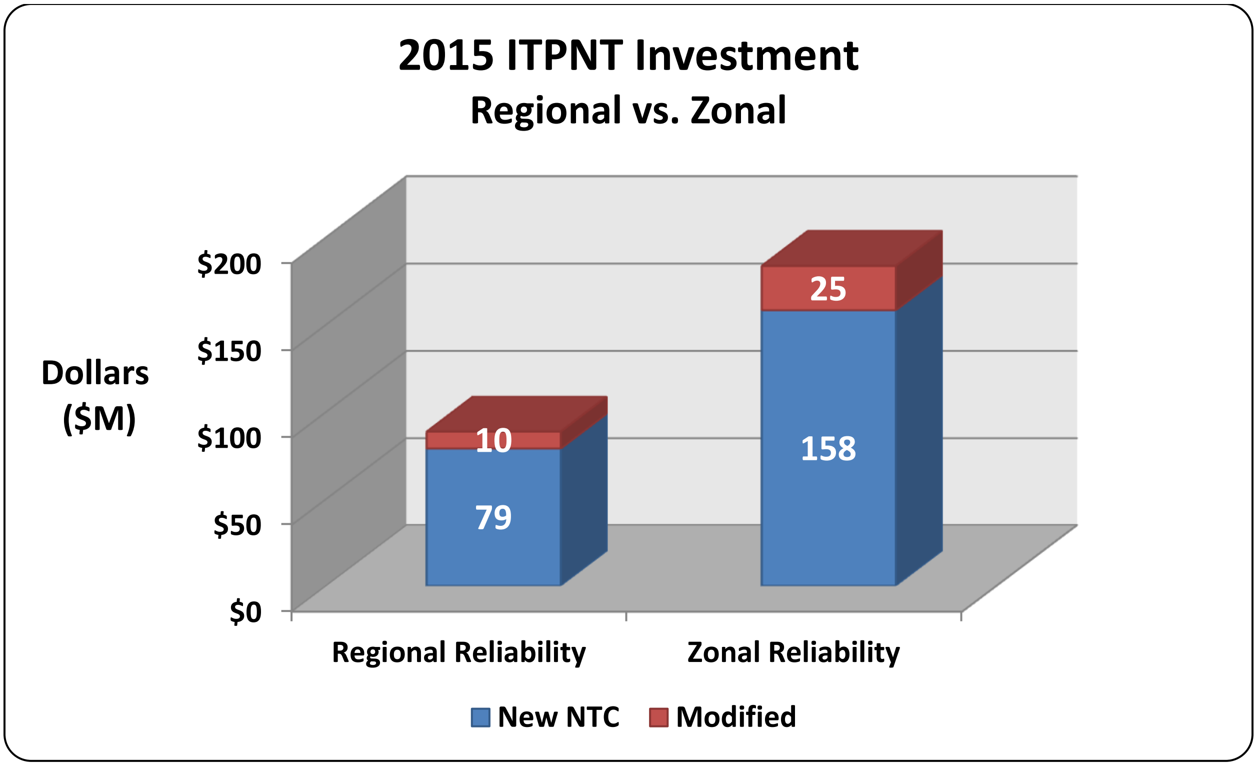

Figure 4.5-9 - 2015 ITPNT Investment - Regional vs. Zonal

The 2015 ITPNT upgrades were run in the SPP Cost Allocation Forecast, the peak ATRR impact year was shown to be 2021.

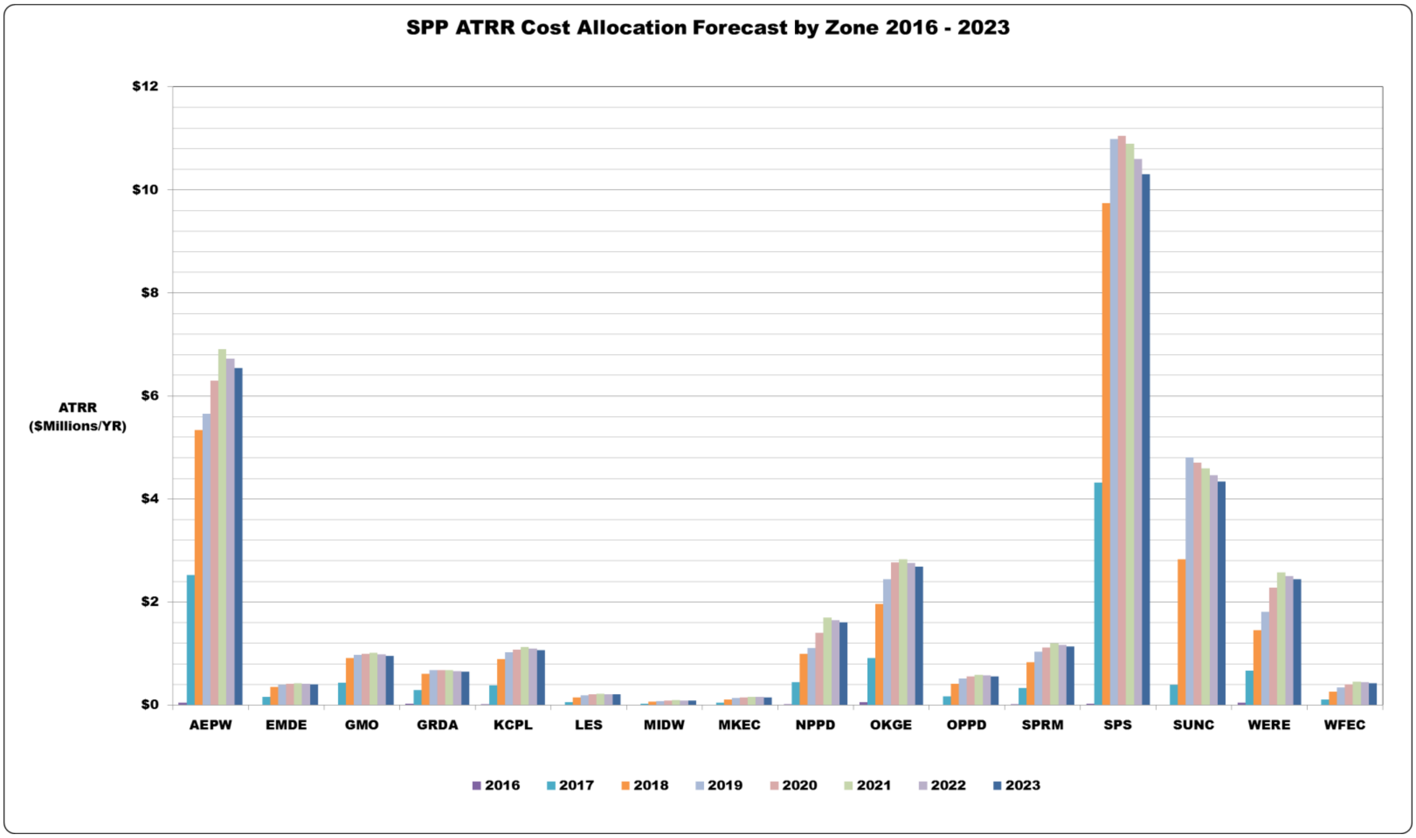

Figure 4.5-10 - ATRR Cost Allocation Forecast by Zone of the 2015 ITPNT

As shown in the following chart, the majority of the 2015 ITPNT projects will be cost allocated to the Pricing Zone hosting the upgrade and a smaller amount will be cost allocated to the SPP region through the regional rate.

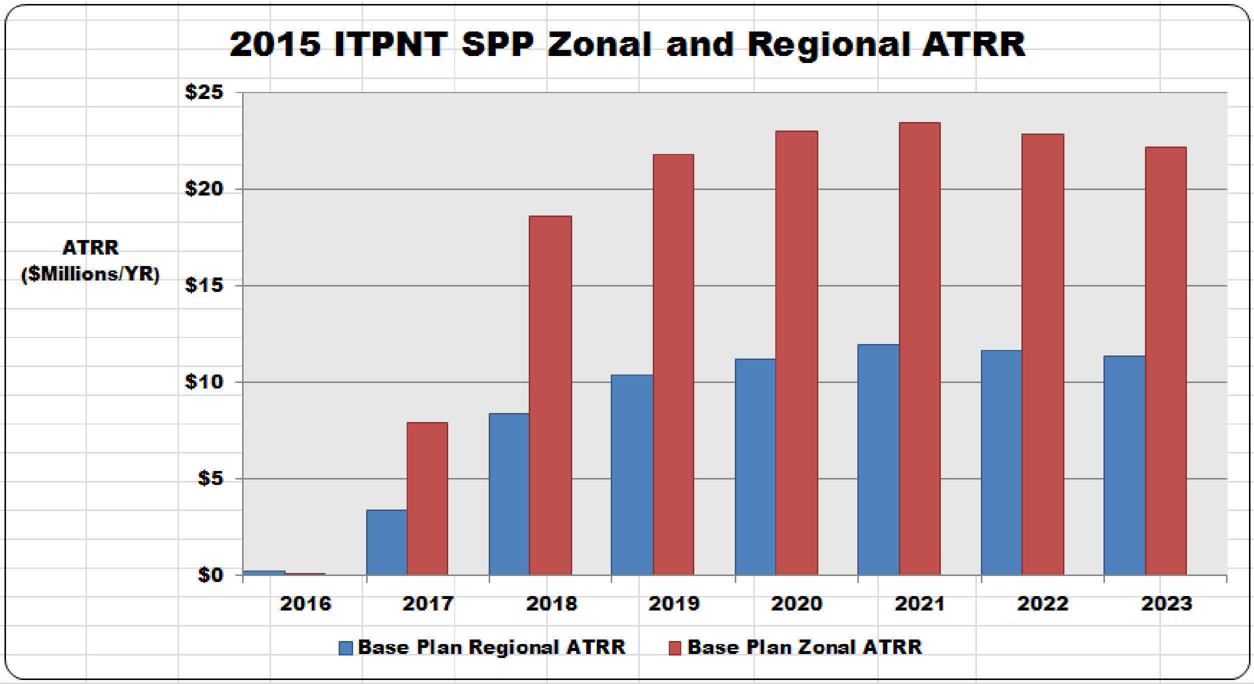

Figure 4.5-11 - Zonal and Regional ATRR Allocated in SPP

The peak year ATRR is converted into a monthly impact on a typical 1,000 kWh per month Retail Residential ratepayer. This is done by dividing the ATRR zonal impact by the zonal energy usage as adjusted for typical losses.

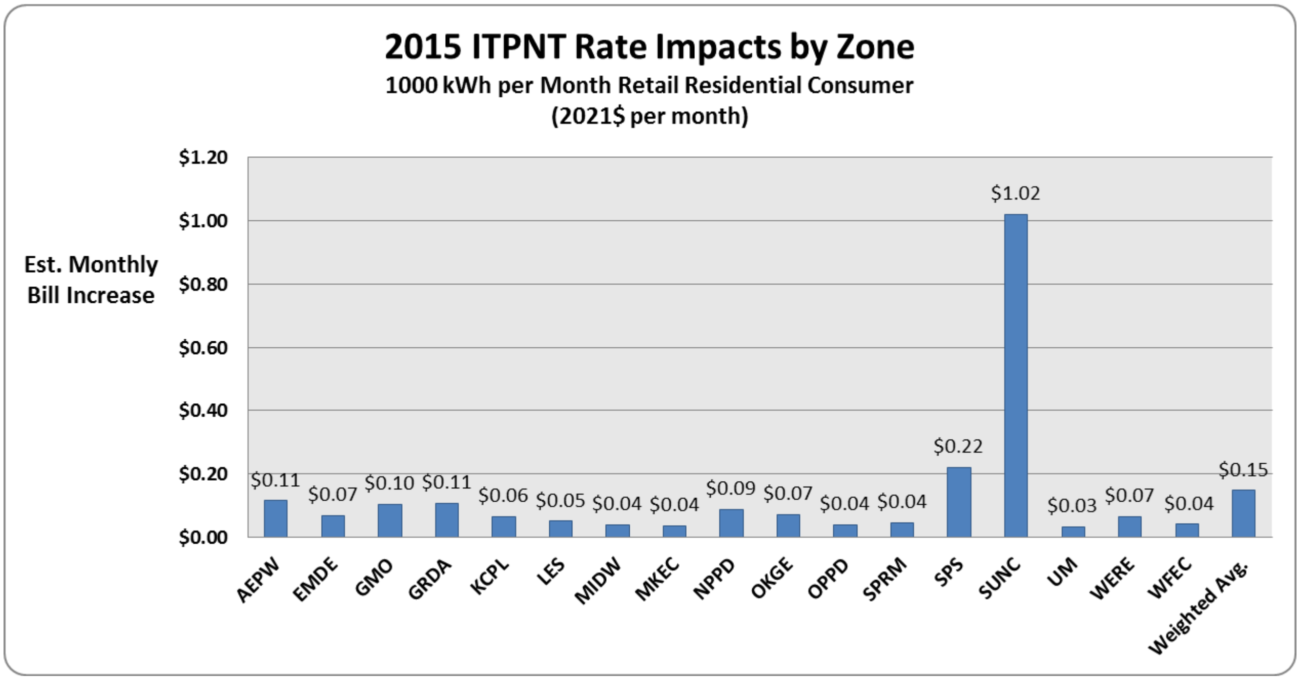

Figure 4.5-12 - 2014 ITPNT Monthly Bill Impact 1000 kWh/Month Retail Residential

Zones providing information on more than one state were combined using a weighted average based on sales projections in each state in the peak ATRR year of 2021.

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*

The revenue credit process for future regional transmission upgrades has not been fully developed by SPP at this time. The Balanced Portfolio cost allocation coupled with newly designed highway/byway cost allocations and previous iterations of base plan funding remain in flux. SPP has forecasted values that were included in the previous sections as to the projected utility-specific ATRR are repeated in *Figure 4.5-13*, for convenience.

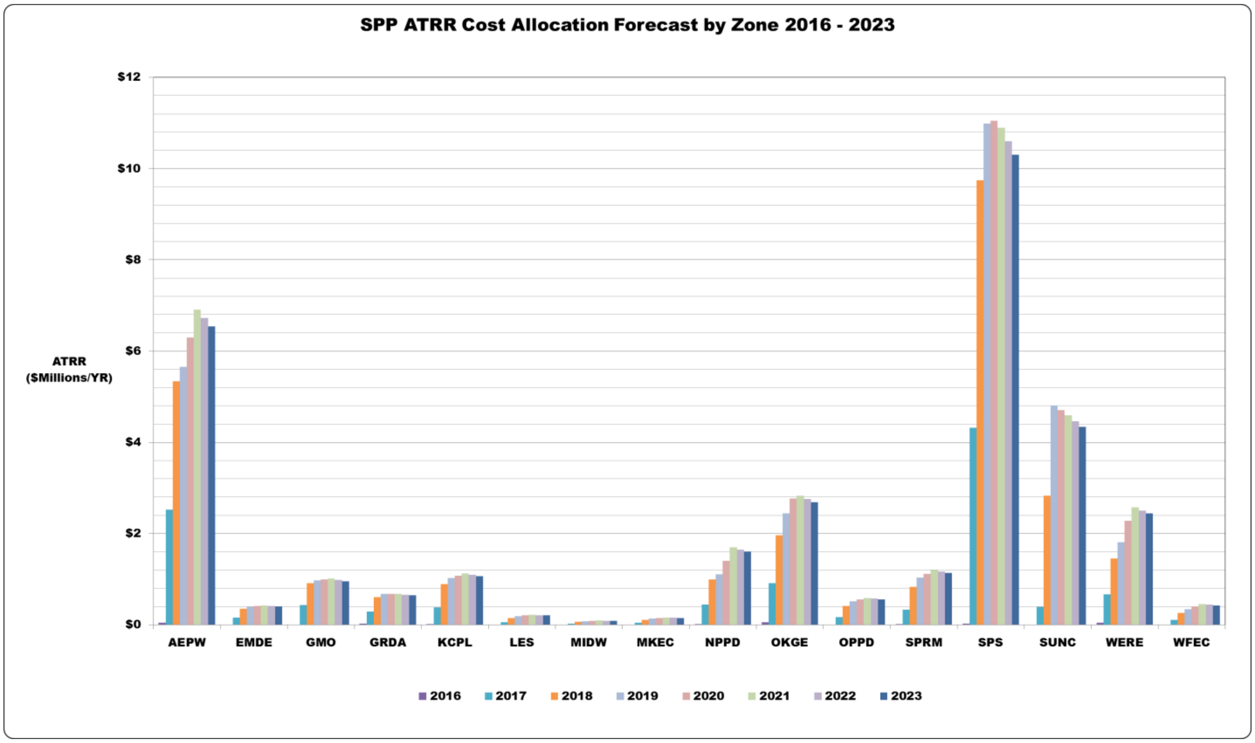

Figure 4.5-13 - ATRR Cost Allocation Forecast by Zone of the 2015 ITPNT

Empire continues to be in the lowest quartile of the utilities shown in *Figure 4.5-13*, as well as representing less than 1.0 percent of the collective ATRR.

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 Balanced Portfolio of regional transmission projects included no projects in the Empire service territory; therefore, there will be no impact on Empire alternative resource plans.

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 the previous sections for descriptions of Balanced Portfolio studies and ITP studies.

3.2.1 Utility Participation in RTO Transmission Plan

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

Empire actively participates in the development of SPP transmission expansion plans through a number of related activities. Please refer to *Table 4.5-6* (previously provided on Page 4.5-43), which lists three dozen SPP stakeholder committee/task force involvements. Several of these groups are directly involved with development of the SPP transmission plan.

Empire is a voting member as well as presently serving Chair of the MDWG which reviews and updates the transmission planning models used for regional transmission expansion analysis. Empire adds transmission projects into the planning models and provides a substation level load forecast for the seasonal and future years planning models. These models include the generation dispatch Empire expects to be required for meeting its native load requirements. The analysis of these models identifies future transmission projects necessary to maintain reliable service and reduce transmission congestion.

Empire is also a voting member of the TWG which works on issues of coordinated planning and NERC and SPP compliance with individual transmission owners. The TWG is responsible for the planning criteria for evaluating transmission additions, seasonal available transfer capability (ATC) calculations, seasonal flowgate ratings, oversight of coordinated planning efforts, and oversight of transmission contingency evaluations. 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 ESWG to develop the scope documents used to direct the analysis and studies performed for the ITP process.

In addition, SPP hosts multiple ITP workshops and Planning Summits each year seeking stakeholder input to the transmission planning process and providing analysis results for stakeholder review. The workshops allow SPP stakeholders to provide input on assumptions for economic analysis and propose transmission projects to reduce congestion and improve reliability. Empire reviews transmission projects in its area and proposes alternatives that may provide better benefit or requests restudy of projects that it believes are not required.

3.2.2 Annual Review of RTO Expansion Plans

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;

Empire reviews SPP overall expansion plans each year specifically for transmission projects in its area. Empire proposes improved alternatives, where applicable, and/or requests restudy for projects that it believes are unmerited. In other instances, Empire may suggest solutions to resolve a transmission problem in order to temporarily delay or potentially avoid new transmission construction. Empire also submits alternative upgrade projects and their associated NTCs to be withdrawn if the requirements for the project changes or if the project is delayed beyond the scope of the study process, thereby postponing project construction or submitting.

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;

Empire reviews SPP transmission expansion plans each year specifically for projects in its area. Some of these are zonal projects that may result in additional obligations to serve or for Empire to comply with specific planning and bulk electric reliability criteria.

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

Empire's participation in the SPP planning processes is continuous throughout the year, directly participating on SPP committees, workgroups, various task forces, and projects reviewing transmission plans and providing recommendations. Empire reviews SPP overall expansion plans each year specifically for transmission projects in its area. Empire proposes improved alternatives, where applicable, and/or requests restudy for projects that it believes are not required. In other instances, Empire may suggest solutions to resolve a transmission problem in order to temporarily delay or potentially avoid new transmission construction. Empire representatives also participate in the overall approval of SPP transmission expansion plans in the market and operating policy committee (full membership) and the 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.

Empire does not currently have any affiliate-built transmission at this time.

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 in the appendix to this report.

Appendix 4.5B	SPP Balanced Portfolio Report
Appendix 4.5C	SPP Priority Projects Phase II Final Report
Appendix 4.5D	2015 SPP Transmission Expansion Plan Report (STEP)
Appendix 4.5E	2015 Integrated Transmission Plan Near-Term Assessment Report (ITPNT)
Appendix 4.5F	2015 Integrated Transmission Plan 10-Year Assessment Report (ITP10)
Appendix 4.5G	2013 Integrated Transmission Plan 20-Year Assessment Report (ITP20)

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;

There are no transmission upgrades needed at present to physically interconnect a generation source within Empire’s footprint. Empire cannot provide a generic list of the transmission upgrades needed to physically interconnect any given generation source within the SPP footprint. Since each interconnection is unique, and each evaluation is site specific. Each Generation Interconnection request is required to submit to the SPP Generation Interconnection process as defined in the applicable SPP transmission tariff. This process examines the specific location proposed for generator interconnection, its unique technical characteristics, and determines the necessary transmission upgrades necessary for that unique interconnection, as required by SPP.

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;*

Requests for firm transmission service are processed through the AFS process in the SPP. Since the AFS is an iterative process, it is not possible to identify a list of the specific transmission upgrades needed to generally deliver energy from a resource in the SPP footprint into Empire unless the process for a specific Transmission Service Request has been completed.

The AFS process occurs three times each year when specific Transmission Service Requests and Generation Interconnection requests are modeled collectively across the entire SPP footprint, based on control area to control area transfers. SPP analyzes the transmission system for the service requests including transmission improvements are identified that would enable the service to occur without standard or criteria violations. Costs for the various upgrades deemed necessary to deliver all of the Transmission Service Requests are allocated or socialized to all transmission customers within SPP. Transmission customers may decline the allocated costs and drop out of the study process, after which the analysis is repeated for the reduced set of Transmission Service Requests. This process iteration continues until a final set of Transmission Service Requests is reached for the remaining customers. 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 cost allocations. These remaining upgrade projects are included in the next cycle of SPP transmission expansion plan process.

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;

Empire cannot provide a list of specific transmission upgrades needed to interconnect a generation resource located outside the SPP footprint without performing a project-specific for SPP Generation Interconnection request for a particular project location.

3.4.4 Transmission Upgrades Report - Deliverability Enhancement Outside RTO

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;

A list of the specific transmission upgrades needed to enhance deliverability of capacity and energy from a particular generation resource located outside the SPP footprint cannot be obtained without actually making a SPP Generation Interconnection request and an associated Transmission Service Request at a particular location.

3.4.5 Transmission Upgrades Report - Estimate of Total Cost

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

Empire presently does not have any active NTCs on file with SPP; therefore, the estimated total cost of each transmission upgrade is $0 (zero). Presently there have been no NTCs issued to Empire since the 2012 ITPNT study; however, Empire continues to participate in the SPP planning process in an effort to continually study the evolution of the regional transmission system.

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.

Empire's estimated fraction of the total cost of transmission upgrades is unknown at this time. Due to the fact that Empire has no active NTCs in which direct charges will be applied, the cost for Empire-specific projects is $0 (zero). 2015 ITPNT zonal cost allocations are displayed in *Figure 4.5-14*.

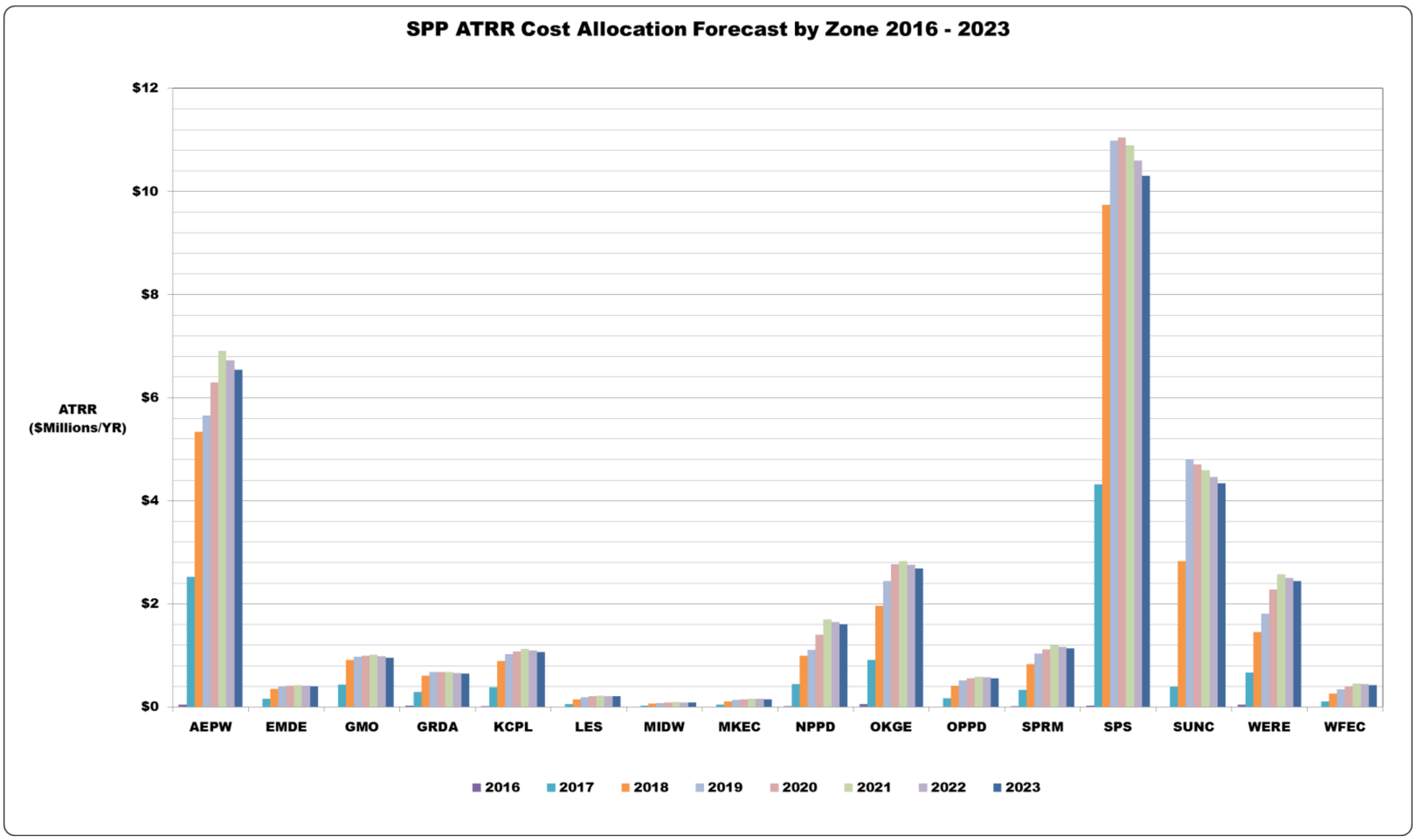

Figure 4.5-14 - ATRR Cost Allocation Forecast by Zone of the 2015 ITPNT

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.

Empire incorporates three main advanced technologies in its transmission system: ADSS and/or OPGW, microprocessor relaying, and automatic throw-over switching schemes on the 69-kV transmission system(s) as previously discussed in Section 3.1.2. Additional technologies are presently included in pilot projects of various scopes and

4.1.1 Operation Toughen Up

The most recent and extensive transmission and distribution improvements that incorporate advanced technologies are the product of Empire's Operation Toughen Up (OTU) program. OTU is an intensive review of issues related to SAIDI and SAIFI on the Empire distribution system. An anticipated amount of $100 million over 10 years was devoted to reducing SAIDI and SAIFI. The two aspects of this initiative involve both transmission and distribution.

In 2010, Empire started the OTU initiative. The focus of the initiative was to lower the SAIDI and SAIFI for Empire customers and increase reliability of the transmission and distribution systems. Individuals within the various facets of Empire were selected for an implementation team in an effort to gain perspective and representation from operations, transmission construction, system protection, and reliability departments. A steering committee was also formed from differing internal departments so that a broad spectrum of specialties would be available to offer guidance to the OTU team. The steering committee tasked the OTU team with addressing the SAIDI and SAIFI for the customers as well as increasing the reliability for power delivery over a 10-year period and allocated $100 million to be used over the 10-year period to address such needs by developing system improvement/hardening plans for existing facilities and future installations which will result in more reliable service for Empire customers. In its efforts, the OTU team was to recommend projects to the steering committee to be addressed and given support by the various Empire departments to budget, scope, and implement the proposed projects.

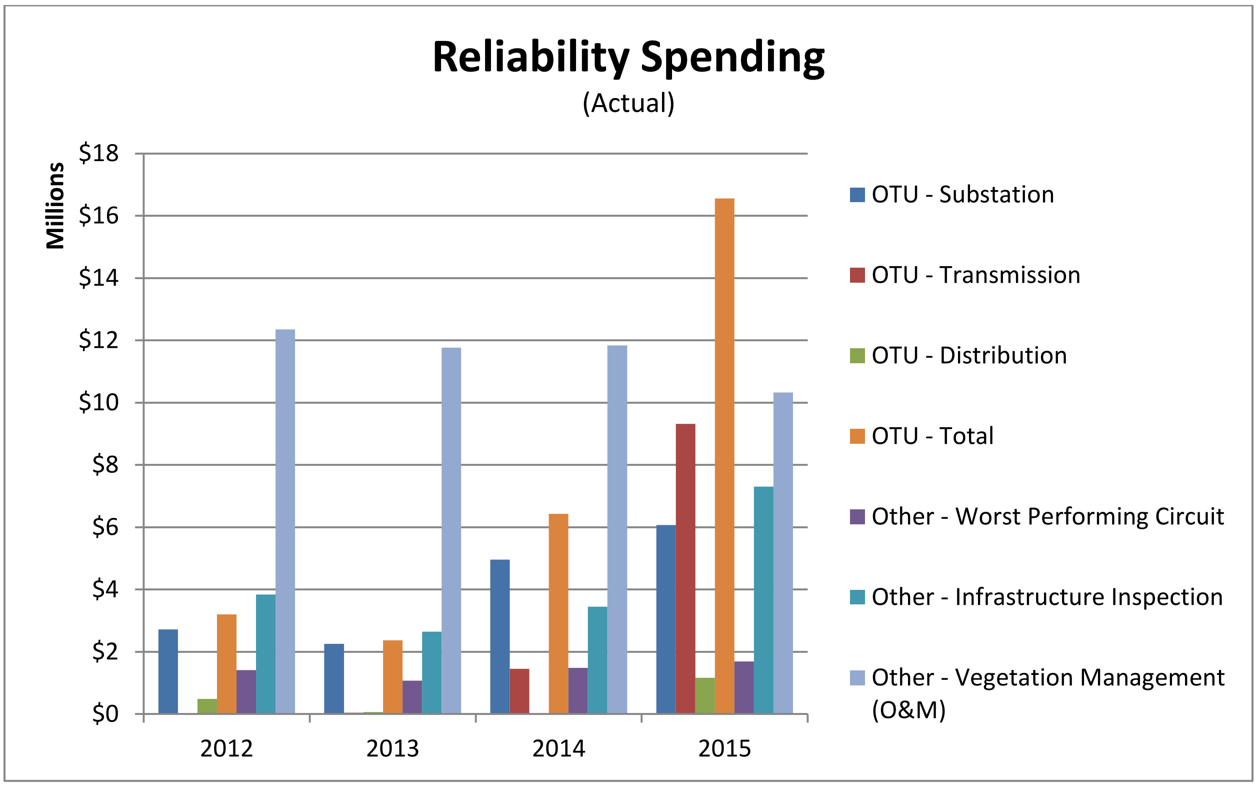

Figure 4.5-15 - Cumulative Operation Toughen Up Annual Spending

The OTU team's review of SAIDI and SAIFI for the distribution and transmission systems and root cause analysis for reported outages relates the indices to causal elements, and proposals for addressing these elements are reflected on an entire system or a more focused effort is applied. As the initial step for evaluation, data was compiled to trend outage causes as compared to the month in which the outage occurred. This data was used as not only a springboard to launch remediation efforts, but also as progress trackers over the course of the initiative. *Figure 4.5-16*, *Figure 4.5-17*, *Figure 4.5-20*, and *Figure 4.5-21* exhibit the Empire cumulative system SAIDI, Empire cumulative system SAIFI, EEI system outage causes, and Empire-related outage causes.

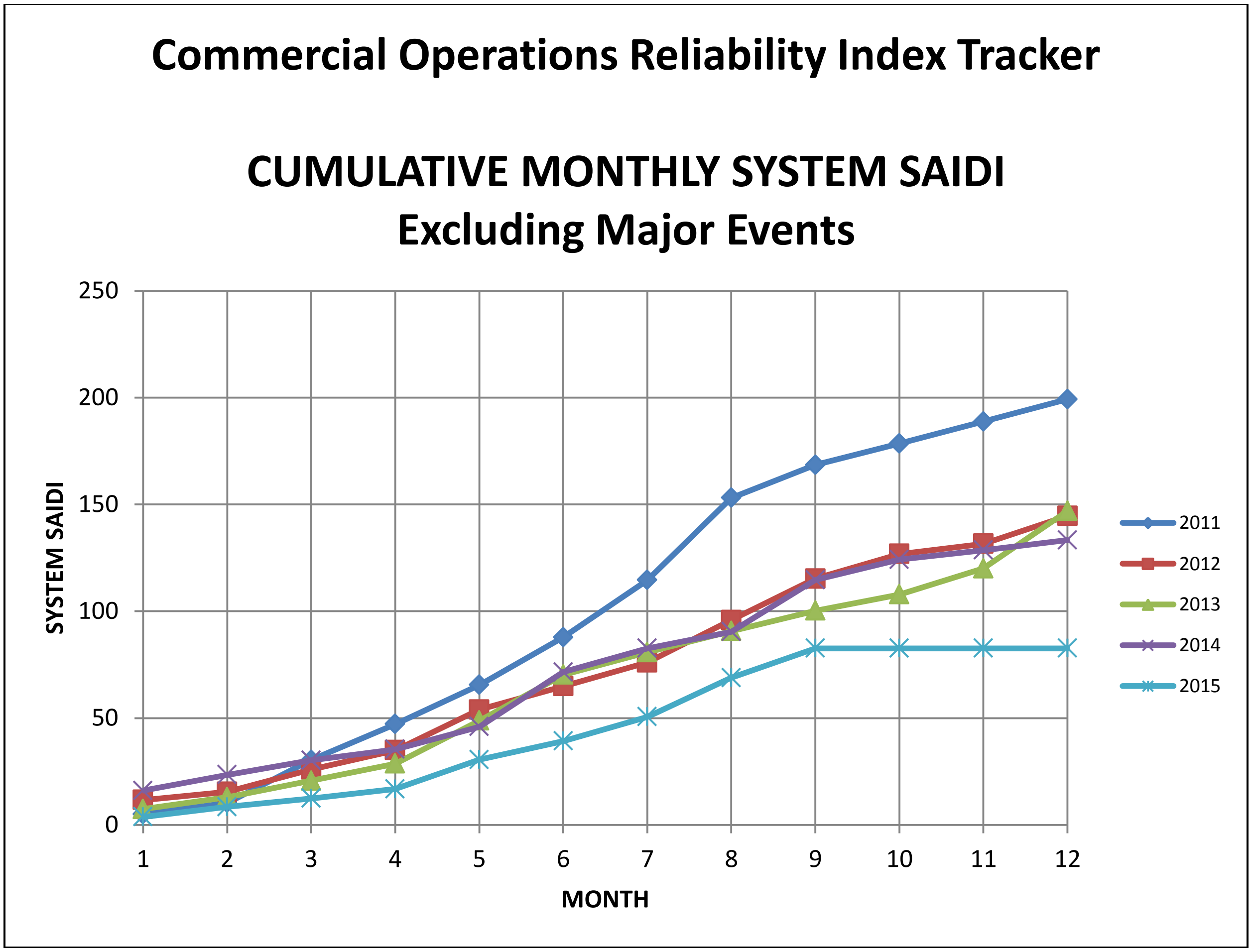

Figure 4.5-16 - Cumulative Monthly Substation System - SAIDI

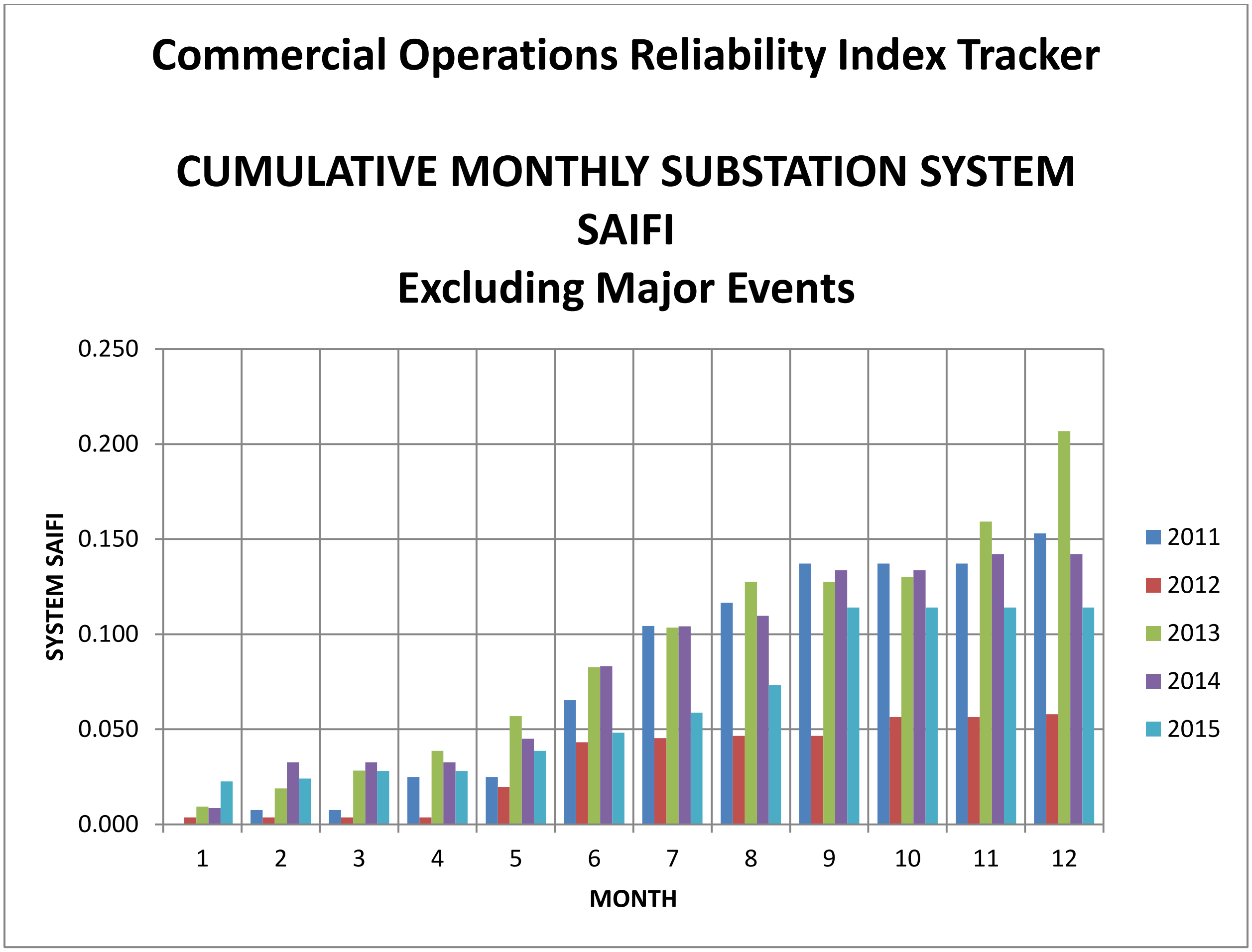

Figure 4.5-17 - Cumulative Monthly Substation System - SAIFI

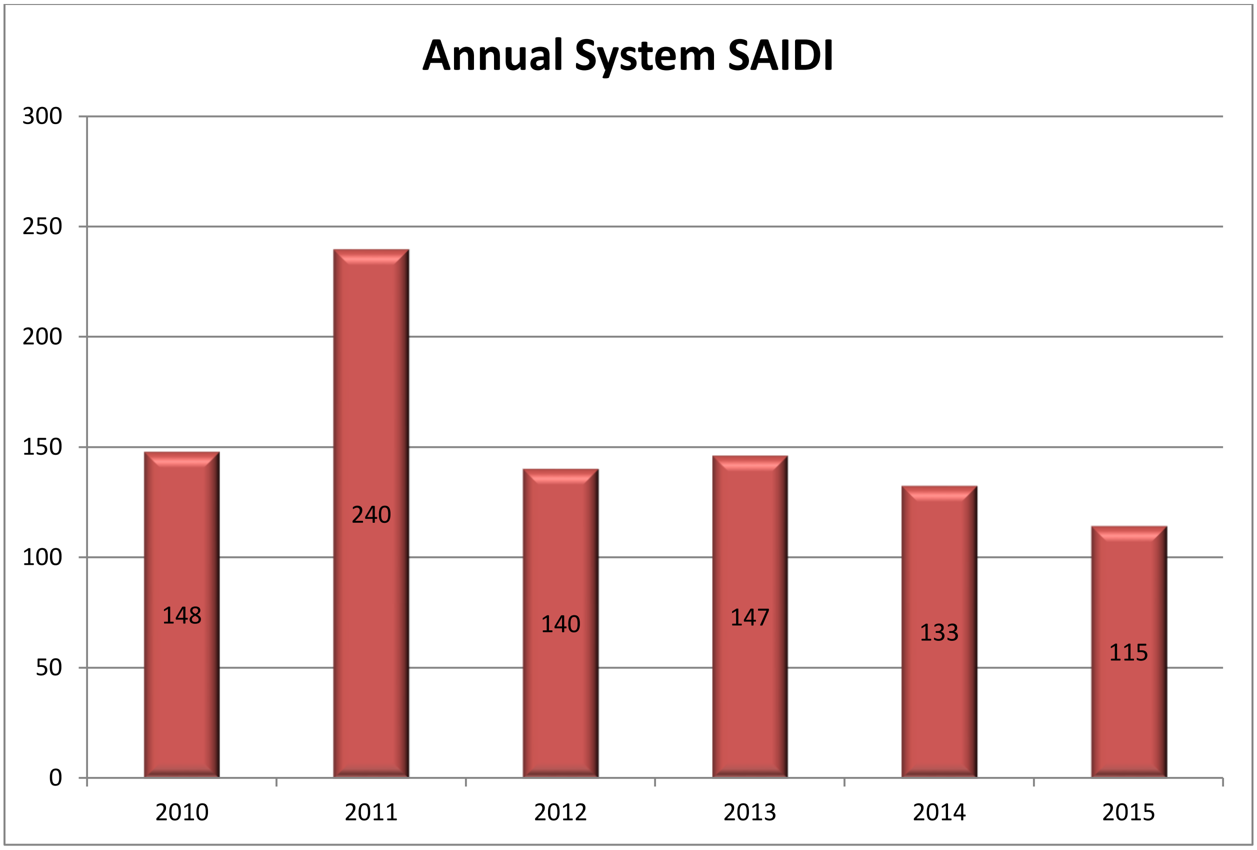

Figure 4.5-18 - Annual System SAIDI

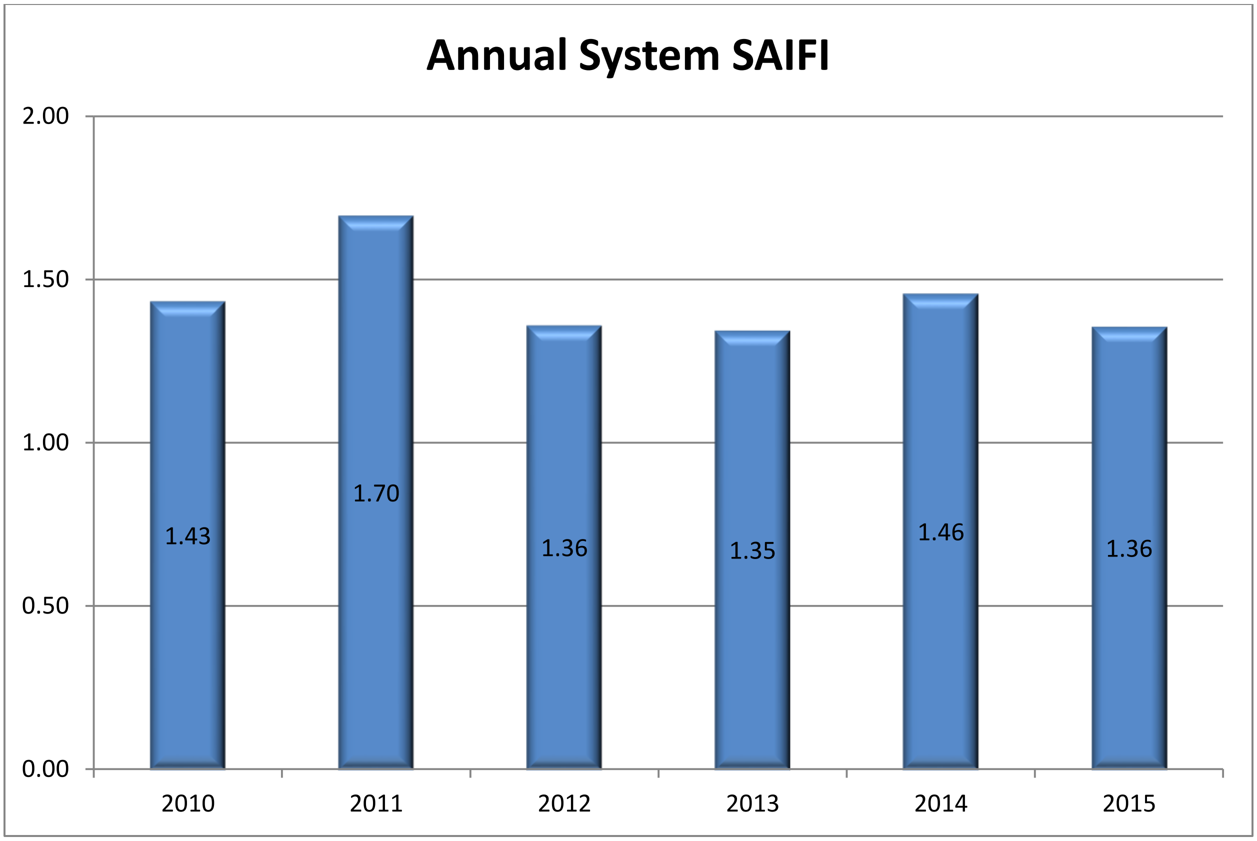

Figure 4.5-19 - Annual System SAIFI

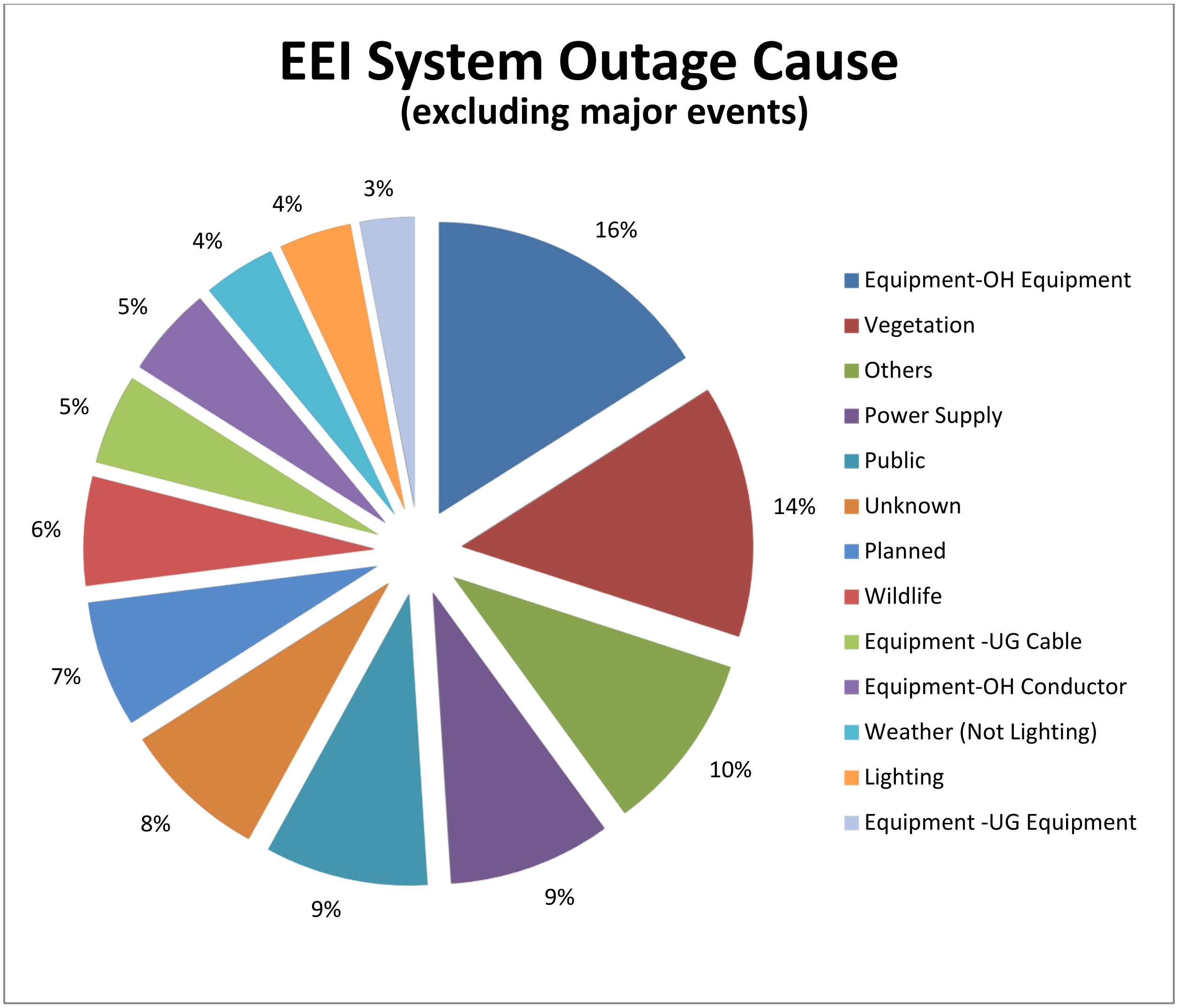

Figure 4.5-20 - EEI System Outage Cause

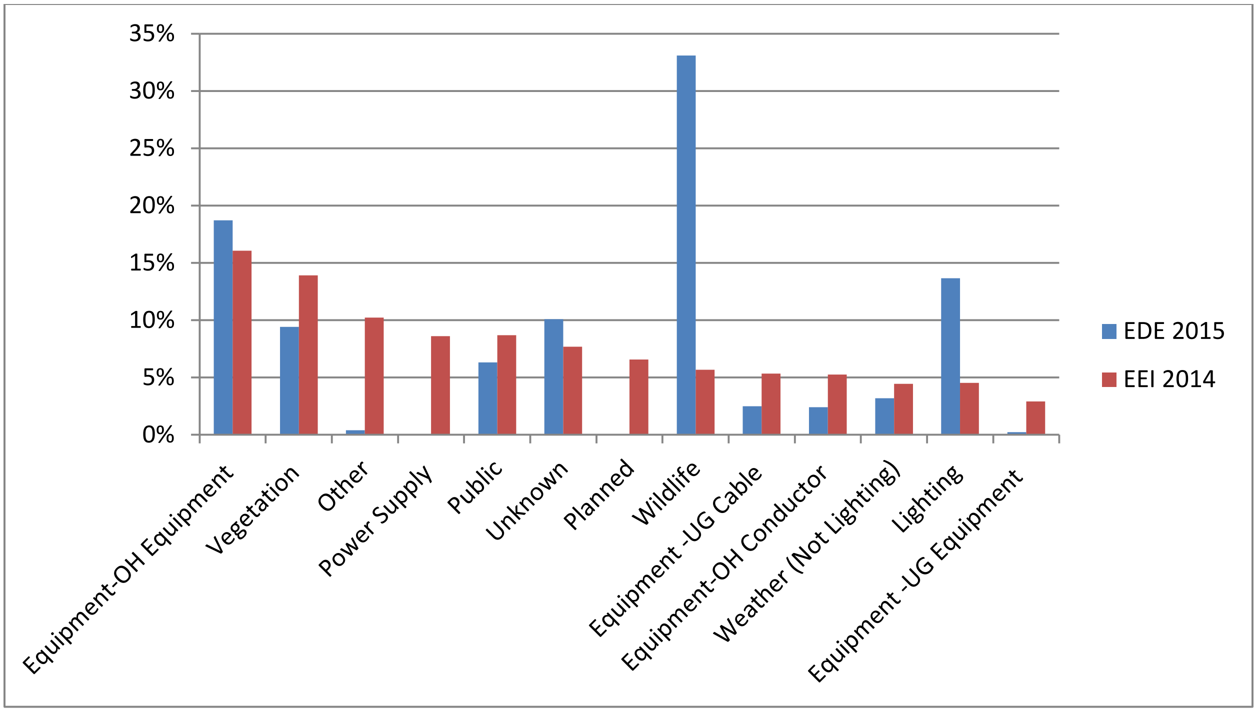

Figure 4.5-21 - Empire-Related Outage Causes

As shown in the above charts, Empire outages as compared to the EEI-reported outages are more frequently caused by equipment failures, lightning, and wildlife. In reviewing these causes, the reliability and OTU teams developed means to address Empire-specific outage causes and ways to better insulate customers from the most common outage causes experienced on the Empire system by using advanced technologies to better automate restoration efforts and improve response time to outages. An example of such is the auto-throw schemes that were developed for vARious load taps on the 69-kV system.

The auto-throw schemes were identified as a sound solution to radially tapped load delivery points on the trANsmission system. The 69-kV system has multiple taps to allow for minimal transmission to be built thereby reducing the impact to customers' rates and right-of-way footprints. The caveat to tapping an existing transmission line versus looping the transmission system is that such taps create a radially fed substation. This radially fed substation is affected by possible faults on either side of the tap (i.e., if a fault occurs on the east side of the tap with breakers at either end of the transmission line, both sides of the tap experience operation). This causes the radially (tapped) substation to experience possible outages as a result of either line section faulting. The determined solution is to apply auto-throw schemes to drastically reduce the exposure for a tapped substation. As the need for a system-wide solution was proposed by the OTU team, Empire engineering developed a standardized auto-throw scheme to BE applied to radially fed 69-kV substations. Standardization of the schemes, not only allows Empire to realize lower cost installations for its customers as compared to uniquely engineered solutions, but coaction is achieved between the various groups within the engineering departments. The auto-throw schemes encompass installation of motor-controlled switches, microprocessor relaying, and breaker coordination which when integrated into a packaged system, allows the exposure for the radially fed load to be drastically reduced. As faults occur, either temporary or permanent, the breakers on either end of the transmission line operate as needed to protect their respective line sections. With the addition of the auto-throw schemes, the motor-operated switches with integrated microprocessor relaying automatically senses the fault, tests either line section for where the fault occurred, and opens the faulted line section while restoring connectivity to the radially line. By incorporating advanced technologies, Empire has significantly reduced the exposure for these tapped load locations and has already experienced a reduction in SAIDI and SAIFI.

In addition to the auto-throw schemes, adVAnced technologies on the 69-kV systems include replacement of electromechanical relaying with microprocessor relaying, installation of additional breakers with microprocessor relaying for improved sectionalization of the transmission system, and utilization/integration of fiber optics with protective relaying communications to further reinforce continuity.

Table 4.5-12 provides a description and schedule of the OTU projects that have been installed since the last filing as well as the projects that are planned for the next three years.

Project Type	In Service Date	Description
Transmission Breakers	April of 2013	Install transmission breakers between Joplin 5th street (#284) and Joplin 10th street (#64) Substations, impacting Joplin downtown customers.

Project Type	In Service Date	Description
Automated Transfer Scheme	May of 2013	Install at Webb City - Cardinal Substation (#436) impacting Webb City customers.
Automated Transfer Scheme	May of 2013	Install at Nixa - North Substation (#114) impacting Nixa area customers.
Transmission Breakers	2014	Engineer two transmission breakers at Neosho-West Substation (#56) impacting customers in the Neosho and Seneca areas.
Transmission Breakers	2014	Engineer two transmission breakers at Wentworth-West Substation (#205) impacting customers in the Wentworth, Sarcoxie and Pierce City areas.
Transmission Breakers	2014	Engineer two transmission breakers at Diamond-H.T. Substation (#131) impacting Diamond and Granby customers.
Transmission Breakers	2014	At Fairgrove South Substation (#397), this project adds a third 69-kV breaker as well as replaces the existing line relay panels. A differential relay panel and communications panel will also be added.
Automated Transfer Scheme	2014	Engineer transfer scheme at Joplin 2nd Street and Division Substation (#372) impacting Joplin area customers.
Re-closer Control Replacement	2014	Three-Phase Recloser Control Replacement: Replace approx. 15 outdated controls on distribution reclosers throughout system. This project will provide sequence coordination of downstream reclosers; it will also provide better data collection and fault finding capabilities to help reduce SAIDI.
Automated Transfer Scheme	2014	Engineer transfer scheme at Sarcoxie - Southwest Substation (#362) impacting Sarcoxie area customers.
Reconductor	2014	Replace 0.27 miles of #6 CU rotten three phase to 336 ACSR along Knox Avenue from Evergreen to Texas Avenue on Hollister East (#387-2) (this has 336 ACSR on both sides).
Reconductor	2014	Replace 0.6 miles of #6/#8 solid CU 3ph conductor with 1/0 ACSR along 12th Street between Euclid and State Line Road in Galena, Kansas.
Reconductor	2014	Replace 0.54 miles of 8 X rotten single-phase conductor to 1ph 1/0 ACSR along FR82 on Greenfield (#614-2) (2 miles north of Greenfield).
Reconductor	2014	Replace 0.54 miles of 6 X rotten single-phase conductor to 1ph 1/0 ACSR alongFR142 on South Greenfield (#614-1).
Reconductor	2014	Replace 0.17 miles of overhead 3ph deteriorated conductor with 3ph 1/0 ACSR along Johnson Drive in Neosho, Missouri.
Reconductor	2014	Replace 3 miles of 8A overhead single-phase deteriorated conductor with 1ph 1/0 ACSR along Base Line Boulevard (Missouri Highway N) from CR120 to CR90 SE of Jasper, Missouri.
Transmission Breakers	2015	At Fairland West SubstatioN (#363), this project adds 2 69-kV breakers and associated relay panels. The additioN of a 2nd motor operator and 69-kV auto throw-over relay scheme will further increase reliability to the area. Line Work: Install 300' of new conductor to tie SHEll Substation into existing 69-kV line. Reroute the incoming and outgoing line segments to allow the breakers to be installed. Additional line rerouting may be required to protect the (#261) Fairland shell tap protection. Line rerouting may not be as severe, with the moving of a switch and some bus work inside of the substation to serve Fairland shell (#261).

Project Type	In Service Date	Description
Transmission Breakers	2015	At Republic Hines Street Substation (#451), this project adds anotheR 69-kV dead end structure, 2 69-kV breakers, and associated relay panels. LiNE Work: Install 300' of new 69-kV line and remove existing transmission switches.
Transmission Breakers	2015	At Republic Hines Street Substation (#451), this project adds anotheR 69-kV dead end structure, 2 69-kV breakers, and associated relay panels. LiNE Work: Install 300' of new 69-kV line and remove existing transmission switches.
Reconductor	2015	Replace 0.14 miles of #6 CU rotten 3ph conductor to 3ph 1/0 ACSR in downtown alley between Church Street and College Avenue (East of Jefferson Park) in Aurora on Aurora Circuit (#124-2).
Automated Transfer Scheme	2016	Engineer transfer scheme at Brighton - East substation (#323) impacting Brighton area customers.
Rebuild	2016	At Baxter Springs West Substation (#271), this project replaces identified B.O. porcelain on switches, bus supports, and D.E. insulators. Line Work: ***2014:*** Construct Phase 1 of 69-kV rebuild from Welch-North (#186) to Chetopa-Twin Valley (#388). ***2014:*** Engineer and purchase RIghts-of-way for Phase 2 of 69-kV rebuild from Welch-North Substation (#186) to Chetopa-Twin Valley Substation (#388). ***2015:*** Construct Phase 2 of 69-kV rebuild from Welch-North Substation (#186) to Chetopa-Twin Valley Substation (#388).
Automated Transfer Scheme	2016	Install at Sub# 372 in downtown Joplin area. Presently a load tap between existing breakers. Will allow for much reduced outage times during contingency events
Automated Transfer Scheme	2016	Install at Sub# 362 Tap in Sarcoxie area. Presently a load tap between existing breakers. Will allow for much reduced outage times during contingency events
Transmission Breakers	2016	At Joplin-Fir Road Substation (#417), this project adds 2 161-kV breakers, a control enclosure, and associated relay panels. This work is the first of a 5 part project involving 5 distribution serving substations as well as addressing protection issues at Asbury. The overreaching project will better sectionalize the transmission circuits in/out of the Asbury generation plant as well as insulate customers served from any of the 5 distribution substations from the extended exposure present. At Joplin Oronogo Junction Substation (#110), this project replaces the existing line relay panel on the line to Asbury (breaker #16154).

Project Type	In Service Date	Description
Transmission Breakers	2016	Substation Work (completed): At Columbus S.E. SubstaTIon #94, this project adds 5 69-kV breakers in a ring-bus configuration, a control enclosure, and associated relay panels. At Columbus Tennessee St. Substation (#282), this project adds a motor-operated, auto throw-over switch scheme. Line Work (work to be completed in 2016): Existing lines will need to be rerouted to allow for the substatiON expansion and inclusion of 69-kV breakers. Provisions should be made for a fifth new line segment exiting the substation to serve the current Columbus tap.
TransmisSIon Breakers	2017	Install (4) 69kV breakers to upgrade existing protections fOR better Coordination between 69kV & 34.5kV networks. Sectionalize 69kV transmission system. Protect associated assets within the substation and Improve coordination on the 34.5kV sub-network.
TransmissIOn Breakers	2017	Install (2) 161kV breakers, a control enclosure, and associated relay panels at Carl Jct. #366. In conjunction with 2016 project at Fir Road #417, this project will allow for further sectionalization of the transmission paths in/out of the Asbury generation substation by way of building on gains from 2016 project. Total project will benefit 5 different substations
Automated Transfer Scheme	2017	Install transfer scheme at Jasper West #403 impacting Jasper, MO area customers.
Automated Transfer Scheme	2018	Install transfer scheme at Commerce #381 impacting Commerce and Quapaw area customers.
Automated Transfer Scheme	2018	Install transfer scheme at Galena #278 impacting Galena area customers.
TransmissIOn Breakers	2018	Install (2) 161kV breakers, a control enclosure, and associated relay panels at Purcell #421. In conjunction with 2016 project at Fir Road #417, this project will allow for further sectionalization of the transmission paths in/out of the Asbury generation substation by way of building on gains from 2016 project. Total project will benefit 5 different substations
TransmissIOn Breakers	2018	Install (2) 161kV breakers, a control enclosure, and associated relay panels at Hollister #387. This project will allow for further sectionalization of the transmission paths on the southern loop of the Branson area service territory. This will eliminatE the load tap present on the 161kV system and lower the exposure to customers in the Hollister/Branson areas.
TransmissIOn Breakers	2018	Install (2) 161kV breakers, a control enclosure, and associated relay panels at Carthage #395. In conjunction with 2016 & 2017 projects at Fir Road #417 & Carl Jct., this project will allow for further sectionalization of the transmission paths in/out of the Asbury generation substation by way of building on gains from 2016 project. Total project will benefit 5 different substations
Automated Transfer Scheme	2018	Install transfer scheme at Joplin NW #341 impacting Joplin, MO area customers.

Project Type	In Service Date	Description
TransmisSIon Breakers	2019	Install (2) 69kV breakers, a control enclosure, and associated relay panels at Neosho #398 to improve sectionalization of area transmission system. Presently 3 separate substations are load taps on the line section in consideration. Additional breakers will allow for line faults to be isolated and improve service to the Neosho area served customers.
TransmisSIon Breakers	2019	Install (2) 69kV breakers, a control enclosure, and associated relay panels at Anderson #322 to improve sectionalization of area transmission system. Presently 2 separate substations are load taps on the line section in consideration. Additional breakers will allow for line faults to be isolated and improve service to the Noel/Anderson area served customers.
TransmissIOn Breakers	2019	Install (2) 161kV breakers, a control enclosure, and associated relay panels at Oakland #432 to improve sectionalization of area transmission system. Present substation is load tap on the line section in consideration. Additional breakers will allow for line faults to be isolated and improve service to the Joplin/Webb City area served customers.
TransmisSIon Breakers	2019	Install (2) 69kV breakers, a control enclosure, and associated relay panels at Golden City #251 to improve sectionalization of area transmission system. Presently 2 separate substations are load taps on the line section in consideration. Additional breakers will allow for line faults to be isolated and improve service to the Jasper/Boston/Lockwood area served customers.

Table 4.5-12 - Three-Year Operation Toughen Up Schedule

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.

Empire's most recent and extensive T&D improvements incorporating advanced technologies involve the OTU program. OTU is an intensive review of issues related to SAIDI and SAIFI across the Empire distribution system. An anticipated amount of $100 million over 10 years was devoted to reducing SAIDI and SAIFI. The two aspects of this initiative involve both transmission and distribution. The relation of OTU to Empire's distribution network is a compilation of sectionalization evaluations, fuse coordination optimization studies, advanced recloser control upgrades, and the implementation of system hardening. All the aforementioned aspects involve the utilization of advanced technology in accomplishing the centralized goal of reducing Empire customers' SAIDI and SAIFI.

The previously employed/evaluated advanced technologies include automated distribution transfer schemes, advanced recloser controls, fuse coordination programs, Optical Ground Wire (OPGW), all-dielectric self-supporting cables (ADSS), microprocessor relaying schema, redundant protective relaying on transmission line panels, and FAS automatic transfer schemes. In support and furtherance of advanced distribution technologies on Empire's system, the company continually evaluates avenues to improve reliability with minimal rate impact in order to better serve its customers. Empire strives to strike a balance between vetting, evaluating, and implementing emerging technologies for the benefit of our customers. A hindrance to this effort is the ambiguity of how advanced distribution technologies are delineated. Without definitive cost/benefit ratios or resolute definitions as to what is considered an advanced distribution technology it is difficult for Empire to evaluate. Empire has proceeded with a focused evaluation as to how the transmission and distribution systems may operate more efficiently and achieve lower cost to the customers.

In review of the causal codes as compared to the EEI Outage Causes in *Figure 4.5-20* (above), Empire focused on substation related equipment to realize the highest benefit to cost ratio with respect to customer experienced outages in a given year. In doing so allowed for the benefits to be dispersed across many customers thereby not only allowing for improved reliability and cost efficiencies but also to further justify possible future roll out of initiatives.
Various applications have been reviewed internally and subsequent pilot programs (as listed and described below) have been initiated. A list of advanced technologies presently being evaluated with associated cost, benefit, and results of ongoing or past evaluations follows:

4.2.1 Transformer Oil Dissolved Gas Monitoring (DGM), Full Suite

4.2.1.1 Application

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4.2.1.2 Benefit

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4.2.1.3 Evaluation Results

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4.2.1.4 Implementation Plan

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4.2.1.5 Cost

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4.2.1.6 Justification

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**

4.2.1.7 Project Status

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4.2.2 Transformer Oil Dissolved Gas Monitor, Light Suite

4.2.2.1 Application

** **

4.2.2.2 Benefit

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**

4.2.2.3 Evaluation Results

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4.2.2.4 Implementation Plan

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4.2.2.5 Cost

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4.2.2.6 Justification

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**

4.2.2.7 Project Status

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4.2.3 Transformer Bushing Monitoring

4.2.3.1 Application

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4.2.3.2 Benefit

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4.2.3.3 Evaluation Results

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4.2.3.4 Implementation Plan

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4.2.3.5 Cost

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4.2.3.6 Justification

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4.2.3.7 Project Status

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4.2.4 Transformer Bushing Monitor with Partial Discharge Monitor

4.2.4.1 Application

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4.2.4.2 Benefit

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4.2.4.3 Evaluation Results

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4.2.4.4 Implementation Plan

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4.2.4.5 Cost

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4.2.4.6 Justification

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4.2.4.7 Project Status

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4.2.5 Transformer Fiber Optic Winding Temperature Sensors

4.2.5.1 Application

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4.2.5.2 Benefit

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4.2.5.3 Evaluation Results

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4.2.5.4 Implementation Plan

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4.2.5.5 Cost

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4.2.5.6 Justification

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4.2.5.7 Project Status

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4.2.6 Transformer Monitor

4.2.6.1 Application

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4.2.6.2 Benefit

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4.2.6.3 Evaluation Results

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4.2.6.4 Implementation Plan

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4.2.6.5 Cost

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4.2.6.6 Justification

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4.2.6.7 Project Status

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4.2.7 Transformer Comprehensive Health Monitoring

4.2.7.1 Application

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4.2.7.2 Benefit

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4.2.7.3 Evaluation Results

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4.2.7.4 Implementation Plan

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4.2.7.5 Cost

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4.2.7.6 Justification

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4.2.7.7 Project Status

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4.2.8 Fiber Optic Substation Data Network

4.2.8.1 Application

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4.2.8.2 Benefit

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4.2.8.3 Evaluation Results

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4.2.8.4 Implementation Plan

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4.2.8.5 Cost

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4.2.8.6 Justification

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4.2.8.7 Project Status

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4.2.9 Substation Data Archive, Server, and Database

4.2.9.1 Application

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4.2.9.2 Benefit

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4.2.9.3 Evaluation Results

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4.2.9.4 Implementation Plan

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4.2.9.5 Cost

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4.2.9.6 Justification

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4.2.9.7 Project Status

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4.2.10 69-Kv Vacuum Circuit Breaker

4.2.10.1 Application

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4.2.10.2 Benefit

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4.2.10.3 Cost

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4.2.10.4 Justification

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4.2.10.5 Project Status

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4.2.11 Welch Feeder Automation System

An example of the utilization of advanced technologies throughout the distribution network is the Empire Welch Substation Feeder Automation System (FAS). A need was identified on a specific feeder which was experiencing longer duration outages than the Empire system average. The feeder in question is fed by way of an approximately 26-mile long radial transmission line; the subsequent distribution feeder extends an additional 14 miles. Any permanent fault along any portion of the 40 miles of exposure could potentially result in an extended outage situation. This exposure coupled with the remote location highlighted this specific distribution feeder as a candidate for automation. The system developed resulted in a distribution automation solution. The project encompasses seven communication radios, two RTU installations, two repeatable antennae, three recloser installations with microprocessor controls, one SCADA mate switch and associated control, two substation breakers, one real-time automation control, and one human machine interface (HMI), all integrated to compile a self-healing network. A schematic of the system is presented in *Figure 4.5-22*.

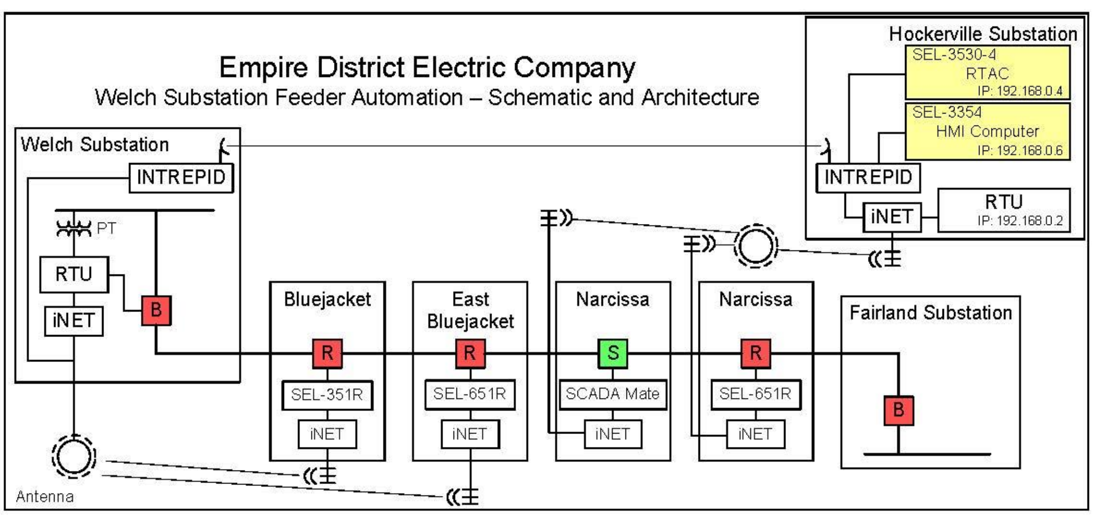

Figure 4.5-22 - Welch Substation Feeder Automation System Schematic

The overarching control of the FAS is referred to as a "scheme", and entails the monitoring and control of the distribution system equipment (substation breakers, reclosers, and switches) included in the FAS extent of control (i.e., other equipment may exist on the power system but is not of interest to or included in the FAS). The FAS defines a feeder (or circuit) as the connected circuit path extending from a source object (e.g. a power source to the system) through closed circuit disconnecting devices up to open disconnecting devices. Feeders can be complex, involving several devices, branches, and line objects, and they are dynamic, changing in response to device open/close operations made by operations people, automatically by the device overload/protection elements or by the FAS itself.

The FAS provides to the Empire SCADA system, system-wide control of the scheme via an enable/disable control point. The FAS provides a "Reset" command and status information for the scheme to the SCADA system. Additionally, the FAS provides the ability for SCADA users to control the breaker, reclosers, and switch, and to change the settings group active in the reclosers.

The complex nature of the installation along with communications complexity restricts the ability to implement this enhancement system wide. However, because of the unique nature of the radial topology of the feeder in question, this project has served the area customers well and drastically reduced the outage time experienced during adverse events.

Other advanced technologies utilized on the Empire distribution system involve the upgrade and replacement of advanced recloser controls and advanced fusing studies. Empire presently has an additional reliability improvement initiative to upgrade existing recloser controls to microprocessors. In doing so, operability, specifically in rural areas, will be further refined, coordination improved, and enhanced sectionalization will be gained.

4.2.12 Advanced Recloser Controls

Empire realized the merits in implementing microprocessor controls and decided to move forward in standardizing towards a more flexible and advanced control type. The advanced recloser controls have the ability to independently operate on a single phase as compared to former control types having strictly three-phase operability. In utilizing single pole tripping, single phase to ground faults' effects on a given phase (which account for the majority of fault types) do not affect customers served on an alternate phase(s).

Empire has also installed a pilot project for a single install of an electronic, single phase recloser with microprocessor controls (SEL-651RS). This will allow for better coordination of downstream fusing and allow for installs regardless of available fault current. The cost of equipment and install is estimated at $50,000/site. Once efficiencies and familiarity are gained, the cost should decrease to a much more manageable amount, if it is determined to be a beneficial program.

4.2.13 Fusing Pilot Studies

4.2.13.1 Application

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4.2.13.2 Benefit

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**

4.2.13.3 Evaluation Results

**

**

4.2.13.4 Implementation Plan

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4.2.13.5 Cost

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**

4.2.13.6 Justification

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**

4.2.13.7 Project Status

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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

Empire's cost to benefit analysis on the above technologies (included individually below for reference) highlights the rural nature and topography of the Empire transmission and distribution systems paired with the location of Empire within the SPP footprint, that optimization of investment of advanced transmission and distribution technologies proves to be cost prohibitive of a broad application of specific technologies yet supports the structured inclusion of others. The analysis of various technologies does not point to a specific advancement which could realize a comprehensive benefit to cost ratio greater than one due to the restrictions of cost deployment. The individualized benefits and costs are included below; please reference sections 4.2.1-4.2.10 for specifics:

4.3.1.1.1 Transformer Oil Dissolved Gas Monitoring (DGM), Full Suite

Benefit

**

**

Cost

**

**

Justification

**

**

4.3.1.1.2 Transformer Oil Dissolved Gas Monitor, Light Suite

Benefit

**

**

Cost

**

**

Justification

**

**

4.3.1.1.3 Transformer Bushing Monitoring

Benefit

**

**

Cost

**

**

Justification

**

**

4.3.1.1.4 Transformer Bushing Monitor with Partial Discharge Monitor

Benefit

**

**

Cost

**

**

Justification

**

**

4.3.1.1.5 Transformer Fiber Optic Winding Temperature Sensors

Benefit

**

**

Cost

** **

Justification

** **

Project Status

**

**

4.3.1.1.6 Transformer Monitor

Benefit

**

**

Cost

** **

Justification

**

**

4.3.1.1.7 Transformer Comprehensive Health Monitoring

Benefit

**

**

Cost

** **

Justification

**

**

4.3.1.1.8 Fiber Optic Substation Data Network

Benefit

**

**

Cost

**

**

Justification

**

**

4.3.1.1.9 Substation Data Archive, Server, and Database

Benefit

**

**

Cost

**

**

Justification

**

**

4.3.1.1.10 69-kV Vacuum Circuit Breaker

Benefit

**

**

Implementation Plan:

** **

Cost

**

**

Justification

**

**

4.3.2 Optimization of Investment - Cost of Advanced Grid Investments

A. Costs of the advanced grid investments;

4.3.2.1 Transmission

Empire utilizes a least-cost, high-value, highest-efficacy approach for optimization of investments for advanced grid technologies. Empire outages triggered by transmission outages were determined as higher impact events due to the large number of customers affected by a single event. By addressing the transmission system and improving sectionalization, high impact outage events were able to be remediated by lower cost installations, thereby optimizing Empire investments in advanced technologies. If radially fed substations are outaged, the resulting number of customers is far higher than if a single circuit sourced from the substation is outaged. As a result, low cost, high impact to outage indices was determined as the optimized solution. This included a review of the causal relationships for transmission outages, radially fed substations, and resultant outage duration. Related to low aggregated, levelized cost across Empire's transmission system(s) and given the ongoing evaluations of various technologies, the optimized investment hinges upon on the application, utilization, and expansion of a communications network by way of the aforementioned fiber optic network project presently in design. Many future technologies will be systematic versus localized management. In constructing a communications platform, devices will be able to gather the needed data, manage said data, and make adjustments to optimize the use and ensure viability of the infrastructure and equipment in place. Empire has committed capital in multiple years to further the advancement of a fiber optic network and will continue to evaluate the benefit to cost of such a deployment.

4.3.3 Optimization of Investment - Cost of Non-Advanced Grid Investments

B. Costs of the non-advanced grid investments;

4.3.3.1 Distribution

By utilizing fusing methodology, Empire has optimized distribution grid investments as opposed to expending efforts and resources in attempting to evaluate newly trended technologies and is able to promote a much more robust system for the customers served off the associated feeders to which the recently formatted methodology is applied. Empire has developed fusing methodology alongside the use of advanced software modeling of the distribution systems. Fusing is considered non-advanced technology due to the longevity of implementation on the electric system. Empire has re-evaluated the methodology used in previous iterations of protective coordination studies and has found improvements could be made in how the distribution system is sectionalized. Evaluation of the fusing methodology entails the use of industry standard fusing and standardization of coordination. Application of the revamped fusing methodology allows for a high efficacy impact on the distribution system sectionalization.

The advancement in fuse technology has allowed for more flexibility and configurability on the coordination on radially fed systems. The previous use of fusing was an improvement over previous guidelines however in evaluating new technologies, Empire has been able to provide and increase in service to distribution customers while lessening the cost to the customers. With the associated costs of newly specified fusing mainly residing in the engineering evaluation and specification, install costs are minimal due to the cooperative efforts in the Worst Performing Circuit (WPC) evaluations. Empire foresees no appreciable cost impacts to the customers due to new fuse deployment at this time. If the scope of deployment veers away from WPC cooperation and to total system implementation, the majority of the associated costs for such an initiative would be encompassed within the labor costs of install. This would be site deterministic and could not be estimated on a system wide basis. Added below for reference, the pilot study benefit, cost and justification further supports the continuation of employing a fusing methodology as a means to optimize the distribution system(s) by use of a non-advanced technology:

4.3.3.1.1 Fusing Pilot Studies

Benefit

**

**

Cost

**

**

Justification

**

**

4.3.4 Optimization of Investment - Reduction of Resource Costs

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

4.3.4.1 Distribution

Through extended analysis and thorough vetting of various and diverse technologies, Empire has determined that the optimization of investment in the reduction of resource costs resides in resource planning on the transmission systems as compared to the capping of benefits able to be realized on the distribution system. There is a lack of benefit to cost ratios greater than one for the technologies presently investigated which yielded a return that could change the projected costs associated with demand response resources. A comparison of open market costs to that of demand response initiatives related to a communications platform prove to be cost prohibitive. Open market prices during the calendar year 2015 for Empire averaged at $30.38 / MW. However, advancements in metering and distribution technologies that may be reasonably anticipated to occur within twenty years may affect the ability to implement or deliver potential demand side programs. This again points to the development and continued advancement of a communications network as a springboard from which future initiatives may be established so as to realize an optimum of future investment.

4.3.5 Optimization of Investment - Reduction of Supply-Side Costs

D. Reduced supply-side production costs;

4.3.5.1 Distribution

Empire has determined that the optimization of investment in the reduction of resource costs resides in resource planning on the transmission systems as compared to the capping of benefits able to be realized on the distribution system. A lack of benefit to cost ratios greater than one for the technologies presently investigated would yield a return that could change the projected costs associated with demand response resources. A comparison of open market costs to that of demand response initiatives related to a communications platform prove to be cost prohibitive. Open market prices during the calendar year 2015 for Empire averaged at $30.38 / MW. No distribution technologies have proven to yield the needed impacts to reduce supply side costs. With minimal impact, Empire has determined that studying resource acquisition will allow for a higher B/C ratio than any distribution technology readily available. Once further advancements are made on the distribution level, an optimum investment strategy may present itself. Metrics may possibly be developed as the deployment of a fiber optic network exhibits unforeseen benefits and avenues in which supply side costs may be lessened in future years.

4.4 Cost Effectiveness of Investment in Advanced Transmission and Distribution Technologies

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

The individualized costs are included below; please reference sections 4.2.1-4.2.10 for specifics:

4.4.1.1.1 Transformer Oil Dissolved Gas Monitoring (DGM), Full Suite

Cost

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**

4.4.1.1.2 Transformer Oil Dissolved Gas Monitor, Light Suite

Cost

**

**

4.4.1.1.3 Transformer Bushing Monitoring

Cost

**

**

4.4.1.1.4 Transformer Bushing Monitor with Partial Discharge Monitor

Cost

** **

4.4.1.1.5 Transformer Fiber Optic Winding Temperature Sensors

Cost

** **

4.4.1.1.6 Transformer Monitor

Cost

** .**

4.4.1.1.7 Transformer Comprehensive Health Monitoring

Cost

** **

4.4.1.1.8 Fiber Optic Substation Data Network

Cost

**

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4.4.1.1.9 Substation Data Archive, Server, and Database

Cost

**

**

4.4.1.1.10 69-Kv Vacuum Circuit Breaker

Cost

**

**

4.4.1.1.11 Fault Recording Capabilities

Electromechanical relaying provides no options for recording capabilities. The lack of recording capability can severely hinder restoration efforts during an outage event. Electromechanical relays simply indicate a fault condition occurred whereas a microprocessor relay has the ability to record pre-fault, fault, and post-fault conditions. These records allow an engineer to review and relate the system conditions to the outage results, thereby reducing the time an outage event exists, lowering SAIDI and SAIFI, and allowing for much more readily realized coordination review.

4.4.1.1.12 Load Data Profile

Load data profiles (LDP) are cumulative data which is gathered for a specific feeder in an effort to profile the usage and/or demand occurring within a given timeframe. Electromechanical relaying does not have the ability to digitally gather such data. LDP is tremendously beneficial in reviewing what specific loading a given feeder experiences during various load and weather conditions. Although microprocessor relaying within the substation is one of many available avenues, the effectiveness of various projects (i.e., DSM, reliability efforts, etc.) could be compared to historical loading data gathered for the feeder in question.

4.4.1.1.13 Event Analysis

Event analysis allows for an engineer to review pre-fault, fault, and post-fault conditions so as to determine the possible location of a fault, the magnitude of currents experienced during a fault, and the event response by the protective device which cleared the fault. None of these parameters is available on electromechanical-type relaying. Electromechanical relaying is heavily restricted in data gathering and therefore, does not allow for review of such events, but rather strictly a notification that an event occurred. As related to non-advanced technologies, the aforementioned troubleshooting efforts in problematic and remote areas of the distribution system are aided with the availability of data during abnormal system conditions. Pairing a fusing program/methodology with microprocessor relaying allows for data to be retained, modeled, and system adjustments to be made after an evaluation of the event data.

4.4.1.1.14 Improved Protective Device Coordination

Microprocessor relaying does not migrate. The settings issued and uploaded to a microprocessor relay are consistent over time, whereas electromechanical relaying requires constant and consistent maintenance. Over time, the mechanical apparatus experiences various temperatures, humidity conditions, and possible physical aberrations. These conditions lead to migration of the mechanics within the relay. As the relay ages, the migrations can become more pronounced. This leads to possible miscoordination with downstream protective devices as well as unintended operation of the primary protective device. Solid-state microprocessor relays do not experience migration due to the lack of mechanized operation. With the absence of mechanized operability, more resilient operation over time is realized and protective device coordination is consistent with given parameters.

4.4.1.1.15 Reduction in Operation and Maintenance Cost(s)

Electromechanical relaying requires constant maintenance due to the aforementioned issues experienced with mechanical devices. The time and cost associated for maintaining an electromechanical device is relatively small on the forefront of operation, but as length of service increases, the intervals between required maintenance shortens. Empire systematically reviews problematic relay types/models and develops replacement schedules in an effort to reduce O&M costs associated with failures. Empire actively reviews automation applications so as to further reduce the burden non-advanced technologies have on operating the electric system. An example is the automated check back systems on the carrier systems. With the new revision to the NERC PRC-005-02 standard, increased maintenance practices requiring enormous amounts of time and manpower to implement become necessary. Upgrading the existing carrier systems on 16 of the 161-Kv line sections will reduce and facilitate the required testing as stipulated by the PRC-005-02 standard. The primary focus of this upgrade is to eliminate the requirement for a manual test of the carrier channel every four months and thereby reduce the manual efforts required in maintaining the non-advanced devices. An additional example is the replacement of electromechanical relaying panels. Empire has developed a standardized line relay panel for upgrades to existing electromechanical relaying panels identified as candidates for replacement. In doing so, the maintenance efforts are greatly reduced and do not necessitate the upgrading of the alternate end relaying panel in addition to laying the foundation for future upgrades to the protective relaying systems. This is a tremendous advantage in realizing upgrades to the protective relaying systems while not requiring an expanded project scope due to issues exhibited at a particular substation while accomplishing the reduction in O&M efforts required for non-advanced relaying technologies.

Comparing the advanced technologies to the non-advanced technologies further supports the continued use of fusing methodology as well as a continued evaluation of new fusing schema. There is a horizon available for the benefits gained before an advanced technology becomes fruitful. Non-advanced technologies are beneficial to an extent, at which point the burden, specifically lack of data, can and may prove cumbersome. This is highlighted in problematic and remote areas in rural topographic systems. Typically the costs of mobilizing manpower and the subsequent investigation(s) of issues arising on a distribution system are not properly allocated to a non-advanced technology. With the ability for data retention and replication of recorded system status during abnormal conditions, advanced technologies, specifically those based on a digital platform and/or microprocessor based, overtake the beneficial horizon of the non-advanced technologies. Empire's evaluation of advanced and non-advanced technologies point to a scenario utilizing both technologies to gain the optimum and most cost effective scheme.

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

The individualized benefits are included below; please reference sections 4.2.1-4.2.10 for specifics and expansion of details:

4.4.2.1.1 Transformer Oil Dissolved Gas Monitoring (DGM), Full Suite

Benefit

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**

4.4.2.1.2 Transformer Oil Dissolved Gas Monitor, Light Suite

Benefit

**

**

4.4.2.1.3 Transformer Bushing Monitoring

Benefit

**

**

4.4.2.1.4 Transformer Bushing Monitor with Partial Discharge Monitor

Benefit

**

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4.4.2.1.5 Transformer Fiber Optic Winding Temperature Sensors

Benefit

**

**

4.4.2.1.6 Transformer Monitor

Benefit

**

**

4.4.2.1.7 Transformer Comprehensive Health Monitoring

Benefit

**

.**

4.4.2.1.8 Fiber Optic Substation Data Network

Benefit

**

**

4.4.2.1.9 Substation Data Archive, Server, and Database

Benefit

**

**

4.4.2.1.10 69-kV Vacuum Circuit Breaker

Benefit

**

**

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

3. Societal benefit, including:

4.4.4.1 Societal Benefit - Consumer Choice

A. More consumer power choices;

4.4.4.1.1 Distribution

Refer to comments in Section 4.3.1.1.

4.4.4.2 Societal Benefit - Existing Resource Improvement

B. Improved utilization of existing resources;

4.4.4.2.1 Distribution

Refer to comments in Section 4.3.1.1.

4.4.4.3 Societal Benefit - Price Signal Cost Reduction

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

4.4.4.3.1 Distribution

Refer to comments in Section 4.3.1.1.

4.4.4.4 Societal Benefit

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

4.4.4.4.1 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 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 Transmission

Section 1.1 and subsequent sections above exhibit the cost ineffectiveness of the use of non-advanced technologies in the attempt to optimize investment. The above analysis points to an optimum investment relating to infrastructure platforms from which multiple future initiatives may be built upon and utilize for further gains to be realized. Empire's analysis exhibits the stranding of capital, both immediate and future, with the installation of non-advanced technologies. Empire is not proposing installation of any new non-advanced transmission grid technologies or programs in this triennial IRP compliance filing. Empire's evaluation points to more merit on installing advanced technologies on the transmissions systems.

4.5.1.2 Distribution

4.5.1.3 Capacitor Control Upgrades

Empire has examined and determined needed upgrades for the automation of capacitor bank controls. Previously, simple time and/or temperature controls were installed for capacitor bank control. Upgraded capacitor controls, which include parameters of time, date, temperature, voltage, and VAr (additional option), are installed on all new installations of cap banks. Present controls are replaced on an as-needed basis as original controls fail or become inoperable or operate incorrectly. The power factor at the substation is also improved by the automated addition and removal of capacitance when demand necessitates. This immediate response to load profile changes allows the distribution system to be manipulated to optimize voltage profile along a given feeder.

4.5.1.4 Regulator Controls Upgrades

In reviewing possible candidates for the installation of regulators on a distribution feeder, the Empire planning department makes use of advanced regulator controls in an effort to optimize the voltage profile alongside the use/installation of capacitor banks with advanced controls. Empire's regulator controls have multiple functionalities and parameters that can be tailored to the feeder specifications. Empire evaluates feeders' voltage profiles and programs as such to attain the most effectual response from the regulator. Empire does not simply raise/buck voltage as a response to demand but also implements the proper bandwidths, timer delays so as not to over-wear contacts within the regulators, and the associated compensative settings (impedance and reactance) for the needed end-of-line response. In utilizing regulator controls to this level, Empire gains multiple benefits (i.e., MW demand reduction from voltage control, substation voltage regulation/flexibility, load tap changer flexibility and manipulative bandwidth, VAr flexibility allowing reflection onto the transmission system, etc.) from not only the regulator itself but also the Empire distribution system as a whole.

4.5.1.5 Relaying Upgrading

In an effort to modernize Empire's distribution and transmission systems, all proposed, merited capital projects are reviewed during Empire's construction budget process to identify gains that could be realized with the inclusion of advanced relaying. When presented with a project, Empire's planning and protection department alongside the substation construction department reviews the scope of work and attempts to identify upgrades needed which would most benefit the customers served off the identified feeders and/or substations. One example would be the auto transformer failure at Empire's Powersite No. 312 in the spring of 2012. Empire's planning and protection department along with the substation construction department were able to identify electromechanical relaying that had limited availability of replacement components, no way of recording event data, non-redundant protection, inadequate overlapping zones of protection, and additional exposure to high value equipment which could drastically affect SAIDI and SAIFI for the area transmission systems. Due to the extent of the work to replace an auto transformer, the relaying was deemed as a prime candidate for upgrade. The job was engineered to not only bring the relaying up to adequate Empire protective specifications, but also to allow for future betterment of the protection scheme at the substation of interest. Empire saw a need and attempted to gain coaction while undertaking a common site task by expanding the original project scope so as to better the reliability for its customers. The gains to be realized once the project has been completed include adequate fault recording for root cause analysis in future events, overlapping zones of protection for the newly positioned auto transformer, and reduction of exposure to out of zone events as related to the auto transformer.

An example on the distribution level is the inclusion of microprocessor relaying in all new feeder breakers. Empire also replaces electromechanical relaying with microprocessor relays as breakers fail or interrupting capabilities are surpassed. Alongside replacement of breakers, each new substations that Empire constructs will be equipped with multiple microprocessor relays so as to better coordinate with downstream protective devices, expand fault data recording, aid in root cause analysis, expansion of load data profiling, allow for over lapping zones of protection, enable bus differential relaying for additional protection capabilities, etc. By making use of microprocessor relaying, much more additional information can be readily reviewed after an event has occurred to adjust, evolve, and streamline the protective schemes to eliminate prolonged customer outages.

4.5.1.6 Utilization of Regulator Controls

Empire utilizes advanced controls in the voltage regulation of its distribution system. These controls are microprocessor driven and allow for acute adjustments to be made on a given feeder. Voltage regulation lessens the infrastructure to be installed due to the ability to raise or lower the voltage profile along a feeder experiencing high or lightened loads. By way of raising the voltage, the current demand is lowered on a given section of primary conductor. Lowering the current to within allowable ampacity ratings, said section of conductor would not require a reconductor, rather offset the cost of construction. Although voltage regulation is not a new concept to the power industry, the combined use of voltage regulation alongside capacitor controls and load tap changers can offset construction costs if these controls are operated in conjunction with each respective controller's effects on the given feeder. Empire conducts such a review if a voltage issue is presented. Empire reviews the lowest cost, highest efficacy solution for a given distribution system by using the aforementioned distribution modeling software (CYMDIST), microprocessor controls, and evaluation of the entire feeder as a system.

Empire is not proposing installation of any new non-advanced distribution grid technologies or programs in this triennial IRP compliance filing, but rather a continuation of present efforts in the development and optimization of fusing schema. Empire will conduct and document such an analysis which demonstrates such an investment to be more beneficial to consumers than an advanced grid technology if Empire is to include such non-advanced technologies in future IRP filings.

4.5.2 Non-Advanced Transmission and Distribution Analysis Documentation

2. Describe and document the analysis.

4.5.2.1 Transmission

Sections 1.1 and various subsequent sections above exhibit the cost ineffectiveness of the use of non-advanced technologies in the attempt to optimize investment. The above analysis points to an optimum investment relating to infrastructure platforms from which multiple future initiatives may be built upon and utilize for further gains to be realized. Empire's analysis exhibits the stranding of capital, both immediate and future, with the installation of non-advanced technologies. Empire is not proposing installation of any new non-advanced transmission grid technologies or programs in this triennial IRP compliance filing. Empire's evaluation points to more merit on installing advanced technologies on the transmissions systems.

4.5.2.2 Distribution

Empire is not proposing installation of any new non-advanced distribution grid technologies or programs in this triennial IRP compliance filing, but rather a continuation of present efforts in the development and optimization of fusing schema. Empire will conduct and document such an analysis which demonstrates such an investment to be more beneficial to consumers than an advanced grid technology if Empire is to include such non-advanced technologies in future IRP filings.

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 Transmission

Although Empire has invested in and piloted various advanced technology applications, there is a limit to the accrued benefit customers will actually realize. Spending on emerging technologies can be boundless. Empire has attempted and will continue to strike a healthy balance of vetting newly emerging technologies in parallel with time proven implements. The benefits of the piloted projects are presently being weighed against their associated costs to implement/deploy, however benefits of such programs are very difficult to capture. An example of such would be, regardless if a transformer monitor is installed and a failure occurs, the resultant would be an outage to a large number of customers. Alternatively, if the DGM program is implemented system-wide and transformer failures subsided, the metrics to attribute the reduction in outages are very difficult to allocate properly among other initiatives across the company. Without clarity as to which metrics' weight utilities should focus alongside the high number of unproven technologies, benefits are difficult to quantify. Presently there is a lack of clarity as to what constitutes an advanced technology, definitive standards in which utilities should focus efforts, and no definable cost to benefit ratios deemed as meriting an investment over others. These aspects in concert with sensitivity to impacts upon customer rates give rise to a difficult path utilities must traverse in implementing emerging technologies. Empire will continue to vet advanced technologies in an attempt to best balance cost to consumer versus attributable benefits. Empire has developed the associated costs in the advanced technologies reviewed above and spoken accordingly to each technology's specific cost and justification, however the benefits are still under development due to the vagueness associated with. Empire has not been able to develop specific metrics in which benefits are readily available. Benefits associated with outages, such as quality of life due to reduced number of outages, societal benefits, and lost productivity associated with outages, etc., are difficult to capture at best, however Empire will continue to attempt to capture benefits in subsequent analyses to pair with the gathered costs for implementation.

4.6.2 Distribution

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4.6.3 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;

4.6.3.1 Transmission

Usage of advanced technologies on the transmission system includes, but is not limited to, microprocessor relaying, fiber optic relaying and communications, transformer oil dissolved gas monitoring, transformer bushing monitoring, transformer bushing monitoring with partial discharge, transformer fiber optic winding temperature sensors, transformer monitoring, comprehensive transformer health monitoring, fiber optic substation data network, substation data archive, server, and database, 69-kV vacuum circuit breakers, has been described in detail within the above sections of this filing. Initial results are positive and appear to serve Empire well by incorporating these elements in recent projects. Empire has been able to attain a more robust transmission system due to the expanded protective advantages realized by the inherent benefits to microprocessor relaying and fiber optic communications. Empire not only makes every effort to incorporate advanced technologies in presently budgeted projects but also actively reviews present relay configurations to determine where merited upgrades would benefit the customers served by the associated transmission line sections.

4.6.3.2 Distribution

Usage of advanced technologies on the distribution system includes, but is not limited to, microprocessor relaying for not only substation breakers but also reclosing applications. Both have initially served Empire well by incorporating these elements in recent projects. Empire has been able to attain a more robust distribution system due to the expanded protective advantages realized by the inherent benefits to microprocessor relaying in addition to improved sectionalization. Empire not only makes every effort to incorporate these technologies in presently budgeted projects but also actively reviews present relay configurations to determine where merited upgrades would benefit the customers served by the associated distribution line sections.

Secondly, the Welch FAS has served as a pilot project in which subsequent installations may be able to be based. It is too early to determine whether this application can be used in alternate locations due to the complexity of not only the installation but also due to dynamic loading characteristics of various alternate feeders. Empire will continue to vet this system as time of in-service increases and will review alternate locations for inclusion. The complex relaying and communications required for such a project has shown to be restrictive in implementation.

4.6.4 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

The implementation of transmission or distribution advanced grid technologies did not influence the selection of resource acquisition strategy. The aforementioned implementations are preparative in nature to be used as a possible springboard for future deployment and are viewed as foundational in possible future development. Empire anticipates subsequent cost benefit analyses could possibly determine several advanced grid technologies to be cost effective. At a minimum, Empire will better understand the extent of implementation at which said advanced technologies become cost effective. Advanced grid technologies on resource acquisition have been shown to be of minimal impact, however Empire will continue to evaluate the possible influence these technologies may have within subsequent future filings.

4.6.5 Transmission Advanced Grid Technologies Impact Description

3. A description of the impact of the implementation of transmission advanced grid technologies on the selection of a resource acquisition strategy.

The implementation of transmission or distribution advanced grid technologies did not influence the selection of resource acquisition strategy. The aforementioned implementations are preparative in nature to be used as a possible springboard for future deployment and are viewed as foundational in possible future development. Empire anticipates subsequent cost benefit analyses could possibly determine several advanced grid technologies to be cost effective. At a minimum, Empire will better understand the extent of implementation at which said advanced technologies become cost effective. Advanced grid technologies on resource acquisition have been shown to be of minimal impact, however Empire will continue to evaluate the possible influence these technologies may have within subsequent future filings.

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.

Empire collaborates with SPP members and non-members in the annual RTO-hosted model building summits, planning summits, and various cooperative joint study meetings. Empire actively participates on multiple committees, working groups, and task forces. Empire participates in the development of and annually reviews the various RTO reports. Empire annually confirms tie line ratings with interconnected utilities in an effort to maintain communication and congruency during the associated model building process.

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.

No economically viable Empire transmission projects are merited at this time for review by the RTO. Empire has previously submitted high value projects for consideration as mitigation to various overloads and voltage issues around the Southwest Missouri areas. Due to muted load growth over the past years paired with the position within the SPP footprint, subsequent evaluations by the RTO and Empire have not exhibited the need for any future transmission projects at this time. Empire has and will continually attempt to identify transmission projects that will have positive impacts for their customers.