2015 ITPNT

2015 Integrated Transmission Plan Near-Term Assessment

January 27, 2015

Engineering

Southwest Power Pool

Revision History

Date	Author	Change Description
12/22/2014	SPP staff	Draft
12/29/2014	SPP staff	Approved by TWG
1/12/15	SPP staff	Removed blank rows in Table 5.3
1/12/2015	SPP staff	Added Final Reliability Assessment section
1/13/15	SPP staff	Updated Table 5.4 with accurate costs per state
1/13/15	SPP staff	Removed 21 mile 115 kV line from Walkemeyer – North Liberal based upon MOPC approval

Table of Contents

List of Figures

List of Tables

Executive Summary

The Integrated Transmission Planning (ITP) process is Southwest Power Pool's iterative three-year study process that includes 20-Year, 10-Year and Near Term Assessments. The 20-Year Assessment identifies transmission projects, generally above 300 kV, needed to provide a grid flexible enough to provide benefits to the region across multiple scenarios. The 10-Year Assessment focuses on facilities 100 kV and above to meet system needs over a ten-year horizon. The Near Term Assessment is performed annually and assesses system upgrades, at all applicable voltage levels, required in the near term planning horizon to address reliability needs. Along with the Highway/Byway cost allocation methodology, the ITP process promotes transmission investment that will meet reliability, economic, and public policy needs[1] intended to create a cost-effective, flexible, and robust transmission network that will improve access to the region's diverse generating resources. This report documents the Near-Term Assessment that concluded in January 2015.

The 2015 ITPNT used two scenario models, Scenario 0 and Scenario 5, built across multiple years and seasons to evaluate power flows across the grid to account for various system conditions across the near-term horizon. The first scenario (S0) contains projected transmission transfers between SPP legacy BA's and generation dispatch on the system. The second scenario (S5) maximized all applicable confirmed long-term firm transmission service with its necessary generation dispatch.

Additionally, a Consolidated Balancing Authority (CBA) model scenario was built across the same years and seasons to show the needs on the SPP transmission system as a result of a Security Constrained Unit Commitment (SCUC) and Security Constrained Economic Dispatch (SCED).

Voltage Class	New Line (miles)	Rebuild/Reconductor (miles)
345 kV	0	0
230 kV	0	0
161 kV	17	0
138 kV	0	19
115 kV	1	76
69 kV	3	67

Table 0.1: 2015 ITPNT Project List Breakdown - Lines by Voltage Class

[1] The Highway/Byway cost allocation approving order is *Sw. Power Pool, Inc.*, 131 FERC ¶ 61,252 (2010). The approving order for ITP is *Sw. Power Pool, Inc.*, 132 FERC ¶ 61,042 (2010).

Voltage Class	New Transformer
345/138	0
345/115	2
230/115	1
161/69	2
138/69	1
115/69	2

Table 0.2: 2015 ITPNT Project List Breakdown - New Transformer by Voltage Class

The total cost of the 2015 ITPNT project plan is estimated to be $248.2 million for upgrades that will receive an NTC, NTC-C, or NTC Modify. Of that total, $213.1 million comes from new projects identified in the 2015 ITPNT Assessment. Upgrades recommended for an NTC Modify account for $35.1 million of the total project plan cost.

These upgrades that will receive an NTC, NTC-C, or NTC Modify solves 208 transmission overload violations and 64 voltage violations.

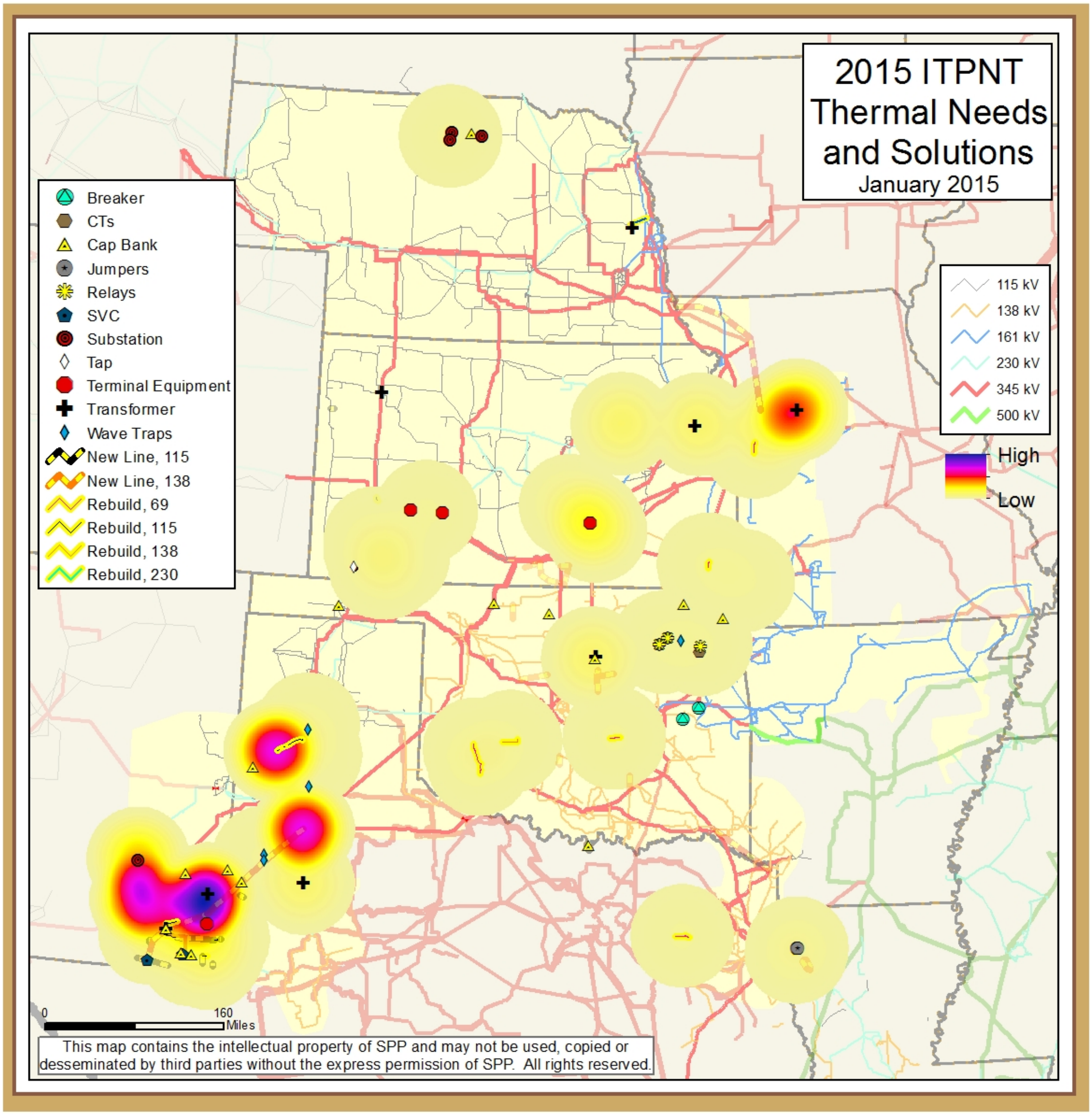


Figure 0.1: 2015 ITPNT Thermal Needs and Solutions

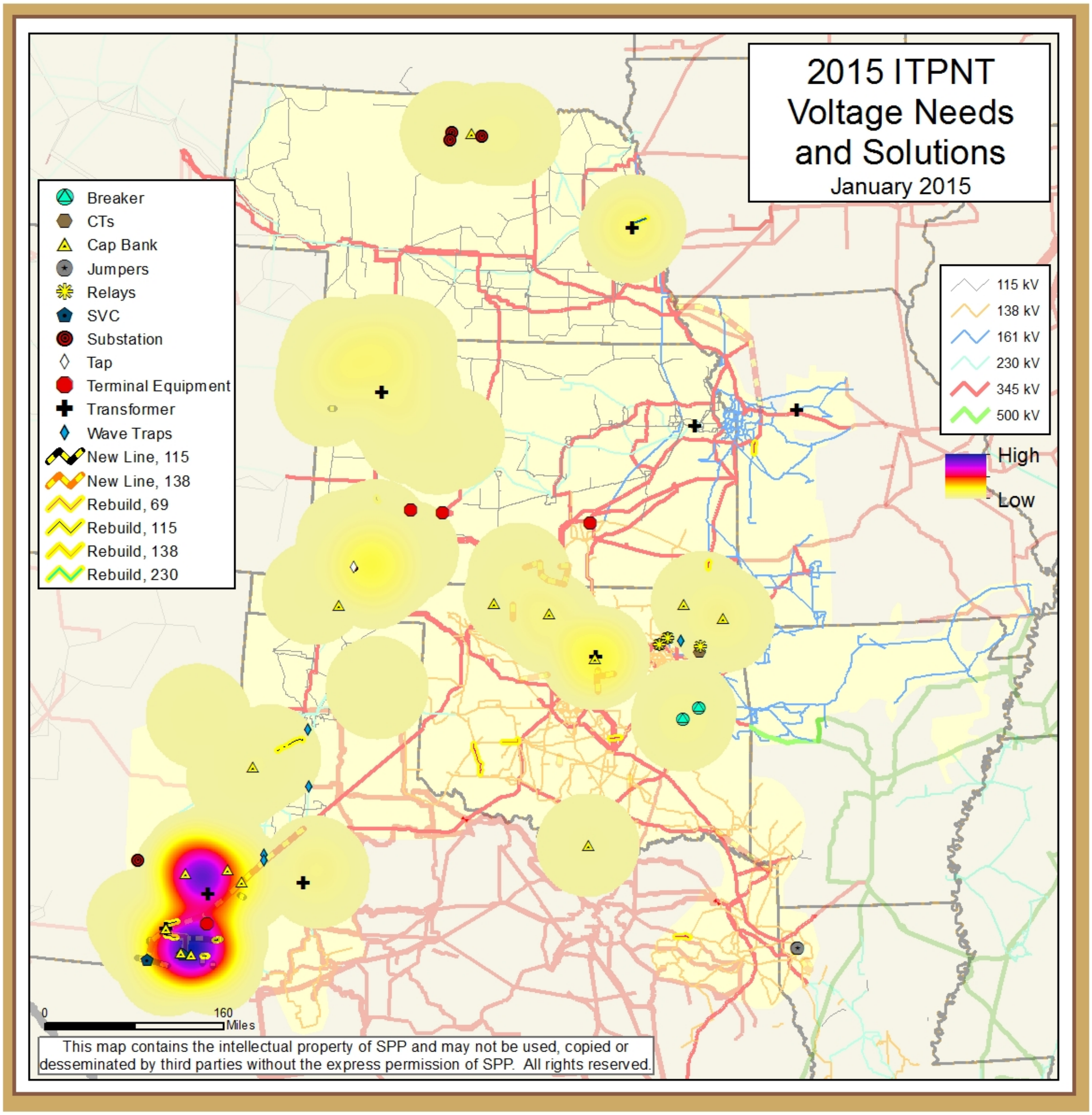


Figure 0.2: 2015 ITPNT Voltage Needs and Solutions

PART I: STUDY PROCESS

Section 1: Introduction

1.1: The ITP Near-Term

The ITPNT is designed to evaluate the near-term reliability and robustness of the SPP transmission system, identifying needed upgrades through stakeholder collaboration. The ITPNT focuses primarily on solutions required to meet the reliability criteria defined in OATT Attachment O Section III.6. The process coordinates the ITP20, ITP10, Aggregate Studies, Attachment AQ Studies, and the Generation Interconnection transmission plans by communicating potential solutions between processes and using common solutions when appropriate. Unlike the ITP10 and ITP20, the ITPNT is not intended to focus on solutions based on a preferred voltage level, but to effectively solve all potential reliability needs in their entirety.

The 2015 ITPNT process produces a reliable near-term plan for the SPP footprint which identifies solutions to potential issues for system intact and single contingency (N-1) conditions using the following principles:

- Identifying potential reliability-based problems consisting of NERC Reliability Standards TPL-001 and TPL-002, SPP Criteria and where applicable, local SPP Member criteria
- Utilizing Transmission Operating Guides
- Developing additional mitigation plans including transmission upgrades to meet the region's needs and maintain SPP and local SPP Member reliability/planning standards

The ITPNT process is open and transparent, allowing for stakeholder input throughout the assessment. Study results are coordinated with other entities, including embedded and Tier 1.

Goals

The goals of the ITPNT are to:

- Focus on local and regional needs
- Evaluate the response of the system on NERC TPL-001 and TPL-002 Standards
- Utilize a cost-effective approach to analyze six year out transmission system needs
- Identify 69 kV and above solutions stemming from needs including, but not limited to the following:
    - Resolving reliability criteria needs
    - Improving access to markets
    - Improving interconnections with SPP's neighbors
    - Meeting expected load growth demands
    - Facilitating or responding to expected facility retirements

- Synergize the ITPNT with the Generation Interconnection (GI) process, Aggregate Transmission Service Study (ATSS) process, Attachment AQ Study process (AQ), and the ITP10 and ITP20 Assessments

The 2015 ITPNT is intended to provide solutions to ensure the reliability of the transmission system during the study horizon which includes modeling of the transmission system six years out (i.e. 2020). The specific near-term requirements of Attachment O are:

- The Transmission Provider shall perform the Near Term Assessment on an annual basis.
- The Near Term Assessment will be performed on a shorter planning horizon than the 10-Year Assessment and shall focus primarily on identifying solutions required to meet the reliability criteria defined in Section III.6.
- The assessment study scope shall specify the methodology, criteria, assumptions, and data to be used to develop the list of proposed near term upgrades.
- The Transmission Provider, in consultation with the stakeholder working groups, shall finalize the assessment study scope. The study scope shall take into consideration the input requirements described in Section III.6.
- The assessment study scope shall be posted on the SPP website and will be included in the published annual SPP Transmission Expansion Plan report.
- In accordance with the assessment study scope, the Transmission Provider shall analyze potential solutions, including those upgrades approved by the SPP Board of Directors from the most recent 20-Year Assessment and 10-Year Assessment, following the process set forth in Section III.8.

1.2: How to Read This Report

This report focuses on the years 2015, 2016, and 2020 and is divided into multiple sections.

- Part I addresses the concepts behind this study's approach, key procedural steps in development of the analysis, and overarching assumptions used in the study.
- Part II addresses the specific results, describes the projects that merit consideration, and contains recommendations and costs
- Part III contains detailed data and holds the report's appendix material.

SPP Footprint

Within this study, any reference to the SPP footprint refers to the set of legacy Balancing Authorities (BA) and Transmission Owners (TO) whose transmission facilities are under the functional control of the SPP Regional Transmission Organization (RTO) unless otherwise noted.

Supporting Documents

The development of this study was guided by the supporting documents noted below. These documents provide structure for this assessment:

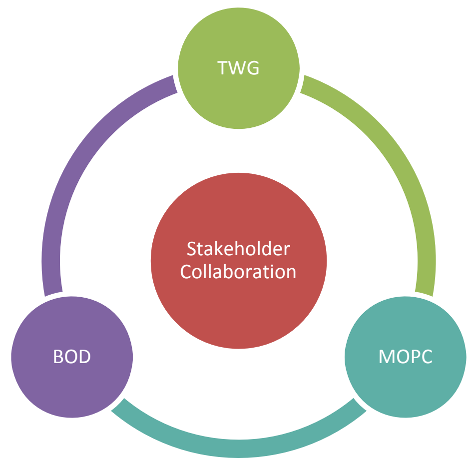
- SPP 2015 ITPNT Scope
- SPP ITP Manual

All referenced reports and documents contained in this report are available on SPP.org.

Confidentiality and Open Access

Proprietary information is frequently exchanged between SPP and its stakeholders in the course of any study and is extensively used during the ITP development process. This report does not contain confidential marketing data, pricing information, marketing strategies, or other data considered not acceptable for release into the public domain. This report does disclose planning and operational matters, including the outcome of certain contingencies, operating transfer capabilities, and plans for new facilities that are considered non-sensitive data.

Section 2: Stakeholder Collaboration



Assumptions and procedures for the 2015 ITPNT analysis were developed through SPP stakeholder meetings that took place in 2013 and 2014. The assumptions were presented and discussed through a series of meetings with members, liaison-members, industry specialists, and consultants to facilitate a thorough evaluation. Groups involved in this development included the following:

- Transmission Working Group (TWG)
- Markets and Operations Policy Committee (MOPC)
- SPP Board of Directors (BOD)

SPP Staff served as facilitators for these groups and worked closely with the chairs to ensure all views were heard and that SPP's member-driven value proposition was followed.
The TWG provided technical guidance and review for inputs, assumptions, and findings. Policy level considerations were tendered to appropriate organizational groups including the MOPC. Stakeholder feedback was instrumental in the selection of the 2015 ITPNT projects.

- The TWG was responsible for technical oversight of the load forecasts, transmission topology inputs, constraint selection criteria, reliability assessments, transmission project designs, voltage studies, and the report.

Planning Summits

In addition to the standard working group meetings, two transmission planning summits were conducted to elicit further input and provide stakeholders with a chance to interact with staff on all related planning topics.

Project Cost Overview

Conceptual Estimates were prepared by SPP staff based on historical cost information submitted by TOs through the project tracking process. Refined cost estimates expected to be accurate within a ±30% bandwidth were then prepared by a third party vendor. All cost estimates utilized in the 2015 ITPNT were developed in accordance with SPP Business Practice 7060, Notification to Construct and Project Cost Estimating Processes Effective January 1, 2012.

Use of Transmission Operating Guides (TOG)

TOGs are tools used to mitigate issues in the daily management of the transmission grid. TOGs may be used as alternatives to planned projects and are tested annually to determine effectiveness in addressing thermal and voltage needs. The 2015 ITPNT identifies all solutions where the use of a TOG is not effective.

Section 3: Study Drivers

3.1: Introduction

Drivers for the 2015 ITPNT were discussed and developed through the stakeholder process in accordance with the 2015 ITPNT Scope and involved stakeholders from several diverse groups. Stakeholder load, generation, and transmission were carefully considered in determining the need for, and design of, transmission solutions.

3.2: Load Outlook

Peak and Off-Peak Load

Future energy usage was forecasted by utilities in the SPP footprint and collected and reviewed through the efforts of the Model Development Working Group (MDWG). This assessment used both summer peak and light load scenarios to assess the performance of the grid in both peak and off-peak conditions.

Load Forecast

Load Serving Entities provided the load forecast used in the reliability analysis study models through the MDWG model building process.

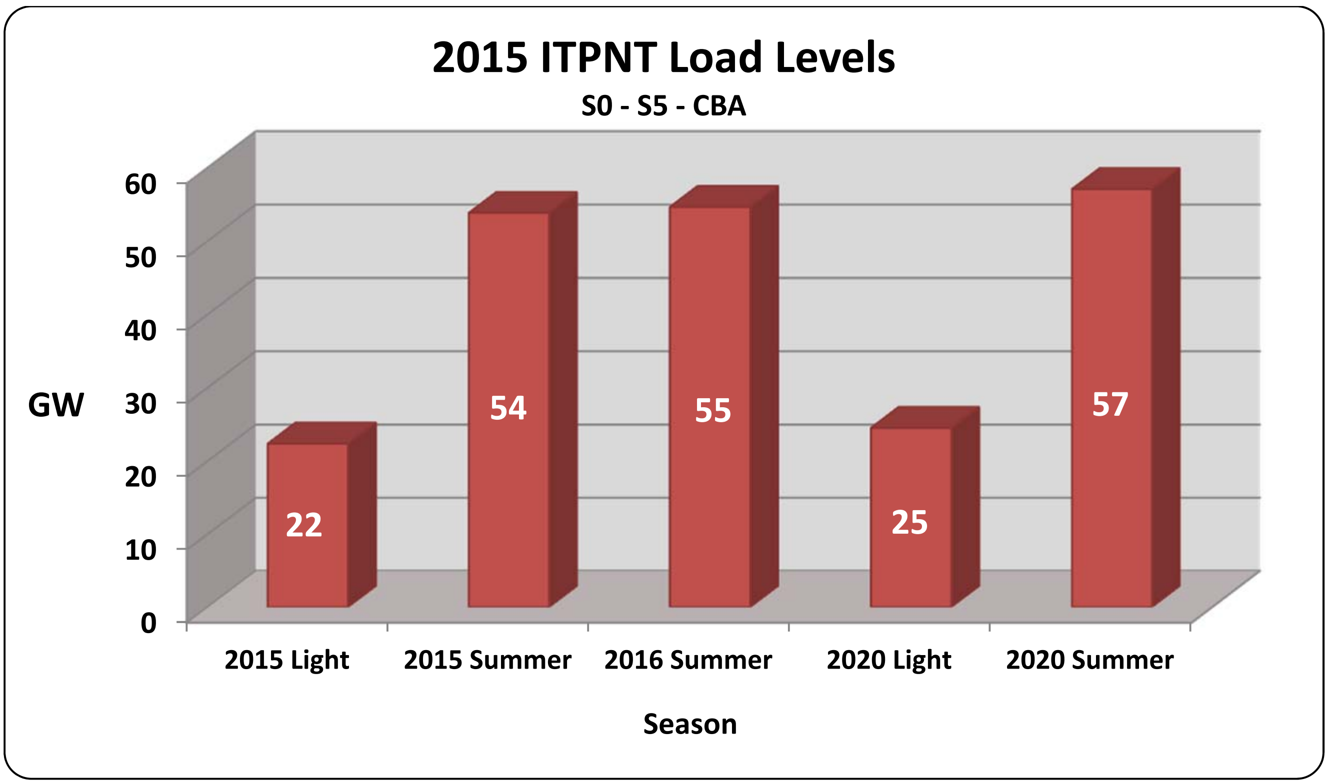


Figure 3.1: 2015 ITPNT Load Levels

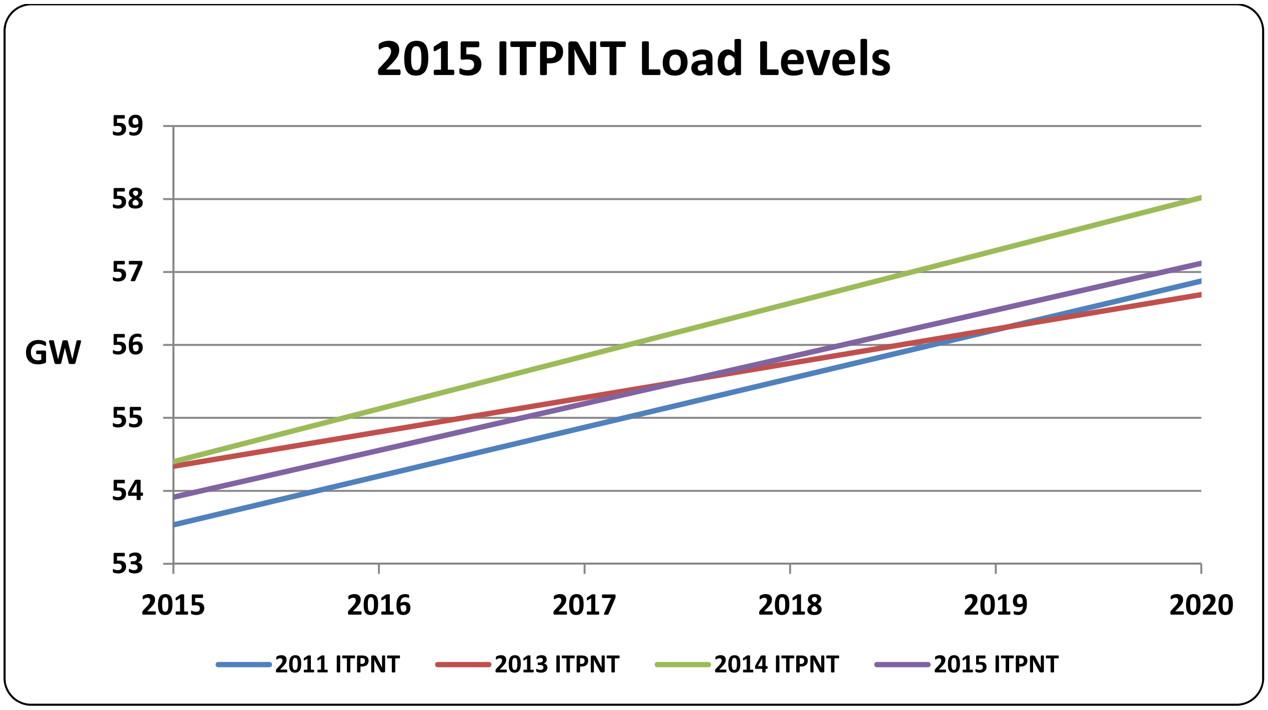


Figure 3.2: ITPNT Load Levels Comparisons

3.3: Generation

The three figures below show the difference between the Scenario 0, Scenario 5, and CBA Scenario models for each season. Note the significant difference in the wind output for the Scenario 5 models. The CBA Scenario dispatch methodology is discussed later in this report.

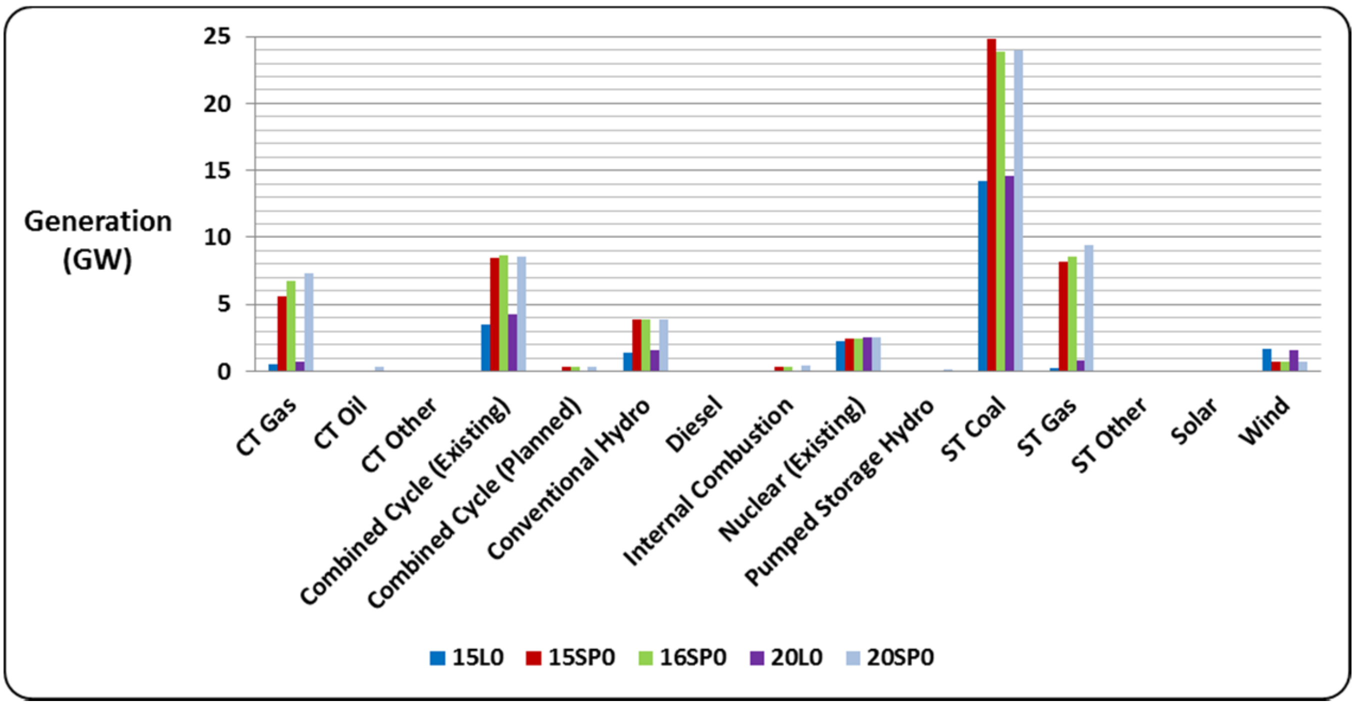


Figure 3.3: 2015 ITPNT Generation Mix Scenario 0

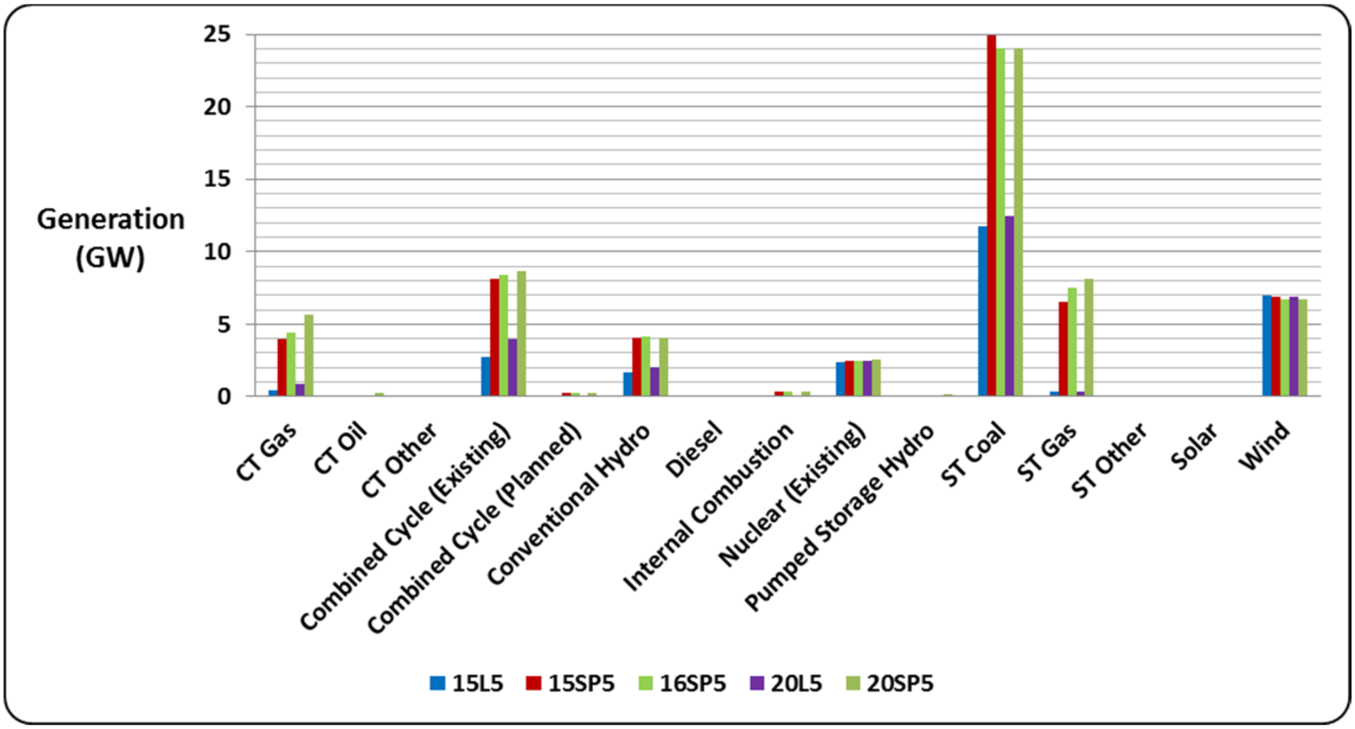


Figure 3.4: 2015 ITPNT Generation Mix Scenario 5

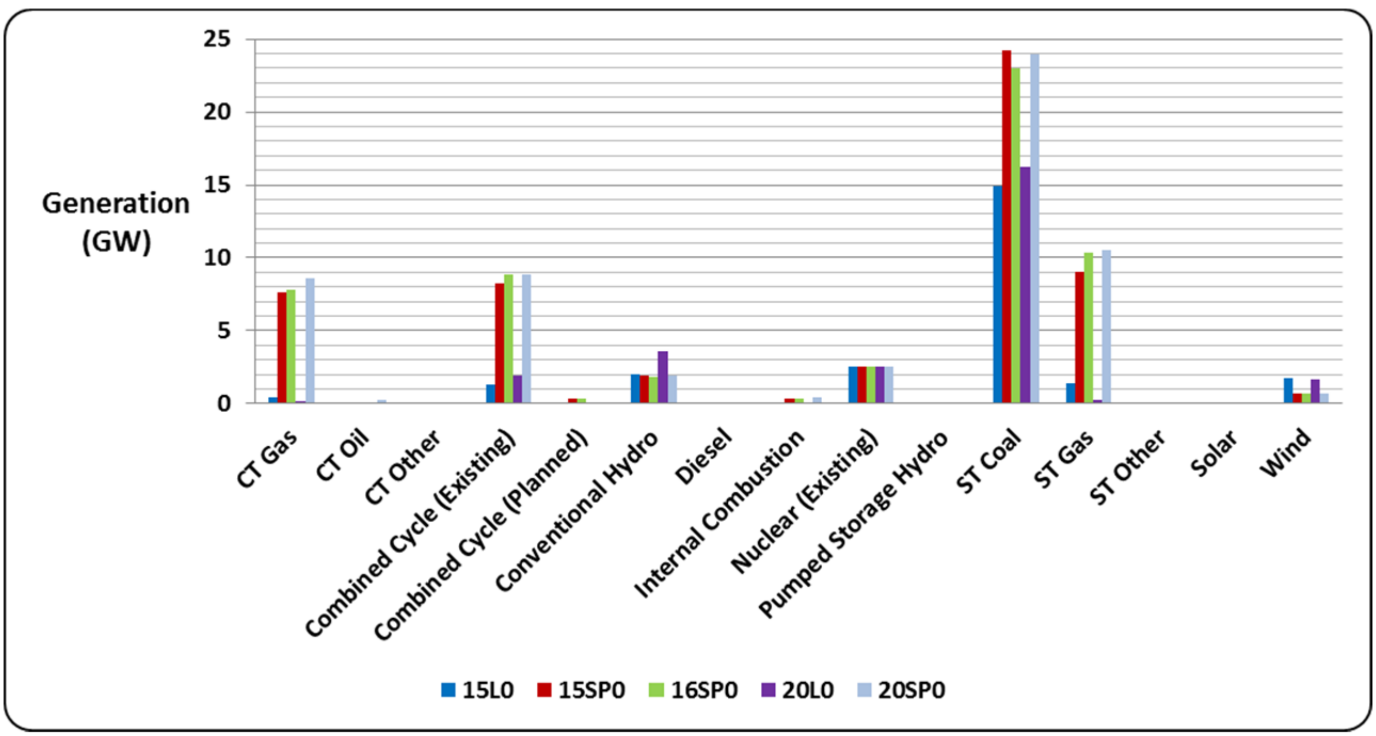


Figure 3.5: 2015 ITPNT CBA Generation Mix

3.4: Utilization of Different Voltage Levels

EHV Design Considerations

When considering the design of an EHV grid, many factors must be considered, such as contingency planning, typical line lengths, line loadability, capacity requirements, voltage, reliability, cost, asset life, and operational issues.

NERC N-1 Reliability Standards

SPP designs and operates its transmission system to be capable of withstanding the next transmission outage that may occur; this is called “N-1” planning and is in accordance with NERC planning standards. Due to N-1 planning, any EHV network must be looped so that if one element of the EHV grid is lost, a parallel path will exist to move that power across the grid and avoid overloading the underlying transmission lines.

Voltage Support

A transmission line can either support voltage (produce VARs) or require voltage support from other reactive devices (consume VARs), depending on its loading level. In either case, transmission system design should account for these factors. Under light-load conditions, system voltages may rise due to VARs being produced from long EHV lines.

Shunt reactors would be necessary to help mitigate the rise in voltage. Some lines may need additional support to allow more power to flow through them. Series capacitors may be added to increase the loadability of a transmission line. However, the addition of series compensation can complicate operations and may lead to stability concerns.

Construction Cost

Cost plays a factor in EHV grid design. Lower-voltage designs cost less to construct initially. Higher voltage lines have a larger initial investment but provide significantly higher capacity and more flexibility in bulk power transport. Lower voltage lines offer more flexibility to act as a collector system for wind generation. Along with the initial cost, the lifetime of the asset needs to be considered. Transmission lines are generally assumed to have a 40-year life.

Section 4: Analysis Methodology

4.1: Steady State Analysis

Facilities in the SPP footprint 69 kV and above were monitored for exceeding 90% thermal loading or voltage below 0.95 per unit. Needs are generated at 100% thermal loading or voltage below 0.9 per unit for non-base case conditions and voltage below 0.95 per unit for base case conditions. All facilities in first-tier control areas were monitored at 100 kV and above. System intact (base case) and N-1 contingency analysis was performed on SPP facilities at 69 kV and above and at 100 kV and above for Tier 1 control areas in the 2015 ITPNT models.

After performing the initial reliability assessment identifying the bulk power problems, thermal and voltage needs were posted on the Trueshare site for stakeholder accessibility.

Order 1000

In order to comply with FERC's Order 1000, SPP developed the Transmission Owner Selection Process. In accordance with Attachment O, Section III.8.b, SPP shall notify stakeholders of identified transmission needs and provide a transmission planning response window of thirty (30) days during which any stakeholder may propose a detailed project proposal ("DPP"). SPP shall track each DPP and retain the information submitted pursuant to Attachment O, Section III.8.b(i). The initial 30 day window for proposals opened on June 30, 2014 for Scenario 0/5 thermal and voltage needs. Additional needs were discovered and a 30 day window opened July 12, 2014. The 30 day window for CBA thermal and voltage needs was opened October 27, 2014.[2]

Project processing methodology

Stakeholders submitted 493 DPPs through the new Order 1000 process and 24 FERC Order 890 projects. In addition to the DPPs and FERC Order 890 projects, 75 SPP staff solutions were considered to address the reliability needs. All together 592 projects were evaluated.

In order to efficiently evaluate the high volume of submitted and created projects that would solve all identified reliability needs within the allotted schedule; a software solution was developed by SPP. This comprehensive project testing tool tested an individual project against each reliability need identified in the Needs Assessment using PSS®E. The output of the tool indicated if the project mitigated the reliability need according to SPP Criteria for both thermal loading or per unit voltage. All automated results were then manually checked for result validation.

[2] Information on the models, needs assessments , and solutions used in the 2015 ITPNT can be found on the SPP website www.spp.org/Engineering/Order 1000/Order 1000 Documents

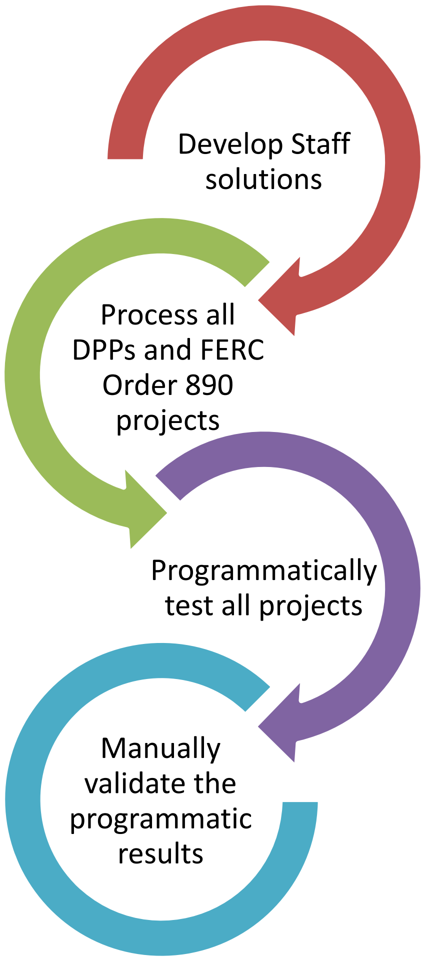


Figure 4.1: Project processing methodology overview

Project selection methodology

SPP staff developed a standardized conceptual cost template for assigning project costs to all stakeholder submitted and SPP staff developed projects. Once all projects were assigned a cost, each project was compared against all other projects using a least cost metric. In order to perform a comparison of the extensive number of projects, a programmatic solution was developed by SPP staff. Using this project selection software, a subset of projects was generated that solved all reliability needs in the most cost effective manner. If two projects solved the same reliability needs, and one was more cost effective, then it was selected to be included in the portfolio for more analysis.

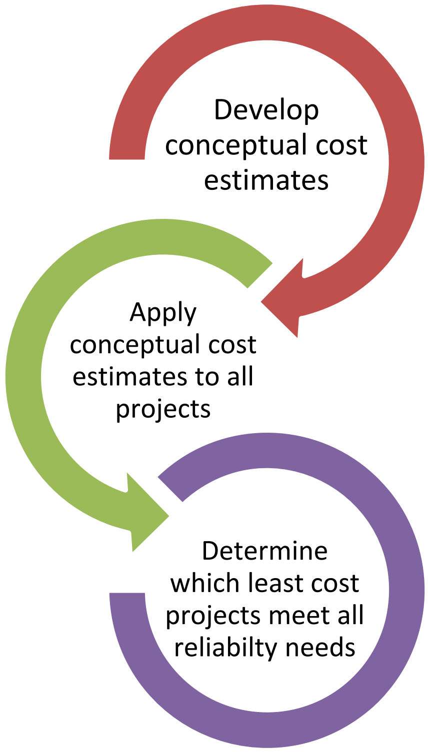


Figure 4.2: Project Selection

Staging

Selected projects were then timed using linear interpolation based on line loading between available model years of 2015, 2016, and 2020. For example, to time a solution due to a 2020 potential overload, SPP interpolated line loadings between the 2016 and 2020 models to determine when the loading exceeded 100%. The need date was assigned based on this analysis. A similar process for timing potential voltage issues was used to check for per unit under-voltage conditions below 0.90.

SPP transmission system performance was assessed from different perspectives designed to identify transmission expansion projects necessary to accomplish the reliability objectives of the SPP Regional Transmission Organization (RTO).

- Avoid exposure to Category A and B NERC Transmission Planning (TPL) standard criteria violations during the operation of the system under high stresses
- Contribute to the voltage stability of the system
- Reduce congestion and increase opportunities for competition within the SPP Integrated Marketplace

4.2: CBA Model Development

In order to account for the impacts of the Integrated Marketplace on the SPP footprint a Consolidated Balancing Authority (CBA) scenario model was developed as part of the 2015 ITPNT Assessment. The CBA scenario modeled SPP as a single BA and only modeled power transfers across the SPP seams. The CBA scenario utilized the SPP portion of the NERC Book of Flowgates updated with information from the 2014 Flowgate Assessment, 2015 ITPNT transmission topology, and 2015 ITP10 2024 Summer Base F1 Scenario economic dispatch data. The goal was to attain a SCUC and SCED for each year and season modeled in Scenario 0 and Scenario 5.

In order to simulate changes that will occur to the SPP portion of the NERC Book of Flowgates due to upgrades coming into service during the defined study period of the 2015 ITPNT Assessment, a constraint assessment was completed to determine if any system constraints should be added, removed, or modified before the SCUC/SCED was created. The constraint list was reviewed and approved by the TWG before being applied to the models.

Making use of the economic data from the 2015 ITP10 Assessment, an economic DC tool committed units, creating a dispatch to deliver the most economical power around the constraints approved by the TWG. This unit commitment and dispatch was the SCUC/SCED that was applied to the power flow model used to complete the N-1 contingency analysis described in the Steady State Analysis section. The security constrained economic dispatch in the CBA was applied to the SPP footprint only. The rest of the Eastern Interconnection remained unchanged.

4.3: Rate Impacts

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 4.1: 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 $248.2 million in 2014 dollars
- Transmission Owner’s estimated individual annual carrying charge %
- Voltage level of each upgrade
- In-service year of each upgrade
- 2.5% annual straight line rate base depreciation
- 2.5% construction price inflation applied to 2014 base year estimates
- Mid-year in-service convention

PART II: STUDY FINDINGS

Section 5:Project Summary

5.1: Model Analysis and Results

The base case (N-0) and contingency (N-1) analysis that was completed provided SPP with a list of thermal and voltage needs. The table below summarizes all the observed unique thermal needs sorted by year and % loading and filtered to be unique by monitored element.

% Overloads	2015	2016	2020
100%-105%	2	2	14
105%-110%	4	3	4
110%-120%	4	1	6
above 120%	11	0	13
Subtotals	21	6	37
Total		64	

Table 5.1: Unique Thermal needs

The table below shows all the observed unique voltage needs sorted by year and the per unit voltage value observed in the base case (N-0) and under contingency (N-1) conditions and filtered to be unique by monitored element.

Per Unit Voltage	2015	2016	2020
.90 - .95 p.u.	1	0	5
.88 - .90 p.u.	4	22	26
.85 - .88 p.u.	4	22	40
below .85 p.u.	21	13	50
Subtotals	30	57	121
Total		208	

Table 5.2: Unique Voltage needs

5.2: Reliability Needs and Solution Development Summary

Transmission upgrades submitted through the Order 890 and Order 1000 processes were analyzed and SPP Staff developed projects to mitigate potential reliability problems that were unable to be solved by mitigation plans or operating guides. Below is the full list of projects in the ITPNT.

Reliability Project(s)	Project Area(s)	Monitored Element(s)*	Miles Added/ Modified	Need Date
Rebuild Hobart-Snyder 69 kV line, upgrade jumpers, switches, CT ratios and relay settings at both substations and upgrade the bus at Synder	AEPW	HOBART - ROOSEVELT TAP 69 kV CKT 1 ROOSEVELT TAP-SNYDER 69 kV	28.7	6/1/2015
New -50/+200 MVAr SVC at China Draw 115 kV, new -50/+200 MVAr SVC at Road Runner 115 kV	SPS	DOLLARHIDE SUB 115 kV AGAVE_RHILL3 115 kV CHINA_DRAW 3 115 kV BATTLE_AXE 3 115 kV		4/1/2015
Rebuild Grand Saline-Mineola 69 kV line, switches, CT ratios and relay settings at both substations, upgrade jumpers at Grand Saline	AEPW	GRAND SALINE - MINEOLA 69 kV CKT 1	13.8	4/1/2020
Rebuild Canyon West-Dawn-Panda-Deaf Smith 115 kV line	SPS	CANYON WEST SUB - DAWN SUB 115 kV CKT 1 DAWN SUB - Panda Energy Substation Hereford 115 kV CKT 1	25.64	4/1/2018
Replace wave traps at Amoco and Sundown 230 kV	SPS	AMOCO SWITCHING STATION - SUNDOWN INTERCHANGE 230 kV CKT 1		4/1/2020
Replace wave trap at Claremore 161 kV	GRDA	PYRAMID CORNERS 69 kV		6/1/2018
Install a second 345/115 kV transformer at Mingo; Install any necessary 115 kV terminal equipment	SUNC	ONEOK 3 115 kV MCDONLD3 115 kV BVERVLLY 115 kV ATWOOD 115 kV		6/1/2015
Install second 115/69 kV transformer at Lovington; Install any necessary 69 kV terminal equipment	SPS	LEA COUNTY REC-SAN ANDRES INTERCHANGE 115/69 kV TRANSFORMER CKT 1		6/1/2015
Upgrade wave trap at Amarillo South Interchange-Swisher County Interchange 230 kV	SPS	AMARILLO SOUTH INTERCHANGE - SWISHER COUNTY INTERCHANGE 230 kV CKT 1		4/1/2020
Rebuild Southwestern Station-Carnegie 138 kV, upgrade jumpers and CT ratios at Southwestern Station	AEPW	CARNEGIE - SOUTHWESTERN STATION 138 kV CKT 1	16.5	6/1/2016
Rebuild of the PCA Interchange and Quahada 115kV line	SPS	PCA INTERCHANGE - QUAHADA 115 kV CKT 1 CARLSBAD INTERCHANGE - PECOS INTERCHANGE 115 kV CKT 1 CENTRAL VALLEY REC-LUSK 69 kV UNITED SALT SUB 69 kV	11.08	6/1/2016
Rebuild of the Little River and Maud 69kV line	OKGE	LTRIVRT2 69 - MAUD 69 kV CKT 1	10.73	6/1/2015
Rebuild of Harrisonville North and Ralph Green 69kV line	GMO	HARRISONVILLE NORTH - RALPH GREEN 69 kV CKT 1	8.76	6/1/2015

Reliability Project(s)	Project Area(s)	Monitored Element(s)*	Miles Added/ Modified	Need Date
Tap the Lawrence Hill-Swissvale 230kV line into Baldwin Creek substation and add a 230/115kV transformer at Baldwin Creek	WERE	LAWRENCE HILL (LAWH TX-3) 230/115/13.8 kV TRANSFORMER CKT 1		6/1/2017
Replace existing 161/69 kV transformer at South Waverly	KCPL	SOUTH WAVERLY 161/69 kV TRANSFORMER CKT 1 ODESSA 161/69 kV TRANSFORMER CKT 1		6/1/2015
Tap Ainsworth-Stuart 115 kV line, install new 9 MVAr Capacitor Bank at new Bassett substation	NPPD	EMMETE.TAP EMMETE.P22 7 115 kV EMMETE.P22		6/1/2016
Install 138/69 kV bus tie transformer in OG&E Stillwater substation and interface OG&E Stillwater 69 kV substation with existing Stillwater Municipal 69 kV transmission system	OKGE	STILLWATER KINZIE (KINAUTO1) 138/69/13.8 kV TRANSFORMER CKT 1		6/1/2019
Rebuild Neosho SES-Labette 69 kV line	WERE	LABETTE SWITCHING STATION - NEOSHO 69 kV CKT 1	4.6	6/1/2019
Upgrade 115/69 kV transformer 1 at Lynn County	SPS	LYNN COUNTY INTERCHANGE (PENN 0154552) 115/69/13.2 kV TRANSFORMER CKT 1		6/1/2019
Rebuild Linwood-South Shreveport 138 kV line and upgrade jumpers at Linwood	AEPW	CEDARGROVE - LINWOOD 138 kV CKT 1 CEDAR GROVE – SOUTH SHREVEPORT 138 kV CKT 1	2.5	6/1/2017
Upgrade 138 kV terminal equipment at Benton	WERE	BENTON (BENT TX-2) 345/138/13.8 kV TRANSFORMER CKT 1		6/1/2015
Upgrade breaker and relay at CPPX 69 kV substation	GRDA	CPP TRANSF #2 - WILGRO 69 kV CKT 1		6/1/2015
Install second one stage 14.4 MVAr Capacitor Bank at Texas County 115 kV bus	SPS	EVA REGULATOR 69 kV		6/1/2019
Install 14.4 MVAr Capacitor Bank at Cargill 115 kV bus	SPS	FRIONA SUB 115 kV DEAF SMITH REC-#20 115 kV DEAF SMITH REC-#6 115 kV		6/1/2019
Rebuild Brooks Street-Edwards Street 69 kV line and upgrade jumpers at each end	AEPW	BROOKS STREET - EDWARDS STREET 69 kV CKT 1	0.8	6/1/2016
Install 14.4 MVAr Capacitor Bank at Boomer 69 kV bus	GRDA	STILLWATER PERKINS TAP 69 kV STILLWATER CENTRAL 69 kV STILLWATER HOSPITAL 69 kV STILLWATER BOOMER 69 kV		6/1/2015
Install 14.4 MVAr Capacitor Bank at Lea County Bronco 69 kV bus	SPS	LEA COUNTY REC-LOVINGTON INTERCHANGE 115/69 kV TRANSFORMER CKT 1		6/1/2015

Reliability Project(s)	Project Area(s)	Monitored Element(s)*	Miles Added/ Modified	Need Date
		LEA COUNTY REC-CROSSROADS 69 kV LEA COUNTY REC-BRONCO TAP 69 kV LEA COUNTY REC-BRONCO 69 kV		
Install 14.4 MVAr Capacitor Bank at the Lea Rec Plains Interchange 69 kV bus	SPS	LEA COUNTY REC-PRICE 69 kV LEA COUNTY REC-LEWIS 69 kV LEA COUNTY REC-NEWTEX 69 kV		6/1/2015
Install 14.4 MVAr Capacitor Bank at Four Corners 69 kV bus	OKGE	KREMLNT2 69 kV KREMLIN 69 kV		6/1/2015
Install new 69 kV breaker at Warner Tap to facilitate closing of the 69 kV switch at Wells substation	OKGE	CHECOTA 69 kV WELLS 69 kV		6/1/2015
Install 12 MVAr Capacitor Bank at Newport 69 kV bus	GRDA	NEWPORT 69 kV MONKEY ISLAND 69 kV		6/1/2015
Install 10 MVAr Capacitor Bank at Lea County Williams 69 kV bus	SPS	LEA COUNTY REC-DALLAS 69 kV LEA COUNTY REC-WILLIAMS SUB 69 kV LEA COUNTY REC-CAPROCK 69 kV		6/1/2015
Install a 5 MVAr Capacitor Bank at Winchester 69 kV bus	WFEC	WINCH_TAP 69 kV WINCHESTER2 69 kV		6/1/2020
Install 3.6 MVAr Capacitor Bank at Childers 69 kV bus	GRDA	PYRAMID CORNERS 69 kV		6/1/2018
Install 3 MVAr Capacitor Bank at Thackerville 69 kV bus	WFEC	THACKERVILE 69 kV		6/1/2019
Replace CTs and relays on Collinsville and Skiatook 69 kV line	GRDA	COLLINSVILLE - SKIATOOK TAP 69 kV CKT 1		6/1/2017
Tap Hitchland-Finney 345 kV line at NewSub, new 345/115 kV transformer at NewSub, new NewSub-Walkemeyer 115 kV line	SPS / SUNC	CTU SUBLETTE - PIONEER TAP 115 kV CKT 1 BUCKNER7 345 - SPEARVILLE 345 kV CKT 1 CIMARRON RIVER PLANT - HAYNE3 115 kV CKT 1 CIMARRON RIVER PLANT 115 kV HAYNE3 115 kV KISMET 3 115 kV CUDAHY 115 kV	1	6/1/2015
Convert RIAC substation to 115 kV, new 3-way 115 kV line switch tapping Roswell Intg-Brasher 115 kV line, wreckout existing 69 kV transmission lines to RIAC substation and rebuild 69 kV line from north with new 115 kV line to RIAC, new breaker terminal at Roswell Intg, new 0.1 mile line out of Roswell Intg-Roswell 115 kV	SPS	ROSWELL INTERCHANGE (AC *017772) 115/69/13.2 kV TRANSFORMER CKT 1	1.5	6/1/2015

Reliability Project(s)	Project Area(s)	Monitored Element(s)*	Miles Added/ Modified	Need Date
Reconductor IMC #1 Tap-Intrepid West, IMC #1-Livingston Ridge, Intrepid West-Potash Junction, Byrd-Monument, Ponderosa Tap-Whitten, National Enrichment Plant-Targa 115 kV lines, upgrade terminal equipment at Byrd 115 kV, upgrade wave trap at Whitten 115 kV, install 100 MVAr Capacitor Bank at Potash 230 kV, install 28.8 MVAr Capacitor Bank at Roadrunner 115 kV, install 28.8 MVAr Capacitor Bank at Ochoa 115 kV, install 28.8 MVAr Capacitor Bank at Agave Hill 115 kV	SPS	National Enrichment Plant Sub - TARGA 3 115KV CKT 1 INTREPDW_TP3 - POTASH JUNCTION INTERCHANGE 115 kV CKT 1 IMC_#1_TP 3 115 kV I. M. C. #1 SUB 115 kV WOOD_DRAW 3 115 kV	31.84	6/1/2015
Upgrade terminal equipment at Buckner and Spearville 345 kV	SUNC	BUCKNER7 345 - SPEARVILLE 345 kV CKT		6/1/2015
Ainsworth - Ainsworth Wind 115 kV Ckt 1 Rebuild	NPPD	STUART 115 kV AINSWORTH 115 kV EMMETE.TAP EMMETE.P22 7 115 kV EMMETE.P22	7.13	6/1/2020
Accelerate NTC 200295 - Install new 161/69 kV transformer at Fremont to accommodate a new 161 kV interconnection, new 69 kV line from Fremont to new substation S6801, new 161 kV line from S1226 to new substation S1301	OPPD	991 TAP 69 kV FREMONT SUB A 69 kV FREMONT SUB B 69 kV	20	6/1/2016

** Monitored Element(s) is/are not the all inclusive list of needs fixed by the project.*

Table 5.3: 2015 ITPNT Projects

Projects accelerated from 2015 ITP10 Assessment

The following projects were identified in the 2015 ITP10 Assessment that solved needs in the 2015 ITPNT:

- Rebuild Canyon West-Dawn-Panda 115 kV line
- Replace wave trap at Amoco and Sundown 230 kV
- Upgrade wave trap at Amarillo South Interchange-Swisher County Interchange 230 kV
- Replace wave trap at Claremore 161 kV
- Install a second 345/115 kV transformer at Mingo; Install any necessary 115 kV terminal equipment
- Install second 115/69 kV transformer at Lovington; Install any necessary 69 kV terminal equipment
- Install 14.4 MVAr Capacitor Bank at the Lea Rec Plains Interchange 69 kV bus
- Tap Hitchland-Finney 345 kV line at NewSub; new 345/115 kV transformer at NewSub; new NewSub-Walkemeyer 115 kV line

5.3: Project Plan Breakdown

The figures below show a breakdown of the 2015 ITPNT project plan. There are 68 proposed upgrades making up 42 projects in the project plan. Of the 42 proposed projects 41 will be issued a new Notice to Construct (NTC/NTC-C). One project has been identified as needing a modified NTC (NTC Modify).

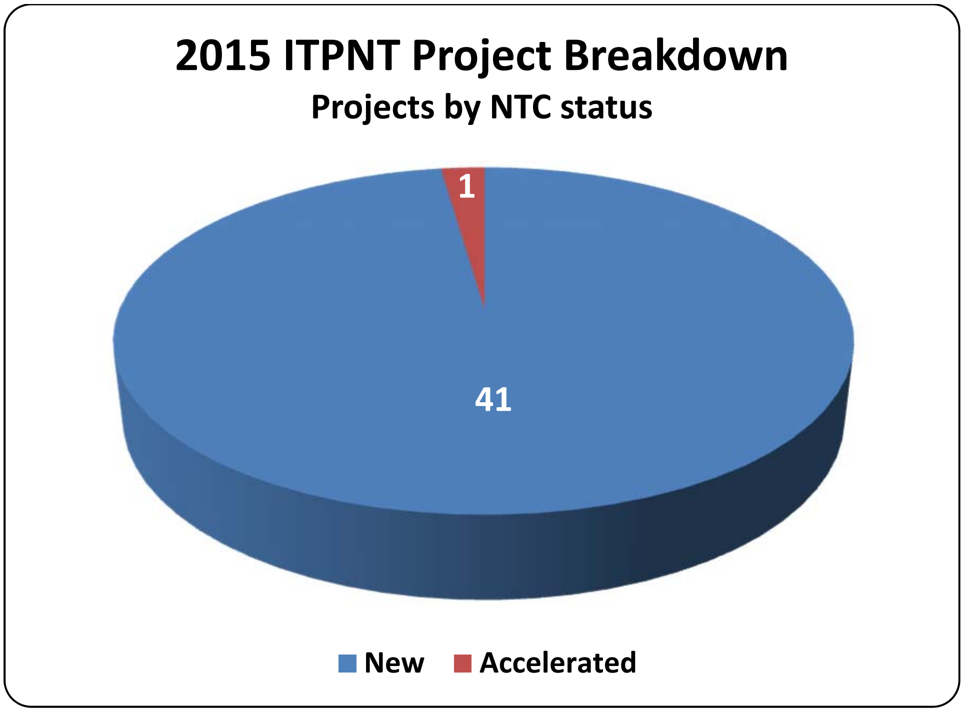


Figure 5.1: 2015 ITPNT Project Breakdown

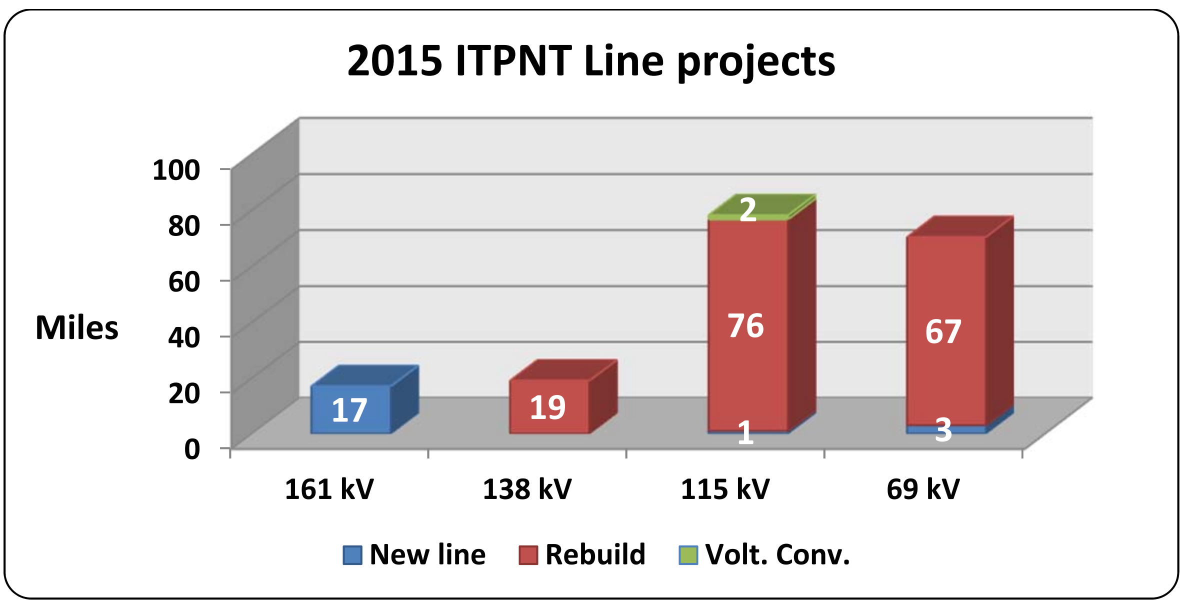


Figure 5.2: 2015 ITPNT Miles New and Rebuild by Voltage Class

The figure below shows the breakdown of new transmission by voltage class in the 2015 ITPNT project plan.

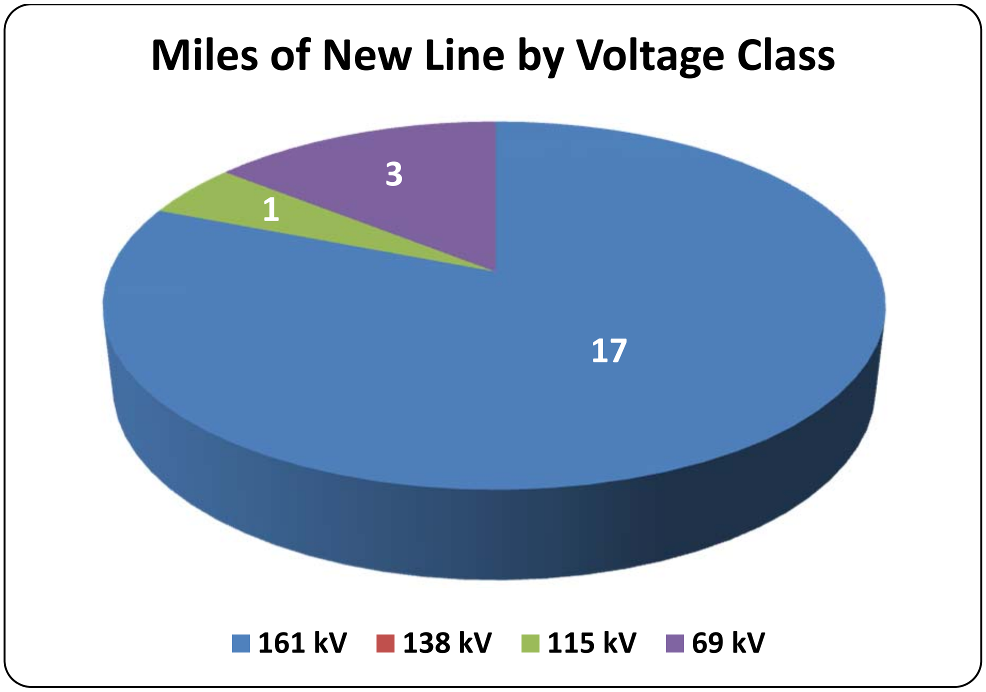


Figure 5.3: 2015 ITPNT New Line by Voltage Class

The figure below illustrates how many miles of existing transmission line that will require a rebuild or reconductor. There are 162 miles of rebuild/reconductor in the 2015 ITPNT project plan.

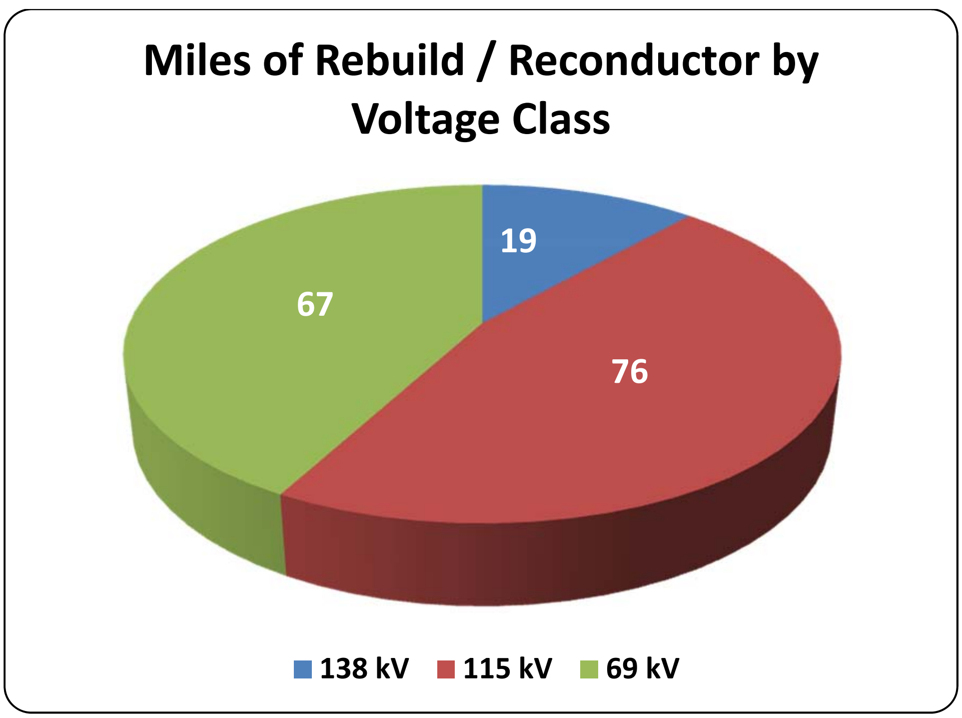


Figure 5.4: 2015 ITPNT Miles Rebuild/Reconductor by Voltage Class

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	37,370,465	0
Louisiana	3,979,734	0
Missouri	5,770,858	0
Nebraska	11,197,764	35,091,946
New Mexico	86,254,614	0
Oklahoma	38,994,767	0
Texas	29,517,730	0
Subtotals	**213,085,931**	**35,091,946**

Table 5.4: 2015 ITPNT Projects by State

The figure below is a representation of the 2015 ITPNT portfolio of new and modified NTCs by voltage class. For each column the cost of the new or modified NTC is also displayed.

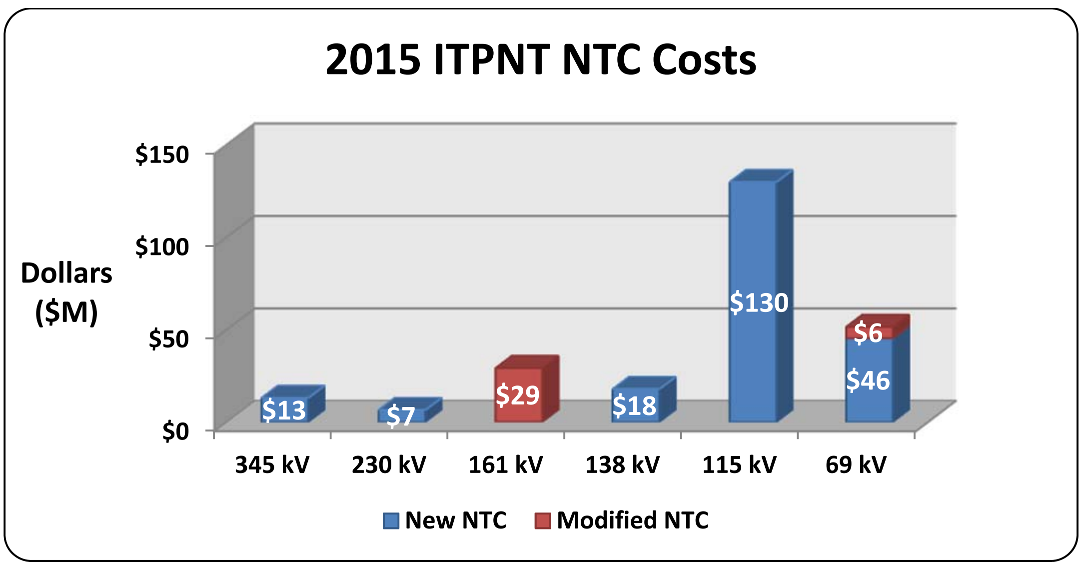


Figure 5.5: 2015 ITPNT NTC Costs by Voltage Class

The figure below shows the 2015 ITPNT projects represented two ways. The blue column represents the number of upgrades by year. The red column represents the dollars that will be invested to place the projects in service.

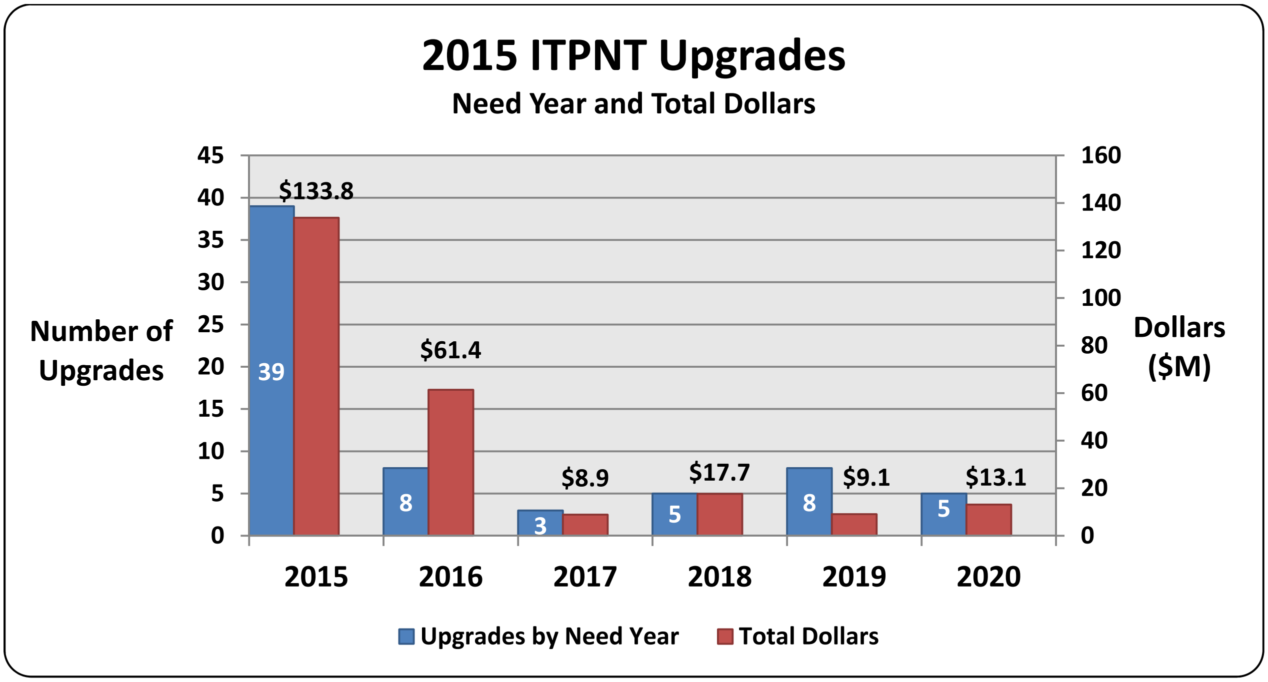


Figure 5.6: 2015 ITPNT Upgrades by Need Year and Total Dollars

The figure below shows the cost allocation of upgrades with new NTCs and modified NTCs between upgrades needed for Regional reliability and Zonal reliability.

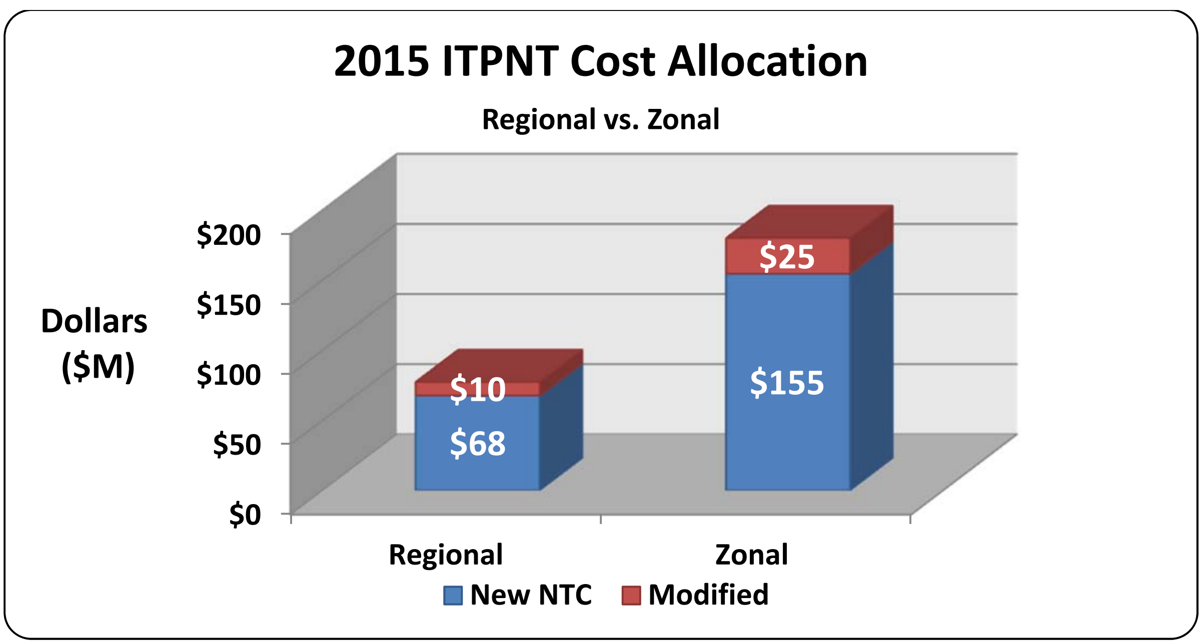


Figure 5.7: 2015 ITPNT Cost Allocation – Regional vs. Zonal

5.4: Project Details

This section details each of the major projects in the 2015 ITPNT project plan. Each of the projects discussed below have an SPP generated cost estimate greater than $15 million and are needed for Regional Reliability.

West Texas & New Mexico Area

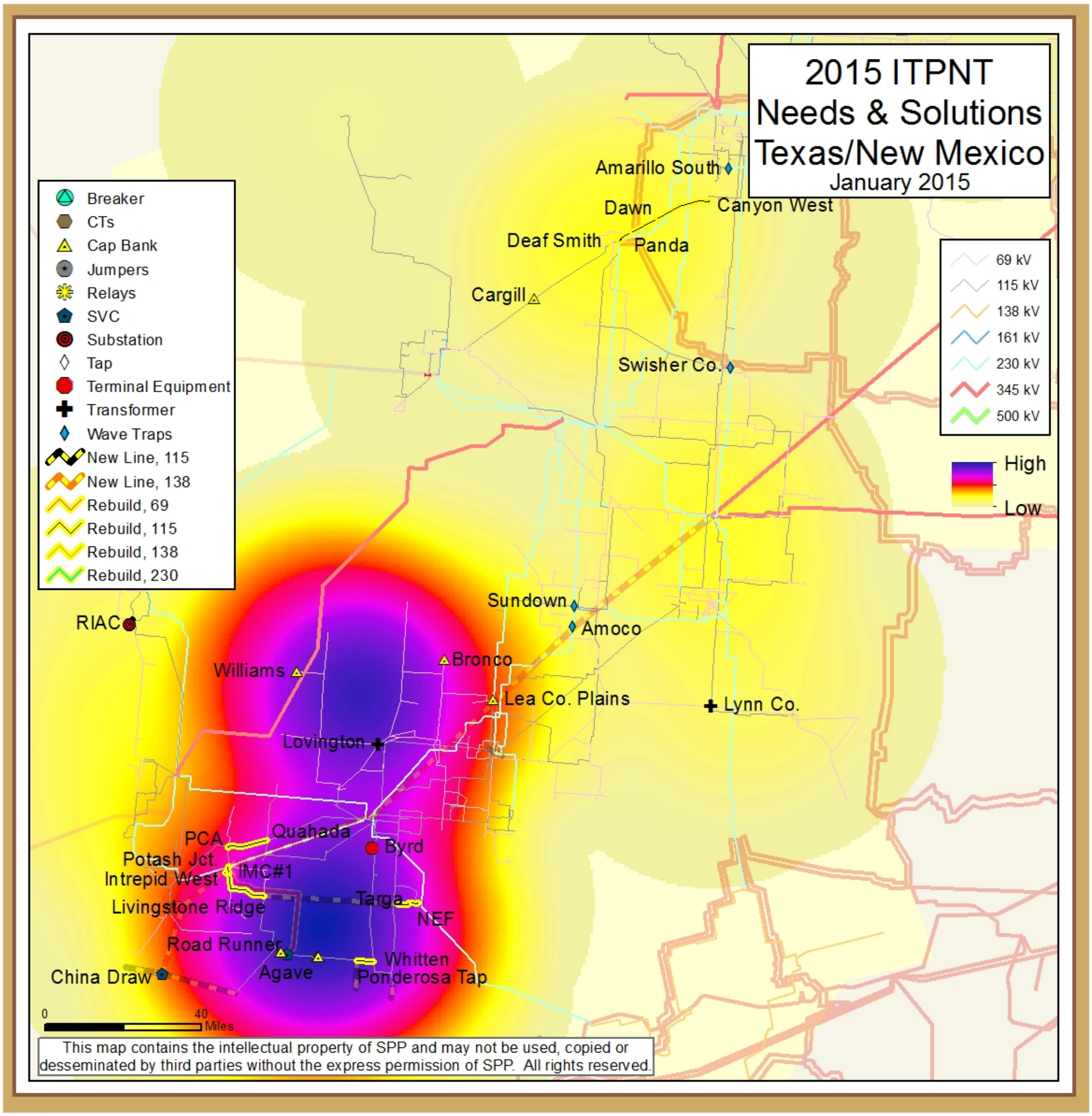


Figure 5.8: 2015 ITPNT West Texas & New Mexico Area Solutions

Deaf Smith – Panda – Dawn – Canyon West 115 kV

The Deaf Smith – Panda – Dawn – Canyon West 115 kV project is a rebuild of the existing 115 kV line. The ITPNT need date is identified as April of 2018. This project consists of three line segment rebuilds. The first from Deaf Smith County Interchange to Panda Energy Substation Hereford for 3.54 miles. The second from Panda Energy Substation Hereford to Dawn Substation for 8.4 miles. The third from Dawn Substation to Canyon West Substation for 13.7 miles. This project will address the overload of these three line segments for the outage of Bushland Interchange – Deaf Smith County Interchange 230 kV ckt 1.

China Draw SVC and Road Runner SVC 115 kV

Both China Draw and Road Runner 115 kV Static Var Compensators (SVCs) are new projects with a ITPNT need date identified as April of 2015. These SVCs provide reactive support that addresses severe voltage needs in the immediate area surrounding the China Draw and Road Runner substations and North of this area. These SVCs provide reactive support that addresses severe overloads on the National Enrichment Plant Sub – Targa 115 kV ckt 1 and National Enrichment Plant Tap – Targa 115 kV ckt 1 lines with multiple N-1 events in the Southeast New Mexico portion of SPS.

IMC area rebuild and Capacitor additions

This project consists of multiple upgrades. Reconductoring IMC #1 Tap-Intrepid West, IMC #1-Livingston Ridge, Intrepid West-Potash Junction, Byrd-Monument, Ponderosa Tap-Whitten, National Enrichment Plant-Targa 115 kV lines, Upgrading terminal equipment at Byrd 115 kV substation. A wave trap will be upgraded at Whitten 115 kV substation. A 100 MVAr capacitor will be installed at Potash 230 kV substation. A 28.8 MVAr capacitor will be installed at Roadrunner 115 kV, Ochoa 115 kV, and Agave Hill 115 kV substations. The ITPNT need date is identified as June of 2015. This project will address overloading of the National Enrichment Plant Sub - Targa 115 kV line for the outage of Kiowa – Roadrunner 345 kV line, Roadrunner 345/115/13.2 kV transformer, and Byrd – Monument Tap 115 kV line.

West Kansas Area

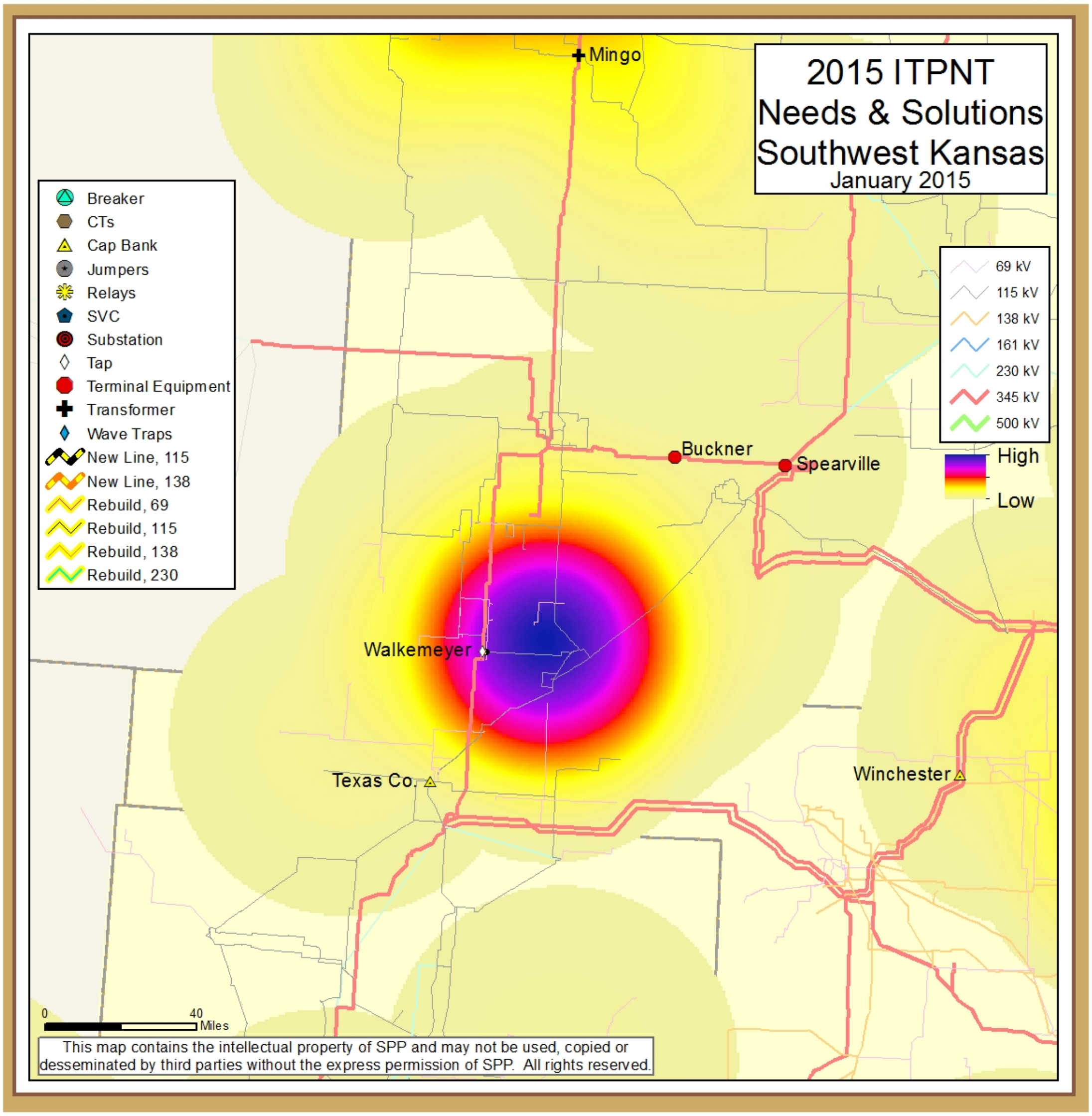


Figure 5.9: 2015 ITPNT West Kansas Solutions

Tap Hitchland – Finney 345 kV and NewSub – Walkemeyer 115 kV

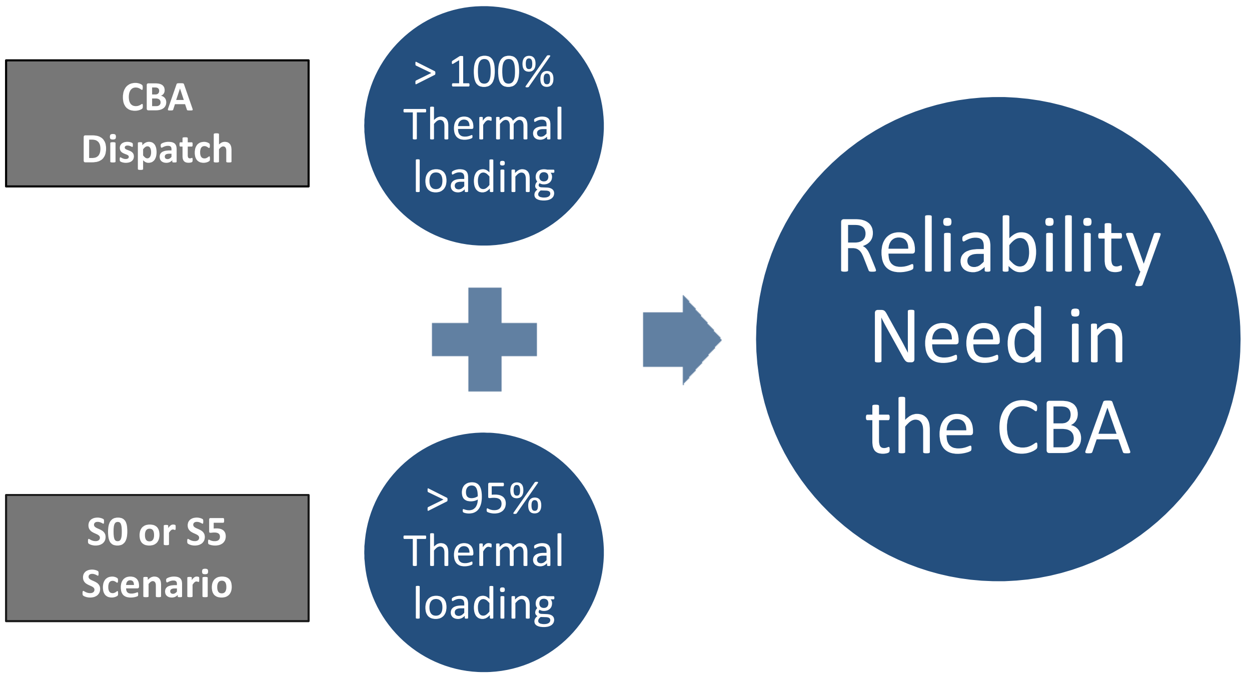
This project consists of tapping the Hitchland to Finney 345 kV line and adding a new substation with a 345/115 kV Transformer. A new 1 mile NewSub to Walkemeyer 115 kV line will be added. The need date for this project is June of 2015. This project will address the overload of the CTU Sublette – Pioneer Tap 115 kV and Cimmaron River Plant – North Cimarron 115 kV and North Cimmaron – Seward 115 kV lines for the outage of Crooked Creek to Cudahay 115 kV line. Other outages of Finney Switching Station – Hitchland Interchange 345 kV line, CTU Sublette – Haskell 115 kV lines, and member-submitted outage of SPP-MKEC-01[3] caused overloading, which was addressed by this project.

[3] Cimmaron River Tap – East Liberal | Cimarron River Station - Cimmaron River Tap | Kismet - Cimmaron River Tap | Kismet – Cudahay | Cudahay – Crooked Creek 115kV lines

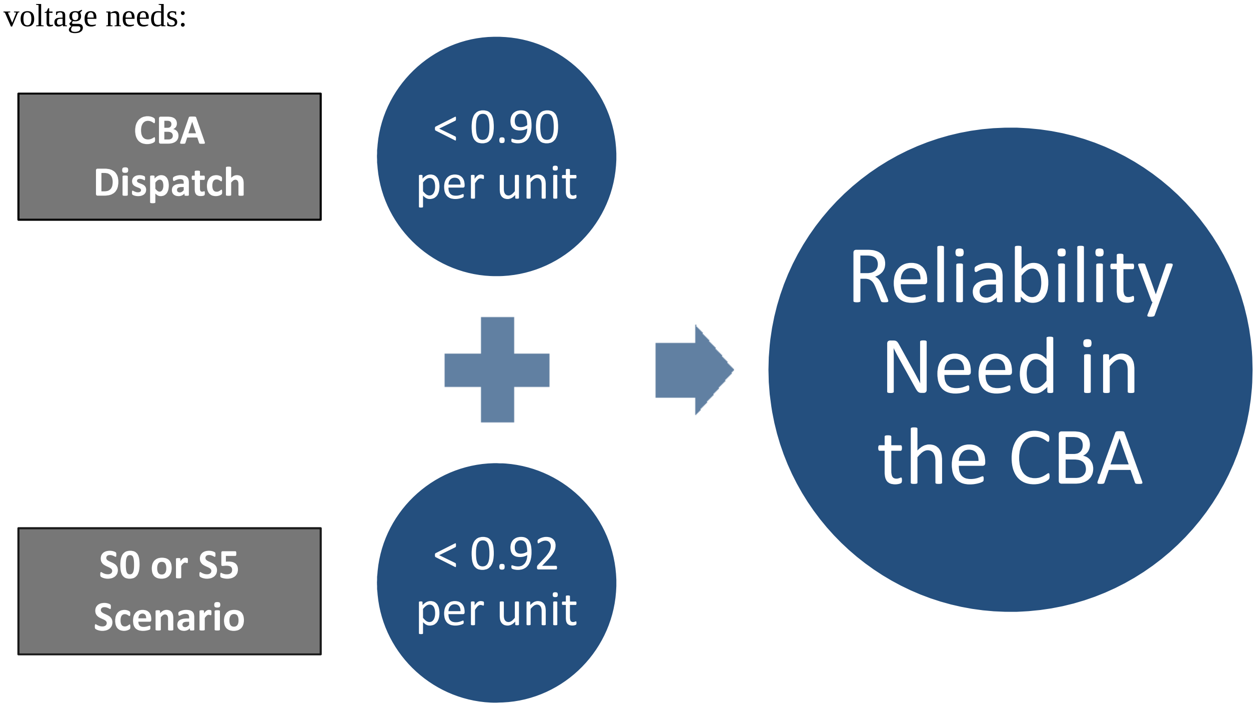
5.5: Reliability Upgrades from the CBA Model

This section details potential reliability issues from the CBA N-1 contingency analysis in the 2015 ITPNT. At the May 14, 2013 Transmission Working Group meeting the TWG approved the process by which a potential additional reliability issue would be identified. The methodology for determining reliability needs in the CBA Scenario is found below.

For thermal needs:



For voltage needs:



Based on this criteria there were two projects identified and are shown in the table below.

Season	Facility	CBA % Loading	Near Term S0/S5 % Loading
15SP	BENTON (BENT TX-2) 345/138/13.8KV TRANSFORMER CKT 1	108.8	98.4
20SP	CARNEGIE - SOUTHWESTERN STATION 138KV CKT 1	104.7	98.2

Table 5.5: CBA Projects

5.6: Rate Impacts on Transmission Customers

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

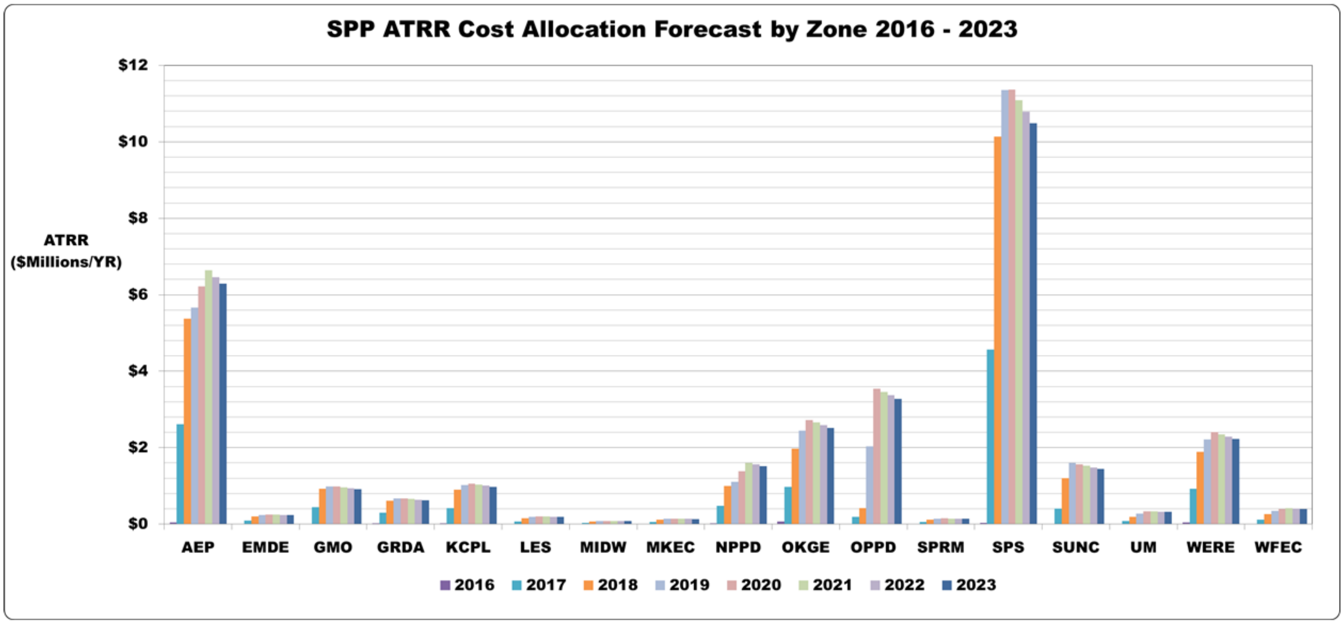


Figure 5.10: ATRR Cost Allocation Forecast by Zone of the 2015 ITPNT

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.

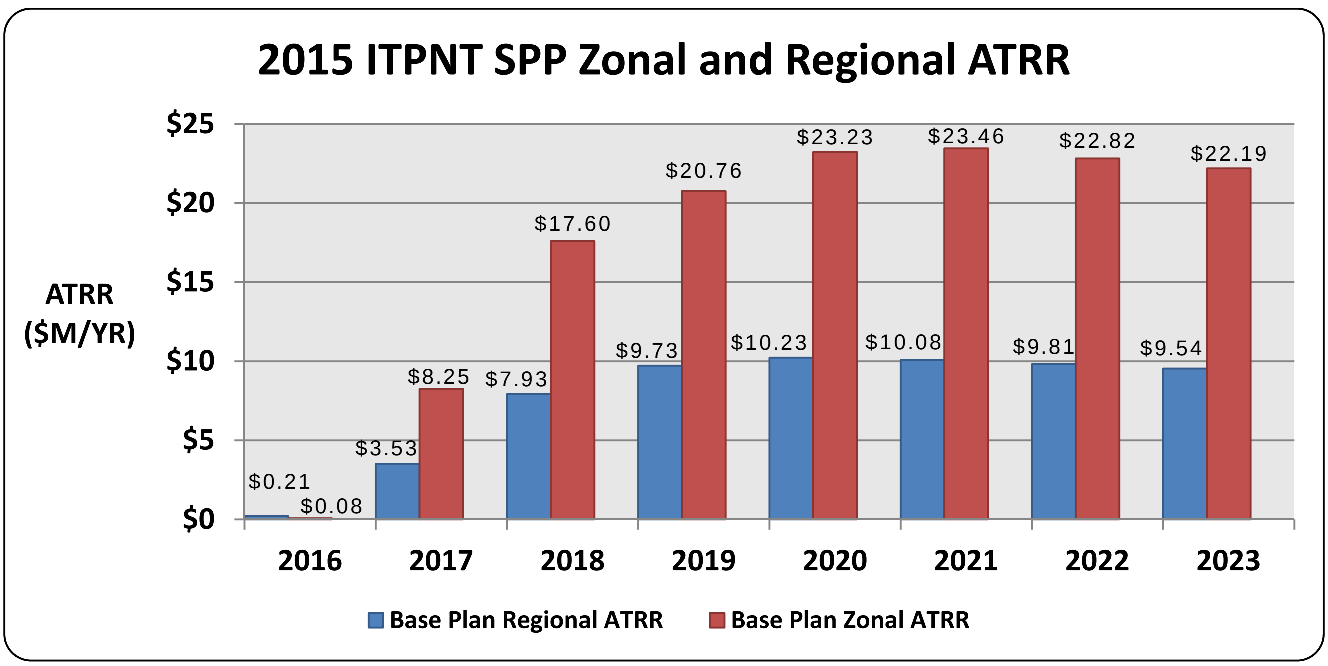


Figure 5.11: Zonal and Regional ATRR allocated in SPP

The peak year ATRR is converted into a monthly impact on a typical 1000 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.

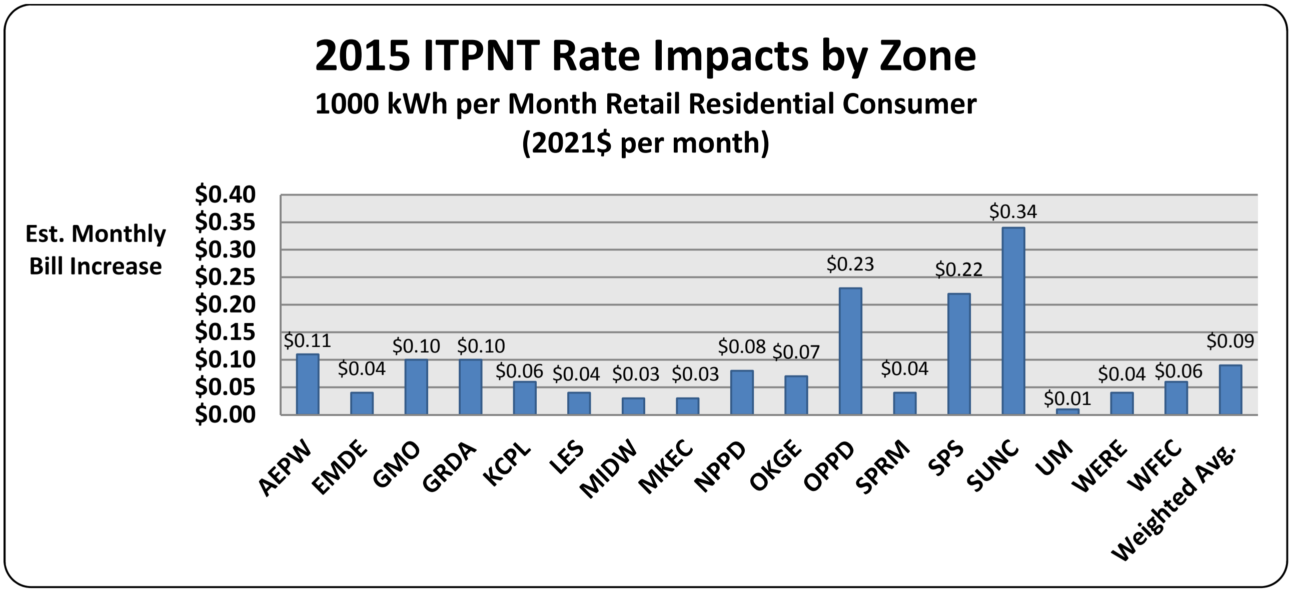


Figure 5.12: 2015 ITPNT Monthly Bill Impact 1000 kWh/Month Retail Residential

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.

5.7: Stability Analysis Results

Transient stability analysis was performed on the ITPNT 2020 Summer peak scenario 5 base case. Since no new rotating machines or 345 kV lines were added and HPILS upgrades were included in the base case, the study was performed on the base case rather than the case with the recommended portfolio. Contingencies were ranked as having a potential steady state stability violation, a loss of generation, or a critical clearing time of less than 9 cycles using PTI's PSS/E Dynamics Package and the PSSPLT Plotting Package. The Fast Fault Screening (FFS) identifies the fault bus and associated outaged branches; however, the fault sequence was determined by SPP, and was as follows:

- Category B: Apply fault at ranked bus for a time span of Critical Clearing Time (CCT) cycles and open "outaged branch"
- Category C: Open first "outaged branch" and allow steady state system adjustments. Apply fault at ranked bus for a time span of CCT cycles and open second "outaged branch"
- Category D: Apply fault at the ranked bus for a time span of CCT cycles and open all "outaged branches" at the bus

Generator rotor speed, rotor angle, real power, and reactive power output were monitored for all SPP generators during the time domain simulation. Those generators exhibiting rotor speed and angle instability were marked for further analysis. This analysis consisted of identifying and correcting the cause of instability.

Any unstable Category D event generator(s) were disconnected according to NERC Standard TPL-004 during the simulation and re-simulated to determine stability for the remaining system.

Fast Fault Screening identified severe fault locations for the ITPNT 2020 Summer case. These locations (buses) were ranked according to their Ranking Index (RI) and CCT for NERC category B, C, and D contingencies. The results are posted on SPP's Trueshare site. The outaged element(s) associated with each fault are shown and are considered only if real power is leaving the faulted bus.

The finalization of the Transient Stability analysis of most severe FFS events indicated no resulting system instability for FFS identified events. There were no identified unstable generators for the ITPNT 2020 Summer peak Scenario 5 base case.

5.8: Final Reliability Assessment

All projects in the 2015 ITPNT project plan were incorporated into the powerflow models and a steady state N-1 contingency analysis was performed to identify any new reliability issues. From that analysis 6 unique potential thermal overloads and 11 unique potential voltage violations were identified. The table below lists these final reliability assessment potential issues.

Season	Monitored Facility	Potential Violation
20SP	BYRD SUB - OIL_CENTER 3 115kV CKT 1	Thermal
20L	BYRON 69kV - WAKITA 69KV CKT 1	Thermal
15SP	EAGLE CREEK (WH RLP1721-2) 115/69/13.2KV TRANSFORMER CKT 1	Thermal
16SP	HARMONY - ST FRANCIS 115KV CKT 1	Thermal
16SP	HOBART - HOBART JUNCTION 69KV CKT 1	Thermal
15SP	OCHOA SUB - PNDEROSATP 3 115KV CKT 1	Thermal
15SP	EAGLE CHIEF 69KV	Voltage
20SP	EUFAULA RES TAP 69KV	Voltage
15SP	FAIRVIEW 69KV	Voltage
15SP	OMPA-FAIRVIEW 69KV	Voltage
20SP	ONAPA 2 69KV	Voltage
20SP	PORUM 69KV	Voltage
15SP	RINGWOOD JCT 69KV	Voltage
20SP	WELLS SPA 69KV	Voltage
15L	WHITEHORSE 69KV	Voltage
15L	WINCH_TAP 69KV	Voltage
15L	WINCHESTER2 69KV	Voltage

Table 5.6: Final Reliability Assessment Potential Issues

PART III: APPENDICES

Section 6:Project Maps

Texas & Louisiana Area

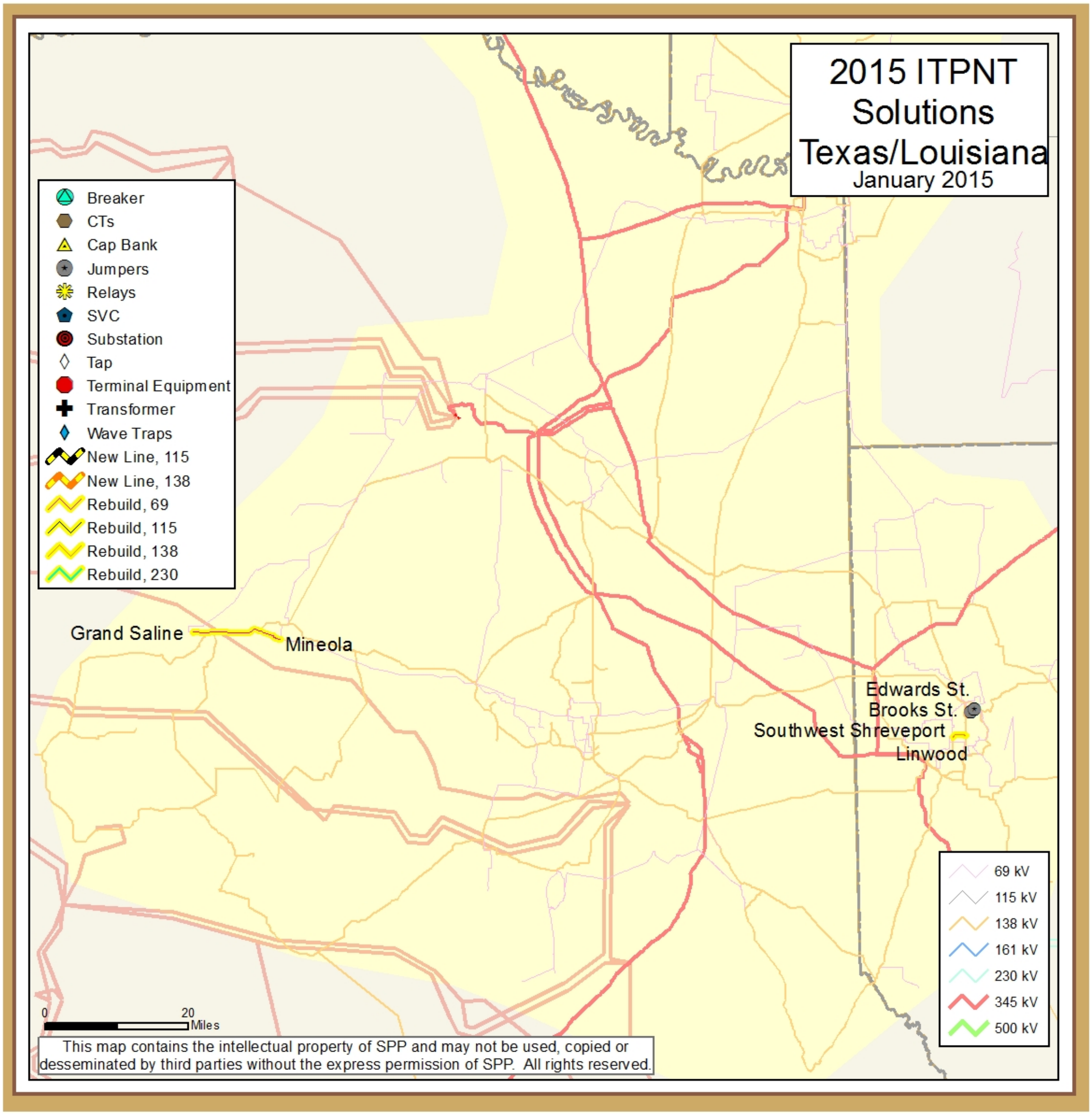


Figure 6.1: 2015 ITPNT Texas/Louisiana Solutions

Nebraska Area

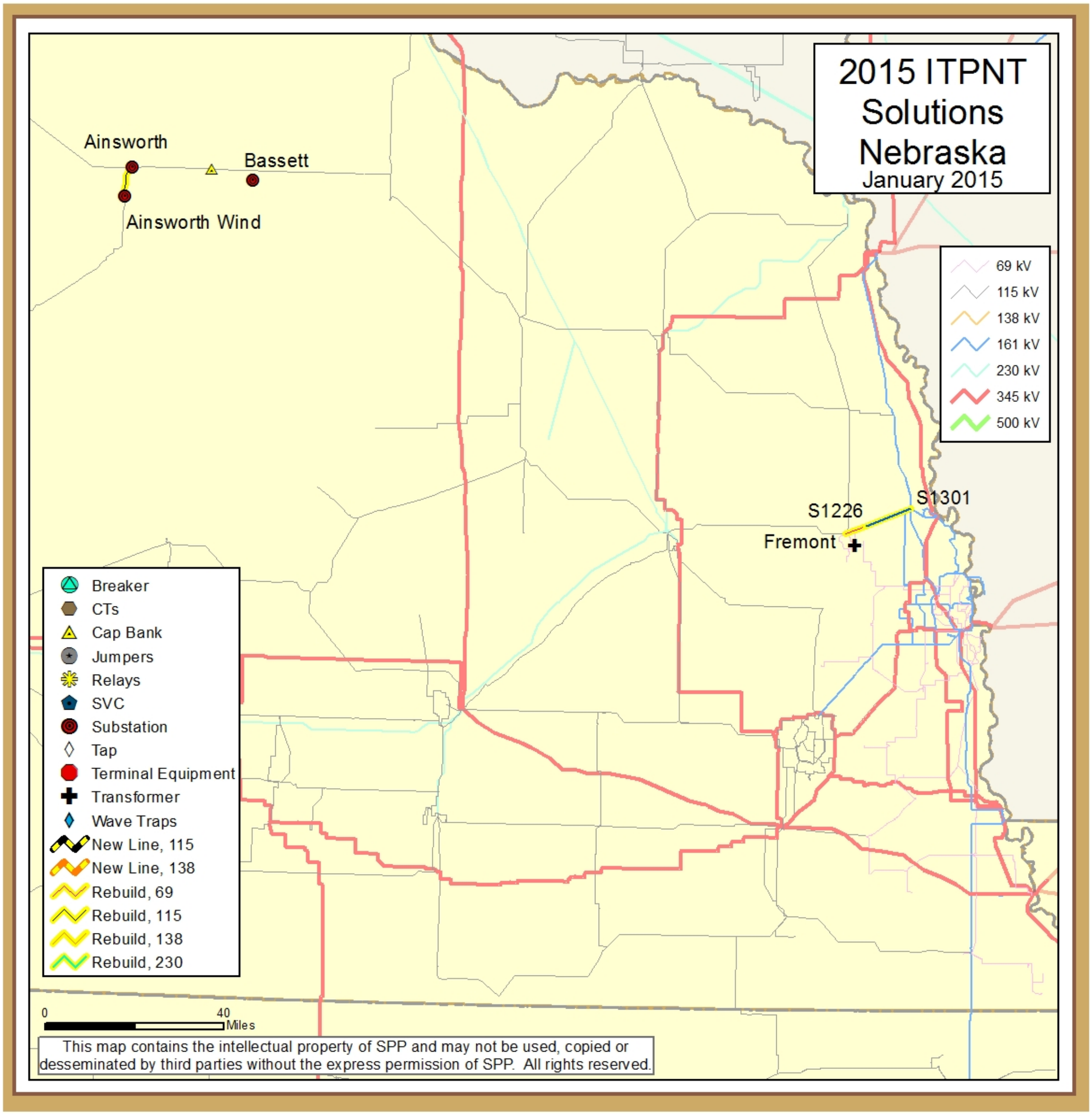


Figure 6.2: 2015 ITPNT Nebraska Solutions

Oklahoma Area

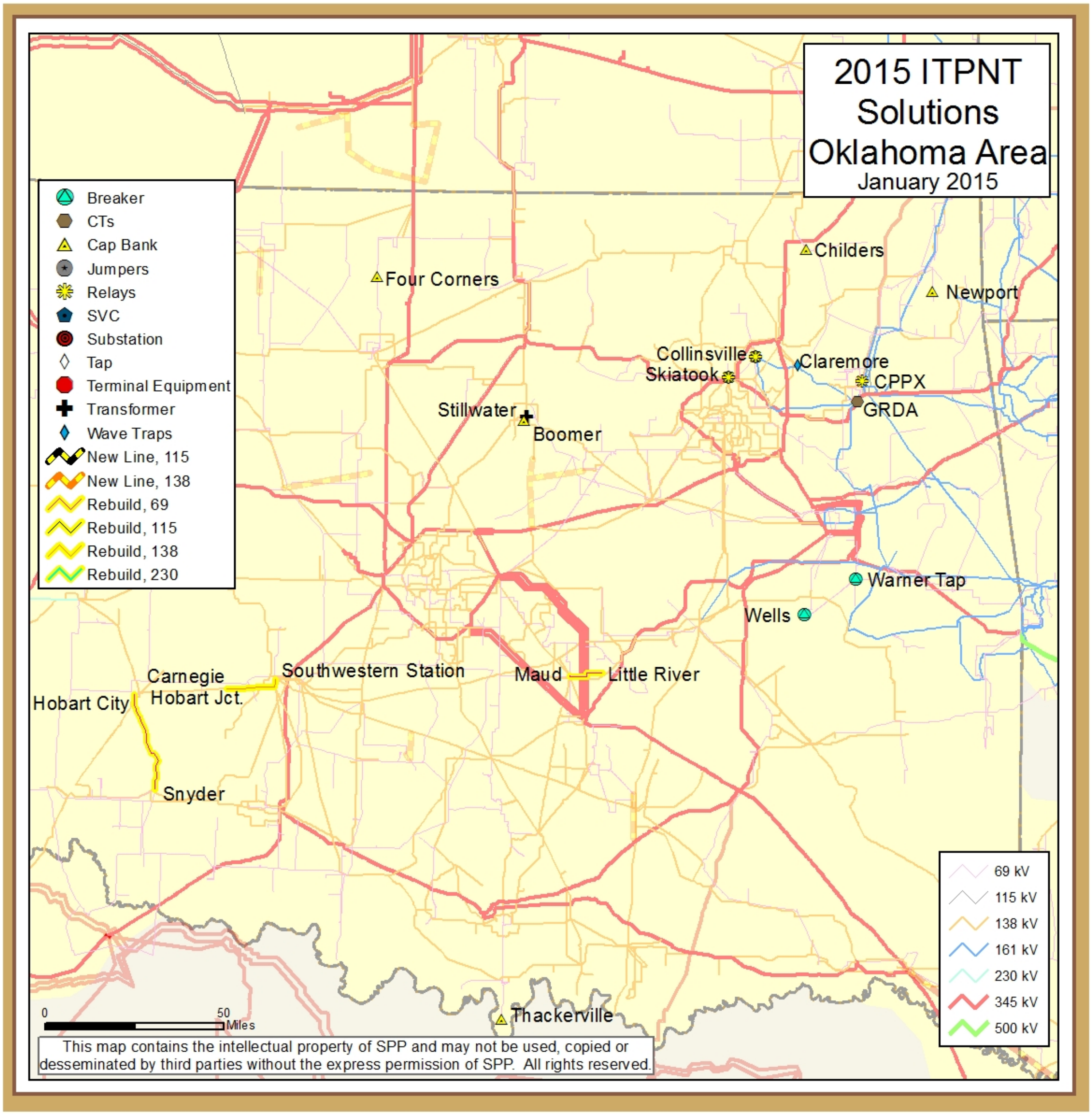


Figure 6.3: 2015 ITPNT Oklahoma Solutions

West Kansas Area

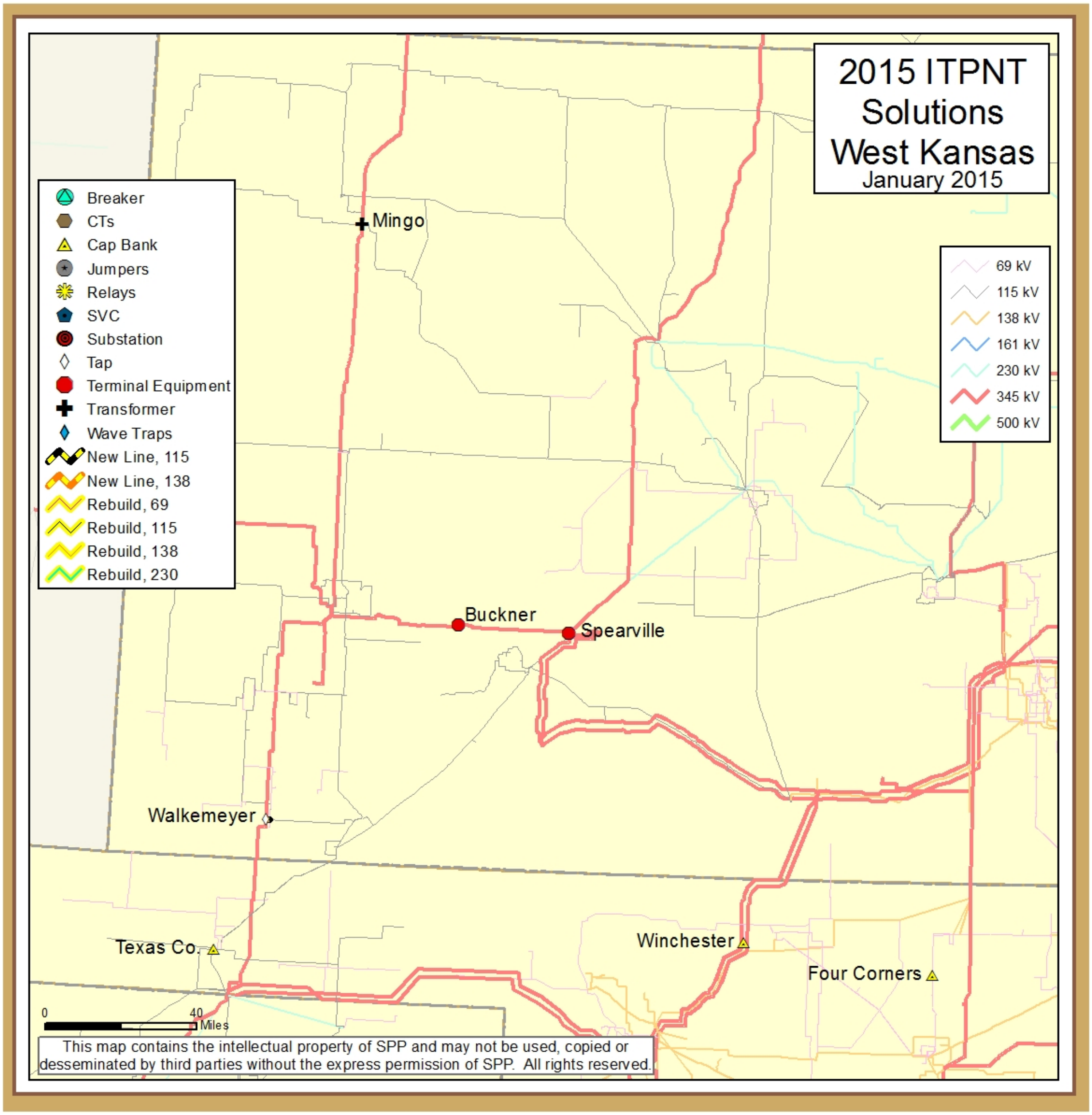


Figure 6.4: 2015 ITPNT West Kansas Solutions

East Kansas & West Missouri Area

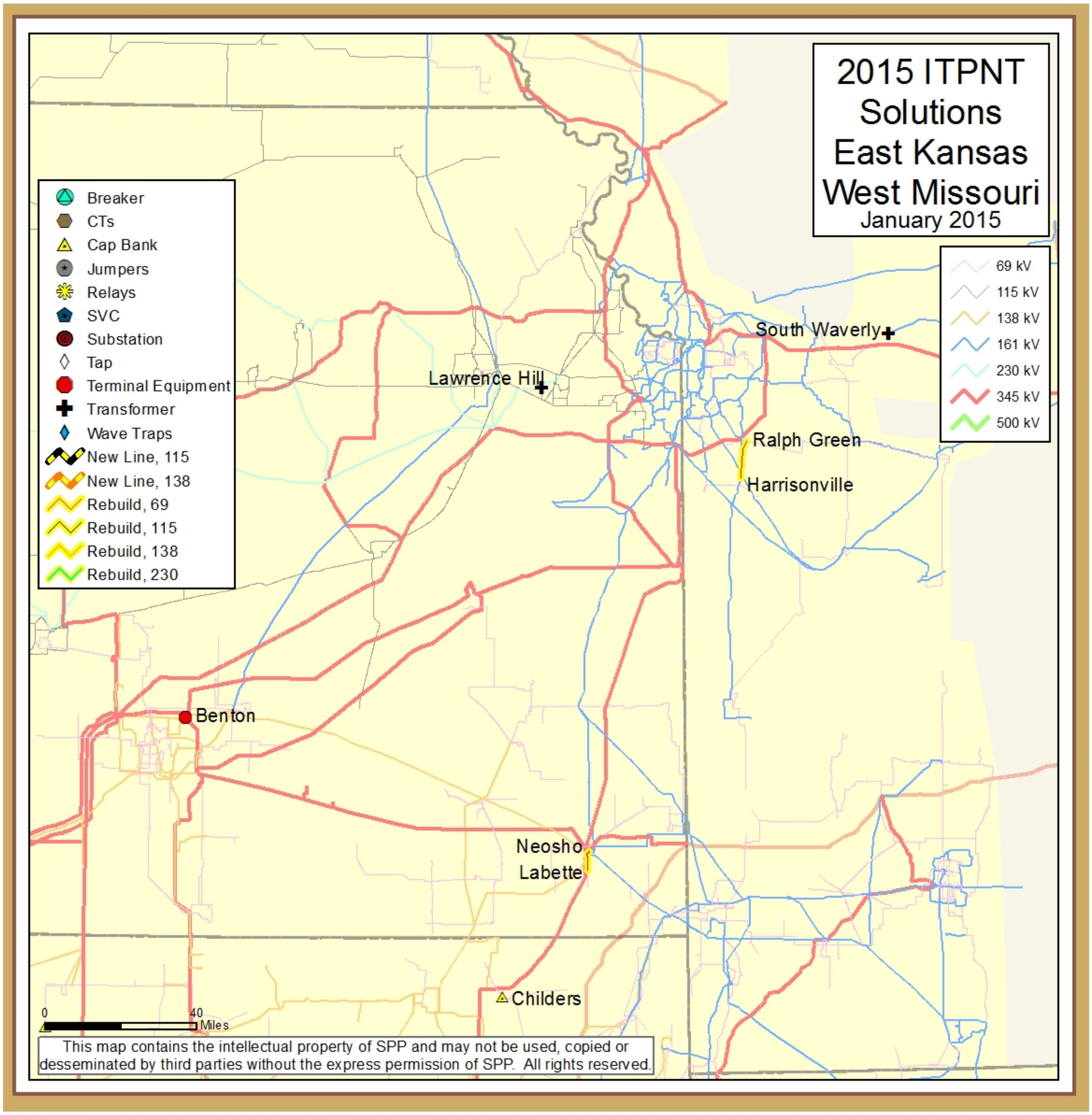


Figure 6.5: 2015 ITPNT East Kansas & West Missouri Solutions

Section 7:Glossary of Terms

The following terms are referred to throughout the report.

Acronym	Description	Acronym	Description
ATRR	Annual Transmission Revenue Requirements	**MVA**	Mega Volt Ampere (10^6 Volt Ampere)
ATSS	Aggregate Transmission Service Studies	**MW**	Megawatt (10^6 Watts)
CBA	Consolidated Balancing Authority	**NERC**	North American Electric Reliability Corporation
BOD	SPP Board of Directors	**NTC**	Notification to Construct
EHV	Extra High Voltage	**NTC-C**	Notification to Construct with Conditions
FERC	Federal Energy Regulatory Commission	**OATT**	Open Access Transmission Tariff
GI	Generation Interconnection	**RITF**	Rate Impact Task Force
GW	Gigawatt (10^9 Watts)	**SPP**	Southwest Power Pool, Inc.
ITPNT	Integrated Transmission Plan Near-Term Assessment	**STEP**	SPP Transmission Expansion Plan
ITP10	Integrated Transmission Plan 10-Year Assessment	**TPL**	Transmission Planning NERC Standards
ITP20	Integrated Transmission Plan 20-Year Assessment	**TO**	Transmission Owner
MDWG	Model Development Working Group	**TOGs**	Transmission Operating Guides
MISO	Midcontinent Independent System Operator, Inc.	**TWG**	Transmission Working Group
MOPC	Markets and Operations Policy Committee		

Table 7.1: 2015 ITPNT Glossary of Terms

Intentionally left blank