ITP10

2015 Integrated Transmission Plan 10-Year Assessment Report

January 20, 2015

Engineering

Southwest Power Pool

Revision History

Date	Author	Change Description
10/29/2014	SPP staff	Part one first draft
06/20/2014	SPP staff	Revised draft presented for Internal Review
10/7/2014	SPP Staff	ESWG Edits incorporated
12/29/2014	SPP Staff	TWG/ESWG Edits Incorporated

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 10-year Assessment that concludes in December 2015.

Two distinct futures were considered to account for possible variations in system conditions over the assessment's 10-year horizon. These futures consider evolving changes in technology, public policy and climate changes that may influence the transmission system and energy industry as a whole. The futures are presented briefly below and further discussed in Section 3:

1. **Business-As-Usual**: This future includes all statutory/regulatory renewable mandates and goals as well as other energy or capacity as identified in the Policy Survey resulting in 11.5 GW of renewable resources modeled in SPP, load growth projected by load serving entities including the High Priority Incremental Loads, and SPP member-identified generator retirement projections. This future assumes no major changes to policies that are currently in place.
2. **Decreased Base Load Capacity**: This future considers factors that could drive a reduction in existing generation. It will include all assumptions from the Business as Usual future with a decrease in existing base load generation capacity.

The recommended 2015 ITP10 portfolio shown in Figure 0.1 is estimated at **$273 million** in engineering and construction cost and includes projects needed to meet potential reliability, economic, and policy requirements. These projects, with a total estimated net present value revenue requirement of **$334 million**, are expected to provide net benefits of approximately **$1.4 billion** over the life of the projects under a Future 1 scenario containing 10.3 GW of wind capacity expected to be contracted by SPP members.

[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).

The following projects make up the portfolio:

Project Description	Area(s)	Type	Future	Mileage	Cost
New wave trap at Amoco and Sundown, increasing rating on Sundown-Amoco 230 kV line	SWPS	Economic & Reliability	F1	0	$55,641
Voltage conversion of Iatan-Stranger Creek 161 kV line to 345 kV	KCPL, GMO, WRI	Economic	F1	14	$16,119,446
Rebuild North Platte-Stockville-Red Willow 115 kV line to 240/240 MVA, new 345/115 kV transformer at Mingo	NPPD, SUNC	Economic & Reliability	F1	80	$53,562,098
New 345/115 kV transformer at Road Runner	SWPS	Reliability	F1	0	$5,733,227
Install 2 stages of 14.4 MVAr capacitor banks on the Ochoa 115 kV bus	SWPS	Reliability	F1	0	$1,659,762
Install 2 stages of 14.4 MVAr capacitor banks on the China Draw 115 kV bus and the North Loving 115 kV bus	SWPS	Reliability	F1	0	$3,319,524
New 230/115 kV transformer at Plant X	SWPS	Reliability	F1	0	$3,497,095
New wave trap at Amarillo South, increasing rating on Amarillo South-Swisher 230 kV line	SWPS	Reliability	F2	0	$27,821
Tap Northwest-Bush 115 kV line at new station, and build new 3 miles of 115 kV line to Hastings	SWPS	Reliability	F1	3	$7,984,549
Upgrade 230/115 kV transformer at Tuco	SWPS	Reliability	F1	0	$3,127,583
Upgrade wave trap and CT on the Park Lane-Seminole 138 kV line	OKGE	Reliability	F2	0	$86,436
Upgrade relays at Sand Springs, increasing ratings on Sand Springs-Prattville 138 kV line	AEPW	Reliability	F1	0	$176,290
Tap Reno-Wichita 345 kV line into Moundridge, new 345/138 kV transformer at Moundridge	WRI	Reliability	F2	0	$14,722,229
Rebuild Forbes-Underpass North 115 kV line to 218/262 MVA	WRI	Reliability	F1	3	$7,878,364
Reconductor Gracemont-Anadarko 138 kV line to 286/286 MVA	OKGE, WRI	Reliability	F1	5	$4,650,558
Rebuild Murray Gill East-Interstate 138 kV line to 286/286 MVA	WRI	Reliability	F2	6	$6,184,325
Reconductor Martin-Pantex North 115 kV line to 240/240 MVA and replace wave trap at Pantex substation	SWPS	Reliability	F1	5	$3,602,175

Project Description	Area(s)	Type	Future	Mileage	Cost
Reconductor Pantex North-Pantex South 115 kV line to 240/240 MVA	SWPS	Reliability	F1	3	$1,824,746
Reconductor Highland Park-Pantex South 15 kV line to 240/240 MVA and replace wave trap and switch at Pantex South and Highland Park tap	SWPS	Reliability	F1	7	$3,649,492
Install 14.4 MVAr capacitor bank at LE Plains Interchange 115 kV	SWPS	Reliability	F1	0	$829,881
Install 14.4 MVAr capacitor bank at Allred 115 kV	SWPS	Reliability	F1	0	$829,881
Replace CT at Claremore 161 kV	GRDA	Reliability	F1	0	$88,560
Install 6 MVAr capacitor bank at Grinnell 115 kV	SUNC	Reliability	F1	0	$345,784
Rebuild South Shreveport-Wallace Lake 138 kV line to 246/246 MVA	AEPW	Reliability	F1	11	$10,268,933
Rebuild Broken Bow-Lone Oak 138 kV corridor to 286/286 MVA	AEPW	Reliability	F1	77	$60,804,427
Install 14.4 MVAr capacitor bank at Ellsworth 115 kV	SUNC	Reliability	F1	0	$829,881
Install 6 MVAr capacitor bank at Mile City 115 kV	WAPA	Reliability	F1	0	$345,784
Upgrade wave traps and switches on Cimarron-McClain 345 kV line	OKGE	Reliability	F1	0	$116,838
New 345/161 kV transformer at S3459	OPPD	Reliability	F1	0	$8,176,238
New 115/69 kV transformer at Lovington	SWPS	Reliability	F1	0	$2,239,599
Rebuild Canyon West-Dawn-Panda 115 kV line to 249/273 MVA	SWPS	Reliability	F2	24	$14,194,453
Tap Hitchland-Finney 345 kV line at new substation and install new 345/115 kV transformer, and build new 23 mile 115 kV line from new station to Walkemeyer and continue to North Liberal	SUNC	Reliability	F1	22	$36,224,893
Total				260	$273,156,513

Table 0.1: 2015 ITP10 Transmission Plan

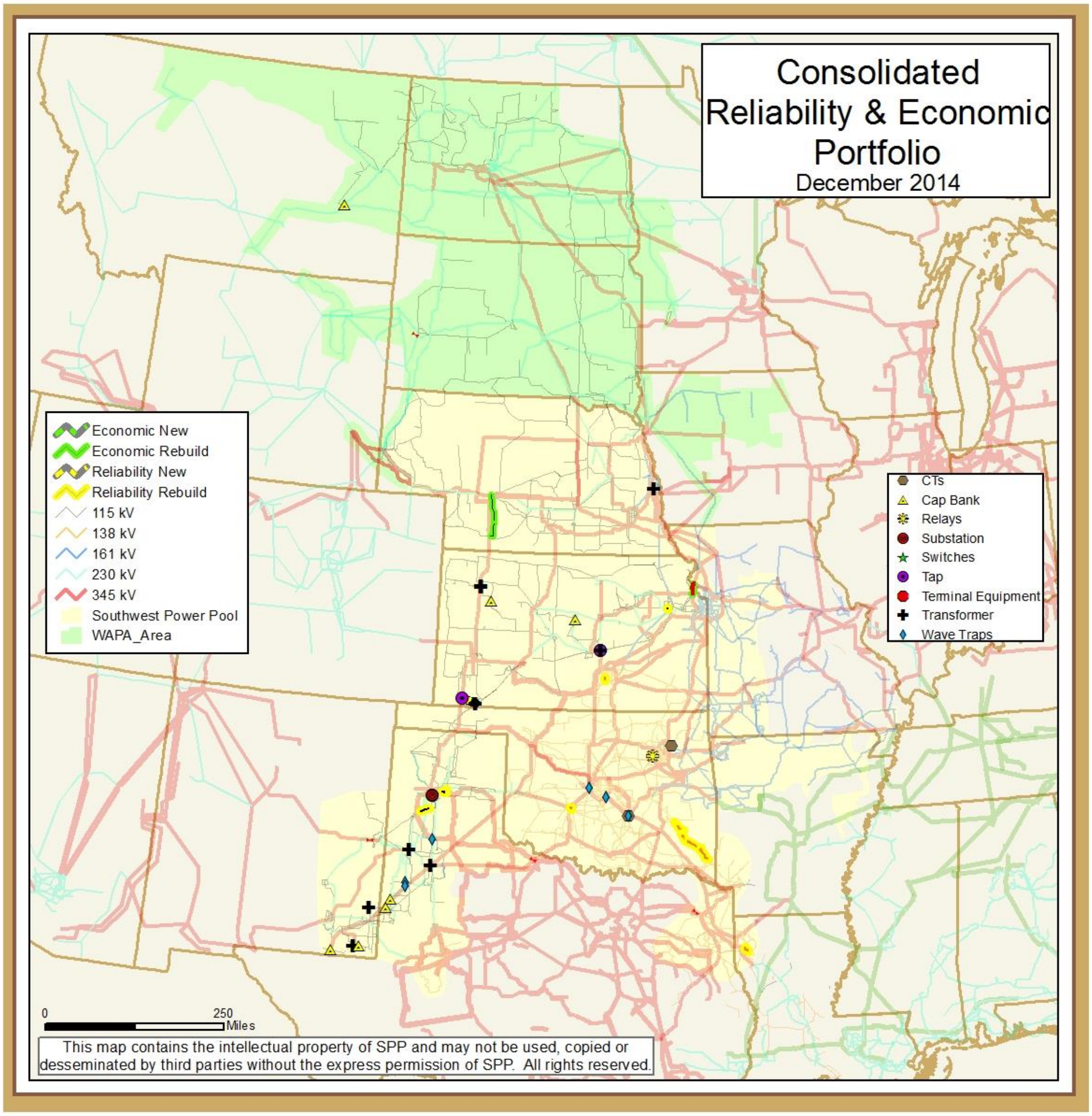


Figure 0.1: 2015 ITP10 Transmission Plan

Part I: Study Process

Section 1: Introduction

1.1: The 10-Year ITP

The 10-Year Integrated Transmission Planning Assessment (ITP10) is designed to develop a transmission expansion portfolio containing primarily 100 kV and above projects needed to address reliability needs, support policy initiatives, and enable economic opportunities in the SPP transmission system within the studied ten-year horizon.

ITP10's goals are to:

- Focus on regional transmission needs
- Utilize a value-based approach to analyze 10-year out transmission system needs
- Identify 100 kV and above solutions stemming from such needs as:
    - Resolving potential reliability criteria violations
    - Mitigating known or expected congestion
    - Improving access to markets
    - Meeting expected load growth demands
    - Facilitating or responding to expected facility retirements
- Meet public policy initiatives
- Synergize the Generation Interconnection and Transmission Service Studies with other planning processes
- Assess the zonal benefits of the final portfolio

1.2: How to Read This Report

This report focuses on the year 2024 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** demonstrates the findings of the study, empirical results, and conclusions.
- **Part III** addresses the portfolio specific results, describes the projects that merit consideration, and contains recommendations, expected benefits, and costs. Please note that negative numbers here are shown in red and in parentheses.
- **Part IV** 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 Transmission Owners[2] (TO) whose transmission facilities are under the functional control of the SPP Regional Transmission Organization (RTO) unless otherwise noted. The Integrated System (IS) has expressed the intention to join the SPP RTO. The Federal Energy Regulatory Commission (FERC) substantively approved the IS joining SPP, which is slated to occur by October 2015. The IS is assumed to be a part of the SPP RTO for this 10-year out study. The IS includes Western Area Power Administration (WAPA), Basin Electric Power Cooperative, and Heartland Consumers Power District.

Energy markets were also modeled for other regions within the Eastern Interconnection. Notably, Associated Electric Cooperatives Inc. (AECI), Mid-Continent Area Power Pool (MAPP), Tennessee Valley Authority (TVA), and Midcontinent Independent System Operator (MISO) were modeled as external energy markets. Entergy and Cleco were modeled within the MISO energy market.

Supporting Documents

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

- SPP 2015 ITP10 Scope
- SPP ITP Manual
- SPP Metrics Task Force Report

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.

1.3: High Priority Incremental Load Study

The High Priority Incremental Load Study (HPILS), conducted during the 2015 ITP10 process, evaluated transmission needs resulting from significant incremental load growth expectations in certain parts of SPP.[3] The SPP Board of Directors approved the HPILS portfolio in April 2014. In accordance with the recommendation of the Economic Studies Working Group (ESWG) and Transmission Working Group (TWG) on July 3, 2013, the HPILS projects with a notification to construct (NTC) or a notification to construct with conditions (NTC-C) were included in the 2015 ITP10 model.

[2] SPP.org > About > Fast Facts > Footprints

[3] HPILS Final Report

1.4: FERC Order 1000

FERC issued Order 1000 on June 17, 2010. Order 1000 requires the removal of federal right of first refusal (ROFR) for certain transmission projects under the SPP Tariff. To comply with this requirement, SPP developed the Transmission Owner Selection Process (TOSP) to competitively solicit proposals for projects that no longer have ROFR[4]. The TOSP is outlined in Attachment Y of the SPP Tariff. For the ITP process, once the applicable ITP study scope has been approved and the needs assessment performed, SPP shall notify stakeholders of the identified transmission needs and provide a transmission-planning response window of 30 calendar days. During this response window, any stakeholder may submit a Detailed Project Proposal (DPP) pursuant to Section III.8.b. of Attachment O of the SPP Tariff.[5]

In addition, SPP Business Practice 7650 outlines the specific DPP processes associated with Order 1000.

[4] SPP.org > Engineering > Order 1000

[5] SPP.org > Engineering > Order 1000 > Detailed Project Proposal

Section 2: Stakeholder Collaboration

Assumptions and procedures for the 2015 ITP10 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:

- Economic Studies Working Group (ESWG)
- Transmission Working Group (TWG)
- Regional Tariff Working Group (RTWG)
- Cost Allocation Working Group (CAWG)
- Markets and Operations Policy Committee (MOPC)
- Strategic Planning Committee (SPC)
- SPP Regional State Committee (RSC)
- SPP Board of Directors (BOD)

SPP staff served as facilitators for these groups and worked closely with the chairs of each group to ensure all views were heard and that SPP's member-driven value proposition was followed.

The ESWG and TWG provided technical guidance and review for inputs, assumptions, and findings. Specifically, the TWG was responsible for technical oversight of the load forecasts, transmission topology inputs, constraint selection criteria, reliability assessments, transmission project impacts stability analysis, and the report. ESWG was responsible for technical oversight of the economic modeling assumptions, futures development, resource plans and siting, metric development and usage, congestion analysis, economic model review, calculation of benefits, and the report.

The strategic and policy guidance for the study was provided by the SPC, MOPC, RSC, and Board of Directors.

Planning Workshops

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

- Key drivers developed by the stakeholders were presented at the planning summit on November 20, 2013.[6]
- Potential upgrades were presented at the planning summit on October 8th, 2014.[7]
- Recommended solutions with completed reliability, stability and economic analysis results were presented at the planning summit on December 16th, 2014.[8]

[6] SPP.org > Engineering > Transmission Planning > 2013 November Planning Summit

[7] SPP.org > Engineering > Transmission Planning > 2014 October Planning Summit

Policy Survey

The 2015 ITP10 Policy Survey focused on projected renewable requirements and additions over the next 10 years. In the survey, stakeholders were asked to identify:

- Existing renewable resources
    - Including renewable resources coming online by end of year 2014
- Renewable Statutory/Regulatory Mandates for renewable generation through the year 2024
- Renewable Statutory/Regulatory Goals for renewable generation through the year 2024
- Other Renewables required to promote company policy or reflect planned future generation additions through the year 2024

SPP used the results of the 2015 ITP10 Policy Survey in the development of resource plans for both conventional and renewable resources, as detailed in Resource Expansion Plan. After modeling existing renewables as reported in the survey, each utility was analyzed to determine if the renewable Mandates, Goals and Other generation quantities as reported in the survey were being met. If a utility was short on renewables, additional capacity was added in order to meet the levels specified in the survey.

Policy Definitions[9]:

- *Renewable Statutory/Regulatory Mandate*: Any currently effective state or federal statute or local law or any regulatory rule, directive or order which requires that an electric utility,[10] subject to the jurisdiction of that state, federal, or local law or regulatory body, must use a certain level (e.g. percentage) of renewable energy[11] to serve load. As used in this definition, a regulatory body is:
    - 1) Any state or federal regulatory body with authority over rate-setting, resource include planning, and other policy matters for electric utilities within its jurisdiction; or
    - 2) An elected City Council, a publicly-elected Board of Directors, a Board of Directors appointed by a publicly-elected official(s), or other governing body as defined by the appropriate governing statutes with jurisdiction over rates, resource planning and other regulatory matters.
- *Renewable Statutory/Regulatory Goal*: Any currently effective state or federal statute or local law or any regulatory rule, directive or order which establishes an aspirational goal to promote the use of a certain level (e.g. percentage) of renewable energy to serve load for an electric utility (subject to the jurisdiction of that state, federal, or local law or regulatory body). This definition does not include renewable energy used by a utility pursuant to Renewable Statutory/Regulatory Mandates, as reported above, or Other Renewables as shown below. As used in this definition, a regulatory body is:
    - 1) Any state or federal regulatory body with authority over rate-setting, resource planning, and other policy matters for electric utilities within its jurisdiction; or
    - 2) An elected City Council, a publicly-elected Board of Directors, a Board of Directors appointed by a publicly-elected official(s), or other governing body as defined by the appropriate governing statutes with jurisdiction over rates, resource planning and other regulatory matters.

[8] SPP.org > Engineering > Transmission Planning > 2014 December Planning Summit

[9] As defined during the policy survey development at the ESWG/CAWG meetings

[10] Some municipalities are exempt.

[11] Some states renewable requirements are capacity based instead of energy based. See Table 2.1.

- *Other Renewables*: Utility company policy which promotes the use of a certain level (e.g. percentage) of renewable energy to serve load or any other renewable resources, not included in the categories defined above.

Renewable Energy Drivers

Renewable energy and capacity requirements are driven by statutory/regulatory standards and court decisions made within each state of the SPP footprint. A brief summary of these requirements are listed below in Table 2.1:

State	Type	Source	Amount
Kansas	Statute (Capacity)	Kansas Statutes 66-1256 - 66-1262	10% - 2011 - 2015 15% - 2016 - 2019 20% - 2020
Missouri	Statute (Energy)	R.S. Mo. § 393.1020 et seq.	2% - 2011 - 2013 5% - 2014 - 2017 10% - 2018 - 2020 15% - 2021
Multiple	Court Order (Capacity)	United States District Court Order for Turk Settlement (SWEPCO)	400 MW of Capacity in SWEPCO Service Territory (AR, LA, or TX)
Nebraska	State Agency (Energy)	Public Power District Board Action	10% - 2020 (NPPD)
New Mexico	Statute (Energy)	Renewable Energy Act ("REA"), §§ 62-16-1 et seq. NMSA	10% - Current 15% - 2015 20% - 2020
Oklahoma	Statute (Capacity)	17 Okl. St. § 801.4	15% by 2015
Texas	Statute (Capacity)	TEX UT. CODE ANN. § 39.904 United States District Court Order (SWEPCO)	5,256 MW - Current 5,880 MW – 2015

Table 2.1: Renewable Energy Standards by State

Load and Generation Review

The 2015 ITP10 Load and Generation Review focused on planned conventional generation and load additions in the next 10 years. Stakeholders were asked to identify:

- existing conventional generation
- new conventional generation
- retired conventional generation
- summer peak load
- energy numbers
- load factors

SPP Used the results of the 2015 ITP10 Load and Generation Review, as approved by the ESWG, to update the base economic model and used to update conventional generation information used in resource planning.

Project Cost Overview

Project costs utilized in the 2015 ITP10 were developed in accordance with the guidelines of the Project Cost Working Group (PCWG). Conceptual Estimates, shown in Table 2.2 below were prepared by SPP based on historical cost information in an SPP database.

Voltage (kV)	New Line ($ Per Mile)	Rebuild ($ Per Mile)	Reconductor ($ Per Mile)	Transformers	New Substation
500	$1,518,968	$1,102,049	$854,593	$12,197,008	$18,468,127
345	$1,427,478	$1,031,114	$760,292	$9,056,700	$13,617,362
345 (Dbl Ckt)	$2,130,236	$1,929,488	$1,352,792	N/A	N/A
230	$926,905	$964,744	$676,396	$5,778,860	$5,609,010
161	$922,334	$902,646	$601,758	$3,859,619	$4,692,577
138	$917,762	$870,466	$549,352	$3,390,798	$3,528,559
115	$815,550	$733,861	$499,254	$2,663,963	$3,348,304
69	$763,056	$733,482	$422,990	$1,978,085	$2,468,852

Table 2.2: 2015 ITP10 Conceptual Project Cost Estimates

The Conceptual Project Costs were used for Pre-Phase I, Phase I, and Phase II of the DPP evaluation process to establish a -50 to +100 cost estimate for each project. Once the grouping with the highest net adjusted production cost (APC) benefit for each future was selected, independent SPP cost estimates were used in Phase III of the DPP process to establish the ±30 cost for each project.

Project Solutions

For the 2015 ITP10, needs were not directly addressed with projects proposed by stakeholders as in the past due to the implementation of Order 1000. Under Order 1000, potential projects were submitted through the Detailed Project Proposal (DPP) process during a transmission-planning response window of 30 calendar days. Potential projects submitted outside this window were considered as Non DPP Submittals.

Section 3: Future Selection

3.1: Uncertainty and Important Issues

Designing a transmission expansion plan to meet future needs is challenging because of the inability to accurately predict the policy environment, future load growth, fuel prices, and technological development over an extended time period. To address these challenges, two distinct sets of assumptions were developed and studied as individual "Futures" for the 2015 ITP10.

3.2: Futures Descriptions

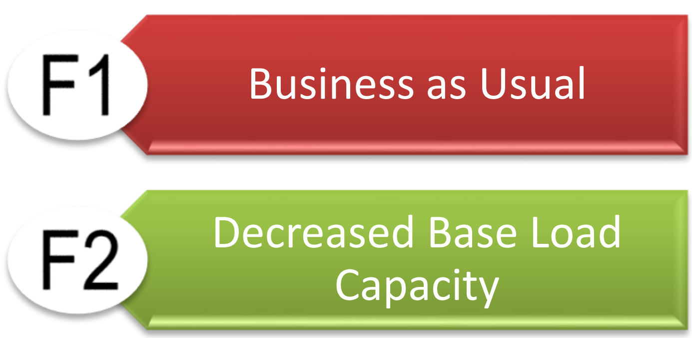
The 2015 ITP10 study was conducted based on a pair of futures. These futures consider evolving changes in technology, public policy and climate changes that may influence the transmission system and energy industry as a whole. By accounting for multiple future scenarios, SPP staff can assess what transmission needs arise for various uncertainties. In all futures, EPA environmental regulations, as known or anticipated at the time of the study, are incorporated.

Future 1: Business as Usual

This future includes all statutory/regulatory renewable mandates and goals as well as other energy or capacity as identified in the Policy Survey resulting in 11.5 GW of renewable resources modeled in SPP, load growth projected by load serving entities including the High Priority Incremental Loads, and SPP member-identified generator retirement projections. This future assumes no major changes to policies that are currently in place.

Future 2: Decreased Base Load Capacity

This future considers factors that could drive a reduction in existing generation. It will include all assumptions from the Business as Usual future with a decrease in existing base load generation capacity. This future will retire coal units less than 200 MW, reduce hydro capacity by 20% across the board, and utilize the Palmer Drought Severity Index for an average of August 1934 and August 2012 to simulate a reduction in existing capacity affected by drought conditions: 10% under moderate, 15% under severe, and 20% under extreme conditions. These target reductions were adjusted, as appropriate, based on locational and operational characteristics provided by the unit owners within each zone.



Section 4: Study Drivers

4.1: Introduction

Drivers for the 2015 ITP10 were discussed and developed through the stakeholder process in accordance with the 2015 ITP10 Scope. Stakeholder load, energy, generation, transmission, and market design inputs were carefully considered in determining the need for, and design of, future transmission upgrades.

4.2: Load & Energy Outlook

Peak and Off-Peak Load

Future electricity usage was forecasted by utilities in the SPP footprint and collected and reviewed by the ESWG. The highest usage, referred to as the system peak, usually occurs in the summer for SPP. The non-coincident peak load, the sum of each Load Serving Entity's peak load, was forecasted to be 60.8 GW for 2019 and 64.4 GW for 2024. The load totals in the 2015 ITP10 include 50/50 (expected) incremental loads from HPILS. Note that all demand figures shown in this section include the loads of the TOs within the SPP footprint as well as all other Load Serving Entities (LSE) within the SPP region. The IS was also included in the SPP region.

Once inputs such as the peak load values, annual energy values, hourly load curves, and hourly wind generation profiles were incorporated into the model, the economic modeling tool calculated the security-constrained unit commitment and security-constrained economic dispatch (SCUC/SCED) for each of the 8,784 hours in the year 2024. This process led to identifying the study's two reliability hours:

1) **Summer peak hour** –The summer hour with the highest load
2) **Off-peak hour** – The hour with highest ratio of wind output to load, in order to evaluate grid exposure to significant output from these resources.

The results indicated that the summer peak hour for 2024 would occur on July 19 at 5 p.m. and the high wind hour would occur on April 6 at 4 a.m.

Peak Load and Energy

The sum of energy used throughout a year, referred to as the net energy for load forecast, was estimated by SPP using annual load factor data provided and approved by the ESWG contacts. Annual net energy for load (including losses) was forecasted at 302 TWh for 2019 and 323 TWh for 2024. Tables 1.1 and 1.2 show the breakdown of the peak demand and annual energy totals. The coincident peak load, or the peak load for the entire SPP footprint, was forecasted at 57 GW for 2019 and 61 GW for 2024. Table 4.1 shows the forecasted monthly energy for 2024.

Load Type	Standard Projected Load	HPILS Load	Total Load	Total Load
	Non-Coincident	Non-Coincident	Non-Coincident	Coincident
2019 Peak Load (GW)	59.6	1.2	60.8	57.0
2024 Peak Load (GW)	62.8	1.6	64.4	61.0

Table 4.1: Breakdown of peak load totals

Energy Type	Standard Projected Energy	HPILS Energy	Total Energy
2019 Annual Demand (TWh)	292.4	9.6	302.0
2024 Annual Demand (TWh)	310.5	12.8	323.3

Table 4.2: Breakdown of annual energy totals

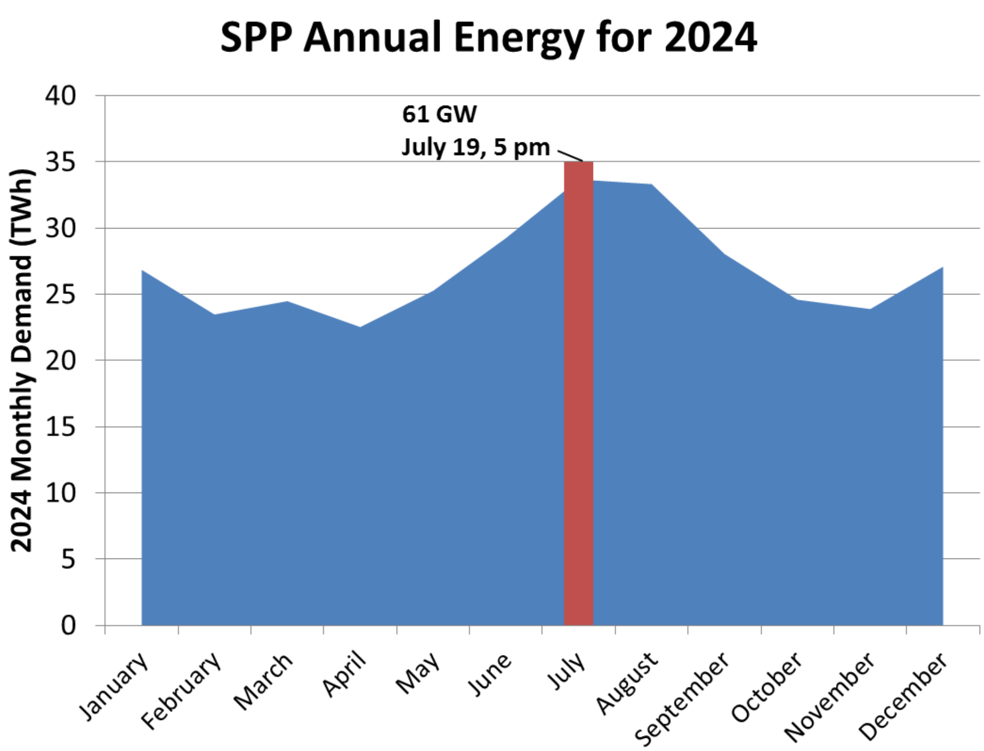


Figure 4.1: 2024 Monthly Energy for SPP

Diverse Peak Demand Growth Rates

The projections included diverse peak load growth rates for each area. Table 4.3 lists the peak load growth rates, which includes incremental loads, for the key areas in the model. These forecasted values result in an average annual growth rate of 1.16% for SPP.

Area	SUNC	MKEC	OKGE	WRI	AEPW	LES	GRDA
Rate (%)	1.81	0.93	0.89	0.72	2.70	1.16	1.93

Area	KCPL	MIDW	WFEC	EMDE	GMO	CUS	SPS
Rate (%)	-0.14	1.37	1.08	0.80	-1.18	1.00	3.02

Area	NPPD	OPPD	BEPC	HCPD	WAPA	CBPC
Rate (%)	1.01	1.64	2.26	0.60	0.00	0.43

Table 4.3: Annual Peak Load Growth Rates for SPP OATT Transmission Owners 2019 - 2024 (%)

4.3: Policy Drivers

Emission price forecasts for SO_2 and NO_X for the study years were based upon Ventyx simulation ready data, specifically, the 2012 Spring Reference Case released in May 2012. No emission price was utilized for CO_2.

4.4: Market Structure

SPP transitioned to a Consolidated Balancing Authority (CBA) and a Day Ahead Market, referred to as SPP's Integrated Marketplace, in March 2014. This market structure is simulated in PROMOD IV and was an assumption utilized across all futures.

4.5: Congestion Issues

SPP identified 50 economic needs for the ITP10. Details of these congestion issues and the drivers for those congestion issues are listed in the Economic Needs Section of the Appendix.

Section 5:Resource Expansion Plan

5.1: Resource Plan Development

Identifying the resource outlook for each future is a key component of evaluating the transmission system for a 10-year horizon. Resources are added and retired frequently, and the SPP generation portfolio will not be exactly the same in 10 years as it is today. Resource expansion plans have been developed for the SPP region and neighboring regions for use in the study that include both conventional and renewable generation plans unique to each future.

After completion of the resource plan development, a decision was made to include the IS as part of the SPP system for purposes of this ITP10 analysis. A resource plan has been developed for the IS. Although the IS resource plan was developed and approved separately from the remainder of the SPP resource plan, the resource plans are presented together in this section.

5.2: Siting Plan

The expected location of future generation was considered in areas with appropriate potential, based on input from and approval by the ESWG. The selected locations for new renewable and conventional generation will impact the power flow and will also drive the potential generation dispatch, congestion, thermal violations, and voltage violations.

5.3: Conventional Resource Plan

A conventional resource plan was developed for each future for the years 2019 and 2024.

Generator Review

An ITP10 generator review was conducted with stakeholders providing inputs for the analysis. This information includes maximum capacities, ownership, retirements, and other operating characteristics of all generators in SPP. The existing generation in the SPP region was updated with this information before development of the resource plan.

Conventional Resource Plan Approach

SPP Criteria 2.1.9[12] states that each load serving entity must maintain at least a 12% capacity margin, and this requirement is not expected to change with the implementation of the Integrated Marketplace. The resource plan was developed with this same requirement. Projected capacity margins were calculated for each zone using existing generation and 2024 load projections. Each zone's capacity was assessed to ensure that it met the 12% minimum capacity margin requirement. Only 5% of wind nameplate capacity was counted towards the capacity margin requirement due to the unpredictability of wind levels. ESWG approved a resource list of generic prototype generators using assumptions from the EIA Annual Energy Outlook (AEO) 2013. These prototype generators comprise representative parameters of specific generation technologies and were utilized in resource planning simulations to determine the optimum generation mix to add to each zone. All new generation identified in the conventional resource plan were natural gas-fired, comprising a combination of combined cycle and

[12] SPP.org > Org Groups > Governing Documents > Criteria & Appendices January 30, 2012

fast-start combustion turbine units. Locations of those generating units were vetted with the various zones and all efforts were made to include the Integrated Resource Plans filed by utilities in their respective state(s).

Generation Siting

After the required generation additions were determined for each zone, they were sited within the zone based on locations identified for the 2013 ITP20 and HPILS. The ESWG and other stakeholders provided input on potential locations for additional gas generation, along with the associated bus information based on space requirements, proximity to gas pipelines, and existing electric transmission. The stakeholder feedback was incorporated and the overall siting plan was presented and approved by the ESWG.

SPP Capacity Additions by Unit Type by 2024 – Summary

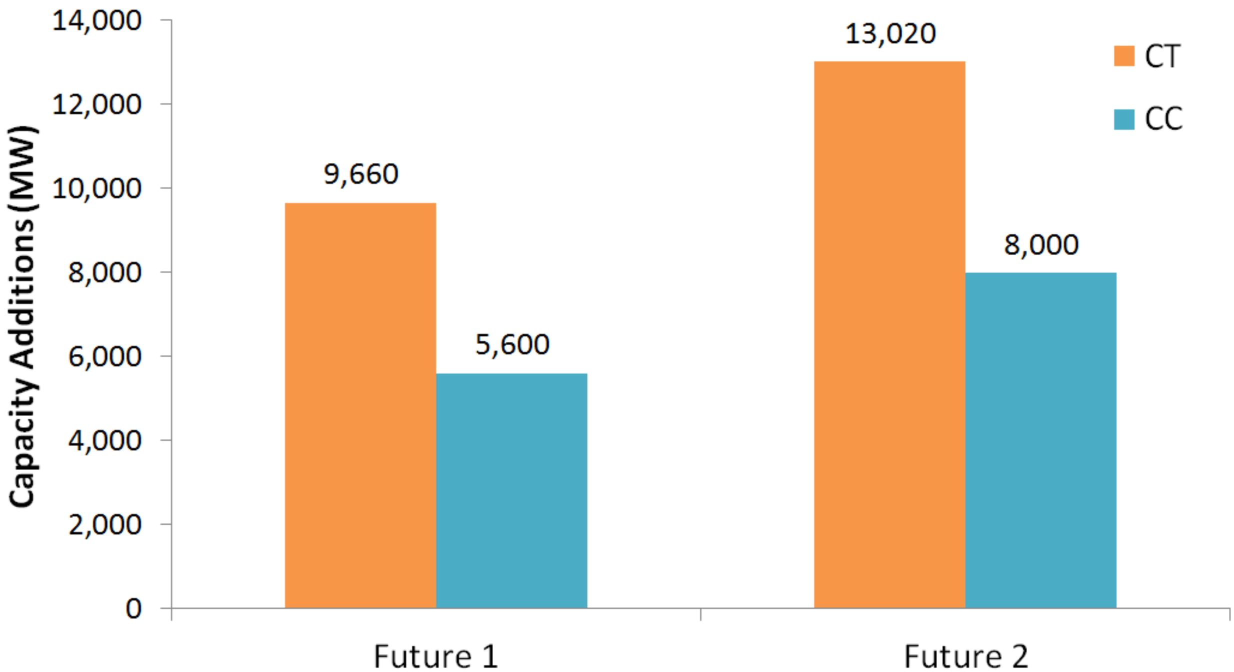


Figure 5.1: Capacity Additions by Unit Type – Conventional Plan

Figure 5.1 shows new generation additions by future for the SPP region. Future 1 has 15.3 GW of generation additions, and Future 2 has 21.0 GW of generation additions. More resource additions are needed in Future 2 due to the decreased base load capacity assumptions of this future. Both futures have resource additions comprised of combustion Turbine (CT) units and combined cycle (CC) units. The CC units are generally included because their moderately low capital cost and low operating costs make them the most economically viable technology for meeting energy needs in these futures. CC units were selected primarily in areas that were low in base load generation, and needed the additional energy to serve load. The CT units are generally included because of the very low capital costs associated with these units make them the most economically viable technology for meeting peak capacity requirements. CT units were selected primarily for areas that already have sufficient base load generation, and need the additional capacity to meet the 12% capacity margin requirement.

Future 1 Conventional Resource Plan for 2024 – SPP

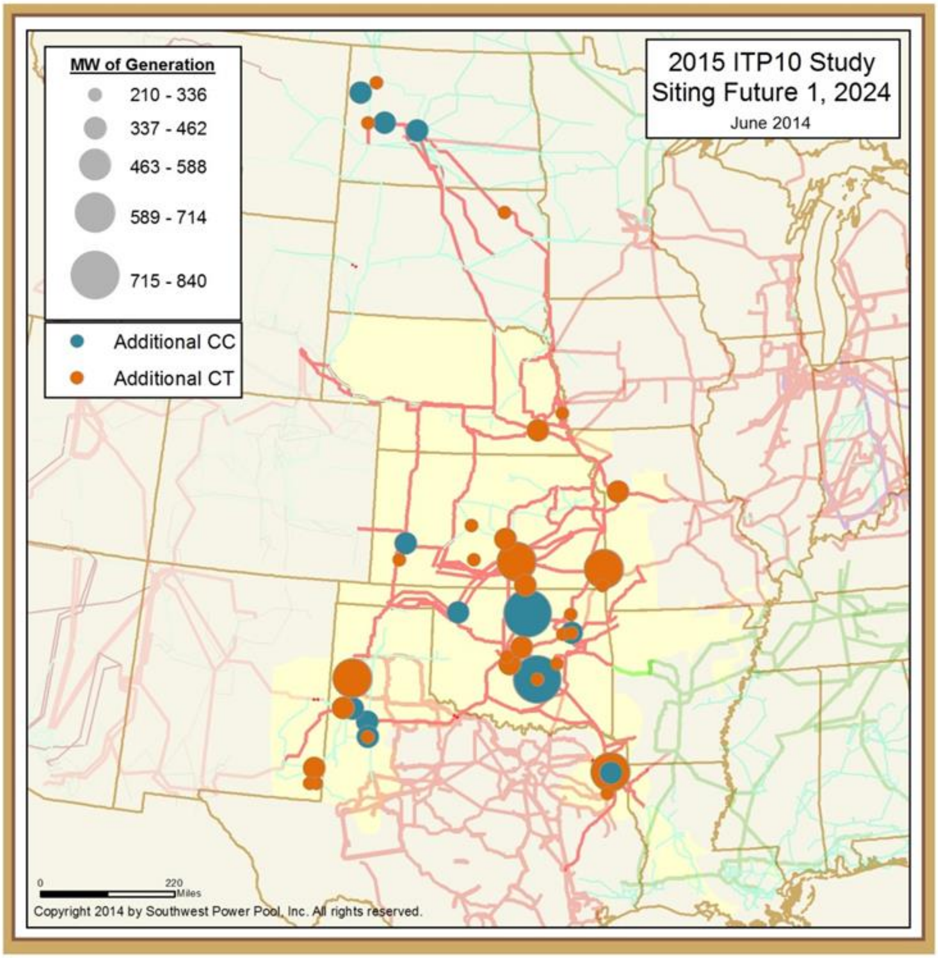


Figure 5.2: Conventional Generation Additions for Future 1

Figure 5.2 shows locations and technology type of all new conventional generation added to Future 1.

- Additional Sites
  - 14 Combined Cycle
  - 46 Combustion Turbine
- Additional Capacity
  - 5.6 GW Combined Cycle
  - 9.7 GW Combustion Turbine

Future 2 Conventional Resource Plan for 2024 – SPP

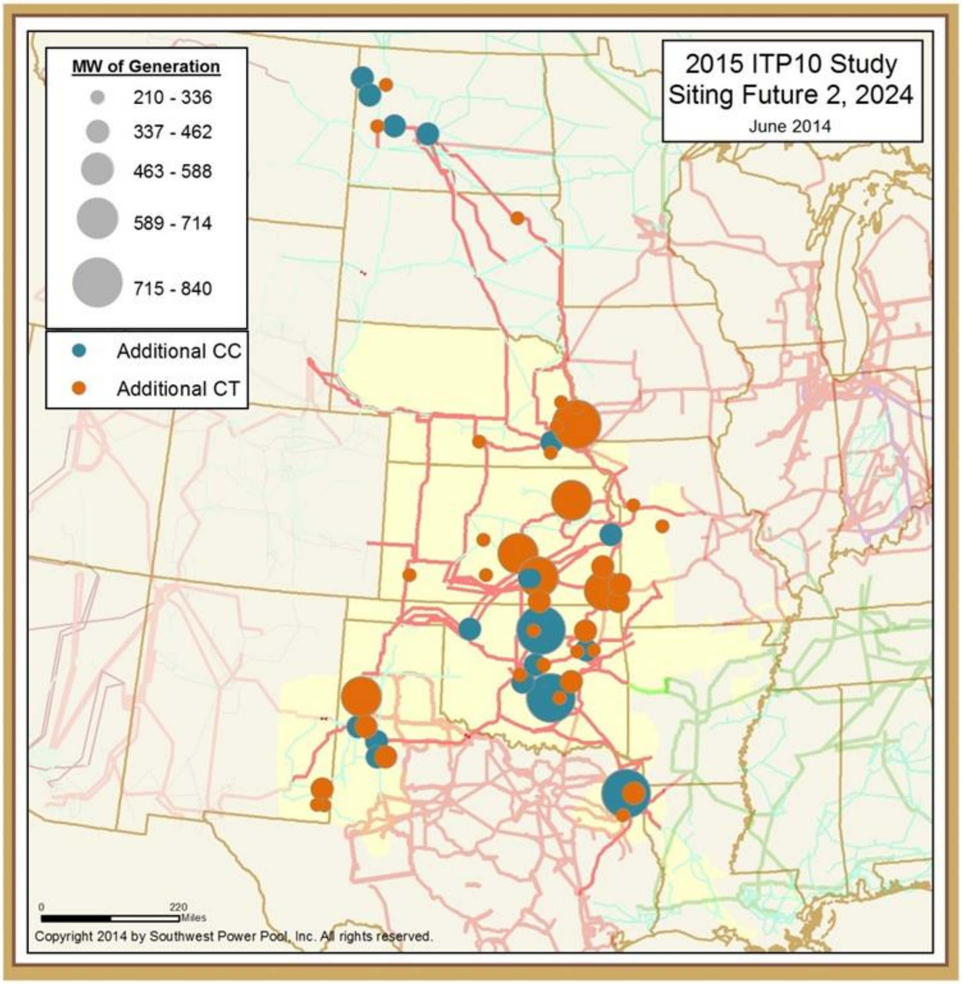


Figure 5.3: Conventional Generation Additions for Future 2

Figure 5.3 shows locations and technology type of all new conventional generation added to Future 2 for 2024.

- Additional Sites
  - 20 Combined Cycle
  - 62 Combustion Turbine
- Additional Capacity
  - 8.0 GW Combined Cycle
  - 13.0 GW Combustion Turbine

Conventional Resource Plan – External Regions

For Futures 1 and 2, resource plans were also developed for external regions. Each region was assessed to determine the capacity shortfall, and natural gas combined cycle and combustion turbine units were added so that each region met their own capacity margin. New units were interconnected to lines with high transfer capacity. Units were added in AECI, TVA, MISO, WAPA and Saskatchewan Power (SASK). SPP Staff contacted these entities to obtain resource plans for 2019 and 2024. The MISO resource plan was based on the MISO Transmission Expansion Planning (MTEP13). SPP Staff calculated the resources needed for Entergy and Cleco, as the MTEP13 did not include these regions in their calculations.

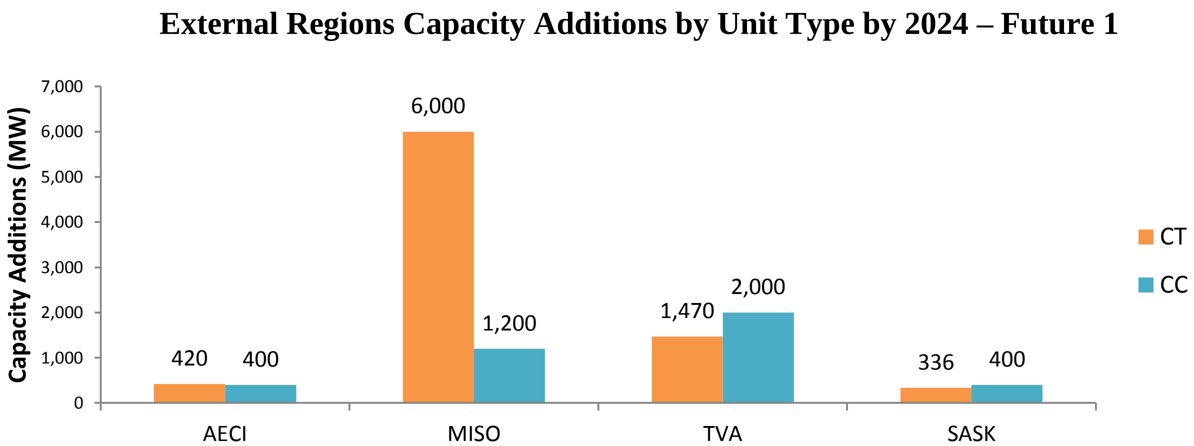


Figure 5.4: Capacity Additions by Unit Type – Conventional Plan Future 1

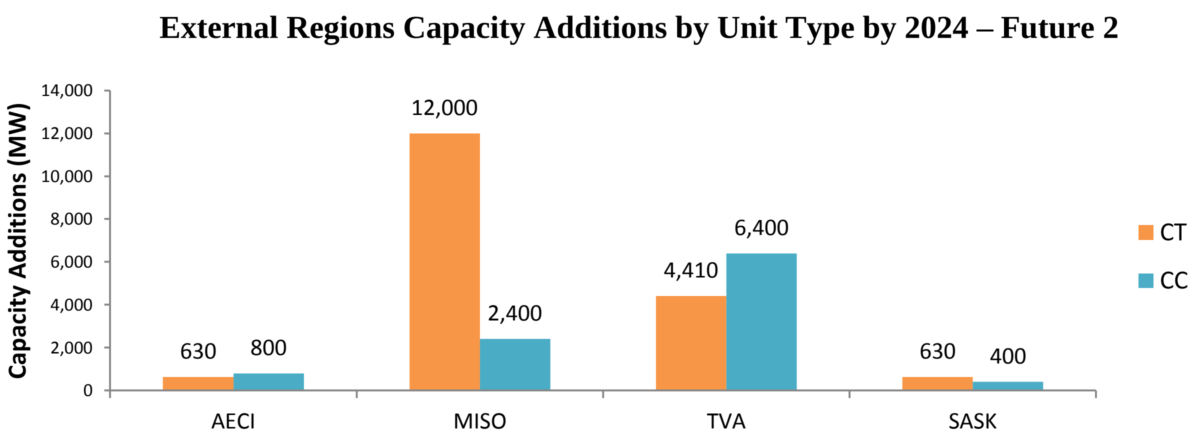


Figure 5.5: Capacity Additions by Unit Type – Conventional Plan Future 2

5.4: Renewable Resource Plan

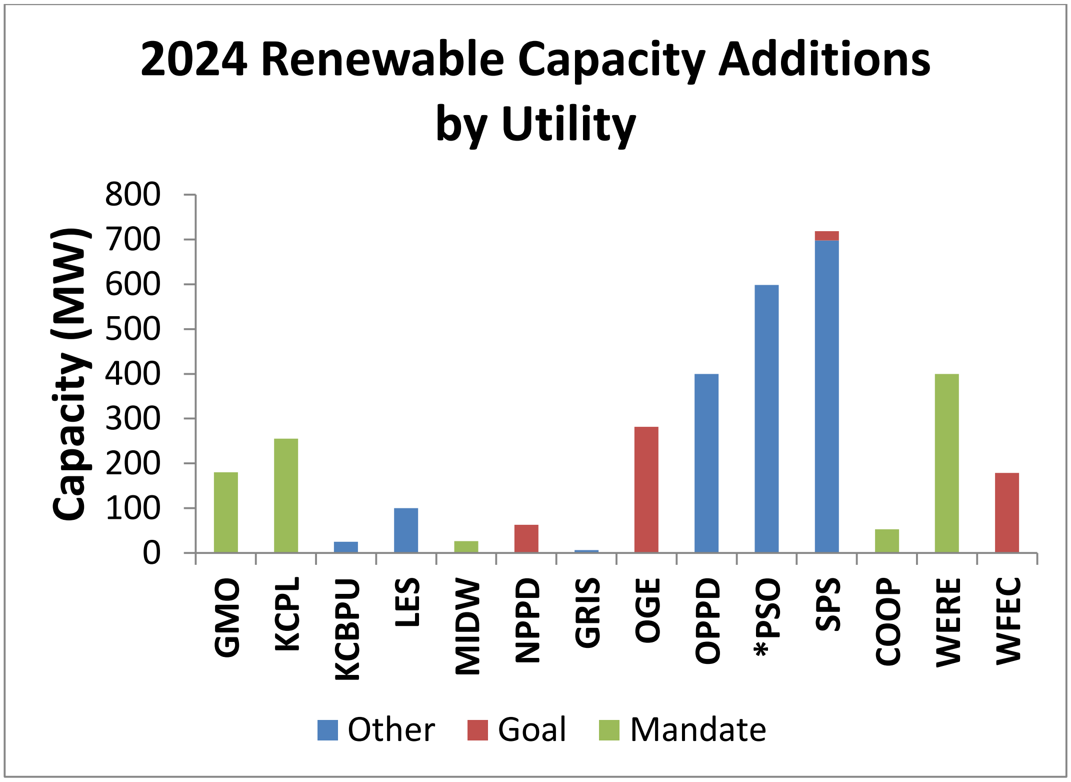
A renewable resource plan was also developed for the years 2019 and 2024. This renewable resource plan applies to all futures.

Existing Wind

The 2015 Policy Survey was used to gather information on existing wind generation in the SPP system for inclusion in the models. Existing wind was defined as wind generation that is in-service or currently in development and expected to be in-service by the end of 2014. Members reported 7.0 GW of existing wind in the SPP region. Another 1.2 GW of existing wind generation is currently contracted for export with firm service and was modeled accordingly. The total existing wind reported by members that is located within the SPP region is 8.2 GW and was included in the models for all futures.

Additional Renewables

The 2015 Policy Survey was used to gather information on members' state renewable Mandates, Goals, and Other expected renewable additions with which to comply with by 2024. Additional wind generation was added to the system when the existing wind was not sufficient to meet these Mandates, Goals, and Other[13] expectations which include economic purchases. The total additional renewables added in the SPP footprint by 2024 is 3.3 GW with allocations based on the policy survey assumptions. The table below shows wind and solar generation added in both futures:



* An economic and company goal number.

Table 5.1: SPP Renewable Generation Additions by Utility

Siting of Additional Renewable Generation

Generic wind sites were selected by the ESWG based upon the locations utilized in previous ITP studies, as well as, NREL sites because of their potential for high wind output. The 3.3 GW of additional wind was apportioned among 18 wind sites in New Mexico, Texas, Oklahoma, Kansas, Missouri, and Nebraska. The 20.5 MW of additional solar was apportioned among two solar sites to meet solar goals in Texas.

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13 . "Other" is defined as utility company policy which promotes the use of a certain level (e.g. percentage) of renewable energy to serve load or any other renewable resources, not included in Mandates and Goals

Futures 1 and 2 Renewable Resource Plan for 2024 – SPP

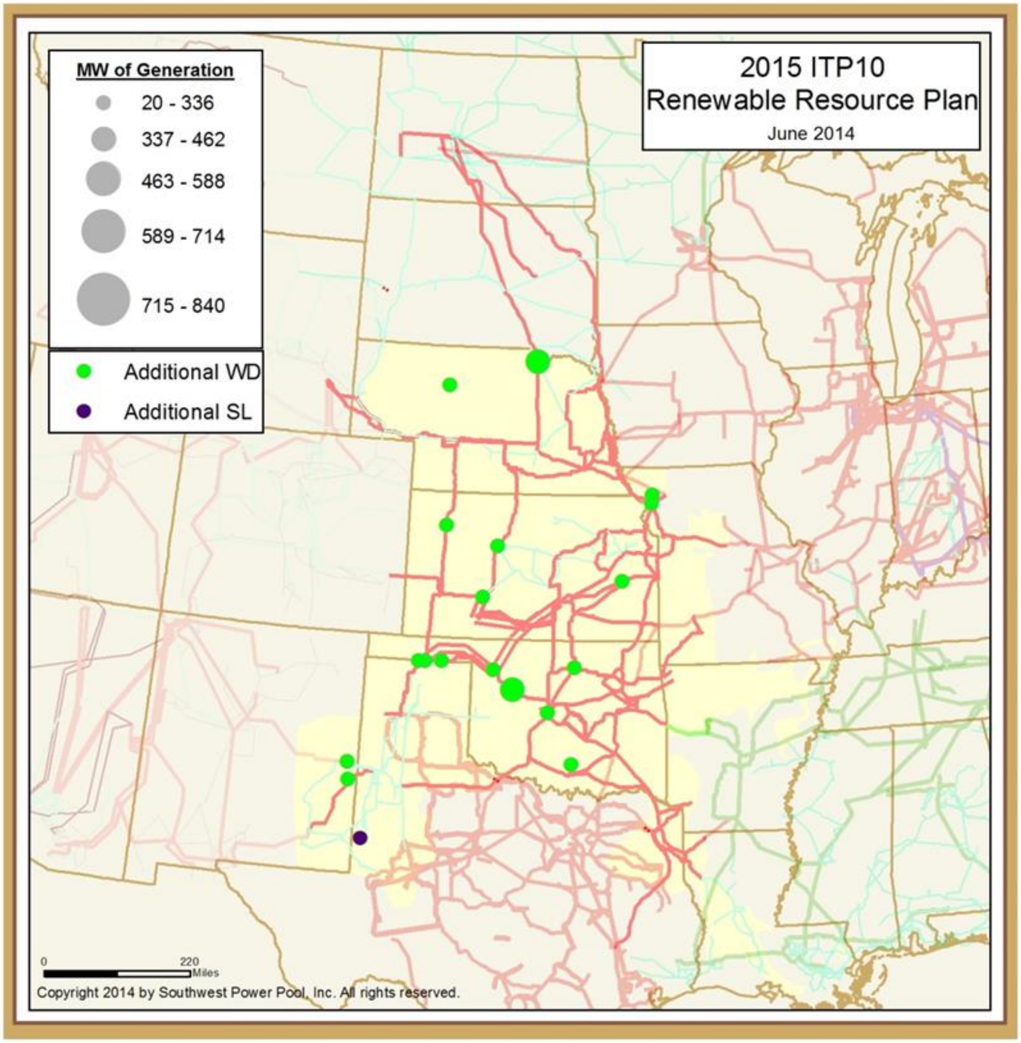


Figure 5.6: Renewable Resource Plan for Futures 1 and 2

Figure 5.6 shows the location of all wind generation for the SPP region for Futures 1 and 2.

- Wind Sites
  - 71 Existing
  - 21 New
- Wind Capacity
  - 8.2 GW Existing
  - 3.3 GW New
  - 11.5 GW Total

Additional information and results of the renewable resource plan are shown in Appendix Z, including zonal breakdown of wind, bus locations, and external region details.

Renewable Resource Plan – External Regions

Renewable resource plans were also developed for external regions for both futures. MISO provided SPP staff with assumptions regarding renewable generation additions, which includes 5.6 GW in Future 1 and 11.2 GW in Future 2 (including solar and wind) of renewables for MISO. These renewable units were sited at high voltage buses with high transfer capacities. The MISO renewable resource plan was based on the MTEP13, and do not include Energy and Cleco. AECI, TVA and SASK were not included in the renewable resource plan.

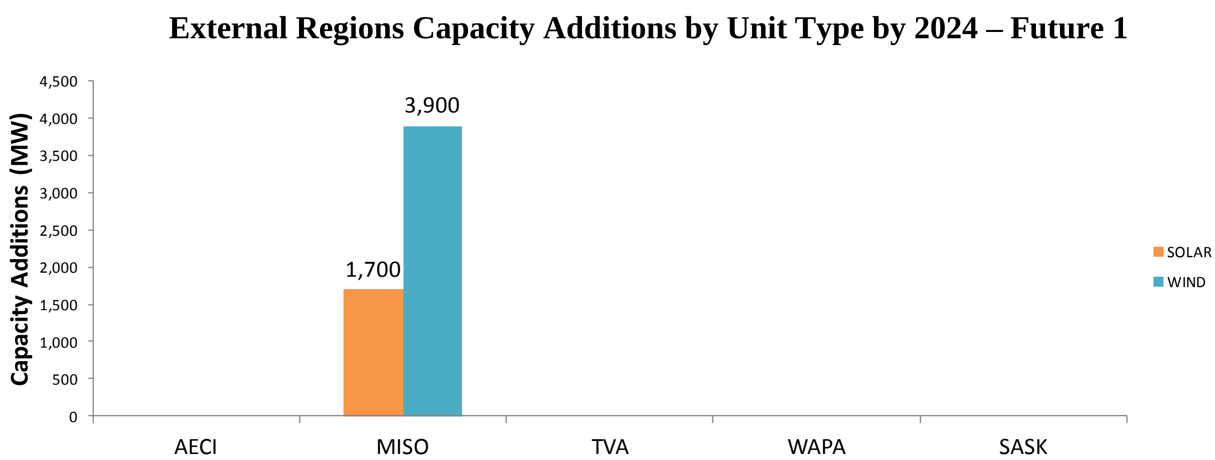


Figure 5.7: Capacity Additions by Unit Type – Renewable Resource Plan Future 1

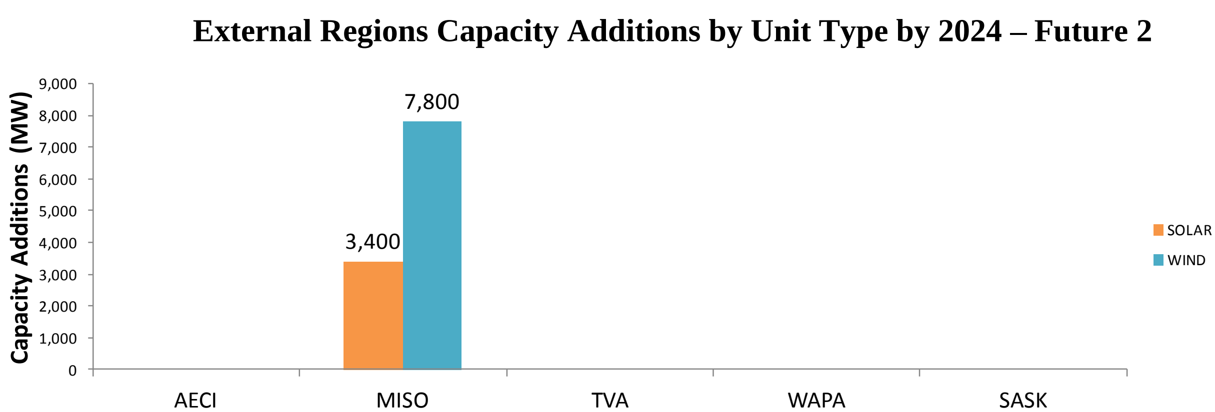


Figure 5.8: Capacity Additions by Unit Type – Renewable Resource Plan Future 2

5.5: Generator Outlet Facilities

Once the new resource plan was applied to the models, Generator Outlet Facilities (GOF) were developed where existing transmission facilities were unable to dispatch 100% of the new resource plan. This would allow new generation to go through the Generation Interconnection process to determine what upgrades would be needed for interconnection. The GOF methodology was developed by staff and approved by the TWG and ESWG to ensure that facilities needed to dispatch the resource plans were not included in the Consolidated Portfolio or issued an NTC. GOF facilities were developed by staff and approved by the TWG for each future. These upgrades were then applied to the base model.

GOF Upgrade	Future
Build CKT2 from Pharaoh - Weleetka 138 kV	Both
Build new 12.3 mile 138 kV line from Weleetka - Wetumka with an emergency rating of 162 MVA	F2
Tap SWPA Weleetka to GreasyCk. Reconductor 2.6 miles of new 2nd circuit between AEP and SWPA Weleetka subs with 795ACSR. Limit is 800A Wtraps	F1
Uprate line from Weleetka - Weleetka from Weleetka Outlets idev.	F2
Install second transformer at Wilkes (508840)	Both
Reconductor Lydia - Welsh 345 kV line to an emergency rating of 1176 MVA	Both
Upgrade terminal equipment to increase rating of Oneta - OEV 345 kV CTK1 and CTK2 to an emergency rating of 1885 MVA	Both
Rebuild Woodward (514785) to Mooreland (520999) 138 kV to and emergency rating of 465 MVA	Both
Reconductor McClain - Draper 345 kV line to an emergency rating of 1792 MVA	F2
Tap Cimaron - Draper 345 kV line and move new McClain generation to high side of the 345/138/13.8 transformer. Rebuild McClain - West Moore 138 kV line to an emergency rating of 571 MVA	Both
Upgrade terminal equipment to increase rating of Jones - Lubbock Sth 230 kV CTK 1 and 2 to an emergency rating of 635 MVA	F1
Build new 10 mile 230 kV line Holly - Wadsworth with an emergency rating of 727 MVA	F2
Convert Hobbs – Hob and Plt - Andrews from 230 kV to 345kV operation. Install 1 345/230/13.2 and 1 345/115/13.8 transformers and build new 57.2 mile 345 kV line from Hob and Plt to Roadrunner	Both
Build LP-Milwakee6 (522823) - LP-Southeast 6 (522861) LP-Holly 6 (522870) 230 kV line with a rating of 727 MVA	F1
Upgrade terminal equipment to increase LP-Holly - Jones 230 kV line to an emergency rating of 502 MVA	Both
Upgrade LP-Southeast 6 (522861) LP-Holly 6 (522870) 230 kV line with a rating of 727 MVA	Both
Reconductor NA_Enrich - Tran-Sub 115 kV to an emergency rating of 304 MVA	Both
Upgrade wavetraps to increase rating of Lubbock_Sth - Wolfforth to an emergency rating of 502 MVA	F2
Build 2nd circuit from Heizer to Great Bend 230 kV	Both
Install 345/115/13/8 transformer at new Finney TP 7 and build 6.44 mile 115 line to Rubart	Both
Reconductor St John - Seward 115 kV to an emergency rating of 239	Both
Tap Hitchland (523097) - Finney (523853) new bus Finney TP 7 (523100)	Both
Tap Viola - Wichita 345 kV line and build new 15 mile 345 kV line to Gill. Move new generation to high side of new Gill transformer. Also reconductor Gill - El Paso 138 kV line with an emergency rating of 478 MVA	F2
Tap Neosho - Blackberry 345 kV and build 17 Mile double circuit 345 kV line to Franklin. Move new Franklin generation to highside of 345/161/13.8 transformers.	Both
Move generators at Gill East 138 kV to Gill West 138 kV and Gill South 138 kV	F1
Upgrade Neosho 138/69 kV transformer to a rating of 165 MVA	F2
Reconductor Marmatan - Neosho 161 kV line to an emergency rating of 223 MVA	F2
Reterminate Waco - Gill West 138 kV at Gill East 138 kV	F1

Upgrade Bus Ties at Gill to an emergency rating of 650 MVA	F1
Rebuild Joplin - Stateline CTK1 to match CTK2 rating	F2
Build new BPS Sub - Hartbine 115kV line	F2
Reconductor BPS Sub - Clatona 115kV and Clatona - Sheldon 115kV for an emergency rating of 212	F2
Upgrade wavetraps and switches to increase rating of Centenl - Paola to 334 MVA	F2
Rebuild Sottowa - Paola to increase emergency rating to 334 MVA	F2
Tap S3456 3 - S3458 3 345 kV line and build new 5.8 mile 345 kV line to S3740 3	F2
Reconductor S3740 - S3455 345 kV line to an emergency rating of 1792	F2
Reconductor 84th - Fletcher 115 kV and 84th - Bluff 115 kV to an emergency rating of 390 MVA	F2
Add 3rd OCE 7 - Oneta 345 kV CTK	Both
Upgrade transformers at NM#4_1	F2
Upgrade transformers at OK6_#2 (560722)	Both

Table 5.2: Generator Outlet Facilities added for both futures

Section 6: Analysis Methodology

6.1: Analytical Approaches

SPP transmission system performance was assessed from different perspectives designed to identify transmission expansion projects necessary to accomplish the reliability, policy, and economic objectives of the SPP RTO. The analysis ensured that the transmission expansion portfolio would:

- Avoid exposure to Category A (system intact) and B (single contingency) SPP standard criteria violations during the operation of the system under high stresses;
- Facilitate the use of renewable energy sources as required by policy mandates and goals; and
- Reduce congestion and increase opportunities for competition within the SPP Integrated Marketplace.

Priority was given to the relief of all of the potential reliability violations seen during two unique system stressing hours (summer peak, light load) and to meet all state renewable policy mandates and goals. The relief of annual congestion and reduction in market prices were pursued where cost-justified. A transmission expansion project was considered cost-justified when it yielded a one-year benefit-to-cost ratio of at least 0.9. In some cases, there was overlap among these priorities. For example, a project may relieve potential reliability violations and reduce annual congestion in a cost-justified manner. This approach was applied to both ITP futures.

SCUC & SCED Analysis for multiple futures

An assessment was conducted to develop a list of constraints for use in the SCUC & SCED analysis. Elements that, under contingency, limit the incremental transfer of power throughout the system were identified, reviewed, and approved by the TWG. Revisions to the constraint definition studies included modification of the contingency definition based upon terminal equipment, normal and emergency rating changes, and removal of invalid contingencies from the constraint definition.

The constraint list included normal and emergency ratings and was limited to the following types of issues:

- System Intact and N-1 situations[14]
- Existing common right-of way and tower contingencies for 100+ kV facilities[15]
- Thermal loading and voltage stability interfaces
- Contingencies of 100+ kV voltages transmission lines
- Contingencies of transformers with a 100+ kV voltage winding
- Monitored facilities of 100+kV voltages only

Neighboring areas were also analyzed for additional constraints to be added.

[14] N-1 criterion describes the impact to the system if one element in the system fails or goes out of service

[15] The current NERC Standard TPL-001-0.1 includes outages of any two circuits of a multiple circuit tower line within Category C, and the loss of all transmission lines on a common right-of-way within category D. NERC Standard TPL-001-4 has replaced this standard and includes such outages in Planning event P7 and Table 1 – Steady State & Stability Performance Extreme Events.

All system needs were identified through the use of a SCUC & SCED simulation that accounted for 8,784 hours representing each hour of the year 2024. AC models were developed from two unique system stressing hours of this simulation to determine reliability thermal and voltage needs.

6.2: Projecting Congestion & Market Prices

Annual Conditions Reviewed by the ESWG

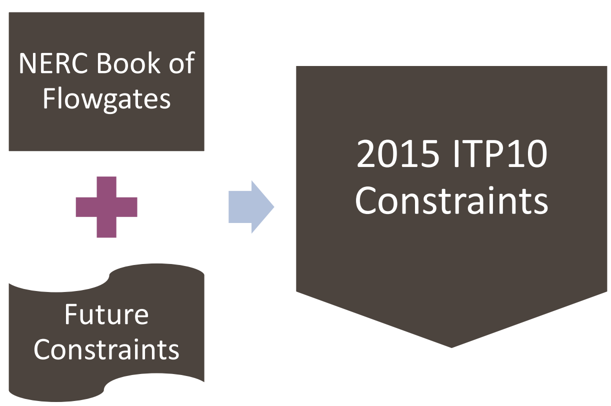
Congestion was assessed on an annual basis for each future considering many variables. Some of these variables change on an hourly basis, such as load demand, wind generation, forced outages of generating plants, and maintenance outages of generating plants. A total of 8,784 hours were evaluated for the year 2024.

Relevant congestion of each constraint was identified through two methods:

- The number of hours congested, and the average shadow price[16] associated with the congestion for all binding hours.
- These two numbers were multiplied together to compute an average congestion cost across all hours of the single year.
- This average congestion cost was used to rank the severity of the congestion for each constraint.

Identification of Additional Constraints

Staff defined the initial list of constraints from the 2013 NERC Book of Flowgates for the SPP, IS, and neighboring regions. Additional constraints were incorporated that would protect facilities from overloads under a number of system conditions. These additional constraints facilitated the capture of both market congestion and economic benefit in expectation of transmission expansion that is not anticipated by the NERC Book of Flowgates.



[16] The "Shadow Price" refers to the savings in congestion costs if the constraint limit in question were increased by 1 MW.

6.3: Projecting Potential Criteria Violations

Reliability Needs

Two hours that represent situations uniquely stressing the grid were identified to perform a reliability assessment of the System.

- Summer peak (July 19, 5pm) – highest coincident load during summer months
- Light load (April 6, 4am) – highest ratio of wind output to coincident load

AC models were developed for each of the two hours in each future. An N-1 contingency scan was performed for the SPP, IS, and Tier 1 footprints to determine thermal and voltage criteria violations, defined as system reliability needs.

6.4: Meeting Policy Requirements

For policy requirements, SPP focused on satisfying statutory/regulatory renewable mandates and goals within a future through use of renewable generation as defined by the SPP Stakeholders through the 2015 Policy Survey. Each mandate or goal can be defined as a capacity or energy requirement. The primary generation technology required to meet these renewable standards, as provided by the stakeholders, was wind generation. A copy of the survey results can be found in the ESWG meeting materials.[17]

Renewable capacity requirements were met with installation of new generating capacity. Renewable energy requirements were analyzed through simulation of the study year. Renewable generation may experience the effects of congestion and be curtailed by the SCED. Shortfalls in the achievement of the renewable requirements of each future due to this curtailment were identified. Companies within each state that experienced an annual renewable energy output less than required were identified as having a policy need.[18]

6.5: Utilization of Past Studies & Stakeholder Expertise for Solutions

SPP shared potential violations with the stakeholders and interested parties for review. The 2015 ITP10 followed the process added to the SPP Tariff in compliance with FERC Order 1000. Potential solutions to the transmission needs identified by SPP were provided through the DPP process. SPP received approximately 1179 solutions. SPP also collected and analyzed other proposed solutions previously identified in past Planning Studies.[19] All of these potential solutions were evaluated for their own merits.

6.6: Treatment of Individual Projects & Groupings

After assessment of the needs, SPP investigated mitigation of the needs through individual projects by performing the following actions:

- Tested to ensure the project met the identified need.

[17] SPP Documents > Org Group Documents > ESWG > ESWG Meeting Materials

[18] This represents a change from previous ITP studies in which shortfalls in renewable energy output were evaluated on an individual resource-by-resource basis, in order to identify policy requirements.

[19] ITP Near-Term, ITP10, ITP20, Transmission Service Studies, Generation Interconnection Studies, High Priority Studies, Coordinated System Planning Studies.

- Measured the impact of the projects upon similar constraints and overloads.
- Identified projects with synergy and that duplicated the value captured by another project.
- Combined reliability, policy, and economic analysis to produce a transmission expansion portfolio of projects.

6.7: Determining Recommended Portfolio

Individual projects within the recommended portfolio provided reliability, economic, and policy benefits within the Future 1. Projects meeting the performance criteria for Future 1 *and* Future 2, outlined in Table 6.1, were included in the recommended portfolio.

Project Type	Future 1 Performance	Future 2 Performance
F1 Reliability	Mitigate a thermal or voltage violation	N/A
F2 Reliability	Mitigate 90% thermal or 0.92 pu voltage limit	Mitigate thermal or voltage violation
F1 Policy	Meet a policy need	N/A
F2 Policy	N/A	N/A
F1 Economic	1-year B/C ≥ 0.9	N/A
F2 Economic	1-year B/C ≥ 0.7	1-year B/C ≥ 0.9

Table 6.1: Consolidation Criteria

Projects mitigating more than one type of need were evaluated against multiple performance criteria. Only one set of criteria is required to be met for a project to be included in the recommended portfolio.

Project Staging

Project staging is the process by which appropriate need dates for new projects are established. Projects in the 2015 ITP10 were staged based on need and/or performance in the staging year, 2019, when compared to the study year, 2024. The result of this analysis is an interpolated need date for each project of the recommended portfolio, between or equal to the study or staging year. For a full description of the staging process see Staging.

6.8: Measuring Economic Value

Monetized metrics are used to measure the value of and facilitate better understanding of the financial impacts of proposed projects. The ESWG chose ten metrics to analyze the recommended portfolio in each Future. While APC benefits were calculated for numerous projects and the final portfolio, the other metrics were calculated only for the consolidated portfolio. For a full description of the benefit metrics see Section 16:.

Section 7:Seams Coordination

7.1: ITP Seams Coordination Enhancements

SPP continues to enhance and refine coordination with neighbors during SPP's regional planning studies, including the ITP10. Enhanced coordination's goal is to better ensure that the planning along the SPP seams is as robust as the transmission planning in the middle of the SPP footprint. To accomplish this, SPP coordinated with its neighbors at every point along the planning process and on the same schedule as SPP staff coordinates with SPP stakeholders. Two 2015 ITP10 seams-planning studies provided additional coordination opportunities and were leveraged in the 2015 ITP10 assessment.

7.2: Coordination Activities

The ITP10 seams coordination focused on SPP's Tier 1 neighbors[20]. Previous sections of this report discuss coordination with SPP's Tier 1 neighbors as it pertains to each specific section. The subsections below provide additional information on that coordination.

Model Development & Resource Plan

SPP used the Multi-regional Modeling Working Group (MMWG) models as a starting point for its model development. SPP also provided its Tier 1 neighbors with an opportunity to review and provide edits to the ITP10 model. AECI and MISO each provided modeling feedback for their respective footprints. This review was similar to those performed by SPP stakeholders, as the Tier 1 neighbors reviewed load, generation, topology, and other modeling inputs. SPP's neighbors also provided feedback on the resource plan SPP used to model the retirements and generation expansion for 2024 in the ITP10. Since SPP and MISO share their regional planning models, SPP was able to utilize the resource expansion plan MISO used in the MTEP 2013. MISO's expansion plan was supplemented by incorporating additional resources, as needed, for Entergy and Cleco, which were not included in the MTEP 2013.

Congestion Assessment

While SPP did provide Tier 1 neighbors with its identified transmission needs to determine whether everyone could coordinate on a joint transmission solution. SPP met several times with AECI to discuss transmission needs close to the AECI seam.[21] SPP also shared its transmission-needs list with MISO. The needs along the seam closely aligned with the transmission needs identified in the SPP-MISO Coordinated System Plan Study discussed below.

Coordination with Ongoing Seams Assessments

Two 2015 ITP10 seams studies are still ongoing. The first is the SPP-AECI Joint Coordinated System Plan Study (AECI Study). The AECI Study focused on identifying and addressing potential reliability needs along the SPP-AECI seam, on either the SPP or AECI system. The AECI Study identified needs closely aligned with those in the ITP10 and the ITPNT, which helped SPP staff coordinate the two

[20] Note MISO coordinated for those SPP Tier 1 neighbors that are MISO members.

[21] These meetings included face-to-face meetings and teleconferences. AECI came to SPP's office in Little Rock for the specific purpose of discussing potential seams projects in the ITP10.

studies with SPP evaluating all of the solutions proposed in the AECI Study in the 2015 ITP10, and likewise the 2015 ITP10 proposed projects were evaluated in the AECI Study.

The second seams assessment is the SPP-MISO Coordinated System Plan Study (MISO Study). The MISO Study began in early 2014 and will conclude in June 2015. The study’s transmission needs were published in October, and it is currently in the solution-development phase. The MISO Study’s model-development data was used, where applicable, to enhance and improve the ITP10 modeling. This gave SPP the most recent modeling of the large seam between SPP and MISO. The SPP system’s transmission needs identified in the MISO Study are consistent with the analysis performed in the 2015 ITP10.

While both seams assessments were separate studies from the 2015 ITP10, their performance during the 2015 ITP10 encouraged a more focused analysis on the ITP10’s seams region through additional updated modeling information, better coordination and exchange of assumptions and data, and an expanded list of proposed transmission solutions.

Solution Evaluation

Evaluating seams transmission solutions includes an additional variable not present when evaluating an SPP regional transmission solution: seams cost sharing. This variable was considered a hurdle for the seams-project planning process in previous ITP assessments; a seams project would provide benefits to regions outside SPP, but SPP’s ITP solution development and evaluation process would assume its stakeholders would pay all costs in the SPP region. The 2015 ITP10 addressed this with a more focused evaluation of potential seams projects earlier in the planning process, and by identifying a seams project’s cost-sharing levels in order to be the most cost-effective solution.

SPP staff identified projects that could potentially benefit one or more of SPP’s neighbors during project screening. The projects with significant potential benefit to SPP and a seams neighbor were then evaluated to determine which cost-sharing level was more cost-effective than SPP’s other regional solutions. After compiling this information, SPP approached the applicable seams neighbor and began working with that neighbor to further evaluate the project to determine its benefits to that neighbor.

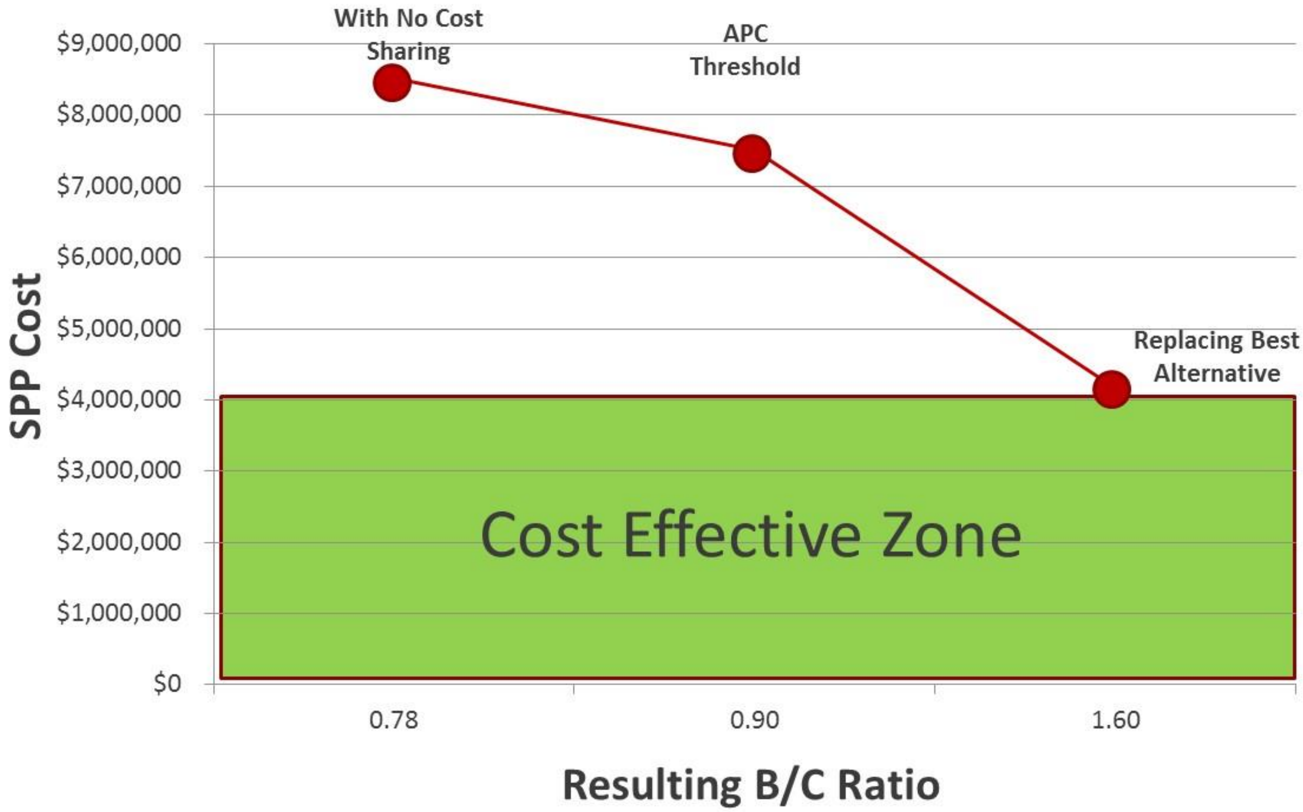


Figure 7.1: Cost Sharing Example

Figure 7.1 above illustrates a generic project that, if SPP approved without a seams partner, would result in an APC B/C ratio of 0.78 which is below the 0.9 B/C ratio threshold used in the ITP10. In order to meet the 0.9 threshold SPP's portion of the costs would have to be reduced by approximately $1 million. This means a seams partner would have to agree to cost share the project and pay at least 12% of the project cost. In this generic example with the 12% cost sharing, the project would meet the 2015 ITP10 APC threshold. However, it would not be the preferred solution as a regional project provides SPP a B/C ratio just under 1.6. In order for this generic example project to be the preferred solution, it must be more cost effective than the regional solution. For this particular example, SPP's portion of the cost could only be $4 million for the B/C ratio to surpass the SPP regional solution. The seams partner would need to agree to pay at least 53% of the total project cost. If there is a cost-sharing agreement where the seams partner agrees to pay 53% of the project, then that project would be considered the preferred solution in the 2015 ITP10.

The analysis described above was performed on 17 projects which appeared to provide significant benefits to SPP and an SPP neighbor. AECI expressed interest in several of the projects evaluated therefore, those projects were evaluated further with AECI to identify the specific value provided to AECI, the project feasibility, and total cost-effectiveness. The evaluation of all potential seams projects indicated no seams projects were both viable and more cost-effective than a regional alternative.

Projects that were shown to potentially benefit MISO will be evaluated in the MISO Study.

PART II: STUDY FINDINGS

Section 8:Benchmarking

Numerous benchmarks were conducted to ensure the accuracy of the data, including:

1. A model, developed in parallel to the study model that reflected transmission and generation in-service as of 2013
2. A comparison of simulation results from the 2013 model with historical statistics and measurements from SPP Operations, SPP Market Monitoring (MMU), and the U.S. Energy Information Administration (EIA).

8.1: Benchmarking Setup

It was important to create a representation of the system that matches actual operations in 2013 as closely as possible. This depiction of the system also had to keep a lineation with the study model, to ensure confidence in the final results.

SPP benchmarked simulation data against historical data provided by SPP Operations and SPP MMU. Area LIPs (Locational Imbalance Price), interchange values, and generation outages were among the data points provided by these departments. It was unreasonable to expect that the simulation results for the benchmarking model would perfectly match historical operations for the following reasons:

1. In addition to outage-triggering events, such as storms, PROMOD is not able to simulate the market as it was in 2013, and
2. PROMOD replicates the operations of a day-ahead market using a consolidated balancing authority, whereas the market in operation in 2013 was the SPP Energy Imbalance Service (EIS) with 16 separate balancing authorities.

SPP focused more on the shape of price curves, rather than the magnitude of the values. Also, capacity factors by generation type were benchmarked, rather than the magnitude of the generation.

8.2: Generator Operations

Capacity Factor by Unit Type

Comparing capacity factors enables measuring the similarity in planning simulations and historical operations. This benchmark provides a quality control check of differences in modeled outages and assumptions regarding renewable, intermittent resources.

When compared with capacity factors reported to the EIA in 2013, most of the capacity factors fell near the expected values. The availability of the EIA generation data was limited, as November data was the latest data posted on their website. However, the same time frame was used from the PROMOD simulations (7295 hours as opposed to 8760).

Unit Type	2013 EIA Capacity Factor	PROMOD Capacity Factor
Nuclear	76.3%	93.3%
Combined Cycle	36.6%	30.1%
CT Gas	4.1%	6.1%
Coal	69.6%	74.8%
ST Gas	16.4%	7.2%

Generator Maintenance Outages

Generator maintenance outages in the simulations were compared with historical data provided by SPP Operations. These outages have a direct impact on flowgate congestion, system flows, and the economics of following load levels. The curves from the historical data and the PROMOD simulations complemented each other very well in shape and in magnitude.

Operating & Spinning Reserve Adequacy

Operational reserve is an important reliability requirement that is modeled to account for capacity that might be needed in the event of a unit failure. Per SPP Criteria, operating reserves must meet a capacity requirement equal to the largest unit in SPP + 50% of the next largest unit in SPP; at least half of this requirement must be fulfilled by spinning reserve. Figure 8.1shows both parts of this requirement were met and exceeded. The spinning reserve capacity requirement was 826 MW and the total operating reserve capacity requirement was 1,652.5 MW.

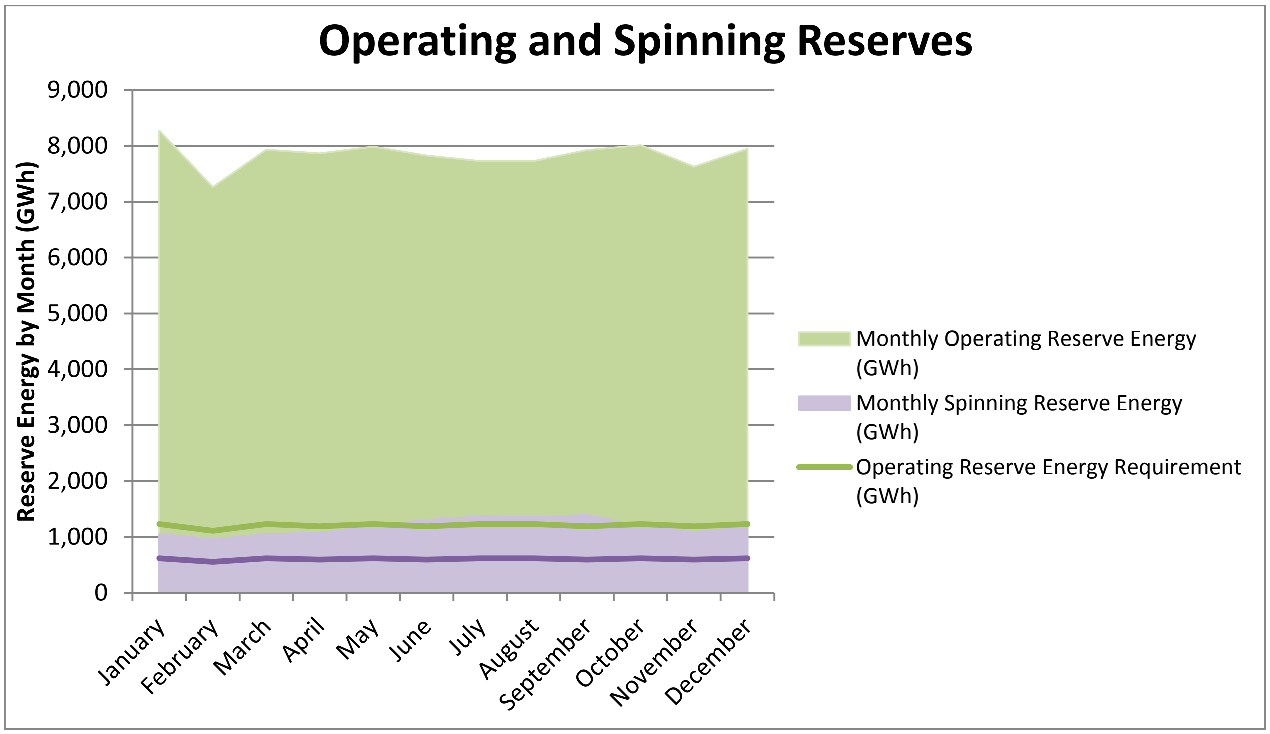


Figure 8.1: Reserve Energy Adequacy

8.3: System LMPs

Simulated locational marginal prices (LMPs) were benchmarked against historical LIPs from the SPP Market Monitoring Unit. This data was compared on an average monthly basis by area. Figure 8.2 shows the results of the benchmarking model for the SPP system and the difference in the two curves. Spikes in the summer months were investigated by looking into congestion and other likely drivers. The questionable values were ultimately attributed to the higher volatility of the LMPs in the Integrated Marketplace compared to the LIPs of the EIS market.

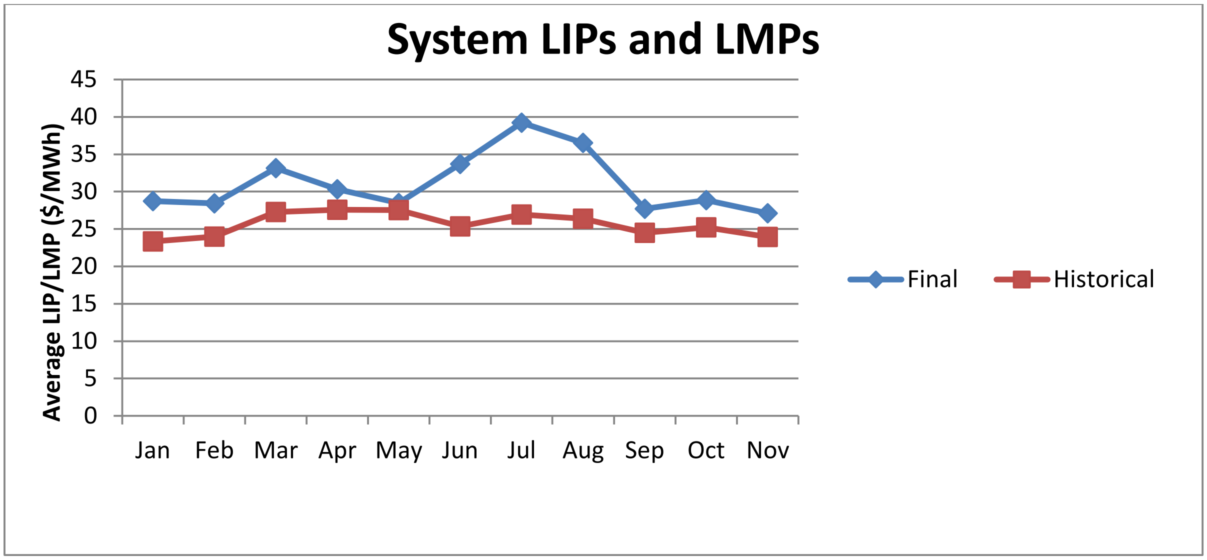


Figure 8.2: *LIP/LMP Benchmarking Results*

8.4: Hurdle Rates

Including hurdle rates between two regions is a modeling technique used to reflect market inefficiencies, such as buying energy from outside one's footprint over utilizing native generation. One goal for this ITP study was to refine hurdle rates between SPP and external regions used in the past. ITP studies have historically used an $8/MWh commitment hurdle rate and a $5/MWh dispatch rate for all interfaces to and from SPP.

With recent enhancements to the PROMOD software, defining and testing custom hurdle rates became a feasible option and was implemented in the 2015 ITP10. In order to determine these new hurdle rates, historical tieline flows from SPP Operations were first aggregated to total interchange between SPP and each of the Tier 1 pools: MISO, the Mid-Continent Area Power Pool (MAPP), and the Southeast Electric Reliability Council (SERC). These interchange totals were compared to flows monitored in the PROMOD simulations. Both sets of values were sorted to easily see the differences and similarities in the magnitude of flows and number of hours SPP is exporting to and importing from each region. Hurdle rates were adjusted to and from each region until reasonably comparable results were achieved. Figure 8.3 shows this sorted interchange data from SPP Operations and from the final benchmarking simulation results that implemented the ESWG-approved hurdle rates. Hurdle rates between external regions, outside of the SPP-Tier 1 interfaces described previously, were set to values applied in the 2012 MISO Transmission Expansion Plan (MTEP12) study.

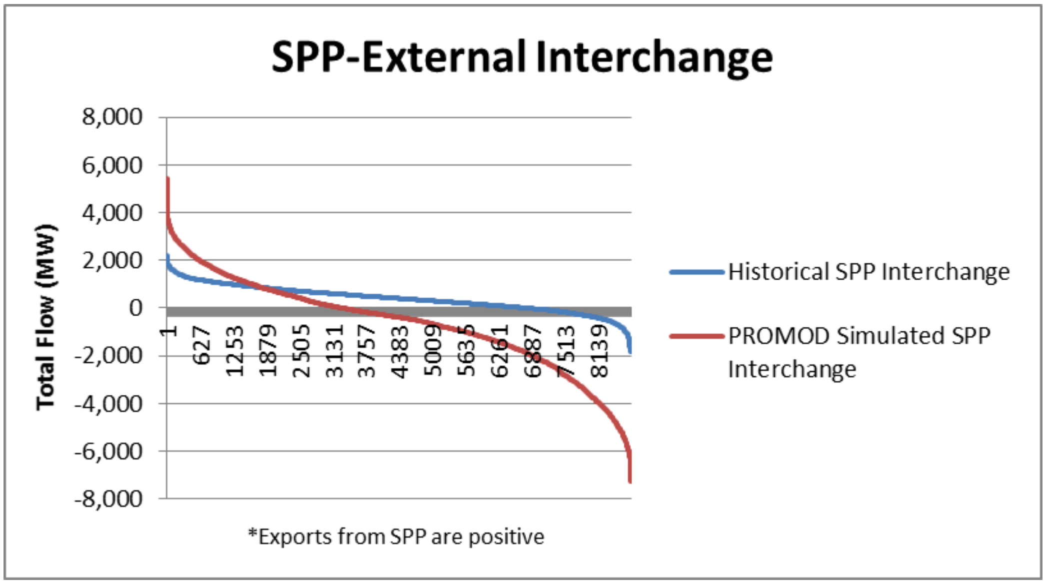


Figure 8.3: Interchange data comparison

		To			
		SPP	MISO	MAPP	SERC
From	SPP	*	10/2.5	10/5	10/1.5
	MISO	10/10	*	10/5.5	10/7.4
	MAPP	10/10	10/6.3	*	*
	SERC	10/10	10/8.3	*	*

Table 8.1: ESWG-Approved Hurdle Rates

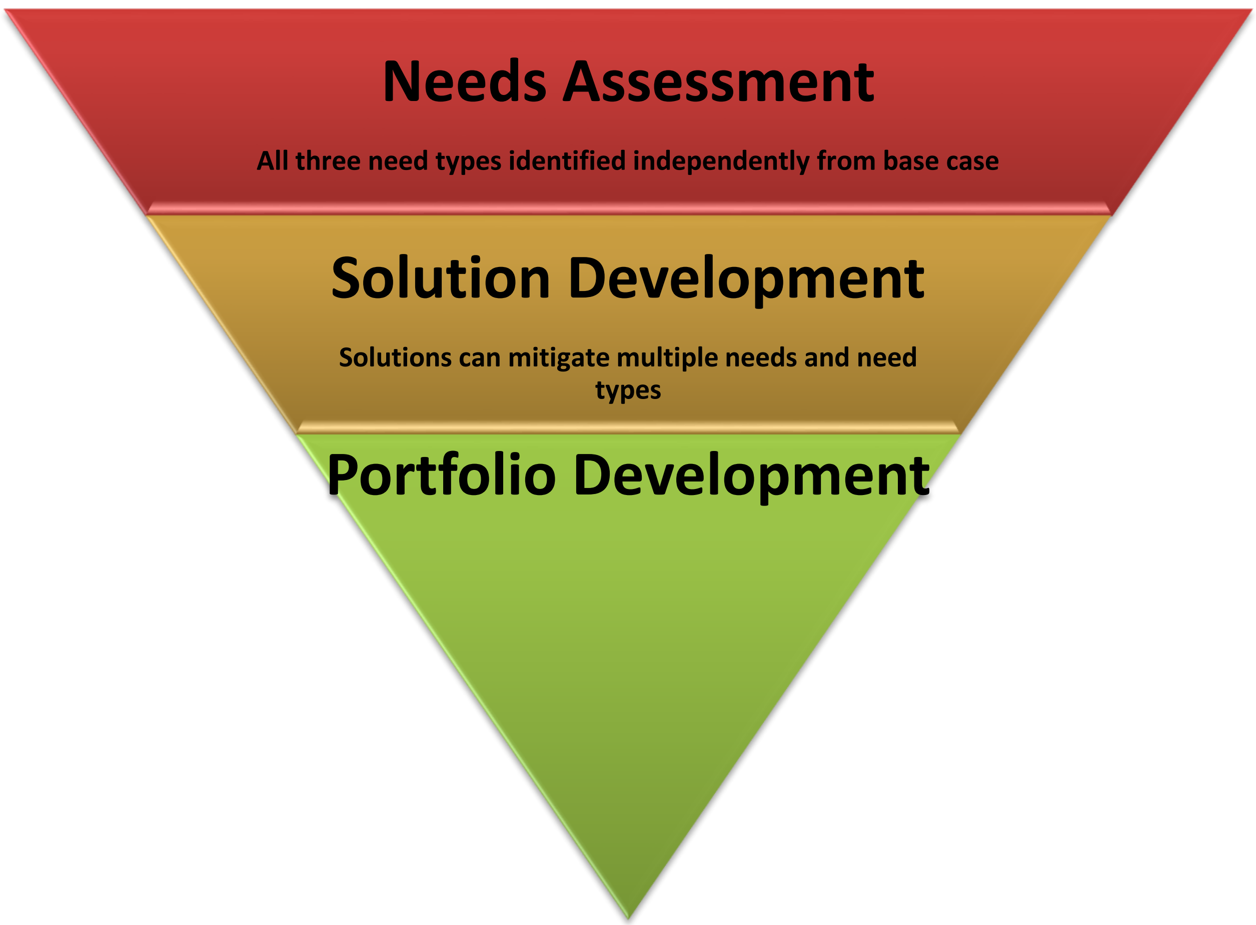
Values displayed are in $/MWh and are reflective of commitment/dispatch hurdle rates

Part III: Needs & Project Solutions

Section 9: Overview

9.1: Transmission Needs and Solution Development

The 2015 ITP10 transmission planning analysis considered three separate types of needs and upgrades: reliability, policy, and economic. Reliability, policy, and economic needs were identified independent of each other. Solutions were then developed for each need and analyzed individually against the base case. Throughout solution development, projects mitigating multiple needs and/or need types were included to develop an efficient portfolio. Thus, a single project could mitigate multiple reliability or economic needs or simultaneously mitigate a reliability and economic need. No policy needs were identified in the 2015 ITP10.



A review of the economic model developed for the Regional Cost Allocation Review (RCAR) II discovered an error related to SPP's implementation of seasonal ratings in PROMOD.[22] The simulation allowed flows up to an entire year's winter line ratings for transmission lines with seasonal rating differences. Working with the software vendor, SPP determined the same error was applicable to the 2015 ITP10 simulations, and implemented an event file change to fix the error.

The error was not discovered until after the needs identification and solution development processes, which include the submittal and evaluation of DPPs, were completed. SPP assessed the impacts of the error and developed a process to move forward with the completion of the 2015 ITP10 that would not jeopardize the integrity of the competitive process nor introduce significant time delays.

Comparing the updated models' results with those from the previous version, Staff identified 1) common needs (those identified in both the original and updated models), 2) new needs that were identified in the updated models, but didn't appear in the previous models, and 3) old needs that were identified in the original models, but no longer appear in the updated models. See the figures below for an illustration.

The plan recommended by SPP was to continue forward with the final portfolios, as determined by the original analysis, for each future and utilize those selected projects to address needs common to both assessments. Projects that did not address common needs were removed from the portfolios. New needs from the updated assessment would be re-evaluated and addressed in upcoming ITP cycles. SPP's recommended plan was approved by the TWG and ESWG on October 29, 2014. As a result, the needs and solutions in the following sections represent that set common to both the original and updated assessments.

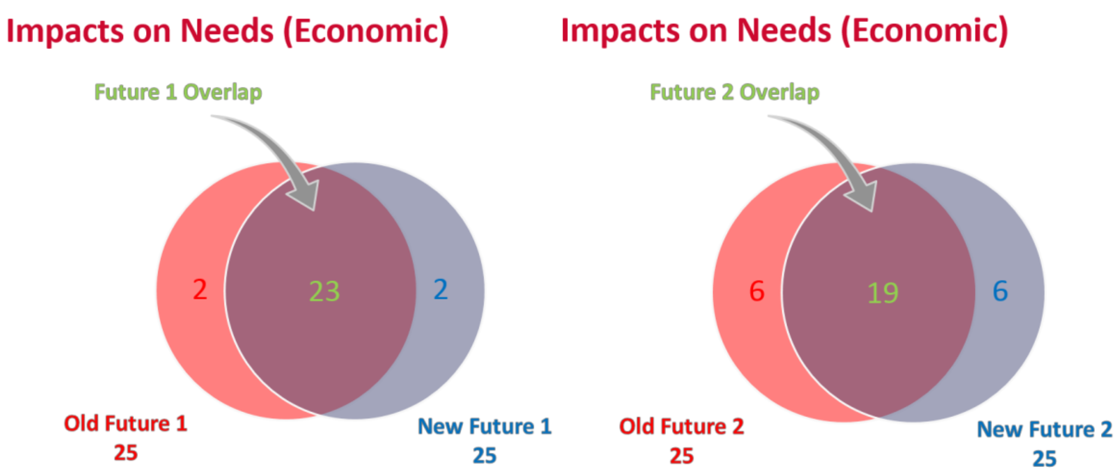


Figure 9.1: Comparison of economic needs between models

[22] The RCAR II process is being conducted in parallel with the 2015 ITP10 and used many of the ITP10 models as a starting point for analysis.

Section 10:Reliability Needs and Solutions

10.1: Background

The 2015 ITP10 reliability needs assessment was performed in parallel with the economic and policy needs assessments. All needs were identified using four distinct models. Potential reliability projects including those from SPP Staff, DPPs, and Order 890 submittals, were tested individually in the base model. A reliability project was selected if it addressed either a single reliability need at the least cost or the most reliability needs at the least cost.

10.2: Reliability Needs

Reliability powerflow models were derived from the economic models through a DC to AC conversion. PROMOD dispatch and load profiles were built in to the powerflow models, which then were used in an AC Contingency Calculation (ACCC) analysis.

These powerflow models identified reliability needs based on analysis of four hours representing situations where the transmission system was uniquely stressed. The four hours considered include two different futures, with Future 1 representing Business as Usual[23] and Future 2 representing a Decreased Base Load Capacity.[24] An N-1 contingency scan outaged 69 kV branches and above in the SPP RTO and Tier 1 footprints. Facilities 69 kV and above were monitored to identify needs in the SPP RTO and Tier 1 footprints. Potential violations, in accordance with the SPP Criteria or SPP member criteria, if more restrictive, were identified in each of these hours during the N-1 contingency scans, and labeled as reliability needs. The voltage level for potential violations could be 69 kV, but projects that addressed these potential violations were no lower than 100 kV.

Once the initial list of reliability needs was identified, only valid and applicable SPP Tariff Transmission facilities were considered.

Hours used to determine reliability needs were:

- **Summer peak hour -** represents the highest coincident load during summer months
- **Light Load hour -** represents the highest ratio of wind generation to coincident load (i.e., low load and high wind), based on a market dispatch

[23] This future included all statutory/regulatory renewable mandates and goals and other energy or capacity as identified in the policy survey, load growth projected by load serving entities through the MDWG model development process, and the impacts of existing regulations. This future assumed no major changes to policies currently in place.

[24] This future considered factors that could drive a reduction in existing generation. It included all assumptions from the Business as Usual future with a decrease in existing base load generation capacity. This future generally retired coal units less than 200 MW, reduced hydro capacity 20% across the board, and utilized the Palmer Drought Severity Index for an average of August 1934 and August 2012 to simulate a reduction in existing capacity affected by drought conditions: 10% under moderate, 15% under severe, and 20% under extreme. These target reductions may have been adjusted based on locational and operational characteristics within each zone.

HOUR NAME	HOUR SIMULATED
Future 1 Summer Peak	July 19, 2024 17:00
Future 1 Light Load	April 6, 2024 04:00
Future 2 Summer Peak	July 19, 2024 17:00
Future 2 Light Load	April 6, 2024 04:00

Table 10.1: Future hours analyzed for Reliability needs

The types of reliability needs identified in the 2015 ITP10 consist of thermal overload and under-voltage needs. Any valid thermal overload greater than 100%, voltage violation under 0.95 per unit for system intact conditions, or under 0.90 per unit[25] for contingency conditions were included as reliability needs. More restrictive needs based upon SPP Member criteria were considered non-competitive needs and therefore were not included in the final needs list, but were provided to the appropriate SPP Member for solution development. Needs identified for non-SPP Transmission Facilities near the Tier-1 seams were separated from the final needs list to allow for possible joint analysis to be performed and for possible seams project development. With the notification from Ventyx about a PROMOD line ratings software issue, SPP compared two resulting sets of needs, one set using winter ratings for the entire year, and the other set using both winter and summer ratings. This comparison produced a common set of needs and new needs. Common needs are unique needs that were found in both the analysis using winter line ratings year-around, as well as the analysis using both winter and summer line ratings, as appropriate. New needs are those identified only in the revised assessment using appropriate summer and winter line ratings and will be analyzed in future ITP studies as was approved by the TWG and ESWG.

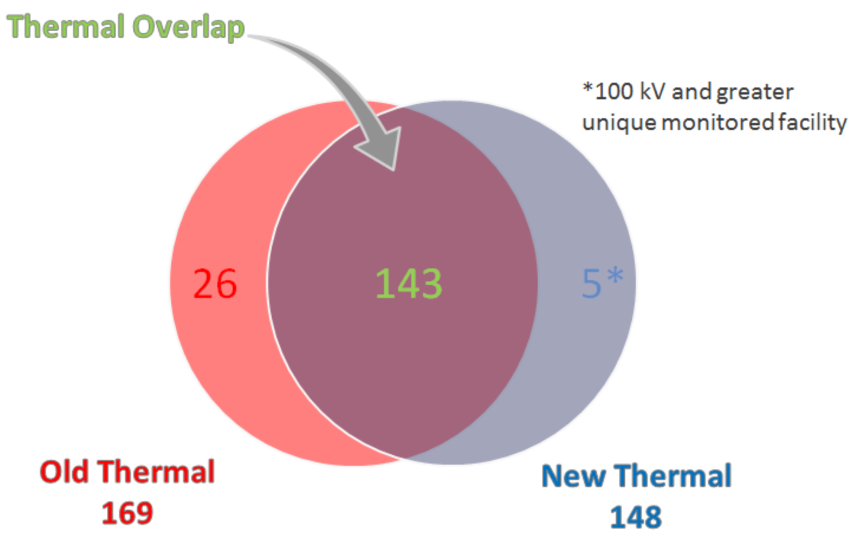


Figure 10.1: Unique Common Thermal Overload Comparison between models

[25] This per unit value is the SPP Criteria voltage per unit threshold for classifying voltage violations under contingency conditions. Voltage violations derived from member submitted criteria that was more restrictive than the SPP Criteria was used in place of the SPP Criteria for needs identification.

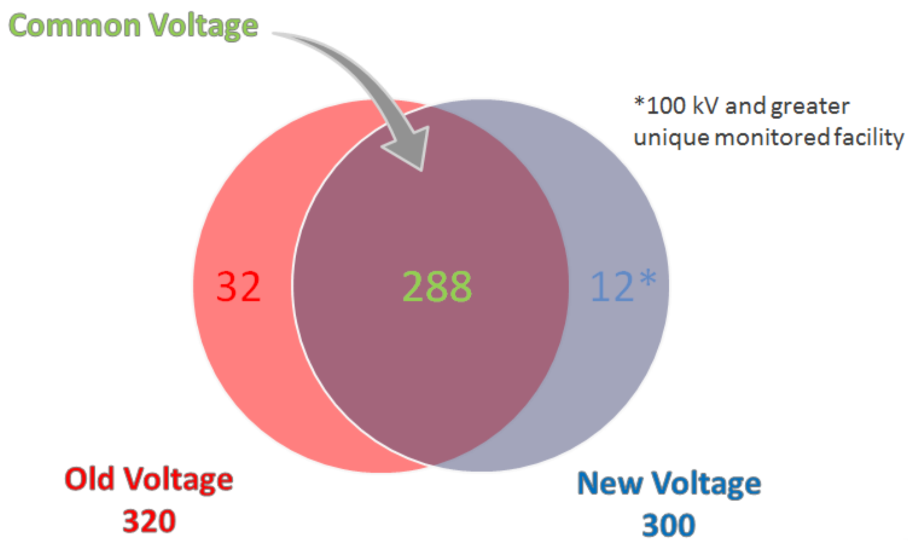


Figure 10.2: Unique Common Voltage Comparison between models

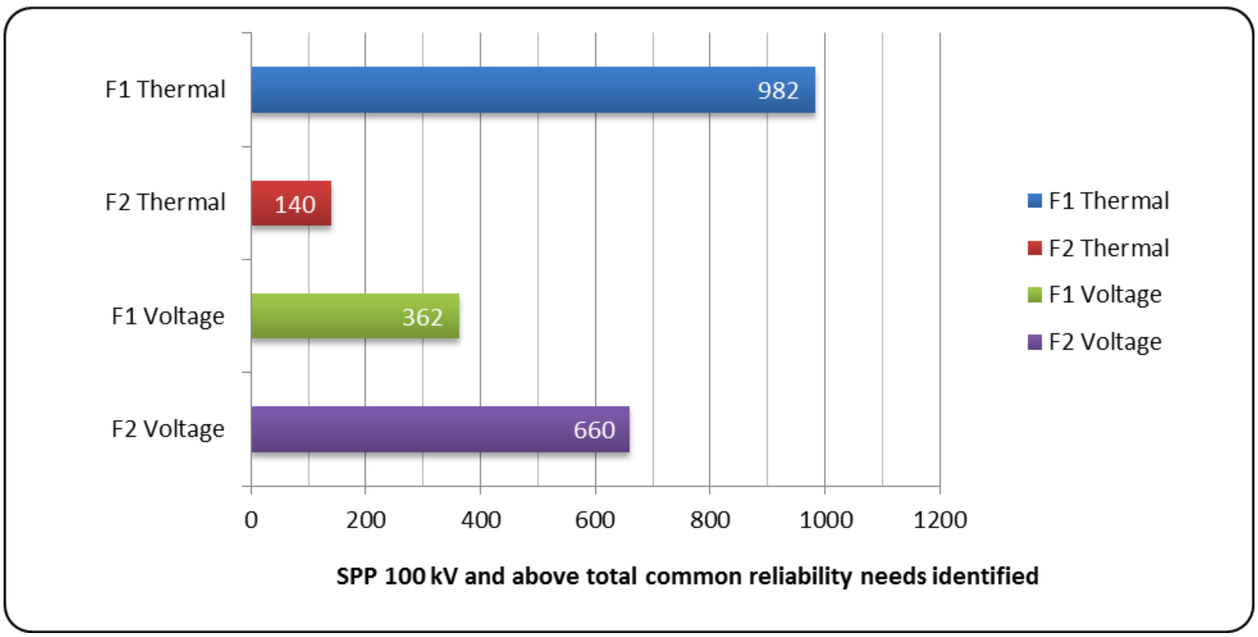


Figure 10.3: Thermal Overload and Voltage Needs Summary by Future

10.3: Project Processing Methodology

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 was opened on May 20, 2014 with the public posting of the final 2015 ITP10 needs list. During this time any stakeholder had the opportunity to provide one or more Detailed Project Proposals (DPPs).

Stakeholders submitted 1,179 DPPs and 56 FERC Order 890 projects. In addition to the DPPs and FERC Order 890 projects, 157 SPP staff solutions were considered to address reliability needs. All together 1,392 projects were evaluated.

In order to efficiently evaluate the high volume of submitted and Staff developed 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.

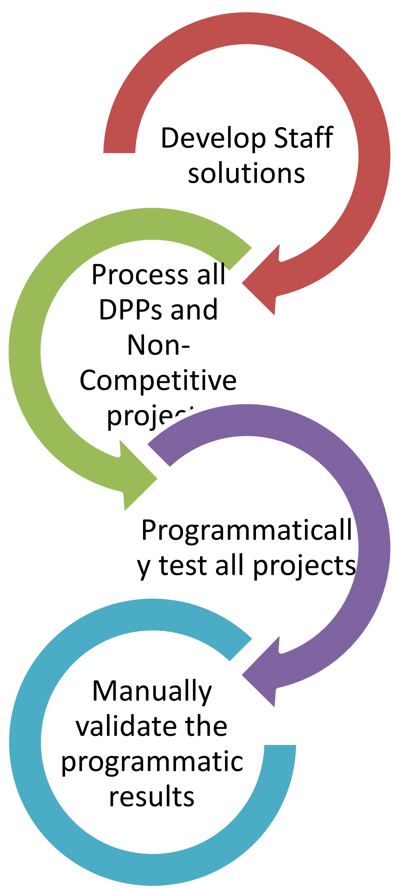


Figure 10.4: Project processing overview

10.4: Project Selection Methodology

SPP staff developed a standardized conceptual cost template for assigning project costs to all proposed projects. Once all projects were assigned a cost, each project was compared against all other projects using a least cost metric as well as a separate comparison using a least cost per need metric. In order to perform a comparison of the large 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. This subset was generated by testing all 1,235 submitted projects and staff solutions to determine which combination of projects addressed all reliability needs at the lowest cost. If two projects solved the same reliability needs, the one that was more cost effective, was selected to move on to the project grouping phase.

In addition, individual projects were combined into a single project and re-evaluated in the project selection process. This process checked whether all reliability needs of the individual projects were met if the combined project was selected as the least cost solution.

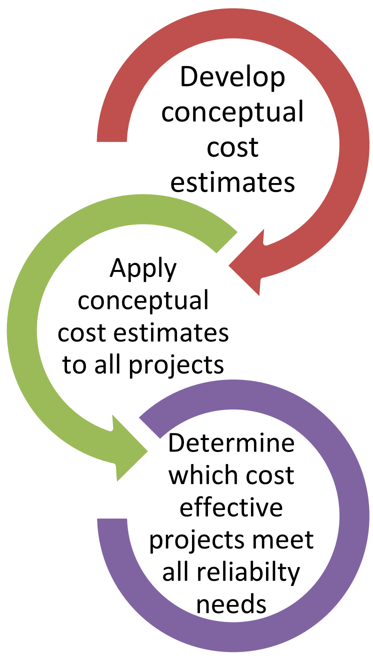


Figure 10.5: Project Selection overview

10.5: Reliability Groupings

For the Consolidated Portfolio, the following criteria, as listed in the approved 2015 ITP10 scope allows for grouping of Reliability projects from Future 1 and Future 2:

Reliability projects will be included in the consolidated portfolio if they mitigate a thermal/voltage violation in Future 1. A Future 2 reliability project will be included if it mitigates a thermal violation in Future 2 and mitigates loading above a 90% threshold in Future 1. A Future 2 project that mitigates a voltage limit violation in Future 2 and voltage below 0.92 pu in Future 1will also be included in the consolidated portfolio.

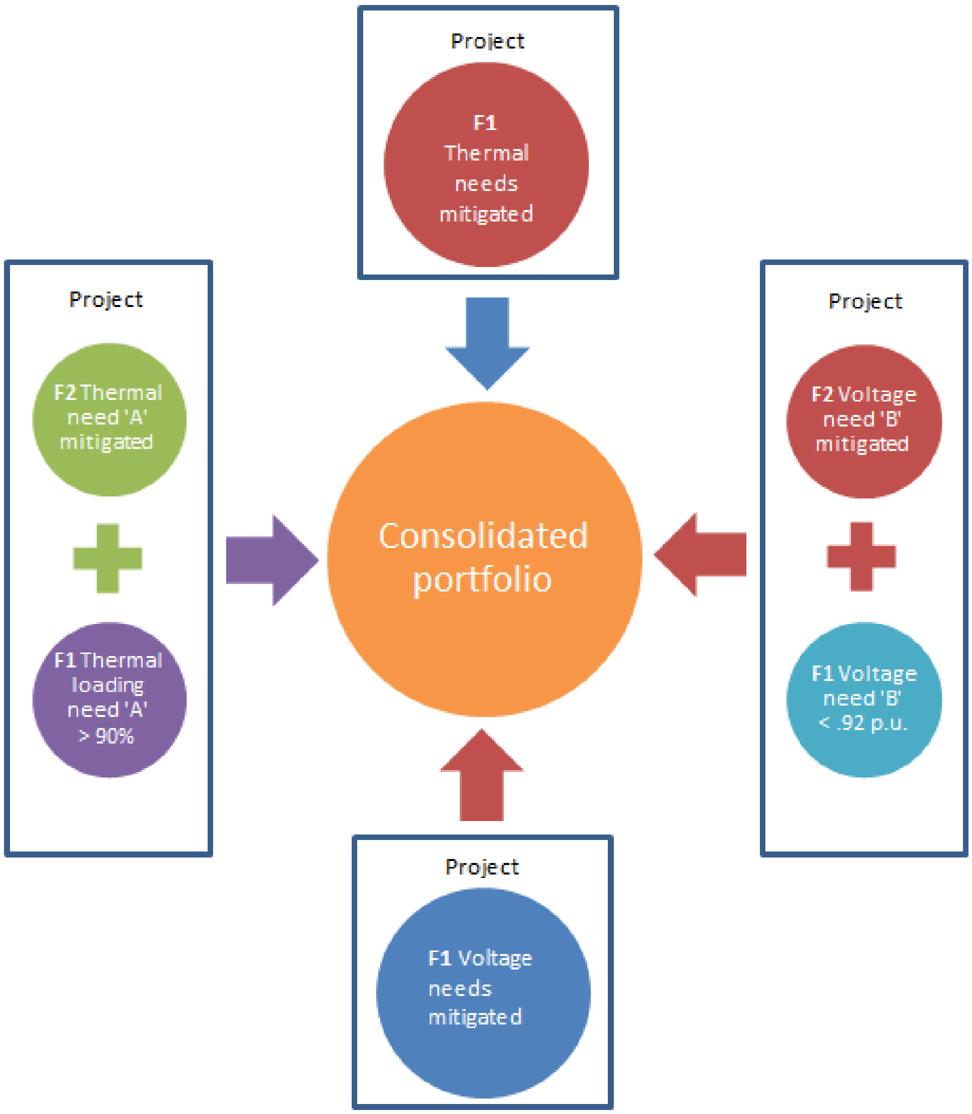


Figure 10.6: Reliability project consolidation methodology

The Consolidated portfolio mix is made up reliability and reliability and economic projects. This table does not include projects that solve economic only needs.

NUMBER OF PROJECTS	FUTURE	RELIABILITY	RELIABILITY & ECONOMIC
5	1	x	
1	1		x
5	2	x	
1	2		x
19	1 & 2	x	

Table 10.2: Reliability project consolidation methodology

All projects that comprise the consolidated portfolio were evaluated for a refined (+/- 30%) cost estimate for each individual project. If a project consisted of multiple upgrades, each upgrade was assigned a specific cost.

10.6: Reliability Solutions

Project solutions were developed by stakeholders and SPP staff. 100 kV and above projects were considered as solutions for reliability needs. All solutions were considered for all reliability needs, and engineering judgment was used to determine the solution that provided the best reliability for the least cost for the region.

Section 11:Policy Needs and Solutions

11.1: Methodology

Policy needs were analyzed based on the curtailment of renewable energy that has been installed to meet a Renewable Energy Standard (RES) mandate or goal. Each entity with a renewable mandate or goal was analyzed for renewable curtailments to determine if they met their mandate or goal. Policy needs are the result of an inability to dispatch renewable generation due to congestion. Any entity not meeting its renewable mandate or goal due to such congestion was identified as having a policy need.

Renewable mandates and goals by entity were determined based on the 2015 Policy Survey. A 3% margin was used in determining the thresholds by entity. This means that if an entity had annual renewable energy generation of at least 97% of their Policy Survey mandate or goal, they were determined to be meeting their renewable requirements, and were not identified as having a policy need.[26] Some mandates and goals were based on installed capacity requirements only. These mandates/goals were not analyzed for curtailment, and were not used to identify policy needs.

Policy projects are developed for any policy needs in order to reduce curtailments such that all entities will meet their renewable mandates or goals.

11.2: Policy Needs and Solutions

The policy needs assessment showed the following wind farms experiencing > 3% annual curtailment:

Wind Farm	Owner & State	Future	Annual Curtailment (GWh)	Annual Curtailment %
Gray County	GMO, MO	F1	29.3	5.64%
Gray County	GMO, MO	F2	29.3	5.64%
New Mexico #4	SPS, NM	F2	76.9	6.91%

Table 11.1: Wind Farm Curtailment

In spite of these curtailments, all entities met their overall renewable mandates and goals. **Therefore, there were no policy needs and no policy projects identified in either future.[27]**

[26] This represents a change from previous ITP studies in which shortfalls in renewable energy output were evaluated on an individual resource-by-resource basis, in order to identify policy requirements.

[27] Note that these curtailments did impact the economic needs, and the development of economic projects addressed the APC benefit of relieving any wind curtailments.

Section 12: Economic Needs and Solutions

12.1: Background

The 2015 ITP10 economic needs assessment was performed in parallel with the reliability and policy needs assessments. All needs were identified using a single base model. Potential economic projects from SPP Staff, DPPs, Order 890 submittals, and previous SPP planning studies were tested individually in this base model. An economic project is justified when its economic benefits to SPP stakeholders are projected to be greater than the project cost over the expected life of the asset. The criterion approved by the ESWG for use in the 2015 ITP10 requires an economic project to have a minimum 1-year B/C ratio of 0.9 or greater. This B/C target was selected because the benefit is expected to increase over a project's assumed 40-year lifespan. Benefits were measured as the difference in the APC, with and without the potential economic project.

12.2: Economic Needs

To assess economic needs, a SCUC/SCED were performed for the full study year, based on the transmission constraints defined for the system. The SCED derived nodal LMPs by dispatching generation economically. LMPs reflect the congestion occurring on the transmission system's binding constraints. The simulation's results revealed which constraints caused the most congestion and the additional cost of dispatching around those constraints. The following process was used to rank each future's economic needs:

1. Binding constraints were ranked from highest to lowest congestion score. Congestion score is defined as the product of the constraint's average shadow price and the number of hours the constraint is binding in 2024.

2. The 25 highest congestion score constraints[28] in the SPP system were identified as the system's economic needs.
3. Potential economic project solutions were developed based on this list of 25 constraints.

[28] This specific criteria was identified in the study scope, prior to analysis of economic needs. The top 25 binding constraints were chosen to be targeted to better understand what parts of the system would be best suited for the testing and development of economic projects. Parts of the system with minimal congestion are less likely to have project solutions with B/C ratios greater than 0.9.

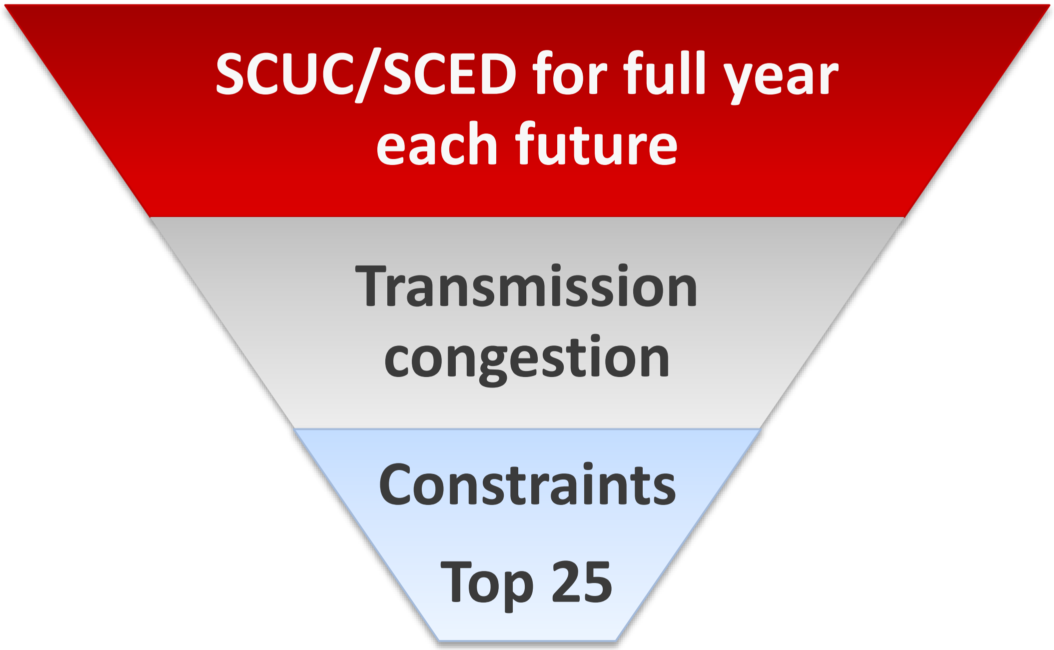


Figure 12.1: Developing Economic Needs

If generation sited from the resource plan was connected to a transformer or branch that caused enough congestion at the facility to make it a Top 25 constraint, then that economic need was ignored because the generator's placement at a different bus in the system could mitigate the need.

The Top 25 constraints were identified without including any of the model's reliability or policy projects. Therefore, some of the Top 25 (shown in the Study Drivers Section) economic needs that arose could have already been addressed through reliability or policy projects.

12.3: Economic Solutions

Economic projects were proposed based on stakeholder recommendations and the projects' potential to mitigate the Top 25 constraints' congestion. Economic SPP Staff solutions, DPPs, Order 890 submittals, and projects previously evaluated in SPP planning studies were evaluated based on a multi-phase process vetted through the ESWG.

The APC for each economic project in the SPP footprint was calculated with and without the proposed economic project for all 8,784 hours of 2024. The change in APC with the project in-service was considered the one-year benefit. The one-year benefit was divided by the one-year conceptual cost of the project to develop a B/C ratio for each project. The one-year cost, or the annual transmission revenue requirement (ATRR), used for analysis is a historical average net plant carrying charge (NPCC) multiplied by the total project cost. For this study the NPPC used was 17%.

In addition to projects targeting the Top 25 constraints, all EHV projects targeting reliability needs were also analyzed for their economic benefit. The 2015 ITP10 did not identify policy needs, so no projects targeting a policy need were tested for economic benefit.

All potential 2015 ITP10 economic solutions were evaluated through a number of phases described below. The ESWG approved different cost-sharing assumptions for any projects identified as potential seams projects. It was assumed SPP will bear 80% of the total project cost for those projects; all other B/C ratio criteria remained the same.

Pre-Phase 1
This phase filtered projects prior to PROMOD testing. Before Phase 1, individual projects went through an initial screening to test for reasonableness. The potential annual APC benefit was calculated for each of the economic *needs* by removing each constraint or group of constraints and rerunning the simulation. Based on this calculation, economic projects moved on to Phase 1 for further testing if 75% of the potential APC benefit compared with the estimated 1-year conceptual cost of a project targeting a particular constraint or group of constraints resulting in a 0.5 1-year B/C ratio or greater.

Due to the complexities of the constraints' interactions and the projects developed to mitigate those constraints' congestion all projects targeting economic needs in the 2015 ITP10 were moved on to be evaluated in Phase 1.

Phase 1
Phase 1 considered an individual project's performance in the base case. Projects moved on to Phase 2 for further testing if they provided a 1-year B/C ratio of 0.75 or greater by reducing congestion.

Phase 2
A project's performance, in concert with other potential projects, was considered in Phase 2. Reliability and economic projects were combined into project groupings for each future and evaluated for redundancies. SPP first evaluated a group of projects meeting all reliability needs as a portfolio to determine any potential overlap with economic solutions by measuring system congestion relieved by the portfolio. After the reliability projects were evaluated as a group, SPP developed groupings for economic projects, considering potential redundancies with other project types.

Project groupings were developed based on the projects' performance in Phase 1. Projects for each grouping were selected by ranking the top projects for each need. Rankings were determined by their individual performance under the criteria for each grouping. A project must have provided a reasonable amount of congestion relief to be considered in the ranking for a particular need or set of needs. This relief was based on the mitigation percentage of flowgate congestion cost and was determined on a per flowgate basis for the set of projects being evaluated. For most flowgates, the determined threshold was no less than 60%-70%, some higher. A project selected for a particular need may also provide a certain amount of congestion relief for another need or set of needs. This overlap was evaluated, to determine the most appropriate project(s) for the needs met, on a case by case basis. Typically, if one project met multiple needs and was comparable in cost and performance to multiple projects meeting multiple needs, the single project solution was selected. Not all economic needs had a project selected. Four groupings were considered per future:

- Cost-Effective: This group included projects that met the study need in the most cost-effective way. If one project mitigated multiple needs, the project's cost was compared to that of one or more projects mitigating that same group of needs.
- Highest Gross APC Benefit: This grouping consisted of the projects that met the needs with the highest gross APC benefit. This grouping did not consider the projects' costs.
- Highest Net APC Benefit: This group included the projects that met the needs of each future with the highest net APC benefit. Each project's cost was subtracted from the APC benefit provided to determine the project's net APC benefit.
- Multi-Variable Grouping: This optional grouping was proposed to allow SPP to layer multiple criteria in forming additional groups for testing. The experience gained from analyzing projects

for the first three groups was to be used to determine projects included in this grouping. This grouping was not developed.

The above groupings were developed by testing individual project performance, and choosing projects meeting each of the grouping criteria. These chosen projects were then tested together to determine their performance as a group. Ultimately, the grouping with the highest net APC benefit for each future moved on for further analysis.

Projects in the selected grouping were tested individually against the Phase 2 B/C criteria, 1-year B/C of 0.9 or greater. This was done by creating a portfolio of reliability, policy, and economic projects as a reference, and removing each economic project one by one to determine the benefit of the project as a part of the full portfolio. If any project did not meet the threshold, it was removed from the portfolio. Potential replacement projects were evaluated from the pool of ranked projects, if the selected project did not meet the phase 2 criteria. The next highest ranked project was chosen for evaluation. Regardless of whether a viable replacement project was found, each project from the portfolio was retested against the Phase 2 criteria. This analysis continued iteratively until a final portfolio was determined for each future.

Phase 3

Phase 3 consolidated both of the Phase 2 groupings of each future into one final portfolio. Future 1 economic projects with a 1-year B/C ratio greater than 0.9 in Future 1 were included in the consolidated portfolio. Future 2 economic projects with a 1-year B/C ratio greater than 0.9 in Future 2, but that also had a 1-year B/C ratio greater than 0.7 in Future 1, were also included in the consolidated portfolio.

Section 13: Future Portfolios

Reliability, policy, and economic projects for each future were grouped together into portfolios unique to each future. In assessing needs and project solutions, reliability, policy, and economics were analyzed independently of each other. For Example, some reliability projects were also good economic projects, because relieving a single constraint's significant congestion could mitigate a reliability problem and provide significant economic benefit.

13.1: Developing the Portfolios

Reliability and economic project groupings were also developed independently of each other, but assessed for overlap. Reliability projects were incorporated into a cost effective grouping solving reliability needs (as described in Reliability Groupings) for each future. Economic projects addressing economically viable needs were incorporated into multiple groupings for each future and tested incremental to the reliability grouping. Each economic grouping was tested for its net benefit performance, as described in phase 2 of Economic Solutions. Based on this analysis, the economic grouping selected for further analysis in Future 1 was the highest net APC benefit grouping, while the cost effective grouping had the highest net APC in Future 2.

The projects selected for further analysis in each future are listed in Table 13.1 and Table 13.2. With the least cost reliability grouping included as a base, the economic projects were tested individually to determine if they met the Phase 2 B/C criteria.

Project	Area	B/C > 0.9?
New 345/138 kV transformer at Seminole	OKGE	No
New 345/230 kV transformer at Potter County	SWPS	No
New wave trap at Amoco and Sundown, increasing rating on Sundown-Amoco 230 kV line	SWPS	Yes
Voltage conversion of Iatan-Stranger Creek 161 kV line to 345 kV	KCPL, GMO, WRI	Yes
Tap Baker-Litchfield 161 kV line into Asbury	WRI/EDE	No
Upgrade terminal equipment at Summit 115 kV, upgrading ratings on Summit 230/115 kV transformers	WRI	No
Rebuild North Platt-Stockville-Red Willow 115 kV line to 240/240 MVA, new 345/115 kV transformer at Mingo	NPPD/SUNC	Yes
New Trenton-Strandahl 115 kV line	WAPA	No[29]
Rebuild Collins-Stockton-Morgan 161 kV line	AECI	No[30]
Rebuild Duncan-Blue Springs East 161 kV line	GMO	No

Table 13.1: Future 1 Net APC Benefit Economic Grouping

[29] A model correction to Williston - Judson 115 kV line was submitted near the end of the Phase 2 process, increasing the line ratings such that the selected project was no longer economically viable.

[30] A model correction to the Collins – Stockton – Morgan 161 kV lines was submitted near the end of the Phase 2 process, increasing the line ratings such that the selected project was no longer economically viable.

Project	Area	B/C > 0.9?
New 345/138 kV transformer at Seminole	OKGE	Yes
New 230/115 kV transformer at Eddy County	SWPS	Yes
Upgrade 230/115 kV transformer at Carlisle	SWPS	No
Tap Baker-Litchfield 161 kV line into Asbury	EDE	No
Upgrade relays at Sand Springs, increasing ratings on Sand Springs-Prattville 138 kV line	AEPW	Yes
New 2nd Hoyt-Hoyt Junction South 115 kV line	WAPA	No
Reconductor Northeast-Charlotte 161 kV line	KCPL	No
Rebuild S1221-S1255 161 kV line to 554/554 MVA	SWPS	Yes

Table 13.2: Future 2 Cost Effective Economic Grouping

Seven of the projects selected for the final grouping in Future 1 did not produce the benefit needed to remain in the final portfolio for Future 1, leaving just three economic projects. Four of the projects selected for the final grouping in Future 2 did not produce the necessary economic benefit, leaving four projects in the final portfolio for Future 2.

13.2: Project Solutions from Previous ITP Studies

Project solutions from previous ITP studies were reviewed and evaluated for performance in the 2015 ITP10. While the system behavior and a few of the 2015 ITP10 system needs were similar to that of the 2013 ITP20, only a handful of projects selected to address needs in the 2015 ITP10 are similar to the projects selected in the 2013 ITP20. Table 13.3 shows 2015 ITP10 upgrades included in at least one future portfolio for which an equivalent upgrade was included in an approved 2013 ITP20 portfolio.

2015 ITP10 Solution	Future(s)	2013 ITP20 Approved Solution
New 345/161 kV transformer at S3459	F1	New 345/161 kV transformer at S3459
Rebuild North Platte-Stockville-Red Willow 115 kV	F1	New Keystone - Red Willow 345 kV

Table 13.3: 2015 ITP10 Upgrades with Equivalent 2013 ITP20 Approved Solutions

13.3: Future 1 Portfolio

The Future 1 Portfolio contains a mixture of Reliability and Economic Projects. It consists of 27 projects, 235 miles of transmission line, and has a 1-year B/C Ratio of 2.9 (calculated on APC only).

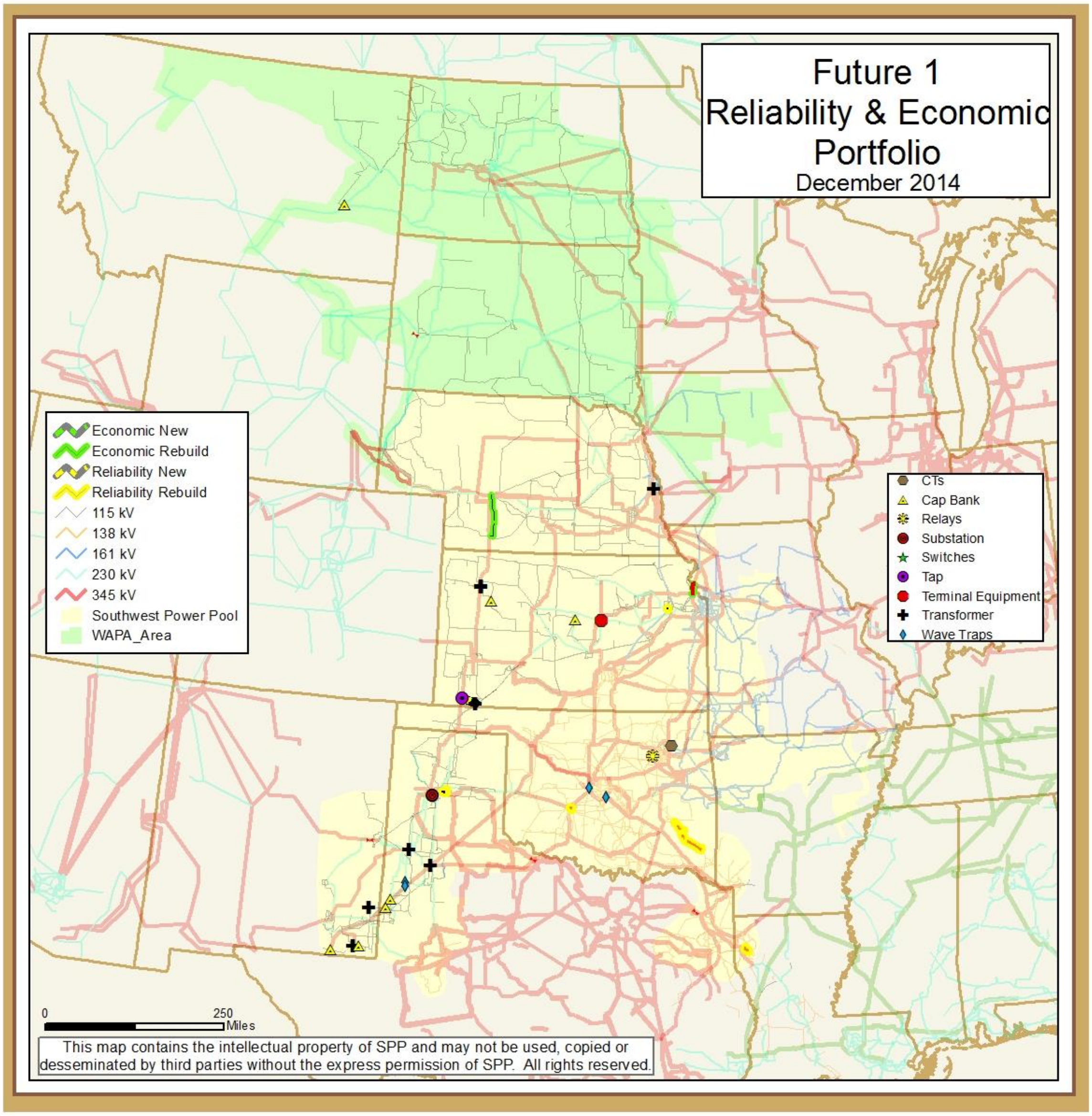


Figure 13.1: Future 1 Portfolio

2015 Dollars	Future 1 Grouping Reliability	Economic	Total
Total Cost	$174.3M	$69.7M	$237.9M
Total Projects	25	3	27
Total Miles	137	94	231
1-Year Cost		$11.9M	
APC Benefit		$35M	
B/C Ratio		3.0*	

1 upgrade in F1 is included in both the economic and reliability portfolios
*B/C includes only APC benefit of economic projects

Table 13.4: Future 1 Portfolio Statistics

Table 13.5 shows details for all Future 1 portfolio projects.

Project	Area	Type	Miles	Cost
Install 14.4 MVAr capacitor bank at Allred 115 kV	SWPS	Reliability	0	$829,881
Install 14.4 MVAr capacitor bank at LE Plains Interchange 115 kV	SWPS	Reliability	0	$829,881
Install 2 stages of 14.4 MVAr capacitor banks on the China Draw 115 kV bus and the North Loving 115 kV bus	SWPS	Reliability	0	$3,319,524
Install 2 stages of 14.4 MVAr capacitor banks on the Ochoa 115 kV bus	SWPS	Reliability	0	$1,659,762
Install 6 MVAr capacitor bank at Grinnell 115 kV	SUNC	Reliability	0	$345,784
Install 6 MVAr capacitor bank at Mile City 115 kV	WAPA	Reliability	0	$345,784
Install 14.4 MVAr capacitor bank at Ellsworth 115 kV bus	SUNC	Reliability	0	$829,881
New 115/69 kV transformer at Lovington	SWPS	Reliability	0	$2,239,599
New 230/115 kV transformer at Plant X	SWPS	Reliability	0	$3,497,095
New 345/115 kV transformer at Road Runner	SWPS	Reliability	0	$5,733,227
New 345/161 kV transformer at S3459	OPPD	Reliability	0	$8,176,238
New wave trap at Amoco and Sundown, increasing rating on Sundown-Amoco 230 kV line	SWPS	Economic	0	$55,641
Rebuild Broken Bow-Lone Oak 138 kV corridor to 286/286 MVA	AEPW	Reliability	76.7	$60,804,427
Rebuild Forbes-Underpass North 115 kV line to 218/262 MVA	WRI	Reliability	3.1	$7,878,364
Rebuild North Platt-Stockville-Red Willow 115 kV line to 240/240 MVA, new 345/115 kV transformer at Mingo	NPPD, SUNC	Economic & Reliability	80	$53,562,098
Reconductor Gracemont-Anadarko 138 kV line to 286/286 MVA	OKGE, WFEC	Reliability	5.28	$4,650,558
Reconductor Highland Park-Pantex South 15 kV line to 240/240 MVA and replace wave trap and switch at Pantex South and Highland Park tap	SWPS	Reliability	7	$3,649,492
Reconductor Martin-Pantex North 115 kV line to 240/240 MVA and replace wave trap at Pantex substation	SWPS	Reliability	5.1	$3,602,175
Reconductor Pantex North-Pantex South 115 kV line to 240/240 MVA	SWPS	Reliability	3	$1,824,746
Rebuild South Shreveport-Wallace Lake 138 kV line to 246/246 MVA	AEPW	Reliability	11	$10,268,933
Replace wave trap at Claremore 161 kV	GRDA	Reliability	0	$88,560
Tap Hitchland-Finney 345 kV line at new substation and install new 345/115 kV transformer, and build new 23 mile 115 kV line from new station to	SUNC	Reliability	23	$36,224,893

Walkemeyer				
Tap Northwest-Bush 115 kV line at new station, and build new 3 miles of 115 kV line to Hastings	SWPS	Reliability	3.1	$7,984,549
Upgrade 230/115 kV transformer at Tuco	SWPS	Reliability	0	$3,127,583
Upgrade relays at Sand Springs, increasing ratings on Sand Springs-Prattville 138 kV line	AEPW	Reliability	0	$176,290
Upgrade wave traps and switches on Cimarron-McClain 345 kV line	OKGE	Reliability	0	$116,838
Voltage conversion of Iatan-Stranger Creek 161 kV line to 345 kV	KCPL, GMO,WRI	Economic	14	$16,119,446
		Total	231.28	$237,941,249

Table 13.5: Future 1 Portfolio Projects

13.4: Future 2 Portfolio

Reliability, policy, and economic projects developed for Future 2 were grouped together into a single Future 2 portfolio. The portfolio features 32 projects, 104 miles of transmission line, and a 1-year B/C ratio of 4.5 (includes APC benefits only).

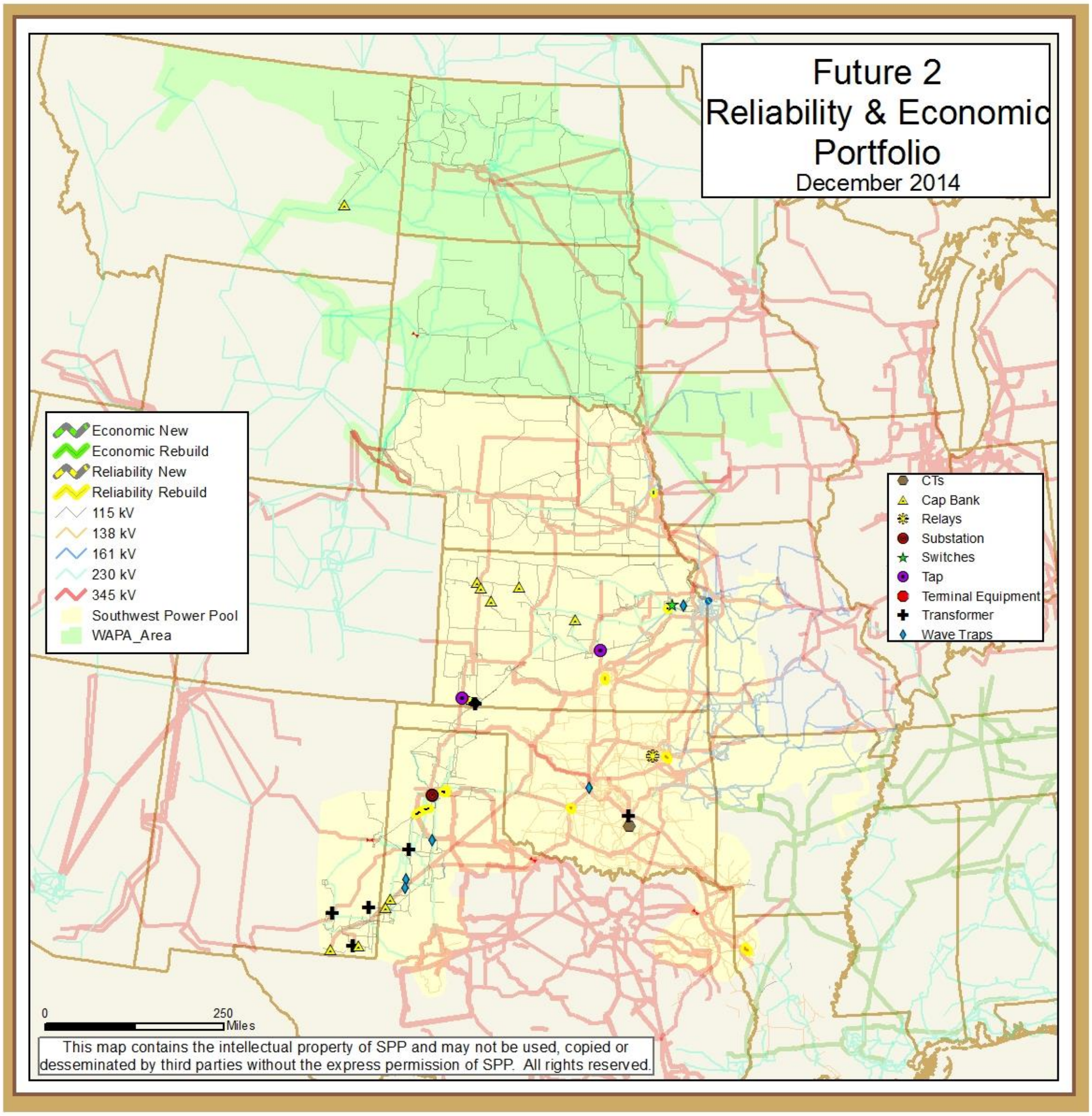


Figure 13.2: Future 2 Portfolio

2015 Dollars	Future 2 Grouping		
	Reliability	Economic	Total
Total Cost	$147.2M	$20.8M	$164.2M
Total Projects	30	4	32
Total Miles	96.9	4.1	96.9
1-Year Cost		$3.5M	
APC Benefit		$15.8M	
B/C Ratio		4.5*	

2 projects in F2 are included in both the economic and reliability portfolios
*B/C includes only APC benefit of economic projects

Table 13.6: Future 2 Portfolio Statistics

Project	Area	Type	Miles	Cost
New 345/115 kV transformer at Road Runner	SWPS	Reliability	0	$5,733,227
Install 2 stages of 14.4 MVAr capacitor banks on the Ochoa 115 kV bus	SWPS	Reliability	0	$1,659,762
Install 2 stages of 14.4 MVAr capacitor banks on the China Draw 115 kV bus and the North Loving 115 kV bus	SWPS	Reliability	0	$3,319,524
New wave trap at Amarillo South, increasing rating on Amarillo South-Swisher 230 kV line	SWPS	Reliability	0	$27,821
Tap Northwest-Bush 115 kV line at Bush Tap, new Bush Tap station, new Bush Tap-Hastings 115 kV line	SWPS	Reliability	3.1	$7,984,549
New wave trap at Amoco and Sundown, increasing rating on Sundown-Amoco 230 kV line	SWPS	Reliability	0	$55,641
New 345/138 kV transformer at Seminole	OKGE	Economic	0	$12,206,436
New 230/115 kV transformer at Eddy County	SWPS	Economic	0	$4,742,668
Upgrade wave traps and switches on Cimarron-McClain 345 kV line	OKGE	Reliability	0	$116,838
Upgrade wave trap and CT on the Park Lane-Seminole 138 kV line	SWPS	Reliability	0	$86,436
Upgrade relays at Sand Springs, increasing ratings on Sand Springs-Prattville 138 kV line	AEPW	Reliability and Economic	0	$176,290
Tap Reno-Wichita 345 kV line into Moundridge, new 345/138 kV transformer at Moundridge	WRI	Reliability	0	$14,722,229
Rebuild Forbes-Underpass North 115 kV line to 218/262 MVA	WRI	Reliability	3.1	$7,878,364
Upgrade terminal equipment at Tecumseh Hill, increasing ratings of 230/115 kV transformer at Tecumseh Hill	WRI	Reliability	0	$162,975
Rebuild S1221-S1255 161 kV line to 554/554 MVA	OPPD	Reliability and Economic	4.1	$3,672,317
Reconductor Gracemont-Anadarko 138 kV line to 286/286 MVA	OKGE, WFEC	Reliability	5.28	$4,650,558
Rebuild Murray Gill East-Interstate 138 kV line to 286/286 MVA	WRI	Reliability	6.3	$6,184,325
Reconductor Martin-Pantex North 115 kV line to 240/240 MVA and replace wave trap at Pantex substation	SWPS	Reliability	5.14	$3,602,175
Reconductor Pantex North-Pantex South 115 kV line to 240/240 MVA	SWPS	Reliability	3.4	$1,824,746

Reconductor Highland Park-Pantex South 15 kV line to 240/240 MVA and replace wave trap and switch at Pantex South and Highland Park tap	SWPS	Reliability	6.8	$3,649,492
Install 14.4 MVAr capacitor bank at LE Plains Interchange 115 kV	SWPS	Reliability	0	$829,881
Install 14.4 MVAr capacitor bank at Allred 115 kV	SWPS	Reliability	0	$829,881
Install 6 MVAr capacitor bank at Grinnell 115 kV	SUNC	Reliability	0	$345,784
Install 6 MVAr capacitor bank at Colby 115 kV, 24 MVAr capacitor bank at Mingo 115 kV, and 9 MVAr capacitor banks at Ross Beach 115 kV	NPPD	Reliability	0	$2,270,657
Rebuild South Shreveport-Wallace Lake 138 kV line to 246/246 MVA	AEPW	Reliability	11.18	$10,268,933
Reconductor Broken Arrow-Lynn Lane East Tap 138 kV line to 286/286 MVA	OKGE	Reliability	7.2	$13,317,210
Install 14.4 MVAr capacitor bank at Ellsworth 115 kV bus	SUNC	Reliability	0	$829,881
Upgrade wave traps and bus at LEC U3 and Midland Junction 115 kV	WRI	Reliability	0	$27,821
Install 6 MVAr capacitor bank at Mile City 115 kV	WAPA	Reliability	0	$345,784
New 115/69 kV transformer at Lovington	SWPS	Reliability	0	$2,239,599
Rebuild Canyon West-Dawn-Panda 115 kV line to 249/273 MVA	SWPS	Reliability	22.1	$14,194,453
Tap Hitchland-Finney 345 kV line at NewSub1, new 345/115 kV transformer at NewSub, new NewSub station, new NewSub2-Walkemeyer-North Liberal 115 kV line	SUNC	Reliability	23	$36,224,893
		Total	100.7	$164,181,150

Table 13.7: Future 2 Portfolio Projects

Section 14:Consolidated Portfolio

14.1: Development

The Future 1 and 2 portfolios were consolidated into a single final portfolio to be analyzed across both futures.

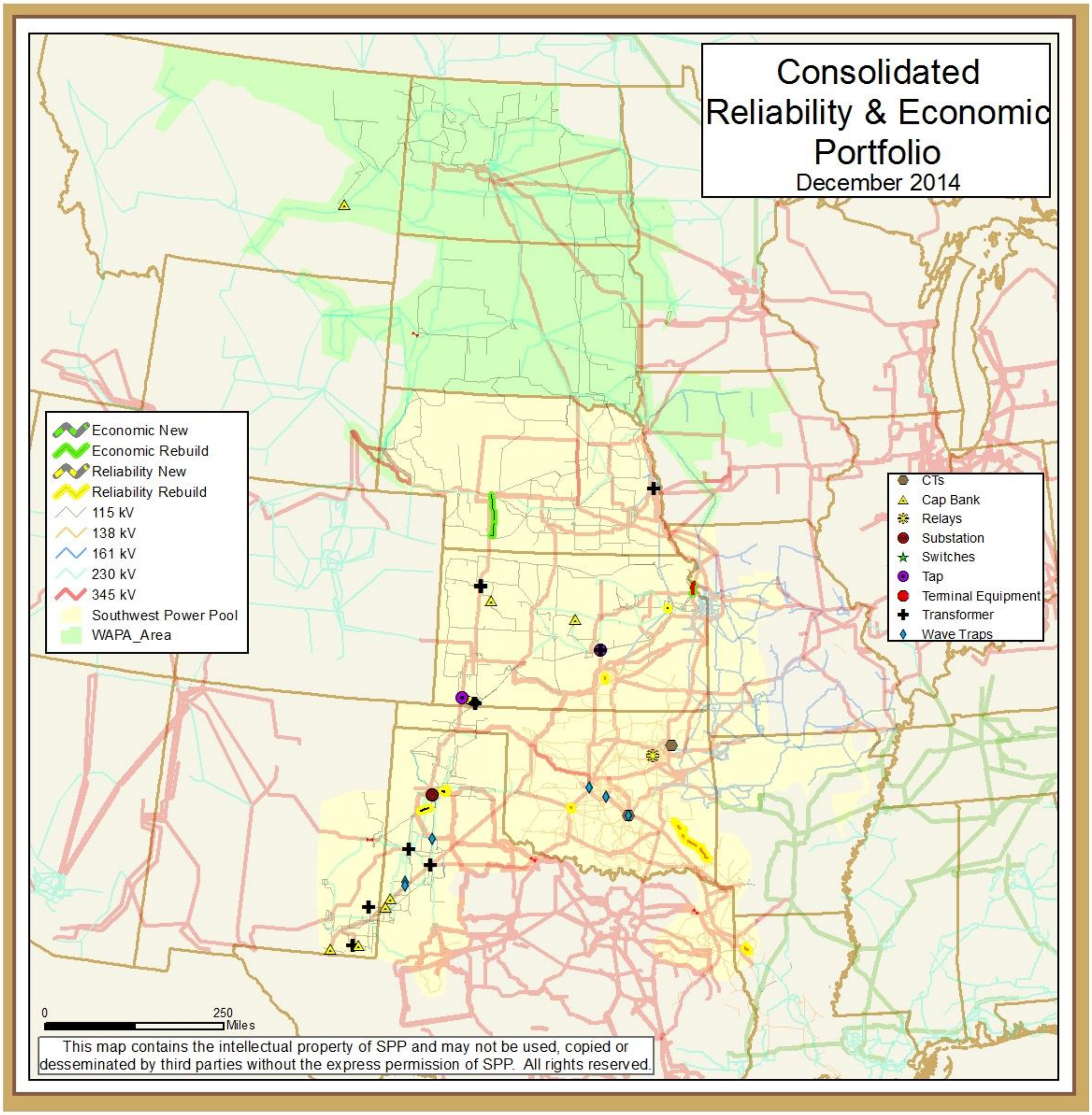


Figure 14.1: Consolidation of Portfolios

2015 Dollars	Consolidated Portfolio		
	Reliability	Economic	Total
Total Cost	$209.6M	$69.7M	$273.2M
Total Projects	31	3	32
Total Miles	166	94	260
1-Year Cost	$11.9M		
APC Benefit	$37.8M		
B/C Ratio	3.2*		

2 projects are included in both the economic and reliability portfolios
*B/C includes only APC benefit of economic projects

Table 14.1: Consolidated Portfolio Statistics

The final portfolio for each future was consolidated into a single portfolio.

The consolidation was based on the following criteria:

Economic Projects

- Economic projects with a 1-year B/C ratio greater than 0.9 in Future 1 were included in the consolidated portfolio.
- Economic projects with a 1-year B/C ratio greater than 0.7 in Future 1, and a 1-year B/C ratio greater than 0.9 in Future 2 were also included in the consolidated portfolio.

Policy Projects

- Policy projects were included in the consolidated portfolio if they met a policy need in Future 1.

Reliability Projects

- Reliability projects were included in the consolidated portfolio if they mitigate a thermal/voltage violation in Future 1.
- Future 2 reliability projects were included if they mitigate a thermal violation in Future 2 and mitigate loading above a 90% threshold in Future 1.
- Future 2 projects mitigating a voltage limit violation in Future 2 and voltage below 0.92 pu in Future 1 were included in the consolidated portfolio.

Although projects with significant potential value were eligible to be selected to be part of the consolidated portfolio, no such projects were included.

14.2: Projects

The Consolidated Portfolio projects are shown in Table 14.2.

Project Description	Area(s)	Type	Future	Mileage	Cost
New wave trap at Amoco and Sundown, increasing rating on Sundown-Amoco 230 kV line	SWPS	Economic & Reliability	F1	0	$55,641
Voltage conversion of Iatan-Stranger Creek 161 kV line to 345 kV	KCPL, GMO, WRI	Economic	F1	14	$16,119,446
Rebuild North Platt-Stockville-Red Willow 115 kV line to 240/240 MVA, new 345/115 kV transformer at Mingo	NPPD, SUNC	Economic & Reliability	F1	80	$53,562,098
New 345/115 kV transformer at Road Runner	SWPS	Reliability	F1	0	$5,733,227
Install 2 stages of 14.4 MVAr capacitor banks on the Ochoa 115 kV bus	SWPS	Reliability	F1	0	$1,659,762
Install 2 stages of 14.4 MVAr capacitor banks on the China Draw 115 kV bus and the North Loving 115 kV bus	SWPS	Reliability	F1	0	$3,319,524
New 230/115 kV transformer at Plant X	SWPS	Reliability	F1	0	$3,497,095
New wave trap at Amarillo South, increasing rating on Amarillo South-Swisher 230 kV line	SWPS	Reliability	F2	0	$27,821
Tap Northwest-Bush 115 kV line at new station, and build new 3 miles of 115 kV line to Hastings	SWPS	Reliability	F1	3	$7,984,549
Upgrade 230/115 kV transformer at Tuco	SWPS	Reliability	F1	0	$3,127,583
Upgrade wave trap and CT on the Park Lane-Seminole 138 kV line	OKGE	Reliability	F2	0	$86,436
Upgrade relays at Sand Springs, increasing ratings on Sand Springs-Prattville 138 kV line	AEPW	Reliability	F1	0	$176,290
Tap Reno-Wichita 345 kV line into Moundridge, new 345/138 kV transformer at Moundridge	WRI	Reliability	F2	0	$14,722,229
Rebuild Forbes-Underpass North 115 kV line to 218/262 MVA	WRI	Reliability	F1	3	$7,878,364
Reconductor Gracemont-Anadarko 138 kV line to 286/286 MVA	OKGE, WRI	Reliability	F1	5	$4,650,558
Rebuild Murray Gill East-Interstate 138 kV line to 286/286 MVA	WRI	Reliability	F2	6	$6,184,325
Reconductor Martin-Pantex North 115 kV line to 240/240 MVA and replace wave trap at Pantex substation	SWPS	Reliability	F1	5	$3,602,175
Reconductor Pantex North-Pantex South 115 kV line to 240/240 MVA	SWPS	Reliability	F1	3	$1,824,746

Reconductor Highland Park-Pantex South 15 kV line to 240/240 MVA and replace wave trap and switch at Pantex South and Highland Park tap	SWPS	Reliability	F1	7	$3,649,492
Install 14.4 MVAr capacitor bank at LE Plains Interchange 115 kV	SWPS	Reliability	F1	0	$829,881
Install 14.4 MVAr capacitor bank at Allred 115 kV	SWPS	Reliability	F1	0	$829,881
Replace wave trap at Claremore 161 kV	GRDA	Reliability	F1	0	$88,560
Install 6 MVAr capacitor bank at Grinnell 115 kV	SUNC	Reliability	F1	0	$345,784
Rebuild South Shreveport-Wallace Lake 138 kV line to 246/246 MVA	AEPW	Reliability	F1	11	$10,268,933
Rebuild Broken Bow-Lone Oak 138 kV corridor to 286/286 MVA	AEPW	Reliability	F1	77	$60,804,427
Install 14.4 MVAr capacitor bank at Ellsworth 115 kV	SUNC	Reliability	F1	0	$829,881
Install 6 MVAr capacitor bank at Mile City 115 kV	WAPA	Reliability	F1	0	$345,784
Upgrade wave traps and switches on Cimarron-McClain 345 kV line	OKGE	Reliability	F1	0	$116,838
New 345/161 kV transformer at S3459	OPPD	Reliability	F1	0	$8,176,238
New 115/69 kV transformer at Lovington	SWPS	Reliability	F1	0	$2,239,599
Rebuild Canyon West-Dawn-Panda 115 kV line to 249/273 MVA	SWPS	Reliability	F2	24	$14,194,453
Tap Hitchland-Finney 345 kV line at new substation and install new 345/115 kV transformer, and build new 23 mile 115 kV line from new station to Walkemeyer and continue to North Liberal	SUNC	Reliability	F1	22	$36,224,893
Total				260	$273,156,513

Table 14.2: Consolidated Portfolio Projects

The project details that follow summarize 2024 system behavior both with and without each project.

14.3: Economic Projects

This section details each of the economic projects in the 2015 ITP10 consolidated portfolio.

Rebuild North Platt-Stockville-Red Willow 115 kV line to 240/240 MVA, new 345/115 kV transformer at Mingo

The western SPP corridor shows a general north to south flow of power from Nebraska into Kansas. The Gentleman to Red Willow 345 kV line carries much of the power flows in this area. An outage of this line causes flow to be redirected to the North Platte to Stockville 115 kV line and the model will bind this constraint at its maximum rating when the north to south system flows are high (need 2015ITP10-E1N0003). Rebuilding the North Platte to Stockville line increases the limits and allows the power to flow unimpeded by the flowgate. The Stockville to Red Willow segment must also be rebuilt as a part of this project so that the congestion isn't just pushed to the next element of the transmission system.

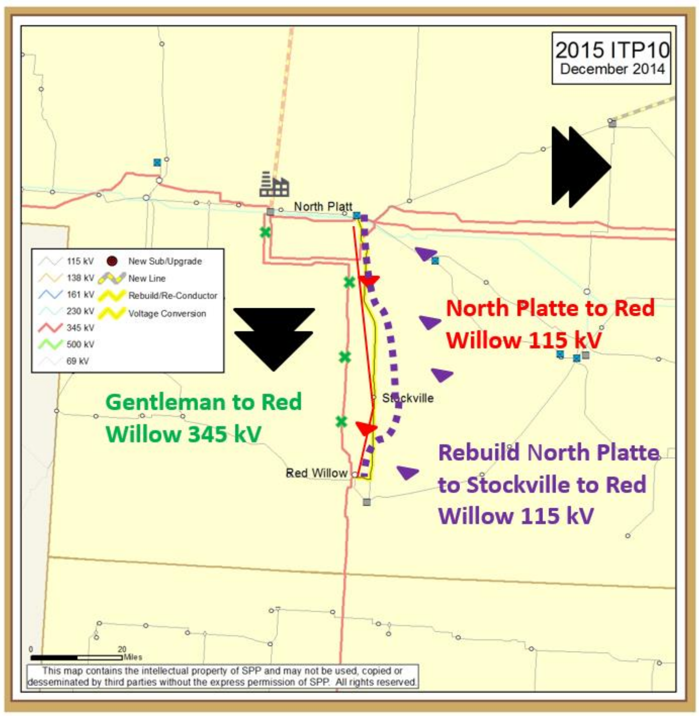


Figure 14.2: Rebuild North Platt-Stockville-Red Willow

This increase in north to south flows created by the rebuild of the North Platte to Red Willow corridor when the Gentleman to Red Willow 345 kV line is out of service, as well as the system intact conditions under high north to south bias hours cause congestion to be pushed south into Kansas. This is particularly realized when power is forced to step down from the 345 kV system to the 115 kV system at the Mingo substation when there is an outage of the Mingo to Setab 345 kV which runs to the south out of Mingo. The increase in power flowing on the Mingo transformer under this contingency from power trying to keep moving south and somewhat east cause the model to bind the existing transformer (Need 2015ITP10-E1N0008). Adding a second 345/115 kV transformer splits the duty and allows the power to step down to the lower voltage, unimpeded by the flowgate.

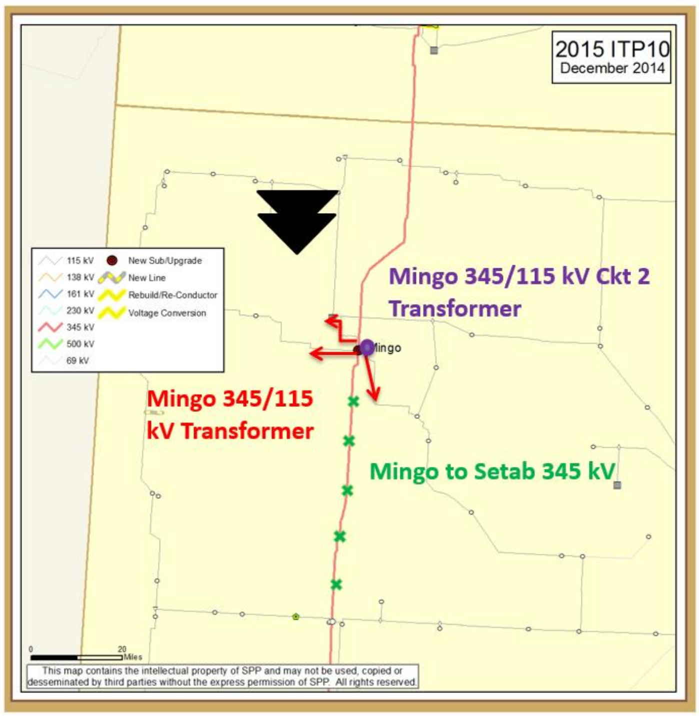


Figure 14.3: New Transformer at Mingo

Voltage conversion of Iatan-Stranger Creek 161 kV line to 345 kV

The Kansas City area experiences general north to south system flows on the EHV network from generation in the north, Cooper nuclear in Nebraska, loop flows from first tier systems, and the Iatan coal plant. The 345 network surrounding Kansas City allows for flows passing through to the south as well as multiple access points for power to step down and serve demand in the city. The western side of the EHV loop around the city normally experiences slightly more flow than the eastern side. When an outage of the Iatan-Stranger Creek 345 kV line occurs, the flow moving south gets redirected to the eastern side of the loop where power begins to step down in greater amounts (needs 2015ITP10-E1N0001 and 2015ITP10-E1N0015). The Hawthorne substation is located more centrally to the load in the city than any other 345/161 kV stepdown on the eastern side, attracting additional flows on the 161 kV system at that point. This additional flow on the 161 kV near Hawthorne causes heavy congestion on the Northeast to Charlotte 161 kV line.

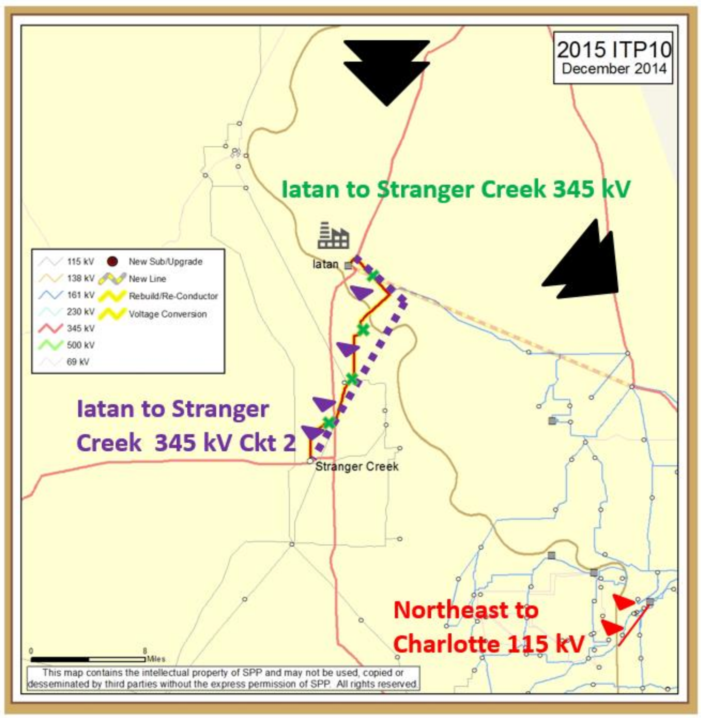


Figure 14.4: Voltage conversion of Iatan-Stranger Creek

When an outage of the Hawthorn to Nashua 345 kV occurs, cutting off the ability of the eastern part of the Kansas City EHV loop to be utilized for the flows from the north, the power is redirected to the west causing additional congestion on the Iatan to Stranger 345 kV line, the main outlet to move power to the south on the western side of the loop.

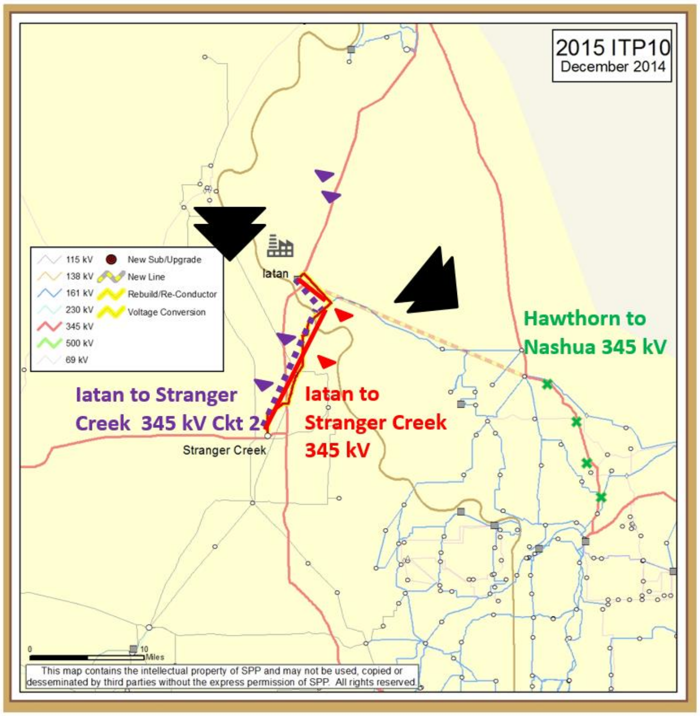


Figure 14.5: Voltage conversion of Iatan-Stranger Creek

In a parallel path to the existing Iatan to Stranger 345 kV line, is an existing 161 kV Iatan to Stranger which was partially built for 345 kV operation specifications. By rebuilding a portion of this line and converting it to 345 kV operation, the outage of the existing 345 kV line is mitigated with a parallel path that relieves congestion on the 161 kV system in the city and the parallel 345 kV creates an increase in capacity sufficient to handle the increase in flows on the western side of the loop when the Hawthorn to Nashua 345 kV experiences an outage.

New wave trap at Amoco and Sundown, increasing rating on Sundown-Amoco 230 kV line
The Amoco/Sundown area of the Texas Panhandle has a general north to south power flow bias. There are a number of loads served on the 115 kV system from Sundown. When the Sundown 230/115 kV transformer is out of service, power has to flow south to Yoakum 230 kV in order to step down to the 115 kV system causing congestion on the Sundown to Amoco 230 kV line (need 2015ITP10-E1N0009).

By replacing wave traps at the Sundown and Amoco stations, the Sundown to Amoco 230 kV line can accommodate an increase in power flows in order to serve load at Amoco Switching Station, and the additional power necessary to flow south to Yoakum in order to step down to the 115 kV system and serve loads in the Sundown area.

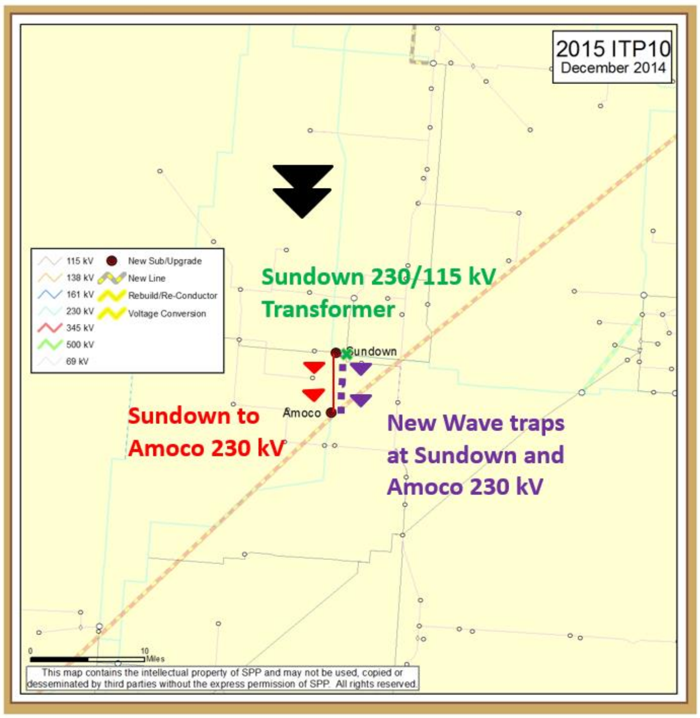


Figure 14.6: New wave trap at Amoco and Sundown

14.4: Reliability Projects

This section details each of the major reliability projects in the 2015 ITP10 consolidated portfolio. Each of the projects discussed below have an SPP generated cost estimate greater than $15 million and are needed for Regional Reliability.

Rebuild Broken Bow – Lone Oak 138 kV line

This project consists of rebuilding the 138 kV line corridor from Broken Bow to Lone Oak. The project upgrades the 16 miles of line from Broken Bow to Bethel to Nashoba to Clayton to Sardis to Enogex Wilburton Tap (Enowilt) to Lone Oak to an updated rating of 286 MVA. This project has a need date of 2023. This project addresses the overloads of Clayton – Nashoba 138 kV, Clayton – Sardis 138 kV, Enowilt – Lone Oak 138 kV, and Enowilt – Sardis 138 kV for the outage of the Pittsburg – Valliant 345 kV line.

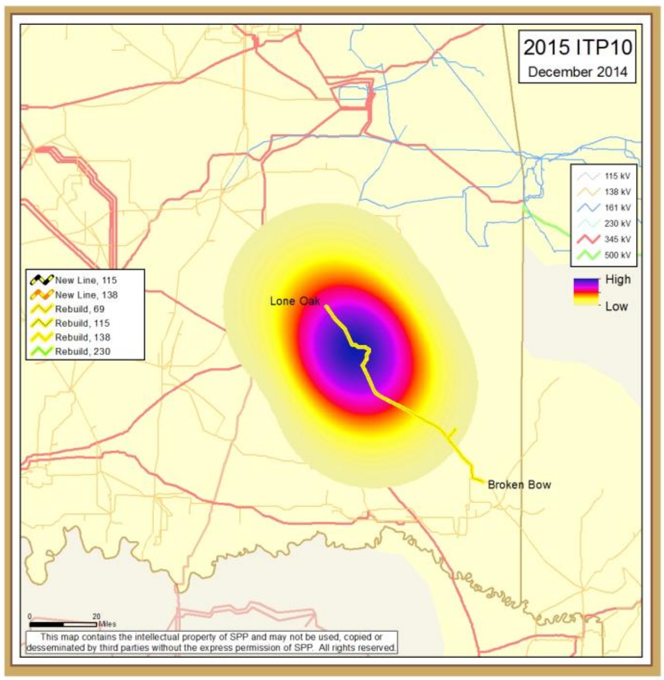


Figure 14.7: Rebuild Broken Bow – Lone Oak

Tap Hitchland – Finney 345 kV and NewSub – Walkemeyer – North Liberal 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. Also a Walkemeyer to North Liberal 21 mile 115 kV line will be added. The need date for this project is June of 2019. This project will address the overload of the Pioneer Tap – CTU Sublette – Haskell – Seward – Cimarron River Plant – Hayne 115 kV lines and area low voltage for the outage of Hugoton – Pioneer Tap 115 kV line. Other contingencies in the area caused overloading and low voltage in the Southwest Kansas area which was addressed by this project.

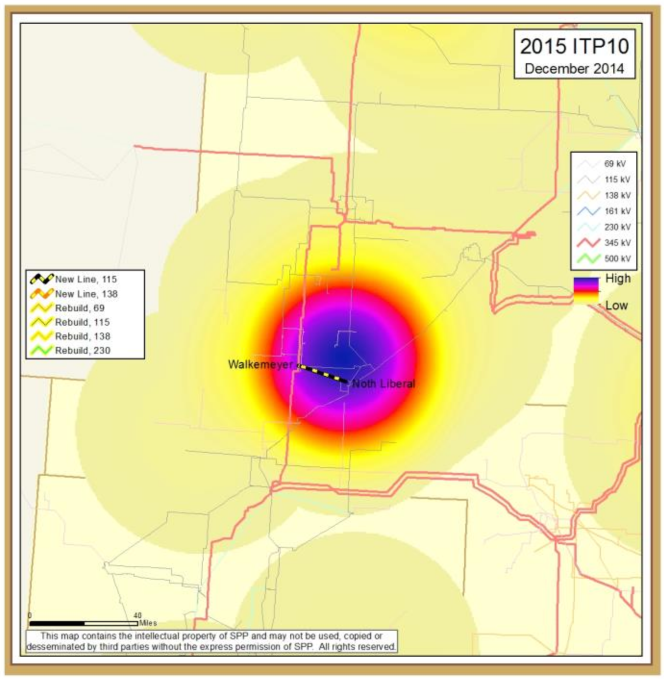


Figure 14.8: Walkemeyer – North Liberal

Section 15:Staging

A project need date is determined, or staged, based on the project's classification(s) and the future from which the project was derived during the consolidation process. In this study, a project can be classified as economic, policy, or reliability depending on which of these needs it mitigated. Multiple classifications could be carried by a single project if it mitigated multiple need types. For example, if a single project simultaneously mitigated economic and reliability needs, per the criteria described on pages 49 through 61 of this report, the project would be classified as both economic and reliability. Multiple classification projects were staged to meet the earliest need date established through the project classification process, as described below. Consolidated portfolio projects derived from Future 2 were staged in 2024. Staging was conducted in the Future 1 model and project lead times were determined according to historical expectations and stakeholder review.

15.1: Staging Reliability Projects

Reliability projects were staged between 2019 and 2024. The process to stage reliability projects utilized AC models representing the summer peak hour in Future 1 for two years: 2019 and 2024. These AC models have the economic dispatch as determined by the DC economic models. Thermal projects were staged based on linear interpolation of thermal loadings from 2019 to 2024. The year in which the loading of the overloaded facility exceeded 100% was identified as the need date. Figure 15.1 provides an example of this interpolation process. Similar to the thermal staging process, voltage needs were also staged based on linear interpolation of voltage per unit from 2019 to 2024. The year in which the voltage was less than 0.95 per unit for base case conditions, or less than 0.90 per unit for contingency conditions was identified as the need date. In the case where a project mitigated thermal and voltage needs, the project was staged to meet the earliest occurrence of either the thermal or voltage need.

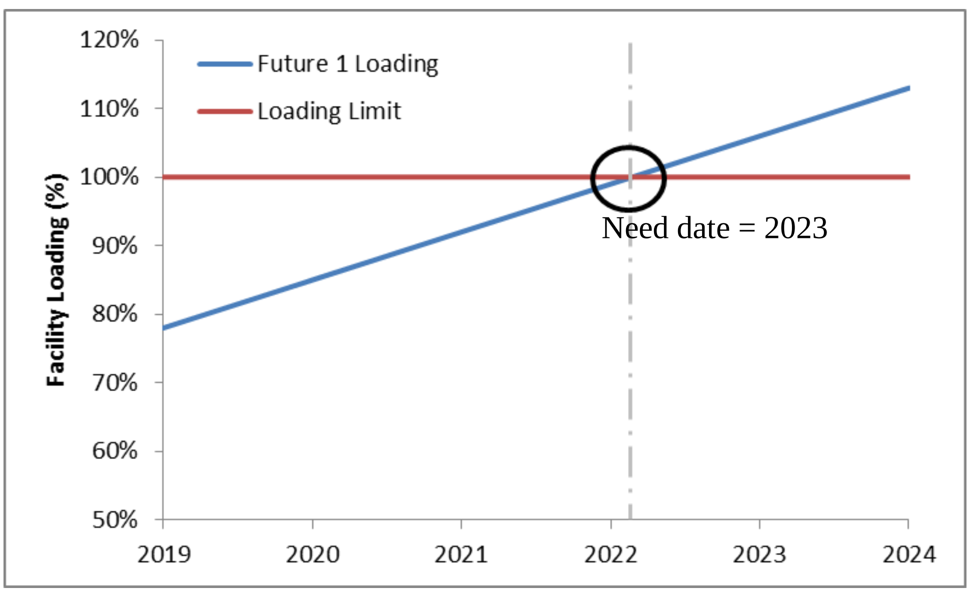


Figure 15.1: Project Staging Interpolation Example

15.2: Staging Economic Projects

The security constrained economic simulation was used to perform a production cost analysis for the years 2019 and 2024 using the Future 1 model. The 1-year B/C ratio for these two years was determined for each of the economic upgrades in the consolidated portfolio. The base case for each model year consisted of the Future 1 model plus reliability projects needed by the respective year. The incremental benefit of each economic project was calculated with the project considered in addition to the base case. The change in the B/C over time was interpolated from the two points in order to determine the staging dates. Economic upgrades were given an in-service date for the first year that their B/C was greater than 1.0 in Future 1.

15.3: Staging Policy Upgrades

Policy projects were to be staged in order to meet renewable requirements. In this study, no policy needs were identified.

15.4: Project Staging Results

As a result of the staging process, 16 projects will be recommended for NTCs. Table 15.1 below provides the staging data for each project in the consolidated portfolio.

Project Description	Lead Time (Months)	ITP10 Need Date	NTC
New wave trap at Amoco and Sundown, increasing rating on Sundown-Amoco 230 kV line	18	1/1/2019	Yes
Voltage conversion of Iatan-Stranger Creek 161 kV line to 345 kV	36	1/1/2019	Yes
Rebuild North Platt-Stockville-Red Willow 115 kV line to 240/240 MVA, new 345/115 kV transformer at Mingo*	30	1/1/2019	Yes*
New 345/115 kV transformer at Road Runner	24	6/1/2019	No
Install 2 stages of 14.4 MVAr capacitor banks on the Ochoa 115 kV bus	24	6/1/2020	Yes
Install 2 stages of 14.4 MVAr capacitor banks on the China Draw 115 kV bus and the North Loving 115 kV bus	24	6/1/2022	No
New 230/115 kV transformer at Plant X	24	6/1/2022	No
New wave trap at Amarillo South, increasing rating on Amarillo South-Swisher 230 kV line	18	6/1/2024	No
Tap Northwest-Bush 115 kV line at Bush Tap, new Bush Tap station, new Bush Tap-Hastings 115 kV line	30	6/1/2022	No
Upgrade 230/115 kV transformer at Tuco	24	6/1/2022	No
Upgrade wave trap and CT on the Park Lane-Seminole 138 kV line	18	6/1/2024	No
Upgrade relays at Sand Springs, increasing ratings on Sand Springs-Prattville 138 kV line	18	6/1/2023	No
Tap Reno-Wichita 345 kV line into Moundridge, new 345/138 kV transformer at Moundridge	24	6/1/2024	No
Rebuild Forbes-Underpass North 115 kV line to 218/262 MVA	24	6/1/2021	No
Reconductor Gracemont-Anadarko 138 kV line to 286/286 MVA	24	4/1/2019	Yes
Rebuild Murray Gill East-Interstate 138 kV line to 286/286 MVA	24	6/1/2024	No
Reconductor Martin-Pantex North 115 kV line to 240/240 MVA and replace wave trap at Pantex substation	24	4/1/2019	Yes
Reconductor Pantex North-Pantex South 115 kV line to 240/240 MVA	24	4/1/2019	Yes
Reconductor Highland Park-Pantex South 15 kV line to 240/240 MVA and replace wave trap and switch at Pantex South and Highland Park tap	24	4/1/2019	Yes
Install 14.4 MVAr capacitor bank at LE Plains Interchange 115 kV	24	6/1/2019	Yes
Install 14.4 MVAr capacitor bank at Allred 115 kV	24	6/1/2021	No

Replace wave trap at Claremore 161 kV	18	6/1/2019	Yes
Install 6 MVAr capacitor bank at Grinnell 115 kV	24	6/1/2023	No
Rebuild South Shreveport-Wallace Lake 138 kV line to 246/246 MVA	24	6/1/2019	Yes
Rebuild Broken Bow-Lone Oak 138 kV corridor to 286/286 MVA	30	4/1/2023	No
Ellsworth 115 kV Cap Bank	24	6/1/2019	Yes
Install 6 MVAr capacitor bank at Mile City 115 kV	24	6/1/2019	Yes
Upgrade wave traps and switches on Cimarron-McClain 345 kV line	18	4/1/2019	Yes
New 345/161 kV transformer at S3459	24	6/1/2019	Yes
New 115/69 kV transformer at Lovington	24	6/1/2020	No
Rebuild Canyon West-Dawn-Panda 115 kV line to 249/273 MVA	30	6/1/2024	No
Tap Hitchland-Finney 345 kV line at NewSub1, new 345/115 kV transformer at NewSub, new NewSub station, new NewSub2-Walkemeyer-North Liberal 115 kV line	36	6/1/2019	Yes

*The 2nd Mingo transformer upgrade is the sole portion of the noted project recommended for NTC.

Table 15.1: ITP10 2015 Project Staging Results

Section 16: Benefits

Benefit metrics were used to measure the value and economic impacts of the Consolidated Portfolio. The ESWG directed that the 2015 ITP10 benefit-to-cost ratios be calculated for the final portfolio of projects, including reliability and economic projects. The benefit structure shown in Figure *16.1* illustrates the metrics calculated as the incremental benefit of the projects included in the Consolidated Portfolio.

Metric Description
APC Savings
Reduction of Emissions Rates and Values
Savings Due to Lower Ancillary Service Needs and Production Costs
Avoided or Delayed Reliability Projects
Capacity Cost Savings Due to Reduced On-Peak Transmission Losses
Assumed Benefit of Mandated Reliability Projects
Benefit from Meeting Public Policy Goals (Public Policy Benefits)
Mitigation of Transmission Outage Costs
Increased Wheeling Through and Out Revenues
Marginal Energy Losses Benefits

Figure 16.1: Benefit Metrics for the 2015 ITP10

16.1: APC Savings

Adjusted Production Cost (APC) is a measure of the impact on production cost savings, considering purchases and sales of energy between each area of the transmission grid. The APC metric is determined using a production cost modeling tool that accounts for hourly commitment and dispatch profiles for the simulation year. The calculation, performed on an hourly basis, is summarized in

Figure *16.2*.

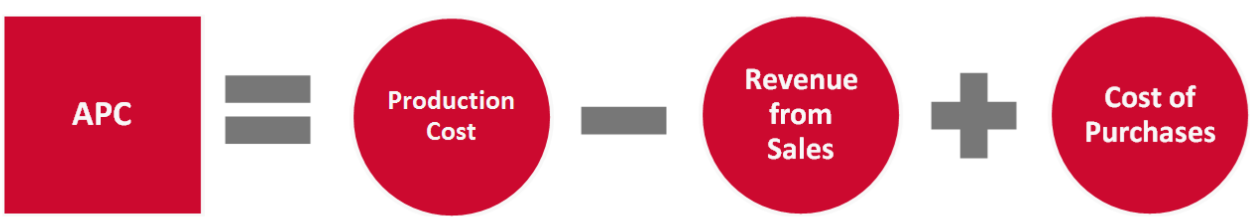


Figure 16.2: APC Calculation

APC captures the monetary cost associated with fuel prices, run times, grid congestion, and unit operating costs, energy purchases, energy sales, and other factors that directly relate to energy production by generating resources in the SPP footprint. Additional transmission projects aim to relieve system congestion and reduce costs through a combination of a more economical generation dispatch, more economical purchases, and optimal revenue from sales.

To calculate benefits over the expected 40-year life of the projects[31], two years were analyzed, 2019 and 2024, and the APC savings were calculated accordingly for these years. The benefits are extrapolated for the initial 20-year period based on the slope between the two points and after that assumed to grow at an inflation rate of 2.5% per year. Each year's benefit was then discounted to 2019 using an 8% discount rate, and a 2.5% inflation rate from 2019 back to 2015. The sum of all discounted benefits was presented as the Net Present Value (NPV) benefit. This calculation was performed for every zone.

Figure 16.3 shows the regional APC savings for the Consolidated Portfolio over 40 years, and Table 16.1 provides the zonal breakdown and the NPV estimates. Future 1 has higher congestion compared to Future 2. Therefore, the proposed projects in the Consolidated Portfolio provide more congestion relief in Future 1 than in Future 2, resulting in larger APC savings.

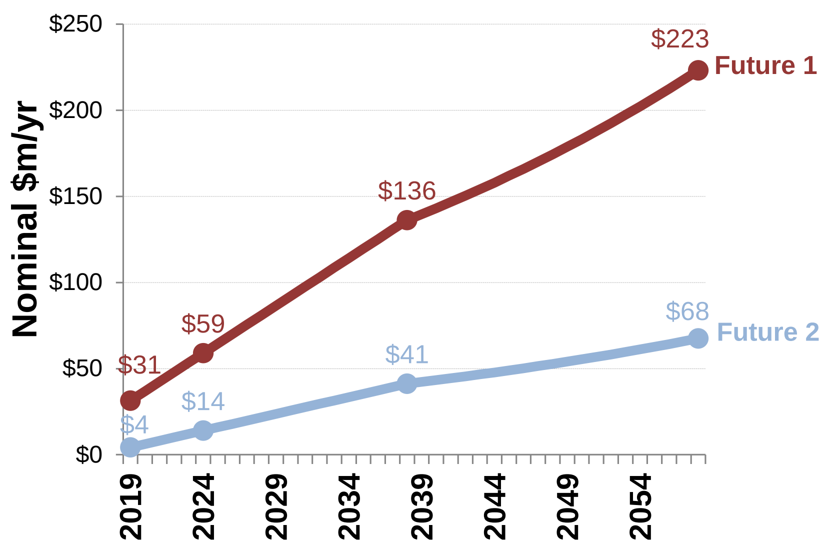


Figure 16.3: Regional APC Savings Estimated for the 40-year Study Period

[31] The SPP OATT requires that the portfolio be evaluated using a 40-year financial analysis.

	Future 1			Future 2		
	2019 (nom. $m)	2024 (nom. $m)	**40-yr NPV (2015 $m)**	2019 (nom. $m)	2024 (nom. $m)	**40-yr NPV (2015 $m)**
AEPW	$1.0	$0.3	**($4.6)**	$1.8	$0.9	**$2.0**
CUS	$0.1	$0.1	**$1.6**	($0.0)	($0.1)	**($0.9)**
EDE	$0.2	$0.4	**$7.5**	$0.1	$0.0	**($0.4)**
GMO	($0.3)	($0.1)	**($0.2)**	($0.1)	($0.3)	**($4.3)**
GRDA	($0.3)	($0.8)	**($15.8)**	$0.0	($0.0)	**($1.1)**
KCPL	$4.8	$11.0	**$202.8**	$0.5	$0.8	**$13.2**
LES	$0.0	($0.1)	**($2.0)**	($0.0)	($0.3)	**($5.6)**
MIDW	$3.4	$2.0	**$9.8**	$0.3	$0.1	**($0.2)**
MKEC	$4.0	$4.4	**$56.6**	$1.2	$1.5	**$20.0**
NPPD	$6.3	$9.2	**$143.4**	$0.9	$0.8	**$9.2**
OKGE	($0.3)	$1.8	**$44.3**	$0.3	($0.0)	**($3.8)**
OPPD	$1.9	$4.3	**$77.5**	$0.2	$6.6	**$149.8**
SUNC	$2.7	$2.8	**$34.4**	$0.4	$0.4	**$5.7**
SWPS	$1.5	$10.3	**$222.3**	($1.9)	$1.7	**$60.1**
WEFA	($0.6)	($1.2)	**($20.5)**	$0.1	$0.3	**$5.4**
WRI	$7.4	$13.6	**$234.9**	$0.6	$1.3	**$24.0**
Sub-Total	**$31.7**	**$57.9**	**$991.8**	**$4.2**	**$13.8**	**$273.2**
BASIN	($2.4)	($2.8)	**($37.9)**	($0.1)	$0.1	**$3.0**
HCPD	$0.5	$0.8	**$14.4**	$0.1	$0.1	**$1.2**
WAPA	$2.8	$4.7	**$77.1**	$0.2	$0.2	**$1.5**
CBPC	($1.2)	($1.7)	**($25.3)**	($0.2)	($0.2)	**($1.9)**
Sub-Total	**($0.3)**	**$1.1**	**$28.3**	**$0.0**	**$0.2**	**$3.7**
TOTAL	**$31.4**	**$59.0**	**$1,020.1**	**$4.3**	**$14.0**	**$276.9**

Table 16.1: APC Savings by Zone

16.2: Reduction of Emission Rates and Values

Additional transmission may result in a lower fossil-fuel burn (for example, less coal-intensive generation), resulting in less SO_2, NO_X, and CO_2 emissions. Such a reduction in emissions is a benefit that is already monetized through the APC savings metric, based on the assumed allowance prices for these effluents. Note that neither ITP10 future assumes any allowance prices for CO_2.

16.3: Savings Due to Lower Ancillary Service Needs and Production Costs

Ancillary Services (A/S) such as spinning reserves, ramping (up/down), regulation, and 10-minute quick start are essential for the reliable operation of the electrical system. Additional transmission can decrease the A/S costs by: (a) reducing the A/S quantity needed, or (b) reducing the procurement costs for that quantity.

The A/S needs in SPP are determined according to SPP's market protocols and currently do not change based on transmission. Therefore, the savings associated with the "quantity" effect are assumed to be zero.

The costs of providing A/S are captured in the APC metrics since the production cost simulations set aside the static levels of resources to provide regulation and spinning reserves. As a result, the benefits related to "procurement cost" effect are already included as a part of the APC savings presented in this report.

16.4: Avoided or Delayed Reliability Projects

Potential reliability needs are reviewed to determine if the upgrades proposed for economic or policy reasons defer or replace any reliability upgrades. The avoided or delayed reliability project benefit represents the costs associated with these additional reliability upgrades that would otherwise have to be pursued.

To estimate the avoided or delayed reliability projects benefit for the Consolidated Portfolio, the 2019 and 2024 powerflow models developed for Futures 1 and 2 are utilized. Excluding the proposed economic projects from these models did not result in thermal overloads in any of the model runs. Therefore, no avoided or delayed reliability projects were identified, and the associated benefits are estimated to be zero.

16.5: Capacity Cost Savings Due to Reduced On-Peak Transmission Losses

Transmission line losses result from the interaction of line materials with the energy flowing over the line. This constitutes an inefficiency that is inherent to all standard conductors. Line losses across the SPP system are directly related to system impedance. Transmission projects often reduce the losses during peak load conditions, which lowers the costs associated with additional generation capacity needed to meet the capacity requirements.

The capacity cost savings for the Consolidated Portfolio are calculated based on the on-peak losses estimated in the 2019 and 2024 powerflow models. The loss reductions are then multiplied by 112% to estimate the reduction in installed capacity requirements. The value of capacity savings is monetized by applying a net cost of new entry (net CONE) of $82/kW-yr in 2015 dollars.

The net CONE value was calculated as the difference between an estimated gross CONE value and the expected operating margins (energy market revenues net of variable operating costs, also referred to as "net market revenues") for a combustion turbine. A gross CONE value of $85/kW-yr was obtained by levelizing the capital and fixed operating costs of a new advanced combustion turbine as reported in EIA's Annual Energy Outlook 2014. Net market revenues of $3/kW-yr were estimated based on the historical data for the margins of gas-fired combustion turbines, as provided in SPP's 2013 State of Market Report.

Table 16.2 summarizes the on-peak loss reductions and associated capacity savings for the region in each study year for Futures 1 and 2.

	2019			2024		
	Loss Reduction (MW)	Capacity Savings (MW)	**Capacity Savings (nom. $m)**	Loss Reduction (MW)	Capacity Savings (MW)	**Capacity Savings (nom. $m)**
Future 1	14.4	16.1	**$1.5**	23.1	25.9	**$2.6**
Future 2	15.2	17.0	**$1.5**	21.0	23.5	**$2.4**

Table 16.2: On-Peak Loss Reduction and Associated Capacity Cost Savings

The 40-year benefits are estimated by extrapolating the results for the first 20 years using the slope between the two points and applying inflation after that. This calculation was performed for every zone separately. Figure 16.4 shows the zonal distribution of the NPV of this benefit, which sums up to **$45 million** in Future 1 and **$39 million** in Future 2 for the entire SPP footprint.

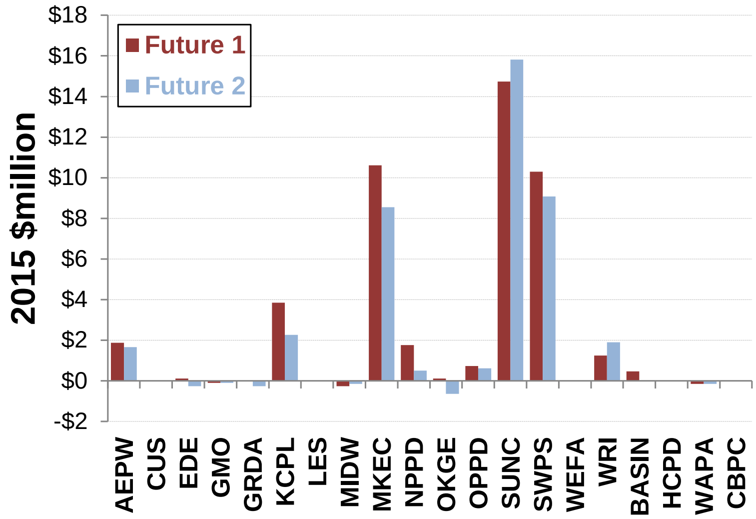


Figure 16.4: Capacity Cost Savings by Zone (40-year NPV)

16.6: Assumed Benefit of Mandated Reliability Projects

This metric monetizes the reliability benefits of the mandated reliability projects. As recommended by the September 2012 MTF report and reaffirmed by the ESWG in 2014, the regional benefits are assumed to be equal to 40-year NPV of ATRRs for the reliability projects, adding up to **$284 million** in 2015 dollars.

The ESWG[32] and BOD[33] approved an allocation of region-wide benefits based on a hybrid approach to reflect different characteristics of higher and lower voltage reliability upgrades:

- **300 kV or above**: 1/3 System Reconfiguration and 2/3 Load Ratio Share,
- **Between 100 kV and 300 kV**: 2/3 System Reconfiguration and 1/3 Load Ratio Share, and
- **Below 100 kV**: 100% System Reconfiguration.

The system reconfiguration approach utilizes the powerflow models to measure the incremental flows shifted onto the existing system during outage of the proposed reliability upgrade. This is used as a proxy for how much each upgrade reduces the flows on the existing transmission facilities owned by the zones. Results from the production cost simulations are used to determine hourly flow direction on the upgrades and then applied as weighting factors for the powerflow results.

[32] http://www.spp.org/publications/ESWGMinutes

[33] http://www.spp.org/publications/BOCMCMinutes

Table 16.3 and Table 16.4 summarize the system reconfiguration analysis results and the benefit allocation factors for different voltage levels. Figure 16.5 plots the overall zonal benefits calculated by applying these allocation factors.

	All Projects	< 100 kV	100–300 kV			> 300 kV		
SPP-wide Benefits								
Total	$240.7	$1.7	$211.9			$27.0		
Analyzed*	$240.7	$1.7	$211.9			$27.0		
Zone	**Approved Hybrid Approach**	**100% SR**	**66.7% SR**	**33.3% LRS**	**Wtd. Avg.**	**33.3% SR**	**66.7% LRS**	**Wtd. Avg.**
AEPW	18.6%	0.0%	19.0%	20.3%	19.4%	0.1%	20.3%	13.6%
CUS	1.4%	0.0%	1.6%	1.4%	1.5%	0.0%	1.4%	0.9%
EDE	1.5%	0.0%	1.1%	2.3%	1.5%	0.1%	2.3%	1.6%
GMO	2.0%	0.0%	1.0%	3.8%	2.0%	0.3%	3.8%	2.7%
GRDA	1.0%	0.0%	0.5%	1.8%	0.9%	0.3%	1.8%	1.3%
KCPL	3.2%	0.0%	0.9%	7.1%	3.0%	0.2%	7.1%	4.8%
LES	1.2%	0.0%	0.9%	1.8%	1.2%	0.3%	1.8%	1.3%
MIDW	0.5%	0.0%	0.4%	0.8%	0.5%	0.1%	0.8%	0.6%
MKEC	6.7%	0.0%	10.3%	1.3%	7.3%	5.1%	1.3%	2.6%
NPPD	3.3%	0.0%	1.6%	6.3%	3.2%	1.1%	6.3%	4.5%
OKGE	9.8%	0.0%	8.4%	13.0%	10.0%	1.6%	13.0%	9.2%
OPPD	3.9%	0.0%	3.0%	4.9%	3.6%	7.7%	4.9%	5.8%
SUNC	8.5%	0.0%	12.4%	1.0%	8.6%	24.3%	1.0%	8.8%
SPS	16.9%	100.0%	19.5%	12.0%	17.0%	9.3%	12.0%	11.1%
WFEC	5.8%	0.0%	7.9%	3.1%	6.3%	0.1%	3.1%	2.1%
WR	11.4%	0.0%	9.8%	10.3%	10.0%	48.9%	10.3%	23.2%
Sub-Total	**95.9%**	**100.0%**	**98.4%**	**91.4%**	**96.1%**	**99.2%**	**91.4%**	**94.0%**
BASIN	3.1%	0.0%	0.1%	8.3%	2.8%	0.0%	8.3%	5.5%
HCPD	0.1%	0.0%	0.0%	0.4%	0.1%	0.0%	0.4%	0.2%
WAPA	0.9%	0.0%	1.4%	0.0%	1.0%	0.8%	0.0%	0.3%
CBPC	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Sub-Total	**4.1%**	**0.0%**	**1.6%**	**8.6%**	**3.9%**	**0.8%**	**8.6%**	**6.0%**
TOTAL	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**

Table 16.3: System Reconfiguration Analysis Results and Benefit Allocation Factors (Future 1) – 2015$ Millions

	All Projects	< 100 kV	100–300 kV			> 300 kV		
SPP-wide Benefits								
Total	$240.7	$1.7	$211.9			$27.0		
Analyzed*	$240.7	$1.7	$211.9			$27.0		
Zone	**Approved Hybrid Approach**	**100% SR**	**66.7% SR**	**33.3% LRS**	**Wtd. Avg.**	**33.3% SR**	**66.7% LRS**	**Wtd. Avg.**
AEPW	15.4%	0.0%	13.5%	20.3%	15.7%	0.1%	20.3%	13.6%
CUS	2.3%	0.0%	3.1%	1.4%	2.5%	0.0%	1.4%	0.9%
EDE	1.8%	0.0%	1.5%	2.3%	1.8%	0.3%	2.3%	1.6%
GMO	4.2%	0.0%	4.7%	3.8%	4.4%	0.8%	3.8%	2.8%
GRDA	1.4%	0.0%	1.3%	1.8%	1.5%	0.3%	1.8%	1.3%
KCPL	4.6%	0.0%	3.5%	7.1%	4.7%	0.1%	7.1%	4.8%
LES	1.3%	0.0%	1.1%	1.8%	1.3%	0.5%	1.8%	1.4%
MIDW	2.0%	0.0%	2.9%	0.8%	2.2%	0.5%	0.8%	0.7%
MKEC	6.8%	1.0%	10.2%	1.3%	7.2%	9.9%	1.3%	4.2%
NPPD	4.5%	0.0%	3.7%	6.3%	4.5%	1.8%	6.3%	4.8%
OKGE	7.1%	1.0%	3.8%	13.0%	6.9%	0.5%	13.0%	8.9%
OPPD	4.3%	0.0%	3.8%	4.9%	4.2%	7.5%	4.9%	5.8%
SUNC	7.4%	0.0%	10.4%	1.0%	7.2%	26.0%	1.0%	9.3%
SPS	14.3%	97.9%	15.6%	12.0%	14.4%	1.2%	12.0%	8.4%
WFEC	4.9%	0.0%	6.4%	3.1%	5.3%	0.1%	3.1%	2.1%
WR	12.8%	0.0%	12.3%	10.3%	11.6%	49.2%	10.3%	23.3%
Sub-Total	**95.4%**	**100.0%**	**97.6%**	**91.4%**	**95.5%**	**98.8%**	**91.4%**	**93.9%**
BASIN	3.3%	0.0%	0.5%	8.3%	3.1%	0.0%	8.3%	5.5%
HCPD	0.1%	0.0%	0.0%	0.4%	0.1%	0.0%	0.4%	0.2%
WAPA	1.1%	0.0%	1.9%	0.0%	1.2%	1.1%	0.0%	0.4%
CBPC	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Sub-Total	**4.6%**	**0.0%**	**2.4%**	**8.6%**	**4.5%**	**1.2%**	**8.6%**	**6.1%**
TOTAL	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**

Table 16.4: System Reconfiguration Analysis Results and Benefit Allocation Factors (Future 2) – 2015$ Millions

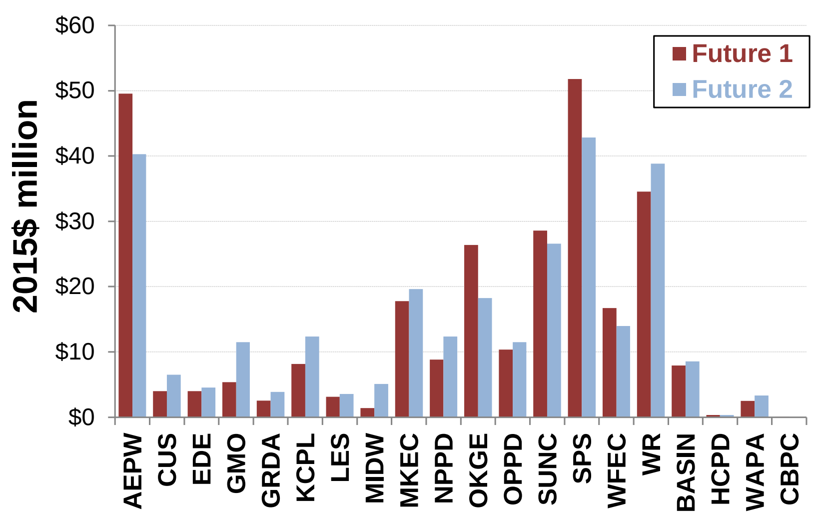


Figure 16.5: Mandated Reliability Project Benefits by Zone (40-year NPV)

16.7: Benefit from Meeting Public Policy Goals

This metric represents the economic benefits provided by the transmission upgrades for facilitating public policy goals. For the purpose of this study, the scope is limited to meeting public policy goals related to renewable energy and the system-wide benefits are assumed to be equal to the cost of policy projects.

Since no policy projects are identified as a part of the Consolidated Portfolio, the associated benefits are estimated to be zero.

16.8: Mitigation of Transmission Outage Costs

The standard production cost simulations used to estimate APC savings assume that transmission lines and facilities are available during all hours of the year, and thereby ignore the added congestion-relief and production cost benefits of new transmission facilities during the planned and unplanned outages of existing transmission facilities.

To estimate the incremental savings associated with the mitigation of transmission outage costs, the production cost simulations can be augmented for a realistic level of transmission outages. Due to the significant effort that would be needed to develop these augmented models for each case, the findings from the RCAR study were used to calculate this benefit metric for the Consolidated Portfolio as a part of this ITP10 effort.

In the RCAR analysis, adding a subset of historical transmission outage events to the production cost simulations increased the APC savings by 11.3%.[34,35] Applying this ratio to the APC savings estimated for the Consolidated Portfolio translates to a 40-year NPV of benefits of **$115 million** for Future 1 and **$31 million** for Future 2 in 2015 dollars.

This incremental benefit is allocated to zones based on their load ratio share, because it is difficult to develop normalized transmission outage data that reliably reflects the outage events expected in each zone over the study horizon. Using load ratio shares as an allocation approach for this metric was initially recommended by the MTF and then approved by the ESWG. Figure 16.6 shows the outage mitigation benefits allocated to each SPP zone.

[34] SPP Regional Cost Allocation Review Report, October 8, 2013 (pp. 36–37).

[35] As directed by ESWG, SPP will periodically review historical outage data and update additional APC savings ratio for future studies. Although the outage data was not updated for the 2015 ITP10, it is being reviewed and updated for the RCAR II Assessment.

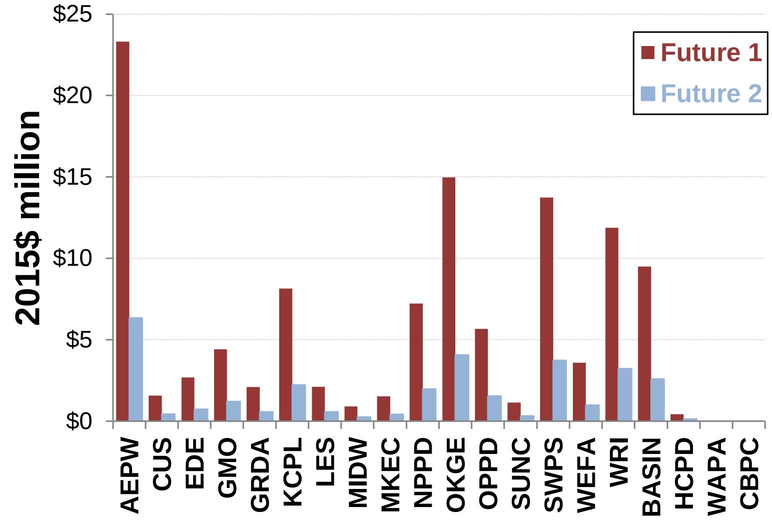


Figure 16.6: Transmission Outage Cost Mitigation Benefits by Zone (40-year NPV)

16.9: Increased Wheeling Through and Out Revenues

Increasing ATC with a neighboring region improves import and export opportunities for the SPP footprint. Increased inter-regional transmission capacity that allow for increased through and out transactions will also increase SPP wheeling revenues.

To estimate how increased ATC could affect the wheeling services sold, the historical long-term firm transmission service requests (TSR) allowed by the historical NTC projects are analyzed and compared against the ATC increase in the 2014 powerflow models estimated based on a First Contingency Incremental Transfer Capacity (FCITC) analysis. As summarized in Table 16.5, the NTC projects that have been put in-service under SPP's Highway/Byway cost allocation enabled 13 long-term TSRs to be sold between 2010 and 2014. The amount of capacity granted for these TSRs add up to 1,202 MW and the associated wheeling revenues are estimated to be $31 million annually based on current SPP tariff rates. The results of the FCITC analysis are summarized in Table 16.6. The export ATC increase in the 2014 powerflow models is calculated to be 1,142 MW which is comparable to the amount of firm capacity granted for the incremental TSRs sold historically.

Point of Delivery	Number of Firm PtP Service Requests	MW Capacity Granted	2014 Wheeling Revenues in $million			
			Sch 7 Zonal	Sch 11 Reg-Wide	Sch 11 Thru & Out Zonal	TOTAL
AECI	5	515	$5.4	$4.8	$2.4	**$12.6**
MISO	2	101	$1.1	$0.9	$0.5	**$2.5**
Entergy	6	586	$8.1	$5.5	$2.7	**$16.3**
TOTAL	**13**	**1,202**	**$14.6**	**$11.2**	**$5.5**	**$31.3**

Table 16.5: Estimated Wheeling Revenues from Incremental Long-Term TSRs Sold (2010–2014)

Export ATC in 2014 Base Case	1,287 MW
Export ATC in 2014 Change Case	2,429 MW
Increase in Export ATC due to NTCs	**1,142 MW**
Incremental TSRs Sold due to NTCs	1,202 MW
TSRs Sold as a Percent of Increase in Export ATC	**105%**

Table 16.6: Historical Ratio of TSRs Sold against Increase in Export ATC

The 2019 and 2024 powerflow models are utilized for the FCITC analysis. The ratio of TSRs sold as a percent of increase in export ATC is capped at 100%, as incremental TSR sales would not be expected to exceed the amount of increase in export ATC. The Consolidated Portfolio did not increase the export ATCs in Future 1, and accordingly, no wheeling revenue benefits are estimated for that future. In Future 2, the proposed upgrades increase the export ATC by 41 MW in 2019 and 52 MW in 2024. Applying the historical ratio suggests that the Consolidated Portfolio could enable incremental TSRs by the same amount, generating additional wheeling revenues of $1–2 million annually in that future.

$$\boldsymbol{Increased\ Wheeling\ Rev}\left(\frac{\$}{yr}\right) =$$

$$\left(\frac{\text{Hist.Wheeling Revenues}\left(\frac{\$}{\text{yr}}\right)}{\text{Hist.TSR Sold (MW)}}\right) \times \left(\frac{\text{Hist.TSR Sold (MW)}}{\text{Hist.ATC Increase (MW)}}\right) \times (\text{ATC Increase Due to ITP10 Proj. (MW)})$$

These revenues are extrapolated for the first 20 years using the slope between the two points and after that assumed to grow at the rate of inflation.

The 40-year NPV of benefits is estimated to be **zero** in Future 1 and **$27 million** in Future 2. These benefits are allocated based on the current revenue sharing method in SPP tariff. Figure 16.7 shows the distribution of wheeling revenue benefits for each SPP zone.

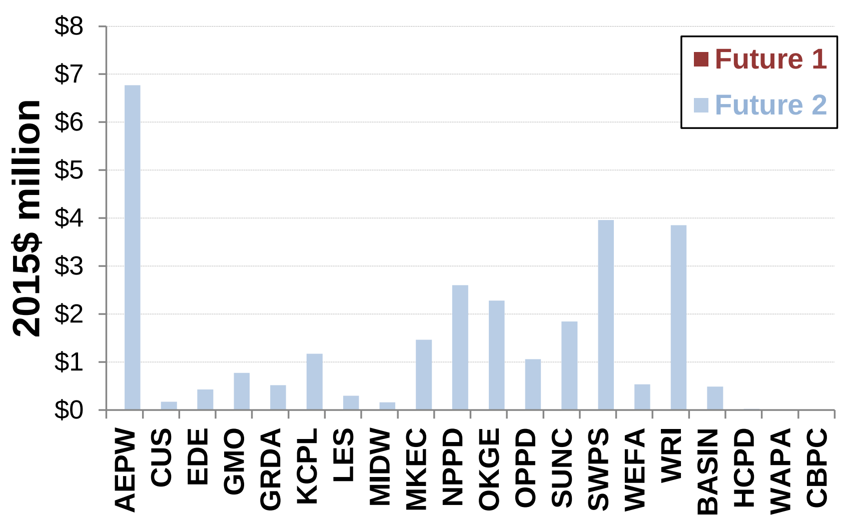


Figure 16.7: Increased Wheeling Revenue Benefits by Zone (40-year NPV)

16.10: Marginal Energy Losses Benefit

The standard production cost simulations used to estimate APC do not reflect the impact of transmission upgrades on the MWh quantity of transmission losses. To make run-times more manageable, the load in market simulations is “grossed up” for average transmission losses for each zone. These loss assumptions do not change with additional transmission. Therefore, the traditional APC metric does not capture the benefits from reduced MWh quantity of losses.

The benefits related to reduced transmission losses can be estimated through post-processing of the production cost simulation results for the change in the weighted average Marginal Loss Component (MLC) of LMPs for generation and load in each SPP zone. Table 16.7 below summarizes the loss reductions and associated production cost savings using the approach that was initially recommended by the MTF, and later refined for inter-zonal transfers and approved by the ESWG.[36] Figure 16.8 shows the zonal distribution of the NPV of benefits.

- In Future 1, the Consolidated Portfolio is estimated to increase the estimated energy losses in SPP by approximately 115,000 MWh/yr, which translates to negative benefits (-$4 million annually in both study years and -$50 million in NPV terms).
    - Negative savings are possible if the upgrades reduce congestion and increase inter-zonal transfers, transmission flows, and the associated losses due to inter-zonal transfers. The SPS zone is the main source of the negative savings in Future 1, and they are net importers both with and without the Consolidated Portfolio upgrades. However, the imports are greater with the upgrades. The upgrades provide congestion relief, which allows SPS access to cheaper resources located farther away. As a result, SPS sees APC savings but this gets partially offset by higher losses from being served by generation farther away.
- In Future 2, the calculated loss savings are minimal in 2019 and approximately 44,000 MWh/yr in 2024. System-wide benefits are estimated to be positive ($0.2 million in 2019, $2.6 million in 2024, and $58 million in NPV terms).

	2019		2024		40-yr
	Loss Reduction (MWh)	**Energy Savings (nom. $m)**	Loss Reduction (MWh)	**Energy Savings (nom. $m)**	**NPV of Savings (2015 $m)**
Future 1	(111,488)	**($4.4)**	(114,140)	**($4.3)**	**($50.7)**
Future 2	(1,812)	**$0.2**	44,036	**$2.6**	**$58.4**

Table 16.7: Energy Loss Reduction and Associated Production Cost Savings

36 http://www.spp.org/publications/ESWGMinutes

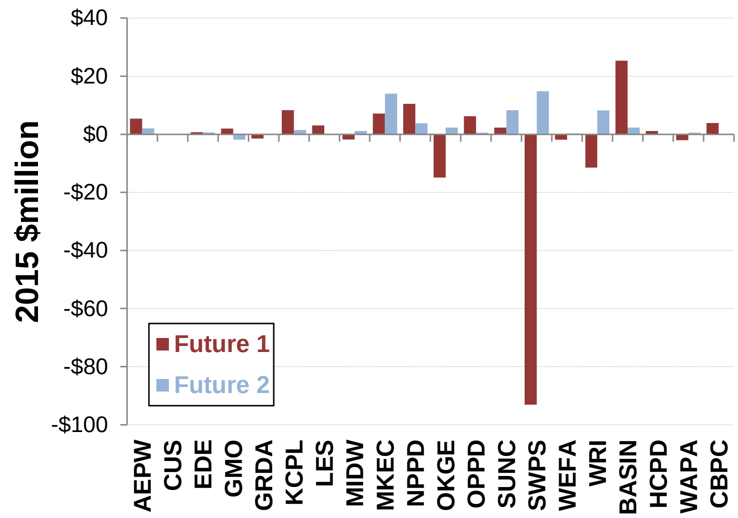


Figure 16.8: Energy Losses Benefit by Zone (40-year NPV)

16.11: Summary

Table 16.8 and Table 16.9 summarize the 40-year NPV of the estimated benefit metrics and costs (in 2015 dollars) and the resulting benefit-to-cost (B/C) ratios for each SPP zone.

For the region, the B/C ratio is estimated to be approximately 4.1 in Future 1 and about 2.0 in Future 2. Higher B/C ratio in Future 1 is driven by the APC savings due to higher congestion-relief provided by the Consolidated Portfolio.

	Present Value of 40-yr Benefits for the 2019-2058 Period (in 2015 $million)										
	APC Savings	Avoided or Delayed Reliability Projects	Capacity Savings from Reduced On-peak Losses	Assumed Benefit of Mandated Reliability Projects	Benefit from Meeting Public Policy Goals	Mitigation of Transmission Outage Costs	Increased Wheeling Through and Out Revenues	Marginal Energy Losses Benefits	Total Benefits	Present Value of 40-yr ATRRs (in 2015 $million)	Est. Benefit/ Cost Ratio
AEPW	($5)	$0	$2	$45	$0	$23	$0	$5	$71	$79	0.90
CUS	$2	$0	$0	$3	$0	$2	$0	$0	$7	$2	3.22
EDE	$8	$0	$0	$4	$0	$3	$0	$1	$15	$3	4.20
GMO	($0)	$0	($0)	$5	$0	$4	$0	$2	$11	$6	1.90
GRDA	($16)	$0	$0	$2	$0	$2	$0	($1)	($13)	$3	(4.35)
KCPL	$203	$0	$4	$8	$0	$8	$0	$8	$231	$11	21.69
LES	($2)	$0	$0	$3	$0	$2	$0	$3	$6	$3	2.17
MIDW	$10	$0	($0)	$1	$0	$1	$0	($2)	$10	$1	8.33
MKEC	$57	$0	$11	$16	$0	$2	$0	$7	$92	$2	46.37
NPPD	$143	$0	$2	$8	$0	$7	$0	$10	$171	$43	3.95
OKGE	$44	$0	$0	$24	$0	$15	$0	($15)	$68	$23	2.91
OPPD	$77	$0	$1	$9	$0	$6	$0	$6	$99	$11	8.85
SUNC	$34	$0	$15	$21	$0	$1	$0	$2	$73	$44	1.67
SWPS	$222	$0	$10	$41	$0	$14	$0	($93)	$194	$54	3.57
WEFA	($21)	$0	$0	$14	$0	$4	$0	($2)	($5)	$5	(1.03)
WRI	$235	$0	$1	$27	$0	$12	$0	($11)	$264	$30	8.76
IS	$28	$0	$0	$10	$0	$10	$0	$28	$77	$13	5.82
TOTAL	**$1,020**	**$0**	**$45**	**$241**	**$0**	**$115**	**$0**	**($51)**	**$1,370**	**$334**	**4.10**

Table 16.8: Estimated 40-year NPV of Benefit Metrics and Costs – Zonal (Future 1)

	Present Value of 40-yr Benefits for the 2019-2058 Period (in 2015 $million)										
	APC Savings	Avoided or Delayed Reliability Projects	Capacity Savings from Reduced On-peak Losses	Assumed Benefit of Mandated Reliability Projects	Benefit from Meeting Public Policy Goals	Mitigation of Trans-mission Outage Costs	Increased Wheeling Through and Out Revenues	Marginal Energy Losses Benefits	**Total Benefits**	**Present Value of 40-yr ATRRs (in 2015 $million)**	**Est. Benefit/ Cost Ratio**
AEPW	$2	$0	$2	$37	$0	$6	$6	$2	$55	$79	**0.70**
CUS	($1)	$0	$0	$6	$0	$0	$0	$0	$5	$2	**2.66**
EDE	($0)	$0	($0)	$4	$0	$1	$0	$1	$5	$3	**1.52**
GMO	($4)	$0	($0)	$10	$0	$1	$1	($2)	$6	$6	**1.01**
GRDA	($1)	$0	($0)	$3	$0	$1	$0	($0)	$3	$3	**1.05**
KCPL	$13	$0	$2	$11	$0	$2	$1	$1	$31	$11	**2.95**
LES	($6)	$0	$0	$3	$0	$1	$0	$0	($1)	$3	**(0.52)**
MIDW	($0)	$0	($0)	$5	$0	$0	$0	$1	$6	$1	**5.07**
MKEC	$20	$0	$9	$16	$0	$0	$1	$14	$61	$2	**30.64**
NPPD	$9	$0	$1	$11	$0	$2	$2	$4	$29	$43	**0.67**
OKGE	($4)	$0	($1)	$17	$0	$4	$2	$2	$21	$23	**0.90**
OPPD	$150	$0	$1	$10	$0	$2	$1	$1	$164	$11	**14.59**
SUNC	$6	$0	$16	$18	$0	$0	$2	$8	$50	$44	**1.13**
SWPS	$60	$0	$9	$34	$0	$4	$4	$15	$126	$54	**2.32**
WEFA	$5	$0	$0	$12	$0	$1	$1	$0	$19	$5	**4.06**
WRI	$24	$0	$2	$31	$0	$3	$4	$8	$72	$30	**2.39**
IS	$4	$0	($0)	$11	$0	$3	$0	$3	$20	$13	**1.55**
TOTAL	**$277**	**$0**	**$39**	**$241**	**$0**	**$31**	**$27**	**$58**	**$673**	**$334**	**2.01**

Table 16.9: Estimated 40-year NPV of Benefit Metrics and Costs – Zonal (Future 2)

	Present Value of 40-yr Benefits for the 2019-2058 Period (in 2015 $million)										
	APC Savings	Avoided or Delayed Reliability Projects	Capacity Savings from Reduced On-peak Losses	Assumed Benefit of Mandated Reliability Projects	Benefit from Meeting Public Policy Goals	Mitigation of Trans-mission Outage Costs	Increased Wheeling Through and Out Revenues	Marginal Energy Losses Benefits	**Total Benefits**	**Present Value of 40-yr ATRRs (in 2015 $million)**	**Est. Benefit/ Cost Ratio**
Arkansas	$5	$0	$0	$12	$0	$7	$0	($1)	$23	$19	**1.24**
Iowa	($14)	$0	$0	$1	$0	$1	$0	$5	($7)	$1	**-8.58**
Kansas	$435	$0	$28	$69	$0	$20	$0	$0	$553	$83	**6.68**
Louisiana	($1)	$0	$0	$6	$0	$3	$0	$1	$9	$11	**0.90**
Minnesota	$2	$0	$0	$0	$0	$0	$0	$0	$2	$0	**11.10**
Missouri	$112	$0	$2	$16	$0	$13	$0	$7	$149	$16	**9.09**
Montana	$7	$0	$0	$1	$0	$0	$0	$1	$9	$1	**13.98**
Oklahoma	$6	$0	$1	$56	$0	$29	$0	($16)	$76	$62	**1.22**
Nebraska	$234	$0	$3	$22	$0	$16	$0	$22	$296	$59	**5.05**
New Mexico	$61	$0	$3	$11	$0	$4	$0	($26)	$53	$15	**3.57**
North Dakota	($10)	$0	$0	$4	$0	$5	$0	$12	$11	$6	**1.72**
South Dakota	$30	$0	$0	$3	$0	$3	$0	$7	$42	$4	**11.21**
Texas	$154	$0	$8	$40	$0	$15	$0	($64)	$153	$58	**2.65**
Wyoming	($0)	$0	$0	$0	$0	$0	$0	$0	$0	$0	**0.38**
TOTAL	**$1,020**	**$0**	**$45**	**$241**	**$0**	**$115**	**$0**	**($51)**	**$1,370**	**$334**	**4.10**

Table 16.10: Estimated 40-year NPV of Benefit Metrics and Costs – State (Future 1)

	Present Value of 40-yr Benefits for the 2019-2058 Period (in 2015 $million)										
	APC Savings	Avoided or Delayed Reliability Projects	Capacity Savings from Reduced On-peak Losses	Assumed Benefit of Mandated Reliability Projects	Benefit from Meeting Public Policy Goals	Mitigation of Trans-mission Outage Costs	Increased Wheeling Through and Out Revenues	Marginal Energy Losses Benefits	**Total Benefits**	**Present Value of 40-yr ATRRs (in 2015 $million)**	**Est. Benefit/ Cost Ratio**
Arkansas	($0)	$0	$0	$10	$0	$2	$2	$1	$14	$19	**0.74**
Iowa	($1)	$0	($0)	$1	$0	$0	$0	$0	($0)	$1	**-0.15**
Kansas	$56	$0	$27	$76	$0	$5	$8	$32	$204	$83	**2.47**
Louisiana	$0	$0	$0	$5	$0	$1	$1	$0	$7	$11	**0.70**
Minnesota	$0	$0	($0)	$0	$0	$0	$0	$0	$0	$0	**1.86**
Missouri	$1	$0	$1	$25	$0	$3	$2	($0)	$32	$16	**1.96**
Montana	$0	$0	($0)	$1	$0	$0	$0	$0	$1	$1	**2.10**
Oklahoma	$3	$0	$0	$46	$0	$8	$6	$3	$66	$62	**1.07**
Nebraska	$154	$0	$1	$26	$0	$4	$4	$5	$194	$59	**3.31**
New Mexico	$17	$0	$2	$9	$0	$1	$1	$4	$35	$15	**2.32**
North Dakota	$2	$0	($0)	$4	$0	$1	$0	$1	$8	$6	**1.37**
South Dakota	$2	$0	($0)	$3	$0	$1	$0	$1	$7	$4	**1.89**
Texas	$43	$0	$7	$34	$0	$4	$4	$11	$102	$58	**1.77**
Wyoming	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**1.29**
TOTAL	**$277**	**$0**	**$39**	**$241**	**$0**	**$31**	**$27**	**$58**	**$673**	**$334**	**2.01**

Table 16.11: Estimated 40-year NPV of Benefit Metrics and Costs – State (Future 2)

16.12: Rate Impacts

The rate impact to the average retail residential ratepayer in SPP was estimated for the Consolidated Portfolio. Rate impact costs and benefits[37] are allocated to an average retail residential ratepayer based on an estimated residential consumption of 1,000 kWh per month. Benefits and costs for the 2024 study year were used to calculate rate impacts. All 2024 benefits and were adjusted to 2015 $ using a 2.5% inflation rate.

The retail residential rate impact benefit is subtracted from the retail residential rate impact cost, to obtain a net rate impact cost by zone. If the net rate impact cost is negative, it indicates a net benefit to the zone. The rate impact costs and benefits are shown in Table 16.12. There is a monthly net benefit for the average SPP residential ratepayer of **5 cents per kWh**.

[37] APC Savings are the only benefit included in the rate impact calculations.

Zone	One-Year ATRR Costs	One-Year Benefit	Rate Impact - Cost	Rate Impact - Benefit	Net Impact: Cost Less Benefit
American Electric Power	$8,895,937	$221,218	$0.17	$0.00	$0.16
City Utilities of Springfield	$198,214	$79,900	$0.06	$0.02	$0.04
Empire District Electric	$337,955	$343,580	$0.06	$0.06	($0.00)
Grand River Dam Authority	$283,545	($661,023)	$0.05	($0.11)	$0.16
Greater Missouri Operations	$556,065	($110,473)	$0.07	($0.01)	$0.08
Kansas City Power & Light	$1,027,400	$8,833,340	$0.07	$0.57	($0.50)
Lincoln Electric System	$265,860	($57,185)	$0.07	($0.01)	$0.08
Mid-Kansas Electric	$191,635	$3,489,151	$0.05	$0.87	($0.82)
Midwest Energy, Inc.	$113,627	$1,623,167	$0.05	$0.73	($0.68)
Nebraska Public Power District	$3,821,408	$7,345,848	$0.22	$0.43	($0.21)
Oklahoma Gas and Electric	$2,224,279	$1,401,473	$0.06	$0.04	$0.02
Omaha Public Power District	$1,044,250	$3,403,180	$0.08	$0.24	($0.17)
Southwestern Public Service	$5,936,703	$8,241,180	$0.13	$0.18	($0.05)
Sunflower Electric	$3,810,188	$2,230,104	$0.93	$0.54	$0.39
Upper Missouri Zone	$1,272,462	$852,049	$0.04	$0.03	$0.01
Westar Energy	$3,021,404	$10,922,556	$0.09	$0.31	($0.23)
Western Farmers	$451,771	($932,679)	$0.05	($0.09)	$0.14
TOTAL	**33,452,703**	**47,225,386**	**$0.11**	**$0.16**	**($0.05)**

Table 16.12: 2024 Retail Residential Rate Impacts by Zone (2015 $ & $/MWh)

Section 17: Sensitivities

A group of sensitivities were developed by the ESWG to understand the economic impacts associated with variations in certain model inputs. These sensitivities were not used to develop transmission projects or filter out projects; they measure the performance of the Consolidated Portfolio projects (economic and reliability) under different input assumptions. The following sensitivities were performed using Future 1 as a base:

- High Natural Gas Price
- Low Natural Gas Price
- High Demand
- Low Demand
- Increased Input Prices
- HVDC Projects
  - Tres Amigas HVDC Tie
  - Plains and Eastern Clean Line HVDC Project

The economic impacts of variations in the model inputs (natural gas price, demand) were captured for the Consolidated Portfolio projects. One-year B/C ratios are shown for all sensitivity and non-sensitivity runs in Figure 17.1, with benefits based on APC savings only. It also shows all sensitivities in which the one-year B/C is less than 1.0.

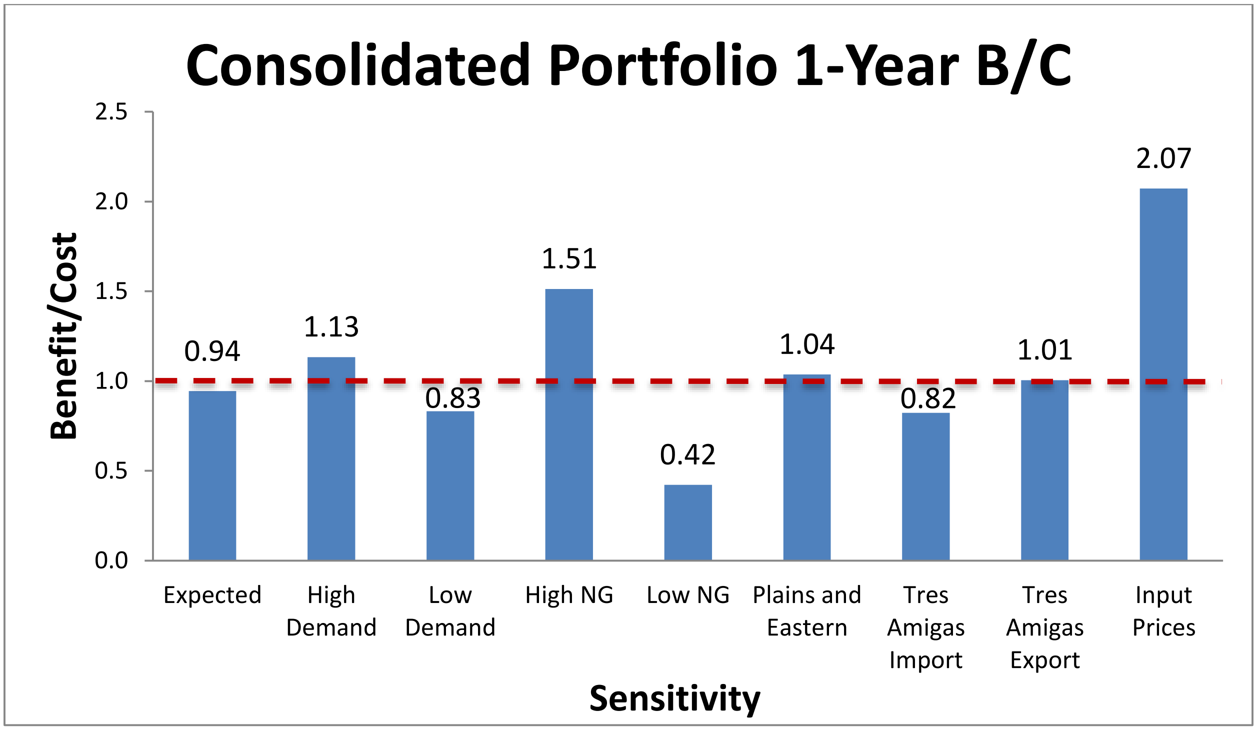


Figure 17.1: Future 1 Sensitivities – APC Benefit

All sensitivity results show one-year benefits and costs, rather than 40-year benefits and costs. The results show the highest one-year B/Cs under the increased input prices and high gas prices assumptions. The lowest one-year B/Cs result from the low gas prices, Tres Amigas import, and low demand sensitivities. The results also show that the Consolidated Portfolio has positive APC benefits for all sensitivities. In some of these cases, the one-year benefit is less than the one-year cost of $58M. For detailed discussion on these results, see the following sections.

Demand and Natural Gas

Two confidence intervals were developed using historical market prices and demand levels from the NYMEX and FERC Form No. 714. The standard deviation of the log difference from the normal within the pricing data sets was used to provide a confidence interval. The Natural Gas Price sensitivity had a 95% confidence interval (1.96 standard deviations) in the positive and negative directions, while the Demand Level sensitivity had a 67% confidence interval (1 standard deviation) in the positive and negative directions.

The resulting assumptions are shown in Table 17.1 and Figure 17.2

Sensitivity	Peak Demand and Energy[38]	Natural Gas Price 2024 ($/MMBtu)[39]
Expected Demand & NG	No change	$6.83 (No change)
High Demand	7.8% Increase	No change
Low Demand	7.8% Decrease	No change
High Natural Gas	No change	$8.69
Low Natural Gas	No change	$4.96

Table 17.1: Natural Gas and Demand Changes (2024)

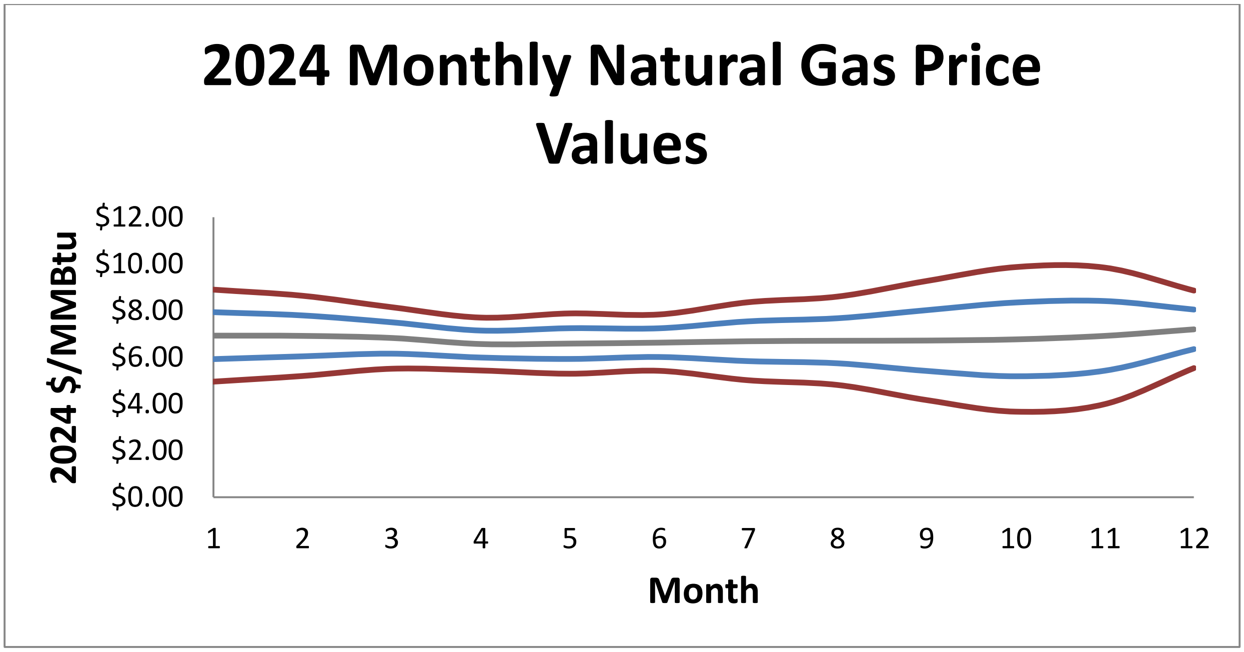


Figure 17.2: Monthly Natural Gas Price Values (2024)

The change in peak demand and energy shown in Table 17.1 reflect the SPP regional average volatility based on historical data. The volatility numbers and resulting high and low bands were calculated and implemented on the Demand Group (load company) level. These high and low bands show a deviation from the projected 2024 load forecasts developed by the Model Development Working Group (MDWG) and reviewed by the ESWG. For those companies which data was not available, the SPP regional average confidence interval was used.

[38] SPP Regional Average

[39] Henry Hub 2024 monthly average

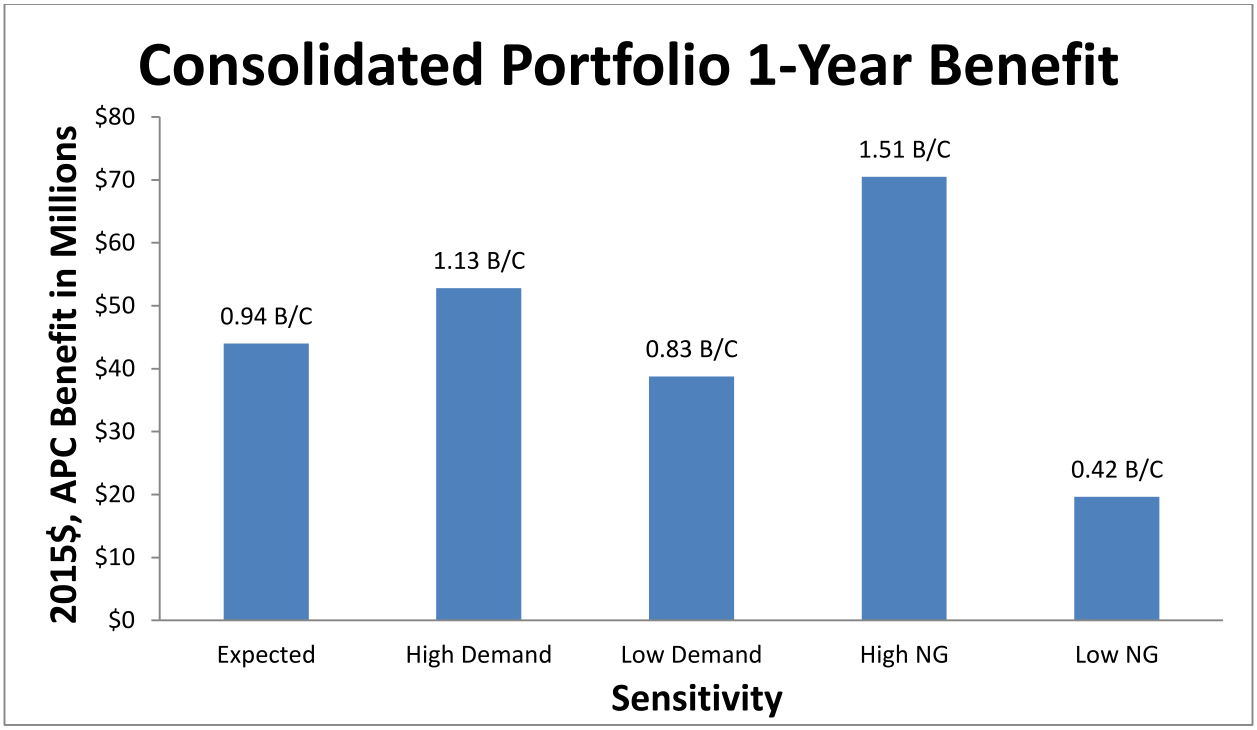


Figure 17.3: *One-Year APC Benefits of Consolidated Portfolio for Demand and Natural Gas Sensitivities*

These high and low band values were included as inputs to the Future 1 base model and the model evaluating the final consolidated portfolio. The results of the demand and natural gas sensitivities are reflected in Figure 17.3 and show an increase in APC benefit for the high demand and high natural gas cases. Low demand and low natural gas assumptions result in less APC benefit than the expected case.

An increase in demand creates an increase in congestion on the SPP system which allows more congestion costs for the consolidated portfolio to mitigate, thus increasing the benefit. The opposite is true for the low demand case. An increase in gas prices has a similar result of an increase in demand, but reflects an increase in price of overall energy, not necessarily an increase in congestion on the system. The high natural gas sensitivity shows the ability of the portfolio to reduce overall energy costs, by allowing cheaper generation to dispatch that was previously trapped by the model constraints. This is the same effect of the portfolio performance in the expected case, but is amplified by the increase in energy prices, thus showing more benefit. The low natural gas sensitivity has the opposite effect.

Increased Input Prices

This sensitivity was driven by considering multiple factors that could result in increased fuel prices, for example, more restrictive regulations over shale fracturing, and a carbon tax on fossil unit emissions. It assumes a threefold increase of natural gas prices and a $36/ton carbon tax. As a reaction to the increased energy prices, the sensitivity also assumes a reduction in the rate of load growth of 1% per year. Because the drivers of this sensitivity could result in a potential shift in resource fleets in the future, the reduction of emissions and emission rates metric was calculated in addition to the APC benefits for the portfolio.

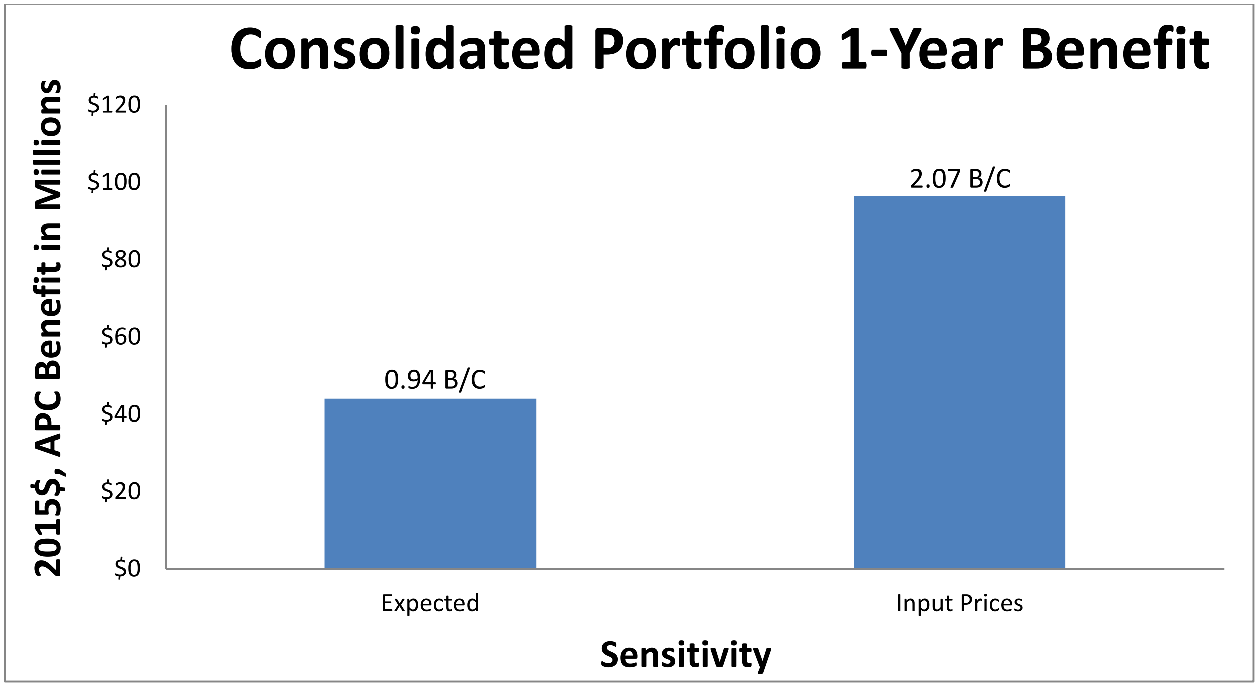


Figure 17.4: *One -Year APC Benefits of Consolidated Portfolio for Increased Input Prices Sensitivity*

Assuming increased natural gas prices and a tax on carbon emissions result in the consolidated portfolio having more than twice the APC benefit of the base case, as seen in *Figure* 17.4. These results are very similar to the high natural gas sensitivity. While the overall cost in energy has increased, the final portfolio still allows for a reduction in energy costs by allowing cheaper generation to dispatch. The fact that both the price of coal and gas were effectively increased in a similar fashion, the resulting resource mix does not change with or without the final portfolio. The carbon tax coupled with the tripling of natural gas prices as an input does not allow for gas to become more competitive than coal. In addition, this sensitivity did not consider an adjustment to the resource plan included in the Future 1 assessment, thus did not realize the potential for a shift in resource fleets to other energy sources, e.g. wind.

Figure 17.5 and Figure 17.6 show a change in emissions and emission rates, respectively, realized by the consolidated portfolio in this sensitivity.

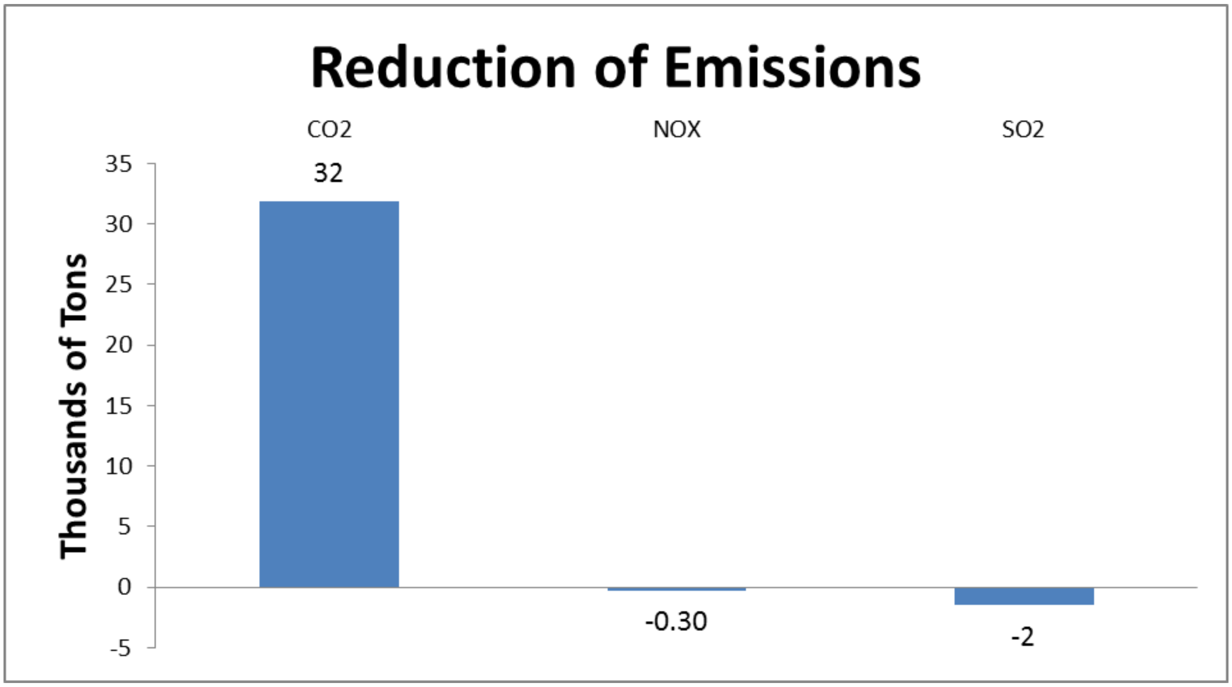


Figure 17.5: Reduction of Emissions in the Increased Input Prices Sensitivity

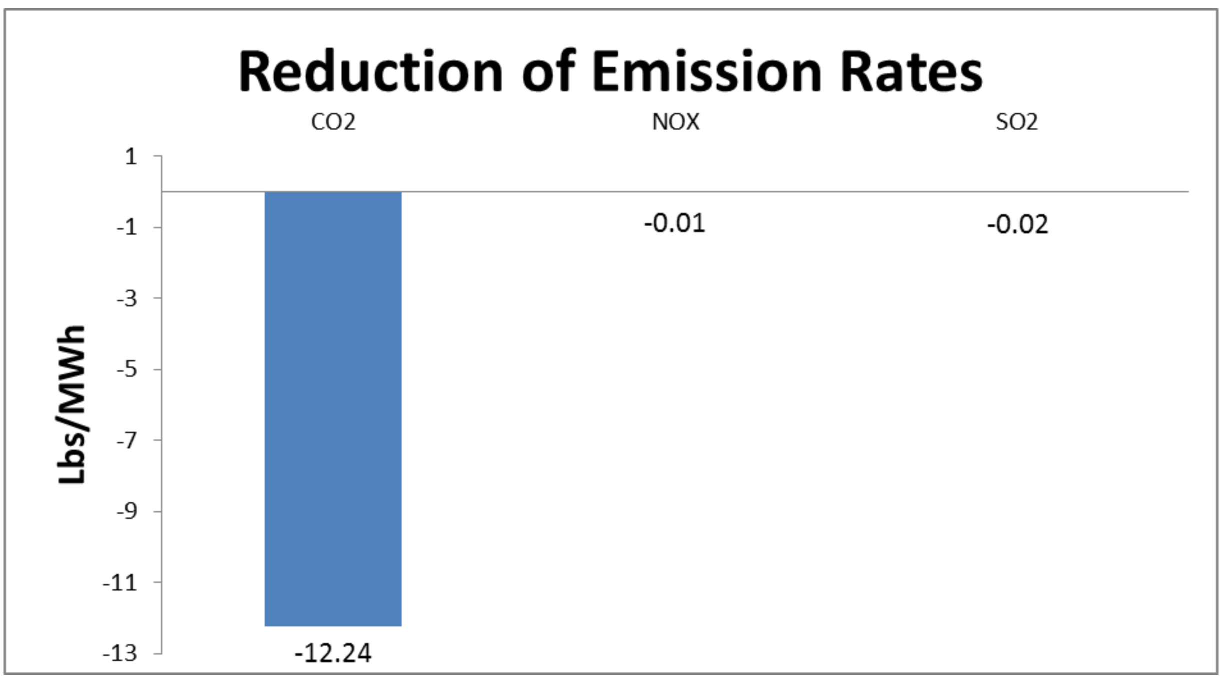


Figure 17.6: Reduction of Emission Rates in the Increased Input Prices Sensitivity

Figure 17.5 shows that the final portfolio allowed for a raw reduction in CO2 with slight increases in NOX and SO2 within the SPP footprint. This is somewhat counter to the reduction of emission rates shown in Figure 17.6 for CO2, which shows an increase in Lbs/MWh for plants within SPP. This is due to the ability of the portfolio to allow more imports from cheaper generation external to the SPP, offsetting slightly more expensive SPP resources. While allowing for more imports, the portfolio also increases emissions of the fleet within SPP. This is driven by the fact that the overall dispatched resource mix of SPP units changes only slightly, actually allowing more and cheaper coal generation to dispatch.

HVDC Projects

In order to understand the flexibility of the Consolidated Portfolio to mitigate unforeseen congestion under the potential integration of HVDC projects, the Tres Amigas HVDC interconnection tie and the Plains and Eastern Clean Line HVDC transmission line were independently included in this set of sensitivities.

The Tres Amigas HVDC project is an interconnection tie expected to connect the Western Interconnection, the Eastern Interconnection, and ERCOT. Located in Clovis, NM, this project is expected to connect to the SPP footprint via the Southwestern Public Service Company transmission system. The portfolio was evaluated under the assumption that the Tres Amigas tie has a 750MW capacity capability with the Eastern Interconnection and the ability to import or export across the tie.

The Plains and Eastern Clean Line project is a 711 mile HVDC transmission line expected to deliver wind power from the Oklahoma panhandle to utilities in the mid-south and southeastern US. The line is expected to connect to the SPP system near Guymon, OK and deliver wind energy to multiple points, ending near Memphis, TN. The portfolio was evaluated under the assumption that the HVDC line would garner customers from the SPP region, requesting transfer of an aggregate 2,000 MW of maximum nameplate power across the line. An energy profile matching that of wind resources in the Hitchland area of the SPS system was utilized for this sensitivity.

The impact of the HVDC projects on the APC benefit associated with the Consolidated Portfolio is shown in Figure 17.7.

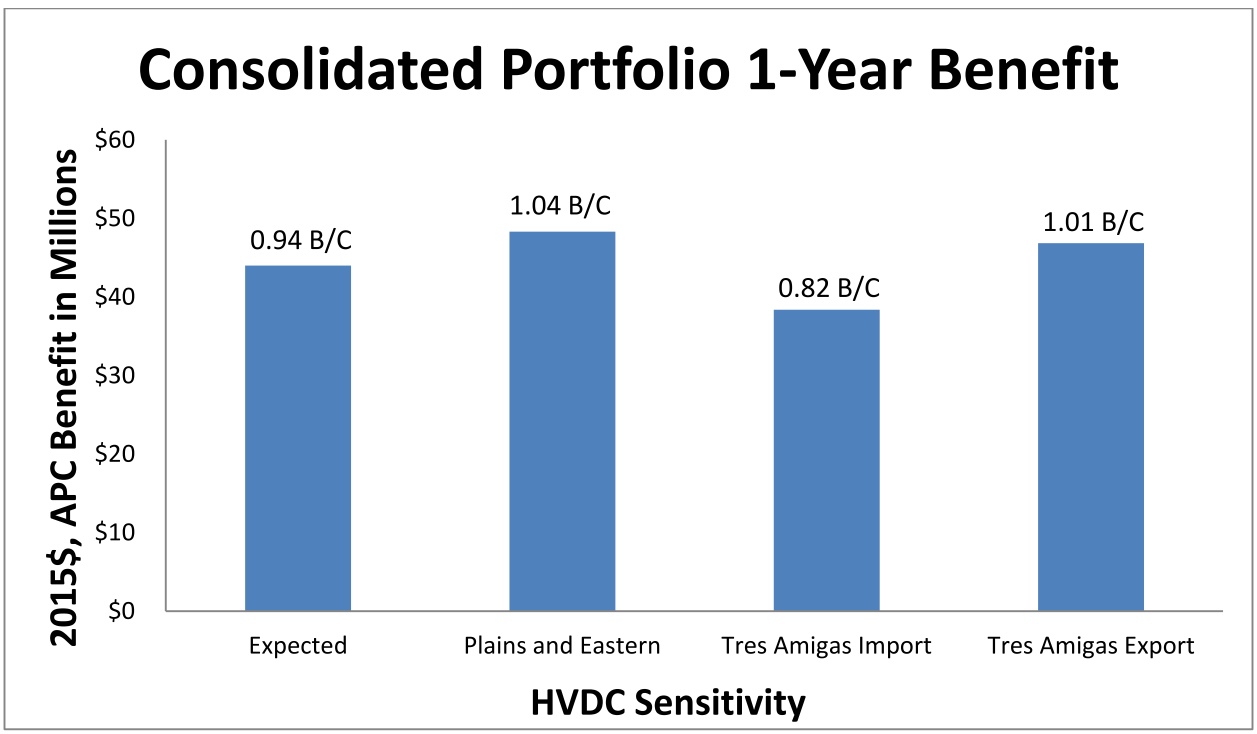


Figure 17.7: One-Year APC Benefits of Consolidated Portfolio for HVDC Project Sensitivities

The benefit of the Consolidated Portfolio increases under the Plains and Eastern Clean Line and Tres Amigas Export sensitivities. This is due to the increase in congestion caused by power flows utilizing these projects similar to that of the base Future 1 model. Both sensitivities increase flows from north to south, further aggravating the general north to south system flows of the SPP footprint. The Consolidated Portfolio is able to mitigate a portion of this increased congestion, thus producing more benefit in a single study year than seen in the base Future 1 model in that same study year.

The benefit of the Consolidated Portfolio decreases under the Tres Amigas Import sensitivity. This is due to anticipated mitigation of congestion through the injection of power in the SPS area by the Tres Amigas project when importing power into the SPP grid, which pushes back against the typical north to south flows of the SPP system. This mitigation of congestion in some areas provides less economic opportunity and lowers the overall benefit of the Consolidated Portfolio within the single study year chosen.

PART IV: APPENDICES

Section 18: Glossary of Terms

The following terms are referred to throughout the report.

Acronym	Description	Acronym	Description
APC	Adjusted Production Cost	**LMP**	Locational Marginal Price
APC-based B/C	Adjusted Production Cost based Benefit to Cost ratio	**LSE**	Load Serving Entity
ATC	Available Transfer Capability	**MDWG**	Model Development Working Group
ATRR	Annual Transmission Revenue Requirement	**MISO**	Midcontinent Independent System Operator, Inc.
B/C	Benefit to Cost Ratio	**MOPC**	Markets and Operations Policy Committee
CBA	Consolidated Balancing Authority	**MTF**	Metrics Task Force
BOD	SPP Board of Directors	**MVA**	Mega Volt Ampere (10^6 Volt Ampere)
Carbon Price	The tax burden associated with CO_2 emissions	**MW**	Megawatt (10^6 Watts)
CAWG	Cost Allocation Working Group	**NCS**	Non Competitive Solutions
DPP	Detailed Project Proposal	**NERC**	North American Electric Reliability Corporation
EHV	Extra-High Voltage	**NREL**	National Renewable Energy Laboratory
EIS	Energy Imbalance Service	**NTC**	Notification to Construct
EPA	Environmental Protection Agency	**NTC-C**	Notification to Construct with Conditions
ESWG	Economic Studies Working Group	**OATT**	Open Access Transmission Tariff
FCITC	First Contingency Incremental Transfer Capability	**RES**	Renewable Energy Standard
FERC	Federal Energy Regulatory Commission	**RSC**	SPP Regional State Committee
GI	Generation Interconnection	**RTWG**	Regional Tariff Working Group
GOF	Generator Outlet Facilities	**SPC**	Strategic Planning Committee
GW	Gigawatt (10^9 Watts)	**SPP**	Southwest Power Pool, Inc.
HPILS	High Priority Incremental Load Study	**STEP**	SPP Transmission Expansion Plan
HVDC	High-Voltage Direct Current	**TPL**	Transmission Planning NERC Standards
IS	Integrated System	**TO**	Transmission Owner
ITPNT	Integrated Transmission Plan Near-Term Assessment	**TOSP**	Transmission Owner Selection Process
ITP10	Integrated Transmission Plan 10-Year Assessment	**TSR**	Transmission Service Request
ITP20	Integrated Transmission Plan 20-Year Assessment	**TVA**	Tennessee Valley Authority
LIP	Locational Imbalance Price	**TWG**	Transmission Working Group

Section 19: Final Assessments

19.1: Final Stability Assessment

An assessment was performed to confirm the wind dispatched for 2015 ITP10 Consolidated Portfolio 2024 Summer Peak case in Futures 1 and 2 can be achieved without the occurrence of voltage instability. The transfer limit (MW) due to transfer of wind to the Tier 1 areas from the SPP footprint was also assessed.

Method

To determine the amount of wind generation that could be accommodated in the ITP10 study for Futures 1 and 2, wind[40] generation in SPP was increased and conventional (i.e. coal, gas, etc.) generation in the Tier 1 footprint was decreased. The plant total wind, used in the study, equated to 12.9 GW, as shown in Table 19.1. The wind transfer units were located in SPP, WAPA, and ALTW. Designated wind plants with long-term firm transmission service to external entities delivered 1,174 MW to SOCO, Entergy, and AECI, as detailed in Table 19.2. After these transfers were included in the base case assumptions, these plants had an additional 472 MW of generation capacity remaining to participate in the wind transfer to Tier 1.

Future	Wind Generation (GW)
1	12.9
2	12.9

Table 19.1: Wind Generation per Future

From Area	To Area	Transfer MW
SPS	SOCO	206
OKGE/WFEC	Entergy	302
WRI/SUNC	Entergy	366
WRI	AECI	300
	TOTAL =	1,174

Table 19.2: Modeled Wind generation per future

To prepare for the wind transfer all SPP wind transfer units that were initially off in the base cases were turned on. The SPP wind was increased while the Tier 1 conventional generation was decreased until voltage collapse occurred in the pre-contingency models.[29] N-1 contingencies of 345 kV and 500 kV facilities were also analyzed for maximum power transfer. A large volume of 345 kV N-1 outages were analyzed, 222 transformers and 321 lines.

[40] Transfer step size is 100 MW. Nebraska Entity (NE) EHV line reactors are ON in the base cases.

Consolidated Portfolio Wind Dispatch

Each Future was evaluated for increasing wind transfer amounts to determine different voltage collapse points of the transmission system, with the final consolidated portfolio in service. Wind plants were increased in 100 MW increments, beginning with the base wind dispatch of the AC model for each specific hour analyzed. In order to reach collapse points which may occur higher than the total installed wind capacity for SPP, existing sites were scaled on a pro-rata basis above their maximum capacity. Multiple transfer limits were determined based on the worst N-1 contingency and independently evaluating the next worst contingency to determine the top 5 MW transfer limits. A single limit may have been reached by one contingency or multiple different contingencies evaluated independently. The maximum transfer limit for system intact conditions was also determined for each Future.

Future 1 wind transfer in the ITP10 consolidated portfolio caused voltage collapse for one N-1 event each at 13.09 GW, 13.69 GW, and 13.79 GW, respectively. The same scenario with Future 1 wind transfer in the ITP 10 consolidated portfolio caused voltage collapse at 13.99 GW for four events and 14.09 GW for 87 events. A wind transfer of 14.19 GW caused voltage collapse under no contingency conditions.

Future 2 wind transfer in the ITP10 consolidated portfolio caused voltage collapse at 12.97 GW for one N-1 event, 13.07 GW for two N-1 events, 13.17 GW for three N-1 events, 13.27 GW for one N-1 event, 13.37 GW for 17 N-1 events, and 13.47 GW for 137 N-1 events. A wind transfer of 13.57 GW caused voltage collapse under no contingency conditions.

A summary of voltage collapse wind transfer limits with outages is in Table 19.3.

Future	Wind Power Peak (MW)	N-1 Wind Power (MW) Scaled to Voltage Collapse Limit 1	Limit 2	Limit 3	Limit 4	Limit 5	N-0 Maximum Transfer (MW)
F1	12,858	13,088	13,688	13,788	13,988	14,088	14,188
F2	12,858	12,968	13,068	13,168	13,268	13,368	13,568

Table 19.3: Modeled Wind generation per future

Future 1 and 2 detailed transfer limits with outages are in Table 19.4 and Table 19.5 respectively.

Wind Dispatch MW	Outage Bus 1	Bus 2	Transformer Bus 3	ID
13,088	HOYT 7 345.	JEC N 7 345.		1
13,688	STILWEL7 345.	LACYGNE7 345.		1
13,788	HOYT 7 345.	STRANGR7 345.		1
13,988	PITTSB-7 345.	VALIANT7 345.		1
13,988	PITTSB-7 345.	SEMINOL7 345.		1
13,988	O.K.U.-7 345.	TUCO_INT 7345.		1
13,988	MUSKOGE7 345.	FTSMITH7 345.		1
14,088	WILKES CC 345.	WILKES 7 345.		1
14,088	HOBANDPLT 345.	RDRUNNER 7345.		1

Wind Dispatch MW	Bus 1	Bus 2	Transformer Bus 3	ID
14,088	8ANO 500.	FTSMITH8 500.		1
14,088	7OVERTON 345.	SIBLEY 7 345.		1
14,088	FLINTCR7 345.	TONECE7 345.		1
14,088	FLINTCR7 345.	BROOKLINE 7345.		1
14,088	CHAMSPR7 345.	CLARKSV7 345.		1
14,088	SHIPERD7 345.	KINGRIV7 345.		1
14,088	LYDIA 7 345.	VALIANT7 345.		1
14,088	R.S.S.-7 345.	REDBUD 7 345.		1
14,088	T.NO.--7 345.	CLEVLND7 345.		1
14,088	DELWARE7 345.	NEOSHO 7 345.		1
14,088	PITTSB-7 345.	JOHNCO 7 345.		1
14,088	O.K.U.-7 345.	L.E.S.-7 345.		1
14,088	CHISHOLM7 345.	GRACMNT7 345.		1
14,088	GRDA1 7 345.	TONECE7 345.		1
14,088	CLEVLND7 345.	SOONER 7 345.		1
14,088	MINCO 7 345.	GRACMNT7 345.		1
14,088	NORTWST7 345.	ARCADIA7 345.		1
14,088	NORTWST7 345.	MATHWSN7 345.		1
14,088	CIMARON7 345.	MCCLAIN TP7 345.		1
14,088	DRAPER 7 345.	MCCLAIN TP7 345.		1
14,088	MUSKOGE7 345.	C-RIVER7 345.		1
14,088	WWRDEHV7 345.	TATONGA7 345.		1
14,088	WWRDEHV7 345.	TATONGA7 345.		2
14,088	WWRDEHV7 345.	BEAVER CO 345.		1
14,088	WWRDEHV7 345.	BEAVER CO 345.		2
14,088	TATONGA7 345.	MATHWSN7 345.		1
14,088	TATONGA7 345.	MATHWSN7 345.		2
14,088	FINNEY 7345.	LAMAR7 345.		1
14,088	POSTROCK7 345.	SPERVIL7 345.		1
14,088	POSTROCK7 345.	AXTELL 3 345.		1
14,088	MINGO 7 345.	SETAB 7 345.		1
14,088	MINGO 7 345.	REDWILO3 345.		1
14,088	SPERVIL7 345.	BUCKNER7 345.		1
14,088	SPERVIL7 345.	CLARKCOUNTY7345.		1
14,088	JEC N 7 345.	GEARY 7 345.		1
14,088	JEC N 7 345.	MORRIS 7 345.		1
14,088	EMPEC 7 345.	LANG 7 345.		1
14,088	EMPEC 7 345.	WICHITA7 345.		1
14,088	RENO 7 345.	SUMMIT 7 345.		1
14,088	STRANGR7 345.	IATAN 7 345.		1

Wind Dispatch MW	Bus 1	Bus 2	Transformer Bus 3	ID
14,088	STRANGR7 345.	IATAN 7 345.		2
14,088	SUMMIT 7 345.	ELMCREEK7 345.		1
14,088	MOUNDRG7 345.	WICHITA7 345.		1
14,088	CANEYRV7 345.	NEOSHO 7 345.		1
14,088	CANEYRV7 345.	LATHAMS7 345.		1
14,088	BENTON 7 345.	ROSEHIL7 345.		1
14,088	BENTON 7 345.	WICHITA7 345.		1
14,088	BENTON 7 345.	WOLFCRK7 345.		1
14,088	WICHITA7 345.	VIOLA 7 345.		1
14,088	WICHITA7 345.	THISTLE7 345.		1
14,088	WICHITA7 345.	THISTLE7 345.		2
14,088	WOLFCRK7 345.	ANDERSONCO 345.		1
14,088	CLARKCOUNTY7345.	THISTLE7 345.		1
14,088	CLARKCOUNTY7345.	THISTLE7 345.		2
14,088	CLARKCOUNTY7345.	IRONWOOD7 345.		1
14,088	MULLNCR7 345.	SIBLEY 7 345.		1
14,088	PECULR 7 345.	PHILL 7 345.		1
14,088	PECULR 7 345.	STILWEL7 345.		1
14,088	ST JOE 3 345.	NASHUA 7 345.		1
14,088	ST JOE 3 345.	G10-056T 345.		1
14,088	PHILL 7 345.	SIBLEY 7 345.		1
14,088	W.GRDNR7 345.	CRAIG 7 345.		1
14,088	W.GRDNR7 345.	LACYGNE7 345.		1
14,088	LACYGNE7 345.	ANDERSONCO 345.		1
14,088	GRPRWND7 345.	FTTHOMP3 345.		1
14,088	RAUN 3 345.	HOSKINS3 345.		1
14,088	AXTELL 3 345.	PAULINE3 345.		1
14,088	GENTLMN3 345.	REDWILO3 345.		1
14,088	GENTLMN3 345.	SWEET W3 345.		2
14,088	GENTLMN3 345.	CHERRYC3 345.		1
14,088	MCCOOL 3 345.	MOORE 3 345.		1
14,088	MCCOOL 3 345.	GR ISLD3 345.		1
14,088	MOORE 3 345.	PAULINE3 345.		1
14,088	SWEET W3 345.	GR ISLD3 345.		1
14,088	HOLT.CO3 345.	GR ISLD3 345.		1
14,088	LARAMIE3 345.	STEGALL3 345.		1
14,088	CHISHOLM7 345.	CHISHOLM6 230.	CHISHOLM1 13.2	1
14,088	FTSMITH7 345.	FTSMITH8 500.	FTSMTH11 13.8	1
14,088	POTASH_JCT 7345.	POTASH_JCT 3115.	POTASH_TR4 113.2	1
14,088	POSTROCK7 345.	POSTROCK6 230.	POSTROCK1 13.8	1

Wind Dispatch MW	Bus 1	Bus 2	Transformer Bus 3	ID
14,088	HOYT 7 345.	HOYT 3 115.	HOYT 1 14.4	1
14,088	GEARY 7 345.	GEARY 3 115.	GEARY1X1 13.8	1
14,088	LANG 7 345.	LANG 3 115.	LANG 1 14.4	1
14,088	SUMMIT 7 345.	SUMMIT 6 230.	SUMMIT 1 14.4	1
14,088	REDWILO7 115.	REDWILO3 345.	REDWILO9 13.8	1
14,188	Pre Contingency			

Table 19.4: Future 1 Voltage Collapse Transfers

Wind Dispatch MW	Outage			
	Bus 1	Bus 2	Transformer Bus 3	ID
12,968	MUSKOGE7 345.	FTSMITH7 345.		1
13,068	CHAMSPR7 345.	CLARKSV7 345.		1
13,068	HOYT 7 345.	JEC N 7 345.		1
13,168	PITTSB-7 345.	VALIANT7 345.		1
13,168	PITTSB-7 345.	SEMINOL7 345.		1
13,168	GRDA1 7 345.	TONECE7 345.		1
13,268	8ANO 500.	FTSMITH8 500.		1
13,368	O.K.U.-7 345.	L.E.S.-7 345.		1
13,368	O.K.U.-7 345.	TUCO_INT 7345.		1
13,368	CHISHOLM7 345.	GRACMNT7 345.		1
13,368	CLEVLND7 345.	SOONER 7 345.		1
13,368	MINCO 7 345.	GRACMNT7 345.		1
13,368	WWRDEHV7 345.	BORDER 7345.		1
13,368	TATONGA7 345.	MATHWSN7 345.		1
13,368	TATONGA7 345.	MATHWSN7 345.		2
13,368	BORDER 7345.	TUCO_INT 7345.		1
13,368	HITCHLAND 7345.	WALKTAP7 345.		1
13,368	FINNEY 7345.	HOLCOMB7 345.		1
13,368	POSTROCK7 345.	SPERVIL7 345.		1
13,368	POSTROCK7 345.	AXTELL 3 345.		1
13,368	HOLCOMB7 345.	SETAB 7 345.		1
13,368	MINGO 7 345.	SETAB 7 345.		1
13,368	MINGO 7 345.	REDWILO3 345.		1
13,368	LACYGNE7 345.	ANDERSONCO 345.		1
13,468	CCS4 CC 345.	WILKES 7 345.		1
13,468	CCS3 CC 345.	WILKES 7 345.		1
13,468	HOBANDPLT 345.	RDRUNNER 7345.		1
13,468	7FAIRPT 345.	ST JOE 3 345.		1
13,468	7FAIRPT 345.	COOPER 3 345.		1
13,468	7SPORTSMAN 345.	GRDA1 7 345.		1
13,468	7OVERTON 345.	SIBLEY 7 345.		1
13,468	FLINTCR7 345.	SHIPERD7 345.		1
13,468	FLINTCR7 345.	TONECE7 345.		1
13,468	FLINTCR7 345.	BROOKLINE 7345.		1
13,468	SHIPERD7 345.	KINGRIV7 345.		1
13,468	NWTXARK7 345.	VALIANT7 345.		1
13,468	LYDIA 7 345.	WELSH 7 345.		1
13,468	LYDIA 7 345.	VALIANT7 345.		1
13,468	CLARKSV7 345.	ONETA--7 345.		1

Wind Dispatch MW	Bus 1	Bus 2	Transformer Bus 3	ID
13,468	WEKIWA-7 345.	T.NO.--7 345.		1
13,468	R.S.S.-7 345.	REDBUD 7 345.		1
13,468	R.S.S.-7 345.	PECANCK7 345.		1
13,468	T.NO.--7 345.	CLEVLND7 345.		1
13,468	DELWARE7 345.	N.E.S.-7 345.		1
13,468	DELWARE7 345.	NEOSHO 7 345.		1
13,468	PITTSB-7 345.	JOHNCO 7 345.		1
13,468	PITTSB-7 345.	C-RIVER7 345.		1
13,468	L.E.S.-7 345.	GRACMNT7 345.		1
13,468	WOODRNG7 345.	SOONER 7 345.		1
13,468	MINCO 7 345.	CIMARON7 345.		1
13,468	SOONER 7 345.	SPRNGCK7 345.		1
13,468	JOHNCO 7 345.	SUNNYSD7 345.		1
13,468	NORTWST7 345.	SPRNGCK7 345.		1
13,468	NORTWST7 345.	ARCADIA7 345.		1
13,468	CIMARON7 345.	MCCLAIN TP7 345.		1
13,468	ARCADIA7 345.	SEMINOL7 345.		1
13,468	DRAPER 7 345.	MCCLAIN TP7 345.		1
13,468	MUSKOGE7 345.	C-RIVER7 345.		1
13,468	WWRDEHV7 345.	TATONGA7 345.		1
13,468	WWRDEHV7 345.	TATONGA7 345.		2
13,468	WWRDEHV7 345.	THISTLE7 345.		1
13,468	WWRDEHV7 345.	THISTLE7 345.		2
13,468	WWRDEHV7 345.	BEAVER CO 345.		1
13,468	WWRDEHV7 345.	BEAVER CO 345.		2
13,468	HUNTERS7 345.	RENFROW7 345.		1
13,468	RENFROW7 345.	VIOLA 7 345.		1
13,468	HITCHLAND 7345.	POTTER_CO 7345.		1
13,468	FINNEY TP 7 345.	FINNEY 7345.		1
13,468	FINNEY TP 7 345.	WALKTAP7 345.		1
13,468	FINNEY 7345.	LAMAR7 345.		1
13,468	HOBBS_INT 7345.	POTASH_JCT 7345.		1
13,468	POTASH_JCT 7345.	NLOV_PLT 7345.		1
13,468	SPERVIL7 345.	BUCKNER7 345.		1
13,468	SPERVIL7 345.	CLARKCOUNTY7345.		1
13,468	HOYT 7 345.	STRANGR7 345.		1
13,468	GEARY 7 345.	SUMMIT 7 345.		1
13,468	EMPEC 7 345.	SWISVAL7 345.		1
13,468	EMPEC 7 345.	WICHITA7 345.		1
13,468	RENO 7 345.	SUMMIT 7 345.		1

Wind Dispatch MW	Bus 1	Bus 2	Transformer Bus 3	ID
13,468	RENO 7 345.	MOUNDRG7 345.		1
13,468	STRANGR7 345.	87TH 7 345.		1
13,468	STRANGR7 345.	IATAN 7 345.		1
13,468	SUMMIT 7 345.	ELMCREEK7 345.		1
13,468	SWISVAL7 345.	W.GRDNR7 345.		1
13,468	87TH 7 345.	CRAIG 7 345.		1
13,468	MOUNDRG7 345.	WICHITA7 345.		1
13,468	CANEYRV7 345.	LATHAMS7 345.		1
13,468	BENTON 7 345.	WICHITA7 345.		1
13,468	BENTON 7 345.	WOLFCRK7 345.		1
13,468	NEOSHO 7 345.	FRANKLIN TP7345.		1
13,468	ROSEHIL7 345.	WOLFCRK7 345.		1
13,468	ROSEHIL7 345.	LATHAMS7 345.		1
13,468	ROSEHIL7 345.	SOONTAP7 345.		1
13,468	WICHITA7 345.	THISTLE7 345.		1
13,468	WICHITA7 345.	THISTLE7 345.		2
13,468	WOLFCRK7 345.	ANDERSONCO 345.		1
13,468	CLARKCOUNTY7345.	THISTLE7 345.		1
13,468	CLARKCOUNTY7345.	THISTLE7 345.		2
13,468	CLARKCOUNTY7345.	IRONWOOD7 345.		1
13,468	MULLNCR7 345.	SIBLEY 7 345.		1
13,468	PECULR 7 345.	PHILL 7 345.		1
13,468	ST JOE 3 345.	EASTOWN7 345.		1
13,468	ST JOE 3 345.	NASHUA 7 345.		1
13,468	PHILL 7 345.	SIBLEY 7 345.		1
13,468	EASTOWN7 345.	IATAN 7 345.		1
13,468	W.GRDNR7 345.	CRAIG 7 345.		1
13,468	W.GRDNR7 345.	LACYGNE7 345.		1
13,468	STILWEL7 345.	LACYGNE7 345.		1
13,468	HAWTH 7 345.	NASHUA 7 345.		1
13,468	CHAVESCO 345.	NM#4T 345.		1
13,468	GRPRWND7 345.	FTTHOMP3 345.		1
13,468	CBLUFFS3 345.	S3456 3 345.		1
13,468	ATCHSNT3 345.	COOPER 3 345.		1
13,468	RAUN 3 345.	HOSKINS3 345.		1
13,468	AXTELL 3 345.	PAULINE3 345.		1
13,468	AXTELL 3 345.	SWEET W3 345.		1
13,468	COOPER 3 345.	MOORE 3 345.		1
13,468	GENTLMN3 345.	REDWILO3 345.		1
13,468	GENTLMN3 345.	SWEET W3 345.		1

Wind Dispatch MW	Bus 1	Bus 2	Transformer Bus 3	ID
13,468	GENTLMN3 345.	SWEET W3 345.		2
13,468	GENTLMN3 345.	CHERRYC3 345.		1
13,468	HOSKINS3 345.	NELIGH.EAST3345.		1
13,468	KEYSTON3 345.	SIDNEY 3 345.		1
13,468	MCCOOL 3 345.	MOORE 3 345.		1
13,468	MCCOOL 3 345.	GR ISLD3 345.		1
13,468	MOORE 3 345.	PAULINE3 345.		1
13,468	SWEET W3 345.	GR ISLD3 345.		1
13,468	HOLT.CO3 345.	GR ISLD3 345.		1
13,468	S3454 3 345.	WAGENER 3 345.		1
13,468	S3458 3 345.	S3740 3 345.		1
13,468	S3458 3 345.	103&ROKEBY3 345.		1
13,468	BELFELD3 345.	CHAR.CK3 345.		1
13,468	LARAMIE3 345.	STEGALL3 345.		1
13,468	4CLEVLND 138.	CLEVLND7 345.	CLEVLND1 13.8	1
13,468	CHAMSPR5 161.	CHAMSPR7 345.	CHAMSPR1 13.8	1
13,468	TONTITN5 161.	TONTITN7 345.	TONTITN1 13.8	1
13,468	SHIPERD5 161.	SHIPERD7 345.	SHIPERD1 13.8	1
13,468	KINGRIV5 161.	KINGRIV7 345.	KINGRIV1 13.8	1
13,468	CHISHOLM7 345.	CHISHOLM6 230.	CHISHOLM1 13.2	1
13,468	FTSMITH7 345.	FTSMITH8 500.	FTSMTH11 13.8	1
13,468	RENFROW4 138.	RENFROW7 345.	RENFRO11 13.8	1
13,468	POTTER_CO 7345.	POTTER_CO 6230.	POTTER_TR 113.2	1
13,468	SETAB 3 115.	SETAB 7 345.	SETAB 1 13.8	1
13,468	WALKTAP3 115.	WALKTAP7 345.	WALKETP-T 13.8	1
13,468	RENO 7 345.	RENO 3 115.	RENO 1X1 14.4	1
13,468	RENO 7 345.	RENO 3 115.	RENO 2X1 14.4	1
13,468	SUMMIT 7 345.	SUMMIT 6 230.	SUMMIT 1 14.4	1
13,468	CLARK_TP 115.	CLARKCOUNTY7345.	CLARK_TER 13.8	1
13,468	ELMCREEK7 345.	ELMCREK6 230.	ELMCREEK1 13.8	1
13,468	W.GRDNR7 345.	WGARDNR5 161.	WGAR T11 13.8	11
13,468	NASHUA 7 345.	NASHUA-5 161.	NASH T11 13.8	11
13,468	LANCER 115.	SPERVIL7 345.	SPRVL-T 13.8	1
13,468	AXTELL 7 115.	AXTELL 3 345.	AXTELL 9 13.8	1
13,468	HOSKINS7 115.	HOSKINS3 345.	HOSKNS19 13.8	1
13,468	MCCOOL 7 115.	MCCOOL 3 345.	MCCOOL19 13.8	1
13,468	SHELDON7 115.	MOORE 3 345.	MOORE 9 13.8	1
13,468	REDWILO7 115.	REDWILO3 345.	REDWILO9 13.8	1
13,468	THEDFRD7 115.	CHERRYC3 345.	THEDFORD9 13.8	1
13,468	STEGALL3 345.	STGXFMR4 230.	STEGALLM9 13.8	1

Wind Dispatch MW	Bus 1	Bus 2	Transformer Bus 3	ID
13,468	WICHITA7 345.	GILL TP7 345.		1
13,468	PLTMOUTH TAP345.	S3458 3 345.		1
13,568	Pre Contingency			

Table 19.5: Future 2 Voltage Collapse Transfers

19.2: Final Reliability Assessment

All projects in the 2015 ITP10 Consolidated Portfolio were incorporated into the ITP10 models and a steady state N-1 contingency analysis was performed to identify any new 100 kV and above reliability issues. From that analysis no new potential thermal overloads or potential voltage violations were identified.

Section 20: Economic Needs

Constraint	From Area	To Area	Avg Shadow Price At Max	Avg Shadow Price At Min	Hours at Max	Hours at Min	Congestion Score
542985NEAST 5 543133CHARLOT5 1 FLO STRANGR7 - IATAN 7 1 34	KCPL	KCPL	-136.71		2124		290,382
652421WILISTN7 659625JUDSON MW71 FLO WILLISTON27 115-MONT 7 1	BASIN	BASIN	-50.74		5703		289,344
640287N.PLATT7 640365STOCKVL7 1 FLO GENTLMN3 345-REDWILO3 34	NPPD	NPPD	-223.81		1075		240,597
524516CANYON_WEST3524590DAWN 31 FLO BUSHLAND 6 230-DEAFSMI	SWPS	SWPS	-114.53		936		107,201
3008165COLLINS 505498STOCKTN5 1 FLO NEOSHO 7 345-LACYGNE7 34	ASEC	SWPA	-106.73		978		104,381
505498STOCKTN5 3001015MORGAN 1 FLO NEOSHO 7 345-LACYGNE7 34	SWPA	ASEC	-105.54		862		90,974
539688S-DODGE3 539699W-DODGE3 1 FLO BASE CASE	MKEC	MKEC		30.51		1294	39,482
531451MINGO 7 531429MINGO 3 1 FLO MINGO 7 345-SETAB 7 34	SUNC	SUNC	-87.25		393		34,290
526435SUNDOWN 6526460AMOCO_SS 61 FLO SUNDOWN - SUNDOWN 1 230/	SWPS	SWPS	-27.33		756		20,659
533180TEC E 3 533192HOOKJCT3 1 FLO TEC E 3 - TECHILE3 1 11	WRI	WRI	-22.56		684		15,428
525830TUCO_INT 6526337JONES 61 FLO TUCO_INT 6 230-CARLISL	SWPS	SWPS	-23.63		463		10,939
526161CARLISLE 6526160CARLISLE 31 FLO ALLEN 3 115-LUBBCK_	SWPS	GOLDEN	-155.55		56		8,711
646221S1221 5 646255S1255 5 1 FLO S3459 3 345-S1209 5 16	OPPD	OPPD		333.18		25	8,329
532937NEOSHO 5 547469RIV4525 1 FLO LITCH 5 161-ASB349 5 16	WRI	EMDE	-25.18		305		7,679
542982IATAN 7 532772STRANGR7 1 FLO HAWTH 7 345-NASHUA 7 34	KCPL	WRI	-14.27		489		6,980
541205BLSPE 5 541235DUNCAN 5 1 FLO SIBLEYPL - CKLES-16 1 16	GMO	GMO		20.43		309	6,311
523961POTTER_CO 7523959POTTER_CO 61 FLO HITCHLAND 7 345-HITCHLA	SWPS	SWPS	-27.23		210		5,718
652565SIOUXCY4 640386TWIN CH4 1 FLO RAUN 3 345-HOSKINS3 34	WAPAUM	NPPD	-147.51		38		5,605
515045SEMINOL7 515044SEMINOL4 P1 FLO SEMINOL4 138-SEMINOL7 34	OKGE	OKGE	-92.14		58		5,344
532873SUMMIT 6 533381SUMMIT 3 1 FLO SUMMIT 6 230-SUMMIT 3 11	WRI	WRI	-107.39		45		4,832
539654CIM-PLT3 539672E-LIBER3 1 FLO HAYNE3 115-NLIBTAP-B3 11	MKEC	MKEC	-0.81		5478		4,447
542981LACYGNE7 532793NEOSHO 7 1 FLO EMPEC 7 345-WICHITA7 345	KCPL	WRI	-20.04		219		4,389
659134SIDNEY 4 640302OGALALA4 1 FLO KEYSTON3 345-SIDNEY 3 34	BASIN	NPPD	-95.54		26		2,484
512638CATSAGR5 509790CATOOSA4 1 FLO CATOOSA4 138-CATSAGR5 16	GRDA	AEPW	-69.40		35		2,429
652519OAHE 4 652521SULLYBT4 1 FLO BASE CASE	WAPAUM	WAPAUM	-93.65		12		1,124

Table 20.1: Future 1 Economic Needs

Constraint	From Area	To Area	Avg Shadow Price At Max	Avg Shadow Price At Min	Hours at Max	Hours at Min	Congestion Score
527799EDDY_NORTH 6527793EDDY_STH 32 FLO EDDY_NORTH 6 230 - E	SWPS	SWPS	-88.44		5019		443,884
646221S1221 5 646255S1255 5 1 FLO S3459 3 345 - S	OPPD	OPPD		408.02		177	72,220
533163HOYT 3 533198HOYTJS 3 1 FLO HOYT 3 115 - N	WRI	WRI	-671.70		70		47,019
539688S-DODGE3 539699W-DODGE3 1 FLO BASE CASE	MKEC	MKEC		33.69		1294	43,601
542985NEAST 5 543133CHARLOT5 1 FLO IATAN - STRANGER CREEK	KCPL	KCPL	-95.87		220		21,092
526161CARLISLE 6526160CARLISLE 31 FLO ALLEN - LUBBOCK SOUTH 1	SWPS	GOLDEN	-246.78		75		18,509
515044SEMINOL4 515178PARKLN 4 1 FLO SEMINOLE - VANOS TAP 1 1	OKGE	OKGE	-106.24		144		15,299
640287N.PLATT7 640365STOCKVL7 1 FLO GENTLEMAN - RED WILLOW 1	NPPD	NPPD	-146.06		79		11,539
543055SEOTTWA5 543066S.OTTWA5 1 FLO CENTENL5 161 - P	KCPL	KCPL		14.90		652	9,715
515045SEMINOL7 515044SEMINOL4 1 FLO SEMINOLE - SEMINOLE 1 34	OKGE	OKGE	-58.30		137		7,987
652451RICHLND7 661056LEWIS 7 1 FLO BELFELD3 345 - C	BASIN	BASIN	-30.97		239		7,401
514876SW134TP4 514902MCCLAIN4 1 FLO MCCLAIN4 138 - P	OKGE	OKGE		24.94		272	6,783
543067CENTENL5 543069PAOLA 5 1 FLO S.OTTWA5 161 - P	KCPL	KCPL		40.00		166	6,640
652565SIOUXCY4 640386TWIN CH4 1 FLO RAUN - HOSKINS 1 345 (M	WAPAUM	NPPD	-101.45		58		5,884
524623DEAFSMITH 6524622DEAFSMITH 31 FLO DEAFSMITH - DEAFSMITH 2	SWPS	SWPS	-20.99		248		5,206
503912FULTON 3 3388753PATMOS-W# 1 FLO LONGWOOD - SAREPATA 1 34	AEPW	AECCEES	-43.85		113		4,955
532937NEOSHO 5 547469RIV4525 1 FLO ASBURY - LITCHFIELD 1 16	WRI	EMDE	-33.38		122		4,072
533008TV1MNDV4 533020NEOSHOS4 1 FLO DELWARE4 138 - F	KEPCWERE	WRI		109.18		36	3,930
509758PRATTV-4 509815S.S.---4 1 FLO RIVERSIDE - EXPLORER GLE	AEPW	AEPW		294.43		11	3,239
659372LARSON 4672603BDV 4 1 FLO FORBES 2 500 - R	BASIN	SPC		3.06		854	2,612
505492SPRGFLD5 549970CLAY 51 FLO HUBEN - MORGAN 1 345 (A	SWPA	SPCIUT	-72.93		34		2,480
525830TUCO_INT 6526337JONES 61 FLO TUCO - CARLISLE 1 230 (	SWPS	SWPS	-13.27		183		2,428
659155LOGAN 7 659307SWMINOT CP71 FLO BLAISDELL 4 230 - B	BASIN	BASIN	-60.87		37		2,252
549984BROOKLINE 7549969BROOKLINE 51 FLO BROOKLINE - XFR 2 345/16	SPCIUT	SPCIUT	-99.68		16		1,595
645457PLTMOUTH TAP645456S3456 3 1 FLO SUB 3740 - SUB 3455 1 34	OPPD	OPPD	-9.58		157		1,504

Table 20.2: Future 2 Economic Needs