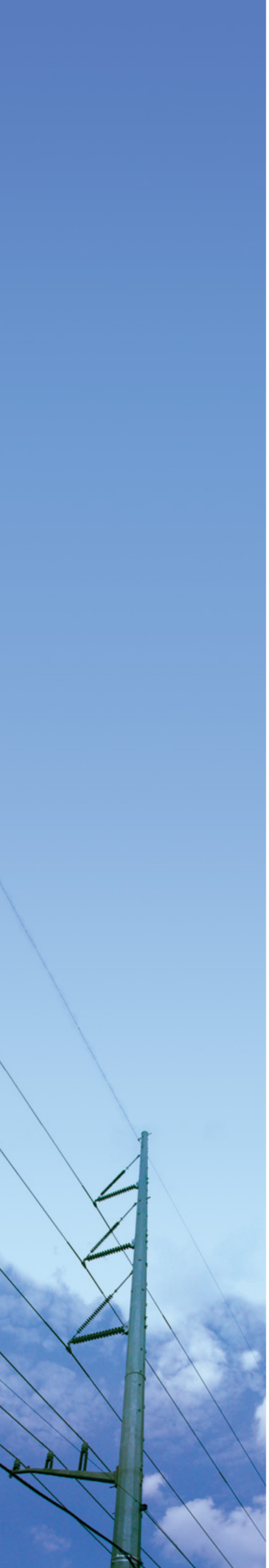

SPP Balanced Portfolio Report

MAINTAINED BY
Engineering/Planning

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Southwest Power Pool

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Executive Summary

The Balanced Portfolio is an SPP strategic initiative to develop a cohesive grouping of economic upgrades that benefit the SPP region and allocates the cost of those upgrades regionally. Projects in the Balanced Portfolio include transmission upgrades of 345 kV projects that will provide customers with potential savings that exceed project costs. These economic upgrades are intended to reduce congestion on the SPP transmission system, resulting in savings in generation production costs. Economic upgrades may provide other benefits to the power grid; i.e., increasing reliability and lowering required reserve margins, deferring reliability upgrades, and providing environmental benefits due to more efficient operation of assets and greater utilization of renewable resources.

The Cost Allocation Working Group (CAWG), of the Regional State Committee (RSC), has worked diligently over an extended period through a stakeholder process to identify upgrades for inclusion in a portfolio that will provide a balanced benefit to customers over the specified ten-year payback period. “Balanced” is defined by the SPP Regional Tariff in Attachment O, such that for each Zone, the sum of the benefits of the potential Balanced Portfolio must equal or exceed the sum of the costs. The Tariff allows for the adjustment of revenue requirements to achieve balance for the portfolio.

After development and review of the Balanced Portfolio, the CAWG endorsed Portfolio 3E “Adjusted” (without Chesapeake, without Reno Co – Summit). Portfolio 3E “Adjusted” provides a significant benefit vs. cost to the SPP region, and would require lower transfer requirements necessary to achieve balance. The CAWG along with the Economics Modeling and Methods Task Force (“EMMTF”, now called the Economic Studies Working Group “ESWG”) reviewed and approved the study assumptions used in the analysis of the Balanced Portfolio. These assumptions are listed in the appendix. Portfolio 3E “Adjusted” contains a diverse group of 345kV transmission projects addressing many of the top SPP flowgates. The projects associated with Portfolio 3E “Adjusted” are as follows:

- Tuco – Woodward District EHV, $229M
- Iatan – Nashua, $54M
- Swissvale – Stilwell tap at W. Gardner, $2M
- Spearville – Knoll – Axtell, $236M
- Sooner – Cleveland, $34M
- Seminole – Muskogee, $129M
- Anadarko Tap, $8M

- Total E&C Costs: $692M

The CAWG endorsed Balanced Portfolio was presented to the Markets and Operations Policy Committee (MOPC) on April 15th, 2009. The MOPC reviewed and discussed the portfolio options and the impact on the SPP footprint. After discussion, the MOPC endorsed the Balanced Portfolio 3E “Adjusted” pending issuance of the final report, according to SPP Tariff.

Portfolio 3E “Adjusted” provides substantial benefit to customers in the SPP footprint. Based on a 1,000 kWh/month usage of a residential customer, the Portfolio provides an estimated net benefit of $0.78/month ($1.66/mo on average versus a cost of $0.88/mo). The existing transmission revenue requirements for the SPP region in this typical monthly residential customer bill are estimated to be $7.58.

The following table demonstrates the full, 10 year portfolio analysis including reliability costs and benefits. These costs and benefits accrue in the years that the portfolio projects impact the reliability plan.

Million of Dollars

Portfolio 3-E "Adjusted"	**Total Benefit**	**Incremental Benefit**	**Total Cost SPP OATT ATRR**	**Reliability Cost**	**Cost (E&C)** $ 692 **Annual**
2012	$ 131.2		$ 93.73	$ 0.03	$ 93.7
2017	$ 193.2	$ 12.4	$ 93.73	$ 2.53	**Total Annual**
2022	$ 239.0	$ 9.2	$ 93.73	$ 2.53	$ 93.8

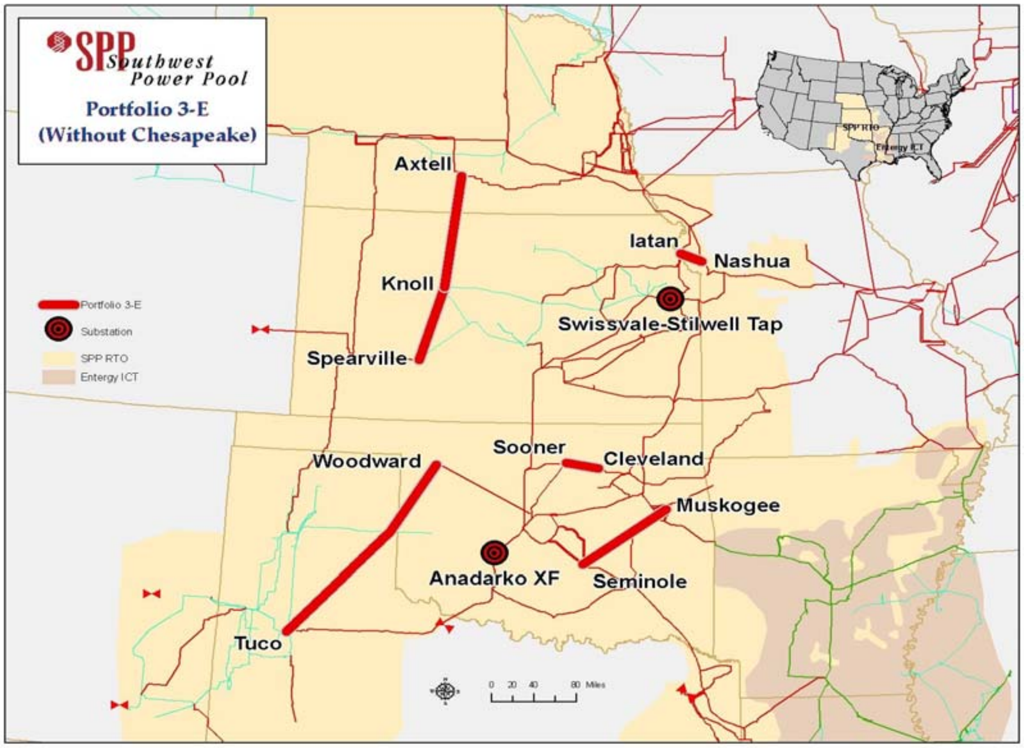
Year	**8.00%** Year #	**Discount Factor**	**Annual Benefits**	**Discounted Benefits**	**Annual Costs**	**Discounted Costs**	**B/C**
2012	1	1.00	$ 131	$ 131	$ 94	$ 94	**1.40**
2013	2	0.93	$ 144	$ 133	$ 94	$ 87	1.53
2014	3	0.86	$ 156	$ 134	$ 94	$ 80	1.66
2015	4	0.79	$ 168	$ 134	$ 94	$ 74	1.80
2016	5	0.74	$ 181	$ 133	$ 94	$ 69	1.93
2017	6	0.68	$ 193	$ 131	$ 96	$ 66	**2.01**
2018	7	0.63	$ 202	$ 128	$ 96	$ 61	2.10
2019	8	0.58	$ 212	$ 123	$ 96	$ 56	2.20
2020	9	0.54	$ 221	$ 119	$ 96	$ 52	2.29
2021	10	0.50	$ 230	$ 115	$ 96	$ 48	2.39
2022	11	0.46	$ 239	$ 111	$ 96	$ 45	**2.48**
Ten Year Totals	Yrs 1-10	7.25	$ 1,837	$ 1,281	$ 950	$ 687	**1.87**
Per Year Levelized				**$ 177**		**$ 95**	**1.87**

The table below outlines the benefits by zones for the 10 year analysis of Portfolio 3E "adjusted".

Attachment H Transfer Adjustments - Portfolio 3E "Adjusted" - Annualized

#	**Zone**	**Portfolio Benefits**	**Portfolio Costs**	**Zonal ATRR Transfers Out (Col. 5 Attach H)**	**Regional Allocation of Zonal ATRR Transfers**	**Net of Zonal Transfers and Transfer Allocation**	**Net Benefit**	**B/C**
1	AEPW	$30.9	$21.3	$0.0	$7.0	$7.0	$2.6	**1.1**
2	EMDE	($0.3)	$2.5	($3.7)	$0.8	($2.8)	$0.0	**1.0**
3	GRDA	$0.9	$1.9	($1.6)	$0.6	($1.0)	$0.0	**1.0**
4	KCPL	$8.4	$7.3	($1.3)	$2.4	$1.1	$0.0	**1.0**
5	MIDW	$12.8	$0.7	$0.0	$0.2	$0.2	$11.9	**14.1**
6	MIPU	($1.3)	$3.8	($6.4)	$1.3	($5.2)	$0.0	**1.0**
7	MKEC	$11.8	$1.1	$0.0	$0.3	$0.3	$10.4	**8.3**
8	OKGE	$26.6	$13.4	$0.0	$4.4	$4.4	$8.7	**1.5**
9	SPRM	($0.1)	$1.5	($2.1)	$0.5	($1.6)	$0.0	**1.0**
10	SUNC	$3.7	$1.0	$0.0	$0.3	$0.3	$2.3	**2.7**
11	SWPS	$56.1	$10.9	$0.0	$3.6	$3.6	$41.5	**3.9**
12	WEFA	$8.0	$3.0	$0.0	$1.0	$1.0	$4.0	**2.0**
13	WRI	$14.2	$11.0	($0.4)	$3.6	$3.2	$0.0	**1.0**
14	NPPD	$5.5	$7.6	($4.6)	$2.5	($2.1)	$0.0	**1.0**
15	OPPD	$2.3	$5.9	($5.6)	$1.9	($3.6)	$0.0	**1.0**
16	LES	($3.1)	$1.8	($5.5)	$0.6	($4.9)	$0.0	**1.0**
Total		**$176**	**$95**	**-$31**	**$31**	**$0**	**$81**	**1.86**

Portfolio 3-E "Adjusted"



Introduction

The Balanced Portfolio is an SPP strategic initiative to develop a cohesive grouping of economic upgrades that benefit the SPP region and allocates the cost of those upgrades regionally. Projects in the Balanced Portfolio include transmission upgrades of 345 kV[*] projects that will provide customers with potential savings that exceed project costs. These economic upgrades are intended to reduce congestion on the SPP transmission system, resulting in savings in generation production costs. Economic upgrades may provide other benefits to the power grid; i.e. increasing reliability and lowering reserve margins, deferring reliability upgrades, and providing environmental benefits due to more efficient operation of assets and greater utilization of renewable resources.

The Cost Allocation Working Group (CAWG), of the Regional State Committee (RSC), has worked diligently over an extended period through a stakeholder process to identify upgrades for inclusion in a portfolio that will provide a balanced benefit to customers over the specified ten-year payback period. “Balanced” is defined by the SPP Regional Tariff in Attachment O, such that for each Zone, the sum of the benefits of the potential Balanced Portfolio must equal or exceed the sum of the costs. The Tariff allows for the adjustment of revenue requirements to achieve balance for the portfolio[†].

Economic Benefits: Adjusted Production Cost

Balanced Portfolio development began with an economic screening of projects identified by stakeholders and SPP staff. After receiving stakeholder feedback, SPP staff compiled a list of economic projects with potential for a positive return.

The first step is to conduct an economic analysis individually on each project considered for the Balanced Portfolio. This process is done by determining the adjusted production cost metric for each project in the screen. Adjusted production cost is defined as:

Adj Prod Cost = Production Cost - Revenue from Sales + Cost of Purchases

Where:

Revenues from Sales = Export x Zonal $\text{LMP}_{\text{Gen Weighted}}$

and

Cost of Purchases = Import x Zonal $\text{LMP}_{\text{Load Weighted}}$

Production cost for each unit is based on fuel, variable O&M costs, environmental costs and both scheduled and forced outages[‡]. Adjusted production cost savings account for the economy purchase and sale of power in the modeling footprint. This is important when benefits are being calculated for zones within the SPP as well as in differentiating overall benefits from the portfolio compared to the benefits accruing to SPP members.

To calculate adjustments to production costs due to an economic transmission project, commercial production cost analysis software is used to estimate hourly unit commitment and dispatch of modeled

[*] Upgrades of voltages less than 345 kV can be included if needed to deliver the benefits of the extra high voltage (EHV) upgrade, where the cost of the lower voltage facilities does not exceed the cost of the EHV facilities.

[†] The Tariff allows for deficient zones to be balanced by transferring a portion of the Base Plan Zonal Annual Transmission Revenue Requirement and/or the Zonal Annual transmission Revenue Requirement from the deficient Zone(s) to the Balanced Portfolio Region-wide Annual Transmission Revenue Requirement.

[‡] SPP is currently using probabilistic techniques to simulate a single draw of outages to simulate forced outages

generators within a context of a modeled transmission system and load delivery points. The commitment and dispatch of the generators is constrained by the software to ensure that no overloads will occur on any monitored transmission element, typically referred to as the NERC book of flowgates, but can include additional congestion points of interest. The software produces a security constrained economic dispatch and unit commitment.

Adjusted Production Cost was the only benefit metric used in the economic analysis. There are other potential benefits which have not been directly quantified such as lowering reserve margins, reducing losses, and providing environmental benefits. For the purpose of this study, these benefit metrics are not used to determine overall portfolio benefits to the region.

Balanced Portfolio Development

The following table provides a timeline for the development of the various candidate portfolios that were developed by the SPP staff and presented during the regularly scheduled CAWG meetings

Table: CAWG Timeline for Balanced Portfolio Development

Months/Year	Key Discussions at CAWG
Aug-Nov 2007	Screening of Candidate Upgrades for Portfolio
Feb –Apr 2008	Initial Portfolios 1, 2, 3 and 4
May 2008	Trapped Generation Issues Discussion Begins
Jun 2008	Spearville-Knoll-Axtell Added to Portfolios 2 and 3
Jul 2008	Portfolios 2 and 3 at 2008 Wind Levels and Turk
Aug 2008	Portfolios 2 and 3: Firm Wind Sensitivities
Sep 2008	Introduction of Portfolios 3-A and 3-B at 345 and 765 kV costs
Oct 2008	Portfolio 3 (high wind) and 3-A (current wind) Analysis
Dec 2008	Portfolio 3-C (modify 3 for high wind)
Jan 2009	Further Analysis of Portfolios 3-A and 3-C with Nebraska
Feb 2009	EMMTF Effort initiated to update and refine economic models
Mar 2009	Final Balanced Portfolio Analysis
Apr 2009	Balanced Portfolio Summit & Balanced Portfolio Recommendation

<u>August-November, 2007</u>: Screening of Candidate Upgrades for Portfolios

Over fifty candidate transmission upgrades for screening were gathered by SPP staff. As agreed by stakeholders, the initial screening analysis was performed based on using only the summer months. A discussion at the CAWG led to additional analyses to include spring-fall months in the calculations of adjusted production cost benefits. The screening analysis was then performed for the summer months and the spring-fall months starting with the spring of March 1, 2012. These estimates of annual benefits were compared to the estimates of engineering and construction (E&C) cost obtained by SPP staff from transmission owners. All projects screened were ranked from highest to lowest according to their benefit-to-cost (B/C) ratios. The SPP staff then used these rankings as a basis for developing a collection of economic upgrades as alternative portfolios[§].

<u>February-April, 2008</u>: Initial Four Portfolios

SPP staff developed four initial portfolios, labeled as Portfolios 1, 2, 3 and 4. Each portfolio had specific criteria for determining which projects to include.

1. Portfolio 1 was a collection of every project from the economic project screening process that had a B/C ratio greater than 1.0.

[§] Note: Balanced Portfolio screening analysis considered assumptions for generation not contained in the subsequent portfolio analysis. Of note in the original analysis was the inclusion of Holcomb 2, Red Rock, Hugo 2 as well as 4,600 MW of generic wind capacity which affected the calculated benefits of certain projects.

2. Portfolio 2 was a subset of Portfolio 1 where projects with similar benefits were narrowed to remove upgrades that would not provide additional benefits.

3. Portfolio 3 was assembled with the intent of ensuring each Zone within the SPP region received a project (projects that crossed multiple zones were considered for each zone), with the most beneficial project chosen in each zone.

4. Portfolio 4 was a collection of projects that would be mutually beneficial, thereby raising the overall benefit of the entire portfolio.

These four portfolios, along with their B/C screening ratios, are shown in the following exhibits.

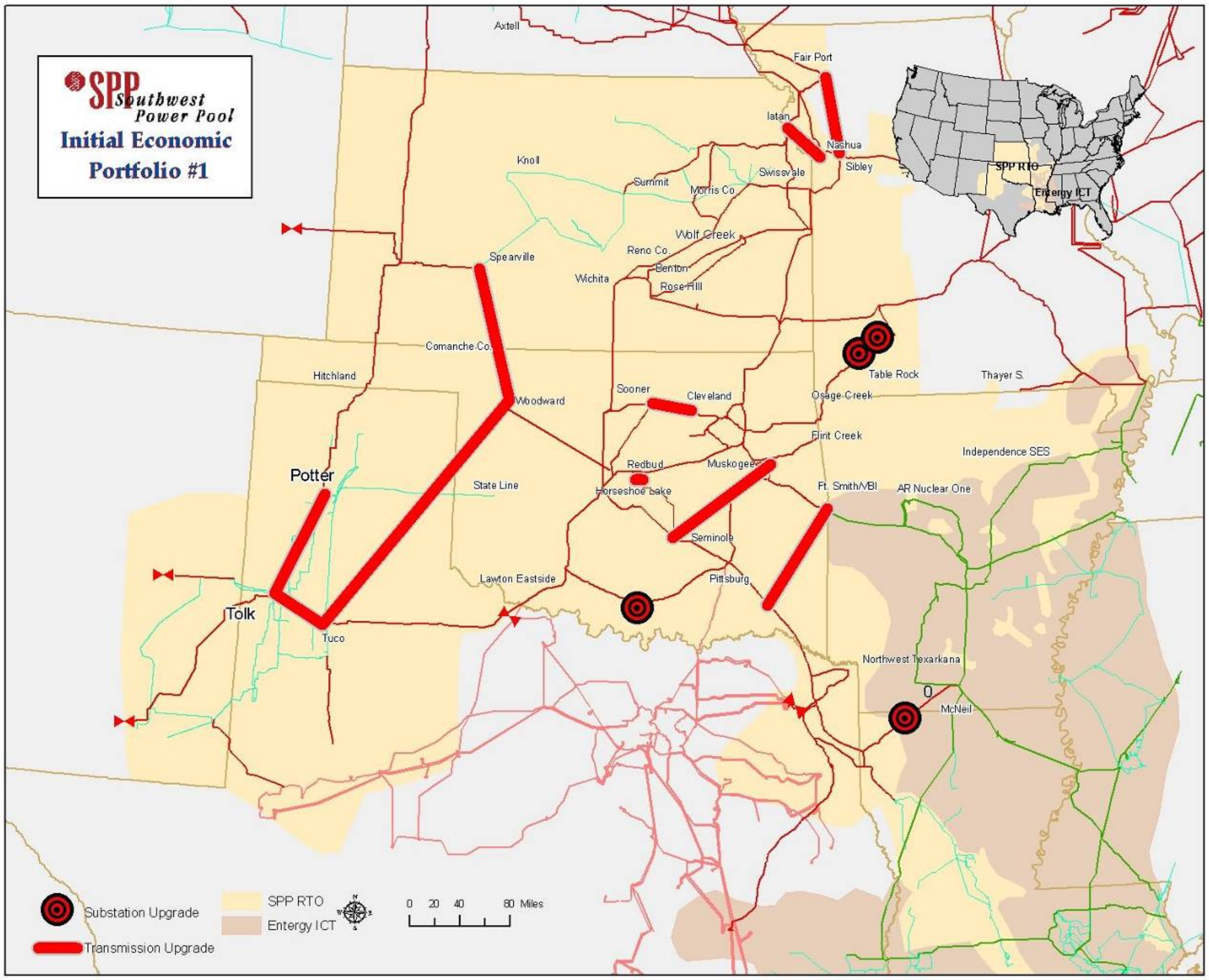
Screening of Proposed Economic Upgrades

Project	Screening B/C Ratio	P1	P2	P3	P4
Tolk - Potter	7.20			+	
El Dorado - Longwood	3.36	+	+	+	
Iatan - Nashua	2.95	+	+	+	+
SWPS - Battlefield	2.66	+	+		
Chesapeake XF	2.26	+	+	+	
Tuco - Tolk - Potter	1.73	+	+		+
Fairport - Sibley	1.31	+			+
Pittsburg - Ft Smith	1.17	+	+	+	
Spearville-Mooreland/Woodward-Tuco	1.13	+	+	+	+
Seminole - Muskogee	1.08	+			
Monett XF	1.04	+			
Redbud - Horseshoe Lake	1.01	+			
Cleveland - Sooner	0.91	+	+	+	+
Sunnyside XF	0.89	+	+		
Northwest XF	0.89	+	+		+
Swissvale - Stilwell	0.67			+	
Anadarko XF	0.48			+	
Turk - McNeil	0.46				+
Mooreland/Woodward - Wichita	0.14				+
Mooreland/Woodward - Northwest	(0.00)				+

(NOTE: "Tolk – Potter" project is a subset of the "Tuco – Tolk – Potter" project.)

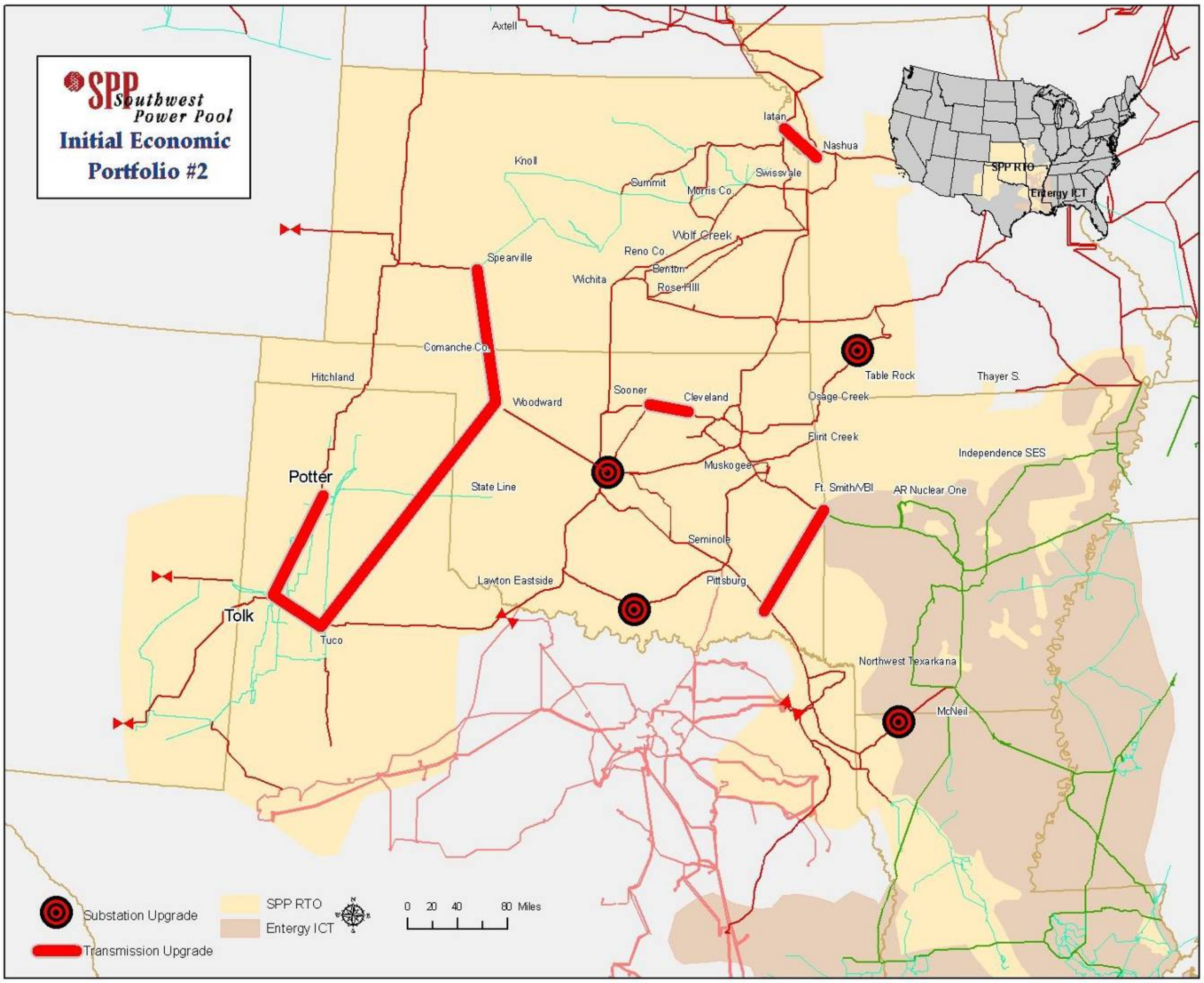
The Balanced Portfolio screening analysis considered assumptions for generation not contained in the subsequent portfolio analysis. Of note was the inclusion of Holcomb 2, Red Rock, and Hugo 2 as well as 4,600 MW of generic wind capacity, each of which affected the calculated benefits of certain projects.

Portfolio 1

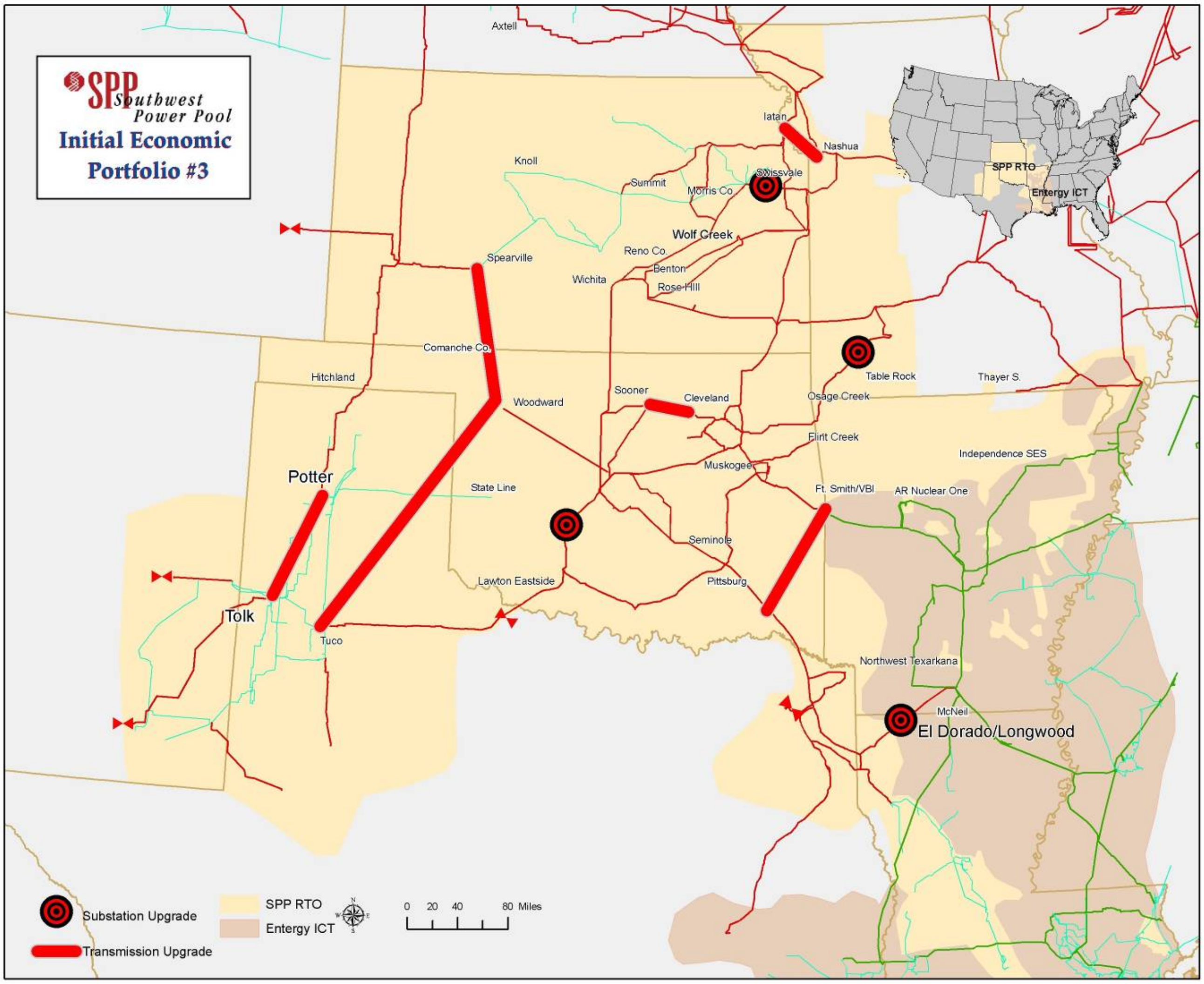


Because Portfolio 2 eliminated duplicative upgrades from Portfolio 1, Portfolio 1 was not carried forward as a possible Balanced Portfolio candidate.

Portfolio 2

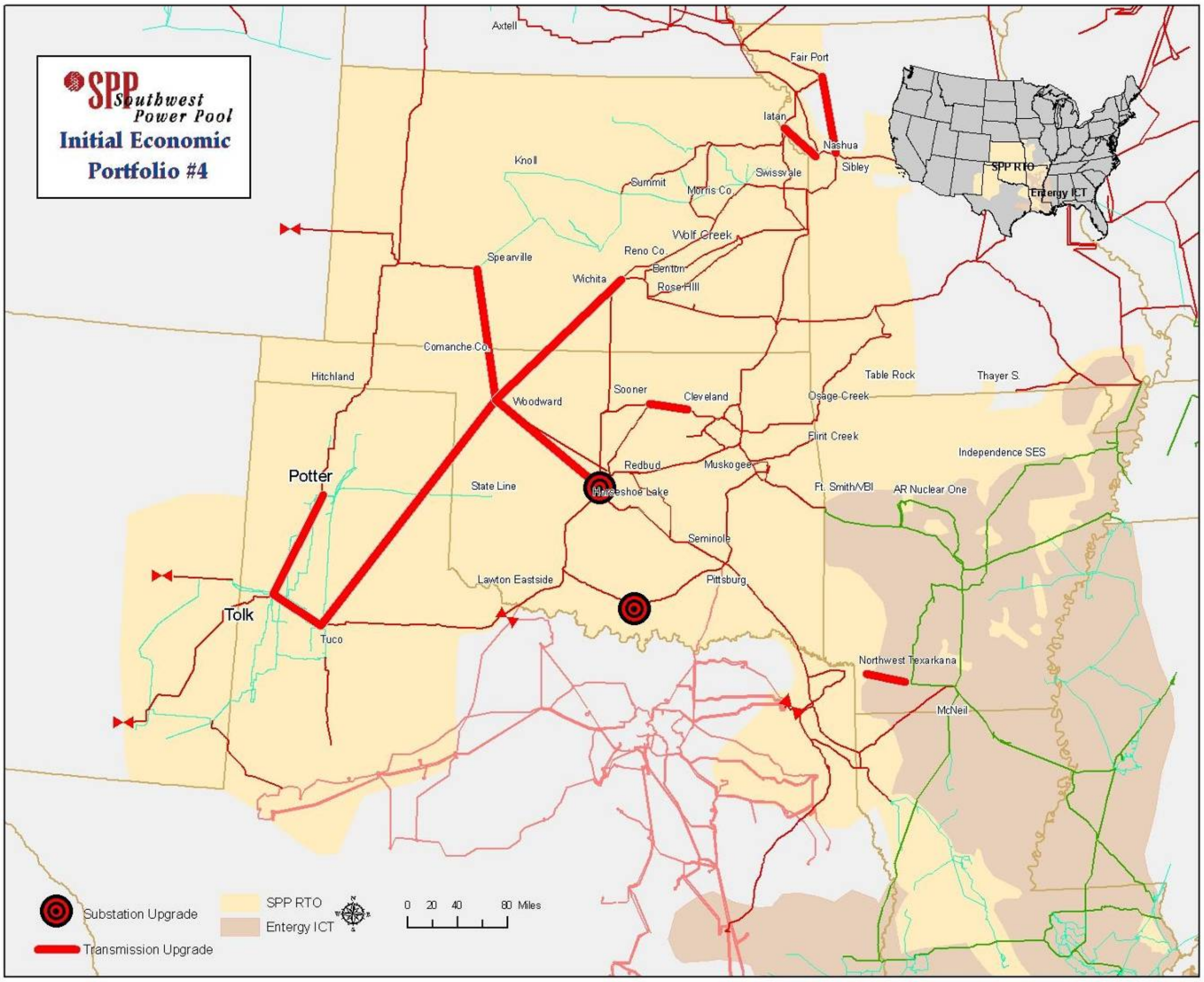

Southwest Power Pool
Initial Economic Portfolio #2
Axtell
Iatan
Nashua
Knoll
Summit
Swissvale
Morris Co.
Wolf Creek
Spearville
Reno Co
Benton
Wichita
Rose Hill
Comanche Co.
Hitchland
Sooner
Cleveland
Table Rock
Thayer S.
Woodward
Osage Creek
Flint Creek
Potter
Muskogee
Independence SES
State Line
Ft. Smith/VBI
AR Nuclear One
Seminole
Lawton Eastside
Pittsburg
Tolk
Tuco
Northwest Texarkana
McNeil
SPP RTO
Entergy ICT
Substation Upgrade
Transmission Upgrade
0 20 40 80 Miles

Portfolio 3



SPP Southwest Power Pool
Initial Economic
Portfolio #3
Axtell
Iatan
Nashua
Knoll
Summit
Swissvale
Morris Co.
Wolf Creek
Reno Co.
Spearville
Benton
Wichita
Rose Hill
SPP RTO
Entergy ICT
Comanche Co.
Table Rock
Thayer S.
Hitchland
Sooner
Cleveland
Osage Creek
Woodward
Flint Creek
Independence SES
Muskogee
Potter
State Line
Ft. Smith/VBI
AR Nuclear One
Seminole
Lawton Eastside
Pittsburg
Tolk
Tuco
Northwest Texarkana
McNeil
El Dorado/Longwood
Substation Upgrade
Transmission Upgrade
SPP RTO
Entergy ICT
0 20 40 80 Miles

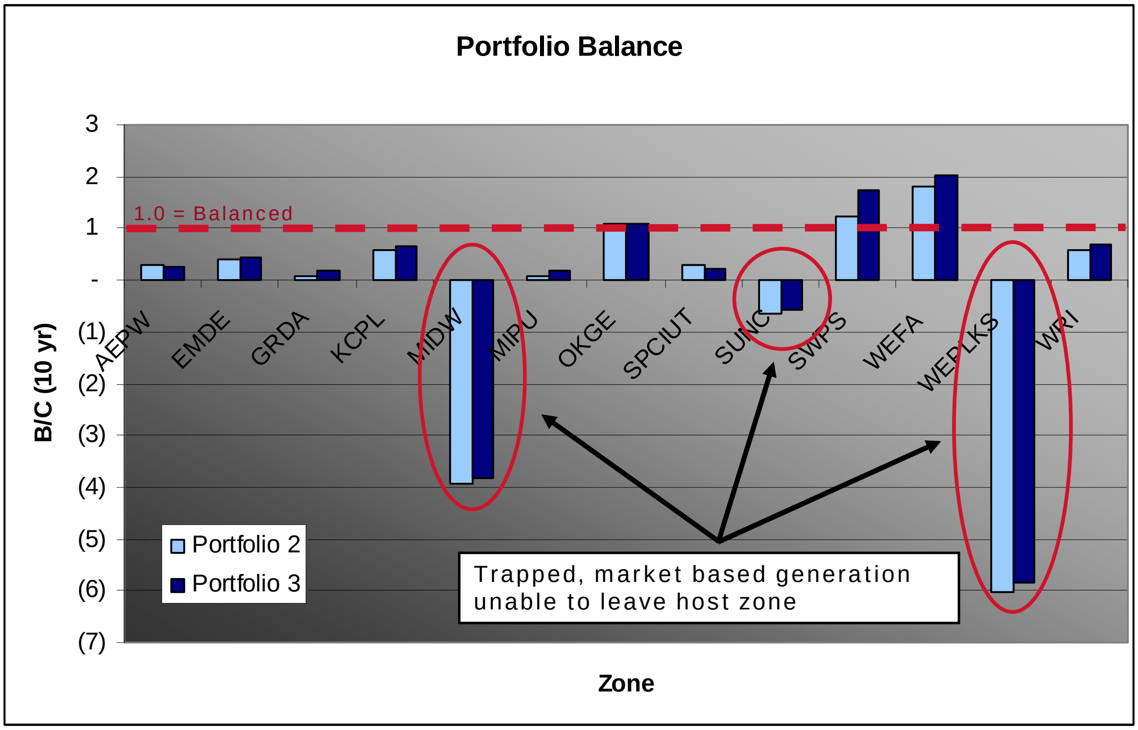
Portfolio 4


Southwest Power Pool
Initial Economic Portfolio #4
Axtell
Fair Port
Iatan
Nashua
Sibley
Knoll
Summit
Swissvale
Morris Co.
Wolf Creek
Reno Co.
Benton
Rose Hill
Spearville
Wichita
Comanche Co.
Hitchland
Woodward
Sooner
Cleveland
Table Rock
Thayer S.
Osage Creek
Flint Creek
Independence SES
Potter
Redbud
Muskogee
State Line
Horseshoe Lake
Ft. Smith/VBI
AR Nuclear One
Seminole
Lawton Eastside
Pittsburg
Tolk
Tuco
Northwest Texarkana
McNeil
SPP RTO
Entergy ICT
Substation Upgrade
Transmission Upgrade
0 20 40 80 Miles

May 2008: Trapped Generation

The CAWG review of the four portfolios, including high wind sensitivities, discovered that the production cost analysis contained significant levels of "trapped generation" (generation that cannot get power out of the host zone due to transmission constraints, significantly impacting the modeling results) related to wind generation. The CAWG initiated the Trapped Generation Task Force (TGTF) to address this issue. The following graph demonstrates effects of trapped generation on portfolio B/C ratios.

Trapped Generation in Economic Models



The TGTF developed guidelines for including generation in the production cost modeling, that were reviewed by the Economic Modeling and Methods Task Force ("EMMTF", now called the Economic Studies Working Group, "ESWG"). The TGTF decided that the base case models should contain wind levels consistent with current wind in service. These models contained 2,600 MW of nameplate wind,[**] down from 4,600 MW of generic wind included in previous models. Change cases could include additional wind generation, but the TGTF recommended that the additional wind above existing levels must be matched with the transmission upgrades that would be needed to deliver the additional wind to the SPP energy market.

June 2008: Wind and Spearville-Knoll-Axtell (SKA)

SPP staff updated the study models after the TGTF determined that 2,600 MW of wind should be used in the base case. The following table illustrates the resultant B/C ratios for Portfolios 2 through 4, where 2,600 MW of wind is also included in the change case. The adjusted production costs

[**] This coincides with the amount of wind in the SPP footprint at the end of 2008, as well as the transmission upgrades required to delivery wind with firm service.

shown are changes in adjusted production costs. Therefore, a red parenthetical represents lower adjusted production costs after an upgrade takes place, and it is the estimate of overall benefit.

Preliminary Portfolio Results, post-TGTF (June 26, 2008 CAWG Meeting)

Project	Total Adjusted Production Cost	SPP	TIER1	Cost ($M)	B/C
Economic Portfolio - P2_June08	($50,482,000)	($41,409,000)	($9,073,000)	$ 371	0.92
Economic Portfolio - P3_June08	($53,325,000)	($42,060,000)	($11,266,000)	$ 347	1.04
Economic Portfolio - P4_June08	($48,429,000)	($38,581,000)	($9,848,000)	$ 608	0.54

SPP staff conducted a sensitivity analysis of Spearville-Knoll-Axtell on the above portfolios to determine its impact. The Spearville-Knoll-Axtell (SKA) 345kV line is a transmission upgrade for which the Kansas Electric Transmission Authority (KETA) issued a Notice of Intent to Proceed with Construction on July 25, 2007. Additionally, the SPP Board of Directors approved this transmission upgrade for inclusion in the SPP Transmission Expansion Plan (STEP). The SPP Board of Directors requested that all projects of 345 kV and above approved for inclusion in the STEP also be considered candidates in the Balanced Portfolio analyses. It was found in the analyses that the SKA project uniformly raised the B/C ratios of all portfolios, and it appeared that the SKA project should be included for consideration, although a similar analysis was not conducted for other low B/C ratio projects that were not included in the original portfolios. The results are shown in the following table.

Impact of Spearville – Knoll – Axtell

Project	Total Adjusted Production Cost	SPP	TIER1	Cost ($M)	B/C
Economic Portfolio - P2_SKA_June08	($90,215,000)	($71,327,000)	($18,889,000)	$ 539	1.13
Economic Portfolio - P3_SKA_June08	($92,307,000)	($72,235,000)	($20,072,000)	$ 515	1.22
Economic Portfolio - P4_SKA_June08	($84,031,000)	($64,709,000)	($19,322,000)	$ 776	0.73

Because Portfolio 4 had a B/C ratio well below one, it was not included in further analyses in the Balanced Portfolio development process.

<u>July 2008</u>: Update Designated Resources

Portfolios 2 and 3 were updated to include the Turk Plant, a Designated Resource planned to be on line by 2012. This change lowered the benefit to cost ratios below one, as shown in the following table. These results were based on the 2008 wind levels in SPP (2,600 MW) but do not include the Spearville-Knoll-Axtell line.

Impact of Updates on Portfolios 2 and 3

Project	Total Adjusted Production Cost	SPP	TIER1	Cost ($M)	B/C	SPP B/C
Portfolio 2 - July 08	($38,291,000)	($28,825,000)	($9,466,000)	$ 371	0.70	0.53
Portfolio 3 - July 08	($42,033,000)	($32,281,000)	($9,751,000)	$ 347	0.82	0.63

<u>August 2008</u>: Firm Wind Sensitivities

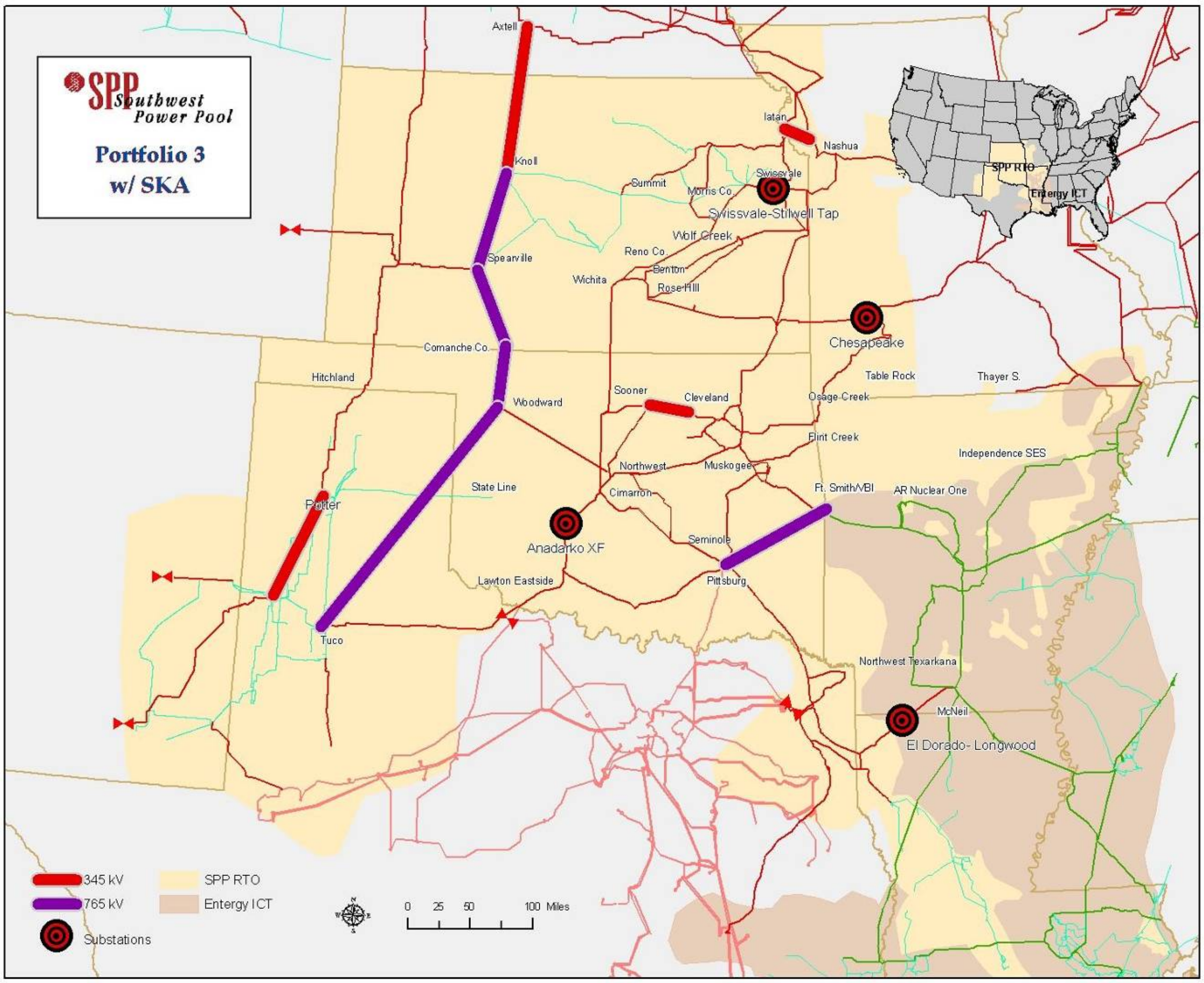
Additional wind sensitivities were conducted for Portfolios 2 and 3 to determine the impact that the amount of wind assumed in the model would have on the benefits. Benefits were estimated for 700 MW of firm wind in the base case and an additional 1,900 MW of market-based wind in the change case. The results showed a significant increase in production cost savings for both Portfolios 2 and 3. The changes in benefits from adding the market-based wind without transmission upgrades were calculated to show the impact of trapped generation. Stakeholders supported the inclusion of all existing wind in the portfolios even though wind without firm transmission service would lower the B/C ratios.

<u>September 2008</u>: Introduction of Portfolio Variations 3-A and 3-B

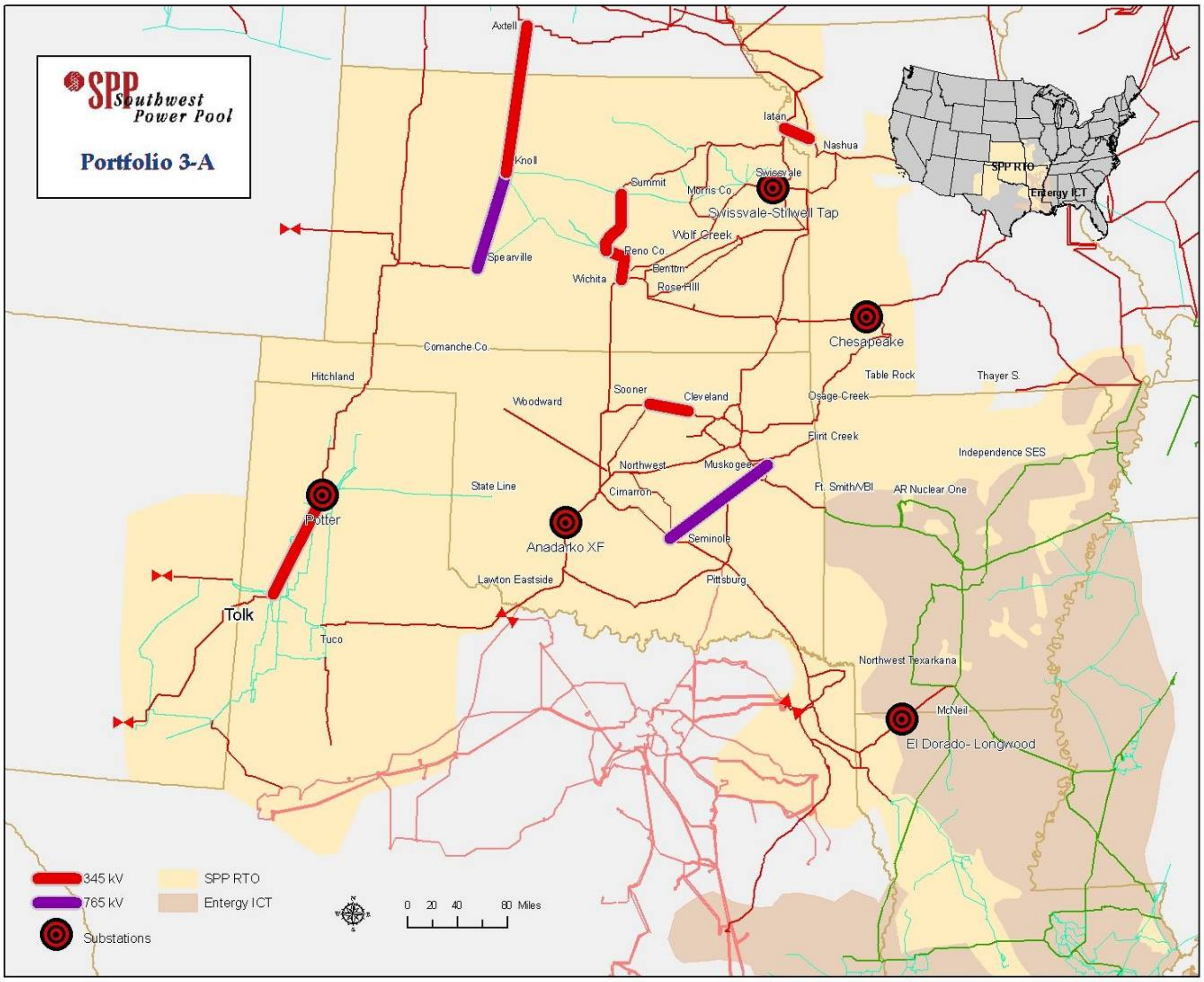
SPP staff developed two modified portfolios based on Portfolio 3. Adjustments to Portfolio 3 included an upgrade of the Wichita – Reno Co - Summit line and carried through the addition of Spearville-Knoll-Axtell. From this modification of Portfolio 3 two variations were developed and labeled 3-A and 3-B. These portfolios are shown pictorially below.

Since many sections of Portfolio 3 included transmission paths that are also in the proposed EHV Overlay Plan, the CAWG decided to consider these common corridor projects for 765 kV construction in the balanced portfolio. The purple lines in the following maps illustrate this construction.

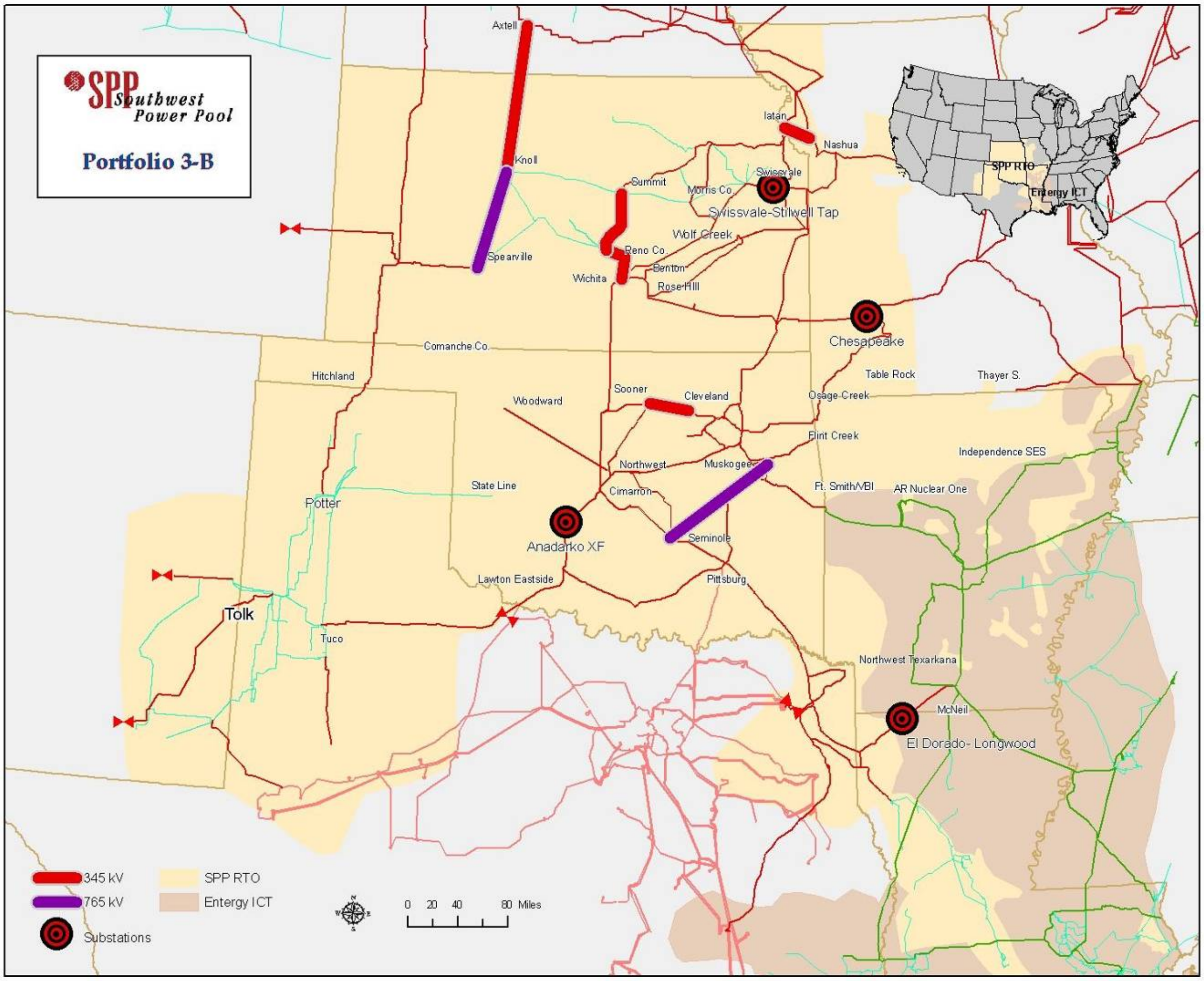
Portfolio 3, with Spearville – Knoll – Axtell (SKA)



Portfolio 3-A with Wichita - Reno Co - Summit



Portfolio 3-B with Wichita – Reno Co - Summit



Modeling assumptions for the dispatch of wind were still an issue in these results where SPP staff used a wind offer price of $20/MWh. Given this caveat, the results showed that both Portfolios 3-A and 3-B had B/C ratios greater than one using 345 kV costs, but were marginal when 765 kV costs were used in the calculations. Portfolio 3-B is a sensitivity of Portfolio 3-A used to test whether or not the Tolk-Potter upgrades would increase the B/C ratio. Since they did, the SPP staff recommended going forward with Portfolio 3-A, as well as subsequent consideration of additional variations of Portfolio 3.

Initial Results for Portfolios 3-A and 3-B

Project	Cost ($M)	Proj 10 Year SPP Benefit ($M)	SPP B/C
345 kV Construction			
Portfolio 3-A	$585	$776	1.33
Portfolio 3-B	$545	$693	1.27
765 kV Construction			
Portfolio 3-A	$761	$776	1.02
Portfolio 3-B	$721	$693	0.96

<u>October 2008</u>: Portfolio 3 (High Wind) and 3-A (Current Wind)

Two different types of analyses were considered for Portfolios 3 and 3-A. Since Portfolio 3 has upgrades similar to those on the western portion of the proposed EHV system, the SPP staff evaluated Portfolio 3 using a high wind (7 GW) scenario with specific wind locations for wind capacity above the current 2008 level of 2.6 GWs. In particular, the B/C ratio was calculated for both 345 kV and 765 kV costs to get a feel for whether or not Portfolio 3 could support a portion of the EHV upgrades in the western SPP region.

High Wind (7 GW) for Portfolio 3

Scenario	SPP 10 Yr Benefit	Cost ($M)	B/C
Portfolio 3 - 345 kV	$ 1,920,593,438	829	2.32
Portfolio 3 - 765 kV*	$ 1,920,593,438	1,213	1.58

SPP staff used Portfolio 3-A to test the sensitivity of a carbon tax on the estimate of benefits from savings in the adjusted production costs. The results indicated that keeping wind at its current levels and imposing a carbon tax would, as expected, result in a significant decrease in benefits for Portfolio 3-A.

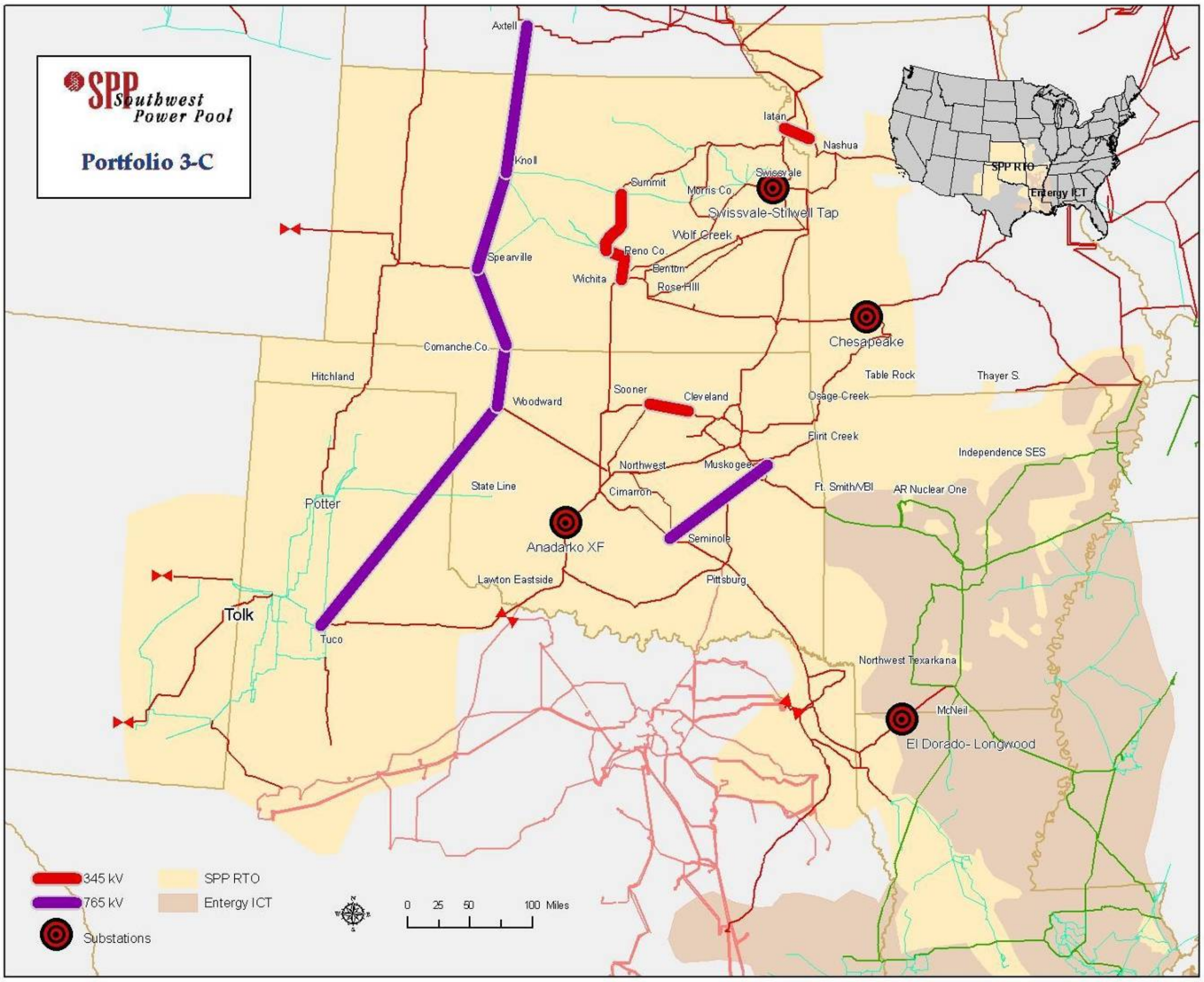
Carbon Tax Sensitivity Results for Portfolio 3-A at Current Wind (2.6 GW)

Project	Total Adjusted Production Cost	SPP NON-OATT	SPP OATT	TIER1	Cost	SPP B/C
Portfolio - P3A - Base	($119,180,000)	($2,454,920)	($111,931,080)	($4,794,000)	$ 597	1.27
Portfolio - P3A - $15 Carbon Tax	($60,140,000)	($4,000)	($52,699,000)	($5,543,000)	$ 597	0.60
Portfolio - P3A - $40 Carbon Tax	($17,992,000)	($317,000)	($16,926,000)	($1,630,000)	$ 597	0.19

<u>December 2008</u>: Portfolio 3-C (Modify Portfolio 3)

Portfolio 3-C was developed as a hybrid of Portfolios 3 and 3-A by removing the Tolk - Potter upgrades but adding the Spearville – Knoll - Axtell and Wichita – Reno Co - Summit lines. The following graph pictorially represents Portfolio 3-C.

Portfolio 3-C



It should be noted that by this time SPP staff had resolved a problem with its application of the PROMOD that had resulted in dispatching wind on a small number of days, resulting in what appeared to be a significant "trapped generation" problem. With the resolution of that issue, wind was now being dispatched from specified injection points at $0.05/MWh. Note that this was an offer price for the wind injection into the market since using an offer price of $0/MWh which caused problems in the modeling. The final clearing price of wind is at the marginal zonal market price for each hour, which is significantly higher than the offer price; i.e. wind in the actual production cost models is priced at the marginal zonal market price.

SPP staff used Portfolio 3-C to perform an analysis of an integration plan for the EHV Overlay. For this effort, scenarios were conducted at 3,300 MW of wind injection in 2012, 7,000 MW of wind injection in 2017, and 13,500 MW of wind injection in 2023, with 765 kV transmission being added to the analysis to accommodate the higher wind levels assumed for wind. The following table shows the B/C ratio that would apply had the results of year 2012 been distributed uniformly over a ten-year period and compared to the ten-year cost. In addition, the results are shown using ten years of Annual Transmission Revenue Requirements (ATRR) for the EHV projects contained in the study periods 2012, 2017 and 2023.

Portfolio 3-C + EHV Build Out		
Benefit - Cost	**Total B/C**	**SPP B/C**
10 yr vs E&C (P3-C)	0.74	0.66
10 yr vs E&C (P3-C+West EHV)	0.79	0.72
10 yr vs E&C (P-3C+West & Central EHV)	2.43	1.45
10 yr vs ATRR	**0.71**	**0.49**
Annual B/C (final year)	1.99	1.19

SPP staff reran portfolio 3-A at 3,300 MW of wind to determine the impact of adding 700 MW of market-based wind to the benefits of this portfolio. The following table gives the results for Portfolio 3-A using 765 kV costs.

Portfolio 3-A		
Benefit - Cost	**Total B/C**	**SPP B/C**
10 yr vs E&C	1.46	1.30
10 yr vs ATRR	**1.19**	**1.06**
Annual B/C (final year)	1.46	1.29

In addition to the adjusted production cost and cost benefit analysis, SPP Staff analyzed the impacts of the portfolio options on basic reliability. Portfolios 3-C and 3-A were considered in this analysis. The results of the total Engineering and Construction (E&C) cost impacts on regional reliability are shown in the table below with 3-C yielding the greatest benefits by reducing reliability needs to a net amount of $31M. More detailed impacts are shown in Appendix D.

P3-A and 3-C impact on STEP reliability assessment

Project	New Violations	Solved Violations	Net
Portfolio 3-A	$4,385,000	$4,004,900	**-$380,100**
Portfolio 3-C	$4,585,000	$35,265,250	**$30,680,250**

<u>January 2009</u>: Further Analysis of Portfolios 3-A and 3-C With Nebraska

At the December 2008 CAWG meeting, further analysis of Portfolios 3-A and 3-C was requested, including the addition of the three pricing zones in Nebraska as a result of the Nebraska entities decision to join the Southwest Power Pool. The emphasis on Portfolio 3-A was in regard to the balance of this portfolio when the Nebraska zones were added, and to compare this balance when Portfolio 3-A upgrades are priced at 345 kV versus 765 kV costs. With the addition of Nebraska, the B/C ratio for Portfolio 3-A at 765 kV increased from 1.06 to 1.11, and at 345 kV from 1.27 to 1.50. The higher costs at 765 kV resulted in significant levels of cost transfers needed to balance the portfolio compared to the lower costs at 345 kV.

Portfolio Balance With Transfers for Portfolio 3-A at 345 KV Costs

#	Zone	Benefits	Costs	Transfer Allocation	Transfer Out	Transfer Net	Net Benefit	B/C	Original B/C
1	AEPW	$20,880,672	$24,939,597	$14,640,350	-$18,699,275	-$4,058,925	$0	1.00	0.84
2	EMDE	$5,828,820	$2,923,755	$1,716,339	$0	$1,716,339	$1,188,726	1.26	1.99
3	GRDA	$1,797,527	$2,170,293	$1,274,032	-$1,646,798	-$372,766	$0	1.00	0.83
4	KCPL	$8,337,354	$8,571,771	$5,031,907	-$5,266,324	-$234,417	$0	1.00	0.97
5	MIDW	$1,590,879	$798,241	$468,593	$0	$468,593	$324,045	1.26	1.99
6	MIPU	$1,598,074	$4,491,010	$2,636,368	-$5,529,303	-$2,892,935	$0	1.00	0.36
7	MKEC	$5,294,897	$1,243,893	$730,206	$0	$730,206	$3,320,798	2.68	4.26
8	OKGE	$44,982,968	$15,731,003	$9,234,607	$0	$9,234,607	$20,017,358	1.80	2.86
9	SPRM	-$29,773	$1,719,556	$1,009,435	-$2,758,764	-$1,749,329	$0	1.00	-0.02
10	SUNC	$389,069	$1,185,151	$695,722	-$1,491,804	-$796,082	$0	1.00	0.33
11	SWPS	$43,102,775	$12,809,661	$7,519,685	$0	$7,519,685	$22,773,429	2.12	3.36
12	WEFA	$11,792,345	$3,508,023	$2,059,323	$0	$2,059,323	$6,224,999	2.12	3.36
13	WRI	$23,072,688	$12,818,241	$7,524,722	$0	$7,524,722	$2,729,725	1.13	1.80
14	NPPD	-$608,956	$8,896,109	$5,222,303	-$14,727,368	-$9,505,065	$0	1.00	-0.07
15	OPPD	-$472,047	$6,896,029	$4,048,192	-$11,416,267	-$7,368,075	$0	1.00	-0.07
16	LES	-$145,808	$2,130,072	$1,250,421	-$3,526,301	-$2,275,880	$0	1.00	-0.07
Total		**$167,411,485**	**$110,832,404**	**$65,062,205**	**-$65,062,205**	**$0**	**$56,579,080**	**1.51**	**1.51**

All numbers in the above table represent annualized costs for Portfolio 3-A over a ten-year period.

Transfers out of a zone represent the dollars that must be moved from the zonal rates to a region-wide rate in order to achieve balance. Two measures of the degree of balance of a portfolio include: a) the number of zones with positive net benefits after the transfers (in this case: 7 of 16 total zones); and b) the ratio of the transfers out to the costs of the upgrades (in this case: 58.7%).

Additional analysis of the EHV upgrades in Portfolio 3-C were performed with and without Portfolio 3-A to determine whether or not portfolio 3-A added more benefits than costs to a zone that would include parts of the EHV (765 kV) overlay. The results indicated that Portfolio 3-A did add more benefits than costs.

Analysis of Portfolio 3-C showed a B/C ratio of 0.58 using 765kV costs and a ratio of 0.94 using 345 kV costs.

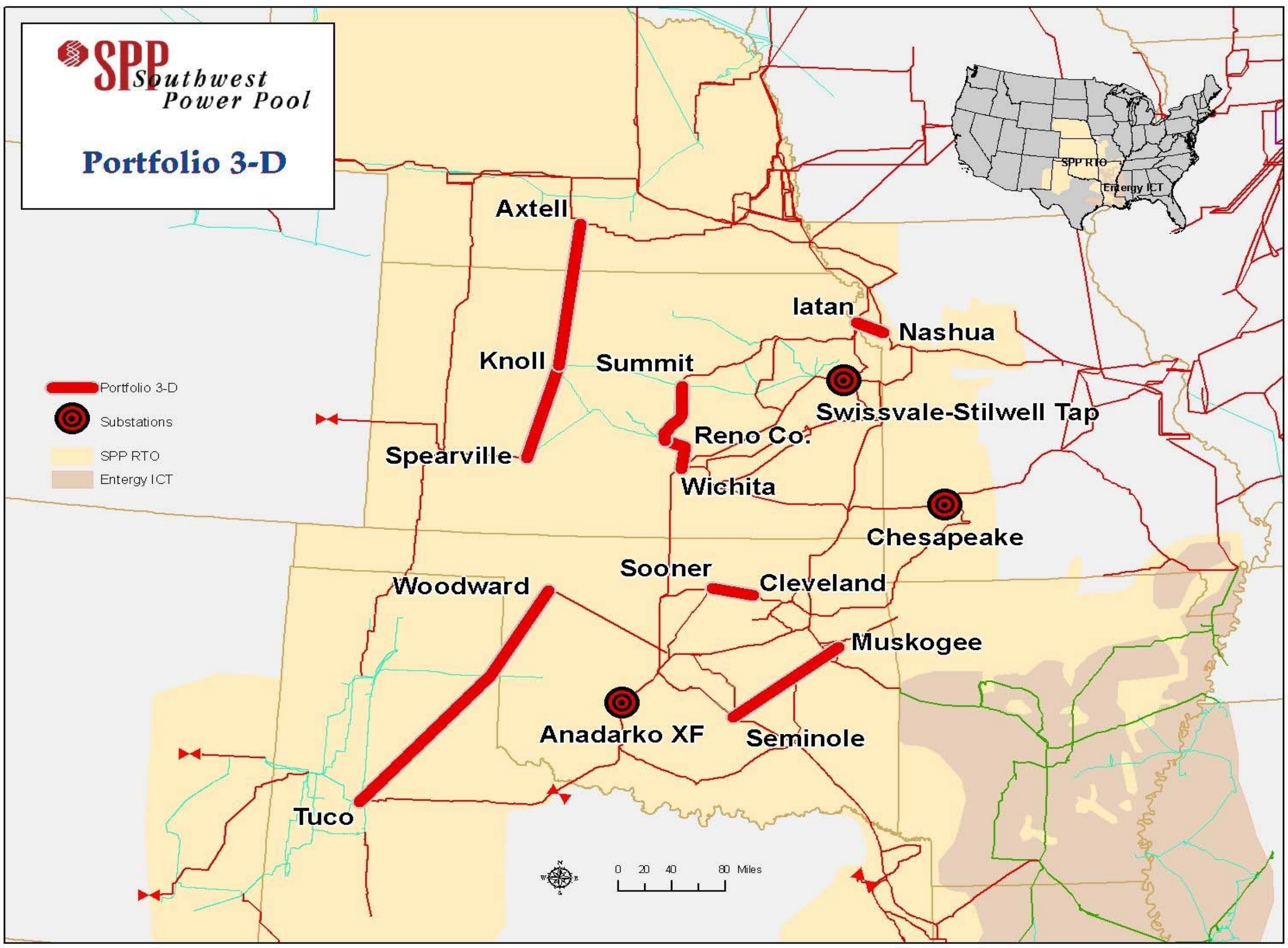
CAWG Response

Due to the difficulty in balancing a portfolio that includes 765 kV projects, as well the high level of uncertainty concerning the level of wind available to the SPP footprint on the planning horizon, it was decided in February 2009 that the Balanced Portfolio should include only existing wind generation in service or under construction. The CAWG directed SPP staff to update the economic models to reflect these changes and to work through the EMMTF to ensure that the models were vetted through the stakeholder process to ensure that all member data was represented accurately. Additionally, the CAWG requested that the Nebraska modeling parameters be updated to include a better, more expansive representation for utilities beyond Nebraska to better account for the economic interchange of energy beyond the Nebraska zones. Lastly, the CAWG requested that SPP Staff work with the EMMTF to update all costs associated with the construction of portfolio projects. The E&C costs had shown a significant degree of variability throughout the course of the Balanced Portfolio effort to date due to changes in the economic climate, leading the CAWG to seek an accurate, updated account of these associated construction costs from each respective constructing member.

SPP Staff Action Plan

SPP staff, in response to the CAWG, developed an action plan to address the issues raised and also developed a timeline for the completion of the Balanced Portfolio analysis that would conclude with a staff recommendation in April 2009. This action plan detailed how SPP staff would work with the EMMTF to address any outstanding modeling and cost issues for the simulation of the Balanced Portfolio. Additionally, the action plan, corresponding to the suggestion by the CAWG, defined that the analysis would consider only existing wind resources. SPP staff worked with stakeholders to determine the exact levels of existing wind resources on the system in the process of facilitating the modeling refinements through the EMMTF. Also, as the RSC directed, Portfolios 3, 3-A and 3-C were used as a starting point for these additional analyses. Lastly, Portfolio 3-D (shown below) was developed and included in the analysis. This action plan was presented to the CAWG at the end of January 2009.

Portfolio 3-D



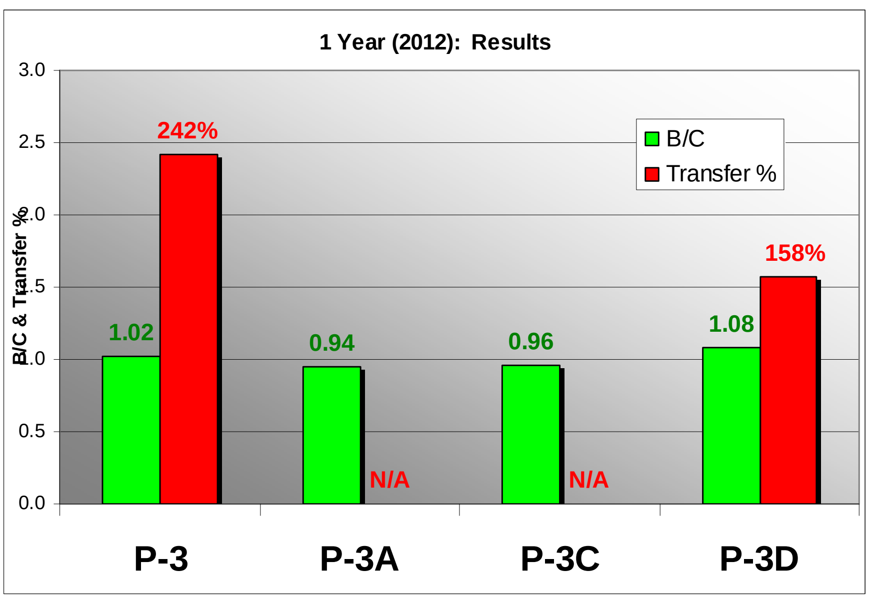
March 2009: Final Balanced Portfolio Analysis

Further material pertaining to the Balanced Portfolio was not presented until the March 2009 CAWG meeting. staff and stakeholders spent the majority of February working through the EMMTF on updating process and refining the engineering models used for the analysis. Additionally, the EMMTF members reviewed their respective output data and provided feedback to SPP staff. The data was checked for the reasonableness of the output results as well as the accuracy of the input into the production cost modeling. These changes were included in the Balanced Portfolio analysis.

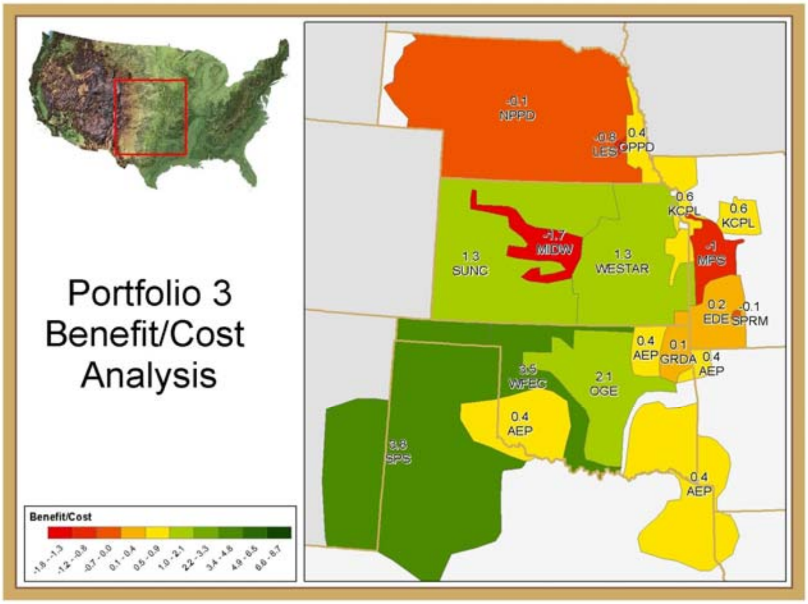
During the March 2009 CAWG meeting, the results from the analysis described above were presented. SPP staff started with a screening analysis on Portfolios 3, 3-A, 3-C, and 3-D. This analysis was conducted on the 2012 model and taken as an annual benefit to cost basis. The results are shown in the following exhibits.

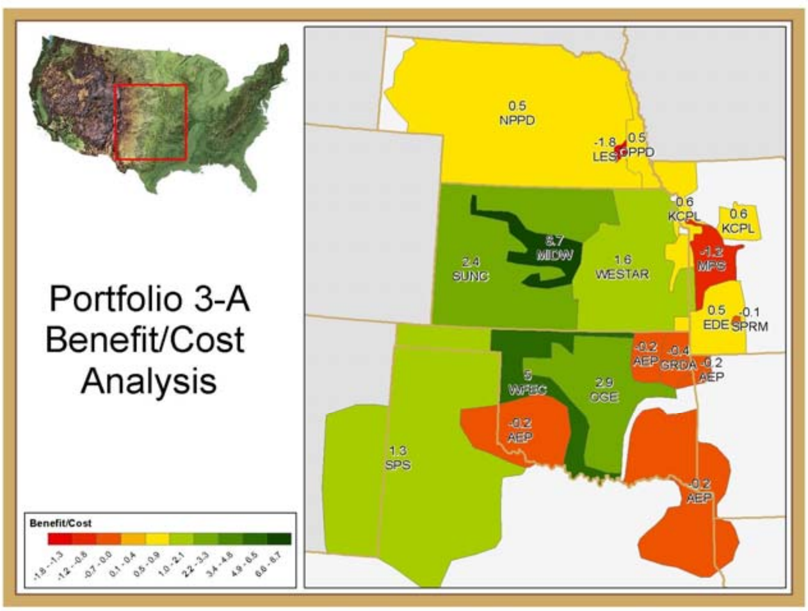
1 Year (2012) Screening Results

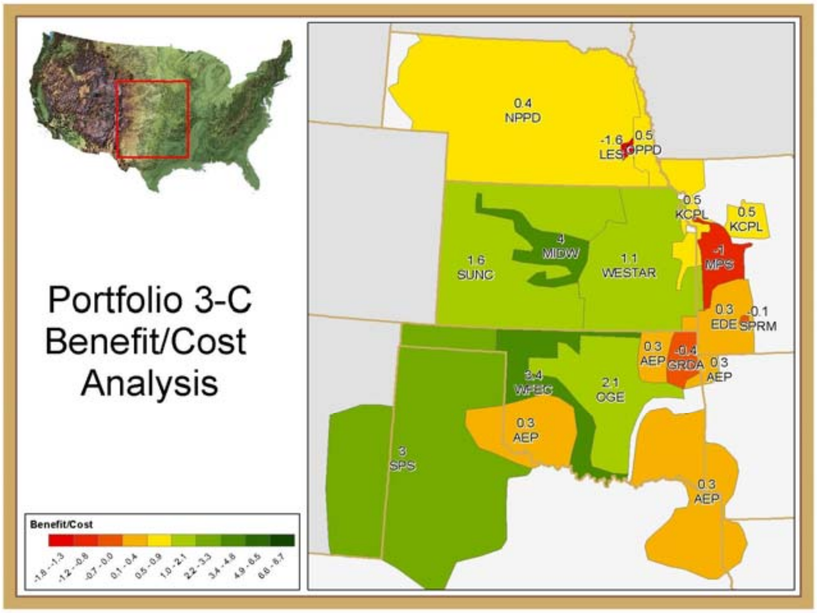
Project	Total APC Benefit ($M)	SPP OATT Benefit ($M)	Tier 1 Benefit ($M)	Annual Total Portfolio Cost ($M)	B/C	Transfer %
P-3	$124	$122	$2.6	$ 120	**1.02**	**242%**
P-3A	$117	$114	$2.7	$ 121	**0.94**	**n/a**
P-3C	$159	$159	($0.4)	$ 166	**0.96**	**n/a**
P-3D	**$148**	**$149**	**($1.3)**	***$ 139***	**1.08**	**158%**

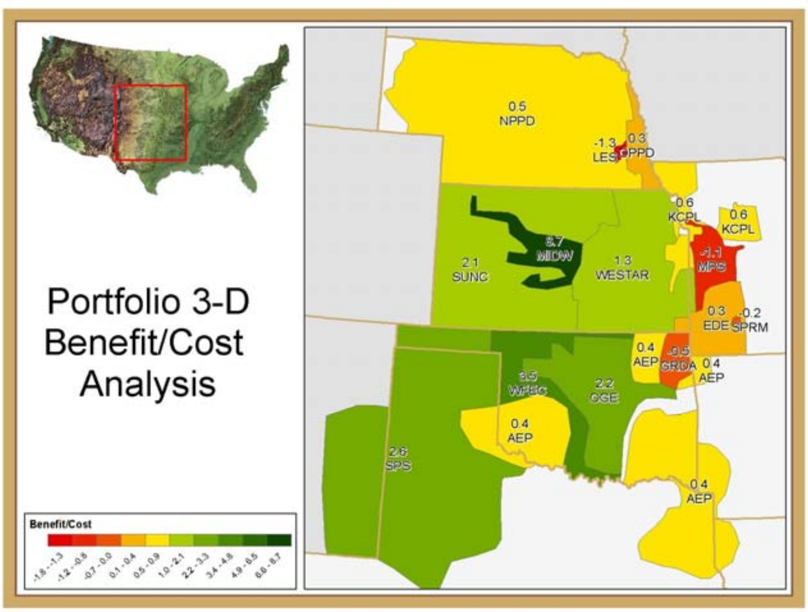


The Benefit to Cost ratio per zone is shown for the respective portfolios in the following pictures. The B/Cs shown here are before transfers have been conducted to balance the respective portfolios.









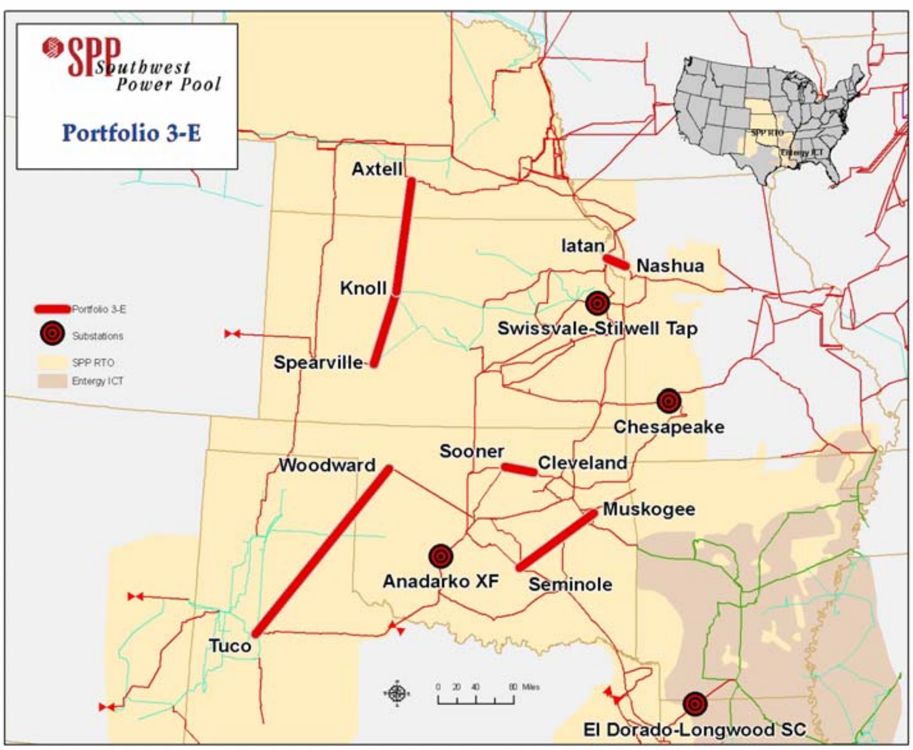
Portfolio 3-D had the highest B/C ratio of the four portfolios screened and was selected for further development. In this analysis, each of the individual projects in the Portfolio was removed to determine the impact of the project on the portfolio as a whole. These results are shown in the following table. The table is divided into total Adjusted Production Cost (APC) benefit, benefit for SPP Open Access Transmission Tariff (OATT) members as well as benefits to areas outside the region, shown here as Tier 1 benefits. The transfer percentage (%) shown is the percentage of the total portfolio cost in dollars that must be transferred, following tariff provisions, to balance the respective portfolios shown below. Ideally, the goal is a lower transfer percentage is desirable with a higher B/C.

Portfolio 3-D Refinement Analysis

Project	Total APC Benefit ($M)	SPP Benefit ($M)	Tier 1 Benefit ($M)	Annual Total Portfolio Cost ($M)	B/C	Transfer %
P-3D	**$148**	**$149**	**($1.3)**	***$ 139***	**1.08**	**158%**
Portfolio 3D sensitivities						
no WRS (P-3E)	**$137**	**$132**	**$4.3**	**$ 107**	**1.24**	**121%**
no SKA	**$127**	**$128**	**($0.8)**	**$ 114**	**1.12**	**111%**
no TW	$121	$116	($1.1)	$ 105	**1.10**	**324%**
no Ches	$146	$148	($1.4)	$ 136	**1.09**	**156%**
no SM	$116	$122	($6.6)	$ 115	**1.06**	**183%**
no IN	$143	$142	$0.5	$ 132	**1.08**	**168%**
no WGard	$152	$149	($1.6)	$ 138	**1.08**	**160%**
no ADK	$146	$147	($0.9)	$ 137	**1.07**	**159%**
no SC	$120	$122	($1.2)	$ 135	**0.90**	**n/a**

The projects that were the best candidates for removal from Portfolio 3-D were (1) Wichita – Reno Co. – Summit, (2) Spearville – Knoll – Axtell and (3) the Chesapeake Transformer. SPP staff recommended during the March 2009 CAWG meeting that the Wichita – Reno Co. – Summit line be removed from the portfolio, but also recommended Spearville – Knoll – Axtell and Chesapeake stay in the portfolio to maintain balance. This Portfolio was labeled Portfolio 3-E and is shown in the following map.

Portfolio 3-E



Portfolio 3-D and 3-E were selected as the candidates for the full 10-year analysis of portfolios as required by the Tariff. The following tables demonstrate the results of the 10-year analysis, with interpolation between simulated years, 2012, 2017 and 2022. The results are discounted back to present worth, using an 8% discount rate. Levelized annual values were also calculated. The annual cost of the each portfolio is given such that the host utility carrying charge rate is assumed to be used for the construction of the project.

Portfolio 3-D: 10 Year Benefit vs. Costs

					Million of Dollars			
Portfolio 3-D				**Total Benefit**	**Incremental Benefit**	**Total Cost SPP OATT ATRR**	**Incremental Cost**	**Cost (E&C)**
2012				$ 149.0		$ 138.55		826.4
2017				$ 208.5	$ 11.904	$ 138.55	$ -	**Annual**
2022				$ 260.3	$ 10.364	$ 138.55	$ -	138.5
Year		**8.00%** Year #	**Discount Factor**	**Annual Benefits**	**Discounted Benefits**	**Annual Costs**	**Discounted Costs**	**B/C**
2012		1	1.00	$ 149	$ 149	$ 139	$ 139	**1.08**
2013		2	0.93	$ 161	$ 149	$ 139	$ 128	1.16
2014		3	0.86	$ 173	$ 148	$ 139	$ 119	1.25
2015		4	0.79	$ 185	$ 147	$ 139	$ 110	1.33
2016		5	0.74	$ 197	$ 145	$ 139	$ 102	1.42
2017		6	0.68	$ 209	$ 142	$ 139	$ 94	**1.50**
2018		7	0.63	$ 219	$ 138	$ 139	$ 87	1.58
2019		8	0.58	$ 229	$ 134	$ 139	$ 81	1.65
2020		9	0.54	$ 240	$ 129	$ 139	$ 75	1.73
2021		10	0.50	$ 250	$ 125	$ 139	$ 69	1.80
2022		11	0.46	$ 260	$ 121	$ 139	$ 64	**1.88**
Ten Year Totals		Yrs 1-10	7.25	$ 2,010	$ 1,405	$ 1,385	$ 1,004	**1.40**
Per Year Levelized					**$ 194**		**$ 139**	**1.40**

Portfolio 3-DE: 10 Year Benefit vs. Costs

				Million of Dollars			
Portfolio 3-E			**Total Benefit**	**Incremental Benefit**	**Total Cost SPP OATT ATRR**	**Incremental Cost**	**Cost (E&C)**
2012			$ 132.3		$ 106.63		657.4
2017			$ 181.2	$ 9.786	$ 106.63	$ -	**Annual**
2022			$ 229.5	$ 9.652	$ 106.63	$ -	106.6
Year	**8.00%** Year #	**Discount Factor**	**Annual Benefits**	**Discounted Benefits**	**Annual Costs**	**Discounted Costs**	**B/C**
2012	1	1.00	$ 132	$ 132	$ 107	$ 107	**1.24**
2013	2	0.93	$ 144	$ 133	$ 107	$ 99	1.35
2014	3	0.86	$ 156	$ 134	$ 107	$ 91	1.46
2015	4	0.79	$ 168	$ 133	$ 107	$ 85	1.58
2016	5	0.74	$ 180	$ 132	$ 107	$ 78	1.69
2017	6	0.68	$ 181	$ 123	$ 107	$ 73	**1.70**
2018	7	0.63	$ 192	$ 121	$ 107	$ 67	1.80
2019	8	0.58	$ 202	$ 118	$ 107	$ 62	1.89
2020	9	0.54	$ 212	$ 115	$ 107	$ 58	1.99
2021	10	0.50	$ 223	$ 111	$ 107	$ 53	2.09
2022	11	0.46	$ 229	$ 106	$ 107	$ 49	**2.15**
Ten Year Totals	Yrs 1-10	7.25	$ 1,790	$ 1,253	$ 1,066	$ 773	**1.62**
Per Year Levelized				**$ 173**		**$ 107**	**1.62**

A reliability impact analysis was conducted on the portfolio projects to determine the impact of the Balanced Portfolio on the STEP reliability analysis as well as on Tier 1 entities, third parties to SPP. This analysis was conducted in the same manner and with the same methodologies used in the 2008 STEP 10 year reliability analysis. The analysis was conducted for the entire collection of portfolio projects considered for the March CAWG meeting. The results are broken into (1) advanced projects, those projects that would be moved up in the reliability timeline due to the Balanced Portfolio; (2) new projects, projects which are now needed that were not identified in the original 10 year reliability planning horizon, but may have been needed beyond that horizon; (3) third party impacts or projects needed on neighboring systems due to the Balanced Portfolio; and (4) deferred projects, projects which are either deferred beyond the planning horizon or mitigated entirely due to the portfolio. A summary of these results is shown in the table below.

Reliability Impact (E&C Dollars)

Portfolio	Advanced Projects	New Projects	3rd Party Impacts	Deferred Projects	Net Benefit
P-3	$ 1.0	$ 3.4	$ 10.2	$ 42.1	$ 27.5
P-3A	$ 1.0	$ 3.4	$ 10.2	$ 27.7	$ 13.1
P-3C	$ 1.0	$ 3.4	$ 10.2	$ 42.1	$ 27.5
P-3D	$ 1.0	$ 19.2	$ 10.2	$ 42.1	$ 11.7
P-3E	$ 1.0	$ 19.2	$ 10.2	$ 42.1	$ 11.7

<u>April 2009</u>: Balanced Portfolio Summit

The material from the March 2009 CAWG meeting was presented at an open meeting in Dallas, TX, April 1, 2009 as an SPP open stakeholder summit. Stakeholder comments and feedback were collected during this summit and incorporated in the final analysis used in the subsequent recommendation to the CAWG on an April 10th conference call.

Feedback from stakeholders and the CAWG included a request to consider the inclusion of a portion of the Wichita – Reno Co – Summit in the final recommendation, if it was feasible, and to include the project given its benefit and costs. Additionally, Empire District Electric Company staff requested that the Chesapeake transformer project be removed from the Balanced Portfolio recommendation due to the complex nature of the project and the associated third party impacts. Also, the CAWG directed SPP to further refine cost estimates of the projects in the portfolio to include greater granularity in the itemization of project costs associated with the portfolio projects, including but not limited to material costs, right of way requirements, labor, etc. Lastly, SPP staff was directed to determine the appropriate carrying charge rates to be used for each host zone to ensure that consistent values were being applied to all projects so that they could be considered on a consistent and reasonable basis.

<u>April 2009</u>: CAWG Conference Call

The work presented during the April SPP open stakeholder summit was refined to reflect the stakeholder feedback and comments and presented to the CAWG on April 10 via conference call.

The first portfolio change was to consider the removal of the Chesapeake transformer. The results are shown in the following tables.

Portfolio 3-E No Chesapeake: 10 Year Benefit vs. Costs

Portfolio 3-E No Ches		Million of Dollars				
		Total Benefit	Incremental Benefit	Total Cost SPP OATT ATRR	Incremental Cost	Cost (E&C)
2012		$ 132.3		$ 93.73		691.9
2017		$ 181.2	$ 9.79	$ 93.73	$ -	**Annual**
2022		$ 229.5	$ 9.65	$ 93.73	$ -	93.7

Year	**8.00%** Year #	**Discount Factor**	**Annual Benefits**	**Discounted Benefits**	**Annual Costs**	**Discounted Costs**	**B/C**
2012	1	1.00	$ 132	$ 132	$ 94	$ 94	**1.41**
2013	2	0.93	$ 145	$ 134	$ 94	$ 87	1.55
2014	3	0.86	$ 158	$ 135	$ 94	$ 80	1.68
2015	4	0.79	$ 171	$ 136	$ 94	$ 74	1.82
2016	5	0.74	$ 184	$ 135	$ 94	$ 69	1.96
2017	6	0.68	$ 181	$ 123	$ 94	$ 64	**1.93**
2018	7	0.63	$ 191	$ 120	$ 94	$ 59	2.04
2019	8	0.58	$ 201	$ 117	$ 94	$ 55	2.14
2020	9	0.54	$ 210	$ 114	$ 94	$ 51	2.24
2021	10	0.50	$ 220	$ 110	$ 94	$ 47	2.35
2022	11	0.46	$ 229	$ 106	$ 94	$ 43	**2.45**
Ten Year Totals	Yrs 1-10	7.25	$ 1,792	$ 1,257	$ 937	$ 679	**1.85**
Per Year Levelized				**$ 173**		**$ 94**	**1.85**

The transfer analysis for portfolio 3-E without Chesapeake is shown in the following table. The analysis concluded that $32M of transfers were required to balance this portfolio.

Attachment H Transfer Adjustments - Portfolio 3E no Ches - Annualized

#	Zone	Portfolio Benefits	Portfolio Costs	Zonal ATRR Transfers Out (Col. 5 Attach H)	Regional Allocation of Zonal ATRR Transfers	Net of Zonal Transfers and Transfer Allocation	Net Benefit	B/C
1	AEPW	$30.8	$21.1	$0.0	$7.2	$7.2	$2.5	1.1
2	EMDE	($0.4)	$2.5	($3.7)	$0.8	($2.8)	$0.0	1.0
3	GRDA	$0.8	$1.8	($1.6)	$0.6	($1.0)	$0.0	1.0
4	KCPL	$8.3	$7.2	($1.4)	$2.5	$1.1	$0.0	1.0
5	MIDW	$12.8	$0.7	$0.0	$0.2	$0.2	$11.9	14.1
6	MIPU	($1.6)	$3.8	($6.7)	$1.3	($5.4)	$0.0	1.0
7	MKEC	$11.7	$1.1	$0.0	$0.4	$0.4	$10.2	8.3
8	OKGE	$26.5	$13.3	$0.0	$4.6	$4.6	$8.6	1.5
9	SPRM	($0.2)	$1.5	($2.1)	$0.5	($1.6)	$0.0	1.0
10	SUNC	$3.2	$1.0	$0.0	$0.3	$0.3	$1.9	2.4
11	SWPS	$56.0	$10.8	$0.0	$3.7	$3.7	$41.5	3.9
12	WEFA	$7.9	$3.0	$0.0	$1.0	$1.0	$3.9	2.0
13	WRI	$14.2	$10.8	($0.4)	$3.7	$3.4	$0.0	1.0
14	NPPD	$5.5	$7.5	($4.6)	$2.6	($2.0)	$0.0	1.0
15	OPPD	$2.2	$5.8	($5.7)	$2.0	($3.7)	$0.0	1.0
16	LES	($3.5)	$1.8	($5.9)	$0.6	($5.3)	$0.0	1.0
Total		$174	$94	-$32	$32	$0	$80	1.9

Next, the inclusion of the Reno Co – Summit portion of the Wichita – Reno Co. – Summit Project was considered for inclusion after the removal of the Chesapeake transformer. These results are shown below.

Portfolio 3-E No Chesapeake, with Reno Co. - Summit: 10 Year Benefit vs. Costs

Portfolio 3-E No Ches, With RS		Million of Dollars	Total Benefit	Incremental Benefit	Total Cost SPP OATT ATRR	Incremental Cost	Cost (E&C)
2012			$ 178.0		$ 105.56		789.0
2017			$ 242.1	$ 12.816	$ 105.56	$ -	Annual
2022			$ 290.4	$ 9.658	$ 105.56	$ -	105.6
Year	**8.00%** Year #	**Discount Factor**	**Annual Benefits**	**Discounted Benefits**	**Annual Costs**	**Discounted Costs**	**B/C**
2012	1	1.00	$ 178	$ 178	$ 106	$ 106	**1.69**
2013	2	0.93	$ 191	$ 177	$ 106	$ 98	1.81
2014	3	0.86	$ 204	$ 175	$ 106	$ 90	1.93
2015	4	0.79	$ 216	$ 172	$ 106	$ 84	2.05
2016	5	0.74	$ 229	$ 169	$ 106	$ 78	2.17
2017	6	0.68	$ 242	$ 165	$ 106	$ 72	**2.29**
2018	7	0.63	$ 252	$ 159	$ 106	$ 67	2.38
2019	8	0.58	$ 261	$ 153	$ 106	$ 62	2.48
2020	9	0.54	$ 271	$ 146	$ 106	$ 57	2.57
2021	10	0.50	$ 281	$ 140	$ 106	$ 53	2.66
2022	11	0.46	$ 290	$ 135	$ 106	$ 49	**2.75**
Ten Year Totals	Yrs 1-10	7.25	$ 2,325	$ 1,632	$ 1,056	$ 765	**2.13**
Per Year Levelized				**$ 225**		**$ 106**	**2.13**

The transfer analysis for portfolio 3-E without Chesapeake but including with Reno Co. - Summit is shown in the following table. The analysis concluded that $62M of transfers were required to balanced this portfolio

Attachment H Transfer Adjustments - Portfolio 3E no Ches with RS - Annualized

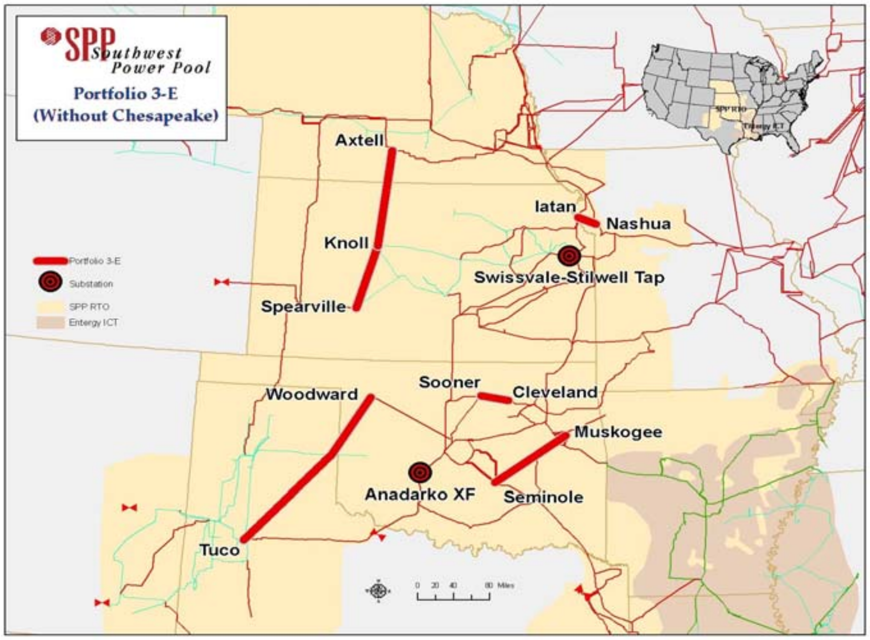
#	Zone	Portfolio Benefits	Portfolio Costs	Zonal ATRR Transfers Out (Col. 5 Attach H)	Regional Allocation of Zonal ATRR Transfers	Net of Zonal Transfers and Transfer Allocation	Net Benefit	B/C
1	AEPW	$25.8	$23.7	($11.8)	$13.9	$2.1	$0.0	1.0
2	EMDE	($0.1)	$2.8	($4.5)	$1.6	($2.9)	$0.0	1.0
3	GRDA	$0.1	$2.1	($3.2)	$1.2	($1.9)	$0.0	1.0
4	KCPL	$8.7	$8.2	($4.2)	$4.8	$0.5	$0.0	1.0
5	MIDW	$12.8	$0.8	$0.0	$0.4	$0.4	$11.6	10.7
6	MIPU	($5.6)	$4.3	($12.4)	$2.5	($9.9)	$0.0	1.0
7	MKEC	$11.3	$1.2	$0.0	$0.7	$0.7	$9.4	6.0
8	OKGE	$36.8	$15.0	$0.0	$8.8	$8.8	$13.0	1.5
9	SPRM	($0.3)	$1.6	($2.9)	$1.0	($1.9)	$0.0	1.0
10	SUNC	$3.6	$1.1	$0.0	$0.7	$0.7	$1.8	2.0
11	SWPS	$55.9	$12.2	$0.0	$7.1	$7.1	$36.6	2.9
12	WEFA	$11.8	$3.3	$0.0	$2.0	$2.0	$6.5	2.2
13	WRI	$59.9	$12.2	$0.0	$7.1	$7.1	$40.6	3.1
14	NPPD	$5.4	$8.5	($8.0)	$5.0	($3.0)	$0.0	1.0
15	OPPD	$2.7	$6.6	($7.7)	$3.8	($3.8)	$0.0	1.0
16	LES	($3.9)	$2.0	($7.1)	$1.2	($5.9)	$0.0	1.0
Total		$225	$106	-$62	$62	$0	$120	2.1

An analysis was conducted to determine the impact on total Annual Transmission Revenue Requirement (ATRR) for each zone in the tariff. The results are shown for portfolio 3-E, "3-E no Chesapeake" and "3-E no Chesapeake with Reno Co – Summit". These results are shown in the following table.

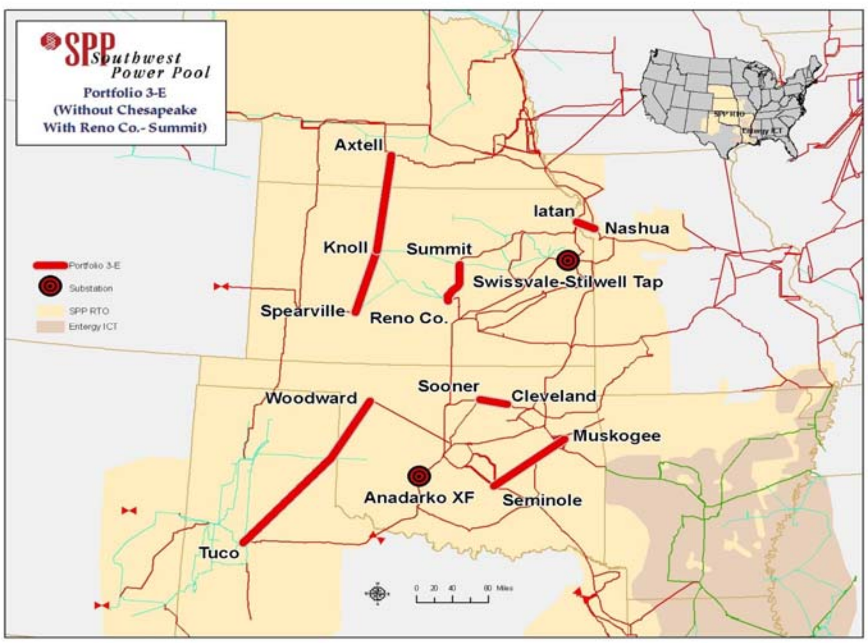
Total ATRR for Proposed Balanced Portfolios

	BP 3E	3E no Ches	BP 3E no Ches w RS
Zone	Annual Zonal plus Annual Base Plan Zonal plus Annual Region Wide RR	Annual Zonal plus Annual Base Plan Zonal plus Annual Region Wide RR	Annual Zonal plus Annual Base Plan Zonal plus Annual Region Wide RR
AEPW	$ 175,484,688	$ 177,104,393	$ 174,641,806
SPRM	$ 8,934,262	$ 8,659,884	$ 8,524,079
EMDE	$ 14,660,746	$ 14,007,997	$ 14,294,209
GRDA	$ 25,891,875	$ 26,032,862	$ 25,312,950
KCPL	$ 43,661,239	$ 44,709,872	$ 45,060,781
OKGE	$ 118,952,010	$ 116,849,771	$ 122,735,245
MIDW	$ 5,277,346	$ 5,170,672	$ 5,469,320
MIPU	$ 19,618,726	$ 19,420,118	$ 15,471,824
SWPA	$ 9,431,500	$ 9,431,500	$ 9,431,500
SWPS	$ 104,700,870	$ 102,989,030	$ 107,781,536
SUNC	$ 16,092,722	$ 15,934,343	$ 16,377,746
WEFA	$ 25,545,806	$ 25,077,005	$ 26,389,469
WRI	$ 128,845,823	$ 129,135,340	$ 134,286,149
MKEC	$ 7,723,354	$ 7,557,124	$ 8,022,505
LES	$ 8,877,057	$ 8,718,252	$ 8,313,564
NPPD	$ 53,140,390	$ 53,181,895	$ 53,125,563
OPPD	$ 38,645,990	$ 38,661,265	$ 39,227,136
	$ 805,484,404	**$ 802,641,325**	**$ 814,465,382**

Portfolio 3-E "Adjusted"



Portfolio 3-E with Reno Co – Summit, without Chesapeake



Recommendation

The CAWG endorsed portfolio 3-E “Adjusted” (without Chesapeake, without Reno Co – Summit). Portfolio 3-E “Adjusted” provides a significant benefit vs. cost to the SPP region, as well as having lower balance transfer requirements. Portfolio 3-E “Adjusted” contains a comprehensive group of economic projects addressing many of the top constraints in the SPP. The projects associated with portfolio 3-E “Adjusted” are as follows:

- Tuco – Woodward District EHV, $229M
- Iatan – Nashua, $54M
- Swissvale – Stilwell tap at W. Gardner, $2M
- Spearville – Knoll – Axtell, $236M
- Sooner – Cleveland, $34M
- Seminole – Muskogee, $129M
- Anadarko Tap, $8M

- Total E&C Costs: $692M

The supporting material for portfolio 3-E was presented to the Markets and Operations Policy Committee (MOPC) in April 2009. The MOPC reviewed and discussed the portfolio options and the impact on the footprint. After discussion, the MOPC endorsed the recommendation for Balanced Portfolio 3-E “Adjusted” pending issuance of the final report, according to the SPP Tariff.

Portfolio 3-E “Adjusted” provides substantial benefit to customers in the SPP footprint. Based on a 1,000 kWh/month usage of a residential customer, the Portfolio provides an estimated net benefit of $0.78/month ($1.66/mo on average versus a cost of $0.88/mo). The existing transmission revenue requirements for the SPP region in this typical monthly residential customer bill are estimated to be $7.58. Additionally, it should be noted that the Portfolio could incur a construction cost increase of up to 113%, or more than double the estimated construction cost, and still provide a benefit to cost ratio of 1.0 for the region. Therefore, the Balanced Portfolio could have a total E&C final cost of over $1.4B and still provide benefits greater than costs.

Estimated SPP average customer impact (based on 1,000 kWh/month usage)

Existing Zonal ATRR	Base Plan		New Base Plan NTCs		P-3E Costs
	1/3	2/3	1/3	2/3	Annual
$688M	$7M	$14M	$33M	$66M	$106 M
Total: $808M					13%
Avg. Cost Per Customer Per Month: $7.58					**88 ¢**

P-3E "Adjusted" Benefit = $1.66

The CAWG and MOPC recommendation of Portfolio 3-E “Adjusted” was presented to the SPP Regional State Committee (RSC) during their April 27, 2009 meeting in Oklahoma City where Portfolio 3-E “Adjusted” was endorsed by the RSC. Staff then presented to the MOPC and RSC the recommended Portfolio during the SPP Board of Directors meeting on April 28th. The SPP Board approved the projects in Balanced Portfolio 3-E “Adjusted” for inclusion in the SPP Transmission Expansion Plan. The SPP Board went on to direct staff to finalize the Balanced Portfolio Report in accordance with the SPP tariff. Furthermore, the Board directed that Notification To Construct letters for the Projects in the Balanced Portfolio be issued once the required Balanced Portfolio Report is finalized after CAWG review and MOPC approval.

Balanced Portfolio Stakeholder Process
The SPP Regional State Committee (**RSC**) requested the Cost Allocation Working Group (CAWG) to consider alternative cost allocations for economic upgrades.

Cost Allocation Working Group (**CAWG**)
The CAWG has been the primary stakeholder group overseeing development of the Balanced Portfolio. The CAWG created the Economic Concepts whitepaper. Many representatives from other SPP stakeholder groups attend the CAWG's monthly meetings.

Trapped Generation Task Force (**TGTF**)
This CAWG Task Force determined wind assumptions in the Adjusted Production Cost (**APC**) models.

Economic Modeling and Methods Task Force (EMMTF)
The EMMTF focused on the planning process and development of additional economic benefit metrics. It initially worked to acquire detailed data on generation units in the model. The EMMTF addressed confidential issues. The EMMTF is currently the Economic Studies Working Group (ESWG)

Regional Tariff Working Group (RTWG)
The RTWG facilitated acquiring FERC approval of Attachment O language for the Balanced Portfolio process.

Markets and Operations Policy Committee (MOPC), Board of Directors (BOD), Regional State Committee (RSC)
These groups will review and approve the Balanced Portfolio.

Planning Summits
Proposed Balanced Portfolios and related concepts were shared at planning summits in May and August.

Posting
Portfolios and associated information are posted on SPP.org:
http://www.spp.org/section.asp?pageID=120

Appendix

<u>Final Benefit to Cost Results for the Balanced Portfolio</u>

The following table demonstrates the full, 10 year portfolio analysis including reliability costs and benefits. These costs and benefits accrue in the years that the portfolio projects impact the reliability plan.

Portfolio 3-E "Adjusted" 10 yr B/C with Reliability Impact

Million of Dollars

Portfolio 3-E "Adjusted"	Total Benefit	Incremental Benefit	Total Cost SPP OATT ATRR	Reliability Cost	Cost (E&C) $ 692 Annual
2012	$ 131.2		$ 93.73	$ 0.03	$ 93.7
2017	$ 193.2	$ 12.4	$ 93.73	$ 2.53	**Total Annual**
2022	$ 239.0	$ 9.2	$ 93.73	$ 2.53	$ 93.8

Year	**8.00%** Year #	**Discount Factor**	**Annual Benefits**	**Discounted Benefits**	**Annual Costs**	**Discounted Costs**	**B/C**
2012	1	1.00	$ 131	$ 131	$ 94	$ 94	**1.40**
2013	2	0.93	$ 144	$ 133	$ 94	$ 87	1.53
2014	3	0.86	$ 156	$ 134	$ 94	$ 80	1.66
2015	4	0.79	$ 168	$ 134	$ 94	$ 74	1.80
2016	5	0.74	$ 181	$ 133	$ 94	$ 69	1.93
2017	6	0.68	$ 193	$ 131	$ 96	$ 66	**2.01**
2018	7	0.63	$ 202	$ 128	$ 96	$ 61	2.10
2019	8	0.58	$ 212	$ 123	$ 96	$ 56	2.20
2020	9	0.54	$ 221	$ 119	$ 96	$ 52	2.29
2021	10	0.50	$ 230	$ 115	$ 96	$ 48	2.39
2022	11	0.46	$ 239	$ 111	$ 96	$ 45	**2.48**
Ten Year Totals	Yrs 1-10	7.25	$ 1,837	$ 1,281	$ 950	$ 687	**1.87**
Per Year Levelized				**$ 177**		**$ 95**	1.87

The following three tables break out the benefits from the economic analysis. These tables do not include the reliability benefits. The numbers represent a change between the change and base cases, with the change case including the Balanced Portfolio. A negative number denotes a reduction in cost which is considered a benefit. Likewise a positive number is a cost increase.

2012 Balanced Portfolio 3E "Adjusted" Benefits

Zone	SumOfChange in Production Cost	SumOfDelta Purchases	SumOfDelta Sales	Adjusted Production Cost
AEPW	$21,285,000	($14,003,000)	$31,439,000	($24,155,000)
EMDE	$2,990,000	($2,096,000)	$207,000	$687,000
GRDA	$72,000	$159,000	$982,000	($751,000)
KCPL	$4,273,000	($637,000)	$9,994,000	($6,358,000)
LES	$1,297,000	$1,226,000	$0	$2,523,000
MIDW	($350,000)	($8,783,000)	$0	($9,133,000)
MIPU	$6,027,000	($3,968,000)	($5,000)	$2,064,000
MKEC	($7,563,000)	($2,015,000)	($925,000)	($8,653,000)
NPPD	$6,519,000	($28,000)	$11,726,000	($5,235,000)
OKGE	($85,787,000)	$52,737,000	($9,386,000)	($23,664,000)
OPPD	$2,165,000	$160,000	$4,247,000	($1,922,000)
SPRM	$734,000	($42,000)	$668,000	$24,000
SUNC	($5,206,000)	($2,096,000)	($5,171,000)	($2,131,000)
SWPS	($70,516,000)	$31,769,000	($519,000)	($38,228,000)
WEFA	($13,163,000)	$4,105,000	($375,000)	($8,682,000)
WRI	($5,257,000)	($359,000)	$2,131,000	($7,747,000)

2017 Balanced Portfolio 3E "Adjusted" Benefits

Zone	SumOfChange in Production Cost	SumOfDelta Purchases	SumOfDelta Sales	Adjusted Production Cost
AEPW	$55,943,000	($17,738,000)	$71,548,000	($33,344,000)
EMDE	$3,525,000	($3,272,000)	$100,000	$153,000
GRDA	($28,000)	$163,000	$889,000	($754,000)
KCPL	$6,229,000	($3,576,000)	$11,897,000	($9,244,000)
LES	$2,019,000	$1,970,000	$0	$3,989,000
MIDW	($764,000)	($14,046,000)	$0	($14,810,000)
MIPU	$5,483,000	($3,915,000)	$79,000	$1,489,000
MKEC	($10,893,000)	($2,667,000)	($793,000)	($12,767,000)
NPPD	$5,842,000	($779,000)	$10,741,000	($5,678,000)
OKGE	($129,794,000)	$88,180,000	($14,032,000)	($27,582,472)
OPPD	$3,030,000	$276,000	$5,663,000	($2,357,000)
SPRM	$603,000	($60,000)	$251,000	$292,000
SUNC	($7,575,000)	($2,386,000)	($6,776,000)	($3,185,000)
SWPS	($80,497,000)	$18,914,000	($924,000)	($60,659,000)
WEFA	($22,863,000)	$14,785,000	($468,000)	($7,610,000)
WRI	($14,392,000)	($1,073,000)	$1,674,000	($17,139,000)

2022 Balanced Portfolio 3E "Adjusted" Benefits

Zone	SumOfChange in Production Cost	SumOfDelta Purchases	SumOfDelta Sales	Adjusted Production Cost
AEPW	$67,322,000	($22,618,000)	$83,884,000	($39,181,000)
EMDE	$4,703,000	($4,421,000)	$91,000	$191,000
GRDA	($480,000)	$123,000	$1,003,000	($1,360,000)
KCPL	$6,624,000	($2,828,000)	$14,974,000	($11,178,000)
LES	$2,249,000	$2,150,000	$0	$4,399,000
MIDW	($736,000)	($14,659,000)	$0	($15,395,000)
MIPU	$2,680,000	($1,044,000)	($19,000)	$1,655,000
MKEC	($14,429,000)	($1,525,000)	($287,000)	($15,667,000)
NPPD	$6,488,000	($1,250,000)	$10,748,000	($5,510,000)
OKGE	($138,499,000)	$85,998,000	($22,388,000)	($30,113,000)
OPPD	$3,787,000	$378,000	$6,258,000	($2,093,000)
SPRM	$637,000	($317,000)	$301,000	$19,000
SUNC	($7,360,000)	($2,495,000)	($3,923,000)	($5,932,000)
SWPS	($89,381,000)	$2,205,000	($1,184,000)	($85,992,000)
WEFA	($20,837,000)	$13,197,000	($575,000)	($7,065,000)
WRI	($11,595,000)	($6,705,000)	$2,730,000	($21,030,000)

The following table demonstrates the benefits, costs and transfers on an annualized basis after the resulting reliability impacts, both the advancement and deferral, are accounted for. The net B/C impact of the reliability projects was an approximate marginal increase of .01 of the total Portfolio.

Portfolio 3-E "Adjusted" Annualized Benefits, Costs and Transfers, including Reliability Impacts

Attachment H Transfer Adjustments - Portfolio 3E "Adjusted" - Annualized

#	Zone	Portfolio Benefits	Portfolio Costs	Zonal ATRR Transfers Out (Col. 5 Attach H)	Regional Allocation of Zonal ATRR Transfers	Net of Zonal Transfers and Transfer Allocation	Net Benefit	B/C
1	AEPW	$30.9	$21.3	$0.0	$7.0	$7.0	$2.6	1.1
2	EMDE	($0.3)	$2.5	($3.7)	$0.8	($2.8)	$0.0	1.0
3	GRDA	$0.9	$1.9	($1.6)	$0.6	($1.0)	$0.0	1.0
4	KCPL	$8.4	$7.3	($1.3)	$2.4	$1.1	$0.0	1.0
5	MIDW	$12.8	$0.7	$0.0	$0.2	$0.2	$11.9	14.1
6	MIPU	($1.3)	$3.8	($6.4)	$1.3	($5.2)	$0.0	1.0
7	MKEC	$11.8	$1.1	$0.0	$0.3	$0.3	$10.4	8.3
8	OKGE	$26.6	$13.4	$0.0	$4.4	$4.4	$8.7	1.5
9	SPRM	($0.1)	$1.5	($2.1)	$0.5	($1.6)	$0.0	1.0
10	SUNC	$3.7	$1.0	$0.0	$0.3	$0.3	$2.3	2.7
11	SWPS	$56.1	$10.9	$0.0	$3.6	$3.6	$41.5	3.9
12	WEFA	$8.0	$3.0	$0.0	$1.0	$1.0	$4.0	2.0
13	WRI	$14.2	$11.0	($0.4)	$3.6	$3.2	$0.0	1.0
14	NPPD	$5.5	$7.6	($4.6)	$2.5	($2.1)	$0.0	1.0
15	OPPD	$2.3	$5.9	($5.6)	$1.9	($3.6)	$0.0	1.0
16	LES	($3.1)	$1.8	($5.5)	$0.6	($4.9)	$0.0	1.0
Total		**$176**	**$95**	**-$31**	**$31**	**$0**	**$81**	**1.86**

The spreadsheet which was used to calculate the transfers in the above table can be found on the [Balanced Portfolio section of the SPP Website.](http://www.spp.org/section.asp?pageID=120)[††]

[††] http://www.spp.org/section.asp?pageID=120

The table shown below demonstrates the MW-mi impact of the deferred reliability projects. This impact is used to determine who receives the benefit for the deferral of each reliability project from the portfolio.

Portfolio 3-E – Reliability Impact MW-mi analysis

	HUNTSVILLE - HEC 115KV CKT 1 - Rebuild	HUNTSVILLE - ST_JOHN 115KV CKT 1 - Rebuild	CLEARWATER-GILL ENERGY CENTER WEST 138KV CKT 1 - Rebuild	EL RENO- EL RENO SW 69KV CKT 1 - Upgrade	LONGVIEW-WESTERN ELECTRIC 161KV CKT 1 - Replace Wavetraps
Date	**2015**	**2015**	**2016**	**2017**	**2018**
AEPW		1.6%			
EMDE					
GRDA					
KCPL					
MIDW	46.7%	16.2%			
MIPU					100.0%
MKEC	19.4%	36.0%			
OKGE	1.3%	5.3%		24.7%	
SPRM					
SUNC	9.9%	10.9%			
SWPS		4.4%			
WEFA				75.3%	
WRI	22.6%	22.1%	100.0%		
NPPD		3.6%			
OPPD					
LES					
	100.0%	100.0%	100.0%	100.0%	100.0%

Reliability Results

The reliability results for the Portfolio 3E "Adjusted" are shown in the following table. The projects are broken into "deferred" and "mitigated" issues and "new" issues. Additionally, projects are shown for potential third party impacts. Note that a project highlighted in yellow (e.g. EARLSBORO – FIXICO) indicates that the project is merely advanced in time and not an entirely new issue.

Portfolio 3e without Chesapeake

Costs of STEP Projects Solved by Portfolio 3e, with STEP date

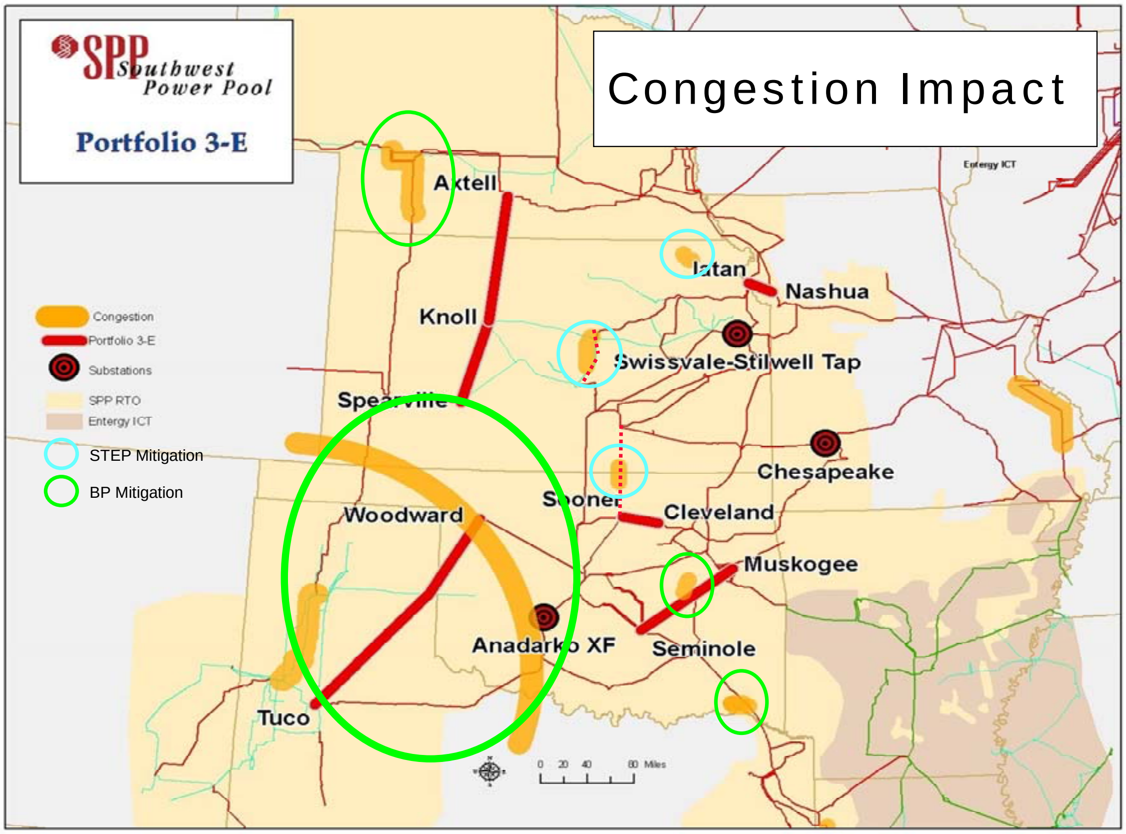
Issue Type	Project Name	Area	STEP Date	Deferred costs to TO: STEP projects solved by BP
Overload	CLEARWATER - GILL ENERGY CENTER WEST 138KV CKT 1 - Rebuild	WERE	16SP	$3,324,375
Overload	EL RENO - EL RENO SW 69KV CKT 1 - Upgrade	WFEC	17SP	$1,950,000
Overload	HUNTSVILLE - HEC 115KV CKT 1 - Rebuild	WERE	15SP	$12,487,500
Overload	HUNTSVILLE - ST_JOHN 115KV CKT 1 - Rebuild	MIDW	15SP	$7,965,000
Overload	LONGVIEW - WESTERN ELECTRIC 161KV CKT 1 - Replace Wavetraps	MIPU	18SP	$50,000
Voltages	None			
			Totals	**$25,776,875**

Cost of potential mitigation for New issues due to implementation of portfolio improvements

Description	Project Name	Area	Date of Needed Mitigation	SPP New Issues, Cost	Third Party Issues: Cost
Overloads-SPP	EARLSBORO - FIXICO 69KV CKT 1 - Increase limits (trap, CT ratio)	OKGE	13SP	$150,000	
Overloads-SPP	MED LODGE-PRATT, ST.JOHN-GREATBENDTAP 115 KV LINE REBUILD	MKEC	18SP	$15,840,000	
Overloads-Third Party	PLATTE CITY 161/69KV TRANSFORMER CKT 1 - Replace AECI XFMR	MIPU-AECI	13WP		$7,500,000
Voltages	None				
			Totals	**$15,990,000**	**$7,500,000**
			Grand Total	**$23,490,000**	
			Net: Solved Minus SPP New	**$9,786,875**	
			Net: Solved Minus Total New	**$2,286,875**	

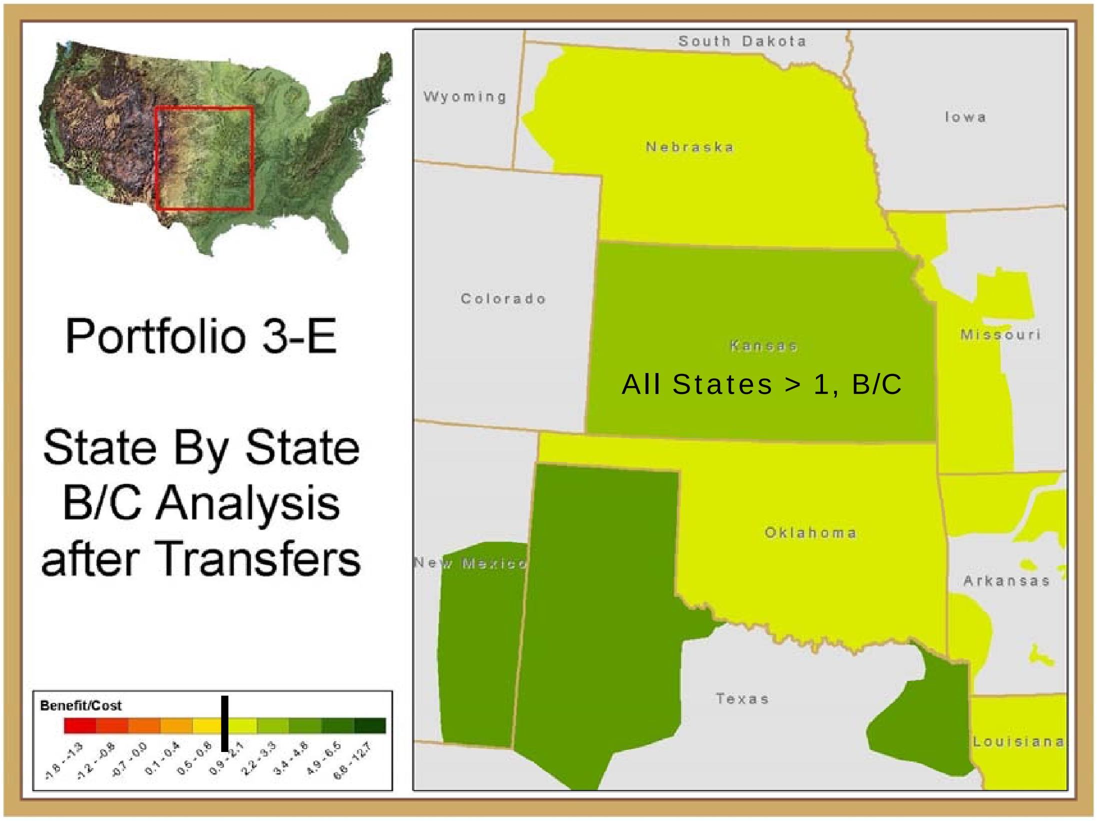
It should be noted that the third party impact of Platte City 161/69 kV transformer was coordinated with Associated Electric Cooperative, Inc. (AECI) staff. AECI staff did not see the same issue in their analysis.

Congestion Impact



The graphic shown above represents the top flowgates in the SPP EIS Market as they exist today. Congestion here is shown as an orange highlight. Portfolio projects, shown on the map as bold red highlight lines, relieve or mitigate much of the congestion that exists today. The congestion relief provided by the portfolio is shown as a green circle. Projects in the 10-year STEP plan that provide additional congestion relief are shown in light blue.

B/C by State



The diagram above demonstrates the B/C ratio of the Balanced Portfolio divided by state boundaries. While it should be noted that the portfolio of projects provides broad, regional benefits to all SPP members, this diagram is a good representation of the balance aspect of the portfolio broken into the respective state boundaries. This picture represents the balance of the portfolio after transfers have taken place in order to balance all zones. As can be seen from the diagram, all states have a B/C ratio greater than 1

	Zone	OKGE	OKGE	OKGE	SPS	KCPL	NPPD	ITC	KCPL	OKGE
	Project	Sooner - Cleveland	Seminole - Muskogee	Tuco - Woodward	Tuco - Woodward	Iatan - Nashua	Knoll - Axtell	Spearville - Knoll - Axtell	Swissvale - Stilwell Tap	Andadarko Sub
	Projected In-Service Date	12/31/2012	12/31/2013	5/19/2014	5/19/2014	6/1/2015	6/1/2013	6/1/2013	6/1/2012	12/31/2011
Cost	Total Cost	$33,530,000	$129,000,000	$79,000,000	$148,727,500	$54,444,000	$71,377,015	$165,180,000	$2,00,000	$8,000,000
	Cost Per Mile	$900,000	$1,250,000	$900,000	$688,750	$1,214,800	$1,416,667	$846,000		$666,666
	Miles	36	100	72	178	30	45	170		3
	Substation Cost	$1,130,000	$4,000,000	$15,000,000	$26,130,000	$18,000,000	$6,827,000	$16,800,000		
	Fixed Charge Rates	15.1%	15.1%	15.1%	12.1%	15.1%	13.5%	12.0%	15.1%	15.1%
Conductor	Size	2 Conductor Bundle 795 ACSR	2 Conductor Bundle 1590 ACSR	2 Conductor Bundle 795 ACSR	2 Conductor Bundle 795 ACSR	2 Conductor Bundle 1192.5, 38/19 Grackle TW	2 Conductor Bundle 477 T2 Hawk	2 Conductor Bundle 1590 ACSR	2 Conductor Bundle 795 ACSR	138 kV line
	Design	Single Circuit	Single Circuit	Single Circuit	Single Circuit	Single Circuit	Single Circuit	Single Circuit		
	Electrical Capacity	2578 Amps 1540 MVA at 345kV	3000 Amps 1800 MVA at 345kV	2578 Amps 1540 MVA at 345kV	2468 Amps Normal	4,100A	2,324 amps per bundle	3,000 amps		
	Other	Fiber-optic Shield wire	Fiber-optic Shield wire	Fiber-optic Shield wire	Fiber-optic Shield wire					
Structure	Type	H-frame	Single Pole	H-frame	H-frame	H-frame	Single Pole	H-frame		
	Materials	Steel	Steel	Steel	Steel	Steel	Steel	Steel		
	Base	Direct buried w/ aggregate backfill	Steel base plate reinforced concrete	Direct buried w/ aggregate backfill	Direct buried with aggregate or natural backfill	Direct Embed	Poured concrete anchor bolt	Direct embed concrete piers		
	NESC Assumption	Heavy	Heavy	Heavy	Heavy	Heavy	Heavy, 1.5 inch ice load			
	Dead Ends	Unknown	Unknown	Unknown	Unknown @ $65,000 each	16 @ $50,000 each	20 @ $140,000 each	60 @ $50,000 each	2 to 3 Deadends	
	Under build	No	No	No	No	No	No	No		
Substations	Transformers	Breakers and Relays	Two 345/138kV	345/138kV 50 MVAR reactor bank	345/230kV 560 MVA	600 MVA	None	345/230kV 200 MVA		345/138 kV
	Breaker Scheme	Ring-bus	Ring-bus, replace 2 2,000 A breakers	Ring-bus	345kV Ring	Ring-bus	Ring-bus	Ring-bus	2 breakers, breaker disconnects, line panels	
	Protection Scheme	included in sub cost	included in sub cost	included in sub cost	$1,000,000	$400,000	$156,000	$220,000		included in sub cost
	Voltage Control			+\- 50 MVAR						
	Cost (millions)	$1	$4	$15	$26	$18	$4	$14		
Construction Labor	Amount	1/3 of line construction	1/3 of line construction	1/3 of line construction						
	Cost (millions)	$14	$52	$27	$18	$7	$17	$49		
Eng Design, Project Management, Permitting	ROW	150ft @$5,500 an acre	200ft @$5,500 an acre	150ft @ $5,500 an acre	150ft	160ft	200ft	150ft		
	ROW Condition	rural, pasture	rural, pasture, hill, rock, high tree clearing cost	rural, pasture	Farmland and Pasture	50% Urban 50% Rural	rural farmland rainwater basin	rural, agri, pasture, range land	No ROW acquisition required	
	Permitting/Certifications	RR and Highway	RR and Highway	RR and Highway	Texas CCN, Highway, storm water, RR, County roads	Yes	NE Power Review Board, NPSC, RR, Airport, etc	Included		
	Escalation Rate	2.5% per year	2.5% per year	2.5% per year		2.5% per year	3% per year	0% for 2 years		
	Eng. Design / Proj. Mang.				Included	$349,000	$8,798,000	$13,770,000		
	Total Cost (millions)	cost included	cost included	cost included	$15	$26	$18	$24		
Loadings and Overheads	Type 1	Included in total cost	Included in total cost	Included in total cost	Included in total cost	$123,000	Included in total cost	20% of line and substation work, $26.7 million		
Other Cost Factors and Notes			$25,000/ mile cost included for tree clearing		Included in substation cost is $6.52 mil for mid-point reactor station	Large portion involves developed urban areas	Environmentally sensitive areas, possible double-circuit for 10 miles	$4.56 mil addition contingency added		

Study Assumptions

Fuel Price Assumptions – Fuel price assumptions are taken from EIA forecasts and updated according to member specific data for particular plants. For the purpose of this study, the average gas price is $6.50/MMBtu starting in 2012. The price is then escalated for inflation for the years 2017 and 2022 at the rate of 1.81%.

Environmental Costs - Carbon sensitivities have been conducted, but were not included in the portfolio selection process. A price of $15 and $40 per metric ton was used in these sensitivities. No sensitivity analysis was conducted for higher SO_2 or NO_X prices. SO_2 and NO_X were priced at $466.50 and $1742.16 per ton respectively.

Plant Outages – Stakeholders provided outage and maintenance rates to SPP staff through the EMMTF data collection effort. Forced outages were taken as a single draw and locked for the change and the base case. Similarly, maintenance outages were also locked down from a single scheduled pattern. These outage rages were plant specific and provided by each member.

Load Forecast – Load forecasts for the region were provided by each stakeholder in early 2009 for the projected years of 2012, 2017 and 2022 through the EMMTF update effort. These non coincident peak loads for the region were, in aggregate, as follows: 2012 - 43,068MW, 2017 – 47,109 MW, 2022 – 51,530 MW. The zonal shares of the 2012 load submittals were used to allocate the costs on a load ratio share basis.

Resource Forecast – The CAWG and EMMTF determined the criteria for inclusion of new resources into the Balanced Portfolio analysis. It was determined that only plants with firm transmission service and signed agreements or plants that were currently under construction would be included in the analysis. The following units are those which were included as a future resource.

- Turk (618 MW)
- Whelan Energy Center 2 (220 MW)
- Iatan 2 (900 MW)
- Central Plains (99 MW)
- Cloud County (201 MW)
- Flat Ridge (100 MW)
- Red Hills (120 MW)
- Smoky Hills (359 MW)

Hurdle Rates – A dispatch hurdle rate of $5/MW and a commit hurdle rate of $8/MW was used to commit resources across regional boundaries.

Demand Side Management – Interruptible load was modeled as supplied by the LSE's.

Market Structure – The simulation was conducted considering a single balancing authority and a day-ahead market structure for the SPP region.

Flowgate Assumptions – The NERC Book of Flowgates was used as the source for flowgates used in the analysis.

DC Tie Profiles - Historical DC Tie profiles were used to simulate best known profiles for all DC Ties in the SPP region.

Wind Profiles – Historical wind profiles were used to simulate the wind output at each wind farm.

Load Profiles – Load profiles were simulated as supplied by each LSE through the EMMTF effort.

RMR Requirements – Each Balancing Authority submitted their respective Reliability Must Run (RMR) requirements to be simulated in the analysis.

Operating Reserves – SPP's current reserve sharing program (as of 2008) was used in the simulation for operating reserves.