REGIONAL COST ALLOCATION REVIEW (RCAR III) FINAL REPORT

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EXECUTIVE SUMMARY

This report contains the results of the third Regional Cost Allocation Review (RCAR III) of Southwest Power Pool, Inc.'s (SPP) Highway/Byway transmission cost allocation methodology in accordance with Attachment J, Section III.D of SPP's Open Access Transmission Tariff (OATT).

The analyses contained in this RCAR III Report (the RCAR Report) were conducted based on the recommendations of the Regional Allocation Review Task Force (RARTF) approved by SPP stakeholders in January 2012 (the RARTF Report), the applicable RCAR I Lessons Learned Report approved in April 2014 and the RCAR II Lessons Learned Report approved in September 2019. These analyses included the calculation of nine out of thirteen benefits approved by SPP's Metrics Task Force (MTF), Economic Studies Working Group (ESWG), Markets and Operations Policy Committee (MOPC), as well as the Members Committee and Board of Directors (Board) in 2012 and in July 2014.

Due to the technical challenges from the methodology used in RCAR I and II, an alternative approach was used in RCAR III by utilizing daily market results from the Integrated Marketplace paired with analysis on transmission planning models and by limiting included projects to those having been in-service prior to January 1, 2020, (Operational approach). This methodology is expected to provide more reasonable results, while avoiding the technical issues observed in past RCAR studies.

When conducting the RCAR III, SPP staff applied nine of the ten principles contained in the RARTF Report:[1]

- Simplicity
- Acknowledgment of the "roughly commensurate" legal standard
- Equity over time
- Use of the best quantifiable information available
- Consistency
- Transparency
- Stakeholder input
- Use of real dollars values

[1] In the RCAR I Lessons Learned the RARTF agreed to not include Principle 8 in the RCAR II analysis. This was continued for RCAR III analyses, and is further explained in Section 3 of this report. The RARTF agreed to use all projects approved for construction as of October 1, 2015 for the RCAR II analysis. See July 8, 2015 RARTF Meeting minutes; https://www.spp.org/documents/29110/rartf%20minutes%2020150708%20draft.pdf. For RCAR III, the RARTF agreed to a new methodology and included only Highway/Byway projects having been in service by January 1, 2020.

- Inclusion in the review of SPP Board approved transmission projects.[2]

Applying these principles this RCAR Report demonstrates a 5.76:1 overall benefit to cost (B/C) ratio to the region for projects approved for construction since June 2010 under the Highway/Byway cost allocation methodology and in-service prior to January 1, 2020. This shows a strong increase from the RCAR II analysis, which showed a 2.45:1 overall benefit to cost (B/C) ratio and the RCAR I analysis, which showed a 1.42:1 B/C for projects issued a Notification to Construct (NTC) since June 2010.

The assessment shows, for projects approved for construction since June 2010 and in-service prior to January 1, 2020:

- Zero Zones were below the .80 threshold established by the RARTF
- Zero Zones were greater than the .80 threshold but below 1.0
- All seventeen Zones were above a 1.0 B/C ratio.

Additionally, the RARTF Report recommends the following next step:

- That the RARTF begin a process to evaluate "lessons learned" from SPP's RCAR III Report and finalize "suggested improvements" to the RCAR process. This recommendation will allow any improvements to be incorporated into the next RCAR process and will be in accordance with Section 7.1 of the RARTF Report.

[2] Attachment J, Section III.D.3 of SPP's OATT, as modified by FERC letter order in Docket No. ER22-331 issued April 5, 2022: *See* Order in ER22-331.

BACKGROUND - OVERVIEW OF PREVIOUS RCAR STUDIES

In approving SPP's Highway/Byway cost allocation methodology, the Federal Energy Regulatory Commission (FERC) also approved a requirement that SPP review the "reasonableness of the regional allocation methodology and factors (X% and Y%) and the zonal allocation methodology at least once every three years."[3] This review is required to "determine the cost allocation impacts of Base Plan Upgrades approved for construction issued after June 19, 2010 to each pricing Zone within the SPP Region as identified in the methodology in Section III.D.4."[4] Thus, the purpose of this analysis is to measure by Zone the cost allocation impacts of SPP's Highway/Byway methodology.

The review is hereinafter referred to as the "Regional Cost Allocation Review" or "RCAR". RCAR I was completed in 2013; RCAR II was completed in 2016.

SPP's Open Access Transmission Tariff (tariff or OATT) requires that "the MOPC and Regional State Committee (RSC) will define the analytical methods to be used" in conducting the RCAR.[5] As a result, the Regional Allocation Review Task Force (RARTF) was created as part of the SPP stakeholder process to develop the analytical methods used for the review.

The original RARTF membership included three representatives from the RSC, three SPP Members, and one member from the independent Board. RARTF members were jointly appointed by then RSC President Jeff Davis and then MOPC Chairman Bill Dowling who were serving in these capacities at the time. The members of the original RARTF were:

Original RARTF Members	
Chairman Michael Siedschlag	Nebraska Public Review Board
Vice-Chairman Richard Ross	American Electric Power
Commissioner Thomas Wright	Kansas Corporation Commission
Commissioner Olan Reeves	Arkansas Public Service Commission
Bary Warren	The Empire District Electric Company
Philip Crissup	Oklahoma Gas and Electric Company
Harry Skilton	SPP Board of Directors

[3] Attachment J, Section III.D.1 of SPP's OATT, modified in 2017 to be every six years

[4] Attachment J, Section III.D.2 of SPP's OATT, as approved on April 6, 2022 in FERC Docket No. ER22-331. *See* Order in ER22-331.

[5] Attachment J, Section III.D.4(i) of SPP's OATT.

Pursuant to the mandate in the RARTF charter, the group prepared a report that recommended how to define the analytical methods to be used in the RCAR. In January 2012, the RARTF Report was approved unanimously by the RARTF, RSC, MOPC, Members Committee, and Board.

After the initial RCAR was completed, the MOPC and RSC agreed to expand the RARTF's membership to include an additional representative from both the MOPC and RSC. This change allowed for more continuity of the group as members of the RSC change from time to time. In July 2013, then RSC President Olan Reeves and then MOPC Chairman Rob Janssen appointed new members to the RARTF. The group's roster was then as follows:

RARTF Members as of July 2013	
Chairman Olan Reeves	Arkansas Public Service Commission
Vice-Chairman Richard Ross	American Electric Power
Commissioner Thomas Wright	Kansas Corporation Commission
Commissioner Steve Lichter	Nebraska Power Review Board
Commissioner Steve Stoll	Missouri Public Service Commission
Bary Warren	The Empire District Electric Company
Philip Crissup	Oklahoma Gas and Electric Company
Bill Grant	Xcel Energy/SPS
Harry Skilton	SPP Board of Directors

In January 2014, Commissioner Olan Reeves left the Arkansas Public Service Commission (APSC) and was replaced on the RARTF by Commissioner Lamar Davis of the APSC. At this time Commissioner Steve Stoll assumed the role of Chairman of the RARTF and the membership remained unchanged through the completion of RCAR II.

RARTF Members as of February 2014	
Chairman Steve Stoll	Missouri Public Service Commission
Vice-Chairman Richard Ross	American Electric Power
Commissioner Thomas Wright	Kansas Corporation Commission
Commissioner Steve Lichter	Nebraska Power Review Board
Commissioner Lamar Davis	Arkansas Public Service Commission
Bary Warren	The Empire District Electric Company
Philip Crissup	Oklahoma Gas and Electric Company
Bill Grant	Xcel Energy/SPS
Harry Skilton	SPP Board of Directors

The current membership of the RARTF as of the completion of RCAR III[6] is as follows:

RARTF Members as of July 2022	
Chair Kristie Fiegen	South Dakota Public Utility Commission
Vice-Chairman Richard Ross	American Electric Power
Commissioner Andrew French	Kansas Corporation Commission
Commissioner Geri Huser	Iowa Utilities Board
Commissioner Randel Christmann	North Dakota Public Service Commission
Bary Warren	Gridliance High Plains
Jarred Cooley	SPS Xcel Energy
Denise Buffington	Evergy Companies
Susan Certoma	SPP Board of Directors

RCAR I

In October 2013, SPP staff completed RCAR I, and stakeholder groups — including the Regional Tariff Working Group (RTWG), RSC[7] and MOPC[8] — reviewed and voted on its results.

The RCAR I consisted of two separate analyses:

- Projects that had received NTCs since June 2010
- Projects that had received NTCs since June 2010 plus authorization to plan (ATP) projects needed within 10 years.

It is noteworthy that not all of the approved benefit metrics were monetized in RCAR I. The B/C results from RCAR I can be found at spp.org.[9]

RCAR I Lessons Learned

At the conclusion of RCAR I, SPP staff led stakeholders in a formal lessons-learned process to develop a list of improvements to be implemented in the next RCAR analysis. The concept of the RCAR I Lessons Learned Report (Lessons Learned Report) was first raised in the 2012 RARTF Report and further detailed in the RCAR I endorsed by SPP stakeholders in 2013.

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[6] Dennis Grennan (NPRB) served as Chair during the development of the RCAR III process (2018-2021).
[7] *See* RSC October 28, 2013 minutes at page 4; http://www.spp.org/documents/21575/rsc102813.pdf.
[8] *See* "MOPC Meeting Minutes & Attachments October 15-16, 2013" at page 5; http://www.spp.org/documents/21032/mopc%20meeting%20minutes%20&%20attachments%20october%2015-16,%202013.pdf
[9] *See* RCAR I Final Report at; http://www.spp.org/documents/37781/rcar%20report%20final%20clean.pdf.

The purpose of the Lessons Learned Report was to evaluate lessons learned from RCAR I and make suggested improvements to the RCAR process. A final Lessons Learned Report was adopted by the RARTF on March 31, 2014 after receiving and reviewing stakeholder comments and suggestions over a six-month period. These recommendations were incorporated into the RCAR II process.

To initiate the lessons-learned process, SPP staff sought stakeholder comments and suggestions. Responses were received from the following SPP stakeholder groups:

SPP Stakeholder Group	Date of Submission
Southwestern Public Service Company (SPS)	November 18, 2013
Omaha Public Power District (OPPD)	November 18, 2013
Lincoln Electric System (LES)	November 18, 2013
Missouri Public Service Commission (MoPSC)	November 20, 2013
City Utilities of Springfield (CUS)	November 21, 2013
Kansas City Power & Light (KCPL)	December 6, 2013

The chart below summarizes stakeholders' comments and suggestions.

Stakeholder Entity	Area of Comment or Suggestion						
	Metrics/ Allocation	Modeling	Remedy	NTC/ATP	PTP Offset	Sched/ Process	Total
CUS	2		4		1	1	**8**
LES	2		1				**3**
OPPD	2		1		4	2	**9**
SPS	1	4					**5**
KCPL	2	2	1	1	1	1	**8**
MoPSC			1	1			**2**
Totals	**9**	**6**	**8**	**2**	**6**	**4**	**35**

On February 3, 2014, the RARTF reviewed stakeholders' suggestions for improving the RCAR process,[10] then met on March 3 in Dallas, Texas to begin finalizing the RARTF Lessons Learned Report after the completion of RCAR I.[11]

On March 24, 2014, the RARTF held a conference call to finalize stakeholder recommendations and approve the RARTF Lessons Learned Report. Once approved by the RARTF, this report was posted publicly and shared with the appropriate SPP working groups.

[10] More than thirty-five SPP stakeholders participated in the RARTF's February 3, 2014 call.
[11] More than thirty-five SPP stakeholders participated in the RARTF's March 3, 2014 in-person meeting.

After reviewing and considering the comments and suggestions from SPP stakeholders, the RARTF adopted ten "lessons learned" which were incorporated into the RCAR II process. Those recommendations were:

LESSONS LEARNED RECOMMENDATION NO. 1:

> That the principles and the detailed guidance provided to SPP staff in conducting RCAR I were a major success of the SPP stakeholder process with meaningful stakeholder input. Notwithstanding this success, improvements to the RCAR process can be made as SPP staff begins to analyze the Highway/Byway for RCAR II. As a result, the RARTF recommends that the January 2012 RARTF Report continue to be the basis upon which SPP staff conducts the RCAR II analysis with the exception of, or additions to, the recommendations contained in this Lessons Learned Report. The recommendations contained in this Lessons Learned Report should be incorporated and used by SPP staff when conducting the RCAR II assessment of the SPP Highway/Byway.

LESSONS LEARNED RECOMMENDATION NO. 2:

> That the Economic Studies Working Group (ESWG) continues to review the benefits contained in the Metrics Task Force (MTF) Report that were approved through the SPP stakeholder process in 2012. This review should be established to provide SPP stakeholders the opportunity to offer wide-ranging improvements to the benefits contained in the MTF Report. Any changes or improvements to the benefits shall be presented to the ESWG, RARTF, MOPC, and RSC for recommendation to the BOD for approval by the July 2014 meeting cycle.[12]

LESSONS LEARNED RECOMMENDATION NO. 3:

> That the ESWG continue to review the benefits contained in the MTF Report that were approved through the SPP stakeholder process in 2012. This review should provide SPP stakeholders the opportunity to suggest which benefits should be included in future RCAR reports. Any changes or improvements to the benefits shall be presented to the ESWG, RARTF, MOPC, and RSC for recommendation to the BOD for approval by the July 2014 meeting cycle.[13]

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[12] Per Lessons Learned Recommendation No. 3, SPP Board of Directors approved changes to Benefit Metrics on July 29, 2014. See, http://www.spp.org/documents/22963/bocmc%20minutes%20072914.pdf.

[13] Per Lessons Learned Recommendation No. 3, SPP Board of Directors approved changes to Benefit Metrics on July 29, 2014. See, http://www.spp.org/documents/22963/bocmc%20minutes%20072914.pdf.

LESSONS LEARNED RECOMMENDATION NO. 4:

That SPP staff continue to work with the SPP Transmission Working Group (TWG) and ESWG to improve models used for RCAR II. This effort should provide SPP stakeholders the opportunity to offer or suggest improvements to models used in future RCAR reports. Any changes or improvements to the models should be vetted by the TWG and ESWG as appropriate. These changes or improvements should also be in alignment with the ten guiding principles contained in the RARTF Report.

LESSONS LEARNED RECOMMENDATION NO. 5:

That SPP staff utilize, to the maximum extent possible, models used in the Integrated Transmission Plan 10-year planning horizon assessment (ITP10) for RCAR II. Conducting the ITP10 and RCAR II processes in parallel should allow leveraging of models and promote consistency and efficiency in the model vetting process. This measure could reduce cost and help to eliminate redundancy of efforts between SPP staff and stakeholders.

LESSONS LEARNED RECOMMENDATION NO. 6:

That SPP staff evaluate remedies for Zones below the threshold in the Notification to Construct (NTC)-only review for RCAR II.[14]

LESSONS LEARNED RECOMMENDATION NO. 7:

That SPP staff continue to work with SPP stakeholders to find ways to improve upon calculating Point to Point (PTP) revenue credits for RCAR II. This effort should provide SPP stakeholders the opportunity to suggest improvements to PTP revenue credits calculations for use in future RCAR reports that most closely align with SPP's OATT. Additionally, by updating how PTP revenue credits are projected with up-to-date information, SPP staff will be using "the most up [-] to [-] date and best available information," consistent with Principle 3 contained in the RARTF Report. Any changes or improvements to the PTP projection methodology should be vetted by the RARTF and RTWG as it was handled during the RCAR I Report in an open and transparent manner that will enable the participation of SPP stakeholders.[15]

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[14] Following the completion of the first draft of the RCAR II Report, SPP staff began communications with City of Springfield, the only deficient zone in the RCAR II analysis.

[15] Per Lessons Learned Recommendation No. 7, SPP staff facilitated a stakeholder process to develop revisions of the SPP Tariff for the purposes of clarifying and ensuring consistency in the treatment of PTP revenue credits for calculating

LESSONS LEARNED RECOMMENDATION NO. 8:

> That the RARTF and SPP stakeholder-approved 0.8 benefit to cost ratio threshold continue to be the basis to determine when it is warranted for members to request and for SPP staff to subsequently study possible remedies as stated in Section 4.1 of the RARTF Report. Additionally, the RARTF recommends that if RCAR II shows that a Zone is above the 0.8 threshold, but below a 1.0 benefit to cost ratio, that this analysis should be used and considered as a part of SPP's transmission planning process in the future.

LESSONS LEARNED RECOMMENDATION NO. 9:

> That SPP staff continue to update and brief the RARTF throughout the RCAR II analysis and seek guidance from the RARTF when input from SPP stakeholders is necessary for SPP staff to complete RCAR II.[16]

LESSONS LEARNED RECOMMENDATION NO. 10:

> That SPP make a filing with the Federal Energy Regulatory Commission (FERC) to amend Attachment J, Section III.D.2 to read as follows:
>
> > For each review conducted in accordance with Section III.D.1, the Transmission Provider shall determine the cost allocation impacts of the Base Plan Upgrades ***approved for construction*** ~~with Notifications to Construct issued~~ after June 19, 2010 to each pricing Zone within the SPP Region.[17]

The Lessons Learned were adopted by the RARTF on March 31, 2014[18] and also reviewed and approved by the RSC and MOPC to be implemented in RCAR II.

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rates. This set of revisions allows PTP revenue credits to be projected in a more reliable manner in the RCAR analysis. The Tariff revisions were ultimately approved by SPP's Board of Directors and the FERC. *See*, FERC Docket No. ER16-165.

[16] SPP staff implemented Lessons Learned No. 9 by facilitating 12 meetings with the RARTF since August 13, 2014. Agendas and minutes for RARTF meetings can be found at: http://www.spp.org/organizational-groups/board-of-directorsmembers-committee/markets-and-operations-policy-committee/regional-allocation-review-task-force/

[17] SPP staff facilitated Lessons Learned No. 10 through SPP's stakeholder process which was ultimately approved by the SPP Board of Directors and FERC. *See*, FERC Docket: ER15-307. This filing was approved by FERC on December 22, 2014.

[18] See RARTF approval of RCAR I Lessons Learned items at page 1 of March 31, 2014 minutes; http://www.spp.org/documents/22238/rartf%20meeting%20minutes%2031%20march%202014%20draftgf.pdf

RCAR II

In July 2016 SPP staff completed RCAR II, and stakeholder groups – including the Regional Tariff Working Group (RTWG), RSC and MOPC – reviewed and voted on its results.

The RCAR II consisted of the following analyses:

- Projects that had received NTCs since June 2010

Unlike RCAR I, all of the approved benefit metrics were monetized in RCAR II. The B/C results from RCAR II can be found at spp.org.

RCAR II Lessons Learned

At the conclusion of RCAR II, SPP staff led stakeholders in a formal lessons-learned process to develop a list of improvements to be implemented in the next RCAR analysis. The concept of the RCAR II Lessons Learned Report (Lessons Learned Report) was first raised in the 2012 RARTF Report and further detailed in the RCAR II endorsed by SPP stakeholders in 2016.

The purpose of the Lessons Learned Report is to evaluate lessons learned from RCAR II and make suggested improvements to the RCAR process. A final Lessons Learned Report was adopted by the RARTF on September 19, 2019 after receiving and reviewing stakeholder comments and suggestions. These recommendations have been incorporated into the RCAR III process.

To initiate the lessons-learned process, SPP staff sought stakeholder comments and suggestions. Responses were received from the following SPP stakeholder groups:

SPP Stakeholder Group	Date of Submission
American Electric Power (AEP	June 17, 2016
Kansas City Power & Light Company(KCPL)	August 1, 2016
ITC Great Plains, LLC (ITC)	August 3, 2016
Sunflower Electric Power Corporation (SEPC)	August 4, 2016
City Utilities of Springfield (CUS)	August 5, 2016
Empire District Electric Company (EDE)	August 5, 2016
Lincoln Electric System (LES)	August 5, 2016

The chart below summarizes stakeholders' comments and suggestions. Of the forty suggestions/comments received from stakeholders, twenty-six were generally addressed by continuing to utilize the Lessons Learned recommendations adopted after the RCAR I assessment.

Stakeholder Entity	Area of Comment or Suggestion						
	Assumptions	Benefits/ Calculations	Costs/ Offsets	Process	Remedy	Threshold	Total
AEP		1					**1**
CUS		6	1	2		1	**10**
EDE		1					**1**
ITC				1	1		**2**
KCPL		1		3			**4**
LES	1				1	1	**3**
OPPD		2				1	
SUNC	2	7	2	5			**16**
Totals	**3**	**18**	**3**	**11**	**2**	**3**	**40**

At the September 13, 2019 RARTF meeting, the RCAR II Lessons Learned Report was reviewed, finalized and approved by the RARTF.[19] Once approved by the RARTF, this report was posted publicly and shared with the appropriate SPP working groups.

After reviewing and considering the comments and suggestions from SPP stakeholders, the RARTF agreed to reconfirm and continue to utilize recommendations made at the conclusion of RCAR I and to adopt four additional recommendations from RCAR II. The new recommendations are:

RCAR II RECOMMENDATION NO. 1:

At the conclusion of the RCAR II assessment the RARTF agreed that due to significant technical challenges that were encountered in both the RCAR I and RCAR II assessments, SPP staff should investigate and propose to the RARTF some alternative methodologies for completing future RCAR assessments. During late 2016 and 2017 staff developed a few proposals for RARTF consideration. Ultimately, the RARTF agreed to a staff proposal that was similar to the process used in developing the SPP Value of Transmission Report published in 2016. This process involves utilizing the daily market runs from the Integrated Marketplace and then removing the selected Highway/Byway transmission upgrades in a subsequent run to capture the value that the removed transmission provided to the SPP region. Other approved benefit metrics will need to be calculated outside of this process and will be included in the overall RCAR results. A more detailed explanation of the recommended hybrid approach to be used in RCAR III can be seen in Appendix 2 of the RCAR II Lessons Learned Report and in Section 3.2.1 of this report, Overview of RCAR III Hybrid Methodology.

[19]*See* RARTF approval of RCAR II Lessons Learned items at page 1 in RARTF September 13, 2019 minutes: https://www.spp.org/Documents/60790/RARTF%20Minutes%2020190913.pdf.

RCAR II RECOMMENDATION NO. 2:

Attachment J, Section III.D.2 of the OATT requires that:

> For each review conducted in accordance with Section III.D.1, the Transmission Provider shall determine the cost allocation impacts of the Base Plan Upgrades approved for construction after June 19, 2010 to each pricing Zone within the SPP Region.

The RARTF recommends that SPP make a filing at the Federal Energy Regulatory Commission (FERC) to modify Attachment J, Section III.D.2 of the OATT to read as follows:

> For each review conducted in accordance with Section III.D.1, the Transmission Provider shall determine the cost allocation impacts of the **certain** Base Plan Upgrades approved for construction after June 19, 2010 to each pricing Zone within the SPP Region **<u>as approved in the methodology in Section III.D.4.</u>**

This change is a reflection of the fact that as future RCARs are conducted a higher percentage of projects will actually be in-service whereas RCAR I and RCAR II had a very small to approximately half the projects in-service. The RARTF finds that a future RCAR may not need to study all approved upgrades (i.e., when only a small amount and/or percentage are only in-service) if real data for Highway/Byway projects in-service may be a better measure for future RCARs. This modification to SPP's OATT gives SPP stakeholders the option to review the results from the daily operational market runs and if those results provide adequate certainty that long-term equity is currently being achieved, the RARTF could provide a recommendation to the Markets and Operations Policy Committee (MOPC) and Regional State Committee (RSC) to forgo any further cost allocation analysis for projects not yet in-service at that time. An order was issued in FERC Docket No. ER22-331on April 5, 2022 approving SPP's request to modify Attachment J.

RCAR II RECOMMENDATION NO. 3 – Develop schedule for stakeholder review

There were a number of recommendations and suggestions about the overall schedule and time of the RCAR II assessment schedule and time allotted for stakeholder review of assumptions, models and results of the assessment. SPP staff should work to develop a schedule that allows for additional time for stakeholder review of these important milestones during the review and approval process.

RCAR II RECOMMENDATION NO. 4 – Miscellaneous recommendations

There were several stakeholder suggestions related to the RCAR II assessment assumptions and processes that should be addressed in future assessments. This 'catch-all' recommendation will address these multiple process concerns and be implemented in the next RCAR assessment.

A. Standard rates and costs for wind energy and gas prices used in the RCAR assessment will be those same rates and costs used in the annual Integrated Transmission Planning (ITP) assessments.

B. Conduct a rate impact analysis study at the conclusion of an RCAR assessment. This is the analysis originally conducted by the Rate Impact Task Force.

C. Stakeholder suggestions and comments requested during and after an assessment will be done in Word format rather than Excel as in the past.

SECTION 1: OVERVIEW OF THE RARTF AND RCAR REVIEW

The next sections of the RCAR III Report highlight the implementation of the RARTF Final Report as modified by RCAR I and RCAR II Lessons Learned Reports.

1.1 OVERVIEW OF SPP TARIFF REQUIREMENTS TO PERFORM THE RCAR REVIEW

Attachment J, Section III.D to the SPP OATT establishes a five-step process for the RCAR analysis. These steps are:

Step 1: The Transmission Provider shall review the reasonableness of the regional allocation methodology and factors (X% and Y%) and the zonal allocation methodology at least once every six years in accordance with this Section III.D. The Transmission Provider and/or the Regional State Committee may initiate such review at any time. Any change in the regional allocation methodology and factors or the zonal allocation methodology shall be filed with the Commission.

Step 2: For each RCAR conducted in accordance with Section III.D.1, the Transmission Provider shall determine the cost allocation impacts of the Base Plan Upgrades approved for construction[20] issued after June 19, 2010 to each pricing Zone within the SPP Region as identified in the methodology in Section III.D.4. The Transmission Provider in collaboration with the RSC shall determine the cost allocation impacts utilizing the analysis specified in Section III.7.d of Attachment O and the results produced by the analytical methods defined pursuant to Section III.D.4(i) of Attachment J to the SPP OATT.[21]

Step 3: The Transmission Provider shall review the results of the cost allocation analysis with SPP's Regional Tariff Working Group

[20] Based on Lessons Learned #9 and approved by FERC in Docket: ER15-307

[21] Attachment J, Section III.D.2 of SPP's OATT.

(RTWG), MOPC, and the RSC. The Transmission Provider shall publish the results of the cost allocation impact analysis and any corresponding presentations on the SPP website.[22]

Step 4: The Transmission Provider shall request the RSC provide its recommendations, if any, to adjust or change the costs allocated under this Attachment J if the results of the analysis show an imbalanced cost allocation in one or more Zones.[23]

i) One year prior to each three-year planning cycle (starting in 2013) the MOPC and RSC will define the analytical methods to be used under Section III.D and suggest adjustments to the RSC and Board of Directors on any imbalanced zonal cost allocation in the SPP footprint.[24]

ii) Starting in 2015 and at any time thereafter, any member company that feels that it has an imbalanced cost allocation may request relief through the Markets and Operations Policy Committee. The Markets and Operations Policy Committee recommendation, if any, will be forwarded with the request for relief to the Regional State Committee and Board of Directors for review

Step 5: In accordance with the SPP Bylaws, the SPP Board of Directors will initiate the appropriate actions, including any necessary filings with the Commission, consistent with the Regional State Committee recommendations.

1.2 OVERVIEW OF RARTF CHARTER

In addition to SPP's tariff requirements, the RARTF's charter defined further additional work and deliverables for the group. Specifically, the charter states:

> The RARTF will make final recommendations to the MOPC and the RSC regarding the analytical methods to be used to review the reasonableness of the regional allocation methodology for the approval of both the MOPC and RSC. In addition to developing the analytical methods to be used in the analysis, the RARTF will provide SPP staff guidance as to the Task Force's expectation for the

[22] Attachment J, Section III.D.3 of SPP's OATT.
[23] Attachment J, Section III.D.4 of SPP's OATT.

> threshold for an unreasonable impact or cumulative inequity. The RARTF shall prepare and issue the report by December 20, 2011.

The charter also defined key deliverables for the RARTF:

> <u>The RARTF scope of work and key deliverables include the following:</u>
>
> 1. Development of and recommendation for a methodology to be used to determine the current and cumulative long-term equity/inequity of the currently effective cost allocation for transmission construction/upgrade projects on each SPP Pricing Zone and/or Balancing Authority.
>
> 2. Develop a recommendation regarding a threshold for determining an unreasonable impact or cumulative inequity on an SPP Pricing Zone or Balancing Authority.
>
> 3. Develop a list of possible solutions for SPP staff to study for any unreasonable impacts or cumulative inequities on an SPP Pricing Zone or Balancing Authority.
>
> 4. Final report containing such recommendations to be prepared and issued by December 20, 2011.

1.3 OVERVIEW OF LEGAL STANDARDS

Pursuant to the RARTF charter, the group has been tasked to "[d]evelop a recommendation regarding a threshold for determining an unreasonable impact or cumulative inequity on an SPP Pricing Zone or Balancing Authority." In researching and discussing how to establish a threshold, SPP staff and the RARTF reviewed and considered the legal significance and relevance of the roughly commensurate standard as articulated by the United States Court of Appeals for the Seventh Circuit ("Seventh Circuit") and the FERC. The roughly commensurate standard is the Seventh Circuit's and FERC's interpretation of the just and reasonable standard as applied to regional cost allocation for transmission facilities.

The term "roughly commensurate" was used for the first time in association with electric transmission facilities by the Seventh Circuit in *Illinois Commerce Commission v. FERC* ("*ICC I*")[25]

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[25] 576 F.3d 470 (7th Cir. 2009). In this case, the Seventh Circuit remanded FERC orders approving 100% region-wide cost allocation for extra high voltage transmission facilities in PJM Interconnection, L.L.C. ("PJM"), on the basis that FERC did not demonstrate that the cost allocation proposal allocated costs to utilities in the western portion of PJM on a

and was subsequently used and elaborated on in two other Seventh Circuit cases also named *Illinois Commerce Commission v. FERC*.[26]

Specifically, the Seventh Circuit stated that FERC may approve a cost allocation mechanism that does not perfectly match costs and benefits, even if FERC cannot precisely quantify the benefits, provided that FERC has "an articulable and plausible reason to believe that the benefits are at least roughly commensurate with" the costs a customer would pay under the cost allocation methodology.[27]

Following the *ICC I* opinion, FERC cited the Seventh Circuit's roughly commensurate standard in approving SPP's Highway/Byway cost allocation methodology,[28] MISO's MVP cost allocation,[29] and California Independent System Operator Corporation's convergence bidding proposal.[30] Additionally, in Order No. 1000,[31] FERC established several cost allocation principles for regional and interregional transmission facilities, including a principle that:

> The cost of transmission facilities must be allocated to those within the transmission planning region that benefit from those facilities in a manner that is *at least roughly commensurate* with estimated benefits. In determining the beneficiaries of transmission facilities, a regional transmission planning process may consider benefits including, but not limited to, the extent to which transmission facilities, individually or in the aggregate, provide for maintaining reliability and sharing reserves, production cost savings and congestion relief, and/or meeting Public Policy Requirements.[32]

Since issuing Order No. 1000, FERC repeatedly has cited the roughly commensurate standard in acting on various utility cost allocation proposals. Additionally, SPP staff notes that various FERC

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basis "roughly commensurate" with the benefits that those utilities would realize from extra high voltage transmission facilities built in the eastern portion of PJM.

[26] 721 F.3d 764 (7th Cir. 2013) (affirming FERC orders approving the Midcontinent Independent System Operator, Inc.'s ("MISO") "multi-value project" ("MVP") regional cost allocation) ("*ICC II*"); 756 F.3d 556 (7th Cir. 2014) (remanding for a second time FERC's orders approving PJM's region-wide cost allocation for extra high voltage transmission facilities) ("*ICC III*").

[27] *ICC I*, 476 F.3d at 477; *see also ICC II*, 721 F.3d at 775.

[28] *Southwest Power Pool, Inc.*, 131 FERC ¶ 61,252, at PP 78, 98 (2010), *order denying reh'g*, 137 FERC ¶ 61,075 (2011).

[29] *Midwest Indep. Transmission Sys. Operator, Inc.*, 133 FERC ¶ 61,221, at P 200 (2010), *order on reh'g*, 137 FERC ¶ 61,074 (2011).

[30] *Cal. Indep. Sys. Operator, Corp.*, 133 FERC ¶ 61,039, at P 64 (2010), *order denying reh'g*, 134 FERC ¶ 61,070 (2011).

[31] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities,* Order No. 1000, 2008–2013 FERC Stats. & Regs., Regs. Preambles ¶ 31,323 (2011), *order on reh'g & clarification*, Order No. 1000-A, 139 FERC ¶ 61,132, *order on reh'g & clarification*, Order No. 1000-B, 141 FERC ¶ 61,044 (2012), *aff'd sub nom. S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41 (D.C. Cir. 2014), *reh'g denied en banc*, 2014 U.S. App. LEXIS 19968 (D.C. Cir. Oct. 17, 2014).

[32] *Id.* at P 622. The United States Court of Appeals for the District of Columbia Circuit upheld Order No. 1000 in its entirety, including this cost allocation principle, in 2014. *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41 (2014), *reh'g denied en banc*, 2014 U.S. App. LEXIS 19968 (D.C. Cir. Oct. 17, 2014).

and court precedents, both before and after the *ICC* line of cases, articulate certain principles that a cost allocation method must satisfy. These include (but are not limited to):

- A cost allocation mechanism may track costs less than perfectly;[33]
- A cost allocation mechanism need not calculate benefits to the last penny or, for that matter, to the last million or ten million or perhaps hundred million dollars;[34]
- A pricing scheme may not require payments from those that derive no benefits or benefits that are trivial in relation to the costs;[35]
- Rates must reflect, to some degree, the costs actually caused by the customer who must pay them;[36]
- Benefits do not necessarily need to be quantified, but there must be an articulable and plausible reason to believe that benefits received by customers are at least roughly commensurate with the costs allocated to customers;[37]
- FERC must compare the costs assessed against a party to the burdens imposed or benefits drawn by that party;[38]
- A cost allocation method need not be perfect, but in fact can be crude; if crude is all that is possible, it will have to suffice;[39] and
- While not requiring exacting precision, the roughly commensurate standard requires "some effort" to quantify or otherwise show benefits.[40]

From these principles, the RARTF determined that "roughly commensurate" does not necessarily mean net cost-beneficial to each customer. Thus, something less than a 1.0 B/C ratio may comply with the standard.

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[33] *Sithe/Independence Power Partners, L.P. v. FERC*, 285 F.3d 1, 5 (D.C. Cir. 2002).
[34] *Nebraska Public Power District v. FERC*, 957 F.3d 932, 941 (U.S. 8th Circuit 2020) (citing to *ICC I*, 476 F.3d at 477).
[35] *MISO Transmission Owners v. FERC*, 819 F.3d 329, 336 (U.S. 7th Cir. 2016) (citing to *IC III,* 576 F.3d 470, 476 (7th Cir.2009).
[36] *Midwest ISO Transmission Owners v. FERC*, 373 F.3d 1361, 1368 (D.C. Cir. 2004) (citing to: *KN Energy, Inc. v. FERC*, 968 F.2d 1295, 1300 (D.C.Cir.1992); *Transmission Access Policy Study Group v. FERC*, 225 F.3d 667, 708 (D.C.Cir.2000); *Pacific Gas & Elec. Co. v. FERC*, No. 03-1025, 373 F.3d 1315, 1320-21 (D.C. Cir. July 9, 2004)).
[37] *Nebraska Public Power District v. FERC*, 957 F.3d 932, 941 (U.S. 8th Circuit 2020) (citing to *ICC I*, 476 F.3d at 477)).
[38] *Id.* (citing to *Midwest ISO Transmission Owners v. FERC*, 373 F.3d 1361, 1368 (D.C. Cir. 2004)).
[39] *Id.* (citing to *IC III* 756 F.3d 556 (7th Cir. 2014)).
[40] *Old Dominion Electric Cooperative v. FERC*, 898 F.3d 1254, 1260 (citing to *Midwest ISO Transmission Owners v. FERC*, 373 F.3d 1361, 1369 (D.C. Cir. 2004).

FERC has said, "the question becomes not whether the Highway/Byway methodology matches cost to the benefits on a utility-by-utility or Zone-by-Zone basis, but whether it will provide sufficient benefits *to the entire SPP region* to justify a regional allocation of costs."[41]

The conclusions drawn in both the RARTF and RCAR I and II reports consider the *ICC* and related cases as well as subsequent FERC orders citing the Seventh Circuit's roughly commensurate standard.

1.4 COST ALLOCATION CHALLENGES FOR TRANSMISSION PROJECTS

The allocation of costs for public projects with significant and widespread public benefits is a complex matter. This is particularly true for electric transmission projects, as stated by FERC:

> Determining the costs and benefits of adding transmission infrastructure to the grid is a complex process, particularly for projects that affect multiple systems and therefore may have multiple beneficiaries. At the same time, the expansion of regional power markets and the increasing adoption of renewable energy requirements have led to a growing need for transmission projects that cross multiple utility and RTO systems. There are few rate structures in place today that provide the allocation and recovery of costs for these intersystem projects, creating significant risk for developers that they will have no identified group of customers from which to recover the cost of their investment.[42]

The RARTF noted the difficulties of implementing cost allocation methods for transmission projects. The RCAR I, II and III Reports reflect the RARTF's reasoned, sound, and well-established methods endorsed by SPP stakeholders in January 2012 with the adoption of the RARTF Report as well as RCAR I Lessons Learned Report in 2014 and the RCAR II Lessons Learned Report in 2019.

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[41] *Southwest Power Pool, Inc*., 137 FERC ¶ 61,075 at P 26 (emphasis added). Indeed, in *ICC II*, the Seventh Circuit rejected arguments by certain customers that the allocation of MVP costs to them was not just and reasonable because MISO and FERC had failed to show that the projects will confer benefits greater than their costs and because FERC failed to compare costs and benefits of the MVPs on a subregion-by-subregion or utility-by-utility basis. *See ICC II*, 721 F.3d at 774 ("It's impossible to allocate these cost savings with any precision across MISO members."). In addition, the Seventh Circuit very recently upheld FERC's decision to approve a MISO cost allocation method for reliability projects that allocates 100% of the costs to the pricing zone(s) in which a facility is located, even though some other zones may receive some benefit from the facilities. *See MISO Transmission Owners v. FERC*, 2016 U.S. App. LEXIS 6279, at *15-16 (7th Cir. Apr. 6, 2016) ("But FERC's calculations suggest that the spillover of benefits to other zones is modest enough to make the local allocation of costs "roughly commensurate" with the allocation of benefits.") (citing *ICC I*, 576 F.3d at 477).

[42] *Transmission Planning Processes Under Order No.* 890, Notice of Request for Comments at 5, Docket No. AD09-8-000 (Oct. 8, 2009).

SECTION 2: SPP'S HIGHWAY/BYWAY COST ALLOCATION METHODOLOGY

2.1 HIGHWAY/BYWAY SUMMARIZED

The RSC established the Highway/Byway cost allocation methodology that was subsequently approved by FERC.[43]

The Highway/Byway methodology assigns 100% of all 300+ kV transmission upgrades' annual transmission revenue requirement (ATRR) to the SPP Zones on a regional basis using the load ratio share (LRS), as a percentage of the whole of regional loads, of each Zone multiplied by the total ATRR of the new upgrade.

New upgrades with a voltage rating between 100 kV and 300 kV are allocated 33% to all Zones in the region on a LRS basis and 67% to the host Zone's transmission customers (TCs).

New upgrades under 100 kV are allocated 100% to the TCs of the host Zone.

Figure 2.1
Highway/Byway Cost Allocation Overview

Upgrade Voltage	Region Pays	Local Zone Pays
>300 kV	100%	0%
100 - 300 kV	33%	67%
<100 kV	0%	100%

The ATRRs assigned to the Zones are collected from their respective TCs using the previous year's 12-month coincident peak LRS.

Cost allocation of new construction is defined in Attachment J of the OATT. The recovery of the ATRR is through OATT Schedule 11 and booked by each Zone in OATT Attachment H.

[43] *Southwest Power Pool, Inc.*, 137 FERC ¶ 61,075 (2011).

Additionally, these costs are offset by point-to-point (PTP) revenues collected by SPP for transmission service sold on the SPP system.

Once PTP revenues are collected, they offset the amount Zones pay under Highway/Byway as provided for in OATT Attachment L.

As described in the RCAR I Lessons Learned Section above, per Lessons Learned No. 7, PTP revenues have been offset for the RCAR III analysis as approved by FERC in Docket Number ER16-165.

Via a settlement agreement in FERC Docket EL14-21, MISO and NRG, Inc. pay SPP transmission owners for the use of SPP transmission facilities. The revenue has been allocated per the methodology conditionally approved by FERC in ER16-791-111.

SECTION 3: RECOMMENDED REVIEW METHODOLOGY

3.1 PRINCIPLES THAT GUIDED HOW SPP STAFF CONDUCTED THE RCAR III REVIEW

Following research, stakeholder input and extensive discussion, the RARTF Report defined ten key principles to guide SPP staff in conducting RCAR analyses:

(1) Simplicity - The RCAR should be as simple as possible, so that the report is understandable.

(2) Roughly Commensurate – The RCAR should use the principle of roughly commensurate as the legal framework and a guidepost when evaluating the reasonable and long-term equity of SPP regional transmission upgrades under the Highway/Byway cost allocation methodology.

(3) Use Best Information Available – The RCAR should use the most up-to-date and best available information for the review.

(4) Consistency – The RCAR should be consistent.

(5) Transparency – The assumptions, inputs, and data used in the RCAR should be transparent to SPP stakeholders.

(6) Stakeholder Input - The assumptions, inputs, and data used in the RCAR should be vetted through SPP's open and transparent stakeholder process.

(7) Real Dollars – The RCAR Analysis and Report should use dollar values of the year in which the report will be issued.

(8) Consideration Given to Certain Plans – The RCAR should give considerations to certain plans that have been approved by the Board. This includes projects that have been approved for construction since June 2010.[44]

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[44] At the time the RARTF was developing the methods under which the RCAR I was to be conducted SPP used a concept known as ATPs. After the approval of the RARTF Report, the term ATP was no longer used. Although the term ATP is no longer used, SPP staff still followed Principle 8 by including projects with an in-service date of ten years or less per the

(9) More Weight should be Given to Nearer Term Projects than Future Projects – Although the RCAR should give consideration to certain plans approved by the Board, less weight should be given to plans which have been given an ATP as opposed to an NTC.[45]

(10) Equity Over Time – The RCAR should adhere to the long term view of the Highway/Byway cost allocation methodology to strive toward regional cost allocation equity over time.

3.2 REGIONAL COST ALLOCATION REVIEW METHODOLOGIES

Because the RCAR evaluates projects built under SPP's Highway/Byway cost allocation methodology, the RARTF recommended that certain projects and plans which are approved by the Board be evaluated. However, due to the uncertainty of some projects, the RARTF recommendation for RCAR I was that emphasis of the review be placed on Board-approved plans that have in-service dates ten or fewer years in the future. Only projects approved for construction by the BOD Board were analyzed in the RCAR II process per Lesson Learned 6.

Due to significant technical challenges encountered in both RCAR I and RCAR II, an alternative hybrid methodology was researched and proposed for RCAR III using daily market runs from the SPP Integrated Marketplace on projects in service for at least two years, paired with analysis on transmission planning models for all other Highway/Byway projects having been approved for construction. The RARTF approved the use of this new approach at its February 27, 2019 meeting.

3.2.1 OVERVIEW OF RCAR III HYBRID METHODOLOGY

Since the conclusion of the RCAR II analysis in October 2016, as described in the RCAR II Lessons Learned Report, the RARTF engaged in several meetings and conversations to develop an alternate approach for the completion of RCAR III that is required to be completed in 2022. The creation of an alternate approach was discussed with the RARTF to address a number of concerns shared by the RARTF members, stakeholders and SPP staff. First and foremost were the technical challenges that were experienced in RCAR II due to the number of upgrades that needed to be removed from the base case planning models used to create the change cases models. These changes were so voluminous that the change case models would not solve without manual interventions and created Adjusted Production Cost (APC) benefits that were distorted in these affected pricing Zones. In addition, due to the large amounts of wind development in certain parts of the footprint, when the Highway/Byway transmission facilities approved and built to support

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RARTF report when conducting RCAR I. Beginning with RCAR II, pursuant to Lessons Learned # 6, only projects "approved by the SPP Board" will be evaluated. *See,* FERC Docket: ER15-307

[45] Per Lessons Learn No. 6, the RCAR II analysis only considers projects that have been approved for construction by the SPP Board of Directors. As a result, RARTF principal 9 was not used during RCAR II or RCAR III.

these generation additions were removed the generation became "trapped" in the local areas and skewed the results.

Ultimately, a hybrid methodology was researched and proposed by staff, and approved by RARTF[46] which combined an Operational approach using daily market runs from the Integrated Market on projects in service for at least two years along with a Planning approach for all other Highway/Byway projects that have been approved for construction. The complete RCAR analysis entails adding the results from the Operational approach and the Planning approach together to develop a single B/C ratio.

As described in the Background section of this report, another one of the RCAR II Lessons Learned was to modify the tariff to allow the RARTF,[47] MOPC,[48] and RSC[49] to all agree that in certain instances not all Highway/Byway projects would be required to be studied in an RCAR analysis. On November 3, 2021, SPP submitted a filing[50] in Docket ER22-331 to the FERC to modify Attachment J of the SPP OATT to request this change. On April 5, 2022, FERC issued a letter Order approving the request to modify Attachment J effective January 3, 2022.[51]

On June 27, 2022, the RARTF passed a motion based on a staff recommendation to finalize the RCAR III Report based solely on Operational results in October 2022.[52] This motion passed unanimously with one abstention. Further, during its July 12, 2022 meeting the MOPC approved the recommendation from RARTF with a 97% approval.[53] Finally, during the RSC's July 25, 2022, meeting, the RARTF recommendation for this recommended approach passed unanimously.[54]

Given these approvals, the final approach used to complete the RCAR III study is based only on the results determined through the Operational approach paired with analysis on transmission planning models and limited to projects having been in-service prior to January 1, 2020.

Further, on September 14, 2022 the RARTF accepted two staff recommendations related to the calculation and allocation of the Assumed Benefit of Mandated Reliability Projects and Increased

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[46] *See* RARTF September 13, 2019 minutes: https://www.spp.org/Documents/60790/RARTF%20Minutes%2020190913.pdf

[47]See RARTF July 27, 2021 minutes: https://www.spp.org/Documents/65461/RARTF%20CC%20100621%20-%201.zip

[48] *See* MOPC October 11, 2021 minutes at page 14: https://www.spp.org/Documents/65775/20211011%20MOPC%20Minutes.pdf

[49] See RSC October 25, 2021 minutes: https://www.spp.org/Documents/66043/Regional%20State%20Committee%20Business%20Meeting%20Minutes%202021%2010%2025%20Draft.pdf

[50] *See* SPP filing: Filing in ER22-331

[51] *See* Order in ER22-331

[52] *See* RARTF June 27, 2022 minutes: https://www.spp.org/Documents/67591/RARTF%20materials%2020220803.zip

[53] *See* MOPC July 11, 2022 minutes: https://www.spp.org/Documents/67538/22-07-11%20MOPC%20minutes.pdf

[54] *See* RSC July 25, 2022 minutes: https://www.spp.org/Documents/67602/RSC%20Minutes%20July%2025,%202022%20v2.pdf

Wheeling Through and Out Revenues metrics for RCAR III. A full description of these changes can be seen in Sections 7.6.3 and 7.6.5 respectively.

The Operational approach for RCAR III focused on studying the estimated production cost change due to Highway/Byway funded projects. The analysis was completed using Day Ahead Reliability Unit Commitment (DA_RUC) cases using production cases from the Integrated Marketplace runs as part of the hybrid approach recommended by the RARTF in RCAR II lessons learned No. 1. To analyze the impacts of the Highway/Byway projects both a change DA_RUC case and a base DA_RUC case were run. The change case removed all possible Highway/Byway projects while the base case left the transmission as it was in the real production environment. Since RCAR III is analyzing the benefit of these projects as a whole, all projects are studied together, not individually. Upon completion the production cost and interchange cost differences were compared to calculate total savings by Transmission Pricing Zone.

The RCAR III Operational approach studied all Highway/Byway projects, including those previously studied in RCAR II, that were placed in service before January 1, 2020. Projects were reviewed to determine if the project was a type that could be assessed as part of the operational approach. Projects with reactor or capacitor upgrades only were not able to be added to the operational model and were not included. There were also some projects that were implemented at locations that no longer existed in the operational model and so they were not able to be assessed if the new or upgraded transmission equipment was no longer in service. It should be noted that the cost of these projects was included in the final RCAR III analysis.[55]

3.3 RARTF RECOMMENDED CALCULATION OF BENEFIT TO COST RATIOS

The RARTF recommended a methodology in which each assessment uses the aggregate value of dollars for all projects studied under the SPP Highway/Byway cost allocation methodology in dollars current to the year the review is conducted. Using the aggregate value of dollars instead of the average B/C ratios provides a more comprehensive view of the total benefits to individual Zones over the course of multiple studies. As a result, RCAR III used 2022 dollars.

[55]In total 538 upgrades were included in the RCAR III ATRR costs analysis. Of those 538 upgrades, there were 123 upgrades that were not included in the operational benefit analysis. These include cap bank and reactor projects and some minor ratings changes that are not picked up in these market models. These projects accounted for approximately 1.3% of the total E&C costs of the 538 RCAR III upgrades.

3.4 RARTF RECOMMENDS USE OF A 40-YEAR PROJECT EVALUATION

To remain consistent with SPP's tariff, the RARTF recommended using a 40-year assessment to evaluate all transmission projects in the RCAR. Pursuant to the tariff, the RARTF recommended that the last 20 years of benefits should have a terminal value. As a result, the RCAR III uses a 40-year assessment.

3.5 RARTF RECOMMENDATION ON THE CALCULATION OF COSTS

When conducting the RCAR, the RARTF recommended using the most up-to-date ATRR for each Zone. As a result, RCAR III uses costs from the June 2022 Project Tracking cost update.

3.6 RARTF RECOMMENDATION ON BENEFITS TO BE CALCULATED

The RARTF recommended that the set of benefit categories listed below be used in the RCAR process. The RARTF further recommended that, before RCAR I was conducted, specific metrics be developed to quantify the benefits in dollars using procedures defined by the MOPC through the work of the ESWG.

For metrics without dollar amounts but in other terms (MW, MWh, Tons, etc.), the RARTF recommended that the ESWG consider recommending a range of values that can be used to monetize those metrics without hard dollar values.

As part of the benefit evaluation, the RARTF recommended that the RCAR use the most conservative or lowest value in any range provided by the ESWG. For metrics that the ESWG does not endorse monetizing, the ESWG would not provide a monetized value for use in the RCAR process. In defining these benefits, the ESWG and the MOPC should also develop a method to distribute these benefits by SPP Zones. For benefits that are shared by some Zones but cannot be distributed to all Zones, if the benefited Zones agree to an alternative method for allocating the benefits, then the agreed upon method will be used.

When conducting the RCAR, the RARTF recommended using the list of benefits provided in their report to assess the B/C ratio. Additionally, the group recommended that the RCAR consider the use of any additional benefits that may be defined and quantified in dollar values or can be converted into dollar values by the EWSG and approved by the MOPC. As a result, RCAR uses benefits developed by the ESWG and approved by the SPP Board of Directors.

- Mitigation of Transmission Outages – The calculation of the benefit remained unchanged; however the allocation of the benefit was changed to load-ratio share. This allocation methodology was proposed by the ESWG and supported by SPP staff. The allocation change was not approved by the MOPC[56] but was adopted by the Board.[57]

- Assumed Benefit of Mandated Reliability Projects – The benefit's calculation remained unchanged, but its allocation was changed to a hybrid allocation as follows:

Upgrade Voltage	Allocation
>300 kV	33% System Reconfiguration 66% Load-ratio share
100 - 300 kV	66% System Reconfiguration 33% Load-ratio share
<100 kV	100% System Reconfiguration

This allocation methodology was proposed by the ESWG and supported by SPP staff. The allocation change was not approved by the MOPC but was adopted by the Board.

- Benefits from Meeting Public Policy Goals - The benefit's calculation remained unchanged, but its allocation was changed to be allocated to Zones based on share of unmet renewable mandates/goals in state(s) driving policy projects. Both the MOPC and Board approved this ESWG recommendation.

- Marginal Energy Losses Benefit – This benefit was monetized for the first time in RCAR II. The benefit value is captured from the Marginal Loss Component of the Locational Marginal Price (LMP) and allocated by the physical location of loss savings. This benefit calculation and allocation was recommended by the ESWG and approved by the MOPC and Board.

- Increased Wheeling Through and Out - This benefit was monetized for the first time in RCAR II. The benefit is captured based on a firm service methodology and allocated based on tariff specified revenue distribution rules. This benefit calculation and allocation was recommended by the ESWG and approved by the MOPC and Board.

The list of benefits the RARTF recommended to be monetized in the RCAR III were:

- **Adjusted Production Cost (APC) Benefits** – APC captures the monetary cost associated with fuel prices, run times, grid congestion, ramp rates, energy purchases, energy sales, and other factors directly related to energy production by generating resources in SPP. APC is calculated by adding a Zone's production cost to the Zone's purchases and

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[56] *See* MOPC July 15-16, 2014minutes Page 4 at http://www.spp.org/documents/22945/mopc%20minutes%20&%20attachments%20july%2015-16,%202014.pdf
[57] *See* July 29, 2014 BOD Minutes Page 9 at http://www.spp.org/documents/22963/bocmc%20minutes%20072914.pdf

subtracting out their sales. Other approved benefit metrics that are captured as part of the APC calculation are:

- **Savings due to Lower Ancillary Service Needs and Production Costs** - Ancillary Services are essential to the reliable operation of the electrical system. A number of operating reserves and products fall into this category—spinning reserve, ramping (up/down), regulation, supplemental reserve.
- **Reduction of Emission Rates and Values** – This metric captures the cost savings associated with reduced SO_2, NO_X, and CO_2 emissions by considering allowance prices for these pollutants.
- **Mitigation of Transmission Outage Costs** – Standard production cost simulations assume that lines and facilities are available during all hours of the year and that no planned or unexpected transmission outages of transmission facilities will occur. In practice, planned and unexpected transmission outages impose non-trivial additional congestion on the system.
- **Marginal Energy Losses Benefits** – Standard production cost simulations used to estimate APC do not reflect that transmission expansions may reduce the MWh quantity of transmission losses. In simulations, loads are "grossed up" for average transmission losses and assume that losses are fixed and do not change with transmission additions.

- **Assumed Benefit of Mandated Reliability Projects** - This metric attempts to identify the benefits of maintaining a reliable transmission system. The benefits of reliability projects are assumed to be equal to the costs. The benefits are then allocated to each Zone using a hybrid approach that considers the load ratio share of each Zone along with a flow-based analysis that considers the change in flows on the transmission system as a result of the upgrade.

- **Increased Wheeling Through and Out** – Increasing the Available Transfer Capacity (ATC) with a neighboring region improves import and export opportunities outside the SPP footprint. Increased inter-regional transmission capacity that causes increased through and out transactions will also increase SPP wheeling revenues. These increased wheeling revenues are a benefit as they will offset part of the transmission projects' revenue requirement.

- **Benefits from Meeting Public Policy Goals** - This metric captures the value of meeting the requirements of public policy.

- **Cost Savings from Reduced On-peak Transmission Losses** – Quantifies the reduction in generating capacity needed due to a reduction on system losses during the peak hour.

- **Avoided or Delayed Reliability Projects** - Economic projects have the potential to address economic and reliability needs simultaneously. If a reliability project is found to be no longer necessary due to the identification of an economic solution, the cost of the avoided or delayed reliability project is captured as an additional benefit beyond the production cost savings of the economic project.

3.7 RARTF RECOMMENDATION ON ASSUMPTIONS TO BE USED

The RARTF recommended that the assumptions used in the RCAR should be vetted through SPP's open and transparent stakeholder process. As with RCAR I and RCAR II, RCAR III uses assumptions vetted by SPP stakeholders.

SECTION 4: REPORT THRESHOLDS

4.1 RARTF RECOMMENDED A REMEDY THRESHOLD

Pursuant to the RARTF's charter, the group recommended that a threshold be established to determine when it is warranted for SPP staff to study possible remedies to address an imbalance based upon the results of an RCAR analysis. The threshold set by the RARTF defined when SPP staff should study a zonal mitigation. If a Zone is determined to be below this threshold, mitigation may be necessary to create equity.

The RARTF recommended that a threshold be set at a 0.8 B/C ratio for projects that were a part of the RCAR I assessment report.[58] This was reaffirmed for use in RCAR II and RCAR III.

The RARTF found during the RCAR I few projects, if any, were actually in service.[59] The importance of considering future plans is highlighted by FERC's Order on Rehearing in Docket No. ER10-1069-001 in which FERC noted that the Highway/Byway cost allocation methodology will be applied to projects other than the Priority Projects.[60]

Significantly more projects subject to the RCAR analysis were in service in RCAR III than in RCAR II, which had more projects in service than RCAR I. Further, RCAR III uses only projects having been in service prior to January 2020. This represents 538 of 741 Highway/Byway-funded upgrades having been approved and issued NTCs or 73% of Highway/Byway-funded upgrades in service. This is in contrast to RCAR II which had 274 of 503 upgrades in service, as well as 48 of 298 upgrades in RCAR I. RCAR III upgrades account for $4.6B out of $6.4B or 72% of the cost of Highway/Byway-funded transmission upgrades.

[58] In RCAR I, the RARTF noted that the 0.8 B/C ratio recommended in the RARTF Report was based upon the ESWG and SPP Stakeholder approving a method to measure the benefits listed in Section 3.8. Additionally, the RARTF noted that the 0.8 B/C may not be appropriate or practical if a Review produces a B/C ratio for all projects lower than anticipated by the RARTF.

[59] The RARTF Report noted that the Tulsa Reactor from SPP's Priority Projects was at the time the only project expected to be in service by June 2012. As of the drafting of the RCAR I report only 48 of the 298 Highway/Byway funded upgrades that are subject to the RCAR I review were in service. These upgrades accounted for only 3.2% of the cost of Highway/Byway funded transmission upgrades and only 1.8% of the new miles of transmission facilities that were included in the RCAR study.

[60] As FERC noted in the October 20, 2011 Order on Rehearing, "the Priority Projects are just one set of projects to be constructed over the years of transmission development in SPP." *Southwest Power Pool, Inc.*, 137 FERC ¶ 61,075 at P 32 (2011).

4.2 RARTF RECOMMENDATION FOR ZONES ABOVE THRESHOLD BUT BELOW 1.0 B/C

Pursuant to the RARTF's charter, the group recommended that a threshold be established to determine when SPP staff should study possible remedies as stated in Section 4.1.

Additionally, the RARTF recommended that any RCAR which shows a Zone is above the 0.8 threshold in Section 4.1 but below a 1.0 B/C ratio should be considered a part of SPP's transmission planning process in the future.

At the conclusion of RCAR I the RARTF and SPP stakeholders debated the use of the 0.8 threshold. The RARTF concluded that the 0.8 threshold was still appropriate and should be maintained for RCAR II. This decision was memorialized in Lesson Learned 8. As a result, RCAR III uses the same policy as RCAR I and II.

SECTION 5: POTENTIAL REMEDIES TO BE STUDIED

5.1 RARTF RECOMMENDED ZONAL REMEDIES

If the results for a Zone following an RCAR are below the threshold in Section 4.1, the RARTF recommended that the SPP staff evaluate and recommend possible mitigation remedies for the Zone. In Figure 5 of the RARTF Report, the RARTF provided a list of mitigation remedies SPP staff should consider for study and to be made part of the report. The purpose of the evaluations is to determine potential remedies that bring the Zone above the threshold. This policy was reaffirmed in Lesson Learned 8 from RCAR II and continued in RCAR III.

The potential list of remedies recommended by the RARTF that SPP staff could evaluate, listed in order of preference, include but are not limited to:

Remedy	Entity with Authority/Duty to Implement
(1) Acceleration of planned upgrades;	**SPP BOD**
(2) Issuance of NTCs for selected new upgrades;	**SPP BOD**
(3) Apply Highway funding to one or more Byway Projects;	**RSC, SPP BOD & FERC**
(4) Apply Highway funding to one or more Seams Projects;	**RSC, SPP BOD & FERC**
(5) Zonal Transfers (similar to Balanced Portfolio Transfers) to offset costs or a lack of benefits to a Zone;	**RSC, SPP BOD & FERC**
(6) Exemptions from cost associated with the next set of projects;	**RSC, SPP BOD & FERC**
(7) Change Cost Allocation Percentages.	**RSC, SPP BOD & FERC**

Figure 5.1
Potential Remedies

SECTION 6: STAKEHOLDER DEVELOPMENT OF MONITIZED BENEFITS

6.1 FORMATION OF THE METRICS TASK FORCE

After the MOPC, RSC, Members Committee and Board approved the RARTF Report, the ESWG established the MTF to address the monetization of benefit metrics for the RCAR. The MTF was commissioned to meet as needed to develop tangible dollar-oriented measures and metrics for use in economic evaluations as identified by the RARTF.

The MTF was to address these categories of benefits and any others that could be monetized:

- **Reduced capacity reserve requirements** - as measured by reduced capacity margin (reserve) requirements. Capital cost impacts have been previously identified therefore the group would focus on a methodology for calculating how transmission improvements would reduce reserves.
- **Improvements in reliability** - improvements other than cost reductions from the elimination or delay of reliability upgrades which have previously been identified.
- **Improvement in import/export limits** - develop metrics that monetize increasing the import and export limits at the SPP borders.
- **Public policy benefits** - develop methods and/or metrics for monetizing the benefits associated with those projects that are identified as Public Policy Projects.
- **Reduced operating reserve requirements** - develop metrics or methods that monetize the benefits associated with a reduced operating reserve requirement in SPP.
- **Other benefits that can be monetized at the recommendation of the task force**

The MTF's roster included:[61]

[61]Hannes Pfeifenberger and Kamen Madjarov from the Brattle Group were engaged to support the MTF: (1) to document the status of the current effort, including the extent to which different metrics have been specified and the quantification/monetization efforts that have been developed; (2) to identify possible overlaps between the specified metrics to avoid double counting of benefits; (3) to identify gaps to the extent which already-selected metrics do or do not completely capture the specified types of transmission benefits; (4) to identify any remaining gaps in the range of potential transmission benefits; and (5) to develop metrics to address the identified gaps.

MTF Members	
Kip Fox	American Electric Power
Roy Boyer	Xcel Energy Services, Inc.
Mike Collins	Oklahoma Gas and Electric Company
Paul Dietz	Westar Energy, Inc.
Tom Hestermann	Sunflower Electric Power Corporation
Greg Sweet	The Empire District Electric Company
Mitchell Williams	Western Farmers Electric Cooperative

The MTF's scope of work and key deliverables[62] included the following:

- A recommendation on which of the benefits identified above can be quantified in dollars.
- Methodologies for the benefits identified above, including the allocation of the benefit to each SPP Zone (defined in the SPP's tariff's Attachment H, Section I, Table 1). An estimate of the effort to calculate the benefits identified above.
- A list of any issues identified from the MTF efforts or any additional direction needed from other working groups.
- A plan for gaining consensus on the metric assumptions and methodologies.
- Progress updates at ESWG meetings.
- A written report containing such recommendations, was to be completed by MTF no later than the July, 2012 ESWG meeting.

6.2 METRICS TASK FORCE DEVELOPMENT OF BENEFIT METRICS

At the conclusion of their work, on September 13, 2012 the MTF submitted a final report to the ESWG that contained a full analysis of the "wide-range of benefit metrics" that had been discussed and vetted through "multiple open and transparent stakeholder meetings."[63]

The MTF Report contained the following summary of the task force's efforts:

> The MTF approached its task as a brainstorming effort followed by refining the most promising alternatives. Members contributed ideas based on existing metrics from MISO, PJM, NYISO, ERCOT, member companies, and industry experience, as well as new ideas provided by the Brattle Group consultants. During the month of

[62]The MTF Charter is posted on SPP's website at: http://www.spp.org/documents/16613/20120227%20metrics%20task%20force%20charter.pdf

[63] The MTF Report is posted on SPP's website at: http://www.spp.org/documents/18175/20120913%20mtf%20report_approved.pdf

March 2012, the MTF identified 28 different ideas for metrics to be evaluated. After review and debate by the MTF, the list was narrowed down to approximately 13 metrics that would be reviewed, analyzed and further developed in order to provide a meaningful update to the ESWG and MOPC in July of 2012. Metrics that did not make it past the brainstorming phase were eliminated for one or more of the following reasons: the idea was not sufficiently developed to proceed further; there were no tangible dollars associated with the metric; the metric would be difficult, if not impossible, to calculate with current tools; or the metric was essentially a duplicate of an existing metric.

At the conclusion of the effort the MTF identified five (5) metrics that are currently used by SPP in the ITP process, eight (8) new metrics that the MTF recommends be calculated as part of the Regional Cost Allocation Review, and nine (9) other metrics that received significant consideration but have not yet gained enough consensus amongst the MTF or cannot currently be monetized for inclusion in the Regional Cost Allocation Review.

The most important aspect of the metrics to be developed is that the metrics should be able to provide "hard dollar" impacts of transmission to rate payers. In terms of this report, "hard dollar" means that each recommended metric must be able to provide incontrovertible evidence that a benefit will result in lowering of the overall cost to a rate payer. As part of this test, the MTF reviewed the metrics through the open SPP stakeholder meetings, transmission summits, and public postings, provided progress updates to the Cost Allocation Working Group (CAWG) to gather their feedback on the acceptability of the metrics being proposed, and sought feedback from the Chair and Vice-Chair of the original RARTF to reasonably assure that the MTF was addressing the metrics the RARTF recommended in the RARTF Report.

Due to the short amount of time before the Regional Cost Allocation Review will commence, the MTF concentrated on those metrics that could be reasonably implemented for the first Regional Cost Allocation Review. Section 9 of this report identifies additional metrics the Regional Cost Allocation Review team may want to consider especially after the Integrated Marketplace goes live in March of 2014 or in the second Regional Cost Allocation Review.

In their report, the MTF recommended that a total of thirteen monetized benefit metrics be utilized in the RCAR process. Of those 13 metrics, five were previously used in the Integrated Transmission Planning (ITP) process and eight were newly developed by the MTF.

6.3 STAKEHOLDER APPROVAL OF METRICS TASK FORCE'S DEVELOPMENT OF BENEFIT METRICS

At the September 13, 2012 meeting of the ESWG, the MTF presented their report, which was amended and approved by the ESWG and sent to the MOPC for approval.[64] At the October 16-17, 2012 MOPC meeting the MTF report was presented for approval, and the MOPC approved it.[65] The report was presented to the Board and Members Committee on October 30, 2012, where the Members Committee approved the metrics unanimously and the Board approved the report.[66]

After the MTF benefit metrics were approved through the SPP stakeholder process, most of these benefits were included in the RCAR analyses. Section 7.6 below discusses which metrics developed by the MTF were used in the RCAR.

6.4 STAKEHOLDER APPROVAL OF THE MTF'S RCAR BENEFIT METRICS

At the conclusion of RCAR I, the MOPC approved Action Item 222[67] that instructed the ESWG and TWG to finalize the benefits and metrics to be used for the 2015 ITP10. These same benefits and metrics would be used for the RCAR II analysis.

After debating the benefit metrics, ESWG presented their recommendations to the MOPC in July 2014.[68] MOPC agreed to three of the five metrics recommendations made by the ESWG. Though a majority agreed on remaining metrics, a supermajority consensus was not reached, so the Assumed Benefit of Mandated Reliability Projects and Mitigation of Transmission Outage Costs metrics were not approved.

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[64] *See* report posted on SPP's website at: http://www.spp.org/documents/18175/20120913%20mtf%20report_approved.pdf

[65] *See* Agenda Item 12 in the MOPC October 16-17, 2012 minutes posted on SPP's website at: http:// http://www.spp.org/documents/18378/mopc%20minutes%20&%20attachments%20october%2016-17,%202012.pdf

[66] *See* Summary of Action Items no. 9 in the Board of Directors October 30, 2012 Minutes posted at: http://www.spp.org/documents/18398/bod103012.pdf

[67] MOPC October 15-16, 2013 Info http://www.spp.org/documents/18378/mopc%20minutes%20&%20attachments%20october%2016-17,%202012.pdf at Page 5

[68] MOPC July 15-16, 2014 Info http://www.spp.org/documents/22945/mopc%20minutes%20&%20attachments%20july%2015-16,%202014.pdf

In the July 2014 Board meeting, the Board approved all five metrics as recommended by the ESWG.

6.5 BENEFIT METRICS USED IN RCAR III

The benefit metrics themselves remain unchanged for RCAR III. However, using the RCAR III Operational approach methodology and the change and base case results, the difference between the cases is reflective of the following benefits: Adjusted Production Cost, Reduction of Emission Rates and Values, Savings due to Lower Ancillary Service Needs and Production Costs, Mitigation of Transmission Outage Costs and Marginal Energy Losses.[69]

The remaining five metrics for the operations assessment were supplemented by a summation of previous results from ITP reports or a supplemental development and use of planning models and analysis.

The RARTF determined that three of the remaining five metrics were to be calculated by summing the benefits associated with each metric from the previously approved ITP reports where benefit metrics were calculated. These reports included the: 2012 ITP10,[70] 2015 ITP10,[71] the 2017 ITP10,[72] and the 2019 ITP.[73] The benefit values from each study were then escalated to 2022 dollars. The following three metrics were determined to be summed from previous ITP assessments:

- Avoided or delayed reliability projects
- Capacity cost savings due to reduced on-peak outages
- Benefits of meeting public policy goals
-

The remaining two metrics were recommended to be calculated using planning models with the necessary projects removed and assessed with a technical approach as determined by the RARTF:

- Assumed benefit of mandated reliability projects – This metric is calculated by summing the change in flows with each project removed individually. Each project studied in the Operations approach is taken out of service one at a time and the increase in flow on the remaining system is summed. This methodology is called system reconfiguration. These summed zonal flow values for each upgrade are multiplied by the ratio of directional flow based upon an economic model with all planning projects removed and operational projects remaining in service. The voltage of each upgrade is then considered in conjunction with each Zone's load ratio share to allocate the benefits accordingly.

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[69] *See* RARTF February 27, 2019 minutes: https://www.spp.org/Documents/59666/RARTF%20Minutes%20&%20Attachments%2020190227.pdf

[70] https://www.spp.org/documents/16691/20120131%202012%20itp10%20report.pdf

[71] https://www.spp.org/documents/26141/final_2015_itp10_report_bod_approved_012715.pdf

[72] https://www.spp.org/documents/51179/2017_itp10_report_board%20approved_april2017_final.pdf

[73] https://www.spp.org/documents/60937/2019%20itp%20report_v1.0.pdf

- Increased wheeling through and out revenues[74] – This metric attempts to identify the benefits associated with increased revenues created through increased available transfer capability out of the SPP region. The benefits created by increased transfer capability are expected to offset the revenue requirements of the transmission projects under evaluation.

These benefits will be forecasted out over the full 40 year analysis period and then will be locked for the remainder of that analysis period.

See Figure 6.5 below for a list of the RCAR III benefit metrics and how each is calculated:

RCAR III Benefit Metric	**Calculation Method**
Adjusted Production Cost	Market Runs
Reduction of Emission Rates and Values	Market Runs
Savings due to Lower Ancillary Service Needs and Production Costs	Market Runs
Avoided or Delayed Reliability Projects	ITP Approach
Capacity Cost Savings due to Reduced On-Peak Transmission	ITP Approach
Mitigation of Transmission Outage Costs	Market Runs
Assumed Benefits of Mandated Reliability Projects	Benefits=Costs Allocated - Technical
Benefits from Meeting Public Policy Goals	ITP Approach
Marginal Energy Losses	Market Runs
Increased Wheeling Through and Out Revenue	Not Monetized
Reduced Cost of Extreme Events	Not Monetized
Reduced Loss of Load Probability	Not Monetized
Capital Savings from Reduced Minimum Required Margin	Not Monetized

Figure 6.5 RCAR III Benefit Metrics

[74] On September 14, 2022 the RARTF voted unanimously to not monetize the Increased Wheeling Through and Out Revenue metric. See Section 7.6.5 of this report for further details. This metric was not monetized in RCAR I and made up 3.6% or approximately $641M of total benefits in RCAR II.

SECTION 7: RESULTS OF RCAR III

7.1 SUMMARY OF BENEFITS AND COSTS

Figure 7.1 summarizes the 40-year present values of the estimated benefit metrics and costs and the resulting B/C ratios by SPP Zone.

	Present Value Benefits for 2018-2057 ($ millions) (2022 $)							2018-2057 ATRRs ($ millions) (2022 $)			
Pricing Zone	**2018-2057 Operational Results ***	**Avoided or Delayed Reliability Projects**	**Capacity Cost Savings due to Reduced On-Peak Transmission**	**Assumed Benefit of Mandated Reliability Projects**	**Benefits of Meeting Public Policy Goals**	**Increased Wheeling Through and Out Revenues**	**Total Benefits**	**Before MISO and PTP Offset**	**PtP and MISO Offset**	**After PtP and MISO Offset**	**Benefit/Cost Ratio**
American Electric Power	$2,181	$21	$6	$757	$0	not monetized	$2,965	$1,640	$115	$1,525	**1.94**
Empire District	$930	$2	$1	$86	$0	not monetized	$1,020	$137	$10	$128	**7.99**
KCPL - Greater Missouri Operations	$3,196	$4	$1	$243	$0	not monetized	$3,444	$202	$14	$188	**18.36**
Grand River Dam	$448	$2	$0	$66	$0	not monetized	$516	$125	$9	$117	**4.42**
Kansas City Board of Public Utilities	$792	$0	$0	$26	$0	not monetized	$818	$47	$3	$43	**18.86**
Kansas City Power and Light	$3,703	$8	$10	$343	$0	not monetized	$4,064	$387	$27	$360	**11.28**
Lincoln Electric System	$210	$1	$0	$66	$0	not monetized	$277	$84	$6	$78	**3.56**
Midwest Energy	$614	$1	$0	$75	$0	not monetized	$689	$81	$6	$75	**9.13**
Nebraska Public Power District	$1,102	$6	$3	$325	$0	not monetized	$1,436	$445	$31	$414	**3.47**
Oklahoma Gas & Electric	$1,697	$44	$0	$558	$0	not monetized	$2,298	$842	$59	$783	**2.93**
Omaha Public Power District	$1,176	$5	$1	$182	$0	not monetized	$1,364	$347	$25	$322	**4.24**
City Utilities of Springfield	$882	$1	$0	$70	$0	not monetized	$954	$69	$5	$64	**14.87**
Sunflower Electric	$788	$13	$30	$276	$0	not monetized	$1,107	$324	$25	$299	**3.70**
Xcel - Southwestern Public Service	$9,030	$2	$19	$601	$0	not monetized	$9,653	$1,502	$101	$1,400	**6.89**
Basin- WAPA - Heartland Integrated System	$2,292	$9	$0	$430	$0	not monetized	$2,731	$359	$61	$298	**9.17**
Westar Electric	$5,840	$10	$8	$555	$0	not monetized	$6,414	$926	$25	$901	**7.12**
Western Farmers Electric	$1,764	$3	$0	$286	$0	not monetized	$2,054	$307	$41	$266	**7.71**
Total	$36,647	$132	$81	$4,945	$0	not monetized	$41,803	$7,822	$562	$7,260	**5.76**

*Operational Results include Adjusted Production Cost, Reduction of Emission Rates and Values, Savings due to Lower Ancillary Service Needs and Production Costs, Mitigation of Transmission Outage Costs, and Marginal Energy Losses benefits that are approved for RCAR.

Figure 7.1 Estimated 40-year Present Value of Benefit Metrics and Costs (2022 $million)

7.1.1 STAFF OBSERVATIONS FROM RCAR III

While performing RCAR III analysis and upon completion, SPP staff had observations that were noteworthy to be included in the final RCAR III Report. These observations are listed below:

Significant Amount of Transmission Upgrades Evaluated in RCAR III: Due to the amount of upgrades studied in RCAR III, the projects placed in service earlier could have impacted the same area or even the same transmission elements as later projects. The value provided by these later projects is then likely understated or even not captured in RCAR III. This is due to the system being reset as close as possible to the topology as it was before all of the Highway/Byway projects were added. This also resulted in some generation being disconnected if their only connection was to a Highway/Byway element. It is estimated that 21 generation resources were heavily impacted by the removal of the Highway/Byway elements resulting in these resources not being available for commitment in all or nearly all of the intervals that they existed in the model. These resources accounted for approximately 4,000MWs of capacity in the market cases.

Extreme prices and RCAR III Mitigation: The amount of transmission removed for RCAR III often resulted in extremely high levels of congestion and this congestion heavily impacted prices in a very regional way. This resulted in the import and export costs or benefits to be heavily impacted by real life outages. To reduce the impact of imports and exports, their cost were capped to the marginal energy component (MEC). It is likely that many of these outages would not have been taken in the same manner without the Highway/Byway projects impacting the analysis.[75]

The Morgan Transformer Project: After RCAR II, SPP staff worked with City Utilities of Springfield (CUS) and Associated Electric Cooperative, Inc. (AECI) to find possible seams projects that benefit CUS due to RCAR II showing CUS as below the .8 benefit to cost threshold. Based upon the 2017 ITP10 study, SPP identified a project on AECI's system known as the Morgan Transformer Project (MTP) that provided large benefits to CUS. With an agreement from AECI to build the MTP and the RSC voting to support regionally funding the MTP, SPP was successful in getting FERC to approve regionally funding the MTP. The MTP went into service on October 24, 2020, which was after the study window of RCAR III and the benefits of this project are not included.

February 2021 Winter Storm Uri: Due to the stresses on the system and the extremely high prices of the February 2021 winter weather event known as Uri, the operations optimization engine had a very hard time solving at all and did not converge to good solutions for RCAR III cases during this time frame. For that reason these days were excluded from the savings calculations. This exclusion significantly reduced the benefits of the Highway/Byway projects studied because without the Highway/Byway projects in place during Winter Storm Uri it is certain that much larger amounts of load would have needed to be shed during this time period as

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[75] *See* RARTF February 25, 2022 minutes:
https://www.spp.org/Documents/66960/RARTF%20Materials%2020220422.zip

transporting the power as was needed would not have been possible. In addition to the reliability benefits not captured, these projects provided significant economic benefits as well.

Zone Interchange Calculation Methodology: A large portion of the final APC savings are attributable to an interchange benefit to the Transmission Pricing Zones. This interchange calculation is conducted as later presented in Section 7.6.1. The Markets Working Group (MWG) discussed and recommended purchase at hourly load weighted zonal LMP and sales at hourly generation weighted zonal LMP to account for energy imbalances between the different Transmission Pricing Zones.[76]

Remote Generation: Generation resources that are not physically located in the transmission pricing Zone, but the output of the resource is owned by the Zone, are included in the zonal interchange calculation. Because of the remote nature of these resources their LMP is often times vastly different than the local generation and load as the congestion and losses can be vastly different. There is no measure of deliverability of the power generated by these resources to their Transmission Pricing Zone, or any differential treatment of this remote power. For example; if a Zone is generating in excess of their load solely because of the inclusion of the remote generation, the remote generation's power is 'sold' at the Zone's hourly generation weighted LMP, even if the remote generation's LMP is very different. During the calculation of the sale of this power, the hourly load weighted zonal LMP is not considered.

Other/Miscellaneous: There are several notable savings values or changes that we can make note of here. In 2018 the transmission Zone Oklahoma Gas and Electric had small total savings for the model year compared to the other years in the RCAR study. This was caused by the outage of two stepdown transformers. Without the RCAR transmission upgrades, these outages produced very low and even negative prices in the Oklahoma Gas and Electric region. The interchange adjustment cost equations resulted in greatly reduced savings for this model year.

The other notable feature is the large drop in savings for regions Midwest Energy and Sunflower Electric from 2019 to 2020. In the change cases the Load Weighted LMP was very expensive until Q2 2020. In Q2 2020 a 300MW wind resource came online in Midwest Energy and Sunflower Electric regions which greatly reduces the Load Weighted LMP in these cases.

In the after cases Load Weighted LMP was always lower, because of the additional transmission available for importing into Midwest Energy and Sunflower Electric. Since the addition of the wind resource in 2020 causes Load Weighted LMP prices to converge between the before and after cases the savings that Midwest Energy and Sunflower Electric realize related to transmission decreases.

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[76]On February 19, 2019 the MWG made a formal recommendation to the RARTF on hourly purchases/sales: https://spp.org/documents/59578/mwg%20minutes%20&%20attachments%2020190219.pdf

7.2 TRANSMISSION PROJECTS EVALUATED IN THIS RCAR REPORT

RCAR III was conducted by evaluating SPP Highway/Byway projects with in-service dates prior to January 1, 2020.[77] These projects were evaluated by looking at their projected costs and estimated benefits. Projects' projected costs were determined by staff using the most recent cost data submitted by project sponsors (as of June 2022). Projected benefit estimations were conducted by SPP by monetizing a subset of benefits developed by the MTF and approved by stakeholders (see Section 6 above).

7.3 RARTF GUIDANCE PROVIDED TO SPP STAFF WHILE CONDUCTING RCAR III

Since the completion of RCAR II in July 2016, SPP staff and the RARTF have anticipated the RCAR III's scheduled completion in 2022. The RARTF provided SPP staff with guidance for RCAR III as listed below.
At the February 27, 2019 meeting[78] the following guidance was given:

- RCAR III will use an alternate/hybrid approach using Highway/Byway projects in service before January 1, 2020 and utilizing market runs from the SPP Integrated Marketplace
- RCAR III should use a historical approach of one to two years for historic market days
- For future studies, automate the Operational process and process daily operational cases going forward, to begin as soon as possible
- Prospective future benefits using Operational approach will use market case runs up to the study year and then extrapolate out to year 20
- Only study projects using Operational approach having been in service for at least two years
- The following approved benefit metrics not captured in the Operational approach should be included in a supplemental analysis: Avoided or delayed reliability projects, capacity cost savings due to reduced on-peak transmission, and benefits from meeting public policy goals should be calculated using data from previous ITP studies; assumed benefit of mandated reliability projects and increased wheeling through and out should be determined using a technical approach
- Use load-weighted LMP for purchases and generation-weighted zonal LMP for sales

[77] On October 6, 2021 the RARTF voted unanimously to "cut-off" any transmission updates to the models being used for RCAR III on December 31, 2021; *see* October 6, 2021 RARTF meeting minutes: https://www.spp.org/Documents/65461/RARTF%20Minutes%20100621%20Final%20Approved%20120221.pdf
[78] *See* RARTF February 27, 2019 minutes: https://www.spp.org/Documents/59666/RARTF%20Minutes%20&%20Attachments%2020190227.pdf

- RCAR III analysis window of 2018-2057 for both costs and benefits

At the September 13, 2019 RARTF meeting[79] the following guidance was given:

- Approved RCAR II Lessons Learned which included four new items addressed in Background section above

At the July 21, 2021 RARTF meeting[80] the following guidance was given:

- Submit a tariff revision to FERC providing flexibility with projects in future RCAR studies, as discussed in detail in Section 3.2.1

At the October 6, 2021 RARTF meeting[81] the following guidance was given:

- To cut off transmission updates to the RCAR III models with projects approved by December 31, 2021

At the February 25, 2022 RARTF meeting[82] the following guidance was given:

- Cap the price of imports and exports used in benefits calculations with the Marginal Energy Component methodology, as addressed in Section 7.1.1

At the June 27, 2022 RARTF meeting[83] the following guidance was given:

- Finalize the RCAR III Report in October 2022 based solely on the Operational approach, with the option to add the supplemental analysis if necessary

At the September 14, 2022 RARTF meeting[84] the following guidance was given:

- For the Assumed Benefit of Mandated Reliability benefit metric, due to an issue with three SPS 345kV projects, these specific projects should be allocated using 2/3 allocation based on load ratio shares and the remaining 1/3 allocated to SPS
- For the Increased Wheeling Through and Out benefit metric, due to concerns over the time involved and whether this metric would even solve, RCAR III should be finalized

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[79] *See* RARTF September 13, 2019 minutes: https://www.spp.org/Documents/60790/RARTF%20Minutes%2020190913.pdf
[80] See RARTF July 21, 2021 minutes: https://www.spp.org/Documents/65461/RARTF%20CC%20100621%20-%201.zip
[81] *See* RARTF October 6, 2021 minutes :https://www.spp.org/Documents/65461/RARTF%20Minutes%20100621%20Final%20Approved%20120221.pdf
[82] *See* RARTF February 25, 2022 minutes: https://www.spp.org/Documents/66960/RARTF%20Materials%2020220422.zip
[83] *See* RARTF June 27, 2022 minutes: https://www.spp.org/Documents/67591/RARTF%20materials%2020220803.zip
[84] *See* RARTF September 14, 2022 minutes: https://www.spp.org/spp-documents-filings/?id=20900

without monetizing this metric and to further review this metric in the RCAR III Lessons Learned

7.4 COST CALCULATIONS CONTAINED IN THE RCAR REPORT

SPP staff conducted cost projections using the 40-year present value of Base Plan Upgrades having been in service for a minimum of two years, with in-service dates prior to January 1, 2020.

In accordance with Principle 3 from the RARTF Report, SPP staff used the most recent cost estimates provided to SPP as of June 2022 for project cost tracking. Thus, the RCAR analysis uses the most up to date and best available information for the review, per Principle 3.

7.4.1 CLASSIFICATION OF PROJECTS

To conduct the RCAR analysis, the Base Plan Upgrades approved for construction and in service prior to January 2020 were classified by the primary driver (Reliability, Economic, and Public Policy).

Figure 7.4.1 below summarizes the capital costs by in-service year, categorized by the primary driver.

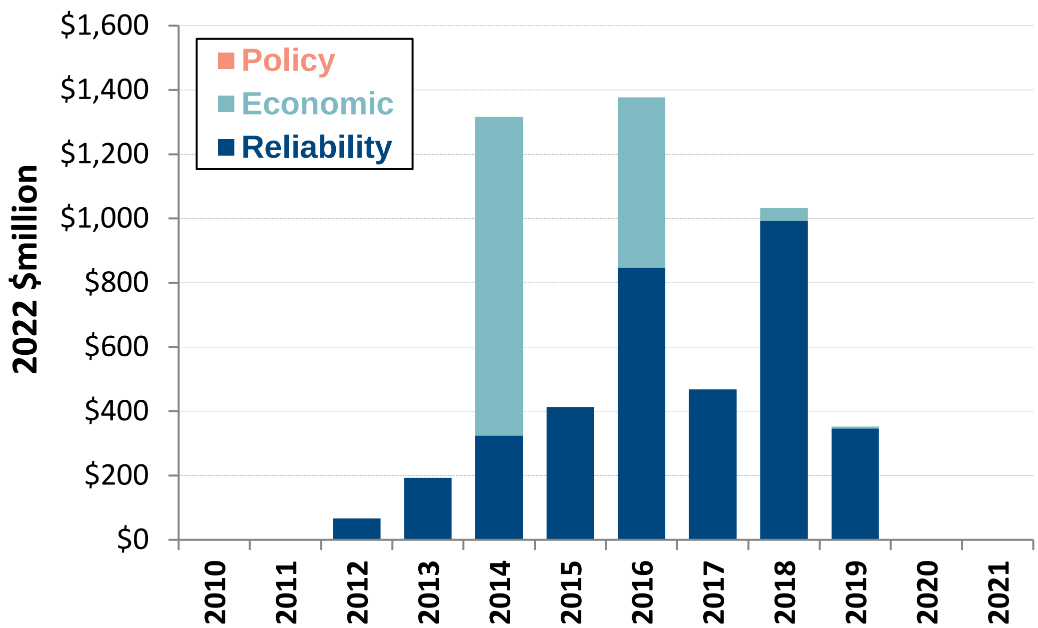

Figure 7.4.1
Summary of Capital Cost by In-Service Year

7.4.2 CALCULATION OF ANNUAL TRANSMISSION REVENUE REQUIREMENTS (ATRRS)

Per SPP's tariff, SPP staff calculated ATRRs for each Zone at the upgrade level, as summarized below:

- Costs allocated to Zones based on SPP's **Highway/Byway methodology**:
  - 100% regional if 300 kV or above,
  - 33% regional, 67% zonal if between 100 kV and 299 kV, and
  - 100% zonal if below 100 kV.

- **Load ratio share (LRS)** based on 2021 12-coincident peak loads used for the portion of costs allocated on a regional basis

- **Net plant carrying charge (NPCC)**, including depreciation expenses, applied at the zonal level to calculate first year ATRRs

- **2.5%/yr straight-line depreciation** applied in calculating declining ATRR profile over time in nominal dollars

- Present values calculated for 40-year depreciated ATRRs for 2018-2057 at a nominal **discount rate of 8.0%**[85]

Figure 7.4.2 below shows the estimated ATRRs over the 40-year study horizon (2018–2057) and summarizes the present values for each SPP Zone. At the regional level, the present value of ATRRs is approximately **$7.8 billion** (in 2022$) for all Base Plan Upgrades approved for construction and placed in service prior to January 1, 2020.

[85] The 8% discount rate used in the RCAR III analysis is consistent with previous RCAR and the SPP ITP studies.

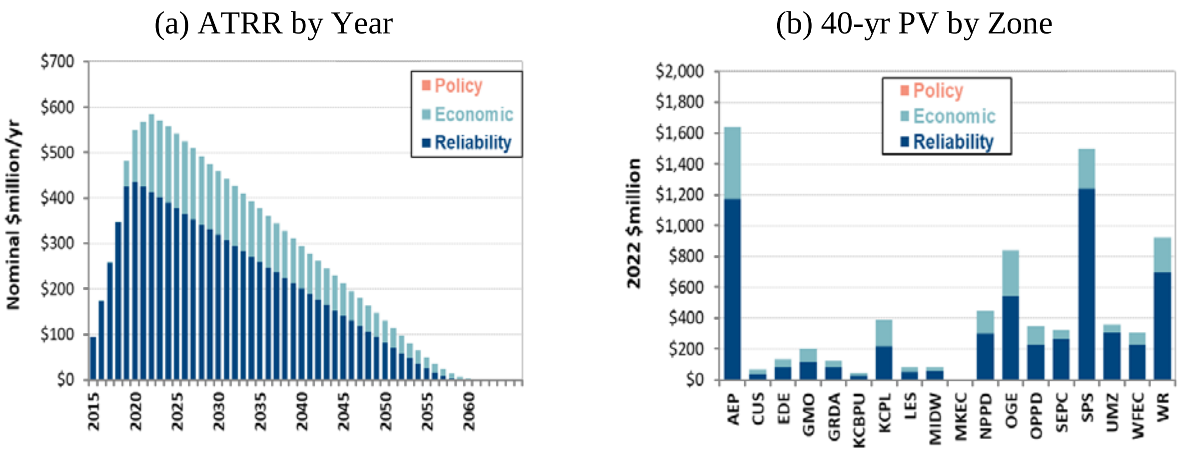

Figure 7.4.2
Summary of Estimated ATRRs by Project Type

7.4.3 CALCULATION OF POINT-TO-POINT (PTP) REVENUE

SPP staff projected a PTP revenue credit to each Zone over the 40 years of the study period. This PTP revenue credit offsets the costs (ATRR) allocated to individual Zones from Base Plan Zonal cost allocation and to all Zones through a reduction in the Base Plan Regional rate. The PTP revenue credit reduces the ATRR that must be recovered in subsequent years by the Network Integrated Transmission Service (NITS) charges to all Transmission Customers of the SPP Zones.

Step 1: Estimate PTP Volumes

PTP revenue was estimated by using historical average PTP volumes for service through and/or out of the SPP region. Activity for the first two study years (March 2018-February 2020) was based on average volumes in those years. There was a substantial reduction in PTP activity in early 2020 due to the expansion of the SPP transmission footprint. Therefore, the two-year average PTP volumes from March 2020-February 2022 were used for the remainder of the study period. Once the average PTP volume was established for each type of service (Annual, Monthly, Weekly, Daily Peak and Off-Peak, and Hourly Peak and Off-Peak), it was fixed over the final 38 years of the study. The following table shows the sales volumes used in the PTP offset calculation in the form of billable daily and hourly MW. The 2018-2019 billing determinants are differentiated from the 2020-2021 billing determinants as described above:

PTP Service Types Considered (Avg. Mar '18 - Feb '20)	Yearly	Monthly	Weekly	Daily On-Peak	Daily Off-Peak	Hourly On-Peak	Hourly Off-Peak
Through (MW)	-	323	156	1,234	494	64,384	32,192
Out (MW)	4,601	3,091	6,125	23,303	9,321	2,446,585	1,223,292

SPP PTP Service Types and Volumes, Averages of March 2018-February 2020

PTP Service Types Considered (Avg. Mar '20 - Feb '22)	Yearly	Monthly	Weekly	Daily On-Peak	Daily Off-Peak	Hourly On-Peak	Hourly Off-Peak
Through (MW)	-	-	-	-	-	995	498
Out (MW)	1,619	2,055	3,826	17,850	7,140	649,443	324,722

SPP PTP Service Types and Volumes, Averages of March 2020-February 2022

Figure 7.4.3a

Since load within the SPP region is served by “Into” and “Within” PTP service, the charges for which are a cost of serving load in the region, amounts for “Into” and “Within” service types were not included in this analysis.

Step 2: Determine PTP Zonal and Regional Rate from RCAR Upgrades

Next, a PTP rate was forecast for each PTP type for the 40 years of the study. The PTP rate forecast was based on the annual ATRR of new Highway/Byway facilities, divided by the SPP 12 CP in MW. The 2023 ITP’s 0.6% annual load growth projection was applied to years after 2022. A PTP rate was calculated for each PTP type (Monthly, Weekly, etc.).

All assumptions associated with the 40-year RCAR costs (ATRR generated by RCAR upgrades) were also included in the ATRR portion of the rate calculation (such as a 2.5% straight line annual depreciation rate and an 8% annual discount rate to derive a 2022 present value)

For the purpose of determining PTP rates, PTP revenue from the previous year was shown as a reduction in current-year ATRR for every year of the study.

Step 3: Estimate Annual RCAR PTP Dollars

Per-year PTP revenues were estimated by multiplying PTP volumes (MW) by the PTP rate ($/MW), both by type. This generated total annual revenues of RCAR PTP revenue for every year of the 40-year RCAR horizon. The resulting 40 years of RCAR PTP revenue estimates were converted to 2022 dollars.

Step 4: Allocate Total PTP Revenues to Each Pricing Zone

Base Plan Zonal (BPZ) PTP revenue was allocated back to the pricing Zone in which upgrades were built.

Base Plan Regional (BPR) PTP revenue was allocated to all pricing Zones in the SPP footprint based on each Zone's Load Ratio Share (LRS percentage) of total BPR PTP revenues.

The total SPP Highway/Byway transmission costs applied to each Zone through cost allocation is reduced by the through and/or out PTP revenue from the previous year that is associated with the Highway/Byway projects. This effectively reduced the cost component in the B/C ratios of each Zone based upon the Zone's allocation of such revenue. Allocated PTP revenue amounts, by Zone, are presented below in Figure 7.4.3b.

Step 5: Calculate an Estimation of MISO Seams Revenue by Zone to Further Offset PTP Revenues for Each Pricing Zone

To derive MISO seams revenue, which is allocated by Zone for the period 2018-2028,[86] the most current megawatt mile allocation percent by Zone of SPP's total MISO seams revenue (Schedules 7, 8, and 11) was applied to an estimate of $13.5 million for Phase III compensation, half of the $27 million total per the language from the Joint Operating Agreement (JOA) in FERC Docket No. EL14-21-000.

Next, the percent of Schedule 11 MISO seams revenue compared to all MISO seams revenue was determined by Zone over the two year period of August 2020 – July 2022 and was applied to the amount above resulting in an annual Schedule 11 MISO seams revenue amount by Zone.

This amount was reduced using a calculated ratio of Highway/Byway costs as a percent of total Base Plan Funded costs by Zone to derive the annual Schedule 11 Highway/Byway MISO seams revenue zonal amounts for 2018 through 2028.

Beginning in 2020 and going forward, a two-percent annual inflation rate was applied, per the JOA language.

Once the stream of MISO seams dollars for 2018-2028 was calculated by Zone, those totals were restated in a 2022 present value using an 8% discount rate.

Finally, the Highway/Byway Schedule 11 portion was further allocated between zonal and regional portions, and the regional portion was reallocated to the Zones based on each Zone's current load ratio share.

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[86] RCAR II used a seven-year projection ending January 2021, which was the initial term of the JOA Settlement Agreement. This agreement can now be terminated with a 12-month notice; thus due to uncertainty of end date and for consistency, RCAR III uses a seven-year future projection.

This present value amount by Zone was then added to the PTP offset calculated in Steps 1-4 above to obtain the total revenue offset amount. Revenue offset amounts, by Zone, are presented below in Figure 7.4.3b:

Zone	PTP Revenue Offset	MISO Seams Revenue	TOTAL
American Electric Power	$ 105,477,784	$ 9,499,545	**$ 114,977,329**
Empire District	$ 8,845,753	$ 709,163	**$ 9,554,916**
KCPL-Greater Missouri Operations	$ 12,933,883	$ 1,231,954	**$ 14,165,837**
Grand River Dam Authority	$ 8,060,169	$ 580,023	**$ 8,640,192**
Kansas City Board of Public Utililties	$ 2,985,241	$ 230,272	**$ 3,215,513**
Kansas City Power and Light	$ 24,827,104	$ 1,973,219	**$ 26,800,323**
Lincoln Electric System	$ 5,390,224	$ 848,295	**$ 6,238,519**
Midwest Energy	$ 5,207,226	$ 337,407	**$ 5,544,633**
Nebraska Public Power District	$ 28,694,158	$ 2,600,713	**$ 31,294,871**
Oklahoma Gas & Electric	$ 54,121,593	$ 4,795,088	**$ 58,916,681**
Omaha Public Power Disctrict	$ 22,408,993	$ 2,417,198	**$ 24,826,191**
Sunflower Electric	$ 21,150,627	$ 3,912,408	**$ 25,063,035**
City Utilities of Springfield	$ 4,415,338	$ 340,522	**$ 4,755,860**
Xcel - Southwestern Public Service	$ 97,059,591	$ 4,217,864	**$ 101,277,455**
Basin-WAPA-Heartland-Integrated System	$ 39,270,016	$ 1,564,714	**$ 40,834,730**
Westar Electric	$ 59,788,095	$ 5,264,136	**$ 65,052,231**
Western Famers Electric	$ 19,701,919	$ 1,383,626	**$ 21,085,545**
TOTAL	**$ 520,337,714**	**$ 41,906,147**	**$ 562,243,861**

Figure 7.4.3b
PTP Revenue and MISO seams Revenue, 40-yr PV 2018-2057 (in 2022$)

Step 6: Apply PTP Revenue Credit (including MISO revenue) to Each Zone's B/C Ratio

The total 40 years of BPZ and BPR PTP revenue credit in 2022 dollars and the MISO seams revenue offset were applied to each Zone's cost component of the RCAR B/C ratio as illustrated in Figure 7.1 above.

7.5 OPERATIONAL MODEL DEVELOPMENT FOR THE CALCULATION OF BENEFIT METRICS

7.5.1 RELIABILITY MODEL DEVELOPMENT

The operational approach reliability model that was used with each rerun DA_RUC case was the network model that was in use for operations for the date the DA_RUC case was originally run. No alterations to this base network model were made. To assess the impacts in the operational approach, RCAR project equipment was put into an 'outage' status or derated in the DA_RUC case as was appropriate to best simulate the system as it would have been without the studied Highway/Byway transmission upgrades in-service.

7.5.2 ECONOMIC MODEL DEVELOPMENT

Under the operational approach, resource costs and offers were used unaltered from the original production DA_RUC case when running the Base and Change cases.

During the calculation of the production costs associated with the Base and Change cases, results straight from the operational optimization engine were not used. These production costs use competitive offers which do not represent the actual cost of supplying the load in these case runs. To more accurately calculate the actual fuel costs, the mitigated energy costs were used instead of competitive offers in the post processing of the case run results.

Because SPP market operations uses market participant information and does not use the transmission planning pricing Zones used in RCAR, a mapping for each load and generation resource was made from the operations location to the associated transmission planning pricing Zone. This mapping did not use the physical location of the load or generation resource, but instead used which transmission planning pricing Zone owned the load or generating resource. This mapping was utilized only during the savings calculations that were conducted after the operational cases were run using the reliability model.

7.5.3 OPERATIONAL MODEL CONSTRAINTS

All original transmission constraints from the original operations DA_RUC case were left in the case. These constraints would include Market to Market constraints that SPP operators had included in the original operations run of the DA_RUC case. It should be noted that the vast majority of Market to Market (M2M) constraints in the DA_RUC case would be those where the monitored element is SPP's. These cases are run before the actual operating day with an approximation of what the external world's impacts will be on constraints, but the actual commitment and dispatch of external fleets, such as MISO's, are not known at the time the case is run. As a result many of the MISO M2M constraints and other external constraints that become congested in real-time are not captured in the original operations set of constraints.

Additional transmission constraints were added during the Simultaneous Feasibility Test (SFT) process as shown in Appendix 2. Up to 100 constraints were added from the SFT process on an interval by interval basis. The SFT process takes the economic dispatch results and assesses if there are any transmission elements that get overloaded either in a base or N-1 scenario. This SFT assessment is performed on an interval by interval basis which allows for transmission constraints to be located where there is the most loading during the case and provides a more dynamic approach to handling transmission congestion while still creating a case that the operations optimization engine can solve.

Resources were constrained to their physical operating parameters that were used in the original operations DA_RUC case run. This contains but is not limited to parameters such as min and max run times, min down times, startup times, ramp rates, economic and emergency operating limits.

7.5.4 SUMMARY

The original operations model was used with RCAR project equipment derated or put into an 'Outage' to simulate the operations model without those projects being implemented. In addition to the existing production transmission constraints, up to 100 additional transmission constraints were added on an interval by interval basis. Resources were constrained to their physical parameters that were used in the original operations DA_RUC case.

7.6 BENEFIT METRICS

The benefit metrics analyzed for RCAR III include all metrics developed, monetized, and approved by SPP stakeholders, provided in Figure 7.6a below, which also shows which metrics were monetized for use in the RCAR I and RCAR II studies.

Benefit Metric Name	**Monetized in RCAR I?**	**Monetized in RCAR II?**	**Monetized in RCAR III?**
Adjusted Production Cost (APC) Savings	✓	✓	✓
Reduction of Emission 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	✓	✓	✓
Mitigation of Transmission Outage Costs	✓	✓	✓
Assumed Benefit of Mandated Reliability Projects	✓	✓	✓
Benefits from Meeting Public Policy Goals	✓	✓	n/a*
Increased Wheeling Through and Out Revenues		✓	**
Marginal Energy Loss Benefits		✓	✓
Reducing the Cost of Extreme Events			
Reduced Loss of Load Probability			
Capital Savings due to Reduction of Members' Minimum Required Margin			

*No public policy projects were identified in RCAR III, as noted in Sec. 7.6.4.

**Not montezied in RCAR III as noted in Section7.6.5.

Figure 7.6a
Benefit Metrics Analyzed in RCAR

7.6.1 Adjusted Production Cost (APC) Savings

As mentioned previously in Section 3.6, under the Operational approach used for RCAR III, the APC savings totals are reflective of the following benefits: Adjusted Production Cost, Reduction of

Emission Rates and Values, Savings due to Lower Ancillary Service Needs and Production Costs, Mitigation of Transmission Outage Costs and Marginal Energy Losses.

When calculating the Production costs for each Transmission Zone there were two main components:

Savings per Zone = Production Cost + Interchange Adjustment

Each load and generation resource was mapped from its Operational location to the Transmission planning pricing Zone. This was not performed using the physical location of the load or generation resource, but instead performed by which transmission planning pricing Zone owned the load or generating resource. Once this was complete it was then possible to calculate the Production Costs and the Interchange Adjustment for each Transmission Pricing Zone.

For operations years 2018 and 2019 there were 35 and 36 cases run, respectively, for each of these two years that were then extrapolated out to estimate the annual savings. For operations years 2020 and 2021 an attempt was made to run a case every day. Some cases were not possible to achieve a good converged solution with the large number of transmission projects that were removed, and some days were excluded due to their outlier results:

2021 -19 Days excluded (this includes the winter weather event February 13th - 20th) 17 Missing

2020 –13 Days excluded, 16 Missing

When the operations optimization engine was not able to solve the case at all the day is considered missing from the data set. When the operations optimization engine was able to arrive at a solution, but the converged solution was of low quality these days were excluded from the data set. For the missing or excluded days the savings were estimated by using the average of the previous and following three successful days.

PRODUCTION COSTS

Production cost calculations captured, as closely as possible, the true fuel costs of the case. For this reason the Mitigated offer instead of the competitive offer was used in the calculation of the production costs. This gives a more accurate value for the fuel costs at the solution's dispatch for each resource.

$$Production\ Costs = \sum_{d=Jan\ 1st}^{Dec\ 31st} \sum_{i=1}^{32} \sum_{r=1}^{n} Energy\ Costs_{r,i,d} + No\_Load_{r,i,d} + Start\_Up_{r,i,d}$$

Where *r* represents each resource, and *i* is the interval in the case for the day, *d*. Summing up the costs for each day in the year gives the total production costs for the model year.

INTERCHANGE ADJUSTMENT

To simulate the cost of importing power or profits from exporting power the power deficit or surplus was calculated for each transmission pricing Zone. When there was less generation in the Zone than the load for the interval then the load weighted LMP of that transmission pricing Zone was used as the cost of the imported power. Similarly when there was more generation than load the generation weighted LMP was used as the cost for the power that was being exported. In both cases the load demand MW or generation output MW was used as the weighting factor.
The price of imports / exports used in this calculation was capped using the Marginal Energy Cost (MEC)[87] of the interval in which the interchange adjustment was being calculated.

Interchange Adjustment =
IF Zone load – Zone gen > 0 (*importing power)*
THEN (Zone load – Zone gen) * load weighted LMP
WHEN Zone load – Zone gen < 0 (*exporting power*)
THEN (Zone load – Zone gen) * gen weighted LMP
WHEN (Zone_load - Zone_gen) = 0
THEN 0

40 YEAR EXTRAPOLATION METHODOLOGY

When calculating the 40 year savings in 2022 Net Present Value (NPV) amounts the following methodology was used:

- Years 1 – 4
    - Savings from case reruns are used
- Year 5
    - Average of annual savings from years 1 - 4
- Years 6 – 40
    - Growth in savings from previous year set at 2.5%[88]
- Net Present Value of savings for 2022
    - Discount rate of 8% is used for the NPV calculation

Looking at the case runs and extrapolated savings for each of the four model years we get Table 7.6.1a:

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[87] *See* RARTF February 25, 2022 minutes: https://www.spp.org/Documents/66960/RARTF%20Materials%2020220422.zip
[88] Consistent with RCAR I and II studies.

Pricing Zone	2018	2019	2020	2021	2018-2021 Total ($M)	2018-2021 Average
American Electric Power	$73	$110	$84	$140	$407	$102
Empire District	$35	$44	$28	$67	$174	$43
KCPL - Greater Missouri Operations	$111	$121	$101	$265	$598	$149
Grand River Dam	$24	$27	$17	$15	$83	$21
Kansas City Board of Public Utilities	$39	$45	$26	$38	$147	$37
Kansas City Power and Light	$135	$158	$138	$261	$692	$173
Lincoln Electric System	$11	$6	$6	$16	$39	$10
Midwest Energy	$27	$67	$12	$7	$113	$28
Nebraska Public Power District	$39	$83	$35	$48	$205	$51
Oklahoma Gas & Electric	$9	$103	$64	$143	$319	$80
Omaha Public Power District	$75	$59	$35	$50	$218	$54
City Utilities of Springfield	$28	$40	$38	$59	$165	$41
Sunflower Electric	$29	$85	$15	$17	$146	$36
Xcel - Southwestern Public Service	$289	$395	$327	$677	$1,689	$422
Basin - WAPA - Heartland Integrated System	$69	$65	$99	$197	$430	$107
Westar Electric	$217	$271	$212	$389	$1,090	$272
Western Farmers Electric	$61	$76	$67	$126	$330	$82
Total	$1,271	$1,755	$1,303	$2,515	$6,842	$1,711

Table 7.6.1a - Model Year Savings

When these annual savings are extrapolated to 2057 and converted to reporting year 2022 NPV we get Table 7.6.1b:

Pricing Zone	40 Year APC Savings (2022 NPV - $M)
American Electric Power	$2,181
Empire District	$930
KCPL - Greater Missouri Operations	$3,196
Grand River Dam	$448
Kansas City Board of Public Utilities	$792
Kansas City Power and Light	$3,703
Lincoln Electric System	$210
Midwest Energy	$614
Nebraska Public Power District	$1,102
Oklahoma Gas & Electric	$1,697
Omaha Public Power District	$1,176
City Utilities of Springfield	$882
Sunflower Electric	$788
Xcel - Southwestern Public Service	$9,030
Basin - WAPA - Heartland Integrated System	$2,292
Westar Electric	$5,840
Western Farmers Electric	$1,764
Total	$36,647

Table 7.6.1b - 40 Year APC Savings

Appendix 2 provides additional detail on fundamental input assumptions in RCAR III.

7.6.2 AVOIDED OR DELAYED RELIABILITY PROJECTS AND CAPACITY SAVINGS DUE TO REDUCED ON-PEAK TRANSMISSION LOSSES

These two metrics were calculated by summing the benefits calculated in previous ITP reports and escalating their dollar amounts into 2022 dollars based upon a 2.5% rate of inflation to be consistent with the other benefit calculations.

The 2012 ITP10, 2015 ITP10, 2017 ITP10, 2019 ITP assessments were utilized for this summation exercise.

It is important to note these studies calculated the benefits associated with the results of the recommended portfolios, which included projects that may not have been approved by the SPP Board of Directors for an NTC. Additionally, early versions of the ITP10 studies calculated the benefits on multiple portfolios of projects that may have had a different set of recommended solutions based upon study assumptions. In these instances the benefits for the metrics were averaged together to create a single value for each study.

The total benefits attributed to each Zone for the Avoided or Delayed Reliability Projects metric can be seen below in Table 7.6.2a. Values are shown in $M and are escalated to 2022 dollars. For the 2015 ITP10 and the 2019 ITP, there were no avoided or delayed reliability projects identified during the course of the study.

In Millions $ for 40-yr NPV (2018-2057)					
Zone	2012 ITP10	2015 ITP10	2017 ITP10	2019 ITP	**Total ($M)**
American Electric Power	$20.66	$0.00	$0.10	$0.00	**$20.76**
Empire District	$2.39	$0.00	$0.01	$0.00	**$2.40**
KCPL - Greater Missouri Operations	$3.87	$0.00	$0.02	$0.00	**$3.89**
Grand River Dam Authority	$1.66	$0.00	$0.01	$0.00	**$1.67**
Kansas City Power and Light	$7.59	$0.00	$0.03	$0.00	**$7.62**
Lincoln Electric System	$1.46	$0.00	$0.01	$0.00	**$1.48**
Midwest Energy	$0.75	$0.00	$0.00	$0.00	**$0.75**
Nebraska Public Power District	$6.05	$0.00	$0.03	$0.00	**$6.09**
Oklahoma Gas & Electric	$43.55	$0.00	$0.07	$0.00	**$43.62**
Omaha Public Power District	$4.80	$0.00	$0.02	$0.00	**$4.82**
City Utilities of Springfield	$1.34	$0.00	$0.01	$0.00	**$1.36**
Sunflower Electric	$12.93	$0.00	$0.01	$0.00	**$12.94**
Xcel - Southwestern Public Service	$0.93	$0.00	$1.03	$0.00	**$1.96**
Basin-WAPA-Heartland-Integrated Sys	$8.86	$0.00	$0.05	$0.00	**$8.91**
Westar Electric	$10.11	$0.00	$0.05	$0.00	**$10.16**
Western Famers Electric	$3.30	$0.00	$0.11	$0.00	**$3.41**
Total	$130.27	$0.00	$1.57	$0.00	**$131.84**

Table 7.6.2a – Avoided or Delayed Reliability Projects

The benefits summed for the Capacity Cost Savings due to Reduced On-Peak Outages are found below in Table 7.6.2b. Values are shown in $M and have been escalated into 2022 dollars. These values are based upon reduced line losses within a Zone. Areas with significant upgrades tend to receive larger amounts of benefits. For example, in the 2015 ITP10 Sunflower Electric had a significant benefit value for this metric; however, Sunflower Electric also had significant transmission projects in their area for the study accounting for 33% of the engineering construction costs of the recommended projects being in the Sunflower Electric Zone.

Zone	2012 ITP10	2015 ITP10	2017 ITP10	2019 ITP	Total ($M)
	Average F1/F2	Average F1/F2	Average F1/F2/F3	Base Reliability	
American Electric Power	$0.93	$2.10	$2.09	$0.88	**$6.00**
Empire District	$0.11	-$0.09	$0.23	$0.74	**$0.99**
KCPL - Greater Missouri Operations	$0.17	-$0.12	$0.23	$0.95	**$1.23**
Grand River Dam	$0.07	-$0.16	$0.17	$0.15	**$0.24**
Kansas City Power and Light	$0.34	$3.63	$0.51	$5.65	**$10.14**
Lincoln Electric System	$0.07	$0.00	$0.00	$0.08	**$0.14**
Midwest Energy	$0.03	-$0.25	$0.00	$0.01	**-$0.20**
Nebraska Public Power District	$0.27	$1.35	$0.23	$1.57	**$3.42**
Oklahoma Gas & Electric	$0.59	-$0.31	$2.15	-$2.91	**-$0.48**
Omaha Public Power District	$0.22	$0.80	$0.00	$0.29	**$1.31**
City of Springfield	$0.06	$0.00	-$0.06	-$0.05	**-$0.05**
Sunflower Electric	$0.10	$29.56	$0.28	-$0.21	**$29.73**
Xcel - Southwestern Public Service	$0.52	$11.52	$7.07	$0.33	**$19.45**
Basin-WAPA-Heartland-Integrated System	$0.40	$0.10	-$0.34	$0.11	**$0.26**
Westar Electric	$0.45	$1.87	-$0.28	$6.02	**$8.06**
Western Farmers Electric	$0.15	$0.00	$0.28	$0.00	**$0.43**
Total	$4.48	$50.00	$12.56	$13.61	**$80.67**

Table 7.6.2b - Capacity Cost Savings due to Reduced On-Peak Outages

7.6.3 ASSUMED BENEFIT OF MANDATED RELIABILITY PROJECTS

The Assumed Benefit of Mandated Reliability Projects metric is the method by which the benefits associated with maintaining a reliable system are allocated. The benefit of a reliability project is equivalent to the cost of the reliability project. The metric uses a hybrid methodology to allocate benefits that considers the load ratio share of each Zone and results of a system reconfiguration analysis System reconfiguration (SR) is a flow-based methodology using a powerflow model to identify the flow reduction that can be attributed to an upgrade.

System reconfiguration analysis for the operations projects was performed on a 2021 ITP year 10 summer peak powerflow model with projects having in service dates after 12/31/2019 removed. Each operations upgrade is taken out of service, one at a time. Once the project is removed the change in MW flow for all elements in the transmission system are measured. Lines with increased flows with the upgrade removed are considered beneficiaries of the project, while lines with decreased flows once the upgrade is removed are considered to be impacted negatively. The change in flows are summed by Zone to provide an overall picture of the change in flows for the entire SPP region.

A production cost model matching the powerflow topology is used to determine the flow direction on each line for the entire 8,760 hours. Hours when flow direction matches the powerflow model are identified as positive flow. Hours when flow direction is the opposite of the powerflow model are identified as negative flow.

The positive and negative MW relief for all Zones are weighted based upon the 8,760 hourly flow direction of the production cost model.

$$\frac{\Sigma\ hours\ with\ positive\ flow\ on\ A \rightarrow B}{8{,}760\ hours} = X\%$$

$$\frac{\Sigma\ hours\ with\ negative\ flow\ on\ A \rightarrow B}{8{,}760\ hours} = Y\%$$

$$If\ \Sigma_{Zone\ 1}\ (Net\ MW\ relief\ on\ facilities) > 0:$$
$$Allocation\ Factor_{Zone\ 1} = \left[\frac{\Sigma_{Zone\ 1}\ (Net\ MW\ relief\ on\ facilities)}{\Sigma_{All\ zones\ with\ positive\ net\ relief}\ (Net\ MW\ relief\ on\ facilities)}\right] * X\%$$

$$If\ \Sigma_{Zone\ 1}\ (Net\ MW\ relief\ on\ facilities) < 0:$$
$$Allocation\ Factor_{Zone\ 1} = \left[\frac{\Sigma_{Zone\ 1}\ (Net\ MW\ relief\ on\ facilities)}{\Sigma_{All\ zones\ with\ negative\ net\ relief}\ (Net\ MW\ relief\ on\ facilities)}\right] * Y\%$$

High voltage projects are expected to support regional flows compared to lower voltage projects that support more local load serving needs. A hybrid benefit allocation was developed to account for the disproportionate allocation of benefits to nearby Zones for high voltage upgrades driven by regional flows. The following table shows the weighted method by which the voltage level of a project is allocated:

Reliability Upgrade kV	Allocation of Benefit
> 300 kV	1/3 SR, 2/3 LRS
100 - 300 kV	2/3 SR, 1/3 LRS
< 100 kV	100% SR

During the course of the metric calculation, the system reconfiguration calculation was unable to solve for three 345 kV lines in the New Mexico portion of SPS. Those lines included:

- Hobbs – Kiowa 345 kV
- Kiowa – North Loving 345 kV
- North Loving – China Draw 345 kV

After investigation, it was determined that an acceptable resolution using the system reconfiguration would not be attainable because of the conditions of the model. Significant transmission from projects placed in service after 1/1/2020 were already removed from this model, while the load required to be served in this area is based upon the most current load forecast provided. The New Mexico portion of the SPS system has experienced significant load growth and is protected by three distinct interfaces that use line loading of specific transmission lines to proxy when voltage collapse conditions may occur. Removing each one of these transmission lines with the system reconfiguration analysis does not allow the model to solve because there is not enough transmission remaining in the models to solve.

The three lines in question total $124.0M that require an alternate method of allocation outside of the approved approach. The RARTF discussed three options during their September 14, 2022 meeting. Those options were:

- Option 1: Allocate all benefits to SPS because the model was unable to solve
- Option 2: Allocate all benefits using load ratio share
- Option 3: Allocate 2/3 ($84M) of the benefits using load ratio share and the remaining benefits (~$21M) to SPS

The RARTF determined that option 3 was the most reasonable approach. This option follows the spirit of the metric as defined by allocating 2/3 of the benefits using load ratio share which is consistent with the hybrid approach for 345 kV solutions. As previously discussed the system reconfiguration methodology assesses the changes in flow on transmission lines due to the upgrades. These three lines were not expected to alter the flows outside of the SPS area because the area is so remote from the remainder of the SPP system, leading the SPS area to receive a majority of the benefits. Therefore, allocating the remaining portion of benefits to SPS is consistent with the expected results of the system reconfiguration analysis.

Table 7.6.3 below shows the Assumed Benefit of Mandated Reliability projects for each Zone based upon the methodology described above.

In Millions $ for 40-yr NPV (2018-2057)	
Zone	**Total ($M)**
American Electric Power	**$757.3**
Empire District	**$86.2**
KCPL - Greater Missouri Operations	**$242.7**
Grand River Dam Authority	**$66.4**
Kansas City Board of Public Utilities	**$26.2**
Kansas City Power and Light	**$342.9**
Lincoln Electric System	**$65.5**
Midwest Energy	**$74.6**
Nebraska Public Power District	**$324.9**
Oklahoma Gas & Electric	**$557.6**
Omaha Public Power District	**$181.9**
City Utilities of Springfield	**$70.4**
Sunflower Electric	**$276.0**
Xcel - Southwestern Public Service	**$601.4**
Basin-WAPA-Heartland-Integrated Sys	**$430.0**
Westar Electric	**$555.4**
Western Famers Electric	**$285.9**
Total	**$4,945.3**

Table 7.6.3 – Assumed Benefit of Mandated Reliability Projects

7.6.4 BENEFITS OF 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 RCAR, it is limited to benefits of meeting public policy goals related to renewable energy. System-wide benefits are assumed to be equal to the cost of policy projects.

Since no policy projects were identified in RCAR III, associated benefits are estimated to be zero.

7.6.5 INCREASED WHEELING THROUGH AND OUT REVENUES

Increasing available transfer capacity (ATC) with neighboring regions improves import and export opportunities for the SPP footprint. Increased inter-regional transmission capacity that increases through- and out-transactions will also increase SPP wheeling revenues.

While the benefit of increased exports is captured in APC savings (which values exports at the weighted average generation LMP of the exporting Zone), APC savings do not capture increases in wheeling out or wheeling through revenues associated with increased transfer capability.

Collected wheeling revenues are not counted in either the exporting or importing region's APC. Increased wheeling revenues are a benefit as they offset part of transmission projects' revenue requirements. Currently, SPP collects wheeling revenues through Schedules 7 and 11 for firm through and out transactions.

This metric was intended to determine the amount of increased ATC resulting from the portfolio. To calculate this metric a historical ratio of service sold over the MW difference in ATC between a powerflow model with and without the transmission projects is:

$$\text{Historical Ratio}_{2014} = \frac{Incremental\ Historical\ TSRs\ Sold\ Thru\ 2014\ (MW)}{ATC_{2014\ Change\ Case}(MW) - ATC_{2014\ Base\ Case}(MW)}$$

That ratio represents the historical transmission service sold per MW increase in ATC due to previous transmission upgrades. This ratio is used to calculate the long-term service sold based upon the ATC increases from the applicable transmission upgrades.

$$Forecast\ Service\ Sold\ (MW) = Historical\ Ratio\ x\ (ATC_{Change\ Case} - ATC_{Base\ Case})$$

The wheeling benefit ($/yr) is then found by multiplying the forecasted service sold (MW) by the incremental wheeling revenues ($/yr) over the incremental historical transmission service requests (MW).

During the RARTF meeting on September 14, 2022, the RARTF discussed an issue with the model build associated with this metric. To build these models, all projects evaluated in RCAR III must be removed. Removing significant amounts of transmission proved extremely difficult and time consuming with significant concerns that the models, once completed, would be unable to be solved to perform the metric calculations. The RARTF approved a motion that due to these challenges this metric would not be monetized for the RCAR III and would be discussed in the Lessons Learned effort for RCAR III.

SECTION 8: RECOMMENDATION ON REMEDIES

8.1 OVERVIEW OF RARTF REPORT ON REMEDIES

The RARTF Report recommended that if the RCAR analysis shows that a Zone is below the 0.8 B/C threshold described in Section 4.1 of the RARTF Report then "SPP staff should evaluate, and recommend possible mitigation remedies for the Zone." The RCAR I Lessons Learned Report re-affirmed this, recommending, "SPP staff should evaluate remedies for Zones below the threshold in the NTC –only review for RCAR II." RCAR III used the same threshold.

8.2 RCAR REPORT ON REMEDIES

RCAR I Lessons Learned Report stated that "If RCAR II does not show that adequate remedies exist, SPP staff, Deficient Zones, and SPP Stakeholders can begin the process of analyzing additional potential remedies for any Zone below the threshold." This Lesson Learned was continued in RCAR II Lessons Learned to be applied in RCAR III. Because no Zones were below the .8 threshold, no remedies are included in the final RCAR III Report.

SECTION 9: GUIDANCE FOR FUTURE RCAR ASSESSMENTS

9.1 OVERVIEW OF RCAR LESSONS LEARNED

In Section 7.1 of their Report, the RARTF made four recommendations in addition to their recommendations of how to conduct the RCAR. Recommendation four stated:

> [T]he RARTF found the process of developing the recommended methodology under which the Regional Cost Allocation Review will be performed to be a very informative and collaborative process. As a result, the RARTF recommends that the task force be reconvened before subsequent Regional Cost Allocation Reviews are performed. This will enable the SPP stakeholders to review lessons learned from prior Regional Cost Allocation Reviews and to suggest improvements to the methodology recommended in this report.

In accordance with the fourth additional recommendation contained in Section 7.1 of the RARTF Report, it is recommended that the RARTF "be reconvened before subsequent Regional Cost Allocation Reviews are performed."

The final recommendation is for the RARTF to begin a lessons-learned process, similar to that used after RCAR I and RCAR II, and to finalize suggested improvements to the RCAR process by the stakeholder meeting cycle. This will allow improvements to be incorporated into the next RCAR process.

APPENDICES

APPENDIX 1
STAKEHOLDER COMMENTS AND RESOLUTIONS FOR RCAR III DRAFT RESULTS AND REPORT

Stakeholder comments and suggestions have been posted at: https://www.spp.org/spp-documents-filings/?id=20184

APPENDIX 2
RCAR III OPERATIONAL APPROACH SCOPE, PROCESS, AND ASSUMPTIONS

Scope

Through the RARTF it was agreed that projects will only be evaluated in the Operational approach when they can have an effective study time of at least two years. This is in order to give projects sufficient time to be valued and not over or under value a transmission project by only studying a smaller amount of in service time. Due to this decision RCAR III covers Highway/Byway projects that were implemented from 06/19/2010 to 12/31/2019. The DA_RUC cases run include at least three cases for every month of 2018 & 2019, and every feasible day of 2020 and 2021. Cases for 2018 and 2019 were selected to best represent the historical study times using a feasible case close to the 10th, 50th, and 90th percentile of production costs for each month.

Process

The process for rerunning the DA_RUC cases for both the change and base case is outlined below in ***figure A***

<u>Base Case:</u>

1. Retrieve original market case files
2. Change study assumption (listed in Section 3.2.1)
3. Run Security Constrained Unit Commitment (SCUC)
4. Run Security Constrained Economic Dispatch (SCED)/Simultaneous Feasibility Test (SFT)
5. Insert newly identified constraints in case files
6. Run SCUC
7. Run SCED
8. Upload Results

<u>Change Case:</u>

1. Retrieve original market case files
2. Change study assumption (listed in Section 3.2.1)
3. Make topology changes / derates in original case files
4. Run Model Initializer (MDLINIT)
5. Run SCUC
6. Run SCED/SFT
7. Insert newly identified constraints in case files
8. Run SCUC
9. Run SCED
10. Upload Results

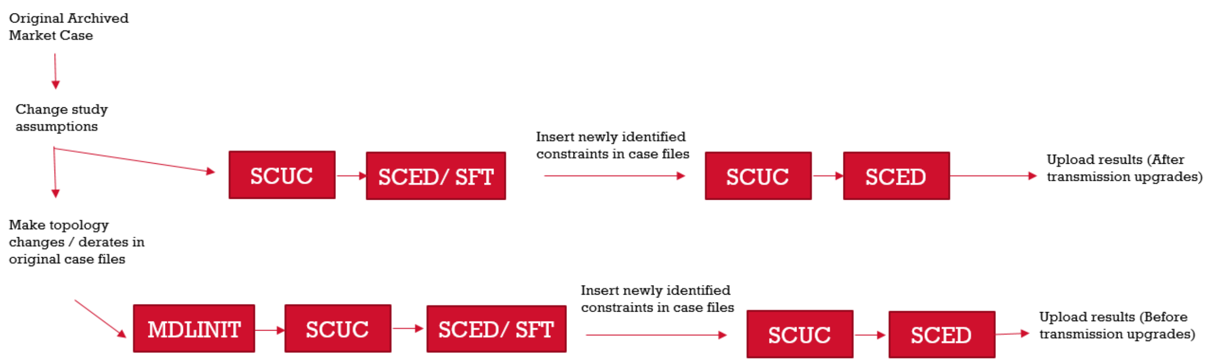


Figure A

An initial SCUC/SCED/SFT run is required to identify new constraints that may not have been impacting in the original production case, but now are due to study assumption and topology changes.

Study Assumptions

- The objective type was changed from minimum capacity cost to minimum production costs to more accurately solve for dispatch.
- Advance notice time is modified to allow any resource to be committed regardless of startup time to represent the notion that without the transmission build out the base system would be committed differently.
- Type NDVER resources are changed to DVER to represent the ability to dispatch all resources.
- The violation relaxation limit (VRL) iteration was changed from 1 to 8 based off a change after the Feb 2021 winter event to ensure all VRLs are solved and solutions do not get stuck on a VRL block.
- The control Zone threshold for AECI is set to 9999. Based off of an assumption also used in HITT projects. This prevents the introduction of AECI transmission constraints into the model during the SFT process.
- Winter Branch limits were used from Dec 1st - March 31st of the next year - Example : Dec 1, 2019 till March 31, 2020
- The current operating plan (COP) was cleared before each run.
- The maximum number of contingencies per constraint was increased to a value of 100.
- After each case solved, the case was reviewed by the RCAR engineering team to determine if it was an optimal solution within the analysis' threshold. If the case was above the threshold, the case was reran. If it did not meet the expected threshold the second time the case was classified as non-convergent and the production day was excluded from use in the final results.
- Outages were left in to more accurately portray an operational environment

Savings Calculations

When calculating the value of interchange for individual transmission pricing Zones, a similar convention to planning studies was adopted. Exports were valued at the generation weighted LMP and imports were valued at the load weighted LMP of the transmission Zone. For the benefit calculations, the case's start-up, and no-load along with the resource's mitigated energy costs were used. Competitive offers were used in the actual running of the case.

Additional Details and Assumptions

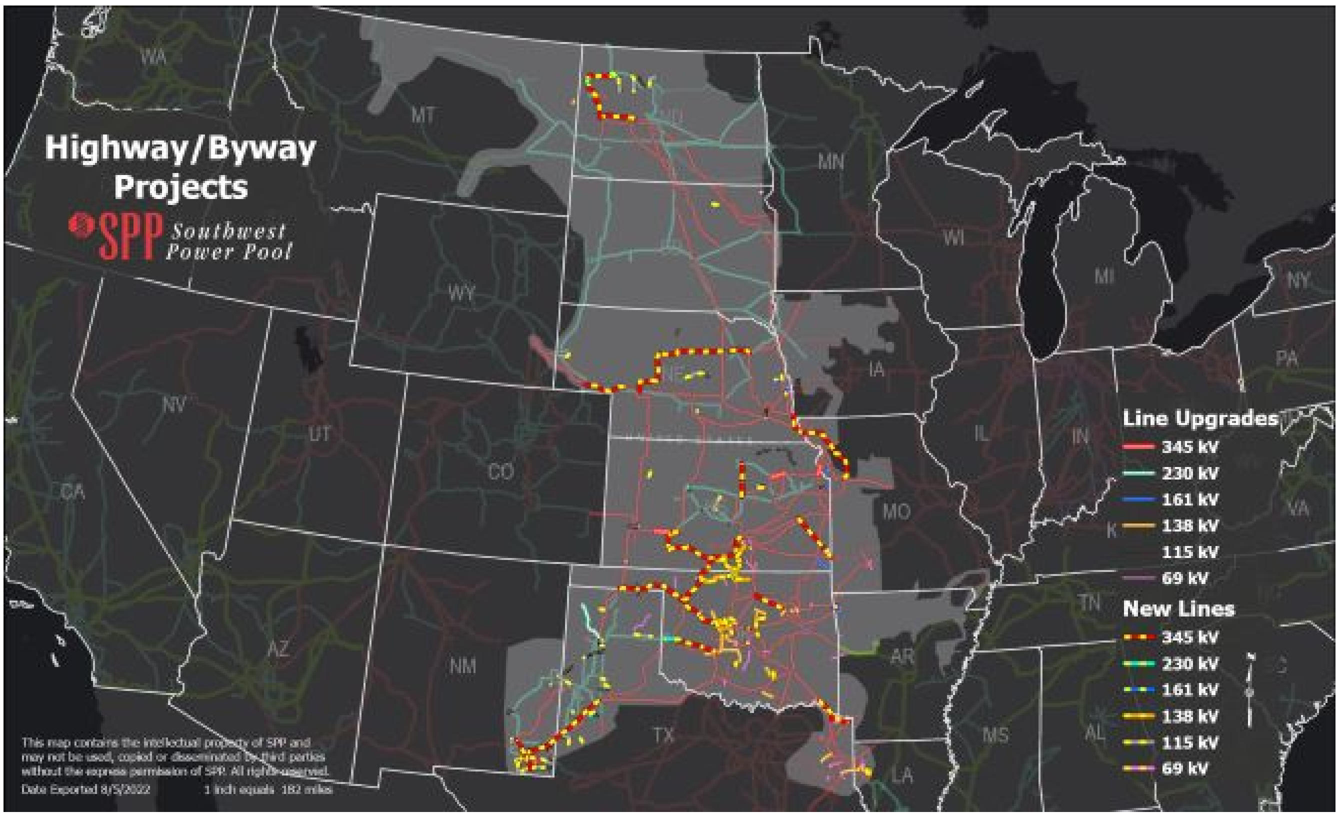
- RCAR III is studying all feasible Highway/Byway projects[89] - even if they were included in RCAR II.
- Two types of equipment upgrades could not be studied in the operational study due to the nature of how the model captures rating changes or outage. These two types of equipment – Reactor and Capacitor.

[89] During the implementation of the Integrated System, certain projects received Highway/Byway funding, as described in Attachment J Schedule 2 of the SPP tariff. These were included in RCAR III.

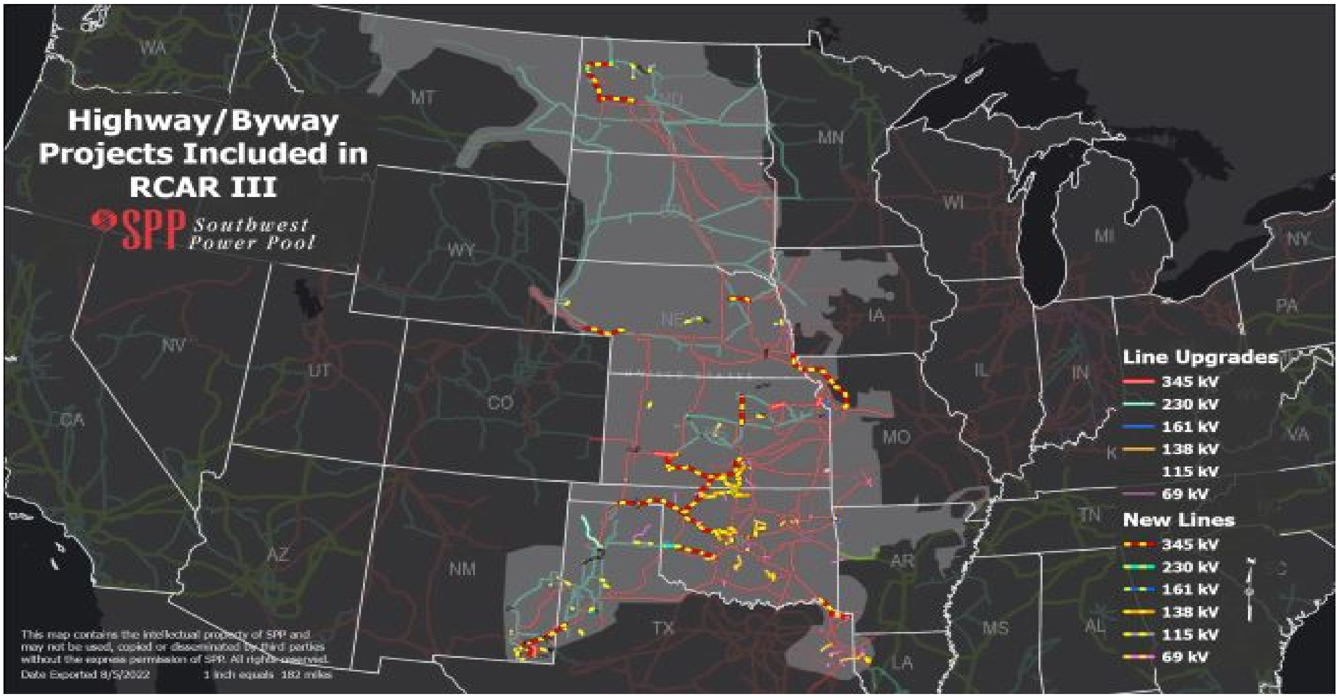
APPENDIX 3
RCAR PROJECT LIST

The RCAR III project list has been published at: https://www.spp.org/spp-documents-filings/?id=20184

The map below shows all Highway/Byway projects approved by SPP:



The map below shows the Highway/Byway projects included in the RCAR III analysis:



This map shows Highway/Byway projects approved by SPP but not included in RCAR III: