REGIONAL ALLOCATION REVIEW TASK FORCE

Approved on September 13, 2019

RCAR II Lessons Learned Report

REVISION HISTORY

DATE OR VERSION NUMBER	AUTHOR	CHANGE DESCRIPTION	COMMENTS
03/26/2019	Ben Bright	Initial Drafting	
09/06/2019	Ben Bright, Paul Suskie	Version 2.0	Finalize Draft Report
09/12/2019	Cindy Ireland (APSC)	Version 2.1	Edits
09/23/2019	Ben Bright	2.2	Additional non-substantive, ministerial edits

CONTENTS

EXECUTIVE SUMMARY

This Report contains the "lessons learned" from Southwest Power Pool's (SPP) second iteration of the Regional Cost Allocation Review (RCAR II) that was performed in accordance with the Regional Allocation Review Task Force (RARTF) Report as prescribed in Attachment J, Section III.D of SPP's Open Access Transmission Tariff (OATT).

The "lessons learned" contained in this Report were adopted by the RARTF on 09/13/2019 after having received and reviewed stakeholder comments and suggestions at the conclusion of the RCAR II assessment.

The concept of this Report was first raised in the 2012 RARTF Report and was further detailed in the RCAR I and RCAR II Report endorsed by SPP stakeholders in 2013 and 2016, respectively. The purpose of this Report is to evaluate "lessons learned" from RCAR I and RCAR II and to make "suggested improvements" to the RCAR process. These recommendations are to be incorporated into the RCAR III process.

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

RCAR II RECOMMENDATION NO. 1 – Use of the hybrid approach for RCAR III

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 early 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 Appendix 2.

RCAR II RECOMMENDATION NO. 2 – Projects to be reviewed

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 **as approved in the methodology in Section III.D.4.**

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.

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 process 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 done so in Word format rather than Excel as in the past.

SECTION 1: OVERVIEW OF LESSONS LEARNED PROCESS

1.1 BACKGROUND – THE RARTF REPORT AND RCAR I

In January 2012, the RARTF issued its report (RCAR Report), which established the methodology upon which the RCAR analysis would be performed the first Regional Allocation Review (RCAR I Report) as required under Attachment J.III.D to the SPP OATT. The RARTF Report was approved by the MOPC, the RSC and the SPP Board of Directors/Members Committee[1].

Based upon the recommendations contained in the RARTF Report, RCAR I was conducted from 2012 to 2013. RCAR I was finalized by the RARTF on October 8, 2013. Subsequently, the MOPC[2] and RSC[3] voted to accept the RCAR I Report during the October 2013 SPP cycle of stakeholder meetings.[4]

In addition to the results analyzing the reasonableness of the Highway/Byway transmission cost allocation methodology, the RCAR I Report contained three additional recommendations on next steps. The third recommendation was that:

> "the RARTF begin a process to evaluate "lessons learned" from SPP's first RCAR Report and finalize "suggested improvements" to the RCAR process by the January 2014 stakeholder meeting cycle. This recommendation will allow any improvements to be incorporated into the RCAR II process and will be in accord with Section 7.1 of the RARTF Report. At 6."

1.2 RCAR I APPROVED LESSONS LEARNED

At the conclusion of RCAR I in 2013 the RARTF provided an opportunity for stakeholders and SPP staff to submit comments and suggestions regarding the experiences in implementing the initial RCAR analysis. The following are the ten Lessons Learned recommendations approved by the RARTF in 2013 which were to be used in large part for conducting the second Regional Cost Allocation Review (RCAR II):

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

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[1] The RCAR I Report was reviewed in the SPP Stakeholder process in October 2013 with the following outcomes; October 8, 203 the RARTF "approved the report as modified"; on October 16, 2013 the MOPC "approved as meeting the requirements of the tariff" and on October 28, 2013 the SPP RSC "accepted the report as presented".

[2] *See* Agenda Item 17 at page 5 in the MOPC October 15-16, 2013 minutes posted on SPP's website at: https://spp.org/documents/21032/mopc%20meeting%20minutes%20&%20attachments%20october%2015-16,%202013.pdf.

[3] *See* "RSC Minutes 10/28/13" at page 4; https://spp.org/documents/21575/rsc102813.pdf.

[4] The RCAR I Report is posted as the "RCAR Final Report 10/10/13" on the SPP website at: https://spp.org/documents/37781/rcar%20report%20final%20clean.pdf.

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 recommendation 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.

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.

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.

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.

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.

RECOMMENDATION NO. 6:

That SPP staff evaluate remedies for zones below the threshold in the Notification to Construct (NTC)-only review for RCAR II.[5]

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.[6]

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.[7]

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.

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:

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[5] Based on RCAR I Recommendation No. 10 this recommendation should reflect that staff will evaluate remedies for zones below the threshold based on a review of the upgrades that have been approved for construction after June 10, 2010.

[6] Per Lessons Learned Recommendation No. 7, SPP Staff facilitated a stakeholder process to develop revisions of the SPP OATT for the purposes of clarifying and ensuring consistency in the treatment of Point-To-Point (PTP) revenue credits for calculating rates. This set of revisions allows PTP revenue credits to be more consistently applied to transmission owners' revenue requirements and helps in projecting a more reliable method in estimating future PTP revenues 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.

[7] In FERC Docket No. EL-19-62, City Utilities of Springfield, Missouri vs. Southwest Power Pool, Inc., FERC denied the Complaint against SPP. The order denying the Complaint contained language that supports the process adopted in developing the original RARTF Report and the subsequent RCAR I and RCAR II Reports. Particularly regarding remedies.

> 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.

All ten of these recommendations were ultimately approved by the RARTF, MOPC and RSC[8] and provided to SPP staff to be used in the RCAR II analysis. Recommendation No. 10 was filed with and approved by FERC on December 22, 2014.[9]

1.3 RCAR II STAKEHOLDER COMMENTS AND SUGGESTIONS

At the conclusion of the RCAR II analysis in October 2016, the RARTF again asked stakeholders to provide comments and suggestions. The RCAR II Lessons Learned process mirrored the process used in the 2013 RCAR I analysis. Responses were received from the following stakeholders:

- American Electric Power (AEP)
- City Utilities of Springfield (CUS)
- Empire District Electric Company (EDE)
- ITC Great Plains, LLC (ITC)
- Kansas City Power & Light Company (KCPL)
- Lincoln Electric System (LES)
- Omaha Public Power District (OPPD)
- Sunflower Electric Power Corporation/Mid-Kansas Electric Company, Inc. (SUNC)

A list of the specific comments and suggestions can be found in Appendix 1 to this report and a general overview of the comments and suggestions from stakeholders are summarized in the chart below:

Entity/Category	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
Total	3	18	3	11	2	3	40

[8] 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

[9] SPP Staff facilitated Lessons Learned Recommendation 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.

The RARTF has reviewed these suggestions multiple times and agreed to postpone any action on the suggestions until the Task Force decides on a methodology to be used when conducing the RCAR III analysis.

SECTION 2: RCAR II LESSONS LEARNED AND RECOMMENDATIONS

2.1 RECONFIRMATION AND EXTENSION OF RCAR I LESSONS LEARNED ITEMS

The RARTF recommends continued utilization of the applicable lessons learned contained in the 2013 RCAR I Lesson Learned Report. Of the forty suggestions/comments received from stakeholders after the RCAR II assessment twenty-six can be generally addressed by continuing to utilize the Lessons Learned recommendations adopted after the RCAR I assessment.

2.2 RCAR II LESSONS LEARNED ITEMS

Of the remaining stakeholder suggestions and comments from RCAR II the RARTF agrees that the following items should be addressed prior to the next RCAR assessment.

RCAR II RECOMMENDATION NO. 1 – Use of the hybrid approach for RCAR III

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 early 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 Appendix 2.

RCAR II RECOMMENDATION NO. 2 – Projects to be reviewed

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

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This change is a reflection of the fact that as futures 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 project in-service.[10] 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 tariff 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 MOPC and RSC to forgo any further cost allocation analysis for projects not yet in-service at that time.

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

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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 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 done so in Word format rather than Excel as in the past.

[10] As of the drafting of the RCAR II Report, 274 of the 503 Highway/Byway-funded upgrades subject to the RCAR II review are in service, as compared to 48 of 298 projects in RCAR I. See RCAR II Report on page 27 at https://spp.org/documents/46235/rcar%202%20report%20final.pdf.

APPENDIX 1: STAKEHOLDER COMMENTS

Item #	Company	Issue Description	Date Submitted
		Assumptions	
A-1	Lincoln Electric System	The RARTF and SPP should provide additional information on the calculations performed to determine how RARTF/SPP arrives at the value of the wind energy rate, set at $8/MWh for RCAR II. Further, RARTF and SPP should reevaluate whether the $8/MWh is still an appropriate rate for wind.	8/5/2016
A-2	Sunflower Electric Power Corporation/Mid-Kansas Electric Company, Inc.	**Issue:** Key assumptions do not seem up to date. RCAR II did not discuss sensitivities in as much detail as RCAR I. In the October 8, 2013 RCAR, natural gas costs were projected to be $4.18 in 2012 rising to $4.89 in 2018 and $9.48 in 2033. Coal and gas prices in the 2012-2016 years were much lower than projected and presumably had a detrimental impact on the B/C that is not apparent. Page 47 of the 7/11/16 RCAR II report states "RCAR II includes approx. 15-30% higher natural gas and coal price assumptions compared to RCAR I." As of today (7/22/2016) the Henry Hub Nymex Natural Gas Futures Annual Strip is $3.06 for 2020 compared to RCAR II $6.03 and $3.87 for 2025 compared to $7.26. The RCAR II report also states "...increasing gas prices by 27.5% would result in 18% higher APC savings." Since historical actual fuel prices were in fact lower, at times by more than 50%, in the more heavily weighted first years, APC savings should have declined by up to 36%. Current available futures prices are substantially lower than the RCAR forecast. Additionally, RCAR II reports greater savings from increased load forecasts. There has been significant discussion of lower overall forecasts in SPP. **Recommendation:** Maybe it is just timing of cut offs, but given that natural gas prices and futures have been lower than the RCAR I price forecasts for nearly 18 months, should the prices be more up to date? Ongoing reporting of expected sensitivity impacts, even if based on prior studies would also be helpful.	8/4/2016

A-3	Sunflower Electric Power Corporation/Mid-Kansas Electric Company, Inc.	**Issue:** RCAR appears to attribute benefits to transmission that are not, or only partially, due to transmission, as demonstrated at Page 47 of the 7/11/16 RCAR II report stating one of the key drivers of higher APC savings is "RCAR II includes 19-24 GW of installed renewable capacity...which is substantially higher compared to the 8 GW assumed in the RCAR I study." Introduction of low marginal cost energy sources (whether renewable or NGCC in low gas markets) will naturally lower market energy prices. This benefit cannot be entirely attributed just to incremental transmission. Generation technology and siting benefits on APC can be fully realized in wind/solar rich zones with minimal transmission upgrades beyond those required by the GI and TSR studies. APC reductions due to the addition of new renewables and the related transmission upgrades that would result from GI and TSR studies are a generation technology and siting choice benefit, not a transmission benefit. This benefit of the generation technology on APC can be fully realized in wind/solar rich zones with minimal transmission upgrades beyond those required by the GI and TSR studies. **Recommendation:** RCAR needs to ensure that all projected generation, with the transmission upgrades that would be required by the GI and TSR studies, are included in the base case. This will lessen the chance that the natural benefits of new generation and its siting are not attributed solely to transmission.	8/4/2016
		Benefits / Calculations	
B-1	American Electric Power	It appears the RCAR process does not adequately evaluate the benefits of the grid to smaller zones. Smaller zones being those transmission zones that are well below average in size and have limited throughput in terms of transmission facilities either existing or regionally constructed. Such zones, at times, appear to have limited APC and other benefits, when in fact they benefit disproportionately by merely being part of the larger planning region. The fact some of such zones rely upon, at times, other zonal facilities the region to move remote Designated Resources at little or no cost. Due to their limited grids and throughput offered to the broader region smaller zones offer very little in terms of the reciprocal. In addition to the existing metrics, and in particular for those zones in the lower 25% quartile in terms of size, SPP should include a new metric reflecting the benefit of not having to pay schedule 9 rates of intermediate zones between the smaller zone and its remote resources.	6/17/2016

B-2	City Utilities of Springfield	Mitigation of Transmission Outage Costs Benefit - The APC savings component of this benefit metric utilizes historical outage data. The historical outage data was not updated for RCAR II (RCAR I data was used). It is recommended that historical outage data be updated for RCAR III purposes. The Benefit Metrics manual indicates that attempts will be made to select a relatively normal recent year for historical transmission outages, and to avoid years that might be outliers due to extreme weather or other factors. The time period for outages studied was December, 2011-November, 2012. This period is after the Joplin tornado of May, 2011. However, the summer of 2012 was an extremely hot summer with a drought, so this time period was not representative of a normal year. Rather than just using one outage scenario and assessing benefits based on that one scenario, consider using a base scenario and several change scenarios. The change scenarios would include minor to major outages, with the various outage scenarios weighted accordingly. The most likely scenarios would be weighted the most.	8/5/2016
B-3	City Utilities of Springfield	Potential overlapping of benefits between Adjusted Production Cost (APC) savings and Assumed Benefit of Mandated Reliability Projects - Recommend for future RCAR reports that supporting information be provided that will allow stakeholders to easily discern that there is no double counting of benefits between APC savings and Assumed Benefit of Mandated Reliability Projects.	8/5/2016
B-4	City Utilities of Springfield	Avoided or Delayed Reliability Projects - Recommend a review to ensure that this benefit is not also captured under APC Savings. For example, if a project addresses thermal reliability it may have already been captured in the PROMOD simulation. This could occur if there are hours in the BASE case where there are constraints violated (which result in either Emergency energy or Dump energy) and in those same hours the issues are mitigated in the CHANGE case. The result would be that the thermal reliability issues related to the Avoided or Delayed Reliability Projects are already being captured in the APC Savings calculation.	8/5/2016

B-4	City Utilities of Springfield	Reduced Capacity Costs Due to Reduced Losses on Peak - Recommend a review to ensure that this benefit does not overlap with the Marginal Energy Losses Benefit. Both benefits attempt to place a value on transmission losses alleviated by a new project. The Reduced Capacity Costs Due to Reduced Transmission Losses on Peak benefit attempts to capture the value of generation capacity no longer required due to a reduction in losses during the system peak. The Marginal Energy Losses Benefit attempts to value the transmission losses based on energy saved.	8/5/2016

B-5	City Utilities of Springfield	Assumed Benefit of Mandated Reliability Projects - Benefits under this metric are allocated as follows: • Less than 100kV -100% System Reconfiguration • 100-300kV - 2/3 System Reconfiguration, 1/3 Load Ratio Share • Greater than 300kV - 1/3 System Reconfiguration, 2/3 Load Ratio share Per the Benefit Metrics Manual, "The System Reconfiguration method measures the incremental flows shifted onto the existing transmission system during an outage of the reliability upgrade being evaluated. It is a proxy for how much the reliability upgrade reduces flows on the rest of the system. Lines with increased flows after the reliability upgrade is taken out of service are identified as beneficiaries of the reliability upgrade". Based on the explanation of the System Reconfiguration method, a general assumption could be made that the local area surrounding the upgrade would receive the most benefit (especially at lower voltages). Upon review of the system reconfiguration allocation (by project) worksheet provided by SPP, we noticed that twelve 69kV projects (with ATRR's of ~$65.6M) had benefits allocated to surrounding zones, but no benefits allocated to the host zone. These twelve projects included 69kV capacitor banks, rebuilds of 69kV lines and 115/69kV transformers. We also noticed ten 115/138kV projects (with ATRR's of ~$65.3M) that had no benefits allocated under the system reconfiguration method to the host zone, but did have benefits allocated to surrounding zones. These ten projects consisted of various line projects. We identified the 22 projects above as our zone had benefits allocated from them. There may additional similar projects affecting other zones.We recommend that the above mentioned projects be investigated (especially the 69kV capacitor banks) to determine why the host zone is not being allocated any benefits for what are essentially local projects. We can supply SPP with this list. If it is determined there is an issue in applying the System Reconfiguration method for certain 69kv and 115/138kV projects, we recommend a solution be proposed to ESWG (for approval prior to RCAR III). We also recommend the explanation of the System Reconfiguration method calculation in the Benefit Metrics manual be expanded prior to RCAR III.	8/5/2016

B-5	Kansas City Power & Light Company	KCPL supports the RARTF recommendations that the next RCAR process should include: 1. A review of how projects are classified in the ITP process, 2. The reasonableness of assuming a 1:1 benefit-to-cost assumption for the Assumed Benefit of Mandated Reliability Projects, and 3. The impacts of the hybrid LRS/System Reconfiguration allocation approach for Assumed Benefit of Mandated Reliability Projects.	8/1/2016
B-5	Sunflower Electric Power Corporation/Mid-Kansas Electric Company, Inc.	**Issue:** The allocation of assumed reliability benefits is not appropriate. The allocation of the assumed benefit of reliability projects is based on a blend of two allocators. Neither allocator actually identify the customers receiving the benefits. One allocation associated with load ratio share assumes that benefits follow costs. This approach ignores benefit received by customers. The allocator for system reconfiguration assumes that benefits follow the geography of physical facilities. Blending two metrics that do not identify the beneficiaries does not create a metric that does. **Recommendation:** Benefit allocations need to be related to customers. To improve and ensure that benefits assigned to pricing zones or assigned geographically are properly identified to the customers receiving those benefits, RCAR needs to account for non-zonal customers benefiting from geographic zonal benefits.	8/4/2016

B-5	Sunflower Electric Power Corporation/Mid-Kansas Electric Company, Inc.	**Issue:** RCAR II introduced a new allocator - "system reconfiguration". This has been described as a measure of "flow relief" on existing lines. The beneficiaries of flow relief are those that contribute to flow. In the Sunflower/Mid-Kansas zones, zonal customers with load in the pricing zone currently consume less than 50% of the energy generated plus imported into the pricing zone (contribute less than 50% to flow). Future projects are already in progress or planned that will reduce that ratio further. It is unclear how RCAR identifies the beneficiaries of flow relief. It is also unclear how the concept of system reconfiguration/flow relief differs from the other quantified benefits of avoided or delayed reliability projects, capacity savings from reduced on-peak losses, marginal energy loss benefits, reduced cost of extreme events, reduced loss of load probability, and capital savings from reduced minimum required margin, all of which are in part or in total the result of reduced line loading. **Recommendation:** We do not think that flow relief identifies a new benefit without also identifying who is using the facility and whether the load relief was necessary. Unnecessary load flow relief does not provide any benefit. RCAR should describe more fully the benefits of system reconfiguration and how it differs from the other quantified benefits. RCAR should describe more fully how the benefiting customers contributing to flow are identified. If this metric continues to be used an appropriate criteria must be developed that takes into account the reasons why the facilities need to be relieved.	8/4/2016

B-5	Empire District Electric Company	Upon reflecting on the present RCARII study results, Empire feels that improvements could be found. One item that was omitted from the results was applying a weighting factor to the impacts that were exhibited from various projects. The benefits from such projects were inflated due to the fact that specific model response(s) were not taken into account after such projects were applied to the models. Case in point:One of the projects which exhibited benefit to the Empire area was a new Coweta capacitor bank (see diagram below to exhibit connectivity to EDE system). As shown in the simplified one line diagram, the connectivity between the AEP_Coweta & AECI_Coweta stations (far left of the diagram and highlighted) and the EDE 69kV system at Decatur (far right of the diagram and highlighted). Please note not all lines connected to all the buses in between the respective systems are displayed to aide in the presentation of the connectivity :	8/5/2016
B-5	Sunflower Electric Power Corporation/Mid-Kansas Electric Company, Inc.	**<u>Issue:</u>** It does not appear that RCAR has followed its stated position to: "[c]onservatively assumes reliability standards have a benefit-cost ratio of only 1.0.” It appears that in addition to the B/C of 1.0 it has included additional benefits from reliability projects in the other quantified metrics of RCAR. This has the effect of: 1) Doubling up the impact of other identified reliability benefits; 2) creates a benefit floor of 1.0 that is, in fact, significantly higher when coupled with the other benefits, including APC, produced by the reliability projects; and 3) masks the B/C ratio of non-reliability projects. **<u>Recommendation:</u>** The RCAR should be corrected to align with its stated position on the 1.0 B/C benefits of reliability projects.	8/4/2016
B-6	City Utilities of Springfield	We recommend that the Benefit Metrics Manual be reviewed and updated by ESWG prior to RCAR III. We request that more detailed explanations of each metric and the related calculations be added.	8/5/2016

B-7	Sunflower Electric Power Corporation/Mid-Kansas Electric Company, Inc.	**Issue:** Benefits from avoided costs that cannot in fact be avoided should not be counted. Example 1: RCAR does not appear to fully consider the near-term realizability of benefits. One example is capacity savings, both from on-peak losses and from reduced minimum required margin. Near term impacts have a larger impact on PV of costs and benefits. The impact on customers is dependent on 1) the term of existing capacity commitments, and 2) the market value of excess capacity. In the near-term many load serving entities will not be able to reduce their fixed commitments for capacity. SPP currently has excess capacity. The value of excess capacity will likely remain well below the CONE until the regional excess is significantly reduced.Example 2: Another example is APC. Many load serving entities made long term power supply commitments before the development of the energy markets. The promised market benefits cannot be realized in the short-run, or even in the long-run. For example, many early wind contracts signed to meet RES requirements were effectively take-or-pay for 20 years. Acting as a 20-year energy price hedge, lower priced market energy will not bring benefits to customers for that portion of their portfolio. Sunflower and Mid-Kansas have significant take-or-pay energy price commitments that pre-date its membership in SPP and other commitments entered into to satisfy RES requirements or agreements. Example 3: Another area is mitigation of transmission outage costs. Many entities may have already hedged their transmission outage risks through TCRs. **Recommendation:** RCAR should consider the near-term and long-term realizability of benefits, as these can significantly impact the present value of benefits. The largest single benefit is APC. RCAR should consider the duration of pre-existing energy hedges when evaluating the realizable benefits of transmission. Additionally, RCAR should consider the near-term realizability of other benefits including, but not limited to, capacity savings and mitigation of transmission outage costs.	8/4/2016

B-8	Sunflower Electric Power Corporation/Mid-Kansas Electric Company, Inc.	**Issue:** Unless it can be objectively demonstrated that trapped generation zones benefit from transmission, the APC benefit attributed to those zones should be assumed to be zero, not positive. The hybrid method of allocating APC inappropriately penalizes renewable rich zones. The method used was not the preferred method recommended by the task force and the outside consultant. The method removed 5.2-5.9GW of wind then attributed to wind saturated zones a portion of the regional APC benefits associated with adding the wind back. Much, if not all, of that benefit is the result of the abundant availability of the natural resource (wind/solar) in those zones, not from transmission. Transmission to export wind from wind saturated zones does not result in any APC benefits, unless it can be demonstrated that it adds import capacity that is both needed and beyond what was previously available. In general, the APC in trapped generation zones (whether gas, coal, or renewable) is depressed by multiple factors: the abundance of natural resources, the choice of the generator to site in the zone, a lower marginal production cost from the trapped generation, and the lack of transmission to export the generation. Three of these components are not related to the general availability of transmission (beyond what is required by GI and TSR studies). Adding transmission reduce the negative congestion price component to the point where the zonal energy price equals the regional energy price. Therefore, the APC benefit of transmission for trapped generation zones is best quantified as zero. **Recommendation:** RCAR should consider changing is allocations to renewable saturated zones to recognize the limited APC benefits actually available from transmission. This impacts not only the APC benefit allocation, but also mitigation of transmission outage costs, and reduced cost of extreme events.	8/4/2016
B-8	Sunflower Electric Power Corporation/Mid-Kansas Electric Company, Inc.	**Issue**: Sunflower is the host of a lot of wind. Nameplate wind in our zone exceeds our load by 2-3 times. RCAR allocates many benefits to our geographic area. It then assumes our load benefits 100%, while most of the wind energy exits our system. **Recommendation:** RCAR needs to consider such a situation where local load is not the predominate user of the transmission system. A different method we propose is to use a “but for” test. Another suggestion would be to develop a threshold level of energy export at which benefits are attributed to the exported energy.	8/4/2016

B-9	Sunflower Electric Power Corporation/Mid-Kansas Electric Company, Inc.	**Issue:** Clarification of methodology. Are benefits only analyzed relative to the flow-gate constrained hours, the on-peak configuration, or relative to the 8760 utilization? If analyzed on peak hour, are renewables included at nameplate or accredited capacity or historical actual? **Recommendation:** For each allocation methodology, more clearly identify the underlying allocation (peak hour, multi-seasonal, 8760, interpolated from a base, etc.)	8/4/2016
		Costs and Offsets	
C-1	City Utilities of Springfield	Ptp and MISO Revenue Offset - Recommend review of the daily and hourly on-peak and off-peak through and out rates. The monthly rates are calculated as the annual rate divided by 12 months. The weekly rates are calculated as the annual rate divided by 52 weeks. The daily rates are separated into peak and non-peak rates. The daily peak rate is calculated as the weekly rate divided by 5 (for 5 peak days). The daily non-peak rate is calculated as the weekly rate divided by 7 (for 7 total days). A problem occurs when a reservation is made for 5 peak days, plus one or two non-peak days in a week. That total will exceed the weekly rate. This could lead to an overstatement of Ptp revenue. The same situation exists for hourly peak and non-peak Ptp revenue. Point to point volumes were determined by averaging the through and out revenues for the years 3/1/14-2/28/15 and 3/1/15-2/29/16 (the first two years of the Integrated Marketplace). There is a noticeable drop-off in Ptp revenues since the start of the Integrated Marketplace, as grandfathered agreements expire, etc. We recommend future studies use the most recent year and project it forward, rather than using an average since the beginning of the Integrated Marketplace. Older historical data in a changing marketplace is not an accurate predictor of future volumes.	8/5/2016
C-2	Sunflower Electric Power Corporation/Mid-Kansas Electric Company, Inc.	**Issue:** Point to Point revenue is treated differently from other benefits in the RCAR calculation of B/C. The cost of a project is the cost of a project. The revenue and cost savings potential of a project are its benefits. **Recommendation:** All revenues and benefits should be included in the numerator of the B/C ratio and all costs of the projects should be in the denominator.	8/4/2016

C-3	Sunflower Electric Power Corporation/Mid-Kansas Electric Company, Inc.	**Issue:** Z2 costs have not been included. **Recommendation:** Z2 costs should be added to the cost side of the RCAR.	8/4/2016
		Process	
P-1	City Utilities of Springfield	Stakeholder Comments Form - As the majority of stakeholder comments are submitted in text, we recommend that future submission forms utilize Word (rather than Excel). This will allow the use of more word processing tools than are available in Excel.	8/5/2016
P-2	City Utilities of Springfield	Ability to identify changes between RCAR studies - Recommend that SPP provide data to stakeholders that will allow them to easily identify changes/results between RCAR studies. Suggestions could be: Consider providing a secondary CHANGE case which includes only projects that were included in RCAR I only and RCAR II only. Consider summarizing the differences between RCAR I, RCAR II and RCAR III network topology, natural gas price assumption differences, generation and load, etc.	8/5/2016
P-2	Sunflower Electric Power Corporation/Mid-Kansas Electric Company, Inc.	**Issue:** Compared to RCAR I, RCAR II reports $2.7B of increased 40 year ATTR costs and $11.2B of increased benefits ($1.1B is for two new benefit metrics). While most would expect to see diminishing returns from incremental projects, that does not appear to be the case with RCAR II. The overall B/C increased from 1.4 to over 2.4 and change from RCAR I to RCAR II was an incremental B/C of 3.7. Although total 40 year PV of ATRR only increased $2.7MM, the assumed 1:1 benefits of reliability projects increased $3.3B. Clearly there are many moving parts to this analysis that are not explained by the report. Such an explanation would help SPP Membership understand the accuracy of the results of the study. **Recommendation:** Report should discuss more quantitatively what has changed and why. How did $2.7B of increased costs result in $11.2B of increased benefits, when $5B of costs in RCAR I only produced $6.4B of benefits? Such discussion should include more quantitatively explicit discussion of the change in PV of ATRR by category; more quantitatively explicit discussion of changes in the underlying assumptions (load, fuel, new projects, etc.) and how they quantitatively impacted the overall results. The reports should include a comparison of projected and actual results for each actual year completed.	8/4/2016

P-3	ITC Great Plains, LLC	The RCAR should be conducted as close as possible to its associated ITP portfolio and should use the same model assumptions. It is challenging (and potentially inadvertently misleading) to create an ITP portfolio under 1 set of assumptions, then use a different set of assumptions to assess the equity of the cost allocations.	8/3/2016
P-4	Kansas City Power & Light Company	The details behind benefit metric calculations should be provided to members when completed, rather than members having to request the data through the stakeholder feedback process. Given the magnitude of APC benefits, SPP should provide details by zone of the production costs, purchases, and sales components, as well as explanations of material changes from prior RCAR reporting. Sharing the detail support for benefit computations should not be limited to the APC benefits, but should also include background for other benefit calculations such as the Marginal Energy Losses benefit.	8/1/2016
P-4	Kansas City Power & Light Company	The RCAR schedule should include time to present the detailed benefit metric calculations to the ESWG and any other appropriate working groups prior to the release of a draft RCAR report, so there is an opportunity for questions and clarifications prior to the release of B/C ratios and the pursuit of remedies for deficient zones. A benefit metrics review period was initially part of the RCAR II schedule and was set to occur prior to the draft RCAR report being presented to the RARTF. However, issues that occurred with the modeling essentially eliminated that review period from the schedule.	8/1/2016
P-4	Sunflower Electric Power Corporation/Mid-Kansas Electric Company, Inc.	**Issue:** Stakeholder Input – Stakeholders did not have an adequate time to fully evaluate the assumptions, calculations and impacts of the RCAR II report. **Recommendation:** Either through a business practice or tariff revision, imposed a requirement that stakeholders have a minimum of 3 months to review any RCAR report prior to obtaining MOPC approval.	8/4/2016
P-5	Kansas City Power & Light Company	An alternative to using a project baseline of June 2010 needs to be developed, as the RCAR model will likely no longer solve in the future given the large amounts of renewable generation (in particular, wind generation) and the resulting 'trapped generation' when transmission projects dating back to 2010 are excluded from the model.	8/1/2016

P-5	Sunflower Electric Power Corporation/Mid-Kansas Electric Company, Inc.	**Issue:** Principle 3 of RCAR II, states "Use the Best Information Available." RCAR II looks only prospectively at benefits and costs. One of the principles for RCAR II is "equity over time." As described by Brattle, costs tend to be front loaded and benefits back loaded. Many of the benefit assumptions assume benefits increase each year, while cost declines. Many projects are Net Plant * NPCC cost driven. This means that as much as 40% of the cost (ATRR NPV) is in the first 5 years of the project. A project that initially has a B/C of 1.0 could appear to have a future B/C of 1.25 after 5 years. This means that if one looks only at future years, each year that passes creates a higher and higher B/C ratio for each project. This approach masks the very real historical costs imposed on the customers and creates a rosier and rosier picture of the B/C of transmission by the mere passage of time. Known historical data is more accurate than projected and assumed data. **Recommendation:** In order to achieve "equity over time," all periods from June 2010 should be included and should be evaluated from inception to year 40, not just from today to year 40. The B/C ratio of a project should not be dependent merely on the passage of time. High cost years should not be removed.	8/4/2016
P-6	Sunflower Electric Power Corporation/Mid-Kansas Electric Company, Inc.	**Issue:** We are puzzled by the lack of public policy projects in RCAR. Every time SPP models anticipated generation and the transmission required for that anticipated generation they are creating public policy transmission projects. We believe such projects should be identified as such. **Recommendation:** RCAR should evaluate a scenario that has no anticipated additional generation and no related transmission. This scenario will provide the minimum transmission required to serve the load, and can be the base for separating reliability projects from public policy projects.	8/4/2016
P-6	Sunflower Electric Power Corporation/Mid-Kansas Electric Company, Inc.	**Issue:** RCAR benefits may not align with rate impacts. **Recommendation:** Conduct a rate impact study concurrent with the RCAR evaluation and include rate impact results in the RCAR report and recommendations.	8/4/2016
		Remedy	

R-1	ITC Great Plains, LLC	The SPP Board should incorporate more transparency into the Remedy Determination process. The decision process should be reviewed at the RARTF and the RSC, in addition to the MOPC and BOD. The deficient entity should not be able to choose remedy determination without stakeholder input. The existing Transmission Planning Processes provide many opportunities for input, and as this is a "remedy process" for Transmission costs, it should by extension also have points for stakeholder input.	8/3/2016
R-2	Lincoln Electric System	The RARTF and SPP should consider the length of time that elapses between an entity falling below the 0.8 benefit to cost ratio threshold and when a potential remedy will bring that entity above the 0.8 benefit to cost ratio threshold.	8/5/2016
		Threshold	
T-1	City Utilities of Springfield	Benefit/Cost Remedy Threshold - The benefit/cost ratio remedy threshold should be increased from .8 to at least 1.0. The original justification for using the .8/1.0 benefit/cost ratio remedy threshold in RCAR I was that few projects were actually in service at that time and not all of the benefits were being captured in the six benefit metrics calculated. At the time the RCAR II report was issued, 274 of the 503 Highway/Byway funded upgrades subject to the RCAR II review are in service (54%). These upgrades account for 41.5% of the cost of the Highway/Byway funded upgrades. There is now considerably less uncertainty than in RCAR I. The RCAR II report incorporates benefit calculations from eight metrics, which is two more than in RCAR I. The Economic Studies Working Group spent several months adding new metrics, reviewing the calculation and allocation of the existing metrics and proposing changes to the existing metrics. All of the proposed ESWG changes were adopted and incorporated into the RCAR II report. The average benefit/cost ratio for RCAR I was 1.39, with five zones below .8 and another five with thresholds between .8 and 1.0. The average benefit/cost ratio for RCAR II was 2.45 (a 76% increase), with one zone below .8 and two zones between .8 and 1.0. With the average benefit/cost ratio increasing 76% from RCAR I to RCAR II (to 2.45/1.0), the .8 benefit/cost ratio remedy threshold is no longer reasonable. As demonstrated in the table above, 14 of the 17 zones (82%) have benefit cost ratios in excess of 1.0. Ten of those fourteen zones have a benefit/cost ratio in excess of 2.0/1.0. Any zone with a benefit/cost ratio of less than	8/5/2016

		1.0 is clearly not benefitting in the same proportion as a large majority of the other zones. It is reasonable for a zone to expect (at a minimum) to receive benefits at least equal to their investment (cost) incurred.	
T-1	Lincoln Electric System	The RARTF and SPP should reevaluate whether the 0.8 benefit to cost ratio is the appropriate threshold to be used in RCAR III.	8/5/2016

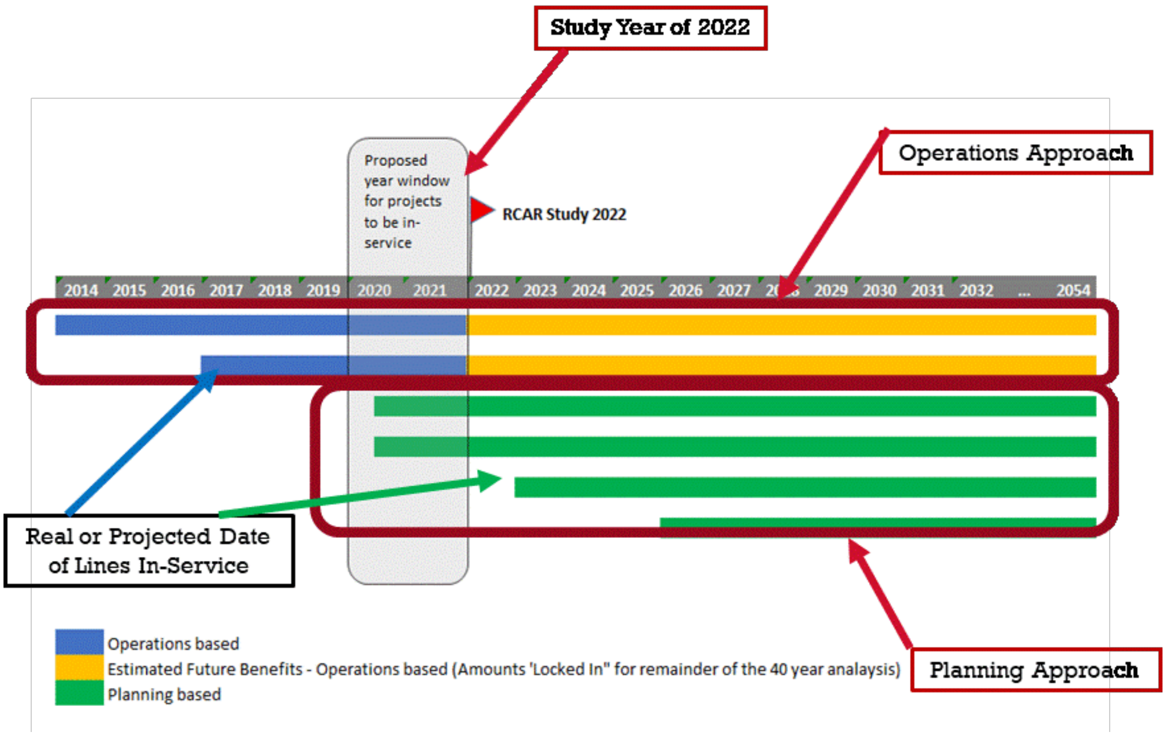
APPENDIX 2: HYBRID APPROACH FOR RCAR III

Since the conclusion of the RCAR II analysis in October 2016, the RARTF has been 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.[11] 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 and capture the Adjusted Production Cost (APC) benefits were so voluminous that models would not solve without manual interventions and created results that were skewed 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 these generation additions were removed the generation became "trapped" in the local areas and skewed the results.

Ultimately, the RARTF has agreed to recommend that a hybrid approach (see Figure 1 below) be utilized in the calculation of benefits for RCAR III. Under this hybrid approach there will be an operations based approach that will be used for those upgrades that have been in-service for at least 2 years prior to the beginning of the RCAR analysis and a planning base approach for those projects that have been approved for construction but not yet in-service or have not been in-service for at least 2 years. At the conclusion of these two processes the benefits will be added together to get a complete benefit projection. Actual reported costs will then be used as a divisor to calculate the benefit-to-cost ratio for each transmission pricing zone.

[11] SPP's OATT originally called for a RCAR analysis to be conducted "at least every 3 years." Based upon the recommendation of the RARTF, SPP stakeholders and FERC approved extending this 3 years to 6 years. See FERC Docket No. ER17-2229.

Figure 1 – Proposed Hybrid Approach for RCAR III



To further develop the hybrid approach the RARTF approved 5 policy recommendations on February 27, 2019[12] to help guide staff in their work. These policy decisions were:

1. From a historical case perspective, the RARTF approved a staff recommendation to complete a limited number of operations based historical cases (~72-120 cases in total) over 1-2 years. This limited option was recommended and chosen because the processing of historical cases is time and resource intensive. This motion passed 8-1.[13]
   For the going forward cases, beginning in January 2020 or as soon as possible, staff will begin processing the operational cases on a daily basis. The RARTF also recommend that staff automate this operational case processing. This motion passed unanimously.

2. The RARTF recommended that the results of the operational cases be used to calculate the benefits for remainder of the 40 year assessment period. To complete this operations data will be used to interpolate the data points from the market case runs up to the RCAR study year and then will be extrapolated out to study year 20. This motion passed 8-0 with one abstention.[14]

3. The RARTF recommended that a transmission facility be in-service for two years before being included in the operations based approach. Those facilities that have not been in service for the

[12] See February 27, 2019 RARTF Meeting minutes at https://spp.org/documents/59666/rartf%20minutes%20&%20attachments%2020190227.pdf
[13] Xcel Energy Services Inc./Southwestern Public Service Company (Xcel) voted against this motion, preferring to only have staff run historical cases on an as needed basis.
[14] Xcel abstained on this vote.

two years would then have their benefits measured as part of the planning based approach for this RCAR analysis. This motion passed 8-0 with one abstention.[15]

4. With this recommendation the RARTF looked five specific benefit metrics that are not specifically included in the results of the operational cases and made a recommendation for each on how they should be calculated and included in the RCAR III analysis.

    a. Avoided or Delayed Reliability Projects – Projects built for economic and policy reasons that displaced reliability projects that would have otherwise been built. Staff recommended that they utilize the data calculated from previous ITP reports for this metric. The RARTF agreed with this approach by an 8-1 vote.[16]
    b. Capacity Savings Due to Reduced On-Peak Transmission - Reduction in losses due to transmission upgrades means less generation build out required for capacity margin requirement. Staff recommended that they utilize the data calculated from previous ITP reports for this metric. The RARTF agreed with this approach unanimously.
    c. Assumed Benefit of Mandated Reliability Projects - There is a benefit associated with having a reliable system and it is monetized as the total cost of reliability projects. Staff recommended to use a technical approach to capture flow data from the operational cases, develop economic models and allocate the benefits. The RARTF accepted this recommendation with an 8-1 vote.[17]
    d. Benefits from Meeting Public Policy Goals - There is a monetary benefit associated with meeting public policy mandates and goals through transmission projects. Staff recommended that since we do not have any projects to date assigned to this category that ITP calculated benefits should be used for RCAR III, if needed. The RARTF accepted this recommendation unanimously.
    e. Increased Wheeling Through and Out - Increased ATC from transmission projects increases import and export opportunities for the SPP footprint. Staff recommended the use of historical settlements data to analyze additional service being sold relative to estimated ATC increases created by the increased transmission. The RARTF accepted this motion unanimously.

5. The RARTF reviewed the options for valuing the purchases and sales transactions in the operational cases. The RARTF had asked for the Market Working Group to review and make a recommendation on the best course of action. The MWG recommended using load-weighted zonal Locational Marginal Price (LMP) for Purchases and generation-weighted zonal LMP for Sales. The RARTF accepted the MWG recommendation unanimously.[18]

Beginning in January 2020, or as soon as possible, staff will begin capturing daily operational cases from the Integrated Marketplace cycles. These original cases will be stored and utilized as the base cases for RCAR purposes. Those transmission facilities that were approved as Highway/Byway facilities and that have met the 2-year threshold for inclusion in the operation approach will then be removed and create a change case. That change case will be reprocessed through the market engine and those differences between

[15] Xcel abstained on this vote.
[16] Xcel voted against this motion.
[17] Xcel voted against this motion.
[18] See February 19, 2019 MWG Meeting Minutes on page 4 at https://spp.org/documents/59578/mwg%20minutes%20&%20attachments%2020190219.pdf

the base case and change case will be captured. The difference between the cases will reflect 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. The other five approved and monetized metrics will be addressed as described in the RARTF policy recommendation #4 in the paragraph above. 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.

The planning based approach is a status quo approach from RCAR I and RCAR II. It will continue to utilize planning models and forecasts to calculate the benefits metrics for those projects that have been approved for construction and are not yet in-service for the 2 year threshold recommended by the RARTF. Unlike the operations based approach that will process daily for the future cases, the planning based approach will only be run when an RCAR study is required and will continue to utilize the latest annual ITP models and assumptions.