Costs an

Item #	Description
CUS-13	Total Cost Allocation - Total cost (PV of 40-year ATRR's) are listed as $7,382M on ESWG slide 3. Could we get a breakdown (listing) of how this total was determined. How was this total allocated to zones, specifically CUS?
CUS-14	PtP and MISO Revenue Offset - Could we get some support for the total calculation for the PtP and MISO offset revenue and how the CUS amount was determined?
KCPL-5 OPPD-1	How has the MISO revenue for use of SPP transmission facilities been captured in the RCAR study? Is it assumed over the entire 40-year period or a shorter time? There is mention of this on page 18 of the draft RCAR II report. Revenues from the MISO settlement for unscheduled flow are included throughout the 40 year window; however, the MISO settlement agreement is only a 7 year agreement. Including such revenues that cannot be reasonably relied on can artificially inflate the benefits, and consequently should not be included beyond the term of the settlement agreement.

Xcel-4	Revenues from the MISO settlement for unscheduled flow are included throughout the 40 year window; however, the MISO settlement agreement is only a 7 year agreement. Including such revenues that cannot be reasonably relied on can artificially inflate the benefits, and consequently should not be included beyond the term of the settlement agreement.
Xcel-5	SPS' share of MISO PTP revenues are high relative to other SPP entities and compared to what was expected based on recent settlement statements and estimates provided resulting from the settlement. In the RCAR II study, SPS is projected to receive more than 10% of the total MISO Seams revenue. Based on settlement statements, SPS actually only receives about 4-6%. This would appear to give SPS more MISO PTP revenue distribution than we would actually receive, resulting in overstatement of our BC ratio due to reduced costs.

Avoided

CUS-7	Avoided or Delayed Reliability Projects - City Utilities is listed as having a $.2M benefit from Avoided or Delayed Reliability Projects on ESWG slide 7. We understand that this rounds to zero but we were expecting this to be zero (before rounding), since City Utilities does not have any economic (or reliability) projects. Could you provide an explanation why City Utilities received any benefit for this metric? Is there a threshold (i.e. in terms of percentage of thermal ratings) before a project is deemed to be needed? There were three projects listed that avoided reliability projects - Wheeler - Howard 115 kV, Potter - Harrington East 230 kV and Carnegie - Hobart Junction 138 kV. Did these lines cross the threshold? Could you provide more detail on the amount of the violations? Are these results obtained from running a single Powerflow case (i.e. summer peak) or multiple Powerflow cases?

A

BEPC-2 CUS-6 KCPL-1 LES-1	These entities posed specific questions regarding the calculation of APC and the impacts on their organizations.
LES-4	Do the APC calculations take into account all generation an entity owns or has contracted for, or only the generation with firm transmission service?

CUS-2	Per the "RCAR II Data" PowerPoint presentation (slide 3), there has been 509 upgrades totaling $7,382M as of the RCAR II report date. Per the RCAR II draft report, page 25, 41.5% of the cost of these upgrades are in service. The total cost of the upgrades in service would be $3,063.5M ($7,382M x 41.5%). As none of these projects would have been constructed under FERC Order 1000, the project's host zone would have the right of first refusal on construction of the upgrades. Has SPP tracked the dollar amount of return on equity paid to the constructing zones/entities? If so, could we get a listing of the return on equity amounts paid? This does not appear to be captured in any of the benefit metric calculations.
LES-5	LES would like SPP to confirm the benefits used to evaluate ITP projects. Clarification: "LES would like to get further explanation on the benefit evaluation process for ITP and how the benefit evaluation for ITP may differ from the benefit evaluation that is done for the RCAR II process."

Metrics - Inc

CUS-11	Increased Wheeling Through and Out Revenues - Please provide support for the regional and City Utilities portion of the benefit calculation for Increased Wheeling Through and Out Revenues. We noticed that while City Utilities has negative APC savings benefit, we are assigned positive transfer capability benefits.
OPPD-3	<u>Increased Wheeling Through and Out Revenues</u> ● The SPP denies a small percentage of transmission service requests. Given that denials of service are infrequent, adding more transmission capacity is unlikely to result in an increase in transmission service revenue. For example, where the supply of widgets meets or exceeds demand, manufacturing more widgets will not result in increased sales.

Reduced Capacity Costs

CUS-9	Reduced Capacity Costs Due to Reduced Transmission Losses on Peak - City Utilities is listed as having a $-.1M benefit from Reduced Capacity Costs Due to Reduced Transmission Losses on Peak on ESWG slide 5. We understand this rounds to zero but are trying to follow this calculation for our zone. Could you supply the data used to calculate our zonal amount?

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BEPC-1 CUS-12 KCPL-4	These entities posed specific questions regarding the calculation of Marginal Energy Losses and the impacts on their organizations. BEPC noted they appeared to have 44% of the total $402M benefit.

Assumed Ben

CUS-10	Assumed Benefit of Mandated Reliability Projects - We understand that this total benefit for the region is assumed to be the cost of mandated reliability projects. This benefit is then allocated either by load ratio share or system reconfiguration, depending on the voltage. We can calculate the load ratio share portions of the metric without any additional detail. We would like to see some detail on the system reconfiguration calculation portion of our benefit and how it was calculated.

Mitigatio

CUS-8	An excerpt from the 6/24/14 ESWG meeting follows: **"Kip Fox (AEP Transource) made a motion for SPP to use the APC Savings methodology to calculate the Mitigation of Transmission Outage Costs benefit metric with periodical review of the historical outages to ensure the methodology is historically reasonable. Paul Dietz (Westar Energy) seconded the motion. The motion was approved unanimously."** It appears that the RCAR I APC savings benefit of 11.3% was also used in RCAR II. The RCAR II report (page 50), indicates "In the RCAR II, the 11.3% of APC benefit was utilized, consistent with the RCAR I and 2015 ITP10". In the 2015 ITP10, page 90, footnote 35 indicates "As directed by ESWG, SPP will periodically review historical outage data and update additional APC savings ratio for future studies. Although the outage data was not updated for the 2015 ITP10, it is being reviewed and updated for the RCAR II Assessment". Was the outage data updated for the RCAR II (and came out exactly the same as RCAR I) or was it just not updated?

OPPD-2	Mitigation of Transmission Outage Costs ● This calculation currently relies on one year of outage data including parts of 2011 and 2012. Outages and their economic impact can be highly variable from year to year, and 2011 was a hot year that included the Joplin tornado. Given this benefit calculation resulted in almost $1B, it's significance warrants the use a multi-year avearage to produce a result with higher confidence. ● Outage data from the Integrated System was not included or relied on in performing the analysis and calculation of Mitigation of Transmission Outage Costs. The analysis postulates outages of the IS and should instead utlize actual outage data to provide a more reliable result.

CUS-5	On page 27 of the Brattle presentation (Zonal Load Ratio Shares and NPCC), City Utilities has an NPCC listed of 23.0%. City Utilities' NPCC on our formula rate filing effective 4/1/15 is 19.36% and 22.21% on our formula rate filing effective 4/1/16. How was the 23.0% NPCC figure determined by SPP?
LES-2	Is SPP including the LES GFA Carve Outs in the calculation? If so, how?
LES-3	Are there any other metrics used in the RCAR II process that had to be accounted for differently due to LES' Carve Out status?

Xcel-6	Since the RCAR study is evaluating the reasonableness of the SPP regional cost allocation methodology, the RCAR II study needs to account for Z2 credits that are Base Plan funded. With the potential magnitude of Z2 credits (nearly $800M) that could be Base Plan funded, the RCAR II study should evaluate the benefits and costs of any Z2 credits that are Base Plan funded.
Xcel-7	Check totals for each benefit metric to ensure that it sums correctly. May want to include a total for each column in each separate sections as a check.

CUS-1	RCAR II includes projects with NTC's that are suspended, but not withdrawn. Could we get a list of those suspended projects along with their respective dollar values and the zone they are located in?
CUS-3	As noted in #2 above, slide 3 of the "RCAR II Data" PowerPoint indicates that 509 upgrades have been awarded totaling $7,382M. Can we get a listing of the 509 upgrades by zone and dollar value?
CUS-4	Were all Integrated Systems (Upper Missouri Zone) projects included in the RCAR II report approved through regular SPP processes, or were some UMZ projects added outside the normal SPP approval processes (grandfathered in)?

NPPD-2	City Utilities of Springfield (CUS) B/C ratio showed a small change from a .63 in RCAR I to a .62 in RCAR II. Under RCAR I, SPP staff worked with CUS and identified with three projects to increase CU's B/C ratio at or above a .80 threshold: • James River – South Hwy 65 69 kV $1.7 million • South Hwy 65 – Sunset 69 kV $1.0 million • Twin Oaks 69 kV $0.9 million Total Cost $3.6 million ATRR (based on 40 year levelized value) for these three projects had an estimated total of $0.5 million, all of which would be shifted to region-wide funding. NPPD believes this would provide a low cost solution and create value for CUS.
Xcel-1	Confirm that 75% of CUS' deficiency that results in the BC ratio of 0.62 is in the latter 20 years of the analysis. Confirm how the APC is interpolated for the latter years.
Xcel-2	Confirm whether CUS is deficient in the first 20 years of the RCAR II study. Based on the available data, CUS may not be a deficient zone given the significant reduction in negative APCs in the first 20 years of the study.

Xcel-3	Given the inherent uncertainty and accuracy with forecasted RCAR data, SPP should not implement any remedies for entities with the majority of deficiencies in the latter 20 years of the RCAR II analysis. Deficiencies in the latter 20 years of the RCAR II analysis should be addressed when the horizon is closer through subsequent RCAR studies. Implementing a remedy in the near-term for deficiencies in the latter term of the study may not resolve an real equity issue and is not reasonable. In the case of CUS, 75% of the negative APC's occur in 2035. Implementing a remedy in the next 10 years will not address the issues that are forecasted to occur in 20 years.

G

BEPC-3	Education Session: You have mentioned that SPP has met one on one with parties looking to understand the analysis and numbers that come out of the calculations. Would it be possible to set up a WebEx meeting to discuss these details?
NPPD-1	NPPD would like to go on record in support of the positive broader benefits revealed in the RCAR II analysis. The outcome reflects the member’s commitment of the substantial investment in the SPP transmission system and the benefits that it has and will provide in the future.

RCAR II

KCPL-2	The RCAR needs to incorporate a standard review process to check for reasonableness of results after the benefits have been monitized by the Brattle Group, and prior to the release of the draft RCAR report. Significant time is spent on modeling inputs, with little to no time spent on modeling outputs/ results. Due to the modeling issues identified by SPP Staff in April for the RCAR II process, the member review/feedback period that had been on the RCAR II schedule for April was never provided. Simultaneous with the release of the Draft RCAR II report to the RARTF, it is noted in the report that SPP staff began communications with the one deficient zone, CUS, on potential remedies. No draft report or discussion on remedies should be released prior to a review period of the modeling results, to allow for corrections of any potential errors.
KCPL-3	The baseline of June 2010 being used for the RCAR needs to be reconsidered, given the large amounts of renewable generation (in particular, wind generation) and the resulting 'trapped generation' that contributes to unreasonable results and models that will eventually be unable to solve. The process is broken, which will make any remedies difficult to defend.
KCPL-6	KCPL supports the RARTF recommendation that there be a review for the next RCAR about how projects are classified in the ITP process, the reasonableness of a 1:1 benefit-to-cost assumption for the Assumed Benefit of Mandated Reliability Projects, and the impacts of the hybrid LRS/System Reconfiguration allocation approach for those benefits.

OPPD-4	<u>Remedy Threshold & B/C Ratio</u> ● There have been several 7th Circuit Appellate Court cases related to the topic of whether FERC is allowed to approve a pricing scheme that results in harm to RTO/ISO members due to funding transmission. In the most recent case, the Court stated, "charging costs greater than the benefits would overcharge utilities" *ICC v. FERC, NOS. 13-13-674, ET AL. (7th CIR. June 25, 2015)* We should implement a 1.0 B/C to avoid legal uncertainty. ● The 0.8 B/C ratio was initially pursued by the RARTF and was largely decided on to address the concern of there being a lack of developed benefit metrics at that time. Since then, considerable effort has been put into developing additional benefit metrics that address the initial concern that sufficient benefits are not being captured in the RCAR analysis. The 0.8 B/C is no longer appropriate and should increased. ● SPP's value proposition states, "SPP is a steward of our stakeholders' resources." Implementing a 0.8 B/C results in intentional harm to affected entities that is not emblematic of stewardship. Creating a system that results in intentional harm is not sustainable.

d Revenue Offsets

SPP Response
Start with E&C cost by TO/Zone and inflate upgrades with future in-service dates at 2.5% annually, then apply the Zone's NPCC to (inflated) cost to determine the Annual Transmission Revenue Requirement (ATRR). ATRR is then allocated using HWBW methodology zonally or regionally based on voltage (100% to region if 300V or above, 33% to region, 67% to zone if between 100kV and 299kV, and 100% to zone if less than 100kV). This zonal and regional ATRR, by zone, is then depreciated at an annual rate of 2.5% to calculate the declining ATRR profile over the 40-yr horizon in nominal dollars, and a six-month shift is applied to the depreciated ATRRs to reflect a mid-year convention (assumed all upgrades placed in service mid-yr). All ATRRs from 2015-2054 (depreciated, with 6-mth shift) are summed and discounted to 2015$ using 8% discount rate. CUS has regional ATRR only of approx. $8.7M before depreciation and 6-month shift.
Used ATRR from RCAR HWBW portfolio to determine BPZ and BPR ATRR by year by Zone for 40 yr period of 2015-2054. Used actual PtP load numbers from Settlements for Mar 2014-Feb 2016 for through and out to determine average of annual, monthly, weekly, daily peak and off-peak, and hourly peak and off peak amounts. 40-yr forecast of PtP rate was based on annual ATRR, divided by SPP 12 CP in MW, using a 1.1% annual growth rate after 2016. PtP $/yr were estimated when PtP volumes by type were multiplied by PtP rate by type, giving a total annual $ of RCAR PtP rev for 2015-2054, discounted to 2015$. BPR PtP rev was allocated to all Zones in SPP based on load ratio share; BPZ PtP rev was allocated back to Zone in which upgrades were built. CUS had 1.42% (LRS) of the total BPR portion of the 40-yr discounted total PtP Rev allocated to them; no BPZ was allocated. For MISO offset, the 2015 amount was taken from the Sch 11 MISO rev dollars provided by SPP Settlements, then a HWBW$ % allocation factor by zone was applied, then this was annualized. For 2016-forward, the mid-point of the band from the FERC Settlement was used (1/2 of $27M or $13.5M) and this was allocated to each zone by their most current MWM allocation % then further reduced to the Sch 11 portion of MISO rev by zone which was reduced again by the HWBW$ % allocation factor by zone. This annual amount was used for 2016-2054, and beginning in 2020, each year was inflated by 2%, per FERC instruction. The 40-yr totals by zone were then discounted back to 2015$ using 8% and then one more allocation was done to split the discounted total out by regional and zonal amounts in order to allocate the regional portion by load ratio share (CUS allocated regional dollars only).
In the initial draft of the RCAR II Report it is calculated over the 40-year study period, 2015-2054. Staff will be asking the RARTF for some guidance on this issue during the June 17 call. Further details explaining how the MISO revenue offset for RCAR II can also be found on CUS #14 and on pgs 38-40 of the draft RCAR II report.

The 40-yr PtP revenue offset discounted totals are distributed to each TO through a zonal (BPZ) and a regional (BPR) allocation. More than half of SPS' PtP offset of $94M is attributable to the BPZ portion of the PtP offset, which is allocated based on the Pricing Zone in which the upgrades were built. SPS had 30% of all SPP BPZ PtP$ allocated to them based on RCAR2 upgrades. BPR PtP$ allocated to SPS made up a lower percentage of the total, and was based on total BPR PtP$ for RCAR2 upgrades, multiplied by SPS' LRS of 11.33%.
The MISO revenue offset has a zonal and a regional allocation, and the total regional portion of the allocation was then re-allocated using LRS so that TO's having no upgrades in the RCAR portfolio would get a regional portion assigned to them based on their LRS. See RCAR2 DRAFT Report May 2016, pages 38-40 for description.

Metrics

l or Delayed Reliability Projects

Avoided/delayed reliability projects are identified if they meet both of the following criteria: 1) A facility is overloaded (>100% of thermal rating) with a Highway/Byway economic project removed, 2) This facility is loaded < 98% when the Highway/Byway economic project is included in the model. The 3 projects identified meet these thresholds. The RCAR II draft report that was posted for the 5/13/16 RARTF meeting includes the details on the amount of the violations in Figure 7.10. These results are obtained from running a summer peak powerflow with the economic projects, and a summer peak powerflow with economic projects removed. For all projects identified, benefits are allocated in the same way that costs would be allocated, had the project been needed. Even though none of these projects are in CUS, CUS would still pay a small portion of the costs for these projects. By avoiding having to build the reliability projects (in which CUS would pick up part of the cost), the benefit quantified here is equal to the costs that each zone is avoiding.

djusted Production Costs

Staff and the consultants will provide detailed explanation for each requesting entity.
The PROMOD modeling and APC calculations take into account all generation an entity owns or has contracted for, based on the 2015 ITP10 Generation Review.

Metrics - General

This is correct that no economic development/construction benefit is being calculated in RCAR. Those benefits have not been defined benefits to be calculated and monetized the RCAR analysis by the SPP Stakeholders. While we do agree that these benefits do exist, it wold be extremely difficult to determine these benefits on a portfolio level. Because there are benefits like these that we are not able to monetize is one of the reasons why the conservative .8 threshold is appropriate.
In the ITP10, the final portfolio of projects is evaluated with the full set of benefit metrics in order to identify additional benefits that these projects provide, consistent with RCAR. In the RCAR 2 modeling, generation is different between base cases and change cases due to known modeling issues (trapped generation and load pockets), and these issues were addressed through the stakeholder process for RCAR 2. Otherwise, all modeling practices and benefit evaluation practices are consistent between the ITP10 and RCAR.

creased Wheeling Through and Out

When SPP sells additional firm transmission service for through and out transactions, the region collects additional wheeling revenues. These additional revenues are distributed to members based on mechanisms in Schedules 7 and 11 of the OATT. These revenues are unrelated to APC savings - they are based on MW-mile impacts of the transactions and based on ATRR shares. Additional details for the Wheeling Through and Out Revenue benefits have been posted to TrueShare at "Wheeling Benefits.xlsx". If there are further questions on the details provided, a conference call can be set up.

This metric was structured and approved to identify increases in transfer capability due to transmission as a proxy for increases in expected wheeling service. If transmission capacity is insufficient, it is likely that there will be fewer transmission service requests. If entities know that the capacity is not there, they are less likely to pay for studies to request service. An increase in transmission capacity is likely to not only result in fewer denials, but result in more requests as well.

s Due to Reduced Transmission Losses on Peak

Transmission losses are calculated by running a summer peak powerflow with the Highway/Byway projects, and a summer peak powerflow with Highway/Byway projects removed. In both the 2020 and 2025 models this resulted in a 0.1 MW increase in losses for CUS. This amounts to around $100K over 40 years. Details for this metric have been posted to TrueShare as "Capacity Savings due to Reduced On-Peak Transmission Losses.xlsx". See line 16 for the change in MW losses for CUS.

Marginal Energy Losses

This metric measures the zonal reductions in production cost due to reduced losses. This includes production costs for generation within the zone and for zonal imports.

Staff and the consultants will provide detailed explanation for each requesting entity.

efit of Mandated Reliability Projects

Upgrade-specific detail behind the Mandated Reliability benefits have been posted to TrueShare as "Mandated Reliability Summary.xlsx". If there are further questions on the details provided, a conference call can be set up.

on of Transmission Outage Costs

RCAR I used a subset of historical outage data from December 2011 - November 2012. An attempt was made to update the transmission outages for RCAR II, to use more recent historical data. However, extensive analysis and stakeholder vetting are required to model a substantial number of outages and properly constrain the system based on these outages. This would require bringing stakeholders criteria for the subset of outages to be modeled, the historical period to be used, and the actual outages based on that criteria and historical period. All of this would need stakeholder buy-in. After that, implementing these outages in the model, performing a constraint assessment, and vetting this with stakeholders is time-intensive, and could not commence until after the RCAR PROMOD model is finalized (it was finalized 3/29/16). The extensive analysis and stakeholder vetting could not be completed with a July 2016 completion date for the RCAR II. Because of this, the outage benefit savings of 11.3% of APC savings was applied to RCAR II. This is consistent with the RCAR I and the 2015 ITP10. Note that this calculation is conservative as the subset of outages modeled to obtain this 11.3% of APC savings was less than 20% of the total historical outages. If the outage data were to be updated, we would hope to be able to model a larger subset of the actual historical outages.

The historical outage data used for this metric spans December 2011 through November 2012, after the Joplin tornado and after the hot months of 2011. RCAR I used a subset of historical outage data from December 2011 - November 2012. An attempt was made to update the transmission outages for RCAR II, to use more recent historical data. However, extensive analysis and stakeholder vetting are required to model a substantial number of outages and properly constrain the system based on these outages. This would require bringing stakeholders criteria for the subset of outages to be modeled, the historical period to be used, and the actual outages based on that criteria and historical period. All of this would need stakeholder buy-in. After that, implementing these outages in the model, performing a constraint assessment, and vetting this with stakeholders is time-intensive, and could not commence until after the RCAR PROMOD model is finalized (it was finalized 3/29/16). The extensive analysis and stakeholder vetting could not be completed with a July 2016 completion date for the RCAR II. Because of this, the outage benefit savings of 11.3% of APC savings was applied to RCAR II. This is consistent with the RCAR I and the 2015 ITP10. Note that this calculation is conservative as the subset of outages modeled to obtain this 11.3% of APC savings was less than 20% of the total historical outages. If the outage data were to be updated, we would hope to be able to model a larger subset of the actual historical outages. Because of the historical period of outages and available data, no outages were modeled for the IS. Had they been identified and modeled, a larger benefit would be expected for the SPP region.

Other

2016 CUS NPCC including depreciation, exclusive of true-up and revenue credit impacts, using inputs from FRT eff 4/1/15: Rev Req $ 12,444,212 / Trans Net Plant $54,063,961=23.02%
The ownership of generation and transactions are consistant with the information provided to SPP through the Gen review approved on 06/18/2015. Please see attachment posted in Trueshare "2_2017 ITP10 Generator Data Submittal_20150611.xlsx" to confirm that they are correct.
No.

The costs to be included in RCAR, per Att J Sec III.D.2 of Tariff, are Base Plan Upgrades approved for construction after June 19, 2010 to each pricing Zone within SPP Region. Therefore, Base Plan funded credit payment obligations for upgrades that are based on the cost allocation methodology prior to June 19, 2010 are not subject to inclusion in RCAR. SPP Staff currently is quantifying all historical credit payment obligations and the Base Plan funded portion of those amounts for the Attachment Z2 project. However, these values have not yet been finalized. Therefore, the Base Plan funded credit payment obligations associated with RCAR II upgrades (post June 19, 2010) are not ready for inclusion in RCAR. Since costs cannot be included in the analysis, it is not appropriate to include the corresponding benefits of those upgrades.
We have made sure all numbers are summing correctly.

Projects

It has been posted to TrueShare as "RCAR 2 suspended NTCs.xlsx"
The project list has been posted at: http://www.spp.org/spp-documents-filings/?id=20184
Many IS upgrades since 2010 have not received Highway/Byway cost allocation, and are not evaluated in the RCAR II analysis. There are some IS projects which have received HWBW cost allocation based on an "Integration Study" conducted by SPP Staff in 2013 that validated the need of certain transmission projects that members of the Integrated System had planned to construct. Some of the proposed projects were identified to be needed prior to the Integrated System joining SPP and others were identified to be needed after joining. As part of the tariff language filed to effectuate the membership of the Integrated System, the projects that were identified as needed after joining SPP were explicitly listed in Schedule 2 to Attachment J. This subset of upgrades are specifically recognized as Base Plan Upgrades designated for cost allocation under Highway/Byway, and have been evaluated in the RCAR II in the same manner as all other Highway/Byway upgrades.

Remedy

No reponse.
Since the projects' economic life is 40 years, evaluating benefits and costs should be based on the full life of the assets. Discounting and the time value of money already account for the reduced present value of the negative benefits in the latter 20 years. For informational purposes, if we were to run a 20-year NPV APC benefit for CUS (2015-2034), the resulting benefit would be -$15.5M rather than the -$30.8M shown for 40 years. APC savings benefits for all years after 2035 are computed by using the rate of inflation (2.5%) as a terminal value.
Based on a preliminary 20-year accounting of the benefits and costs, while taking into account the time value of money, CUS B/C ratio remains below the 0.8 threshold.

No response.

General Statements

SPP will schedule an education session with Basin.
No response needed for NPPD.

Lessons Learned

The process used in RCAR II was consistent with that used in RCAR I. This is a staff analysis and draft results are initially given to the RARTF for review. Other technical group have been included inthis review as well. There is a significant amount of time spent by Staff and the consultants in analyzing modeling output and results to see that they are reasonable.
Hold for RCAR LL
Hold for RCAR LL

Hold for RCAR LL