RESPONSE TO PEER REVIEW COMMENTS ON WESTERN'S SLCA/IP FIRM ELECTRIC SERVICE RATE IMPACTS PRESENTED IN THE GLEN CANYON DAM LONG-TERM ENVIRONMENTAL AND MANAGEMENT PLAN DRAFT ENVIRONMENTAL IMPACT STATEMENT

Prepared by

Western Area Power Administration

March 2016

Appendix K.3 of the Long-Term Experimental and Management Plan Environmental Impact Statement (LTEMP EIS) was provided to three peer reviewers by the Grand Canyon Monitoring and Research Center (GCMRC) on November 6, 2015. The three peer reviewers submitted a number of comments and questions to GCMRC. These were forwarded to the Western staff analysts. In response, Appendix K.3 was modified to address the questions of the peer reviews and to offer additional clarity. The document was subsequently included in the LTEMP EIS Public Draft. The following contains peer review comments and responses by the Appendix K.3 authors. Page and line numbers refer to the November 6 draft report. Where the peer reviewers had several and/or related comments on a single subject, the comments and responses are grouped by subject.

PEER REVIEW COMMENTS AND RESPONSES

Peer Review Comments	Responses
General	
One reviewer found the entire write-up to be poorly organized and lacking necessary detail. The reviewer recommended that WAPA redo the entire analysis and prepare a new appendix.	We have added significant new detail to the K.3 report. We believe the revisions are detailed and clear. We did not redo the analysis or significantly rewrite or reorganize the report.
K.2 Introduction (page K-1) • Discuss specific pricing goals/objectives for the wholesale rates associated with firm capacity and firm energy.	Western included section "K.2.3. SLCA/IP Rate Setting" that describes Western's SLCA/IP rate setting goals and processes and compares this with the more common practices used by regulated electrical utilities.
• Line 10: The description of economic impact is unusual and probably unnecessary. This section is only about changes to wholesale rates.	The description regarding the scope and nature of this study has been changed. This report is now described as a financial study and attempts to clearly define its relation to the economic studies.

Peer Review Comments	Responses
• Line 15: There is no real discussion of the “distribution of economic impacts” in this section. • Line 17: Clearly define “economic costs” relative to marginal costs and accounting costs.	The new section K.2.3 explains the nature of this analysis and offers clarification.
• Lines 18-19: Will WAPA’s contractual obligations to each wholesale customer remain constant over time? What is that contractual period?	The contract period and assumptions regarding the continuation of Western’s contracts are explained in section K.2.7.
• Add a “Glossary” for definition of acronyms/letters used in this report. Refer to the Glossary in the Introduction section and place the Glossary at the end of the report.	A glossary has been added to the report.
K.2.1. Relationships between Economic Impacts (page K-1, lines 30-38) • Develop and insert a diagram/chart that clearly links the major sections of K.1, K.2, and K.3. See references to K.1 on lines 32 and 36. The current reference/links are useful.	This suggestion will be considered in the final EIS as appropriate.
• Line 38: Define the term “region” for this analysis.	The region is defined in K.1. The wholesale rate impact section tiers off the power economics analysis.
K.2.2 Temporal Scope of the Analysis and Input Data (pages K-2, lines 1-21) • Line 4: Explain the basis for the assumption associated with the SLCA/IP rate.	A clarification of the assumption that the SLCA/IP rate for each alternative remains over the temporal scope of the LTEMP EIS has been included.

Peer Review Comments	Responses
• Lines 4-6: If the PRS repayment period extends beyond 2034, why does the rate analysis end in 2034? How does WAPA deal with "end effects," especially given the balloon payment methodology as described on page K-12, lines 28-33? Is the balloon payment methodology used by the CRSP Management Center legislatively required? And, if so, does that methodology affect the rate calculations shown in Table K.2-6? If so, how? • Line 6: If the study period is 2013-34, why is an assumption about "post 2034" relevant?	Additional details were included in the report regarding the time-frame used in establishing SLCA/IP rates, and why the repayment period extends beyond 2034.
• Line 5: Does the SLCA/IP rate "not change" in real or nominal terms?	In nominal terms.
• Lines 9-21: Explain the basis for the key input data and any relationships among the input data.	A sentence has been added explaining that key input data for K.2 are taken from K.1.
• Lines 20-21: Identify the specific technologies selected by the Aurora model, the formula used to create the levelized cost payment, and the inputs to that formula, such as the interest rate.	These explanations, the specifics of the Aurora model, and specifics regarding the choice of generating technologies and how they are priced, are part of K.1. This K.2 report uses the analysis derived from K.1 as inputs for this analysis.
• In reference to the previous comment, explain how this levelization approach for capacity is consistent with the balloon payment methodology.	The SLCA/IP rate study adds the costs of capacity additions in the years they occur according to the analysis in K.1.
• Furthermore, explain how the capacity levelization approach, which calculates an actual capacity payment requirement, is consistent with the assumed 50-50 allocation of rates between capacity and energy described on page K-14, lines 5-6.	The 50/50 allocation of the SLCA/IP rate between energy and capacity is independent of how and when the costs of capacity and energy actually occur.

Peer Review Comments	Responses
K.2.3 Calculation of Net Electrical Energy Expense (pages K-2, lines 24 thru page K-6, line 22) • Figure 2-1 doesn't point to an annual calculation. • Are the three outcomes at the bottom of Figure 2-1 contractually stipulated? • On page K-2, line 34: Cite the specific page numbers (references) for section K-1.	The chart does not indicate that these are annual dollar costs. Instead, it describes the process used to develop these annual dollar values. The text explains that these are annual dollar costs.
• On page K-3, Line 7, cite the specific year associated with Table K.2-1. • For Tables K.2-1 and K.2-2: Label the specific water year (WY).	As explained in the text, these monthly contractual obligations occur every year through 2024.
• On page K-3, Line 14: Define the concept of water year.	Water year is the same as the Federal fiscal year. It is October through September.
• Explain how the data in Tables K.2-1 and K.2-2 relates to comparable information in previous (recent) years.	These monthly data occur every year through 2024.
• On page K-3, Lines 21-29: Summarize the actual experience of surplus and shortages over the past 5 years for SHP commitments.	Historical experience over the past 5 years would not be a representative sample due to recent dry hydrological conditions.
• Line 23, transmission losses of 8.3% seems higher than many systems.	Western used transmission line losses of 8.3% because it is the figure consistently used by the CRSP MC Energy Management and Marketing Office, for planning purposes.
• Page K-4, Table K.2-1, What is CROD? • Line 12, What are the "seasons"?	The definition of CROD has been added to the glossary.

Peer Review Comments	Responses
• **Comments related to the criteria for offering AHP:** Page K-4, Line 31 – Page K-4, Line 17: Line 32, What is the basis for the 20% AHP criteria? This material discusses the 20% surplus AHP trigger. If this assumption is "for modeling purposes only and does not represent established policy or practice," why use it? What is established policy and practice? • Why is that not a more rational basis for the AHP assumption than the 20% rule, which is completely arbitrary? Why is there so much forecasting error in hydro availability by season?	Further clarification has been added to explain the development and use of criteria for modeling offers of AHP.
• How does the selected 20% trigger level compare to practices at other major hydro-generation locations? Doesn't GCD have specific draw-down rule curves, based on reservoir height? • What are the magnitudes of these forecast errors that supposedly justify the 20% assumption, but not established policy and practice? Provide evidence that these forecast errors mean the 20% assumption is valid.	No comparison of the criteria for offering AHP was added. AHP offers by Western for SLCA/IP resources are likely unique within Federal marketing agencies and regulated electrical utilities. The 20% criteria are not based on forecast error. When energy above SHP is anticipated, Western decides if AHP energy is sufficient to justify the transaction costs involved in modifying contract documents, operating schedules and deliveries as well as the changes in electrical purchase plans required by customers.
• Provide a detailed example of the application of the methodology using long and short positions along with associated revenues and costs on an hourly basis.	Explanations regarding how energy and capacity offers above SHP, how Western firms SHP, and the cost and revenues associated with these long and short positions are the main subject of K.2.
• On Page K-6, Line 21: Define the concept of spot prices.	Spot prices are electrical energy purchased in real time at exchange nodes.
• Page K-6, Line 4: Given that inter-BA capacity sales are sometimes (if not often) difficult or even impossible, who does WAPA buy this capacity from? Who will WAPA buy this capacity from in the future?	This is explained in K.2.6. Western has purchased long-term firm capacity in the recent past. In addition, it is explained in K.2.6 that when regional capacity is in short supply, Western's purchases of firming energy is likely to include a capacity premium.

Peer Review Comments	Responses
• Line 10: Does WAPA ever hedge the risk that generation is below SHP obligation, with something like call options?	This is not currently a practice of Western's CRSP MC.
• Line 17: The explanation of having excess seasonal generation leads to generation being less than load is confusing.	Additional explanation is included.
K.2.4 Calculation of Capacity Expenses and Total Net Costs (Pages K-6, Line 27 thru Page K-8, Line 11) • On Page K-8, Lines 8 thru 11: Clearly explain why no capacity expenses are required until years 2017 and 2018, as presented in Table K.2-3.	These explanations are in K.1. This K.2 report takes the data on the timing of capacity explanation and additions from K.1.
• Page K-4, Lines 25-29: Why doesn't WAPA simply sell ALL surplus energy and capacity into the market and then refund the money it makes to its customers? The result should be the same (or possibly better because it lowers wholesale rates and may allow WAPA to purchase needed generation at a lower cost) and is far easier from an accounting standpoint. (See also Page K-6, Lines 10-12.)	Western's practices are established pursuant to Federal Law.
K.2.5 Western Replacement Resources (Pages K-8, Line 10) • On Page K-8, Lines 18 thru 22: Is the assumption based on historical experiences? Is the amount of a specific type of capacity that WAPA requires to meet its obligations times the capacity expense calculated in AURORA? Is WAPA limited in any way to capacity types which might be different from what AURORA is building? Please explain.	Assumptions regarding the types of generators added and the cost of the construction and operation of capacity is determined by the Aurora model and explained in K.1.

<table>
<tr><th>Peer Review Comments</th><th>Responses</th></tr>
<tr><td>Line 18: Purchases of firm power have a capacity component. Is the capacity associated with the purchases of firm power, either historical or projected, counted toward any capacity deficits? That is, is there a possibility that projected purchases of firm power (energy and capacity) would be sufficient to fill a capacity deficit?</td><td>The additions of capacity and the timing of these additions are determined through the Aurora model and are explained and presented in K.1.</td></tr>
<tr><td colspan="2"></td></tr>
<tr><td>Page K-5, Table K.2-2: Although this table is superfluous, if it is included, please identify the units of measurement (presumably MW).
Also, the table goes from October-September. Although this corresponds to the water year, it may be easier to provide a calendar year table. Also, are the loads shown in this table contractual? If they are actual loads, state the year.</td><td>Table K.2-2 presents the daily load shape used in the analysis (in MWh) and shows the differences in load shape by month and by weekday vs weekend days.

Western’s rates are consistently computed on a fiscal year basis. So, the data input values are presented by FY to make it easier for the reader to track the analysis and to remain consistent with our published rate schedules.

The hourly SHP data in Table K.2-2 are not contractually set. The contract requires that FES customers schedule their SLCA/IP energy delivery within certain parameters. These numbers are in average of hourly values based on historic information.</td></tr>
<tr><td colspan="2"></td></tr>
<tr><td>K.2.6 The Post-2024 Marketing Period (Page K-10, Line 13 thru page K-11, Line 24)
On Page K-10, Lines 22 thru Page K-11, Line 5: Are these assumptions concerning “bookends” and outcomes possible in the development of the post-2024 marketing plan based on historical experiences? Please explain.</td><td>We’ve added explanation about these bookends. The authors believe these bookends represent possible scenarios for Post-2024 marketing.</td></tr>
<tr><td colspan="2"></td></tr>
<tr><td>Concerning the assumptions relating to “bookends”: Provide some basic quantitative numerical implications.
These “bookends” seem like a reasonable approach to the “post 2024” period.</td><td>Quantitative information regarding these bookends is included.</td></tr>
<tr><td colspan="2"></td></tr>
</table>

Peer Review Comments	Responses
• Page K-6, Lines 33-36 and Page K-8, Table K.2-3: The table shows levelized costs based on the Aurora Analysis, but WAPA states it does not recover capacity costs in this manner, but instead does so on a balloon payment basis. As this appendix is supposed to describe the projected rates SLCA/IP customers will pay, using these fixed costs from Table K.2-3 would seem to be inaccurate, as would Figure K.2-2. Please explain the discrepancy or explain why there is no discrepancy.	The manner in which expenses occur do not have to be exactly matched by the method Western uses to collect revenues to meet operations and repayment expenses. This is an example of a case in which they do not match.
• Page K-8, Lines 20-21: Please describe "capacity firming costs." If this simply refers to the additional capacity WAPA must purchase when its contractual capacity obligation is greater than what its generating resources provide, then state that.	The explanation of Western's purchases of capacity and/or purchase of firming energy at a price that includes a capacity premium is explained in section K.2.6.
• Page K-9, Lines 10-11: WAPA states that the capacity expenses are the differences. (It can be inferred from Table K.2-3, but again, that table is not consistent with WAPA's balloon payment assumptions.)	Table K.2-4 has been added. Western believes this table and the accompanying explanations have clarified this issue.
• Page K-9, Lines 7-11 and 22-25: Does WAPA actually purchase capacity in the market, or does it purchase firm energy when it needs additional generation to meet its contractual obligations? This matters because the capacity costs Aurora spits out are resource-specific, and may have little to do with actual market prices for firming energy. This needs to be explained clearly.	This explained in a new section, K.2.6.
• Page K-10, Lines 10-11: Is WAPA calculating wholesale rate *differences*, or actual projected wholesale rates?	The SLCA/IP rates in Table K.2-6 are actual projected wholesale rates.

Peer Review Comments	Responses
• Page K-10, Line 14 – Page K-11, Line 4: Why are the two assumptions (i.e., existing FES contract commitments continue through 2034, or they are reduced such that WAPA's obligations equal actual generating output) the "bookends"? What happens if SLCA/IP customers request additional power to meet growing loads? Is that contractually prohibited? If so, state that. See also Page K-11, Lines 21-24 regarding the "reasonableness" of WAPA's assumptions.	Western is currently conducting a public process to remarket its resources (including the GCD resource) for the period after the current contracts expire. Although any range of "what ifs" could have been developed (including SLCA/IP customers requesting additional power to meet growing loads), Western believes the bookends used in the analysis are reasonable and sufficient to provide a range of projected wholesale rates.
• Page K-12, Lines 13-14: Here is the reference to the "appropriate interest rate" assumption I discussed in my review summary. What is the appropriate interest rate? What is the economic (or other) basis for WAPA having selected that rate?	The interest rate used by Western is established pursuant to Federal Law and is outside of the discretion of Western.
• Page K-12, Lines 28-40: If WAPA receives only interest payments on outstanding principle, how does WAPA design rates when the balloons "pop?" There appears to be a disconnect between how Aurora models capacity expansions and costs, how WAPA claims to levelized rates for this analysis, and how WAPA actually designs wholesale rates. This requires additional explanation.	Additional clarification has been included about how Western develops SLCA/IP rates.
• Page K-13, Table K.3-4: Negative net expenses means that WAPA is paying the buyers, rather than the other way around. This seems like an odd outcome. If these are differences between Alternative A, then why does Alternative A also have negative outcomes? • What causes the significant reduction in annual expenses in all scenarios in 2022-2014?	These numbers are in relation to Western's FES commitments. These numbers are NOT all costs, but only costs relative to SHP commitment levels. Positive numbers indicate firming costs. Negative numbers indicate sales of energy beyond SHP. Positive numbers are net negative <u>firming</u> costs. In some years, net negative <u>firming</u> costs occur in Alternative A. Projected wet hydrological conditions. Wet conditions cause increased sales beyond contracted firm commitments. These sales can be to the market or they can be AHP sales.

Peer Review Comments	Responses
• Page K-14, Table K.2-5: This table needs further explanation. Why do the purchase power expenses go negative in years 2023-24, when the "bookend" starts in FY 2025? (See also Page K-15, Lines 13-14.)	Further clarification has been added. These numbers are net <u>firming</u> expenses. The years 2023-24 are years of wet hydrological conditions. In wet years, Western has sufficient generation to meet its SHP obligations and can sell additional energy – either as AHP or to the market.
• Lines 12-14: What is the basis for the $4 million assumption for operational purchase power costs for Montrose? Is that through 2024 only? Wouldn't that change under WAPA's 2025-2034 "bookends?"	The $4 million annual expense is Western's estimate of the net minimum purchase power costs of operating the CRSP electrical system. It is the current estimate included in Western's rate.
• Page K-13, Line 23: What is "aid to participating projects?"	"Aid to Participating Projects" is now a defined term in the glossary.
• Lines 16-23: This entire discussion of "pinch-point" years for rate analysis is unclear and unsupported in the appendix. (See also Page K-16, Lines 13-31.) It is not clear how this assumption affects the actual rate comparisons or, in light of different "pinch-point" years, how rate comparisons can be made on an equivalent basis.	The concept of pinch-point years has been better defined and clarified.
• How are expenses zero in years 2025 and beyond? Isn't there debt service to be paid? And other fixed costs?	These numbers are only firming costs. They are zero in one of the bookends after 2024 because contractual obligations are set equal to generation produced; consequently, there are no firming costs.
• Page K-14, Lines 16-20: The assumed 50/50 energy/capacity split is never explained. In designing electric rates, capacity costs are fixed costs, whereas energy costs are variable costs.	An explanation has been added.

Peer Review Comments	Responses
• Page K-15, Table K.2-6: WAPA emphasizes the differences between Alternative A and the other alternatives. Yet, this table presents (allegedly) overall energy and capacity rates. Moreover, it is not clear whether these are levelized rates and, if so, over what period. This table, which arguably is the most important result of the analysis, is not useful in its current form, and requires additional explanation.	Explanations have been added regarding the data in Table K.2-6.
• Because the temporal patterns of these projected rates are different, I recommend calculation and presentation of NPVs at some standard discount rate. I would also recommend a table that shows the percent differences between A and the other alternatives.	The authors believe that an NPV calculation of the SLCA/IP rates would confuse rather than clarify the impact of the LTEMP EIS alternatives.
• RA rates are sometimes greater and sometimes less than NC rates, depending on the alternative. What would cause that?	We have added further clarification.
K.2.7 Power Repayment Studies to Determine Rate Impacts (Page K-11, Line 27 thru Page K-15, Line 4) • On Page K-11, Lines 29 thru 41: Clearly present the primary pricing goals for Western (WAPA) and discuss any trade-offs that exist in meeting these pricing goals. • On Page K-12, Lines 5 thru 6: Develop the discussion of the FERC's filing requirements and procedures for Western (WAPA).	Western's pricing goals are now presented in a new section K.2.3. SLCA/IP rate setting. It describes the goals and legal requirements of Western's SLCA/IP rate setting and makes a comparison to regulated private utility. FERC review of SLCA/IP rate setting is also included in the new section K.2.3.
• On Page K-14, Line 23 thru Page K-15, Line 4: Explain the basis or rationale for a mills/kWh and no $/kW for the composite rate.	Composite rates are in mills/kWh. Capacity rates are $/kW-month. A definition of composite rate is in the glossary.
• Referring to Table K.2-6: Explain the reasons for the highest rates for Alternative G relative to other alternatives.	The SLCA/IP rate impacts almost match the pattern of total hydropower impacts determined in K.1. Explanations of the pattern and size of these impacts are provided in K.1.

Peer Review Comments	Responses
K.2.8 Results • In the Results Section, K.2.8: Present major policy conclusions from the analysis and relate to other “K” reports.	Policy conclusions have not been provided in K.2 because it is intended to be a technical report. Policy implications and conclusions are beyond the scope of this analysis.
• At the end of the report: Present a list of relevant references concerning wholesale electric rates and hydro issues. Include any relevant reports prepared by WAPA.	No references were added to K.2 but could be added for the final EIS.
• Results from a case study analysis of a major wholesale buyer/customer (i.e., municipal) would be informative with focus on rate designs and bill impacts. This approach could serve as a “link” to analysis in K-3 report.	A case study might be helpful and provide context. However, generating asset portfolios among SLCA/IP customers vary greatly and just one (or even two or three) case studies may misrepresent the variety of ways in which changes to the SLCA/IP rate impacts FES customers.
• K.2.8.1: It would be helpful to have a brief explanation of how shifting the pinch-point affects the SLCA/IP rate. That is, if the pinch-point moves closer to the present, does that cause the rate to increase? Why? For example, what is the impact of moving the pinch-point from 2031 to 2055, all else equal?	The SLCA/IP rate is the revenue requirement over a time period divided by anticipated sales over the same time period, all other things equal. However, required repayment obligations for SLCA/IP capital features and replacements vary significantly through the years. This is why pinch-point years exist. All other things equal, if collecting revenues for a capital payment is extended over more years – if the pinch-point year if moved further out, the SLCA/IP rate would be lower. Further explanation and sensitivity studies could be considered in the final EIS as appropriate.