RESPONSES TO PEER REVIEW COMMENTS ON THE HYDROPOWER ANALYSIS METHODOLOGY FOR THE GLEN CANYON DAM LONG-TERM ENVIRONMENTAL AND MANAGEMENT PLAN DRAFT ENVIRONMENTAL IMPACT STATEMENT

Prepared by

Les Poch and Tom Veselka
Energy Systems Division, Argonne National Laboratory

March 2016

This report addresses peer review comments following the second independent review of the hydropower analysis methodology which occurred during December 2014 to January 2015. Lucas Bair of the Grand Canyon Monitoring and Research Center prepared a summary of the comments from the review panel. He noted four general review comments in the summary and these are addressed below. We will also address comments submitted by each reviewer.

General Comments

Comment: There was a lack of discussion of economic theory; namely, the avoided cost method, used to estimate the hydropower metrics.

Response: The current document now provides a considerable amount of detail about the methodology used in the analysis. We tried to refrain from using too much "jargon" but in some cases that is unavoidable. However, we did try to clearly define terms that could be considered "jargon." We also attempted to be clear about what we mean when discussing economic value and how it is calculated.

Comment: Using Intercontinental Exchange (ICE) market electricity market price information to scale spot market electricity prices in the analysis should be done to correct only for misspecification of economic costs. Scaling market prices in AURORA over the planning period should only be done after prices are normalized for weather and outages.

Response: In the latest documentation we include substantially more information related to this topic. We discuss locational market prices (LMPs) as it relates to the economic value of energy, the topology used to project future market prices (i.e., LMPs) with AURORA and the use of scaling factors to align 2013 prices with those reported by ICE for the Palo Verde hub. These discussions are found in various sections of Appendix K.1 and Attachment K-2.

Pricing assumptions tend to be controversial because there are many sources of information and price assumptions can make a significant difference in the resulting valuation of energy and the expansion path of new capacity. Some analysts prefer using historical energy prices because they can be tied to a specific set of purchase transactions. Others prefer to use *estimates of future costs under the assumption that historical costs do not necessarily predict future prices. Prices for historical and future energy can be obtained from a variety of sources.*

In the current application, energy price is the main driver that shapes SLCA/IP federal hydropower plant operations. This includes those at the Glen Canyon Dam Powerplant. Depending on the alternative, energy values account for approximately 18 to 45% of the economic cost difference between alternative A (no action) and another alternative. As discussed in more detail in Appendix K.1, the fundamental reasons for the economic energy cost differences are threefold; (1) seasonal/monthly market price spreads (not the absolute value) among months of the year causes economic cost differences that result from different monthly water release volumes among alternatives; (2) weekly/daily market price spreads among hours of the year causes cost differences due to differences in operating criteria (e.g., allowed ramping and daily change flexibility) among alternatives; and, (3) the absolute price of energy causes cost difference related to different non-power water releases among alternatives. We found that AURORA tended to underestimate both prices and price spreads.

The scaling method applied in the LTEMP EIS is very similar to the ones used in previous CRSP power systems economic studies. For example, the "Colorado River Interim Guidelines for Lower Basin Shortages and Coordinated Operations for Lakes Powell and Mead" EIS (a.k.a. Shortage Criteria EIS) conducted by Reclamation scaled AURORA model prices to those in a Dow Jones, Inc. electricity price index. Advantages of this approach are that prices exactly match statistical information compiled from values reported in a price index and that trends projected by the AURORA model are retained. Although the monthly scaling factors are constant over the projection period, price spreads and absolute values change over time as indicated by the AURORA model. For example, if AURORA shows a narrowing of price spreads (in percentage terms) over time due to increases in solar penetration, then price spread narrowing will also occur using the current methodology.

Use of the scaling factors assumed that the market price index reflects marginal production costs and can therefore be used as a surrogate for the economic value of energy. Secondly, the scaling factors that were used to adjust model results to those reported by ICE were also applied to future years and do not change over the study period.

Finding and correcting the root cause of price differences between model outputs and index values would be an arduous and difficult task. In the document we list many challenges associated with modeling large scale power systems such as the Western Interconnection (WI) over long time periods. Many of these have challenged modelers for decades. For example, much of the information needed to resolve these issues is considered proprietary by facility owners. Information in the public domain is useful for modeling broad systems interactions and trends; however, it is often not adequate to model very specific system behaviors. It is beyond the scope of this analysis to resolve these issues. It is our opinion that there are no simple "fixes" to solve the root cause of the problem such as changing the load profiles input into the model. If not done properly, adjusting model input data and parameters to merely match historical values may not be an improvement over the post-modeling scaling method if actual cause/effect relationships are not adequately addressed.

Because it is very difficult to precisely model WI market prices using physical representations of the system and general equilibrium models such are AURORA, it is also very challenging to definitely prove that market price signal such as those reported by ICE reflect actual marginal production costs. We acknowledge that no market is perfect and that on occasion market participants will attempt to manipulate market prices to their benefit. Recent FERC enforcement reports document cases where they are investigating or have investigated alleged violations of the statutes, regulations, rules, orders, and tariffs administered by the Commission. (e.g., http://www.ferc.gov/legal/staff-reports/2013/11-21-13-enforcement.pdf, http://www.ferc.gov/legal/staff-reports/2014/11-20-14-enforcement.pdf). For example, the 2014 report states "On October 9, 2013, the Commission filed a petition in the United States District Court for the Eastern District of California (the court) to affirm the Commission's assessment of civil penalties of $435 million against Barclays and of $18 million against the named Traders and to order disgorgement by Barclays of $34.9 million plus interest in unjust profits. Previously, on July 16, 2013, the Commission determined that Barclays and the Traders violated the Commission's Anti-Manipulation Rule, 18 C.F.R. § 1c.2, by engaging in loss-generating trading of next-day, fixed-price physical electricity on the Intercontinental Exchange (ICE) with the intent to benefit financial swap positions at primary electricity trading points in the western United States."

Measures are in place however, that foster an open and competitive electricity market in the WI. Congress enacted the Energy Policy Act of 2005 (EPAct 2005), which added anti-manipulation provisions to the Federal Power Act, 16 U.S.C. § 824v (2012). To implement these provisions, FERC issued Order No. 670, adopting the Commission's Anti-Manipulation Rule, which has been codified as 18 C.F.R. § 1c (2014) (http://www.ferc.gov/market-oversight/guide/energy-primer.pdf). In addition the CAISO has a Department of Market Monitoring closely watching its markets. It should be noted that Palo Verde is a key point in the CAISO market. The CAISO market monitor also works with the ISO Market Surveillance Committee (https://www.caiso.com/market/Pages/MarketMonitoring/Default.aspx).

We recognize the shortcomings of the simplified approach that was utilized. However, under LTEMP EIS time and budget constraints, we contend that the end result of the scaling methodology is reasonable for the purposes of the LTEMP EIS; that is, to rank alternatives and provide decision makers with comparative economic values. As described in more detail in Appendix K.1, we show that projected LMPs at the Palo Verde hub are highly correlated with Energy Information Administration (EIA) natural gas price projections. This correlation is strongly evident in historical trends. Since energy prices are volatile and cannot be predicted with certainty, it is our opinion that any additional efforts on this price issue would be best spent on an energy price sensitivity analysis as driven by a range of utility fuel prices projected by EIA. In addition, as suggested by a reviewer, one reasonable sensitivity analysis would be to model the SLCA/IP system without scaling AURORA model results -- presumably on the basis that AURORA may possibly produce results that better reflect economic costs than prices reported by ICE. In general, we agree that there types of exercises would be informative, but it would require additional time, effort and funding.

Comment: Forecasts of ancillary services should be documented and discussed in more detail.

Response: The section in the methodology document describing ancillary services now has considerably more detail. The power system team performed a sensitivity study on ancillary services which is described in the revised methodology document or Appendix K.1. The sensitivity study analyzed how the generation at Glen Canyon Dam under each alternative was affected by the ancillary service obligations. The analysis used the time series of hydrological conditions projected by the representative trace. As such the analysis covered a wide range of hydrological conditions. The sensitivity study showed that assumptions concerning the amount of ancillary services required at Glen Canyon Dam have very little effect on firm capacity and energy value for the LTEMP alternatives.

Comment: Exceedance levels used to model SLCA/IP facilities should be further explained.

*Response: We hope that the revised document is clearer when describing exceedance levels. It appears that the confusion arises about exceedance levels related to **capacity available** at the SLCA/IP facilities based on a 90% exceedance level and exceedance levels related to **water flow rates** for the Yampa River when modeling Flaming Gorge Dam. The latter being discussed on pages 14 and 15 of the December 2014 methodology version and on page K-27 of the current version (specifically lines 7 to 21).*

The 90% exceedance level is used to determine the amount of SLCA/IP capacity that can be credited toward the power system reserve margin. It is based on the coincidental time series of capacity values for all SLCA/IP resources for all 21 traces over the 20-year study period. The 90% exceedance level is consistent with the level Western has used in the past when offering capacity contracts to its customers. An average hydropower condition is used to model energy production in the AURORA model capacity expansion runs because this better approximates the economics of energy values over the study period which is a much different product than capacity.

The 50% exceedance level is used to select model inputs for the Yampa River. The monthly Yampa River water flow into the Green River at the confluence of the Yampa and Green, which is downstream of the Flaming Gorge Dam, is based on monthly flow rate exceedance curves that are constructed from historical USGS gauge flow data. Half of the time the Yampa River flow rate at the confluence was greater than the selected level and half of the time it was lower. These flows are important because they impact flows at the Jensen Gage, which is 29 miles downstream of the confluence. This assumption affects the dispatch of Flaming Gorge because Yampa flows affect flows at the Jensen Gage. The determination of capacity at Flaming Gorge does not account for Yampa River flows since it is assumed the operational restrictions during the peak load month of August that pertain to fishing activities below the dam will reduce fluctuation at the Jensen Gage below the 0.1 meter allowable range (see Appendix K for more detail). Rather than stating the Yampa River flow as an exceedance level, it may have been less confusing to use the term median flow.

We will next address specific comments from the peer reviewer documents provided us in January 2015. Comments of the reviewers are shown in bold text. Argonne's response is shown immediately afterward in plain text.

Reviewer 1

Comment: Authors of this document should prepare a "plain English" description of what they are doing, rather than the jargon-laced version I have read and reviewed.

Response: The methodology description in Appendix K of the DEIS was modified to clarify and simplify the description of the methodology.

Comment: The WECCi-leaks study peer-review should determine the reasonableness of the results of that study before the GCD study is completed.

Response: Preliminary results of the study show that the effect of operational changes at Glen Canyon Dam is limited to the service territories of the SLCA/IP customers. It should also be realized that the Glen Canyon Dam powerplant is only a tiny fraction of Western Interconnection supply resources. NERC Electricity Supply and Demand Report the total potential capacity resources in the Western Interconnection is over 195 GW. In contrast, the amount of flexible capacity at Glen Canyon (i.e., amount that can respond to market prices and follow daily load patterns) is almost always less than 340 MW under the No Action alternative; that is, only 0.15% of the total capacity. Except for Alternative B the level of flexible capacity under other alternatives is lower than No Action. Since there is currently no shortage of capacity in the region and none is expected to occur in the future it is highly unlikely that actions taken at any single resource in the interconnect would have an appreciable impact on market prices under almost all conditions. If there was a shortage, in our expert opinion, the interconnected energy market would be less stable and more expensive since each individual generator would essentially have some degree of market power.

Comment: I recommend completion of the peer-review of the WECCi-leaks study to determine whether LMPs at western regional hubs are, in fact, insensitive to changing output of the SLCA/IP hydroelectric plants.

Response: LTEMP EIS alternatives are directed specifically at Glen Canyon Dam, not the entire SLCA/IP federal hydropower system which are upstream of the dam and largely unaffected by EIS alternatives. Since Glen Canyon Dam accounts for 75% of the SLCA/IP capacity, 25% of the capacity is unaffected. A more detailed response to the impact of Glen Canyon on energy market prices is provided below.

Comment: Although the ANL document states (p. 10) that load forecasts will be taken from WAPA member Integrated Resource Plans (IRPs), the authors should ensure that all of these plans are based on a consistent set of assumptions.

Response: The IRPs used were all written and published about the same time (all but one IRP document was published in 2012 or 2013). They do not all use the same assumptions about fuel prices and costs. However, in our judgement, in terms of load growth, it is the best source of information to use since each utility is knowledgeable about the economic situation/trends, demographic makeup/trends, and population/industrial growth in its service territory. These are the main drivers of load growth. Factors such as delivered fuel prices and the price of energy *are important for the selection of technologies used for capacity expansion. These and many other underlining assumptions are all consistently applied across all utilities modeled for both capacity expansion and dispatch runs; this is, consistently based on AEO projections made by EIA.*

Comment: With regard to renewable resource requirements, the document (p. 11) states that renewable resources will all be assumed to be located in the specific state having the requirement. That is incorrect. The least-cost renewable generation should be developed, regardless of location. Moreover, ANL assumes one type of renewable generation in each state. It seems reasonable to have Aurora model wind and solar resources and add what is least-cost, especially given those resources' different operating characteristics and effect on ancillary services required.

Response: The purpose of this study is to look at the economic costs of changes in operations at Glen Canyon. The AURORA model did not expand wind and solar resources above the mandated state RPS which remained static among alternates. We agree that building only one type of variable energy resource in a state is most-likely not the optimal way to comply with the RPS. Given the overwhelming complexity of determining the optimal mix it is well beyond the scope of this study and the capabilities of the AURORA model. At a minimum the model must be able to operate at sub-hourly time steps - 5 minutes or less for dispatching, and in the range of 6 seconds or less for ACE/AGC simulations. In addition, a realistic treatment of wind and solar production forecast error would need to be incorporated into the model. It is our expert opinion that a different mix of wind and solar resources would have very little impact on the value of Glen Canyon Dam and a negligible if any impact on differences among alternatives as well as alternative ranking.

Comment: It seems more reasonable for a sensitivity analysis to be based on a 50% to 99% range, rather than a 90% to 99% range, so that the study can provide an upper bound economic impact associated with the alternative operating criteria.

Response: A 90% exceedance level is the base case but sensitivity study was performed for a 50% and 99% exceedance level. Hopefully this is clearer in the revised methods document (Appendix K). The 90% exceedance level is used to determine the amount of SLCA/IP capacity that can be credited toward the power system reserve margin. It is based on the coincidental time series of capacity values for all SLCA/IP resources for all 21 traces over the 20-year study period. The 90% exceedance level is consistent with the level that Western has used in the past when offering capacity contracts to its customers. An average hydropower condition is used to model energy production in the AURORA model capacity expansion runs because this better approximates the economics of energy values over the study period which is a much different product than capacity. The 50% exceedance level discussed on pages 14 and 15 of the December 2014 method document (and now on page K-27 of Appendix K.1) is used select GTMax-Lite model inputs for the Yampa River. The monthly Yampa River water flow into the Green River at the confluence of the Yampa and Green rivers is based on monthly flow rate exceedance curves that are constructed from historical USGS gauge flow data. Half of the time Yampa flow rate at the confluence was greater than the selected flow level and half of the time it was lower. These flows are important because it impacts flows at the Jensen Gauge, which is 29 miles downstream *of the confluence. Rather than stating the Yampa River flow as an exceedance level, it may have been less confusing to use the term median flow. You can find more details about exceedance levels in the document that collates responses for all peer reviewer comments.*

Comment: If the impacts of GCD from the alternative operating criteria are all modeled based on a 90% exceedance level, then shouldn't the generation output provided by the GTMax-Lite (2) facilities be modeled based on the same exceedance levels?

Response: Capacity and energy are two distinctly different product and are therefore treated differently. Capacity expansion is based on risk and the need to make decision at the moment based on an uncertain future due to the long-lead time that is required for planning, permitting, and constructing new facilities. On the other hand, operators can quickly adjust to hydropower conditions. It is unrealistic to assume that adverse hydropower conditions would continue throughout the life of a project.

Comment: I assume that there is a high degree of correlation between flows into GCD and flows into the other hydroelectric facilities.

Response: This correlation is accounted for in the CRSS and SBM which provide inputs into GTMax-Lite configurations. Aspinall powerplants are a tightly coupled and modeled as an connected cascade with water flow and reservoir interactions.

Comment: Will the overall present value cost associated with the different GCD operating alternatives be based on the sum of eight individual expansion plan changes, or will the eight largest customers be modeled as a group?

Response: This has been clarified in the methods document; all customers (both large and small) in combination with SLCA/IP federal hydropower resources are modeled as a single group (or system) for capacity expansion and dispatch purposes. Loads are modeled for individual large customers and as aggregates for small customers and project use loads. Aggregation is based on geographic location. Loads may be summed to get a composite total.

Comment: I note that page 20 states, "All other CRSP facilities in the SLCA/IP system are upstream of GCD and are assumed to have identical monthly-level operations (i.e., water releases and reservoir conditions) under all alternatives and sediment conditions." I assume this means that these facilities will be operated solely based on hydrologic conditions as they are now.

Response: Operational constraints for these upstream facilities are constant among alternatives, but hydrological conditions will be different in the future as projected by monthly CRSS/SBM ensemble forecasts. Hourly modeling of these resources reflects these changing conditions.

Comment: Spot market prices reflect existing power system constraints (e.g., forced outages) and loads that fluctuate with weather.

Response: Based on our interpretation of AURORA model documentation and discussions with EPIS staff (distributor of AURORA), loads represented in the default AURORA Western Interconnection model cover the entire range from night time lows to daytime peaks that vary from day to day. Zonal representative load shapes are derived from historical observations and then "normalized." Shapes are adjusted over time such that they are consistent with monthly and annual energy and peak load targets. These zonal shapes are not coincidental and therefore are not driven by actual weather events/patterns. Future loads are based on peak load and total load growth rates. Therefore at the zonal level, the full range of expected hourly loads is represented. It is not known, if the method utilized by EPIS produces a coincidental peak that is either higher or lower than the actual level. We assumed that it is not substantially different. If that assumption is correct, spot market prices should reflect a wide and representative range of Western Interconnection loads. The AURORA model accounts for outages by derating unit capacities. We agree that this representation will tend to dampen modeled price volatility. When Western's customer loads were modeled in Aurora using the detailed SLCA/IP system representation (the middle tier analysis - see Appendix K.1; namely section K.1.3.2), Argonne used a representative hourly sequence of loads based on historical, coincidental observations (see Appendix K.1 for more details). These loads are driven by historical weather conditions that occurred concurrently over the entire footprint modeled.

Comment: By using the set of scalars shown in Table 1, ANL assumes that the same weather pattern and outages observed in 2013 will continue for the entire 20-year study period. That is not reasonable.

Response: As long as a full range of loads are represented in the model (as we have done), attempting to model the weather accurately over the 20-year time period is not practical. Keep in mind that the primary purpose of the analysis is to rank alternatives and provide information on the relative magnitudes of the economic impacts of alternatives. It is not intended to project hourly market prices for current or next day trading-- using one or more different weather patterns to drive 20-years of load patterns would be very expensive and time consuming, and in our opinion provide decision makers with little additional information.

Comment: It is unclear whether the authors used actual 2013 load patterns in Aurora for their validation.

Response: We used the default load pattern provided by EPIS for WI market price forecasting (top layer analysis). However when modeling the SLCA/IP system in more detail (middle tier analysis) model runs were based on a typical year load profile for the aggregate system. The selection of this year was based on a detailed examination of historical load profiles for the 8 large customers.

Comment: The other option for validating the Aurora results would be to estimate a simple econometric model of 2013 hourly loads based on weather characteristics and use the results to construct a set of hourly weather-normalized loads for the year. These weather normalized loads could then be input into Aurora and the calibration analysis re-run.

Response: We disagree that simply changing the load profile would correct the problem. Attempting to find and correct (if even possible) for the root cause of price differences between model outputs and actual values would be an arduous and difficult task. In the document we list many shortcomings of large system scale modeling. Many of which have challenged modelers for decades. It is beyond the scope of this analysis to solve these issues. Rather in the document we show that the prices are reasonable based on historical correlations amount energy prices and natural gas and the projected price of natural gas made by EIA and the energy prices used by the model. Since energy prices are volatile and uncertain, any additional efforts would be better spent on an energy price sensitivity analysis.

Comment: If the scaling does change the relative cost ordering of the alternatives, then additional analysis and calibration will be required.

Response: Such an analysis would require another entire set of runs using unscaled prices and would be a time consuming and costly task. We do not believe this analysis would fundamentally change our conclusions regarding the relative impacts of alternatives.

Comment: Attachment 8 states that price adjustments between 2012 and 2015 are based on the Western Regional Consumer Price Index (CPI). I suggest this is an inaccurate approach.

Response: The discount rate discussion is now Attachment K-4. It is in the appendix to provide background for the selection of a 3.375% discount rate for the LTEMP study. The paragraph above Table 1 does discuss how prices for "economic modeling" were adjusted to a reference or baseline year. However, that is not the technique used in the LTEMP study. Attachment K-8 describes how prices were brought to a baseline year. In a future version of the document we should delete the paragraph before Table 1 and after Table 1 to avoid confusion.

Comment: Prices would be more accurately adjusted (and more commonly adjusted in these sorts of analyses) using the gross domestic product implicit price deflator (GDPIPD).

Response: As described in the revised document, we used the GDPIPD where appropriate.

Comment: ANL assumes that the required level of ancillary services (referred to by ANL as "flexibility") remains constant across alternatives. The forecast of ancillary services required is shown in Table 2 (p. 30). There is no documentation of this forecast and no explanation why ancillary service requirements remain constant after the year 2030.

Response: The section describing ancillary services (AS) now has considerably more detail. The AS projection was provided by the Western Area Power Administration in May 2013 and was predicated on a considerable amount of variable energy resources being constructed during the LTEMP study period and not because of SLCA/IP customer load growth. However, in December 2014 Western said their AS projection had changed considerably and that original projection was much too aggressive. Although it was too late to make new model runs, the power system team performed a sensitivity study on AS which is described in the methodology document which is Appendix K.1.

Comment: In my previous review, I noted that the proposed flow restrictions reduce GCD's provision of ancillary services.

Response: As discussed in more detail in Appendix K.1, operating criteria do not affect the ability of GCD to provide ancillary services. This is primarily due to the fact that flow restrictions are applied to average hourly flows (not instantaneous flows) and exception criteria that allow operations to exceed restrictions under grid emergency situations.

Comment: I am concerned that ANL's proposed methodology can double-count impacts that are already incorporated into its capacity cost impact methodology.

Response: There is no double counting. Ancillary services impact our estimates of firm capacity (i.e., the marketable capacity that Western sells to customers on a long-term firm basis). Western has historically backed out capacity needed for ancillary services when determining the level of capacity it would market to its customers. These operating reserves typically affect the hourly dispatch of a plant. However, in the case of GCD it typically does not because of the aforementioned flow averaging time and exception criteria. It only effects operations under high hydropower conditions when the plant will be allowed to operate at its maximum potential output. Under all alternatives, operating criteria rarely allow the plant to operate near this maximum. Note that under most hydropower conditions the maximum release rate is 25,000 cfs. The maximum physical combined flow rate of the turbines is about 33,000 cfs at the nominal head.

Comment: Previously, ANL suggested that other generators will provide the lost ancillary service capacity, reducing those generators' output to meet demand will be reduced commensurately. As I pointed out, this would lead to an overestimation of the capacity impact from the GCD operating restrictions. Given the continued lack of detail over the modeling of ancillary service impacts, I cannot determine whether ANL's proposed approach is reasonable.

Response: On rare occasions when Glen Canyon Dam is unable to provide ancillary services (due to outages or hydropower conditions) these duties are shifted over the plants in the Aspinall Cascade. This is a standard business practice that we mimic in the GTMax-Lite model.

<u>Reviewer 2</u>

Comment: The discussion of GTMax-Lite raises some issues that need clarification, in particular the discussion of how the Fontenelle-Flaming Gorge and Aspinall "cascades" are treated. According to the draft document, "reservoirs in the first cascade [Fontenelle-Flaming Gorge] are very loosely connected, but reservoirs in the Aspinall Cascade are very tightly coupled." Is the tightness of the connection just embodied in how the hydraulics are modeled or is the connectivity also captured in how the objective function of GTMax-Lite (which I assume would also apply to the full version of GTMax) is specified?

Response: Reservoirs and power plants in the Aspinall Cascade that consist of Blue Mesa, Morrow Point, and Crystal are tightly coupled in terms of hydraulics because the three *reservoirs are all connected by the Gunnison River and water flow travel times between these reservoirs are short (i.e., less than one hour). In addition, reservoir operating constraints at Morrow Point and Crystal often require releases be coordinated in order to comply with reservoir operating criteria. The tight coupling is described in more detail in Appendix K.1. Both reservoir operating constraints and environmental release requirements from Crystal impact model economics (i.e., the model objective to maximize the economic value of hydropower). On the other hand, on a short term basis, Flaming Gorge operations are only loosely connected to (or dependent on) upstream operations at the Fontenelle reservoir. The connections are significantly looser than the Aspinall Cascade operations because releases from Fontenelle are constant and the Flaming Gorge reservoir is much larger and has less operating restrictions than the Crystal reservoir. Operations of both cascades are optimized simultaneously in a single model formulation; however, there is no hydraulic connection between the two cascades. The operations of both reservoirs are driven by the same market price vector that is used by the objective function.*

Comment: Later on in the discussion of GTMax, there is a statement about how water is released and stored diurnally, namely, "To the extent possible the GTMax-Lite model uses its limited energy/water resource stored in a reservoir (i.e., Lake Powell at the GCD) to first generate electricity during on-peak hours when it has the highest economic value. Any remaining energy is scheduled during lower-priced hours." This is a little different from my understanding (and my understanding can certainly be incorrect) that water is released during on-peak periods to meet firm contract commitments (which are more valuable to Western customers during on-peak periods) and any off-peak demand is met either through off-peak period releases or purchases for resale (which costs less to Western customers). These two interpretations suggest different ways of specifying the objective function in either GTMax or GTMax-Lite. Perhaps this is too subtle a distinction to raise, and perhaps one problem is the dual of the other problem.

Response: The objective function in GTMax-Lite is to maximize the economic value of energy generated Glen Canyon Dam Powerplant operations driven principally by a time vector of market prices specified by the user. Operations must comply with operating criteria specified by an Alternative. We agree with the reviewer that the price-driven problem formulation will at times differ from the full GTMax model which places a priority on using SLCA/IP federal hydropower resources to first meet long term firm customer loads. If there is any energy left after serving project use and firm loads, it is sold on the market. We originally planned to use the full GTMax model, but time and budget constraints necessitated the use of GTMax-Lite because it requires significantly less input data and user interactions. It also runs considerably faster. The decision to use GTMax-Lite was justified on technical grounds because both models produce similar generation patterns. That occurs because load and market prices have very similar, albeit not always identical, shapes. Also, this is also an economic analysis in which we are modeling the system-level benefits of Glen Canyon Dam as opposed to customer-specific benefits. For example, Western's firm energy sales to a customer may enable that customer to use its own generating resources to sell more energy on the day-ahead and/or real-time markets. Financial transaction among individual entities are not tracked in this economic analysis, but are indirectly accounted for in the least-cost system modeling methodology used by the power-systems team.

Comment: On pages 25 and 26 of the draft document, the "limits and equations" that are used to compute "power plant maximum possible output levels for CRSP power plants" (page 26) are specified. This is preceded by noting that "the marketable capacity used for planning purposes (or the Aurora model expansion mode) differs from the maximum output-level that is achievable during the system dispatch" (page 25). What about hourly dispatch? Presumably, storage changes continually (with inflows and releases), releases cause generation and outflows, storage and elevation are updated, etc. How is the (functional) relationship between turbine capacity, reservoir elevation, water storage, water release rates, head (as a function of forebay and tailwater elevations) specified? It sounds like from the discussion that there is a distinction between how "maximum possible output levels" are determined and how hourly generation based on releases (and the other factors stated above) is determined. If there is a difference, then the discussion should be expanded to include the model structure for hourly dispatch, generation, and the state variables of the model.

Response: Additional text was added to the document that should clarify the difference between firm capacity used for the purpose of AURORA model reserve margin calculations and the powerplant maximum output used for hourly SLCA/IP federal hydropower plant dispatch. The determination of firm capacity is based on: (1) a statistical distribution (in terms of an exceedance curve) of projected capacity based on CRSS/SBM outcomes of reservoir elevations and releases during the month of August; and, (2) a user specified exceedance level (i.e., risk of not having adequate capacity). A single firm capacity level is used throughout the study period. In contrast, the maximum powerplant production for hourly dispatch is based on monthly hydrological conditions that vary over time and among both alternatives and hydrological traces.

<u>Reviewer 3</u>

This reviewer made many editorial comments that were incorporated into the revised document so it was clearer and more understandable. Technical comments are addressed below.

Comment: 105 monthly traces implies 8.75 years. Is this the meaning of "monthly trace"? If so, why 8.75 years, and how do those 8.75 years relate to the 48 years from 2013 through 2060? Are the 105 traces repeated to "fill out" the 48 years?

Response: We used an ensemble forecast that consists of 105 monthly time series of plausible hydrological conditions data over the 20-year study period. It is not a single forecast that has a duration of 105 months. This is clarified in the draft final EIS.

Comment: It would be nice to know what kinds of contracts are omitted, and perhaps something about the order of magnitude. Contracts to sell what by whom to whom? For what duration? In what amounts?

Response: Instead of using hourly requests for generation from Western's customers as the driver of hourly operations at the hydropower facilities, it was assumed that the driver would be market prices; that is, generation would be scheduled to maximize the electricity value within *the operating criteria constraints of the hydropower facilities. The assumption is that customer power requests track electricity prices. This method was used because it is streamlined and solves the problem much faster. This method is now described in more detail in K.1.5.4.*

Comment: I understand that Aurora is an hourly unit commitment and system dispatch model. At some point, a discussion is necessary regarding intra-hour or sub-hourly operations, because of the growing importance of ancillary service markets. Capacity set-asides for regulation and spinning reserves are discussed below, so the topic is relevant. Is Aurora taking into account the growing role of solar in the West, which is producing new hourly price patterns? Or is GCD economically isolated from that phenomenon due to various constraints (legal, contractual, technical)?

Response: The modeling of ancillary services and Glen Canyon's role in supplying them is addressed in several previous comments.

Comment: Some additional justification for scaling Aurora to 2013 actuals seems to be required. Again, what if 2013 were an outlier for some reason? What if Aurora were compared with 2012 actual prices? Would that reinforce the need for scaling Aurora to "actual" prices?

Response: This comment about price scaling is addressed in more detail in a previous comment. We also addressed it in more detail in K.1.5.10 and Attachment K-2.

Comment: This figure refers to a new concept (or maybe just a label): load following, which looks like regulation. I suggest sticking to one term to describe a given service. Also, the figure appears to suggest that regulation services are provided by the same capacity that is available for spinning reserves. If that is the case, then it should be explained. If not, then the figure needs to be fixed. [LP54]

Response: We will clarify the use of load following in the figure in the final EIS.