BAMx Comments on the CAISO Draft 2013-14 Transmission Plan

The Bay Area Municipal Transmission group (BAMx)[1] appreciates the opportunity to comment on the CAISO Draft 2013-14 Transmission Plan (Draft Plan). The comments and questions below address the multiple *Draft Transmission Plan* studies, findings and recommendations included in the CAISO Draft 2013-14 Transmission Plan dated February 3, 2014 and were subsequently discussed during the February 12th stakeholder meeting. We request that the CAISO address these issues in its Revised Transmission Plan expected in March 2014.

Introduction

As detailed below, BAMx believes that the CAISO has done an excellent job in the 2013-14 Transmission Plan in a number of areas:

1. **Evaluation of the Impact of Preferred Resources:** The CAISO efforts in this area, although in its early stages, has taken a major step forward in identifying the likely impact of preferred resources on the transmission grid.
2. **Cooperation with State Agencies**, especially with the CPUC's 2012 LTPP Track 4 proceeding.
3. **Comprehensive Study Approach,** in particular, the refinement of the probability of occurrence and likely impact of rare events in the San Francisco peninsula.

Most of the BAMx comments below are driven by a concern about the impact of the CAISO's proposed recommendations and decisions on the Transmission Access Charge (TAC) for load served on the CAISO grid. The High Voltage (HV) TAC projections made by the CAISO, which we believe understate the likely future increases, indicate that the HV TAC is expected to increase from the current rate of $8.5/MWh to $13.5/MWh in 2023.

We believe that the steep increases in HV TAC, which has risen from $1.4/MWh when the CAISO was formed, deserves the utmost attention by the CAISO management, as well as the Board of Governors (BoG). We have some suggestions in these comments that are consistent with the objectives of providing a reliable CAISO electric grid at least cost to its customers.

Below we provide comments on the six (6) major areas.

- Reliability Assessment;
- San Francisco Peninsula Extreme Event Assessment;
- Southern California (LA Basin/San Diego) Reliability Assessment;
- Policy-Driven Studies and Recommendations;
- Economic Studies and Recommendations; and
- Transmission Program Impact on HV TAC

[1] BAMx consists of Alameda Municipal Power, City of Palo Alto Utilities, and City of Santa Clara, Silicon Valley Power.
[2] WECC Supporting Document for Reliability Criteria for Transmission Planning, August 1994.

Reliability Assessment

Below we provide some comments and questions on the transmission projects that are recommended for approval by the CAISO based on the Reliability Assessment.

Mesa Loop-In

As we have stated in our comments dated October 10, 2013, the Mesa Loop-In project is presented as a mitigation to address two different *T-1-1* (C3) contingencies. Loss of a 500/220 kV transformer is very rare. WECC published data indicate a failure rate of about one in 27 years (compared to once in seven months for a transmission line)[2].

That would suggest that the probability of the independent overlapping loss of two transformers would be extremely rare. Therefore, before concluding that the appropriate mitigation for this extremely unlikely and rare event is the construction of a $550M-$700M transmission expansion, consideration should be given to less expensive measures including fire walls between transformers, system spares in addition to the on-site spare and utilizing customer interruption as a backstop measure. Since customer interruption is allowed under WECC and NERC standards for Level C events and is the mitigation used on the CAISO grid for rare, but much more likely events, it should be considered for this extremely unlikely event/overlapping contingencies.

The Appendix C (2013/2014 ISO Reliability Assessment - Study Results) of the Draft Plan identifies additional reliability issues in the SCE LA Basin area that could presumably be addressed by *Mesa Loop-In* along with the remaining *Group I* transmission projects. As we elaborate in our comments on the "Southern California Reliability Assessment," there are potentially additional competing alternative mitigation measures available to address those issues besides building new expensive transmission projects.

Henrietta 230 kV breaker-and-a-half Upgrade

The Draft Plan[3] mentions a *Henrietta 230 kV breaker-and-a-half Upgrade* project, which entails "Reconfiguring the existing 230 kV buswork to a breaker-and-a-half configuration to improve substation reliability." This project is expected to cost more than $50M, and will require a BoG approval. However, the Draft Plan does not provide any justification for the recommendation for this project. Moreover, this project was not presented in the February 12th Stakeholder meeting. We request that the CAISO not recommend this project for approval in the 2013-14 Plan without a more detailed project justification and proper stakeholder review.

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[2] WECC Supporting Document for Reliability Criteria for Transmission Planning, August 1994.
[3] ***Executive Summary*** and *Table 7.2-1: New reliability projects found to be needed*.

Midway-Kern PP #2 230 kV Line

The CAISO's Draft Plan recommends this project, which entails reconductoring and unbundling the existing Midway-Kern PP 230 kV line into two circuits and looping one of the new circuits into the Bakersfield substation. The stated reason for the reconductoring is to match the rating of the rest of the circuit into which it is looped. Is it possible to avoid reconductoring of the 12-mile segment of the line going into Bakersfield substation by terminating both of the circuits into Bakersfield Substation at Kern PP? If so, would that allow the CAISO to postpone reconductoring the Midway-Kern #1 line? In the Final Transmission Plan, please clarify why reconductoring was selected over looping the 230 kV into Kern PP.

Morgan Hill Area Reinforcement Project

The CAISO's Draft Plan recommends this project, which entails constructing a new 230/115 kV substation, Spring Substation, west of the existing Morgan Hill Substation. The CAISO has recommended this project to increase the reliability of the Morgan Hill area by adding a new source into the area. According to the CAISO, the new 115 kV source will avoid potential electric load interruptions for most of the Morgan Hill and Gilroy area, following the loss of the Metcalf-Morgan Hill and Metcalf-Llagas 115 kV double circuit tower line (Category C5).

The CAISO **planning standard 6.1** indicates that up to 250MW of load can be dropped for a category B event.[4] What is the CAISO policy for loss of load for a category C event? If there is no such loss of load policy for category C, then a Benefit to Cost ratio (BCR) should be calculated to justify a transmission project.[5]

Description of RAS

BAMx appreciates CAISO's development of the Table 3.3-1 in the Draft Plan, which summarizes the recommendations for each SPS reviewed and updated as a part of the 2013-2014 transmission planning process. BAMx believes this table can be improved by providing more details on these SPSs in the Revised Transmission Plan such as, the type and amount of generation or load tripping allowed under the SPS.

San Francisco Peninsula Extreme Event Assessment

The CAISO, with PG&E's cooperation, has done a credible analysis of trying to assign some probability of occurrence and assess the consequences of some extremely unlikely events. BAMx applauds these efforts and the CAISO's recognition that more work needs to be done prior to any major new infrastructure (costing approximately $450-$550 million) to be recommended for approval to the CAISO BoG. At the same time, BAMx supports the concept of spares and other inventory to minimize outage times, as well as the concept of hardening the system. The CAISO's analysis is unparalleled in California in its effort to quantify the probability and impact of unlikely transmission system events, finding that seismic risk greatly

[4] **Source:** "Planning for New Transmission versus Involuntary Load Interruption Standard," in California ISO Planning Standards, dated June 23, 2011.

[5] *Ibid*. CAISO planning standard 6.4 states that "Upgrades to the system that are not required by the standards in 1, 2 and 3 may be justified by eliminating or reducing load outage exposure, through a BCR.

surpassing other identified risks. We also agree that in case of a large seismic event there would likely be damage to significant infrastructure in the area, including both the transmission system and the distribution system and, therefore, it is unlikely that the entire load serving capability would need to be immediately restored.

Given the cost of new supplies into San Francisco and the potential that any such new equipment could also be damaged in such an event, BAMx supports continued study of this risk in the next Transmission Planning cycle. While the CAISO has focused on further analysis of the reliability risks and the benefits that potential reinforcement options would have in reducing those risks, there are additional areas that should be explored in the preparation of a plan. BAMx identified such areas in our comments dated June 19, 2013 (attached as Exhibit A).

We have also had the opportunity to review and consider comments made by others including the CPUC staff. BAMx endorses the following points made by the CPUC staff, which request that the Final Assessment should include

- A Consideration of Extreme Events across the CAISO Balancing Authority Area before Approving Major, New Transmission Projects as Part of the SF Extreme Event Assessment.
- Examination of Seismic Effects on Distribution Substations, Even If Not Modeled.
- List of Potential Mitigations Including Portable Generators and "Hardening" the Existing Facilities.
- A Discussion of Geologic and Soils Hazards for Underground (Dry Land) and under Bay Transmission Project Alternatives.
- Seismic Risk Information in Terms of Probabilities and Examples of Historical or Hypothetical Earthquakes Relevant to the Calculations.

We also support the CPUC's contention that the San Andreas Fault could cause extensive damage that would affect San Jose, San Diego, or the portions of the greater Los Angeles area within the CAISO's balancing area. We, therefore, request that the CAISO assess the consequences of loss of 115kV and 230kV busses and the outage of the entire Ravenswood and Newark substations. We do not believe the character of the load in San Jose, Santa Clara, Mountain View and Palo Alto is much different than that of the upper San Francisco Peninsula and most of the City and County of San Francisco. Each substation would be subject to damage by the earthquake under consideration.

While BAMx supports continued analysis before embarking on major system upgrades for such Category D events, this support for analysis should not be taken as advocating inaction. BAMx supports work on restoration plans and spare equipment strategy to minimize outage times for seismic events throughout the San Francisco Bay Area. BAMx also supports consideration of opportunities to harden the system to make it less susceptible to the types of extreme events considered.[6]

[6] This includes, but limited to, such actions as recently announced by PG&E to increase the security measures at critical substations.

In the identification of a preference for the Moraga-Potrero 230 kV solution, the CAISO noted that PG&E has identified some preliminary emergency cable ratings in San Francisco that, when coupled with the new Embarcadero-Potrero 230 kV cable, would mitigate the 115 kV constraints to receiving additional power at Potrero. BAMx requests that more information be made available about these emergency ratings, including any limitations on their use and to what extent they would mitigate the deficiencies identified in the assessment of this area. The CAISO's analysis has also shown that such a new supply into San Francisco does not need to be of Direct Current (DC) design to control flow. This could be an important cost saving measure. However, the CAISO was silent as to whether other AC forms of flow control may be needed, either series reactors as PG&E proposed or a phase shifter. Consideration should also be given in the Plan of Service to accommodating the future installation of control equipment, should it be needed.

Southern California Reliability Assessment

BAMx supports the rapid progress that has been made in understanding the electric system performance and needs without the San Onofre Nuclear Generating Station (SONGS) and the Once-Through Cooling (OTC) generating units in southern California. While recognizing it is a difficult task, BAMx appreciates the coordination with other State Agencies that has occurred. We especially appreciate the standardization of assumptions across the CPUC Track 4 Long Term Procurement Proceeding (LTPP) and the CAISO Transmission Planning Process, as well as bringing the description of the residual reliability need to a common basis to facilitate the comparison of alternatives. The CAISO has also made great strides in advancing the efforts to identify characteristics and locations of preferred resources, which can be used to most effectively provide for an electrical grid for the LA Basin and San Diego that complies with the State's Loading Order. We recognize this as an early effort in this area and highly encourage the CAISO to build upon this early effort in future analysis.

BAMx also supports the CAISO restraint in not seeking to identify transmission improvements to address the entire residual reliability need in this initial cycle so that future iterations in local resource procurement and demand side programs can be considered. It is important to recognize that there are backstops available to preserve reliability to the area in the event local supply and/or demand side solutions do not fully materialize. Such backstops include potential extension of the OTC unit compliance dates with SWRCB requirements, extension of the economic life of the non-OTC units currently assumed to retire, extending the reliance on the San Diego SPS, SCE's proposed backstop generation siting, etc. Such backstops allow for measured steps to be taken with respect to transmission expansion to help avoid excessive ratepayer impacts.

As an extension of the CAISO's efforts to coordinate with State Agencies, we encourage the CAISO to reevaluate the candidate transmission projects with full consideration of the final decision on CPUC LTPP Track 4 procurement.[7] The transmission planning process would

[7] "Decision Authorizing Long-Term Procurement for Local Capacity Requirements Due To Permanent Retirement of The San Onofre Nuclear Generations Stations," CPUC Rulemaking 12-03-014, dated February 11, 2014.

benefit from closer coordination between the CPUC and the CAISO The CAISO has already decided to defer the recommendation of some transmission projects to a later date with the possibility that the CAISO management may come to the CAISO BoG after March 2014 and propose these transmission additions as amendments to the 2013-14 Transmission Plan. The CAISO should consider the final decision on the Track 4 proceeding, which should be available shortly, before recommending transmission solutions. This will also allow the CAISO to perform further analysis and to resolve some issues surrounding the projects proposed in the current Draft Plan. We believe a few months delay on the final decision of which transmission additions should be included in the 2013-14 Transmission Plan is justified. The CAISO's delaying of its decision on *Group I* projects as it further refines its work on the effect of preferred resources and fully accounts for the resources authorized in the ultimate decision in Track 4 process would represent the next step in State Agency co-operation on this issue.

This Draft Plan identifies a large number of potential upgrades of varying cost and efficacy. While the CAISO has done exhaustive work in identifying this menu of transmission alternatives, we are concerned that the method of selecting from the menu may not result in the most economic, least regrets transmission plan. The Draft Plan parses the upgrades into three groups based upon their utilization of existing transmission lines and, for new lines, whether they are intra- or inter-area lines. Then for these three groups of upgrades, the CAISO identifies the potential benefits in reducing the residual need for local resources. Based upon this analysis, the Draft plan recommends proceeding with the *Group I* Upgrades.

BAMx believes the best metric for decision-making would be a complete analysis of the economic impact of each transmission alternative. Ideally this would include the complete economic impact of trading off increased transmission to import existing generation into the LA Basin and San Diego local areas against the preferred or gas fired resources within the local areas under consideration in the Track 4 proceeding. We would encourage the CAISO to consider employing its modeling expertise to perform such economic analysis based upon a reasonable set of assumptions. We encourage the CAISO to perform this type of analysis in next year's (2014-2015) TPP. In the further analysis for this year's plan, it would be good to include a metric that captures the relative capability for the transmission solutions to offset preferred and/or gas-fired local resources in the local areas of concern. A simplified high level, useful metric could simply be the cost of a transmission alternative divided by its kW reduction in the residual local need ($/kW). As these benefits are non-linear, the incremental benefit of each upgrade varies based upon the assumed sequence of upgrades. Therefore, several values of this metric would be appropriate with each reflecting the assumed sequence in the series of upgrades. This simplified approach should be achievable in the further analysis contemplated for this year's amended plan.

Such a metric also suggests a potential sequence of priority for approval (though not necessarily a chronological sequence). The initial pass at a package of solutions could then be built up by incrementally selecting the next most efficient from this metric's perspective. Once the target transmission capacity is reached, the resulting package of upgrades can be reordered chronologically to test whether the upgrades provide adequate capacity in the intervening years until the development of the full package is forecast to be complete. If there are reliability issues in the intervening period, adjustments to the plan can be made.

We believe this approach would be more likely to afford a focus on the most cost-effective transmission solutions. Based upon the rough numbers presented so far, the most costly *Group I* project is probably the Mesa Loop-In. This CAISO analysis of this project based upon its assumed sequence of project approval, shows a reduction of local generation need of between 300MW to 640MW. However, the cost of up to $2,333/kW appears expensive, especially compared to the other *Group I* projects. Furthermore, based upon the CAISO presentation, the *Mesa Loop-In* cost could increase to over $3,097/kW if it is considered incremental to the *TE-VS-new Case Springs 500kV* line in the *Group II*.

Based upon the information presented as indicated above, BAMx believes additional analysis is called for before deciding on a group of projects to be included in a revised 2013-2014 TPP. If the CAISO decides it wants to go forward now before such further analysis, we would recommend the incremental least regrets approval be given to the Imperial Valley Flow Controller, assuming that the desired control can be accomplished by the less expensive Phase Shifting Transformer (PST). Such early approval of the clearly most cost effective solution may help with achieving CFE support for it. If such an effort is unsuccessful, a more expensive control solution, such as the back-to-back DC (B2B DC), can be further considered as a candidate transmission project in an amendment to this year's plan. As part of that additional analysis, if the PST is proposed to be replaced by the B2B DC, the CAISO needs to clearly describe why the PST is not an adequate solution. If the decision will primarily be driven by CFE requirements, it is important to know what is the driving requirement(s) and how might they impact the ability to reduce the residual resource need in the local areas.

BAMx does not support approving the other *Group I* projects at this time. The additional 450 MVAR of dynamic reactive support at San Luis Rey should be deferred until the local supply/demand solutions are better understood. As the CAISO noted in the stakeholder meeting, the San Diego system is reaching a point of diminishing benefit of incremental reactive supply. Furthermore, consideration should be given to lower-cost options such as fast-switched capacitors before specifying dynamic reactive support devices. Reactive power sources traditionally have short procurement lead times. Given that the CAISO is also proposing a +300/-100 MVAr dynamic reactive power device at Suncrest 230 kV, a least regrets strategy would be to postpone this element until the possible amended plan or until the next planning cycle.

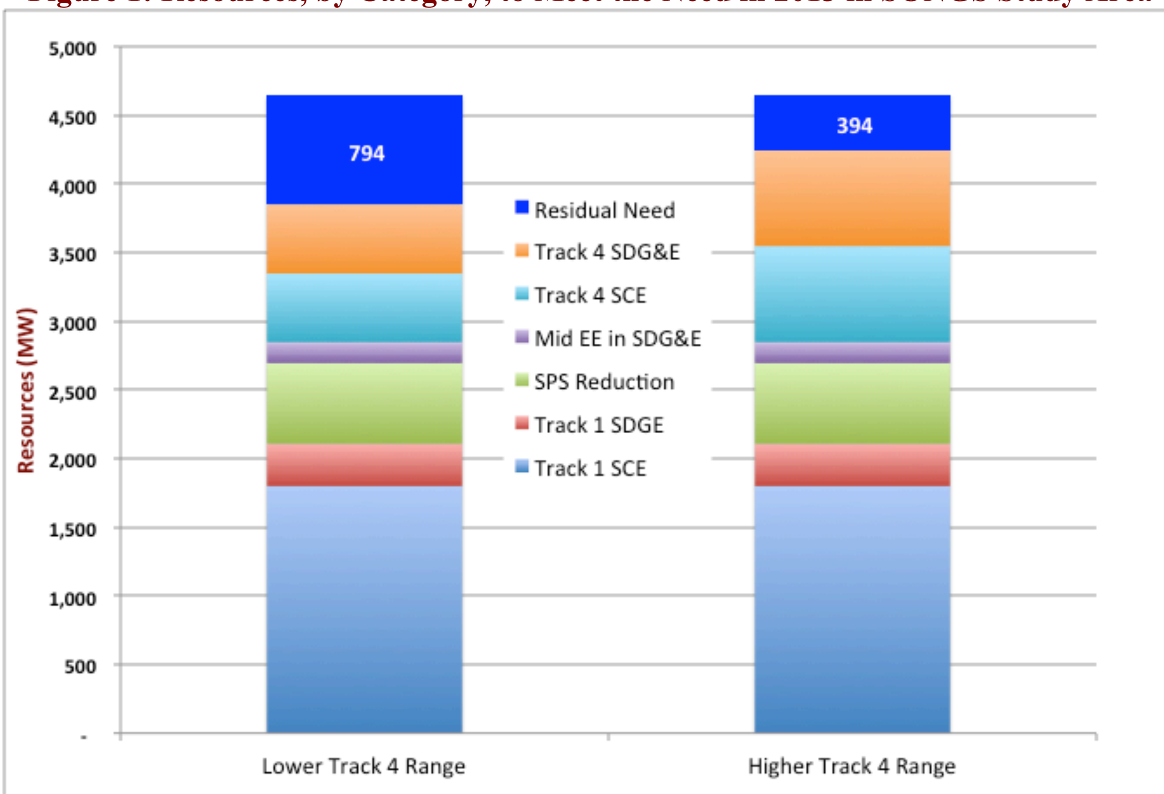
In Figure 1, we show how the current Track 1 and proposed Track 4 resource authorizations by the CPUC in 2012 LTPP proceeding stack up against the 4,642MW need identified for 2022/23 within the SONGS area[8] identified by the CAISO. It shows a residual need of 394MW-794MW depending upon the level of Track 4 authorizations that can be met by a single *Group I* transmission project, i.e., Imperial Valley Phase Shifter, which is expected to provide local resource reduction benefit in the range of 400-840MW.[9]

[8] Combined San Diego and LA Basin areas.
[9] Based upon Table 2.6-5: Summary of Proposed Transmission Solutions, Cost Estimates and Local Resource Reduction Benefits in the Draft Plan.

Alternatively, the procurement authorized in the 2012 LTPP Track 1 and Track 4 could be supplemented by

a) Procurement of additional preferred resources (beyond the assumptions used by the CAISO in Track 4 models) as anticipated in the Track 4 proposed decision; or
b) Additional procurement authorized in future LTPP proceedings; or
c) Potential delay in retirements of OTC plants to facilitate implementation of options (a) and/or (b).

Figure 1: Resources, by Category, to Meet the Need in 2013 in SONGS Study Area



Given the multiple options available to meet future residual resource need in the SONGS study area, the great strides that have been made in these procurement and transmission planning cycles, and the value in allowing time for market response to these steps, we urge the CAISO to delay the approval of projects beyond the Imperial Valley phase shifter at this time. Most questionable of the *Group I* projects appears to be the SCE proposed Mesa Loop-In project. With a benefit that can drop to as little as 226 MW[10] and a cost of as much as $614-700 million, this project does not fit a least regrets strategy and represents an unnecessary risk. It should be considered again in a later amendment or in next year's plan after full refinement of its expected cost and changes to its proposed configuration as identified by the CAISO.

[10] Table *B3-5: Assessment Summary of Various Transmission Line Alternatives Strengthening LA Basin and San Diego Local Capacity Areas* of **Appendix B** of the Draft Plan indicates with the Enhanced TE-VS project, the incremental benefit of *Mesa Loop-In* is limited to 226MW.

Policy-Driven Projects

Deliverability Assessment and the State's System RA Needs

Consistent with its past practices, the CAISO has also performed a deliverability assessment on the base case portfolio assuming all the renewable generation projects in the base case portfolio need to be delivered to the "aggregate of load" based upon a strict set of deliverability criteria. BAMx has consistently questioned the need to rely on new renewable resources to meet the State's system resource adequacy needs. As indicated by the CPUC, there is no immediate need for new system capacity.[11] This planning process is also occurring at a time that the CPUC is developing a probabilistic equivalent load carrying capability (ELCC) tool that better evaluates the incremental resource adequacy benefits of new renewables. Early indications are that there is very little resource adequacy benefit that can be attributed to the addition of new intermittent resources.[12] The CAISO should coordinate the transmission planning process and deliverability assessment protocols with the development of the ELCC to account for future changes in RA counting rules by the CPUC

There is no state policy that renewable projects should provide Resource Adequacy irrespective of economics.[13] Rather than designating transmission projects as policy-driven solely to allow intermittent renewable projects to satisfy the State's system RA needs, the CAISO should undertake a cost-benefit analysis to show that any proposed new transmission project to assure deliverability of new resources and/or to decrease envisioned congestion is justified. The CAISO needs to determine whether the new proposed transmission is both necessary and the most economical alternative to meet the State's resource adequacy needs.

Imperial Valley Deliverability Constraint

After spending $1.9 billion on the SDG&E Sunrise Powerlink, it is disturbing to find out that there is no deliverability available in the Imperial zone. This is especially troublesome as an extreme example of adverse ratepayer impact of assuming it is a State Policy to obtain RA deliverability from intermittent resources in the renewable portfolios.

The CAISO identified that adding the Imperial flow controller and restoring the Sycamore-Suncrest 230 kV line emergency ratings to the levels assumed in the previous power system studies may recover almost half (800 of 1,715) of the MW identified in the CPUC portfolios by 2018. The Delaney-Colorado River 500kV line, if approved, would increase the deliverability by another 200 MW in 2020.

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[11] **Source:** 2012 LTPP, See Appendix B. Data shown is the Base Scenario from D. 12-12-010, Appendix C, and page C-1. Also, see the presentation by Edward Randolph, Director Energy Division, CPUC at CPUC-CAISO Long-Term RA Summit, February 26, 2013.

[12] See slide #20 (Renewable ELCC) in "Renewable Energy Flexibility (REFLEX) Results," by Energy and Environmental Economics, at CPUC Workshop dated CPUC Workshop, August 26, 2013. Also see, slide #39 in the "Resource Adequacy Staff Proposals Workshop" Presentation, dated January 27, 2014.

[13] Senate Bill 2 (1X) mandated new RPS procurement requirements are renewable energy, and not resource adequacy capacity requirements for renewables.

In any event, in concert with BAMx comments above, we believe that before the CAISO approves "a major transmission upgrade" to raise the deliverability for this area, the CAISO should explore associated cost vs. benefit of such an addition. If the portfolio for the Imperial zone remains above that which can be designated as Fully Deliverable with the approved upgrades, the CAISO should only consider any additional upgrades through its annual economic planning studies to assess the cost/benefit of the line. The benefits could include any reduced congestion and availability of RA capacity of the transmission addition.

CAISO Category 1 Recommendations

The CAISO identifies the Suncrest Dynamic Reactive Power Device as a policy driven project specifying, "The dynamic reactive power support is required to provide continuous or quasi-continuous reactive power response following system disturbances. It needs to be one of the following types of devices: SVC (Static VAR Compensator), STATCOM (Static Synchronous Compensator), or Synchronous Condenser."[14] If other than cost, please identify how the CAISO will select between a SVC, STATCOM or Synchronous Condenser solution. Also, the CAISO should identify why fast switchable shunt capacitors are not an acceptable solution.

Economics-Driven Transmission Project Needs & Recommendations

BAMx Appreciates the CAISO's Efforts

BAMx recognizes the tremendous amount of effort over past several years that has been made in improving its production cost database and analysis included in its economic assessment. The CAISO staff's efforts in modeling additions/changes to the TEPPC database as well as developing the sensitivities involving loads, hydro conditions, natural gas prices, GHG models and California RPS portfolios are commendable. As we suggest in other sections of these comments, this extensive modeling effort should be utilized to help decide what is needed in the LA basin and San Diego areas to replace OTC and SONGS generation.

In our comments dated December 5, 2013, we made several arguments that question the CAISO's extrapolation of the production cost savings and the calculations of the capacity benefits associated with the candidate transmission projects. The CAISO has modified its capacity benefits assumptions and calculations; however, almost all the issues raised by BAMx have remained unaddressed. Below we have repeated some of our December 5th comments and have expanded the discussion based upon the updated analysis included in the Draft Plan.

Extrapolation of the Production Cost Benefits

We question the Net Present Value (NPV) calculations of the benefits of the candidate transmission projects. For example, when looking at the Delaney – Colorado River (DCR) 500 kV line project, the CAISO calculated the production benefits in years 2018 and 2023 to be **$31M** and **$26M**, respectively. Our understanding is that the CAISO interpolated these benefits for the intervening years and assumed a flat benefit of $26M in years 2026 onwards. We question the CAISO's rationale for such extrapolation of economic benefit. The CAISO has estimated the NPV of benefits over 50 years discounted at 7% to be **$364M**. We have verified

[14] CAISO Draft Transmission Plan, Appendix F, Section F5.1.

these calculations. However, when we apply a trend on the benefits that extrapolates them beyond 2023 (which accounts for a significant drop in the benefits from 2018 to 2023), the NPV benefit is **$264M** over 50 years. This is nearly a 1/3rd reduction in production benefit calculated by the CAISO.[15] This exercise demonstrates that the CAISO's calculation of the benefits based on only two years of data is very dependent on how the extrapolation of these benefits are calculated. BAMx believes that it is important to recognize the benefit has dropped from 2018 to 2023 and question why such a decrease would not likely continue to future years. It is likely there will be an increasing buildup of the low variable cost renewables within the CAISO BAA. We recognize the tremendous effort that goes into analyzing the results with differing assumptions on fundamental drivers such as loads, hydro conditions, renewable development, etc. However, we are concerned about the lack of scenario analysis around the 50-year projection of benefits from two data points. As indicated above, we also observe that that the buildup of renewables will continue to increase within the CAISO in the later years, forcing a reduction of the benefits of the out-of-state (OOS) transmission projects, such as *DCR* and *HAE*.

The Transmission Economic Assessment Methodology (TEAM) implemented for the Palo Verde Devers #2 500kV line (PVD2) project proposed two different ways of extrapolating the two study years' benefit to outer years. A conservative assumption was that these longer-term benefits are zero. Alternatively, the other proposal was to extrapolate the average benefits for the two years used in the study to the outer years.[16] In Table 1, we provide a comparison of the production benefits as calculated for PDV2 and DCR. In case of PVD2, since the analysis showed that the production cost benefit was actually increasing, extrapolating the average benefit of these two years was found to be reasonable. When PVD2 was studied in the 2002-05 timeframe, a large amount of renewable build-up within California was not anticipated. This is clearly not the case with the current transmission economic analysis for DCR, given the current rapidly changing regulatory and market environment. It is evident from the CAISO's production cost analysis that the production cost benefit of the candidate project is primarily derived from the difference in potential economic efficiencies of gas-fired units in Arizona relative to those in California. In addition to the potential increase in price-taking renewables built within the State in the future, the production cost benefits of the projects such as DCR would tend to decrease, as more OTC units are repowered in California with more efficient gas-fired units, as well as growth in preferred resources.

Table 1: A Comparison of Production Benefits (M$) for PVD2 and DCR in Two Study Years

Study Year	PVD2	DCR
Year 1	$41 M	$30 M
Year 2	$54 M	$25 M

[15] Applying the trending to the benefits actually results in negative benefits in the later years; therefore, we assumed the benefits to be $0M in our example calculations.
[16] See Table VII.1 in "Economic Evaluation of the Palo Verde-Devers Line No. 2 (PVD2)," prepared by the California ISO Department of Market Analysis & Grid Planning, February 24, 2005.

Therefore, due to the uncertainty around future benefits, BAMx recommends that the CAISO explicitly identify the range of uncertainty associated with the extrapolation method.

CAISO Has Not Performed Sensitivity Analysis for Capacity Benefits

The CAISO's preliminary findings indicate substantial capacity benefits associated with the Delaney – Colorado River 500 kV line project. Table 2 shows how the capacity benefits that were identified in the prior assessment to be less than **$10M** NPV over fifty years are now projected to be as high as **$150M**. Since the capacity benefits for DCR are a significant portion of the overall project benefit, essentially justifying its economic viability, we believe that the CAISO should perform several sensitivity analyses for the calculation of the capacity benefits of the proposed project, similar to the work that the CAISO has done for the production benefits. Additional capacity benefits sensitivity calculations are reasonable, as such analyses will likely take relatively less effort and time—these calculations do not require deployment of the resource intensive production cost tool and analysis.

Table 2: A Breakdown of Production and Capacity Benefit (M$) of the Delaney – Colorado River 500 kV line project Under Multiple CAISO Findings

Benefit Category	Dec-11	Feb-13	Nov-13	Feb-14
Production Benefit (M$)	$300 M	$902 M	$364 M	$364 M
Capacity Benefit (M$)	$0 M	<$10 M	$281 M	$150 M

We understand the CAISO has derived capacity benefits based on the assumptions that California will continue to have a resource adequacy requirement and that Arizona can be the source of contracted capacity to serve California load. Additionally, a key assumption for these savings is that the future cost of capacity in Arizona will be significantly less than the cost in California. For these assumptions to hold true in the long run, the following conditions need to persist:

- A need in California for system capacity above that which exists and future by capacity built in California for local and flexibility needs.
- The capital and fixed operating costs for a peaking unit must remain less in Arizona as compared with a California peaking unit or preferred resource resulting in comparatively lower capital and operating costs in Arizona which may translate into a system capacity price difference.
- There will be a greater resource surplus in Arizona than in California during the early years of the project resulting in a lower demand for capacity in Arizona as compared to California.

BAMx agrees that such a set of conditions is one possible future scenario. However, the CPUC 2012 LTPP source cited earlier suggests that the system planning reserve margin is expected to be in the range of 120% during the 2020-2022 time period. The CAISO analysis assumes California will be resource deficit by 2020-22. The CAISO has included a source to indicate the California resource deficiency in 2022.[17] Although this source highlights the need for greater

[17] CAISO's System operational flexibility modeling study using the Standardized Planning Assumptions and Scenarios as determined in the CPUC Dec 24, 2012 decision (12- 03-014).

flexible resources in the outer years, it does not identify system resource inadequacy. Furthermore, the CAISO has not provided any justification why new resources will be built in Arizona instead of within the State to satisfy the flexible upward ancillary services and load-following need. We note that during the February 12th Stakeholder meeting, several stakeholders commented that there are adequate, even flexible, resources available in Southern California that can meet the future flexible and system RA needs in the future.

The CAISO should explore additional alternative sensitivity scenarios and evaluate their impact on the capacity benefit associated with the candidate transmission projects. Furthermore, the CAISO's capacity benefits calculations assume that the entire capacity benefit would be attributed to CAISO ratepayers. TEAM, on the contrary, assumes that the capacity benefit is split equally between the buyers and sellers of capacity. Thus, if the estimated annual societal benefit for DCR is **$9 million** ($44/kW-Yr), then the assumed CAISO benefit should be half that amount or **$4.5 million**. In other words, the NPV of the capacity benefit to CAISO ratepayer, who will ultimately pay for the proposed DCR transmission project, should be restricted to **$75M**. Moreover, the capacity benefits of DCR are dominated by the values in the earlier years (in the range of $11M-$20M). In the later years, the capacity benefits are restricted to $9 million per year. This means that if DCR is delayed for some reason, then its capacity benefit over fifty years will be reduced significantly.[18]

Better to Wait to Approve DCR in Rapidly Changing Market and Regulatory Environment

BAMx supports the CAISO's decision to postpone the HAE project until the impact of NVE joining the CAISO Energy Imbalance Market (EIM) is better understood. BAMx urges the CAISO to continue its study of the potential benefits and refine costs of projects that can import power from other States, but to make no recommendations on DCR in the current transmission planning cycle. In these comments, we have provided several reasons to delay such approval until a fuller analysis can be completed. First, the changes to the production and capacity benefits attributed to the candidate transmission projects in the latest CAISO analysis need to be clearly explained and justified. Second, a reasonable extrapolation method should be applied to the production cost benefit as calculated in the two study years (2018 and 2023) that captures varying expectations of regulatory and market conditions. Third, similar to the sensitivities analyzed for the production benefits, the capacity benefits also should be computed under several sensitivity scenarios, as they form a substantial portion of the overall project benefits, per the latest CAISO analysis. Fourth, the capital costs for the candidate transmission projects need to be understood and explained in more detail. Fifth, if there are any additional benefits attributed to DCR that are not accounted in the economic studies, they need to be clearly explained and quantified under different sensitivity scenarios.[19]

Transmission Program Impact on HV TAC

[18] Our calculations indicate that the capacity benefit will be reduced from $150M to $126M or $120M if the DCR project is delayed by three or five years, respectively. Such an outcome would result in having the Benefit-Cost ratio to be less than 1 for DCR.
[19] The Draft Plan indicates that Delaney-Colorado River 500 kV project would increase the deliverable renewable resource amount in the Imperial Valley by 200MW.

BAMx appreciates the CAISO staff and management effort in developing the TAC Model. For the last several years, BAMx has been encouraging the CAISO to address growing concerns over increasing upward pressure on transmission costs. We believe the CAISO's development of the High Voltage (HV) TAC Model is a good starting point to increase the awareness among the stakeholders and policymakers in terms of understanding how much transmission costs are increasing. These costs are no longer a small portion of consumer electricity bills.

In BAMx's comments dated October 28, 2013, we had identified several areas where the CAISO TAC model needs to be improved including missing data and documentation, input assumptions, and some of the functionalities. BAMx hopes that its comments are incorporated into the next revision of the TAC model and that it is allowed to critique the latest forecast before said forecast is expected to be presented to the CAISO BoG in March.

BAMx appreciates the opportunity to comment on the CAISO Draft 2013-14 Transmission Plan. BAMx would also like to acknowledge the significant effort of the CAISO staff to develop the Draft Plan, as well as the staff's willingness to work with the stakeholders in the process to more fully develop it. We hope to work with the CAISO staff to continue to improve and enhance its capabilities.

If you have any questions concerning these comments, please contact Barry Flynn (888-634-7516 and brflynn@flynnrci.com) or Robert Jenkins (888-634-0777 and robertjenkins@flynnrci.com) or Pushkar Wagle (888-634-3339 and pushkarwagle@flynnrci.com).