BAMX Comments on the Draft 2017-2018 Transmission Plan and Materials from the February 8, 2018 Stakeholder Meeting

The Bay Area Municipal Transmission group (BAMx)[1] appreciates the opportunity to comment on the draft 2017-2018 Transmission Plan (Draft Plan, hereafter) and materials presented at the February 8th, 2018 stakeholder meeting. We request that the CAISO address these issues in its final comprehensive Transmission Plan expected in March 2018.

Review of Previously Approved Transmission Projects

BAMx applauds the CAISO's work in what has been a three-year process to review previously approved transmission projects in light of the changing energy landscape. In this cycle alone, the project cancellations and scope reductions reduce the anticipated capital expenditures by about $2.7 billion. While reviewing all the transmission projects represented a significant commitment of engineering resources, the resultant saving for transmission system users would be enormous. For instance, BAMx estimates that a reduction in $2.7 billion of capital expenditure, the majority of which is associated with the low voltage transmission facilities would reduce the PG&E-specific low voltage transmission access charge (LV TAC) by approximately $3.5-$4/MWh in 2025.

While the effort within this transmission planning cycle represents a significant milestone, there are still follow-up activities to this task.

a) First, there are still six projects on-hold for another year representing a total cost of over $600 million, which built would increase the CAISO-wide high voltage transmission access charge (HV TAC) by approximately $0.32/MWh in 2025.[2] While BAMx supports not rushing into doubtful transmission projects, BAMx encourages the CAISO to resolve the fates of these projects expeditiously.
b) Second, BAMx encourages the CAISO to establish a process whereby once transmission projects are approved, they are continuously reviewed as to their necessity and scope until the project starts construction. While the need for all projects should be continuously monitored, a special monitoring of projects should be initiated for those that have been delayed beyond their initially proposed on-line dates as well as those with on-line dates during the second half of the planning horizon.
c) Third, stakeholders are seeing tremendous and chronic cost escalation after a transmission project is approved by the CAISO. Some examples from the February stakeholder meeting include the Cottonwood-Red Bluff 60 kV line and substation, cost increase of 426%, Davis Voltage Conversion 79%, South of San Mateo Capacity Increase 900%, Morgan Hill Reinforcement 677%, and general cost doubling for four other projects. This issue is not just limited to one PTO. For example, the West of Devers 230 kV Upgrade cost changed considerably from its initial estimate at $384

[1] BAMx consists of City of Palo Alto Utilities and City of Santa Clara, Silicon Valley Power.
[2] Estimate based upon using the CAISO 2016-17 TAC Forecasting Model and assuming $450 million (out of overall $600 million) associated with the high voltage facilities.

million when it was studied by CAISO in 2010 to its current estimate of $1.01 billion[3], or 163%. Fortunately for the projects presented during this planning cycle were re-evaluated with information on their burgeoning costs. This may not always be the case and such cost increases can materially impact the selection of the preferred alternative or overall scope of work. During the post approval transmission project monitoring that BAMx suggests in item (b) above, BAMx also recommends that the CAISO monitor cost escalation for both scope creep in the event work unnecessary to the project objectives may be added to the project and whether any such cost increase should trigger a project review as has been performed by the CAISO for the past several planning cycles.

Impact of Changing Load Profiles

BAMx supports the CAISO's acknowledgement that the significant levels of both grid-connected and behind-the-meter generation being developed will drive changes in the way that the transmission system is being planned.[4] The resultant shift in the peak demand to the evening hours should have a major impact on the protocol for assessing the transmission necessary to support resource capacity counting, especially for non-dispatchable resources that have driven much of the deliverability network upgrades approved in the prior transmission planning cycles. BAMx looks forward to a stakeholder initiative to revisit the deliverability methodology in light of this changing planning environment. Such review and any resultant changes need to occur before any additional Delivery Network Upgrades (DNUs) are specified in either the CAISO's Generation Interconnection and Deliverability Assessment Process (GIDAP) process or new Area DNUs are identified as policy upgrades in the Transmission Planning Process.

The impact of changing load profiles can have additional impacts on planning as well. For example, transmission equipment, especially overhead transmission lines, are rated based upon assumed ambient environmental conditions. This can include ambient temperature, solar input, and wind speeds that may be appreciably different during an evening peak resulting in potentially higher equipment ratings. While daytime system performance would still need to be assessed using current rating methodologies, BAMx recommends that the CAISO instruct the PTOs to develop rating methodologies and assumptions appropriate for evening peaks. How such new parameters would be integrated into the planning process would need to be determined. As a transitional method, BAMx proposes that before transmission projects driven by a shifted peak load are approved, an assessment of the system capability with compatible assumptions in equipment ratings be undertaken.

Need for Additional Coordination Between CPUC IRP and CAISO TPP

The Draft Plan has found four (4) upgrades to be needed as economic-driven projects in the 2017- 2018 planning cycle.[5] Three (3) out of these four upgrades have been justified primarily based upon their local capacity requirements (LCR) reduction benefits. The CAISO's approach to evaluate proposed project's ability to improve the importing capacity into an LCR area is consistent with its updated Transmission Economic Assessment Methodology (TEAM)

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[3] Estimates from CAISO Transition Cluster Phase II Interconnection Study Report (SCE's Eastern Bulk System) July 08, 2010, CPUC D.16-08-017 in A13-10-020 respectively.
[4] Draft Plan, p. 25.
[5] Draft Plan, p. 264.

documentation, which envisions scenarios with and without the transmission upgrades in order to compare the LCR costs.[6] There are a several assumptions made in the economic assessments conducted in the Draft Plan such as, the price (value) for the local capacity and the share of overall capacity savings allocated to the LCR benefit.[7] BAMx requests that the CAISO update the TEAM documentation by including these assumptions that are critical to the LCR reduction benefit assessment.

BAMx believes that California Public Utilities Commission's (CPUC) Integrated Resource Planning (IRP) process is an appropriate forum to determine economic tradeoffs between retaining existing generation and reducing that need via new transmission or new local resources. The capacity expansion models such as RESOLVE utilized in the CPUC IRP proceeding are more suitable for performing any economic comparison of alternatives for meeting LCR than the CAISO TPP by itself. In particular, RESOLVE includes a constraint that requires that sufficient new generation capacity must be added to meet the local needs in specific LCR areas. To characterize these local capacity needs, RESOLVE relies predominantly on the CAISO's TPP.[8] In other words, a flow of information from the CAISO's TPP to the CPUC IRP on the local capacity needs exists today. Similarly, the determination of the least-cost best-fit alternatives to meet LCR needs the CAISO TPP needs to rely on the CPUC IRP process as it is better equipped in evaluating competing resource alternatives such as, natural gas generation, renewables, energy storage, and demand response.[9] For a particular area, if timing of the CPUC IRP cycle is a constraint, then the CPUC needs to direct its relevant jurisdictional LSE to conduct a Request For Offers (RFO) specifically targeted to procuring local resources including the preferred resource options. Such a solution was suggested by the CAISO to determine the true costs of the preferred resource alternatives to the Puente Project.[10]

In addition to assessing the LCR reduction benefits associated with the economic-driven projects, the Draft Plan recommends the approval of a reliability-driven project[11] which includes building an energy storage which would be treated as a transmission asset. We understand that the energy storage was chosen as a more cost-effective mitigation solution to address the reliability issues over other transmission alternatives. BAMx does not believe that the energy storage or any other local resource costs should be fully allocated to the CAISO-wide Transmission Access Charge (TAC) unless it is not possible to obtain any system benefits from the installation of a local resource. The CAISO seems to be proposing that for some storage installations in this Draft Plan, the cost recovery for that storage would be fully allocated to the TAC for the first time. BAMx suggests that this cost allocation issue deserves more attention,

[6] CAISO, "Transmission Economic Assessment Methodology," November 2, 2017, p.22.
[7] Draft Plan (p. 253) indicates the use of the Capacity Procurement Mechanism (CPM) soft offer cap price of $6.31/kw-month to value the local capacity. Also, the Draft Plan acknowledges that the local capacity in a given area could also provide other benefits such as flexible generation, and therefore allocated only half the benefit of the local capacity price to the transmission project.
[8] RESOLVE Documentation: CPUC 2017 IRP Inputs & Assumptions, September 2017, p.77.
[9] *Ibid*, p.29.
[10] California Energy Commission, Docket 15-AFC-01, Testimony of Neil Millar of CAISO, Transcript of 9/14/2017 Evidentiary Hearing, (TN# 221283), p. 13.
[11] The revised scope for the Reedley 70 kV Reinforcement as described in the Draft Plan, p.142.

possibly in a proceeding at the CPUC and/or in a separate stakeholder process at the CAISO.

Alignment of the LCR and Transmission Planning Criteria

In response to the proposed transmission upgrades for the Moorpark area, BAMx previously commented that the critical contingency is an extreme event, loss of a single element followed by the common mode loss of two additional elements. BAMx's comments identified that this extreme contingency is beyond the NERC/WECC/CAISO transmission planning standards requiring mitigation. The CAISO response was that this contingency is included in its tariff as part of the Local Capacity Technical Study Criteria and that the transmission project is the most economic method of meeting said criteria.

However, the CAISO's response failed to state ***why*** areas with local generation are apparently being planned to a higher standard than areas of the system without local generation. Specifically, why the Local Capacity Technical Study Criteria includes contingencies that are beyond those generally used in the reliability assessment of the transmission planning process and beyond those in which those that NERC and WECC standards require mitigation.

While resolving this apparent inconsistency may not be timely for the Moorpark area due to imminent deadlines and the relatively modest scope of work, this issue may appear again as additional generation units seek to retire due to economic pressures. BAMx requests that the issue be fully addressed a stakeholder forum where the justification for inclusion or exclusion of this extreme event in the justification of expansion of the transmission system can be discussed among stakeholders and the CAISO Planning Standards and the CAISO Tariff subsequently aligned.

Morgan Hill Reliability Project

Morgan Hill Reliability Project was approved during the 2013-2014 Transmission Planning Cycle. The cost estimate from the request window application submitted by PG&E for the project was $35 to $45 Million. The most recent cost estimate for the original scope of the project is $250-$350 Million[12].

The originally proposed scope of work consisted of the following upgrades:

- Construct new 230/115 kV Spring Substation in Morgan Hill, with connections into the Metcalf-Moss Landing No. 2 230 kV Line and the Morgan Hill-Llagas 115 kV Line.

The updated scope of work is identified as the following:

- Rebuild Metcalf - Green Valley 115kV into the Green Valley - Morgan Hill 115kV (all new structures; 15 miles) and rebuild Morgan Hill 115kV into a BAAH

[12] Costs and the scope of the project was obtained from Appendix B to the 2017-2018 draft transmission plan

The cost estimate for the updated scope of work is $72-$104 Million. BAMx members applaud the CAISO for its efforts in identifying a more cost-effective solution in response to an increased cost estimate for the project and would encourage the CAISO to continue this practice going forward. BAMx members would also like to propose a potentially lower cost solution to the identified thermal overloads and voltage violations as outlined below.

The two critical P6 contingencies driving the reliability project are identified in Table 1 below are the loss of Metcalf-Morgan Hill 115kV circuit followed by the loss of Llagas-Gilroy 115kV circuit and Metcalf-Llagas 115kV circuit followed by the loss of Llagas-Gilroy 115kV circuit. Both of these contingencies cause overloads on the remaining circuit feeding the Morgan Hill 115kV substation. The highest overload identified within the CAISO Reliability Assessment Study Results for these contingencies is for the 2027 Summer Peak case, where Metcalf-Morgan Hill 115kV circuit is overloaded by 114 percent over its emergency rating.

Table 1: Excerpt from the CAISO 2017-2018 Transmission Assessment[13]

Overloaded Facility	Contingency Description	2019 Summer Peak	2022 Summer Peak	2027 Summer Peak
Metcalf-Llagas 115kV Line	LLAGAS-GILROY-GILROY F-GILROYPK 115kV & METCALF-MORGAN HILL 115kV(N-1-1)	**102**	**111**	**114**
Metcalf-Morgan Hill 115kV Line	MTCALF D-LLAGAS 115kV & LLAGAS- GILROY-GILROY F-GILROYPK 115kV (N-1-1)	91	96	99

The loss of Llagas-Gilroy 115kV circuit (which drops the contribution of the Gilroy units) in addition to one of the circuits supplying Morgan Hill substation causes a thermal overload on the opposite circuit as well as low voltages on Morgan Hill substation. The non-sensitivity case showing the highest overload is the Summer Peak 2027 case where Metcalf-Llagas 115kV circuit is at 114 percent of its emergency rating. Our internal analysis shows that adding additional 30MVAR of voltage support devices alleviates all low voltage violations and reduced the identified overload to about 106 percent. The reactive support could be installed at either Morgan Hill or Llagas substations. BAMx recommends that the CAISO consider a mix of preferred resources, demand response, or energy storage, which could be used after the first contingency, to eliminate the 6 percent overload.

[13] Source: Draft Plan, APPENDIX C: Reliability Assessment Study Results for PG&E Greater Bay Area.

If the CAISO does decide to continue with the modified scope of work, the justification for rebuilding Morgan Hill 115kV circuit into a breaker and a half configuration as opposed to expanding the existing the substation bus to accommodate an additional circuit has not been justified.

Midway-Andrew Transmission Project

As in the previous comments submitted, BAMx members would like to re-iterate that previously implemented "Los Padres Transmission Project" installed an SPS at both Mesa and Santa Maria 115kV Substations to address the Mesa area transmission standards violations by dropping approximately 230 MW of load. Similarly, the Divide SPS Project installed an SPS to mitigate standards violations in the Divide 115kV area by dropping approximately 145 MW of load following the loss of Mesa-Divide #1 & #2 115kV lines. These solutions are acceptable under the applicable Planning Standards as the Los Padres area is a non-urban area and both the CAISO and NERC planning standards allow for post contingency load dropping for a higher level of contingencies.

Therefore, the Midway-Andrew 230 kV Project is designed to provide a level of service above that required by the Planning Standards. The originally proposed project is estimated to cost up to $150 million.[14] While BAMx is encouraged that the CAISO is considering lower cost options that would repurpose existing assets, this misses a fundamental point. As a reliability project, whether the Midway-Andrew 230 kV Project or an alternative such as described in the stakeholder meeting, such project justifications should include a cost/benefit assessment as described in the CAISO Planning Standards (Section 5.4). The CAISO has identified the nature of load being dropped and its inability to schedule outages in this area as additional justifications for this project. If this is the case, additional justifications need to be made in regards to what load cannot be dropped as part of this SPS which is armed to react to an extremely low probability event.

If the CAISO decides to proceed with the implementation of the Midway-Andrew Project due to the inability of obtaining clearances on equipment, further justification should be provided in regards to which clearances are not able to be scheduled under the current configuration with the knowledge that the SPS will drop load and protect the system even in an abnormal system configuration.

[14] The PG&E cost estimates for the Midway-Andrew 230 kV project now range from $215M (PG&E AB 970 Report Oct 2, 2017) to $414M (PG&E EL16-47)

Gates-Gregg Transmission Project

BAMx supports the CAISO's analytic method used to evaluate the Gates-Gregg 230 kV project whereby initial assumptions favorable to the transmission project were tested to assess project viability.

Conclusion

BAMx appreciates the opportunity to comment on the CAISO Draft 2017-18 Transmission Plan. BAMx would also like to acknowledge the significant effort of the CAISO staff to develop the Draft Plan that should lead to significant reductions in the CAISO TAC that would not have been achieved without the CAISO Staff's diligence in reviewing previously approved transmission projects. BAMx also appreciates 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 the Transmission Planning Process.

If you have any questions concerning these comments, please contact Kathleen Hughes (khughes@SantaClaraCA.gov or (408) 615-6632).