The ISO received comments on the topics discussed at the February 18, 2016 stakeholder meeting from the following:

1. AltaGas
2. Bay Area Municipal Transmission group (BAMx)
3. Boston Energy
4. California Public Utilities Commission (CPUC)
5. Eagle Mountain
6. Imperial Irrigation District (IID)
7. NextEra Energy Transmission West (NEET West)
8. Office of Ratepayers Advocates (ORA)
9. Pacific Gas & Electric (PG&E)
10. Port of Oakland and Alameda Municipal Power
11. Regenerate Power
12. San Diego Gas & Electric (SDG&E)
13. Southern California Edison (SCE)
14. TransCayon
15. Transmission Agency of Northern California (TANC)

Copies of the comments submitted are located on the 2015-2016 Transmission Planning Process Page at: http://www.caiso.com/planning/Pages/TransmissionPlanning/2015-2016TransmissionPlanningProcess.aspx.

The following are the ISO's responses to the comments.

No	Comment Submitted	CAISO Response
1	**AltaGas** **Submitted by: Christopher J. Doyle**	
1a	1. AltaGas had the opportunity to participate in the ISO's September 21-22, 2015 Stakeholder meeting in which the 2015-2016 Transmission Plan preliminary Reliability assessment results were discussed. This presentation was very well done by the ISO staff. AltaGas was specifically interested in the evaluation of SCE's Eastern bulk system and noted existing problems in this area including thermal overloading, voltage violations under light load conditions, and dynamic issues under double contingencies as well as N- 1-1 contingencies. In particular, the Julian Hinds - Mirage 230 kV line was a major bottleneck that would overload under a variety of contingencies. The current 2015-2016 draft Transmission Plan and Appendix C (Reliability Assessment Results) do not mention even once the overload of J.Hinds -Mirage line. Is this line not overloaded if you lose the J.Hinds - Eagle Mountain line or if you lose the Red Bluff - Devers # 1 and #2 lines? This overload was identified in September 21-22, 2015 presentation. What has changed?	The J Hinds – Mirage line overloads to about 129% under the N-1 J Hinds – Eagle Mountain 230 kV or N-2 Red Bluff – Devers 500 kV contingency. The Blythe Energy SPS is triggered to turn off 1 CT Unit in 15 cycles. The flow on the J Hinds –Mirage line then reduces to below 100%.
1b	2. In Appendix C, SCE Eastern Area results, AltaGas does not see the results for some single contingencies that are likely to cause overloads. For example, an analysis of the 2017 Summer Peak case (from CAISO portal) shows the J.Hinds - Mirage overloads to 117% for a loss of the Palo Verde -Col River 500 kV line. Is this result correct?	Yes. Under the N-1 Palo Verde-Col River 500 kV contingency, J Hinds – Mirage line overloads to about 116%. The Blythe Energy SPS is triggered to turn off 1 CT Unit in 15 cycles. The flow on the J Hinds – Mirage line then reduces to 88%.
1c	3. What are the consequences of a loss of both Red Bluff -Devers #1 and #2 500 kV lines? Any overloads? Voltage issues? Stability problems? Potential mitigation? The CAISO notes that there are existing issues associated with JH-Mirage overloading for the Devers- Red Bluff N-2 condition and highlighted them in the Buck Blvd. Generation Tie Loop-in Pro ject study presentation in a September 22, 2015 TPP stakeholder meeting. These don't seem to be identified in the draft 2015/2016 plan presented in February.	For the base cases studied, the Colorado River Corridor SPS and the Blythe Energy RAS were assumed to be activated and as a result no overloads or voltage problems were identified.
1d	4. In the Buck Blvd. Generation Tie Loop-in Pro ject study and presentation of September 21-22, 2015, Stakeholder meeting, the CAJSO identified a potential SPS guideline violation associated with the Devers-Red Bluff N-2 contingency in both the pre-project and post-project policy cases. The 2015/2016 draft transmission plan does not make mention of the N-2 issues identified in the Sept 2015 presentation. If the reliability issue exists -as identified by the CAISO in September, would one expect to see it addressed in the final draft plan as well?	The ISO agrees that the SPS in this area is a concern and any changes to this area need to be scrutinized with this concern in mind. However, the existing system is adequate.

No	Comment Submitted	CAISO Response
1e	5. Analysis for numerous N-1-1 contingencies appear to be missing. For example, loss of J.Hinds - Eagle Mountain followed by Loss of Palo Verde - Col River. What are the results?	Most of the contingencies result in overloading the J Hinds- Mirage line or the MWD section of the J Hinds bus. Under the Blythe Energy SPS, 1 CT Unit is tripped in 15 cycles, and if the overload is not relieved, the Buck Blvd 220 kV CB at J Hinds will be opened. All the overload of the J Hinds – Mirage or MWD section can be relieved after implementing the Blythe Energy SPS.
1f	6. Analysis for some bus faults appears to be missing. For example, loss of 230 kV tie breaker at Julian Hinds that opens up the connection between SCE and MWD. What are the results of this contingency?	The J Hinds – Mirage line overloads up to 152% under the N-1 J Hinds – JH MWD contingency. The Blythe Energy SPS is triggered to turn off 1 CT Unit in 15 cycles. The flow on the J Hinds –Mirage line then reduces to below 100%.
1g	7. In the past several years, J.Hinds -Mirage 230 kV circuit was considered as a "congested path" with some cost associated with congestion. In 2015-2016 Transmission Plan, there is no mention of any congestion cost related to J.Hinds - Mirage. Congestion data from the CAISO OASIS indicates that in 2013 and 2014, the line indicated congestion nearly 100 hours for each year, and greater than 500 hours in 2012. Is this circuit no longer a congested path?	There was no congestion identified on the J.Hinds-Mirage 230 kV line for the 2020 and 2025 study years.
1h	8. The CAJSO notes that the current JH (SCE and MWD) and Eagle Mountain voltage issues and the JH-Mirage overloads are mitigated with various operating procedure s, SPS, and soon to add more shunt reactors. Note that these mitigations can and are, at times, at the expense of the AltaGas ' generation facility and threaten revenue.	The addition of reactors at Eagle Mt. are expected to substantially mitigate high voltages in the area and reduce the impact on the AltaGas generation facility.
1i	9. Per Tariff Section 24.3.4.1, there is a whole list of criteria that the CAISO is supposed to use to determine whether or not to conduct an economic planning study. Rather than review the request according to that criteria, the draft plan simply states that the project "has not been found to be needed at this time." P. 124. 296.	As stated on page 296 this project was assessed as part of the 2014-2015 ISO transmission planning cycle. Circumstances have not significantly changed since the completion of that study.
1j	10. Tariff Section 24.3.4.1 also provides for stakeholders to submit their own economic studies to support a transmission line. AltaGas did so, and the study supports inclusion of the project in the Transmission Plan. Also, I understand that the CAISO has effectively conceded that AltaGas has demonstrated the economic benefits of the project. Therefore, the CAISO should consider inclusion of the project in the Plan, per Tariff Section 24.4.6.7. Simply stating it's "not needed" doesn't seem to be a sufficient analysis.	Please see response above.

No	Comment Submitted	CAISO Response
2	**Bay Area Municipal Transmission group (BAMx)** **Submitted by: Joyce Kinnear**	
2a	**Reliability Transmission Projects** Many of the transmission projects proposed for approval in this planning cycle are voltage control projects and reflect about 64% of the total recommended capital costs. Most of these are reactive projects in the PG&E area designed to reduce system voltages. As stated in prior comments, it is it is unclear why the high off-peak voltage problem has emerged and, therefore, it is not understood whether this is a short term problem, perhaps due to the hydroelectric unit commitment during the drought, or if the PG&E load power factors may be excessively leading during low load periods. BAMx recommends that the cause of the increasing system voltages should further studied for another year before approving the major capital additions (which total $192 million), so that the most appropriate mitigation can be implemented. While almost all of the proposed large reactive installations are at 230 kV, one of the recommended projects is to install a 100 MVar shunt reactor on the Cottonwood 115 kV bus. It is unclear why this installation is recommended at a different voltage level than the others. Also, it is unclear whether installation of such a large reactor at 115 kV could lead to future 230/115 kV transformer bank capacity issues at Cottonwood. BAMx supports the CAISO's continued review of previously approved projects to assess whether the planning assumptions have changed sufficiently to cancel or defer a project. CPUC Staff, ORA and BAMx all supported this review of previously approved transmission projects in prior comments. BAMx supports the CPUC Staff request for a list of all previously approved projects that have not yet begun construction and were reviewed by the CAISO. With the increased reliance on Preferred Resources, where the location may not be determined toward the end of the planning horizon, and with the recent legislative mandate to double the energy efficiency goals, BAMx recommends maintaining a list of approved projects that have not yet begun construction, so that the continuing need and timing can be reviewed as part of future planning cycles.	The ISO observed in the planning studies of this cycle, as well as in past cycles, increasing voltages primarily in off peak cases. In addition, voltages in real time have increased, resulting in high voltage issues that have operational impacts. The ISO has requested approval of the reactive projects in the areas with the need to address at this time. The ISO will continue to monitor voltage issues in the entire system in the next planning cycle. The Cottonwood 115kV reactor was selected as the optimal location, and the ISO did not observe any concerns impacting the transformers at the station. Regarding construction status, the ISO utilizes the quarterly reporting mechanism in place with the utilities and the CPUC.

No	Comment Submitted	CAISO Response
2b	In addition to the 13 projects cancelled in this transmission planning cycle, BAMx recommends that further investigation of the following previously approved projects: Midway-Kern PP #2 230kV Line The project was justified based on the overloads identified by manually adjusting the demand levels upwards from the load shown in the TPP series base case that was developed from the CEC forecast. For the resulting overloads associated with increased loads, PG&E stated: "The Special Protection Schemes (SPS) approved in the 2012-2013 TPP as a part of the Kern 230 kV Area Reinforcement will mitigate concerns with the NERC Category C5 contingencies of the Midway-Kern PP 230 kV lines, however, the SPS's proposed will not cover the NERC Category B, and C3 contingencies identified in this reliability assessment." The identified Category B contingency exhibited only a 1% overload in the 2023 horizon year. With increased energy efficiency and new solar projects projected for this area,3 BAMx recommends review of this project to assess whether it can be deferred.4 Midway-Andrew 230kV Circuit: The following justification was used to approve the project during the 2013-2014 Transmission Planning Cycle: "The Midway-Andrew 230 kV Project will fully mitigate the voltage collapse problems presently observed in the Mesa and Divide 115 kV system and protect against approximately 270 MW of load drop following loss of any two of the 230 kV sources at the Mesa substation (Category C5, C2 and C3 outages). For the Divide area, the project will avert system voltage collapse and protect against approximately 145 MW of load shedding following loss of Mesa-Divide #1 & 2 115 kV Lines." The load forecast for the Central Coast area has been declining in recent planning cycles. BAMx recommends considering whether increased local reactive support and a reduced level of load dropping within the NERC and	The project review was comprehensive based on the study approach taken, and the projects remaining as mitigation were found to be needed. The ISO relies on the CEC load forecast that is coordinated with the CPUC as a study input assumption and was used for the 2015-2016 planning studies. Re the Eldorado-Lugo and the Lugo-Mohave Series Capacitor Projects, as set out in the ISO's study plan, the ISO relies on the renewable generation portfolios provided by the CPUC, with input from the CEC, as the basis for policy-driven transmission to support California's renewables portfolio standard.

No	Comment Submitted	CAISO Response
	CAISO Planning Standards would address the identified deficiencies. If this is insuffiicent, energizing the idle Midway-Santa Maria 115 kV line may provide additional relief. Eldorado-Lugo and the Lugo-Mohave Series Capacitor Projects The Eldorado-Lugo Series Capacitor Project was originally identified in the Cluster 3-4 Phase II study report as an upgrade required to provide deliverability for the SCE Eastern Group interconnections. It was subsequentially approved as a policy-driven project in the 2012-2013 Transmission Plan. Similarly, the Lugo-Mohave Series Capacitor Project was identified in the 2013-2014 Transmission Plan as a policy-driven project. Since the approval of these projects, 1,690 MW of the 2061 MW of the Cluster 3&4 generation projects in the SCE Eastern Bulk System have withdrawn from the CAISO interconnection queue. One remaining request is a 221 MW Energy Only interconnection request, leaving only a 150 MW FCDS request from this cluster. BAMx recommends that this transmission project be reviewed as to whether it is still needed. Such a review should align with the CPUC upcoming decision concerning West of Devers Upgrades, which was also justified to provide FCDS transmission capacity for this same SCE Eastern Area.	
2c	**Special Study – Local Capacity Requirements** BAMx supports the TPP's continued monitoring of the reliability issues in southern California as the mitigation plan is implemented to mitigate the reliability impacts of the shutdown of both SONGS and the Once Through Cooling (OTC) units. It is important that timely information be provided to the CPUC, so that local resource procurement authorization can be adjusted to match the needs in a timely fashion. In this cycle, the transmission studies identified new concerns about the loading on the 220 kV transmission circuits out of Mesa substation. Information as to what adjustments to the CPUC's current procurement instructions and the potential alternative transmission costs necessary to mitigate this new issue need to be clearly identified for both the CPUC and SCE. If the 220 kV loading concern cannot be addressed through refinements in the resource procurement, BAMx supports the CAISO's consideration of lower cost transmission options, such as series reactors as the CAISO staff identified in the stakeholder meeting.	The ISO will continue to evaluate the need for either additional procurement or lower cost transmission options (i.e., series reactors, SPS, etc.) to address the potential local reliability issue concerning the south of Mesa 230kV lines in the western LA Basin in the 2016-2017 transmission planning process with the recently CEC-adopted demand forecast and targeted RFOs for local capacity procurement by SDG&E for preferred resources in the San Diego area. Costs and feasibility of lower cost transmission options as identified in the 2015-2016 draft Transmission Plan will be examined and analyzed as part of the 2016-2017 transmission planning process.
2d	**Special Study – Gas-Electric Coordination Transmission Planning Studies**	The special study in 2016-2017 TPP will address this.

No	Comment Submitted	CAISO Response
	The interdependence between the gas and electric infrastructure potential impact on electric reliability needs to be better understood in northern California. BAMx recommends that future planning cycles include such a gas-electric coordination study for the San Francisco Bay Area.	
2e	**Special Study – 50 Percent Renewable Energy** BAMx is highly encouraged by the findings of the investigation into the feasibility and implications of using energy-only procurement to integregrate the additional renewable resources necessary to meet California's 50% RPS goal. In addition to the report's recognition that the need for future renewable generation to provide system resource adequacy capacity is diminishing, BAMx notes that the study demonstrates that nearly 26,000MW of In-State resources can be accommodated on the existing transmission, which significantly exceeds the maximum of 15,000 MW of incremental renewables needed in the CAISO balancing authority area to transition from 33% to a 50% RPS goal. This suggests significant locational flexibility in selecting resources that minimize the risk of curtailment while balancing resource quality and permitting concerns. The availability of congestion and curtailment information, such as presented, is important for the market to make informed resource development and selection decisions. BAMx also supports increasing use of the interties in the studies to expand exports during times of over-generation. As the initial findings from the SB 350 study have shown with the RESOLVE model, increased export assumptions allow for lower cost implementation of the RPS goals by easing the integration of greater levels of In-State solar generation. Therefore, the CAISO's sensitivity analysis of three export capability assumptions helpful in understanding the value of such capability. Future enhancements to the 50% RPS studies could include: 1. Clear explanations that the study considered the potential availability of out-of-state resources that can be brought in on the existing interties. The Out-of-State 50% Portfolio included over 4,000 MW of Wyoming and New Mexico wind, but it does not appear that renewable resources in proximity to existing external delivery points utilizing transmission were considered. The initial information from the SB 350 studies suggests that this may be a cost effective alternative. A valuable enhancement for future planning cycles would be to more fully explore	The comments have been noted and will be considered in future study scopes.

No	Comment Submitted	CAISO Response
	the potential for such "neighboring imports." While the SB 350 study assumed an availability of 3,000 MW of such imports, it would be valuable to study the potential range of imports that the system can accommodate on the existing transmission in conjunction with the In-State resource portfolios. 2. Future planning cycles should seek to better define this range to better inform the portfolio selection. This special study looked at a net export range from 0 to 8,000 MW. As noted previously, the ability to manage and export surplus resources is critical to the integration of high penetrations of in-state solar resources. 3. Better explanations of the risk of renewable curtailment under maintenance scenarios. BAMx agrees that, in particular for the Riverside area, the ability to either reduce Arizona imports or schedule power east from this area to manage congestion from renewable generation needs to be understood.	
2f	**Special Study – Bulk Energy Storage** The Bulk Energy Storage Resources Study with 40% RPS in 2024 found that the economic benefits of energy storage are marginal and that a more diversified portfolio may be a more cost effective solution. BAMx suggests that in future planning cycles the CAISO expand this study to: 1. Consider whether the value of pumped storage changes as the RPS portfolio expands to 50%. Would energy storage appear more cost effective than the reliance on Wyoming and New Mexico wind to achieve a diversified portfolio? 2. Analyze whether the potential value of energy storage would be enhanced if such storage were sited close to the renewable resources, so that in addition to managing over- generation, the energy storage would also help reduce the potential for curtailment associated with internal transmission congestion. One enhancement to the value of such storage implementation would be to redefine how storage would receive FCDS in such an application. For example, reviewing whether storage could be allocated FCDS without any additional DNUs up to the difference in the local solar nameplate rating and its capacity counting value. From this standpoint, the storage could be viewed as "firming" the solar energy. This could increase the capacity value of energy storage sited in congested transmission areas.	The comments have been noted and will be considered in future study scopes. Regarding (1), the ISO has indicated that the study in the 2015-2016 transmission plan will be updated to consider a 50% RPS scenario and additionally that an updated 50% analysis will be included in the 2016-2017 planning cycle using updated assumptions. The timing has not been determined at this time.

No	Comment Submitted	CAISO Response
3	**Boston Energy** **Submitted by: Michael Kramek**	
3a	**Newark-Ravenswood 230 kV Transmission Project** In our review of the previously approved transmission projects included in the 2015/2016 draft plan we noticed the Newark-Ravenswood 230 kV transmission line project was no longer included in the list. According to the CAISO 2014/2015 board approved transmission plan the project had a projected in-service date of October 2016. Can the ISO explain why the project in no longer included in the list of previously approved transmission projects?	The Newark-Ravenswood 230 kV project is operational and in-service as of December 2015.
3b	**PG&E Capital Maintenance Projects Approved in the 2014/2015 Transmission Plan** The 2014/2015 transmission plan discussed 115 kV cable upgrades associated with SF Peninsula extreme events reliability assessment. The ISO characterized the 115kV cable upgrade as capital maintenance work to be conducted by PG&E. Given the transmission elements are part of the ISO-controlled transmission system, Boston Energy request the ISO include narrative in the plan regarding the status of these projects. At a minimum the CAISO should provide market participants with an estimated in-service date for these upgrades.	These projects are capital maintenance projects that PG&E will be upgrading in the San Francisco area. The comment has been noted.

No	Comment Submitted	CAISO Response
4	**California Public Utilities Commission (CPUC)** **Submitted by: Keith White**	
4a	1. The CAISO Should Clarify Key Relationships and Differences Among Varied Reliability and Local Capacity Requirements (LCR) Study Cases, as Well as How These Different Cases Jointly Inform Infrastructure Recommendations. CPUC Staff appreciate and find very useful the CAISO's analysis and discussion of multiple interacting reliability risk drivers, uncertainties and solutions, particularly for the Los Angeles Basin and San Diego. In its assessment and recommendations the CAISO relies on numerous area-specific reliability studies representing multiple informative reliability impact snapshots (summer peak, off-peak with high renewables output, etc.) and also on Local Capacity Requirements (LCR) studies that provide somewhat different area-specific perspectives. These various study cases have important similarities but also important differences that can be consequential regarding whether and what kinds of reliability risks are identified. CPUC Staff request that in its Transmission Plan and related activities and reports the CAISO place increased emphasis on clarifying and making more explicit a. the relationships among the different reliability and LCR study cases and their load and resource (and any other key) assumptions, b. the relationships between key assumptions in particular cases versus the reliability risks identified in those study cases that are attributable to those particular assumptions, and c. how the entire set of diverse cases and study results is combined and interpreted jointly, to produce the CAISO's recommendations, especially recommendations regarding commitments to infrastructure investments. For example, Tables 2.3-1 and 2.3-2 of the Draft Plan summarize the different system reliability impact snapshots studied for different parts of the grid, and Tables 4-7 through 4-10 of the Final Study Plan for the 2015-2016 Transmission Planning Process describes dispatch levels assumed for different kinds of renewable resources in different areas under different reliability study conditions.	Your comments have been noted. The ISO notes that many of these comments relate to issues that properly need to be considered and incorporated into the study plan process, and we will look to specific input received in that process for the 2016-2017 planning cycle. Several issues also relate to the CEC load forecasting methodologies, e.g. in regard to behind-the-meter generation assumptions. Regarding questions about LCR methodology, the ISO notes that the LCR methodology is developed and managed through separate processes coordinated with the state's resource adequacy program, and methodology proposals should be raised in that forum.

No	Comment Submitted	CAISO Response
	Which specific dispatch (and load) assumptions were used for all kinds of resources in which specific reliability study cases needs to be clarified and made explicit. This clarification needs also to be extended to include the contrasting load and dispatch assumptions for LCR studies, for the same grid areas. Beyond this, those reliability and LCR study case-specific identified reliability risks (e.g., standards violations) that alone or in combination with results of other study cases drive identification of needs - - should be explicitly attributed (linked) to the specific underlying case- specific load or resource assumptions responsible for producing the identified risks. Furthermore, the CAISO should explain and help stakeholders understand how the results of these different, contrasting cases are balanced and interpreted jointly (in the aggregate) to produce ultimate recommendations including but not limited to infrastructure needs. For example, specific updated wind and solar resource output assumptions used for LCR studies apparently contributed to modeled violations in the West Los Angeles (LA) Basin LCR studies, contrasting somewhat with results of reliability studies for this area. The kinds of clarification requested above should help inform consideration and discussion of study methodology questions and refinements that may need to be considered and discussed due in part to growing importance of variable renewable generation as well as various kinds of preferred and behind-the-meter resources having nonconventional operating patterns and constraints. For example: i. How is identification of which system scenarios are most useful for reliability and LCR studies influenced by growing penetration of variable generation and preferred resources, especially within load centers? ii. Based on what criteria would the "peak" hour for such studies be moved later in the day under increasing PV penetration? iii. If NQC values are assigned for front-of-the-meter resources in LCR studies, should something analogous be done for all behind-the-meter resources? iv. On the other hand, should the use of NQC in LCR studies be reassessed and how? v. Which changes in the above modeling conventions are likely to significantly impact results, including identification of needs?	

No	Comment Submitted	CAISO Response
	The above discussion and CPUC Staff requests under this topic 1 are also relevant to the CPUC's role in permitting transmission projects and overseeing CEQA analyses. In these CPUC-administered processes, a project must have one or more clearly defined objectives, and if significant environmental impacts are found, alternative ways to meet those objectives must be adequately analyzed. The objective of reliability-driven transmission projects is presumably to maintain electrical service to specified load areas while avoiding excessive risk of transmission overloads or other reliability violations, under prudently selected stress scenarios, such as study cases selected for reliability and LCR studies. Thus, perhaps for transmission planning and also for CEQA analysis the objective of reliability-driven transmission projects is basically to perform acceptably under specific studies cases, or perhaps a more appropriate characterization of the objective is to perform acceptably across a variety of study cases when interpreted (and appropriately emphasized or discounted) jointly. Thus, how the project objective is defined in terms of performance under one or many scenarios, and if/how multiple scenario-specific performances are combined, weighted or discounted - - has bearing on how the project objective should be defined for CEQA purposes and therefore on what appropriate alternatives may need to be studied. Clarification of interrelationships among, and overall interpretation of, multiple varied reliability and LCR study cases as requested by CPUC Staff above, should provide helpful guidance in making these decisions. Additionally, some consequential reliability and LCR study assumptions may change over time (as discussed in topic 2 below), such as between time of project approval by the CAISO and some later date such as either a later CAISO Transmission Plan or permitting and CEQA analysis overseen by the CPUC. This creates additional planning challenges for all, and managing those challenges is facilitated by better understanding of the issues raised above, in CPUC Staff's comment topic 1.	
4b	2. Where Selection of Substantial Infrastructure Investments is Followed in Short Order by the Need for Follow-On Investments or Measures to Maintain the Projected Benefits, Causes of and Ways to Manage This Situation Should be Examined.	

No	Comment Submitted	CAISO Response
	Transmission planning especially in complex circumstances can experience the “whack- a-mole” effect, where adding infrastructure at one location to address a problem can be followed in short order by problems that consequently pop up (like moles) elsewhere. The Los Angeles (LA) Basin and San Diego electrical areas may be prone to this condition, which affects planning for both transmission and resources. The CAISO should help the CPUC and other stakeholders better understand the drivers, implications and solutions for such situations. Most recently, circumstances surrounding the Mesa loop-in project and its role regarding local reliability and capacity needs illustrate this kind of situation. This project approved in the 2013-2014 Transmission Plan would loop a new 500 kV line as well as two additional 230 kV lines into a Mesa substation that would be entirely rebuilt, thus bringing high voltage/high capacity import transmission deeper (electrically) into the LA Basin load center. As approved, the Mesa loop-in project had an in-service date of December 31, 2020, an estimated cost of $464 million to $614 million, and an estimated electrical benefit of reducing West LA Basin local capacity needs by 300 to 640 MW. Page 128 of the 2013-2014 Transmission Plan states that “This analysis supports the view that the Mesa Loop-in project along with the additional local capacity additions effectively alleviates the loading concerns identified in the Metro area because of the retirement of SONGS and OTC generation.” The Mesa loop-in project is currently before the CPUC for a permit to construct (proceeding A.15-03-003). Subsequently in the 2014-2015 Transmission Plan, 230 kV upgrades downstream from the Mesa substation were approved. Now, Section 2.6 (Southern California Bulk Transmission System Assessment) of the draft 2015-2016 Transmission Plan describes a potential need for additional local capacity or transmission upgrades “due to contingency loading concerns on the south of Mesa 230 kV lines.” This is stated as being identified in the long-term local capacity assessment, and Appendix D of the Draft Plan identifies a driver of this overloading as being a 2000 MW increase in modeled renewable generation output north of Mesa attributed to increased NQC levels for the given amount of capacity. Possible operational, local resource and transmission investment solutions are identified, indicating some preference for the latter.	The analogy used by the CPUC staff is normally considered in situations where addressing one issue creates an off-setting and equally sized issue in another location, and as such, the ISO does not agree with that characterization. Major and significant changes in the LA Basin and San Diego areas have been occurring more or less simultaneously, and at a time of particular uncertainty regarding load forecasting, specific location and timing of various preferred and conventional resources, and permitting processes. With major mitigations under development materially shifting historical load patterns and fundamentally changing the sources of supply into the local areas, it is not unexpected that secondary issues within the areas will emerge as load and distributed energy forecasts evolve and more information becomes available as to the locations of preferred resources within the local areas.

No	Comment Submitted	CAISO Response
	Additionally, sensitivity LCR studies showed that the presence (vs. absence) of the Mesa loop-in project in the mid-term (2021) decreased estimated West LA Basin local capacity requirements by only about 110 MW.6 CPUC Staff and other stakeholders would benefit from a fuller assessment of causes and solutions for apparent "whack-a-mole" situations like this. Such understanding is important for various CPUC responsibilities. For example: a. Were follow-on effects investments or measures apparent, and would they have deserved inclusion in the original assessment? b. Were follow-on investments or measures apparent only under changed information and forecasts regarding real-world conditions (loads, resources, transmission), and to what extent would it be appropriate to proactively examine such alternative conditions (e.g., sensitivity scenarios assuming higher flows into a substation)? c. To what extent does identification of follow-on investments or measures result from contrasting and/or updated modeling approaches (e.g., reliability versus LCR studies, new NQC values)? Would this indicate a need to better harmonize different analytic methodologies and their assumptions, or to refine and make more transparent the process for jointly interpreting the results of multiple study cases, to inform decisions?	
4c	3. CPUC Staff Commends the CAISO for Assessing and Canceling Previously Approved Transmission Projects No Longer Needed Under Declining Load Forecasts, and Emphasizes the Need to Continue Such Review Especially in Light of Continuing Decline in Load Forecasts Plus Accelerated Energy Efficiency Goals Mandated by Senate Bill 350. CPUC Staff appreciate the CAISO's productive effort to analyze the current need for a number of previously approved PG&E-area transmission projects, resulting in a determination that 13 of these projects are no longer justified and should be canceled, even if assuming zero additional energy efficiency or "AAEE". Such assessments should be made periodically, for all load areas, especially in a time of great energy system change. We reiterate that the CAISO should list the major reasons for each cancellation. The CAISO in discussion at the February	Your comment has been noted. Regarding the speculation that future load forecasts may continue to decline, the ISO relies on the load forecasting performed by the CEC, coordinated with state agencies including the CPUC. Some level of forecast uncertainty is managed through sensitivity studies required as part of NERC's mandatory standards, but the ISO is not considering replacing reliance on the CEC forecast. Further, regarding ISO approval timelines (re the comment that "Absent compelling reasons, projects should not be approved earlier than needed to provide prudent lead times such as for permitting and construction"), the ISO strives to not seek approval significantly earlier than is prudent y to allow for permitting and construction activities. This

No	Comment Submitted	CAISO Response
	18 stakeholder meeting indicated that lower load forecasts played a major role. We point out that load forecasts are continuing to decline. This prudent reassessment approach also has some relevance for initial approval of projects in each planning cycle. Absent compelling reasons, projects should not be approved earlier than needed to provide prudent lead times such as for permitting and construction. Even then, long lead time projects should be reevaluated based on updated information as was done in the present planning cycle. Lastly, implications of declining load forecasts are heightened by anticipated growth of distributed energy resources as well as accelerated energy efficiency measures to meet Senate Bill 350 goals.	can be challenging, however, in light of the permitting uncertainties the CPUC notes below (comment 4e).
4d	4. The Need for SDG&E Area Reliability Projects Should be Assessed and Where Applicable Reassessed Considering Declining Load Forecasts (Consistent with Topic 3 Above) and the Rationale for Two Particular Projects Should be Clarified or Revisited as Described Below. Recent CAISO transmission Plans have included considerable reliability-driven transmission additions in the San Diego area, relative to that area's share of overall CAISO area load. The need for such projects should be assessed and where appropriate reassessed based on latest planning information including the recent and anticipated trend in declining load forecasts. This is discussed at more length under topic 3 above. Based on a power flow analysis using a 2018 summer peak case provided by SDG&E, a review was conducted for the CPUC of certain, but not all, projects that have been identified for this area. In light of this review, the CAISO is requested to clarify or revisit the rationale for two of the SDG&E area projects included in the Draft Plan. The first project involves reconductoring of the Silvergate-Urban 69 kV line. Review conducted for the CPUC indicates that adding a second Silvergate-Urban line and installing a small series reactor on the existing Silvergate-Urban 69 kV line would solve additional problems in the Silvergate/Urban/Station B area that are not otherwise mitigated in the Draft Plan. The first of the two additional problems involves overlapping outages of the Station B – Urban line and the Silvergate – Urban line causing all of the Urban load to be shed. The	Regarding the "anticipated trend in declining load forecasts", the ISO encourages the CPUC to provide its input to the CEC – as noted above, the ISO intends to continue utilizing the CEC load forecast for reliability project planning purposes. Although the ISO's analysis is conducted according to a publicly vetted study plan and with interim results provided for stakeholder input, the comments provided here regarding CPUC-commissioned studies do not provide sufficient detail for the ISO to respond to. The Urban substation is in a high population density urban area (downtown San Diego) and a new line will be required to go underground. In addition, the Urban substation is fully built out and there is no room for expansion; accommodating a third line will require Urban to be re-built as GIS. This alternative was looked at in the past and received strong local opposition to the idea. Successful permitting is considered to be unlikely and the alternative appears to be very costly. For the Mesa Heights loop-in project, the reconductoring alone without the loop-in is sufficient to mitigate the overloading caused by the N-1-1 Mission-Mesa Heights and Mission-Kearny contingency. The cost of both options is similar, \$18.8M for the reconductoring alone, and \$18.1M for the reconductoring and loop-in. The reconductoring alone option needs to reconductor an additional 1.5 miles of lines from Mesa

No	Comment Submitted	CAISO Response
	second problem involves overlapping outages of either of the two Silvergate – Station B lines and the Silvergate – Urban line causing the remaining Silvergate – Station B line to have a significant overload. The CPUC requests that the CAISO describe why, as stated on page 141 of the Draft Plan, it is "not feasible" to add a second Urban – Silvergate 69 kV line. If such a line is feasible, it would solve the problem stated in the Draft Plan, as well as both of the additional problems described in the above paragraph. A comment box on page 143 of the Draft Plan indicates that the CAISO is investigating this matter further, with findings to be discussed at the February 18 stakeholder meeting. However, it does not appear that such findings have been released to date. Another project in the Draft Plan consists of a Mesa Heights loop-in plus reconductoring, to mitigate overloads under a P6 contingency. Part of the analysis conducted for the CPUC indicates that the reconductoring alone without loop-in would provide sufficient mitigation. The CAISO should explain why the loop-in is justified and if reconductoring alone is insufficient, what would be the cost savings from using a tap rather than a loop-in.	Heights to Kearny that offsets the saving of equipment cost of looping into the Mesa Heights substation. The tap option costs an additional $1M ($19.1M total) because of additional switch pole needed and replacement of the cable from the cable pole for the current TL 676 reconductor project. In addition to the relatively cheaper cost, the loop-in project also provides additional reliability for the Mesa Heights substation. Currently there are only two lines connecting Mesa Heights. An N-1-1 contingency of Mission-Mesa Heights and Kearny-Mesa Heights will lose all loads (63 MW for 2017 case, 66 MW for 2025 case) in the Mesa Heights substation. The loop-in project provides an additional link to other substations to prevent losing loads for such contingency.
4e	5. Unrealistically Early In-Service Dates for Projects Should be Avoided, and the CAISO and Project Developers Should Identify Such Risks as Early as Possible, Seeking Advice from CPUC and Others Where Necessary. Contrasting with the reassessment of previously approved projects noted in items 3 and 4 above, the CAISO needs to review project in-service dates based on up-to-date information on permitting and planning lead times. Especially where substantial permitting and siting requirements are foreseeable, the CAISO should make every effort to establish realistic in- service dates. In cases where permitting and siting requirements evolve in such a way as to impact in-service dates, the CAISO should work with project developers to reassess expected online dates as part of the transmission planning cycle. A recent example is the reactive controls project competitively awarded to NextEra Energy Transmission (NEET) West, which is seeking to build a static VAR compensator (SVC) station near the existing Suncrest substation. The project is currently in permitting review at the CPUC, but meeting the specified	Your comment has been noted. The ISO has taken additional steps to increase visibility of the transmission planning process with CPUC staff, and will continue to encourage input from the CPUC regarding reasonable permitting expectations.

No	Comment Submitted	CAISO Response
	in-service date of June 2017 may be infeasible given a realistic permitting timeline. Other large projects to watch for online date feasibility include Sycamore – Penasquitos as well as the Martin substation project. The CAISO should have a process to monitor these dates in light of emerging information. For planning efficiency and for system reliability it is important to avoid planned in- service dates that are unrealistic under foreseeable timelines. To help avoid such situations, CPUC Staff can provide informal advice regarding reasonable permitting timelines. However, it is essential that the CAISO and transmission developers assess the realism of planned in-service dates taking into account potential for significant siting/permitting requirements, (a) to establish realistic in-service dates, and/or (b) to consult on those projects where timeline feasibility may be questionable. CPUC Staff may sometimes be able to identify timeline issues by monitoring public planning information from the CAISO. In general, however, timeline issues are identified in the most timely and efficient manner if called to the CPUC's attention early in the process.	
4f	6. The CAISO Should Further Explain and Discuss Causes for and Alternative Solutions to Overvoltage Issues Responsible for Most of the Proposed Reliability- Driven Transmission Investment in the Draft Plan. Most of the estimated investment cost for reliability-driven transmission upgrades in the Draft Plan comes from reactive controls at a number of PG&E substations, to address overvoltage issues. Those issues have been described as increasing over time in both modeling results and in real-world monitoring. CAISO staff indicated that an important driver of this development is the changing generation mix and particularly the growth of renewable generation. To aid proactive and cost-effective planning and investment, the CAISO should identify and discuss with stakeholders the specific types and locations of resource developments most responsible for this growing overvoltage problem, including prospects for exacerbation as we pursue 50% renewable energy penetration. Is periodic as-needed investment in reactive controls the best long-term solution, or should we plan other solutions? For example, could future overvoltage issues be addressed with appropriate reactive controls on asynchronous resources as being pursued by the CAISO and also in the CPUC's Rule 21 distribution-level interconnection reforms, or might overvoltage	As a part of the ISO transmission planning process, the ISO posts the reliability results in mid-August with a stakeholder meeting to discuss the reliability constraints identified as well as the PTOs go through potential mitigation alternatives they have identified so that stakeholders can provide input on these potential alternatives as well provide different alternatives in the request window that closes in mid-October.

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	problems be significantly reduced by pursuing appropriate types and locations of renewable and preferred resources?	
4g	7. CPUC Staff Request that the CAISO Clarify if the Assumed Delayed In-Service Date for the Vaca-Dixon/Lakeville 230 kV Reconductoring Has Resulted in Modeled Reliability Violations and in What Year, and if Pittsburgh Units Scheduled to Retire Were Modeled Online to Mitigate This or Other Reliability Issues. Permitting for the Vaca-Dixon/Lakeville reconductoring project is currently delayed and uncertain, and it appears that reliability studies for the 2015-2016 Transmission Plan have pushed the assumed in-service date back to 2019. CPUC Staff request that the CAISO explain if this later assumed in-service date has produced modeled reliability violations, and whether continued operation of Pittsburgh generating units otherwise assumed to retire at the end of 2017 was modeled as a mitigation for (a) such reliability violations, or for (b) any other modeled reliability violations. In addition, CPUC Staff request, especially in light of declining load forecasts since the project was approved, that the CAISO identify in which year modeled overloads first occur (if at all) that would trigger the Vaca-Dixon/Lakeville reconductoring. Finally, the CAISO should clarify if reliability modeling for 2015-2016 Transmission Plan assumed identical 450 MVA emergency ratings (under N-1 conditions) for both the Vaca-Dixon/Lakeville and Vaca-Dixon/Tulucay 230 kV lines , or whether other assumptions were used and what they were.	The ISO will assess the impacts of the recent delay in the in-service date for the Vaca-Dixon/Lakeview 230 kV Reconductoring project on the OTC compliance for Pittsburg. This assessment will not be done as a part of the 2015-2016 TPP due to the timing of the updated information, but will be conducted as a separate assessment by the ISO.
4h	8. CPUC Staff Appreciate the CAISO's Initial Informational 50% RPS Study and Its Lessons for Future Studies, and Identify Selected Areas Where We Look Forward to Continuing Insights. CPUC Staff appreciate the CAISO's initial informational study of implications and feasibility of pursuing the legislatively established 50% renewable energy goal. The CAISO examined the implications of two portfolios of energy-only renewable resource additions going- forward, where "energy only" delivery trades off reduced investment and environmental costs for transmission versus increased potential for renewable generation curtailment and possibly more complex operational reliability measures. We look forward to adjustment of assumptions in the CPUC's RPS calculator based on this initial study, as well as refinements	Your comment has been noted.

<table>
<tr><th>No</th><th>Comment Submitted</th><th>CAISO Response</th></tr>
<tr><td></td><td>and insights from future studies of this type. Some areas where we look forward to further insights from future studies include

• Benefits (e.g., reduced curtailments) and needs (e.g., for reliability) for different levels of transmission upgrades, all of which should nevertheless be much less than what would be needed for full capacity deliverability.

• Clarification of how conditions expected or assumed at the distribution level impact feasibility, costs and preferences for pursing the 50% RPS goal - - considering expansion of distributed energy resources (DER) , potential for DER reactive controls and ability to curtail, storage penetration, and general DER responsiveness to broader system (not just local host) needs.

• Further insights into the important but still uncertain role of ability to export surplus renewable generation in affecting costs and feasibility of different high renewables futures - - including impacts on transmission needs and reliability issues such as examined via the CAISO's power flow studies.

• Further insights into the extent to which potential problems revealed in power flow studies resolve themselves via reasonable fine tuning of assumptions regarding how/where post-33% renewable additions will be deployed - - as opposed to still leaving the need for significant curtailments, operational solutions, or transmission upgrades.</td><td></td></tr>
<tr><td>4i</td><td>9. CPUC Staff Look Forward to Further Assessments of Frequency Response Issues Particularly Under High Renewables Futures, and Request Additional Clarity Regarding Renewable Resource Assumptions, Interaction with Flexible Reserves Requirements, Under-provision by Frequency Response-Capable Resources, and Frequency Response from Additional Kinds of Sources in the Next 10-15 Years.

CPUC Staff understand that the CAISO's latest frequency response study reported in the Draft Plan indicates that the CAISO would have sufficient primary frequency response capability under a 2025 spring off-peak case even for</td><td>Your comment has been noted. The ISO will be continuing to assess frequency response in the 2016-2017 TPP with a focus on the modeling issues that have been identified. CPUC staff should also refer to the ongoing ISO Frequency Response stakeholder process, details of which are available at:

http://www.caiso.com/informed/Pages/StakeholderProcesses/FrequencyResponse.aspx</td></tr>
</table>

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	sensitivities having higher renewables output or reduced headroom, but would not have sufficient frequency response capability under a 50% renewables case. The CAISO should clearly describe how frequency response capability requirements were modeled in economic studies for the 2015-2016 TPP, whether as commitment constraints or otherwise - - even if this approach is to be supplanted in 2016. For future frequency response studies or for further insights into studies recently conducted, the CPUC Staff request additional information as follows. • To provide context relative to other studies such as for a 50% RPS or CAISO expansion, the CAISO should identify the overall renewables composition in the 2025 study cases, the 50% renewables case, and in studies going forward - - both within and outside of California, particularly relative to recent RPS portfolios being studied in California and included in the latest TEPPC Common Case. • For the current studies and going forward, the CAISO should provide greater quantitative insight into how commitment of resources to meet frequency response needs interacts with flexible reserves commitment to manage load/wind/solar variations and uncertainties. For example, are the flexible reserves (for load/wind/solar variability) versus frequency response needs fully additive, overlapping, or somewhere in-between? • In describing the frequency response study the CAISO notes that modeled frequency response appears to exceed what has been obtained in practice. Further, the CAISO's frequency response initiative has considered possible need for measures to increase or motivate frequency response performance from resources currently capable of providing frequency response. This all suggests that some resources technically able to provide frequency response may not be reliably providing it. The CAISO should clarify if this is a reason for modeled frequency response exceeding observed performance, and how both modeling and market reforms will address this situation.	

No	Comment Submitted	CAISO Response
	• The CAISO's recent study indicated inadequate frequency response under a 50% RPS scenario, and the CAISO should examine and discuss with stakeholders (a) the potential for additional sources of primary frequency response not modeled in recent studies especially looking out 10-15 years, and (b) how the CAISO plans to model and assess such additional sources of frequency response. Additional sources might include, for example, thermal and hydro generation not presently assumed or modeled to provide primary frequency response, storage, demand response, other preferred resources, and frequency response obligation contracts with other BAs such as from Northwest hydro systems.	
4j	10. The Bulk Storage Study Adds Useful Data Points to Diverse Studies Of Storage and Other Renewable Integration Measures, and Requires Fuller Explanation of Storage Valuation Based on Market Revenues as Well as Fuller Examination of the Impacts of Alternative "Net Export" Constraints on the Value of and Need for Additional Bulk Storage. The CAISO's bulk (pumped) storage study adds to accumulating information and data points regarding the effectiveness of storage in managing the physical and economic challenges of integrating high levels of variable renewable generation in pursuit of energy policy goals. CPUC Staff request that as the CAISO develops final reporting for this study and plans for any future extensions, the following information be provided. First, page 18 of February 18 presentation slides on the bulk storage study depicts the value versus revenue requirements (for capital recovery) of a hypothetical pumped storage project, showing "net revenue" (a measure of value) of $194 million and $170 million with solar-heavy and wind-heavy resource additions respectively, calibrated to achieve a 40% RPS. These net revenues are stated to be based on energy, reserves and load following revenues, minus costs of energy and operation. Based on other tables in the presentation, these net revenues substantially exceed cost-based bulk storage benefits if calculated as the reported reduction in WECC production costs plus the reported reduction in wind/solar overbuild costs to offset curtailments. The CAISO should provide more complete information on the numerical values and computational rationale for the different components of the revenues-based	The comment has been noted. Please refer to the response to comment 2f.

No	Comment Submitted	CAISO Response
	valuation of bulk storage, e.g., the energy, reserves, and load-following revenues versus offsetting energy and operating costs. Second, the CAISO should examine and report the value of added bulk storage under a range of assumptions regarding the magnitude of net exports that could be achieved to facilitate integration of the added in-state renewable generation. Ability to export surplus energy has in numerous studies been shown to be a key driver of the cost of developing and integrating high levels of variable (especially solar) renewable resources in California, thus affecting the attractiveness and feasibility of different kinds of portfolios of renewable resources. Variations in the presently uncertain ability to export energy under unprecedented physical and market conditions in the future are typically examined by applying different constraints or caps on the amount of hourly net exports allowed in the modeling. For example, the CAISO's SB350-mandated BA expansion study is examining 2000 MW, 5000 MW and 8000 MW (hourly) net export limits under a "BAU" case, and the CAISO's special 50% RPS informational study reported within the Draft Plan is examining net export limits of zero, 2000 MW, 8000 MW and unlimited (the latter presumably enforcing only physical constraints). The effects of a comparable (ideally, identical) range of net exports should be examined and reported for the bulk storage study. Beyond providing more robust information on the potential value of bulk storage additions, this would make results and insights more useful by placing them within the context of a broader range of studies that include consideration of different net export levels.	

No	Comment Submitted	CAISO Response
5	**Eagle Crest Energy** **Submitted by: Susan Schneider, Consultant**	
5a	• ***In this study cycle, CAISO should modify the Storage Study*** to do the following: ➢ Extend the analysis to reflect a 50% RPS, to match 50% RPS Study findings and provide a longer time horizon to reflect development timing and asset life. If this cannot be done in the final Plan, the CAISO should issue a supplement soon after completion of the Plan. ➢ Correct the study calculations to zero out Delivery Network Upgrade (DNU) costs, which likely account for most of the transmission costs. The Project can provide all market services (including contingency reserves, Regulation, flexible ramping, voltage support, and frequency response) without Full Capacity Deliverability Status (FCDS), and the associated DNU costs to obtain FCDS. However, if the availability of the Project to the CAISO can reduce the need to procure Flexible RA capacity (as discussed further below), that attribute should be added as an economic benefit. State the value of the gross system benefits provided by the storage facility (e.g., curtailment avoidance), as well as the dollar amount of the merchant revenues the study found the facility would receive. Important policy decisions about storage procurement may depend on the system benefits figures that cannot be monetized through markets.	The comment has been noted. Please refer to the response to comment 2f.
5b	• ***In the 2016-7 study cycle, the CAISO should do the following:*** ➢ Extend the Storage Study to consider: ▪ <u>Greater pumped-storage capacity</u>. The study this cycle says benefits were limited by the 500 MW assumed facility capacity. Several feasible facilities under development in California could provide more pumped storage capacity (individually or in total), so assessment of a greater level of storage capacity is warranted. ▪ <u>Potential locational benefits</u>. There are only a limited number of known, feasible California pumped-storage locations. The value of storage to ratepayers is the sum of benefits from several kinds of attributes, and a system-level analysis underestimates total storage benefits. An assessment of locational benefits, such as congestion relief, is also needed to inform important policy decisions about bulk-storage procurement.	The comment has been noted. Please refer to the response to comment 2f.

No	Comment Submitted	CAISO Response
	▪ Extend the 50% RPS Study work to determine a feasible range of net exports. It is not clear that system over-supply problems can be addressed through large quantities of exports, due to physical and operational limitations (e.g., required by reliability criteria), legacy contracts, and policy/political decisions of adjacent Balancing Authorities that collectively could restrict such exports in the study time horizon.	
5c	**Storage Study** ECE appreciates the CAISO's willingness to study pumped storage in the Transmission Planning Process (TPP), and the study in the draft Plan is a reasonable start. However, further analytic work to measure the economic and renewable integration value of pumped storage is needed in order to inform important policy decisions (perhaps as soon as next year) regarding procurement, funding, and development of pumped storage. Specifically, the study should be enhanced and extended, in this cycle and the next, as described below. • **Several basic assumptions should be updated.** The study is based on outdated assumptions from the 2014 CPUC Long-Term Procurement Proceeding (LTPP). Those LTPP assumptions pre-dated adoption of the 50% RPS in SB350, and so the study assumes a 40% RPS instead of the new 50% target. Furthermore, it does not consider the long development timeline (e.g., the need to make procurement decisions in the next year or two in order to preserve the likelihood of commercial operation in the 2024 timeframe) or useful life of bulk storage assets (far beyond 2030). The study also does not consider changes in key variables, like higher carbon emissions costs in the post-2024 timeframe.	The comment has been noted. Please refer to the response to comment 2f.
5d	• **Assumed transmission costs should be reduced.** The study assumes that the pumped storage facility would have FCDS for all of its capacity, with high transmission costs to achieve it but no revenues for that attribute. The $16.50/kW-year transmission cost translates into about an $8-10 million annual revenue requirement (depending on whether the multiplier is the 500 MW generation capacity or the 600 MW pumping capacity), which implies a transmission cost of about $40-100 million. Most of this cost is likely associated with DNUs to provide FCDS. There are several problems with this approach: (1) As noted above, all the project services and associated operational benefits could be provided without any RA deliverability; (2) this assumption is inconsistent with the reduced need	The comment has been noted. Please refer to the response to comment 2f.

No	Comment Submitted	CAISO Response
	for FCDS from new resources reflected in the 50% RPS Study; (3) no RA or Flexible RA revenues were assumed in the conclusions about merchant-revenue coverage; and (4) the facility developer would only be willing to pay for those upgrades if the expected RA revenue would exceed the cost. More generally, pumped storage may not make sense as an RA Resource, particularly if the RA capacity is not needed. One benefit of pumped storage is its ability to maximize transmission utilization, while FCDS attainment is assumed here to trigger additional transmission upgrades. Thus, at most, the net transmission cost should reflect only Interconnection Facilities and Reliability Network Upgrades, which for a facility of this size would be unlikely to exceed about $8-10 million ($2-3 million annual revenue requirement). In other words, the net DNU cost should conservatively assumed to be zero, i.e., the facility would either be Energy-Only (if the RA revenue would not justify paying for DNUs) or FCDS with RA revenues at least high enough to cover the DNU costs.	
5e	• ***The study should distinguis h be twee n "gross " sy s tem be nefits a nd those covered by market revenues.*** There are several reasons why this is important. First, the study finds that CAISO market revenues would not sufficiently compensate pumped storage resources for the project revenue requirement. While market value is an important consideration, virtually no projects in California are developed, constructed or financed as merchant projects. Thus, as with new generation resources, at least some revenues should be assumed to come from sources other than CAISO market revenues, e.g., bilateral contracts or other compensation. Second, one reason why financing new pumped storage facilities is difficult is that such facilities provide benefits that are <u>not</u> reflected in market revenues. For example, the benefits associated with reduced renewable-energy curtailment, emissions reductions, or need to overbuild the system to accomplish state RPS policy goals would not accrue to the storage facility owners but would be shared throughout the market, and in advancement of the State's larger economic and clean energy goals. The Study acknowledges that compensation for these non-market benefits is needed to make such facilities economic, stating (at p. 258 of the Plan), that "the net revenue from the market would not reasonably be the only revenue stream –	The comment has been noted. Please refer to the response to comment 2f.

No	Comment Submitted	CAISO Response
	consideration should also be given to how the storage resource would be compensated for the benefits it brings to the system." In order for the study results to inform these compensation policy decisions, the CAISO should clearly state which benefits would be covered through market revenues and which would have to be covered through some other source. To inform decisions about those other funding sources, the CAISO needs to consider and quantify all of the transmission-related benefits, including voltage support, frequency response, avoided transmission costs, congestion relief, and (depending on the funding structure) reduction in Flexible RA procurement needs. Finally, this initial study covers only system benefits. As explained further below, a storage assessment should also reflect potential locational benefits.	
5f	***• The study should provide guidance about the optimal location and size of bulk storage facilities.*** As noted above, the economic and operational justification for large storage facilities will likely rely on the sum of different kinds of benefits, and the CAISO should not ignore important local benefits that can inform storage policy decisions going forward. There are only a small number of feasible locations for such facilities, and the CAISO should expand its bulk storage studies in the next planning cycle to explore available local benefits. As the 50% RPS Study illustrates, there may be localized congestion or other problems that could be addressed by bulk storage facilities. For example, additional renewables development in high-potential renewables areas such as East Riverside, or imports from other areas (which may become part of an expanded west-wide ISO/RTO by joining with the CAISO), could be accommodated through locating bulk storage facilities there. The same may be true for possible pumped-storage locations in norther California. The study also notes that, in many instances, the assumed 500 MW size of the facility limited the benefits provided. Far higher renewables curtailments (>13,000 MW) were seen in the 50% RPS Study, indicating that a larger facility could provide greater net benefits. Therefore, the CAISO should explore whether increasing the hypothetical bulk storage facility size (e.g., to at least 1,000-1,500 MW or more, or running sensitivities for various larger sizes) would provide a commensurate increase in benefits. A larger project is also likely to	The comment has been noted. Please refer to the response to comment 2f.

No	Comment Submitted	CAISO Response
	lower the per-MWh pumped storage costs due to economies of scale and thus increase the cost/ benefit analysis.	
5g	***50% RPS Study*** This study examines net-export scenarios between 2,000 and 8,000 MW. However, the study does not attempt to determine which export levels may be realistic, so it is not clear whether large quantities of exports are a viable long-term solution. The CAISO's ability to export is premised on the ability and willingness of neighboring regions to absorb its over-supply. That ability and willingness will depend on several factors: • The physical ability of adjacent/nearby regions to absorb excess energy when it is likely to be available. Neighboring states have relatively small loads compared to California and their own resource fleets to manage, and many of their large native resources lack significant operating flexibility. This is exemplified by the issues surrounding the current inflexibility of "block" imports, which has actually been exacerbated since implementation of CAISO 15-minute markets. • The willingness of other regions to forego the economic and other benefits of developing renewable-energy facilities. The entire west has abundant and economic renewable resource potential, and native development is an economic driver in many Western states. It's unclear why neighboring state would want to forego the economic benefits associated with native renewable development in favor of procuring excess California energy. On the contrary, many regions are considering joining the CAISO EIM and/or an expanded west-wide ISO/RTO because they desire expanded access to California markets to sell energy from high-potential renewables or other production in their own areas, to reap the associated jobs and other economic benefits from such development. • Legacy transmission agreements. Many of these areas have less-flexible, long-term transmission agreements in place that could reduce the use of those assets by others. If other western regions cannot absorb California's excess energy due to these or other factors, California will be forced to adopt new strategies. In the next planning cycle, the CAISO should attempt to determine which export levels would be realistic – probably not zero, but probably not in the upper ranges assumed either.	The ISO agrees that the net-export consideration is material, and there is significant uncertainty about how much oversupply can be absorbed by neighboring systems through exports. As the limitations are expected to be more based on the supply and demand considerations and market frameworks than purely transmission capacity limitations, this issue is expected to evolve through broader industry dialog than unilateral ISO analysis.

No	Comment Submitted	CAISO Response
6	**Imperial Irrigation District (IID)** **Submitted by: Nisar Shah**	
6a	1. CAISO, in its 2013-2014 Transmission Plan page 143 made the following statement regarding IID Maximum Import Capability (MIC), "The ISO has established in accordance with Reliability Requirements BPM section 5.1.3.5 the target maximum import capability (MIC) from the Imperial Irrigation District (IID) to be 1,400 MW in year 2020 to accommodate renewable resources development in this area." Further down on the same page CAISO explains the decrease in IID MIC primarily due to early retirement of SONGS but makes the following commitment, "However, the ISO is planning to identify further upgrades, as part of the 2014-2015 transmission planning process that would be required to achieve the original 1,400 MW MIC target for IID." It has been two years since the CAISO's original commitment to restore IID MIC. IID would like to know what efforts CAISO has done or plans to do to meet its commitment?	Consistent with the direction the ISO received from the CPUC regarding renewable generation development, the ISO studied portfolios in the 2014-2015 planning cycle including 1000 MW Imperial area generation above then-existing renewable generation, and 2500 MW Imperial area generation above then-existing renewable generation. The 2500 MW portfolio was expected to equate to sufficient generation to accommodate generation already moving forward connecting to the ISO in the Imperial area as well as 1400 MW maximum import capability from IID. The 2500 MW scenario was a sensitivity study, and as such was provided to the ISO by the CPUC for the purpose of identifying but not approving new policy-driven transmission. The ISO was able to identify operating measures – which did not require project approval and, when combined with previously-approved projects, would provide 1700 to 1800 MW of additional deliverability to the Imperial area above the then-existing renewable generation. Taking into account the new generation that is moving forward in the Imperial area and providing resource adequacy capacity to ISO utilities (240 MW of which is connecting to IID), the ISO has estimated that 500 to 750 MW of deliverability is available on a first-come, first-served basis. Other options for additional increases in deliverability were identified in the analysis of the 2500 MW portfolio but lacked the necessary policy support and direction for approval. Each year, the ISO studies renewable generation portfolios provided by the CPUC for purposes of planning and approving policy-driven transmission.
6b	2. Switching back to the current CAISO 2015-2016 Transmission Plan, CAISO states on page 280, "Since all the constraints observed in Imperial zone can be mitigated by using SPS, the 2015-2016 policy-driven analysis confirms that the mitigation measures recommended in 2014-2016 TP have restored Imperial zone deliverability to ~1,700 to 1,800 MW." If Imperial	This reference has been edited in the revised draft Transmission Plan to add "incremental above then-existing renewable generation" at the end of the sentence.

No	Comment Submitted	CAISO Response
	Zone deliverability have been "restored" then IID MIC should be back to its original value of 1400 MW in 2020. This Transmission Plan, on page 168 last paragraph, assigns IID MIC of 702 MW in 2020. How do you explain this discrepancy?	The forecast incremental deliverability is being relied upon in part to forecast increasing the MIC from IID to 702 to reflect the generation projects that have moved forward in IID with resource adequacy capacity provisions under contract with ISO utilities, and by generation connecting directly to the ISO grid in the Imperial area. As noted in the 2014-2015 Transmission Plan, the ISO forecast that after taking into account those other resources, approximately 500 to 750 MW of forecast deliverability remains for future generation not already moving forward, which will be used on a first come, first served basis for resource adequacy capacity resources connecting in the Imperial area (whether to the ISO controlled grid or via IID.)
6c	3. The deliverability numbers of 1700 to 1800 MW in Imperial Zone in the above paragraph are questionable. Imperial zone consists of 98% IID system and only 2% CAISO system. How much of this 1700-1800 MW were modeled in (or determined from) IID system?	Resources were modeled in the Imperial zone based on information provided by the CPUC renewable generation portfolios. The ISO's cases are available on the ISO's secure website.
6d	4. IID's internal studies have indicated that Imperial CREZ can actually accommodate up to about 2800 MW depending upon where generation is located while respecting the ECO-Miguel constrained path and Path 42 limits. Did CAISO consider the Locational Effectiveness Factor (LEF) for the generators while determining the 1700-1800 MW limit?	Please refer to 6c.
6e	5. If CAISO would like to explore the LEF further, IID is recommending that CAISO take a lead and include other interested PTOs and / or Stakeholders including IID to identify the most promising locations for new renewables in the Imperial CREZ.	Please refer to 6c. The ISO will continue to strive to coordinate with IID on relevant planning issues, and encourages IID to support the CPUC's portfolio development processes.
6f	6. A discussion paper focusing on the use of Locational based methods to assess Deliverability, prepared by ZGlobal on behalf of IID, is attached for reference [refer to IID comments for paper].	Please refer to 6c.
6g	7. On Page 208 of the Draft Transmission Plan, Table 3.4-3, the Greater Imperial Zone is estimated to have 2633 MW of Renewable resources (in-state portion). How much of this 2633 MW is considered or modeled within the IID service territory? Since IID service territory represents majority of the Imperial Zone, is it reasonable to include IID while modeling renewable resources within Imperial Zone?	Please refer to 6c.

No	Comment Submitted	CAISO Response
7	**NextEra Energy Transmission West** **Submitted by: Edina Bajrektarevic**	
7a	CAISO Planning Standards, North American Electric Reliability Corporation's ("NERC") Reliability Criteria (TPL 001-4, NUC-001-2.1) and the Western Electricity Coordinating Council's" ("WECC") Regional Criteria serve as the foundation for CAISO's regional transmission plan and provide the minimum transmission system performance standards. Over the last several years, NEET West has valued and appreciated CAISO's efforts in its planning of a high voltage transmission grid while involving very complex and sometimes competing priorities. At the same time, CAISO has considered more than just the minimum reliability criteria by taking into account other complex changes that could impact transmission system reliability and result in savings for customers. For example, CAISO has included studies that are associated with emerging issues, such as the implications of significant displacement of conventional generation with renewable resources that do not have the same inherent fundamental operating characteristics, how low hydro conditions (i.e., Big Creek) impact reliability, or extreme contingency events such as a catastrophic seismic event in the San Francisco area. To aid in CAISO's comprehensive long term transmission planning process evaluation, NEET West respectfully requests that CAISO consider several recommendations explained below to broaden CAISO's study policies and to more comprehensively assess the benefits of all viable reliability-driven transmission alternatives. **NEET West Recommends the Implementation of a Comprehensive and Consistent Metric System for Evaluating Viable Alternative Reliability Transmission Solutions** NEET West believes that the identification of the most appropriate and cost effective reliability solution among multiple competing reliability projects should be performed by using a consistent framework for quantifying important costs and overall reliability benefits. One such framework for evaluation is CAISO Transmission Economic Assessment Methodology ("TEAM")1, which is designed to evaluate both economic and reliability driven projects. NEET West recommends that CAISO apply and share with stakeholders a comprehensive and consistent metric system for evaluating viable competing reliability solutions that includes:	The list of potential issues documented in the comments is helpful, and the ISO will look to take these issues into account on a case by case basis going forward. We do not see it feasible to incorporate the extensive analysis recommended in the comments in all cases and without regard for the details of the specific reliability issue being addressed, as the analysis needs to be tailored to address those specifics, and it would further be wasteful to perform unnecessary and unhelpful analysis in all cases. We support and encourage stakeholders to identify specific issues that they consider relevant in individual study analysis, on a case by case basis.

No	Comment Submitted	CAISO Response
	• Evaluating all alternatives for reliability and performance by testing system thermal loading, voltage performance and control, stability performance, short-circuit margins, extreme contingency performance, and interface impacts (internal/external). • Assessing overall project viability including constructability, environmental impact, rights-of- way impact, in-service dates, outage requirements and impacts. • Determining any long-term project benefits including expansion capabilities, lifetime efficiency and expectancy. • Examining operational and maintenance related issues and costs on a high-level basis to ensure that solutions do not introduce new operational or maintenance related concerns. This component of the evaluation should outline the benefits to “Operational Reliability” or “Operational Flexibility” (more options for maintenance outages, additional flexibility for switching and protection arrangements). • Evaluating the overall costs and benefits (possibly including a net present value analysis) and performance of the viable competing reliability projects to determine which is the most appropriate and cost-effective solution. The cost/benefit evaluation should include items that may impact project selection such as: construction costs, long-term congestion impacts, cost of outages associated with construction, costs associated with operation and maintenance of the assets, cost of losses, local capacity requirement benefits and reductions that otherwise would have to be purchased through reliability-must-run (RMR) contracts, capacity benefits of the transmission upgrade(s) (potential increases to reserve sharing and firm capacity purchases, and associated decrease to the amount of local area power plants that have to be constructed to meet adequacy requirements), environmental benefits of avoiding local air emissions, etc. • Incorporating high voltage transmission aging infrastructure decisions into the ongoing TPP. The aging transmission infrastructure represents a significant element in the operational and long-term planning followed by a risk evaluation aimed at anticipating and mitigating the impact of significant transmission loss events. Similar to efforts performed in other regions2, the analysis, as part of the long term transmission plan, should take into account the aging of high voltage transmission elements in the system over CAISO’s entire footprint. In addition,	

No	Comment Submitted	CAISO Response
	the analysis should include stakeholders review and engagement in the development of transmission solutions to mitigate operational, reliability, and market impact of such transmission losses. • Communicating the final results, including appropriate metrics of all tested alternatives to all stakeholders and publishing the results in the CAISO TPP. NEET West recognizes that some of the factors, such as "Operational Reliability" have dimensions that are not easily measurable in monetary terms (e.g., the value of avoiding the adverse impact to society of a system-wide blackout). NEET West recommends that some of the factors as described herein are considered as complimentary to the existing reliability studies and detailed cost evaluation and that they are intended to help support differentiation of a particular project in making a final selection.	
7b	**NEET West Requests Additional Stakeholder Engagement and Participation throughout the Project Analysis Phase** NEET West appreciates CAISO's effort to follow its Federal Energy Regulatory Commission (FERC) approved transmission planning process, which FERC found to be just and reasonable and not unduly discriminatory or preferential. CAISO has provided for open and transparent access and stakeholder consultation opportunities as set out in that process. NEET West appreciates the current CAISO transmission planning process, which provides for the opportunity to submit needed reliability projects, to participate in stakeholder meetings, and to submit comments throughout the process. In order to have a more meaningful impact upon the CAISO TPP and its objective to determine the most cost-efficient solution, NEET West requests that CAISO allow interested stakeholders to participate in the project analysis phase for specific regions of interest, where competing reliability projects are under evaluation.	The ISO's planning process is conducted through the open stakeholder process that NEET West is participating in. It is not clear what additional involvement opportunity NEET West is seeking in its comment. "NEET West requests that CAISO allow interested stakeholders to participate in the project analysis phase for specific regions". The ISO currently provides its reliability findings in advance of a stakeholder session, creates opportunities for review of ISO and utility draft mitigations and access to system models, and presents draft reliability results for discussion before the transmission plan is ultimately approved.
7c	**NEET WEST Requests Clarity for the Process Used by CAISO in the Evaluation of NEET West's Reliability Proposed Projects Against Alternative Proposals.** **Evaluation of Reliability Transmission Solutions for the Lugo – Victorville Thermal Overload** Southern California Edison ("SCE") submitted the joint Lugo-Victorville 500 kV line upgrade project to mitigate the Lugo-Victorville 500 kV thermal overload, which has an estimated in-service date of 12/31/2018. NEET West proposed an	The impact of 50% RPS on Lugo-Victorville 500 kV line was examined as part of the 50% special study which was an energy-only informational study. Under the stressed snapshots selected for Southern CA area, the studies did not demonstrate increased reliability concerns on this line due to considerably different flow patterns. The reliability impact of a maintenance outage on Lugo-Victorville 500 KV line was captured in the reliability assessment since severe N-1-1

No	Comment Submitted	CAISO Response
	alternative solution which consisted of a new 17- mile 500 kV transmission line between Lugo 500 kV substation and Adelanto 500 kV substation, which has an estimated in-service date of 6/1/2022. The 2015-2016 TPP Draft Plan provides the following response to the NEET West proposed alternative: "The proposed project provides thermal overloading relief to the Lugo-Victorville 500kV line under contingency conditions. However, the proposed project includes construction of a new 500 kV line, which needs to go through an environmental review permit process, and has a higher cost, and a later proposed in-service date, than the recommended Lugo- Victorville 500 kV Upgrade Project. For these reasons, the project was not found to be needed." The 2015-2016 TPP Draft Plan suggests that the evaluation criteria utilized by CAISO for alternative reliability projects was limited to a comparison of capital cost and online date. To improve upon the analysis of the Lugo –Victorville thermal overload, NEET West requests that the 2016-2017 TPP evaluation include the reliability assessment of the NEET West Lugo – Adelanto project and a comparison of the NEET West project alternative against alternatives considered to determine the most cost effective solution. In addition, the 2016-2017 TPP evaluation should include the following: • Evaluation of the congestion management costs under normal operating conditions, currently estimated at a cost of $43 million since January 2013.3 • This analysis would need to include the WECC Path P61 rating, and the impact of both projects to this rating. There is a potential that the Lugo-Adelanto alternative will eliminate the operating nomogram completely, while the Lugo-Victorville Upgrade project will not. • This analysis would need to include the impact that 50% RPS will have on the path. The assumption that all renewables over 33% are Energy Only may change in the next planning cycle. The addition of additional Full Capacity Deliverability Status units to this region can easily surpass the capability of the Lugo-Victorville Upgrade Project. • Evaluation of the congestion management costs under construction conditions of the Lugo- Victorville Upgrade project versus the Lugo-Adelanto alternative.	combinations of contingencies were run. The N-1-1 combinations with Lugo-Victorville 500 kV line indicated only one potential overload issue on a 115 kV line only during off-peak conditions. This issue can be easily mitigated by using congestion management. This observation indicates that congestion impacts during the upgrade construction would be minimal. The CAISO will continue to consider construction outages in this area in the 2016-2017 TPP.
7d	**NEET West Recommends CAISO Develop a Long-Term Reliability Transmission Solution for the Pacific Gas &Electric (PG&E) Oakland Area**	

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<tr><th>No</th><th>Comment Submitted</th><th>CAISO Response</th></tr>
<tr><td></td><td>To improve the reliability and to mitigate thermal overloads within the Oakland area, NEET West submitted a new transmission solution that consists of a new 230 kV transmission source connecting Sobrante 230 kV substation to a new Oakland C 230 kV substation, with an in-service date of 6/1/2022.

In the 2015-2016 TPP, CAISO indicates that they will continue to consider transmission, generation or non-transmission solutions as they revisit the assessment of Oakland area needs in the 2016-2017 TPP cycle. In the near-term, the Oakland area relies on Special Protection Systems ("SPS") with a relatively small amount of load shedding as allowed per the CAISO Planning Standards; however CAISO will consider alternatives for the long-term horizon.
• NEET West requests that the CAISO's 2016-2017 TPP cycle include a special assessment of the Oakland/East Bay area and to evaluate the NEET West project alternative against alternatives considered to determine the most cost effective solution. Due to its characteristics, long-term planning for the Oakland/East Bay Area should incorporate an approach similar to the San Francisco Peninsula Extreme Event Reliability Assessment previously performed in the CAISO's 2015-2016 TPP cycle. The Oakland East Bayassessment should explore all viable mitigation options that address the special circumstances for this area; some of these circumstances include:
A high-density urban area consisting of over 400MW of load.
Potential retirement due to age4 of Oakland area combustion turbine (CT) generation. It should also be noted that previous versions of the CAISO Planning Standards included the Greater Bay Area Generation Outage criterion, which recognized a higher unavailability of these units due to their age and forced outage rates.
Elimination of the reliance on SPS or Remedial Action Schemes ("RAS") per the CAISO's new High Density Urban Load Area planning standard, which no longer allows "non-consequential load dropping in high density urban load areas in lieu of expanding transmission or local resource capability" to mitigate NERC TPL standard contingencies and transmission system impacts (for facilities ≥115 kV). NEET West recognizes there are multiple existing Special Protection Schemes in the East Bay (PG&E Greater Bay Area: Moraga-Oakland J 115 kV line OL RAS, Grant 115 kV OL SPS, Oakland 115 kV C-X Cable OL RAS,</td><td>Due to the uncertainty of existing local generation and development of non-transmission solutions in the East Bay area, the ISO will continue to evaluate the extent of long-term reliability needs considering these developments in the 2016-2017 TPP.</td></tr>
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No	Comment Submitted	CAISO Response
	Oakland 115 kV D-L Cable OL RAS); these schemes are designed to drop load in order to comply with NERC TPL contingency events. • The environmental restrictions and economic impacts of the Oakland combustion turbines (that are RMR units) and Northern California Power Agency ("NCPA") combustion turbines in Alameda have on the system and how these restrictions and economics may be impacted with the addition of the NEET West Oakland Project. • Exposure and restrictions of transmission system topology. Existing critical overhead transmission sources (Moraga-Claremont, Moraga-Station X, and Moraga Station J 115kV circuits) are confined to multiple-circuit corridors and traverse heavily-wooded areas, foothill ridges and canyons. These conditions limit accessibility, and expose these facilities to causes of common-corridor outages (such as fire). Likewise, downtown Oakland's aging network of 115 kV underground cables (gas-filled pipe-type cables constructed in the 1960's) offer limited access due to heavy urban development, and are also exposed to seismic considerations (proximity and orientation to the Hayward Fault). All these factors complicate the timely restoration and/or reinforcement of existing circuits, and likewise present routing challenges for new facilities. Planning studies should consider the implications of multiple-circuit/extreme outages, and the potential for sustained unavailability of one or more circuits.	
7e	**NEET West Recommends CAISO Develop a Long-Term Reliability Transmission Solution for the PG&E Fresno Herndon Area** CAISO planning analysis has shown that a Category P2 and P2-1 outages of Bus fault at Herndon 115 kV bus, Herndon Bullard #1 115kV line, or Herndon Bullard #2 115kV line will cause an emergency overload of the Herndon Bullard #1 115 kV line or Herndon Bullard #2 115 kV line starting in 2017, up to 140% in 2025. In addition, and under multiple NERC category (P2 and P2-2) contingencies as listed in Table 1 below, CAISO 2015-2016 TPP preliminary reliability results indicate: • Transient Stability Performance Issue for a Bus 2 fault at Herndon 115 kV bus. • Thermal overloads on the Pinedale to Bullard 115 kV lines. To improve the reliability and thermal overloads within the Herndon area, NEET West submitted a proposal to construct a new 230 kV transmission system that	After further evaluation of the fault modeling of the Herndon Bus 2 fault, we found no transient stability violations at Herndon, which eliminates any need for a solution. Mitigation options For the P2-1 and P2-2 category bus fault at Herndon will be reviewed in the future planning cycles, which could include SPS, NEETS Transmission Solution or other more economical solutions.

No	Comment Submitted	CAISO Response
	consists of a new 230/115 kV Transformer at Bullard Substation and a new 230 kV transmission line from Ashlan Ave to Bullard Substations, which has an in-service date of 6/1/2021. The NEET West 230 kV transmission line between Ashlan Ave to Bullard removes the identified transient stability issues for a Bus 2 fault at Herndon 115 kV. CAISO reviewed the submission and based upon the reliability assessment found a need for further evaluation in 2016-2017 TPP of potential mitigation to address the category P2 longer term issues identified. NEET West requests that the 2016-2017 TPP evaluation include the reliability evaluation of the NEET West Herndon project and a comparison of the NEET West project alternative against alternatives considered to determine the most cost effective solution.	
7f	**NEET West Recommends CAISO Develop a Long-Term Reliability Transmission Solution for the SCE Big Creek Area** The 2020 Summer Peak with Low Hydro Reliability Assessment for the SCE Tehachapi and Big Creek Corridor revealed thermal performance concerns (including Magunden – Vestal 230 kV 1 or 2, Rector – Vestal 230 kV 1 or 2, and Magunden – Springville 230 kV 2) under various category P1, P3, and P7 outages. Based on the assessment results, the ISO proposed to manage hydro generation to utilize during peak hours to avoid load arming. Furthermore, the Tehachapi and Big Creek Corridor Baseline and Sensitivity Scenario reliability assessment identified transient stability concerns under Big Creek 1-Big Creek 2 230 kV line (P5) outage. To mitigate this concern, SCE will be installing second (dual) high speed protection for this line with OD of December 2017. In the interim, for faults at the remote terminal ends of Big Creek 1 - Big Creek 2 and upon loss of the high speed protection, the total output of the Eastwood unit should be maintained below 160 MW. To improve the reliability, thermal overloads, and transient stability concerns in the Big Creek area, NEET West submitted a proposal to construct a new Pittman Hill 230 kV substation project that will tie the following transmission lines together: • Helms – New E1 230 kV #1 & #2 Lines (PG&E) • Big Creek 3 - Rector 230 kV Line #2 (SCE) • Big Creek 4 - Springville 230 kV Line (SCE)	The 2015-2016 Transmission Plan investigated one sensitivity study under extreme drought conditions and identified potential transmission deficiencies in the Big Creek/San Joaquin Valley area. Given this result, an in depth review is needed to establish assumptions for credible drought conditions, and corresponding production of the SCE owned Big Creek Hydro. The CAISO will work with SCE on this in-depth review and discuss the results with stakeholders. As described in the 2016-2017 Transmission Plan Study Plan, drought condition assumptions will be considered in the base scenario studies for this area. If transmission deficiencies are identified under agreed upon credible drought conditions assumed in the base scenarios, then various solution alternatives will be considered, including proposals submitted such as NEET's proposal.

No	Comment Submitted	CAISO Response
	• Big Creek 1 - Rector 230 kV Line (SCE) This project has an estimated in-service date of June 1, 2021. The CAISO 2015-2016 TPP indicated that CAISO will continue to study Sensitivity Scenarios with Low Hydro conditions in future TPP cycles and will consider alternative projects if managing hydro is not sufficient to mitigate the thermal overloads. NEET West requests that further TPP 2016-2017 evaluation include the following key factors regarding the SCE Big Creek Area: • Evaluate all alternatives, including NEET West Pittman Hill project, for reliability and performance by testing system thermal loading, voltage performance and control, stability performance, short-circuit margins, extreme contingency performance, and interface impacts (internal/external). • Evaluate the Midway 500 kV Substation Extreme Event outage and capture additional reliability benefits that the NEET West Pittman Hill Project has over any other alternatives. • Evaluate potential for less reliance on Helms Pumped-Storage RAS. • Evaluate load dropping RAS at Rector under contingency conditions for all alternatives. • Determine the necessary reliance on Big Creek Generation under contingency conditions. • Quantify benefits for potential increased operational flexibility of the Helms Pumped- Storage Plant.	

No	Comment Submitted	CAISO Response
8	**The Office of Ratepayer Advocates (ORA)** **Submitted by: Charles Mee**	
8a	The CAISO states in its draft 2015-2016 Transmission Plan: *As a part of the 2015-2016 planning efforts, the ISO [Independent System Operator] conducted a separate and standalone review of a large number of local area low voltage transmission projects in the PG&E service territory that were predominantly load forecast driven and whose approvals dated back a number of years. In reviewing the continued need for those projects in light of materially lower load forecast levels since those projects were approved, the ISO took into account existing planning standards, California local capacity requirements, and deliverability requirements for generators with executed interconnection agreements. As a result of the review, 13 predominantly lower-voltage transmission projects that were found to be no longer required and are recommended to be cancelled. Only one of the 13, a 230 kV to 60 kV transformer addition, had a regional (e.g. greater than 200 kV) component.* ORA agrees with the CAISO's recommendation to cancel 13 previously preapproved projects in PG&E's service territory. The CAISO states that these lower-voltage transmission projects are no longer required due to lower load forecast levels. Similarly, ORA recommends the CAISO reassess all previously preapproved projects within the entire CAISO's Balancing Authority Area to determine the necessity of those projects. In the draft transmission plan, CAISO also states: *The ISO reviewed the need based upon:* • *Transmission planning process and applicable reliability standards (NERC standards, WECC regional criteria and ISO Planning Standards)* • *Local Capacity Requirements* • *Deliverability requirements for generators with executed interconnection agreements.* With the Governor's goal to have 12,000 MW of distributed energy resources (DERs) interconnected to the distribution grid in California, this will help provide power supply capacity to the distribution system and reduce the need for	Your comments have been noted.

No	Comment Submitted	CAISO Response
	transmission infrastructure. Therefore, ORA recommends the applicability of the deliverability criteria in transmission planning be reevaluated to account for the development of DERs.	

No	Comment Submitted	CAISO Response
9	**Pacific Gas & Electric (PG&E)** **Submitted by: Matt Lecar**	
9a	PG&E supports the conclusions and recommendations in this year's Draft Plan. Specifically, PG&E supports the CAISO's recommended approval of the seven new reliability-oriented transmission projects in PG&E's service territory. PG&E also supports the continuing review of PG&E's proposed Round Mountain 500kV, Tesla 230 kV, and Gold Hill 230 kV substation shunt reactor projects in the 2016–17 TPP. We also appreciate the CAISO's sensitivity analysis of the local reliability issues associated with aging generation in the East Bay Area, and look forward to the development of long-term recommendations in the 2016–17 TPP. PG&E also would like to thank the CAISO for beginning the process of re-evaluating projects that were approved in previous planning cycles, but for which the need is no longer present due to changed circumstances. PG&E supports the CAISO's recommended cancelation of the 13 identified projects in PG&E's service territory. PG&E supports the CAISO's undertaking of the 50% RPS Special Study and believes the Special Study provided useful information regarding the possible procurement of Energy Only resources. PG&E especially appreciates that the CAISO sought to distinguish between curtailment from over-generation and curtailment from congestion. The CAISO should work together with the CPUC to update the RPS Calculator based on the results and recommendations in the Special Study in order to continue refining the creation of RPS portfolios with energy only resources for future TPP cycles. As stated in prior comments, PG&E does not believe there is a requirement that all generation procured to meet RPS targets needs to be fully deliverable. Partially deliverable and energy only contracts are currently a viable option for some renewable resources. PG&E encourages the CAISO to continue to work closely with the CPUC and the CEC to clarify the intended state policies for the level of deliverability for resources within its portfolios. The Special Study is a useful first step in evaluating Energy Only	Your comments have been noted.

No	Comment Submitted	CAISO Response
	resources, but the CAISO should now start to address the practical implications of what Energy Only procurement would mean for the TPP and GIDAP processes. PG&E also supports the CAISO's continued undertaking of the frequency response issue and associated efforts such as this year's special study. PG&E agrees with CAISO that as renewable resources increase and conventional generators are being displaced a broader range of issues need to be considered. One such issue directly related to frequency response for instance is the loss of physical inertia from synchronous generators bring replaced by renewable resources without physical inertia which can potentially lead to reliability concerns during transmission system disturbances and if the response of the remaining units is insufficient. The CAISO should continue its work to investigate measures to improve the CAISO frequency response particularly as the State is moving to a 50% RPS target.	

No	Comment Submitted	CAISO Response
10	**Port of Oakland and Alameda Municipal Power** **Submitted by: Nicolas Procos**	
10a	These comments are motivated by the CAISO's planning methodology and criteria that point to the need to develop a long-term plan for the East Bay. The Port of Oakland and Alameda Municipal Power are encouraged that the CAISO acknowledges that the Draft Plan is relying on aging generation in the East Bay area. In section 2.3.3.5 of the Draft Plan, the CAISO states that unless otherwise noted, they assume that resources retire at the age of 40 years. The Oakland CTs turn 40 years old very soon and no formal announcements have been made by the owners as to the long-term plan for these units. Therefore, the CAISO planning methodology does not support the current assumption that these units are available for the 10-year planning horizon without some further explanation supporting an exception for these units. In addition, CAISO acknowledges that they do rely on load shedding but only say that they "will consider other alternatives in the long-term horizon." The CAISO planning standards do not allow for continued use of load dropping SPS for single or multiple (old Category C) contingencies in this area. Therefore, to be within the CAISO Planning Standards, there should not be any reliance on load dropping for these contingencies in the long-term. Until this is addressed, the Draft Plan does not conform to the CAISO Planning Standards. The East Bay is a dense urban area, so any solution will require 5-10 years of planning, environmental review, and construction. The Port of Oakland and Alameda Municipal Power urge the CAISO to revise the draft plan to include the development of a plan for the East Bay so this effort can begin immediately.	The ISO Planning Standards do allow for the reliance of load dropping in the near-term planning horizon. As indicated in the draft 2015-2016 Transmission Plan, the ISO will be continuing the assessment of longer-term alternatives for the area in the 2016-2017 TPP.

No	Comment Submitted	CAISO Response
11	**Regenerate Power** **Submitted by: Reyad Fezzani**	
11a	Objective Regenerate Power have submitted a proposed Midway – Devers 500kv line in the CAISO TPP and wishes to point out our views through this high level comparison of renewable energy produced from wind resources located in Wyoming with the renewable energy produced from geothermal resources located in California's Imperial Valley. In addition, we present other important factors such as transmission losses, resource viability, and economic justice along with the Salton Sea restoration efforts that we request that CAISO to consider in their TPP and analysis supporting SB 350 implementation Effort and further evaluated. Transmission Overview Similar to paying tolls to drive across a bridge, energy produced in Wyoming and delivered to California would require fees be paid to multiple transmission service providers. The common term "Pancaking" describes paying rates under each service provider's open-access tariff. If transmission rights were not available because a system or systems are fully subscribed (usually an initial review indicates when transmission capacity is or is not available), a new transmission line would be required. A new line would require construction along a route of approximately 1,000 miles at an estimated cost of $29/MWh1. Similar multi-regional transmission facilities currently in process have spent more than 10 years stuck in the development phase. Wyoming wind generation would be interconnected to either the Western Area Colorado Missouri (WACM) service area or Pacific Corp (PACE). Resources located in the Imperial Valley and interconnected to the Imperial Irrigation District's (IID) balancing area would need to acquire and pay for transmission rights from a single transmission service provider (IID). The figure below is a diagram of balancing areas in the Western United States showing how a resource in Wyoming would transmit energy to California. Energy Losses	The ISO appreciates the input on this project, and refers Regenerate Power to the ongoing Renewable Energy Transmission Initiative (RETI 2.0), which the California Energy Commission, California Public Utilities Commission, and the California Independent System Operator have initiated to facilitate electric transmission coordination and planning. Although RETI 2.0 is not a regulatory proceeding in itself, the insights, scenarios, and recommendations it develops will frame and inform future transmission planning proceedings with stakeholder-supported strategies to help reach the state's 2030 energy and environmental goals. More information on the initiative can be found at: http://www.energy.ca.gov/reti/

No	Comment Submitted	CAISO Response
	Electricity transmitted through power lines produces heat that, through energy exchange become losses. For example, a kWh of energy produced does not result in a kWh of energy available for consumption. The farther the distance the generation source is from the end consumer of energy, the higher the losses. Every transmission service provider calculates losses to determine how much electricity is lost as it moves through its system. Typically, losses are in the 3-4% range. For example, when electricity leaves Wyoming and is transmitted across multiple service areas, the amount of electricity received in California is roughly 10% less than the original transmitted amount. Energy produced closer to consumer's experience far fewer losses. IID's current loss factor is 3%. Energy Production Characteristics Wind generation is characterized by its dependency on the intermittency of wind. Wind generation in Wyoming operates at an estimated 46%2 annual capacity factor3. This means that a 1 MW wind generator will produce 4,030 MWh of electricity annually4, which corresponds to providing electricity for 598 California residential households5. Because geothermal generation is derived from a constant heat source, the capacity factor for typical geothermal facilities is in the range of approximately 97%. A 1 MW geothermal resource will produce 8,497 MWh of electricity annually, which corresponds to sufficient electricity to serve approximately 1,262 California residential households. Grid Integration Because both resources are dependent upon fuel sources that are not controlled, System Operators have to account for uncertainty in electricity production. System Operators must maintain a set of generation resources that can be called upon within seconds when electricity production or consumption changes. The cost of addressing that uncertainty is higher for wind resources than more certain baseload of geothermal resources. Studies estimate that the cost for wind integration is $5.00/MWh6, while the cost for geothermal is near zero. Impact to Local Economy	

No	Comment Submitted	CAISO Response
	In communities where these projects are located; especially in a high unemployment area such as Imperial County these projects provide opportunities for work to the local community. The most recent (2014) unemployment statistics showed an unemployment rate of over 23.5 percent in Imperial County the highest in California7. Nearly one in four residents of Imperial County live at or below the federal poverty level. The development of the renewable energy industry in Imperial County will provide economic development and jobs to a region of California that is in desperate need. These projects are estimated to generate ~ $2.5 billion in earnings and $6.5 billion in total economic activity for Imperial, Riverside and San Diego Counties. High Solar Quality The Imperial Valley has long been at the forefront of renewable energy production. For nearly 20 years, more than 500 MW of geothermal capacity and associated energy has been produced and delivered to California Load Serving Entities ("LSE"). There is a significant amount of additional geothermal resources in the Imperial Valley. These renewable resources produce zero emissions, utilize proven technologies and are produced in-state. Imperial County is also located near the Chocolate Mountain area which has one of the highest known geothermal resource potential in the country. In addition, the area has the highest solar irradiance as shown in Table 1 [shown in Regenerate Power's comments]. Permitting Renewables and Right of Way On August 2013, the Bureau of Land Management adopted a Record of Decision that approved an amendment to the California Desert Conservation Area ("CDCA") Plan to create the West Chocolate Mountain Renewable Energy Evaluation Area ("West Chocolate Mountain REEA"). The West Chocolate Mountain REEA is located on Federal lands in the Imperial Valley between the Salton Sea and West Chocolate Mountain. After preparing a Final Environmental Impact Statement, BLM has approved this amendment to the CDCA Plan that identifies BLM managed lands in the West Chocolate Mountain REEA as suitable for geothermal leasing and development as well as strong solar development. In addition, in 2015, the	

No	Comment Submitted	CAISO Response
	CDCA in collaboration with the California Department of Fish and Wildlife, the federal Bureau of Land Management, and the U.S. Fish and Wildlife Services outlined a specific "preferred alternative" that sets aside more than 2 million acres for renewable energy development in an effort to provide space for up to 20,000 megawatts of new generation by 2040. Solar, wind and geothermal projects would be fast- tracked across these so-called "development-focused areas," benefiting from streamlined environmental review and permitting processes. The preferred alternative is along the Proposed STEP project in Imperial and Riverside counties. In support of further renewable development, Regenerate Power has proposed the Strategic Transmission Expansion Plan ("STEP") that would provide the necessary transmission for Southern California load centers to access renewable energy from the West Chocolate Mountains REEA. The STEP initiative is designed not only to facilitate the export of Imperial Valley renewables to the Southern California load centers but also to deliver this energy to other regions of the Southwest. Approximately 70 percent of the proposed STEP system has already been permitted by IID. This will greatly ease the burden of siting and permitting. Cost Effective Regenerate Power submitted its STEP proposal into the CAISO 2013-14 and 2015-16 Transmission Planning Process request window. Although its proposed configuration could be refined, the STEP proposal's key element is a new 1100 MW; 500 kV AC transmission line from IID's existing Midway substation to SCE's existing Devers substation. The 500 kV circuit will span about 75 miles from the Imperial Valley to SCE's substation near Palm Springs. The STEP also allows for further expansion of AC line capability by an additional 1100 MWs as well as further expansion of the capacity on the collector system in the Imperial Valley. Furthermore, this project could be completed with relatively limited environmental impacts. STEP maximizes the use of transmission. The ability for STEP to be able to tap into three renewable resources is quite advantageous from ratepayers' perspectives.	

No	Comment Submitted	CAISO Response
	The use of transmission capacity is typically measured by the capacity factor (cf). The higher the capacity factor, the lower the cost to ratepayers. The summer daily capacity factors are listed below [shown in Regenerate Power's comments]. Conclusion The capital cost of the proposed STEP is approximately $375 million for 1100 MW. This project represents significant (by a factor of 2 to 6) lower cost that recent and similar completed transmission projects in Southern California. Therefore, the cost to California ratepayers is significantly below the current 10$/MWh transmission cost. This project will not increase the current transmission rate but would rather decrease it. On the surface, wind resources in Wyoming appear to be a low-cost, high capacity factor source of renewable energy for California. However, when other important aspects (transmission, grid integration, energy production characteristics, resolving the Salton Sea Environmental disaster and impacts to local economy a) are considered, geothermal resources located in Imperial Valley become a superior and more viable alternative than wind from Wyoming. The table below summarizes the key points of this comparison [shown in Regenerate Power's comments].	

No	Comment Submitted	CAISO Response
12	**San Diego Gas & Electric (SDG&E)** **Submitted by: Fidel Castro**	
12a	• SDG&E submitted a project to eliminate the Miramar LCR sub-area (Miramar 230/69 kV substation). We recommend approval of this project, as it has immediate reliability, economic and operational flexibility benefits at a modest cost. This project also has the benefits of connecting the 230 kV system to a possible energy storage site at Miramar and can shorten the black start path from the Miramar Energy Facility (MEF) to major San Diego-area generation.	The ISO evaluated the local capacity reduction and dispatch benefits of this project and determined that they were minimal. This is the first time that black start benefits have been attributed to this project, so the ISO will work with SDG&E in the next cycle to better understand this potential benefit. We will also monitor the benefits to potential energy storage.
12b	• SDG&E submitted a comprehensive project to address the long-term need for a double-circuit 230 kV loop around the San Diego downtown area. This area serves contains multiple commercial, civic, and national security resources (Qualcomm Stadium, Petco Park, North Island NAS, Marine Corp Recruit Depot San Diego (MCRD), Lindbergh Field, Stone Brewing at Liberty Station, and "King" Stahlman Bail Bonds). We strongly recommend that the CAISO consider approving the project as a whole and avoid a piecemeal approach, as this will make the CPUC permitting process simpler.	The ISO will continue to evaluate the need for this project in the next planning cycle.
12c	• SDG&E submitted a project to accommodate a new substation with an initial 60MVA capacity, ultimate 120MVA (Ocean Ranch Substation). Together with the new San Luis Rey to Monserate line (submitted in 2012/2013 TPP cycle, CAISO deferred) and a the TL694A Reconductored (submitted in 2013/2014 cycle, CAISO deferred) will not only accommodate Ocean Ranch Substation but will also eliminate the LCR need in the Pala sub area. We recommend approval of this project.	The ISO concurs with the interconnection of the Ocean Ranch substation by single loop-in configuration. The ISO did not find a need at this time to loop-in the second transmission line into the new substation, and reconductor the transmission line section between San Luis Rey and Ocean Ranch. The economic benefits of eliminating the Pala sub area LCR need is not expected to be significant because this generation is also needed for the San Diego sub-area. However, the ISO will continue to evaluate the need for this project in the next planning cycle.
12d	• SDG&E submitted a third 500/230 bank installation at Miguel. This project will mitigate the T-1 thermal violation at Miguel and it will eliminate the existing SPS. In addition a third bank at Miguel will eliminate the voltage deviation violation at the Miguel 500kV bus when TL50001 is tripped and keep the Synchronous Condensers from tripping under the same contingency. We recommend approval of this project.	The ISO did not identify a voltage deviation violation on any load bus including the synchronous condensers terminal buses for the TL50001 outage that also trips the Synchronous Condensers at Miguel. The T-1 thermal violation on the Miguel Banks #80 or #81 would be mitigated by modifying the existing Miguel BK80/81 SPS to open the Miguel 525/230 kV bank for the other bank outage. Appendix B addresses the T-1 thermal overload concern in more detail.

No	Comment Submitted	CAISO Response
12e	• SDG&E recommends the CAISO modeling of the south to north flow on the retired Path 44 conform with recent actual historical flows under peak load conditions. In addition, we recommend against assuming the 500 kV series capacitors at Miguel, Suncrest and North Gila are bypassed in studies assuming peak load conditions. Switching of the series capacitors is an appropriate short-term operating measure, but is not an appropriate long-term mitigation, as it reduces the scope of operator action during extreme system conditions. Grid Operations generally prefers to maintain the flexibility to switch the series capacitors depending on system conditions.	In the Reliability section of the 2014-2015 Transmission Plan the ISO recommended to "normally by-pass series cap banks on SWPL and SPL 500 kV lines to eliminate potential overloads on SWPL/SPL 500 kV lines, Miguel 500/230 kV banks, Suncrest 500/230 kV banks, and Suncrest-Sycamore 230 kV lines for Category B and C outages in the SWPL and SPL systems". The long term LCR section of the report included normally bypassing these series capacitors as a documented assumption. The Policy section of the report identified bypassing these series capacitors as the mitigation to address the same overloads as identified above and to ensure deliverability of Imperial area renewable generation. Stakeholder response to this proposal was consistently supportive. The ISO will continue to review this issue with SDG&E in the 2016-2017 planning cycle.
12f	• Throughout multiple TPP cycles, including the current plan, the CAISO has approved multiple capital projects to address the congestion issues at northern part of the West of River (WOR) path, including the Lugo-Victorville 500 kV Upgrade currently recommended for approval. Assuming that the CAISO's current set of studies included bypassing of the series capacitors in the southern part of WOR path (specifically SRPL and SWPL) as one of the basecase assumptions, and also assuming the series caps in the northern part of the WOR path are all switched in, it appears to artificially push the flow from south to the north, thereby artificially increasing congestion in the northern part of the WOR path. It certainly would raise the question of why bypassing the series capacitors is acceptable in one portion of the CAISO-controlled system, but not elsewhere. SDG&E would urge the CAISO to apply the study assumptions uniformly across the system footprint by studying the congestion in the southern part of WOR with all northern part of series cap bypassed.	Bypassing the SRPL and SWPL series capacitors provides the numerous benefits described above and primarily shifts flow of power to the Paloverde-Delaney-Colorado River-Devers 500 kV system. The series capacitor upgrades to Eldorado-Mohave-Lugo system and existing line upgrades to Lugo-Victorville 500 kV line are primarily driven by generation development in the Eldorado area and retirement of generation in the LA Basin. The ISO is not aware of any benefits that could be associated with placing the SRPL and SWPL series capacitors in-service and bypassing the northern part of the WOR series capacitors.
12g	• In the draft plan at pg. 135, there are multiple instances where SDG&E's 500kV system is referred to as a "525Kv system". SDG&E's 500 kV system is operated at 1.05PU, which is the same way as PG&E and SCE's 500kv systems are operated. Throughout the draft report, however, PG&E and	SDG&E clarified that its extra high voltage system is rated and nominally operated at 525 kV, but is traditionally modeled and labeled as 500 kV in WECC and the ISO power flow cases. Voltage criteria applied in the ISO transmission planning are based on <u>nominal</u> voltage

No	Comment Submitted	CAISO Response
	SCE's system all labeled as 500 kV, with SDG&E being the only exception. SDG&E would urge the CAISO to apply the definition of bus nominal voltage uniformly across the system footprint.	which often is not the labeled or modeled voltage. Nevertheless, for reading convenience, the ISO has relabeled the subject SDG&E buses in the report to the traditional 500 kV label.
12h	• In the draft plan at pg. 136, CAISO states, "The studies performed for the heavy summer conditions assumed all available internal generation was being dispatched with targeted San Diego import level in a range of 2400 to 3500 MW". SDG&E would be very interested if CAISO can share with SDG&E the 3500MW import power flow cases and study results.	A sensitivity study case with heavy renewable output and minimum gas generation commitment on heavy summer of the 2025 study year assumed the 3500 MW import level via the SDG&E import transmission interface. The study results are posted on ISO secured website and reported as part of reliability results in Appendix C. The power flow case is available on the website.
12i	• In the draft plan at pg. 199, Table 3.3-3, Reliability Assessment Results, lists the reliability concerns under the Winter Gas Curtailment Reliability Assessment. The CAISO suggest for the N-1 contingency of Miguel 500/230KV bank, tripping the 2nd parallel bank as the mitigation. This will result in loss of entire SWPL import path. This appears to be counter-productive, as in the event of gas curtailment, in-basin thermal generations will be curtailed therefore it's crucial to maintain an import path that brings in the renewable energy from the east into San Diego load center. Installation of a 3rd 500/230Kv bank at Miguel will effectively mitigate this violation, **in addition to aforementioned other benefits**.	The 500kV transmission system in the southern San Diego area is a networked system that includes a second 500kV line as well as 230kV facilities to bring renewable and conventional resources connecting from Imperial Valley to the San Diego load center. The second parallel path is of the Sunrise Powerlink which carries power flow into the San Diego load center upon losing the Southwest Powerlink. With the IV phase shifting transformers in service, the 230 kV facilities will play a more important role in bringing in the renewable energy and supportingt the San Diego load during contingencies. Simply adding third transformer bank at Miguel would not increase generation deliverability since the SouthWest PowerLink system's capability is limited by the Miguel-ECO 500 kV line rating. Please also refer to the response to Question 12g.
12j	• In the draft plan at pg. 197 the CAISO indicates: "The second most critical reliability concern was the potential post-transient voltage instability concern due to overlapping outage of the ECO-Miguel 500 kV line, system readjusted, followed by the Ocotillo – Suncrest 500 kV line. The post-transient voltage instability concern is mitigated with re-scheduling of voltage control of the synchronous condensers that are being installed in northern San Diego and southern Orange County." Then on pg. 199, Table 3.3-3, the CAISO suggests "Reschedule voltage regulation at terminal voltage with 1.05 – 1.1 p.u. for synchronous condensers located in northern San Diego and southern Orange County". Assuming the CAISO intends to reschedule the voltage at pre-contingency base, SDG&E has these concerns: 1) the precontingency voltage of 1.05 – 1.1 p.u. would force all the synchronous	The rescheduling of the synchronous condensers' voltage regulation would be performed as part of system readjustment after the first 500 kV line contingency in preparation for the second contingency. The amount of var output may not be at or near its maximum capability. The reschedule of the synchronous condensers' voltage regulation is intended so that reactive output from the synchronous condensers are at or near their capability to provide voltage support after the occurrence of the second 500 kV line contingency.

No	Comment Submitted	CAISO Response
	condensers to be at or near their MVAR output limits; therefore when a contingency occurs, there will not be any marginal dynamic VAR support available; 2) the gas curtailment can be a long duration event. To operate the equipment long term at or near their short term design limits of 1.1 PU, could result in damage to the synchronous condensers, as well as other system elements.	
12k	• In the draft plan at pg. 197-198 the CAISO indicates: “Another reliability concern associated with this overlapping contingency is the potential overloading on the La Rosita – Rumorosa 230 kV and the Otay Mesa – Tijuana 230 kV line, which can be mitigated by bypassing the series capacitors under pre-contingency basis on the ECO-Miguel 500 kV or Ocotillo – Suncrest 500 kV line (depending on which line had the outage first) and reducing imports via Path 45 to ISO balancing authority area from 300 to 200 MW.” Then on pg. 199, Table 3.3-3, the CAISO suggests “Bypass series capacitors on the ECO-Miguel 500kV line and Ocotillo-Suncrest 500kV line pre-contingency” as mitigation. Similar to the tripping of the ML transformer bank, SDG&E considers bypassing of the series capacitors on the two major 500kV import gateways pre-contingency to be counter-productive. In the event of the gas curtailment, in-basin generation will be tripped therefore it’s crucial to maintain the import paths for renewable energy from east into the San Diego load center, instead of bypassing the series cap to “choke down” the natural flows.	Please see response above regarding bypassing these series capacitors.

No	Comment Submitted	CAISO Response
13	**Southern California Edison** **Submitted by: Rabindra Kiran, Daniel Donaldson, Garry Chinn**	
13a	**<u>3.1.3 & 3.1.4 "Minor Transmission Upgrades"</u>** CAISO identified a number of small-scale transmission upgrades which were evaluated for mitigating contingency overload concerns on the south of Mesa 230 kV lines resulting from an increased dispatch of renewable generation. Three options were highlighted as being more effective and potentially lower cost. 1. Opening the Mesa 500/230 kV Bank #2 under contingency conditions 2. Re-arranging the Mesa – Laguna Bell 230 kV lines and opening the Laguna Bell – La Fresa 230 kV line under contingency 3. Installing 10-Ohm series reactors on the Mesa – Laguna Bell #1 230 kV transmission line As part of the evaluation of the Mesa 500 kV Substation project, SCE investigated Option 2, and determined that it is not feasible to re-arrange the Mesa – Laguna Bell lines due to constraints in line routing and substation arrangement. The other options may be feasible but will require further analysis. Given the scale of the upgrades, further analysis of these and other options can be performed in the 2016-17 TPP and still meet the 12/31/20 need date. Based on the uncertainty present in the assumptions, SCE agree that mitigation is not prudent at this time to address the potential deficit in the LA Basin/San Diego Area.	Your comment has been noted.
13b	3.1.3 & 3.1.4 – Sensitivity 2021 LCR Assessments for the LA Basin/San Diego Area As part of the 2013-14 Transmission Plan, the CAISO Board approved a group of projects to maintain reliability in Southern California to address the loss of Once Through Cooling units including San Onofre Nuclear Generating Station. This group of projects included an additional 450 MVAR of dynamic reactive support at San Luis Rey, the Imperial Valley Phase Shifter, and the Mesa 500 kV "Loop-in" project (Mesa). In March 2015, SCE filed with the CPUC for a permit to construct Mesa with the intent to complete the Project by December 31, 2020. In addition to these transmission projects there are several other components which contribute to meeting the reliability need in the combined San Diego and LA Basin area. This includes resource procurement authorized as part of the 2012 Long Term Procurement Plan (1,812 MW in SCE and 707	Your comment has been noted.

No	Comment Submitted	CAISO Response
	MW in SDG&E), increasing Additional Achievable Energy Efficiency (1,568 MW in SCE by 2025), and availability of fast acting Demand Response programs. As part of the 2015-16 Transmission Plan, CAISO performed a sensitivity analysis to consider the possible impacts of a potential one-year delay in Mesa. The results of the CAISO analysis identified that a delay of Mesa would result in a 682 MW deficit. The CAISO states that this deficit could be met through an extension of the OTC compliance schedule of the Redondo Beach generating facility until Mesa is completed. Avoiding such an impact to the OTC compliance schedule will require the CPUC and SCE to work expeditiously to ensure all regulatory approvals and project milestones are met. The CAISO's sensitivity analysis also includes a new factor not present in the 2013-14 Transmission Plan; a higher dispatch of renewable resources (about 2,000 MW) to reflect CPUC NQC value. If the location of these resources, or their anticipated output changes, the deficits identified in the sensitivity analysis would also change. The current draft identifies a deficit of 576 MW with Mesa and 682 MW if Mesa is delayed. At the February 18 stakeholder meeting, CAISO stated that with Mesa and a "minor transmission upgrade" located south of Mesa Substation there would be no deficit. This type of sensitivity analysis may be meaningful in assessing the impact of a potential project delay but should not be used as an indicator of the overall value of a project. Mesa was approved as part of a large group of mitigations, and the order in which the projects are studied plays a significant role in the perceived value a particular project may display. Due to the interconnected nature of the transmission system, a large group of mitigations will interact with each other and impact the value of a project when a specific project is assessed incrementally. For example, the sensitivity analysis implies a potential value for Mesa of 106 MW (682 – 576). Furthermore, if we assume the projects behave independently from each other, an alternative to fill the deficit without Mesa would be 106 MW of resources and the "minor transmission upgrade". Neither of these possible interpretations can be conclusively drawn from these sensitivity results. The "minor transmission upgrade" is dependent upon the presence of Mesa and	

No	Comment Submitted	CAISO Response
	would not significantly alter the deficit independently. A deficit would remain for the LA Basin/San Diego area if Mesa was replaced by 106 MW and the "minor transmission upgrade". This interdependency among projects demonstrates that the value provided by each project in a large package of mitigations cannot be calculated simply based on an incremental analysis.	
13c	**<u>2.7.1 Tehachapi and Big Creek Corridor</u>** The generation assumptions for the low hydro sensitivity study that the CAISO performed for this area is not stated in the report. The maximum generation level available north of Magunden Substation during low hydro conditions is a key variable driving results and this assumption should be documented. The CAISO lists modifying the existing RAS as a mitigation for low hydro conditions. The RAS was modified in early 2015 to add various P1 (N-1) contingencies to the existing Big Creek/San Joaquin Valley (BC/SJV) RAS. The current TPL-001-4 standard only allows for non-consequential load loss of up to 75 MW. A forecast of hydro capacity over a decade or more is not available and as the drought in California continues there is the potential that the 75 MW limit may be exceeded. Historical data of the last forty-one years has shown two significant low hydro capacity events occurring during droughts; 2015 summer (630 GWH) was the lowest hydro capacity followed by 1977 as the second worst (764 GWH). The CAISO also lists managing hydro generation during peak hours as a mitigation. While this may be possible during normal conditions, it may not be an option during droughts. SCE did manage water supplies in 2015 to meet peak load demands, but this required cooperation from down-stream farmers. The water is not owned by SCE and SCE has a contractual obligation to deliver the water to owners down-stream. It is uncertain whether the water management practices used in 2015 will be able to be utilized in future years. Under low Big Creek hydro conditions (Southern California was in its fourth year of drought), SCE's 2015 Annual Transmission Reliability Assessment (ATRA) identified seven (7) category P1 thermal overloads for the years 2017, 2020 and 2025. The maximum load drop required was 366 MW in 2020 for the loss of either Magunden-Vestal No. 1 or No. 2 230 kV lines. NERC's current TPL 001-4 standard does not allow planned non-consequential load loss to exceed 75 MW for a category P1 contingency.	The 2015-2016 Transmission Plan investigated one sensitivity study under extreme drought conditions and identified potential transmission deficiencies in the Big Creek/San Joaquin Valley area. Given this result, an in depth review is needed to establish assumptions for credible drought conditions, and corresponding production of the SCE owned Big Creek Hydro. The CAISO will work with SCE on this in-depth review and discuss the results with stakeholders. As described in the 2016-2017 Transmission Plan Study Plan, drought condition assumptions will be considered in the base scenario studies for this area. If transmission deficiencies are identified under agreed upon credible drought conditions assumed in the base scenarios, then various solution alternatives will be considered, including proposals submitted such as SCE's TCSC proposal.

No	Comment Submitted	CAISO Response
	Based on the best transmission alternatives considered and in order to be compliant with TPL 001-4 at the earliest possible date, in September 2015 SCE proposed to install four (4) thyristor controlled series capacitors (TCSC) on the Big Creek 230 kV lines. SCE continued to study the issue and in January 2016, SCE developed a more cost effective alternative with three (3) TCSC's on the Big Creek 230 kV lines. By installing TCSC's on three of its 230 kV transmission lines and rapidly adjusting impedances post-contingency to control the power flow, the BC/SJV transmission system can reduce its local generation need to as low as 260 MW as well as limit load shed for a P1 contingency to below 75 MW in the year 2025. In conjunction with Distributed Energy Resources (DER) in the Big Creek area, the TCSC's will delay the need for large-scale transmission and generation projects in the area beyond 2025 by optimally utilizing existing transmission capacity and can be implemented with a short lead time at an estimated cost of $69 million. To ensure reliability without the Big Creek TCSC in 2017, 476 MW of existing local generation north of Magunden Substation will be required to mitigate the worst P1 contingency. This generation requirement will grow to 574 MW by 2025. Due to the on-going drought conditions, ensuring an adequate amount of hydro generation may not be possible. SCE continues to believe the Big Creek TCSC project is needed to meet reliability criteria and requests the CAISO to approve the project as part of the 2015-16 Transmission Plan.	

No	Comment Submitted	CAISO Response
14	**TransCanyon, LLC** **Submitted by: Jason Smith & Bob Smith**	
14a	We encourage the CAISO to continue to monitor the Once Through Cooling ("OTC") generation along with other resource procurements moving forward especially in the context of local capacity requirements ("LCR") and the reliability in the LA Basin and SDG&E areas. It appears that the studies are relying heavily on various mitigation plans during contingency conditions especially in the short term. Though this analysis has provided adequate signals for the California Public Utilities Commission ("CPUC") to determine procurement plans for LSEs, TransCanyon believes that for a system to perform robustly, in addition to proper procurement, there needs to be adequate margins in transmission during contingency conditions. Maximizing the utilization of the current transmission infrastructure could lead to undesirable consequences during real-time system operations.	Your comment has been noted.
14b	The CAISO has indicated that the Suncrest reinforcement project proposed by CAISO as a possible mitigation for reliability concerns and also by SDG&E as a PTO project is not needed at this time because sufficient short term mitigations from SPS, re-dispatch, and additional preferred resources are available for contingency response. TransCanyon believes that there may be scenarios such as high imports of renewables into the SDG&E system due to generation interconnections at Imperial or due to other policy initiatives which could result in more severe system response to these contingencies. TransCanyon understands the desire to utilize the short term mitigations and looks forward to further analysis in future assessments by the CAISO for a more permanent transmission solution that would reflect any policy and economic benefits that the Suncrest reinforcement project may have. TransCanyon appreciates the efforts from the CAISO on the 50 percent Renewable Energy Special Study. We would like to make the following comments for the CAISO's consideration. • It is unclear how the transmission capability estimates for renewable zones were computed by the CAISO. Understanding that this is more a qualitative effort, it would be useful to include additional description of the assumptions along with a methodology. As a new version of the RPS calculator is being	The transmission capability estimates for renewable zones were initially estimated based on previous studies and engineering judgment. After performing the informational study, the information from this study was utilized to revise the estimates.

No	Comment Submitted	CAISO Response
	developed, it would also be helpful to obtain information on how additional constraints being included in the model would result in a change in the outcomes of the amount of generation and selection of the renewable zones. TransCanyon believes that these changes may affect the selection of CREZ zones and eventually may trigger further policy or reliability projects within CAISO. • The results of varying the level of export limits are also of particular interest to TransCanyon. We believe that relieving any physical constraints on exports with new transmission may enable the integration of additional renewable energy and the seamless exchange of power between neighboring balancing areas under the current CAISO footprint as well as under an expanded footprint. TransCanyon believes there is significant value in quantifying the costs of the curtailments so that a cost benefit analysis can be performed to determine if additional policy driven transmission to reduce the curtailment would be beneficial.	
14c	TransCanyon appreciates the assessment of the economic projects submitted in the planning window and the determination of the amount of congestion on Path 15, Path 26 and on COI. The CAISO indicated that it does not expect the congestion on these paths to increase in the planning horizon. TransCanyon would like to get clarity on these constraints in a high renewable case (40% delivered or a 50% RPS) and if there are any transmission projects that may gain more benefits under these circumstances. TransCanyon recommends that the CAISO continue evaluating its system in the different special studies i.e., the gas electric coordination, storage and frequency response study in order to inform stakeholders about the various system conditions that can put the system at risk. TransCanyon again appreciates the opportunity to provide these comments. We look forward to continued participation with the CAISO and other stakeholders in the Transmission Planning Process, including presenting comments on the draft study plan for the 2016-2017 Transmission Planning Cycle.	The CAISO expects to use the 33% RPS as the base assumption for renewable generation modeling in the 2016~2017 planning cycle. These paths as indicated in the comment will be monitored and assessed under this assumption in the 2016~2017 planning cycle. Further clarity of renewable energy goal will be taken into account in future planning cycles. Your comment has been noted.

No	Comment Submitted	CAISO Response
15	**Transmission Agency of Northern California (TANC)** **Submitted by: Ann Czerwonka**	
15a	TANC's primary comment/issue is that the California-Oregon Intertie (COI) and/or full system is not being modeled to reflect the realities that continue to occur and are likely to continue on the high-voltage grid in the evolving marketplace. Specifically, TANC has three key issues: 1. Historic congestion on the COI leads to market inefficiencies and costs California consumers tens of millions of dollars annually. The evolving operating procedures for the COI indicates that transfer capability between California and the Pacific Northwest may be further eroded in the future. 2. Previously approved upgrades on PG&E's transmission system are being delayed, including projects that have a direct impact on the transfer capability of the COI. 3. CAISO sponsored benefit studies related to PacifiCorp joining as a Participating Transmission Owner (PTO) indicate that one of the limiting factors to additional benefits is the lack of transfer capability between the CAISO and PacifiCorp. Currently, the only interconnection is at COI, therefore efforts to maximize and/or enhance COI transfer capability should be paramount to insure the benefits modelled by the CAISO are actually attainable.	Please see the responses below to the detailed comments provided.
15b	**Economic Studies** The table below [refer to TANC's comments for table] provides actual congestion on the CAISO portion of the COI and this data far exceeds the de minimus congestion cost forecast for Path 66 in the Draft Plan. TANC commented on this issue in prior stakeholder meetings and the CAISO responded to those comments with a table indicating the modeling of transmission outages in less than 1.5% of the hours. The table below [refer to TransCanyon's comments for table] indicates that operational reality of the COI is much different with limitations 60-90% of the time. TANC believes that CAISO's economic studies could be improved in future study cycles to better reflect operational realities that cost Californians millions of dollars annually in congestion costs. TANC strongly supports the CAISO's consideration of a sensitivity study to model congestion (and potential	The transmission outages modeled in the 2015~2016 planning cycle database were based on the historical data from 2012, 2013, and 2014. These outages were selected because they resulted in significant derate on COI limit. As time evolves, the CAISO will update the transmission outage modeling in the future planning cycle databases with considering the new historical data. Still, as indicated in one of the responses to stakeholder comments to the 2015 November stakeholder meeting, the historic congestions and the congestions observed in the economic planning studies are different for number of reasons. Mainly, 1. As indicated in the stakeholder comment and also as the ISO responded in the stakeholder meeting, the major outages on the 500 kV lines enduring several months were not modeled in the production cost models. The frequency of such events is

No	Comment Submitted	CAISO Response
	remedies) for COI transfer capability based upon historic and future expected operating realities on Path 66/COI.	low and should not be a driver of economic benefit that is assessed for 40 to 50 years. 2. The production cost models used the COI nomogram developed for the future year, which has taken into account of the approved transmission upgrades that help to mitigate local constraints along the COI corridor hence increase the transmission capability of the path. The approved transmission projects can be found in the transmission plan. 3. Hydro modeling in the production cost model is based on the 2005 hydro condition, which is in the TEPPC common case 4. The ISO's planning production cost models include 33% renewable portfolio that has much higher renewable generation penetration than today and several years back. The high instate renewable generation essentially provide push back flow on the importing interfaces depending on the renewable modeling in other states.
15c	**South of Palermo 115-kV Reinforcement Project Delays** The South of Palermo 115-kV Reinforcement Project was approved by the CAISO for PG&E in the 2010-11 Transmission Plan with an estimated in-service date of May, 2014. Since then its in-service date has been extended three times in subsequent transmission plans. The latest plan shows an in-service date of May 2022, which is three years from the most recent update.1 This project is of particular concern to TANC as it is needed to mitigate the PGE Blk-T-24 thermal overload in the PGE bulk system reliability study. The option in the interim is to limit COI transfer capability per the COI nomogram.2 Delay of this project prohibits the bulk electric transmission system from optimal performance and efficiency. This delay will come three years after the January 1, 2019 projected start date for PacifiCorp to join the CAISO as a PTO, and could limit the benefits that would accrue from this merger. TANC would also note that PG&E has extended the in-service dates of a large number of their CAISO approved projects. TANC is concerned that the delays,	Your comment has been noted.

No	Comment Submitted	CAISO Response
	or otherwise overly optimistic initial in-service dates, are impacting the COI transfer capabilities and may not allow the CAISO to model the bulk electric transmission system accurately in subsequent planning cycles. TANC is pleased that the CAISO reviews and comments upon PG&E proposed projects and hope those that continue to be found needed are completed in a timely manner.	
15d	**Potential COI Impacts on the Benefits of PacifiCorp Joining as a PTO** The Technical Appendix to the PacifiCorp Benefits Study uses the full 982 MW transfer capability between PacifiCorp into the CAISO to develop benefits. However, this is unlikely to be the case much of the time which limits potential benefits. On page 2 of the report it states that "…coordinated transmission planning could significantly increase transfer capability between an integrated PacifiCorp-ISO system, which could increase the level of incremental benefits in this report." Additionally on page 8 "The quantity of capacity savings from peak load diversity depends on three factors…(2) transfer limits between ISO and PacifiCorp that constrain the maximum amount of capacity savings…" TANC's understanding is that in order to achieve the benefits modelled in the CAISO's report (and potentially more benefits) robust transfers across the COI must occur. Therefore, we struggle to understand why the TPP and CAISO seem to disregard historic congestion, lowering operating capability due to the evolving operating procedures and the fact that the CAISO would cite limitations on the COI as a mitigation action in no less than seven contingencies found in Appendix C – PGE-Blk-12, 17 (2), 18, 19, 20, 24. TANC remains committed to work with the CAISO and the other owners of the COI to develop options and alternatives to maximize the transfer capability of the COI. TANC encourages the CAISO to work with the COI owners to focus on those issues limiting COI transfer capability, and develop solutions that address this significant issue for California consumers and the expansion of the CAISO's market.	Your comment has been noted. Please refer to the response to the above comments. The ISO expects to continue working with TANC and other stakeholders on these issues.