California ISO
Shaping a Renewed Future

Stakeholder Comments
Preliminary Reliability Results and PTO's Proposed Mitigations
September 26 & 27, 2012

No	Submitter (Name & Company)	Comment Submitted	ISO Response
1	Douglas Draeger, Alameda Municipal Power (AMP)	The CAISO assessment identifies a Category C thermal overload on Moraga to Oakland J 115kV beginning in 2017. See Table 1 below. We are under the impression that the CAISO had approved PG&E's *Moraga-Oakland "J" SPS* project in the 2009-10 transmission plan in part to mitigate this issue. We request the CAISO/PG&E to provide an update on the implementation of this project. In addition PG&E had submitted the *Moraga-San Leandro and Moraga-Oakland J 115kV Reconductor* projects in the 2010 Request Window, but our understanding is that the project was not approved. Subsequently, the CAISO approved the *East Shore - Oakland "J" 115 kV Reconductor* project in 2011-12 Transmission Plan. Presumably, this approved project and the *Moraga-Oakland "J" SPS* projects were modeled in the 2012-13 assessment base cases. Therefore it is concerning that even with the approval of the two projects mentioned above, this year's reliability assessment indicates deficiencies. A long-term solution for the Alameda/Oakland area needs to be developed and implemented as soon as possible to address these reliability concerns.. We believe the Oakland/Alameda metropolitan area deserves a level of reliable service at least equal to if not superior to other metropolitan areas. During the CAISO's September 27th stakeholder meeting, PG&E presented its *Moraga to Potrero 230kV* project entailing the construction of another major transmission line to San Francisco, with this one being a 230 kV AC cable from Moraga to Potrero substation. AMP believes that this project has synergy with the Alternatives 1 and 2 that were proposed by	The Category C thermal overload on Moraga to Oakland J 115kV is prior to the operation of the identified SPS which provides the mitigation for this condition. The ISO comprehensive transmission plan will provide additional information on reliability concerns of the San Francisco Peninsula area and the ISO will be continuing to assess these concerns.

		PG&E in 2009 under the Oakland Long Term Plan. Since Alameda forms a significant portion of the load that must be served in the area, we want to participate in the process that selects the long-term solution. We are currently engaged with PG&E on some operational issues concerning our two systems. We would like to see a separate but related forum developed that would assist the CAISO in selecting the long term transmission solution for the Oakland/Alameda area. We believe that the interests of the area are best served by minimizing the period of reliance on the SPS (that is still being developed) and encourage the CAISO to welcome and participate in efforts to that end.	
2	Robert Jenkins, Bay Area Municipal Transmission group (BAMx)	**PART I: CAISO Reliability Assessment Results** BAMx appreciates the CAISO staff efforts in issuing the study information that is timely and complete. In past years, the completeness of the analysis and the designation of proposed remedies for criteria violations have been inconsistent across the CAISO grid, and some areas were much better documented. However, this year, we found that more information was included in almost all the CAISO presentations as well as in the PTO presentations, most notably the ones made by the PG&E staff. Even though there were substantial improvements, we encourage the CAISO to consider further improvement to the presentations of their assessment results. Specific examples of improvement needed are contained in the comments below. ***CAISO Assessments Finds More Deficiencies Even with Recently Approved Projects*** Our review of the CAISO's assessment in several study areas indicates that there are deficiencies even though the CAISO has approved	The ISO appreciates the feedback on the presentation material. In regards to the detailed question, please see the following: 1. Greater Bay Peninsula Area: The identified approved project addresses the category B conditions. The Category C condition still exists with mitigation options being to re-rate line or to drop load either manually or thru SPS as appropriate. 2. East Bay: The overload identified is prior to the operation of the identified SPS which provides the mitigation for this condition. 3. Humboldt: PG&E is proceeding with the reconductoring with an expected completion of May 2014. The line upgrade has been identified as needed with the approved projects identified.

		transmission projects in those areas in the very recent planning cycles. Below, we provide some examples. **1. Greater Bay Area- Peninsula:** The CAISO assessment includes a Category C contingency overload on the *Jefferson - Stanford 60 kV* Line. See Table 1 below. There is an approved project to build a new Jefferson-Stanford #2 60 kV line to address a prior Category B issue. Please confirm that this overload exists after adding the new *Jefferson - Stanford 60 kV* Line. **2. East Bay:** The CAISO assessment identifies a Category C thermal overload on Moraga to Oakland J 115kV beginning in 2017. See Table 2 below. We are under the impression that the CAISO had approved PG&E's *Moraga-Oakland "J" SPS* project in the 2009-10 transmission plan in part to mitigate this issue. In addition PG&E had submitted the *Moraga-San Leandro and Moraga-Oakland J 115kV Reconductor* projects in the 2010 Request Window, but our understanding is that it was not approved. Subsequently, the CAISO approved the *East Shore - Oakland "J" 115 kV Reconductor* project in 2011-12 Transmission Plan. Presumably, this approved project as well as the *Moraga-Oakland "J" SPS* projects were modeled in the 2012-13 assessment base cases. Is there another capacity deficiency on the horizon for load served from Oakland J so soon after the approval of the reconductor project? **3. Humboldt:** The CAISO assessment identified a category B overload on the *Humboldt Bay – Humboldt 60kV line #1* and provided reconductoring of this line as the mitigation measure. The CAISO 2011-12 Transmission Plan indicated that the *Humboldt Bay-Humboldt 60 kV line #1* would be upgraded by October 2014 as a part of PG&E's Infrastructure Replacement Project, which is a maintenance project that does not require ISO	

		approval.[1] Please provide any updates on this project. Also please confirm that this project is needed even with the previously approved 60kV projects such as, the *Humboldt - Eureka 60 kV Line Capacity Increase* and the incremental LGIA (renewable interconnection) -driven *Humboldt 60 kV upgrades*. ***BAMx Supports CAISO's Consideration of Non-transmission Alternatives.*** During the September 26th meeting, the CAISO indicated that they were looking for opportunities for Stakeholder input on non-transmission alternatives. BAMx generally supports this CAISO initiative. We agree with the CAISO that Stakeholder comments on Unified Planning Assumptions is an appropriate forum/timing for Stakeholders to provide their input, especially on load forecast-related non-transmission alternatives such as, Energy Efficiency, Demand Response Programs, Combined Heat and Power and Distributed Generation. We encourage the CAISO to closely work with the CEC staff to model these non-transmission alternatives at appropriate locations.	
3	Robert Jenkins, Bay Area Municipal Transmission group (BAMx)	**PART II: PTO Request Window Project Applications** ***Post the Request Window Applications*** We have reviewed the PTO Request Window (R/W) presentations that were made on September 27th. However, they do not present an adequate description, especially in regards to the alternatives studied by the PTOs/project developer. In order for stakeholders to provide any meaningful input into the 2012 R/W projects and the 2012-13 transmission plan in general, we need to have access to the following data:	The request window submissions have been posted on the ISO secure website. In regards to the detailed question, please see the following: 1. North Fresno 115kV Reinforcement Project: This project addresses overloads and voltage collapse in the area due to several Category C contingencies at McCall and Herndon substation by increasing the support into the Fresno 115kV area.

[1] See Section 2.5.1.4 Recommended Solutions of the CAISO 2011-12 Transmission Plan, March 14, 2012.

		• A detailed description of "Other Alternatives Considered" and why they were found to be less preferred; • Key issues such as, requirement for CPCN, Common Mode Exposure Items, and related existing SPSs; • *GE PSLF* modeling information; and • Power flow/study results findings. Such detailed information is only available in the R/W submissions (as evident in the CAISO's posting in March 2012 for 2011 R/W applications). There are several 2012 PTO R/W projects, which refer to other alternatives, but do not adequately describe them in the brief PTO presentations. In addition, no such data is available for non-PTO R/W applications, if any. Posting the R/W applications in March 2013 would be too late in terms of providing any meaningful stakeholder input. Please post these R/W applications on the CAISO secured website (covered under the TPP NDA) as soon as possible. ***Provide Details on BCR Calculations*** The PG&E staff, in some of the R/W project presentations, showed that Benefit-Cost Ratios (BCR) for the following Central Valley projects was greater than one, such as, • Salado 115/60 kV Transformer Addition; and • Ripon 115 kV New Line. In response to the questions asked on these BCR calculations, the PG&E staff indicated that these calculations were based on *Value of Service* analysis to address the CAISO Grid Planning Standard #6.[2] Please explain	This project provides a strong source into the Fresno 115kV system by way of Sanger 115kV substation. This project will allow Helms PGP and Kerckhoff 2 PH to inject power directly into the Fresno 115kV area at Sanger 115kV. The development also alleviates a 138% overload on the Manchester-Herndon 115kV line in the 2014 Summer Peak case and beyond where the cases didn't solve for later years. Alternatives that could be considered would be the addition of transformers at Herndon 230 kV, McCall 230 kV as well as reconductoring of several 115 kV to address the reliability requirements with an expected cost similar or higher than the North Fresno 115kV reinforcement ($125-200 million). 2. Midway-Wheeler Ridge 230kV Capacity Increase – This project was identified to address contingency conditions and limitations for the theCDWR to remain in serevice and pumpduring these conditions, including when one line is out of service for maintenance. The ISO will continue to assess these concerns within this planning cycle or future planning cycles. 3. Greater Fresno Area Upgrade – The ISO appreciates the issue raised with respect to results not being complete at the time of the September stakeholder session. The ISO has presented additional findings at the December 11th and 12th stakeholder session with detailed analysis provided in the February 1st Draft Transmission Plan along with the recommended development in the area.

[2] "Planning for New Transmission Versus Involuntary Load Interruption Standards," CAISO Grid Planning Standards, June 23, 2011.

		the criteria and methodology underlying these BCR calculations that were performed only to a subset of the PG&E R/W projects. We encourage broader applications of BCR calculations for R/W submittals. BAMx also requests PG&E/CAISO to provide details on the BCR calculations for the PG&E projects listed above. ***PG&E Request Window Applications*** Below we seek more information on three (3) specific PTO Request Window applications that were presented during the September 27th Stakeholder meeting. 1. **Northern Fresno 115 kV Area Reinforcement** At the September 27th CAISO Stakeholder's Meeting, PG&E presented a proposal for a project named Northern Fresno 115 kV Area Reinforcement. This project was described as needed to address 20 NERC *Category C* violations. Given the high cost of the proposed project ($110M - $190M), insufficient information has been provided to assess whether the proposed project is the most cost effective method to address low probability *Catgeory C* contingencies. More information needs to be presented on: i. The specific *Category C* contingencies and overloads being addressed by the project. For example, a single weak link in the transmission system can result in many criteria violations, so the number of violations being addressed is not necessarily a good indicator of the scope of a transmission problem or the scale of mitigation required. ii. The cost of the alternatives being considered and how each	SDG&E Request Window Applications The ISO will take these comments into account while evaluating all the reliability-driven request window projects. The ISO comprehensive plan will have more discussion on these projects.

		element of both the proposed project and the alternatives address the criteria violations found. This is in recognition that not all violations have the same cost of mitigation. It may be justified to install new capacity to address some violations, others may indeed be best addressed by load dropping for *Category C* events. iii. There are many proposed new generators in the Fresno area and from a planning perspective the potential for new generation in the area is in flux. A better understanding is needed as to whether the need for the proposed project is sensitive to this planning uncertainty and if so, what can be done to manage the risk of defining an improper project scope in the face of such uncertainty. Therefore, the project as presented does not contain sufficient information to be included in the CAISO 2012-13 Transmission Plan. 2. **Midway-Wheeler Ridge 230 kV Capacity Increase** This project was described as needed to address the following concerns: • Load growth in the Wheeler Ridge area has led to transmission capacity limitations between Midway and Wheeler Ridge substations on the two 230 kV lines. The *Midway-Wheeler Ridge 230 kV line #1* or *#2* are projected to exceed their normal ratings under clearance conditions and during summer peak loading conditions for an outage of either line (*N-1*) with pumping load online. The potential cost is identified as $85M to $128M over two phases. The assessment identifies overloads on the *Midway-Wheeler Ridge No. 1 230 kV* circuits associated with several *Category C* outages due to breaker	

		or bus failures in Midway Substation. The potential solution in the assessment is to drop CDWR pump load. While the PG&E presentation alluded to other alternatives involving reinforcing the system or building new facilities from Kern PP are still under evaluation but are expected to be more expensive, the low cost solution of dropping the CDWR pumps for these low probability *Category C* events was not addressed. Additionally, we understand that the high cost of the proposed reconductoring is partially due to the current condition of the existing line. As CDWR is a 75% owner of this line, will CDWR be asked to fund a portion of this work as needed line maintenance. Also, if the capacity increase is funded by PG&E and rolled into TAC, how will the capacity increase be allocated between PG&E and CDWR? Given the potential for a low cost solution identified in the CAISO assessment, the project as presented does not contain sufficient information to be included in the CAISO's 2012-13 Transmission Plan. 3. **Greater Fresno Area Upgrade Project** Though this project appears to be a scaled down version of the previous *Midway-Gregg-Tesla* project, it is still a very large project with an estimated cost of \$400M-\$500M of just direct costs. There was insufficient information presented at the stakeholder's meeting to justify a project of such a scale. The presentation noted Category A, B and C overloads on the *Bellota-Gregg 230 kV* line in the CAISO assessment. The overloads identified on this line in the assessment were generally quite small (2% to 5%) except for a 2017 partial peak case where the *Category A* loading on the *Warnerville-Wilson 230kV* portion of the line was 157% of the line rating. The identified mitigation in the assessment	

		was to turn on Helms if available. For all but the partial peak case, the minor overload suggest that reconductoring the *Bellota-Gregg 230 kV line* would provide sufficient capacity margin well beyond the planning horizon. The power flow assumptions in the partial peak case that would drive such high flows during this moderate system condition are not clear. Additionally, the PG&E presentation did not address the ability to generate at Helms during this condition as identified in the CAISO assessment. As such, the material presented was inadequate to justify a project of such magnitude. Furthermore, the PG&E proposal was incomplete. The western terminus of a proposed line into *Raisin City Junction* has not been determined. This project clearly requires further investigation before it is sufficiently defined and justified to be considered for inclusion in the CAISO 2012-13 Transmission Plan. BAMx recommends that the system deficiencies identified in the assessment be addressed in the *Central California Transmission Study* being prepared during this planning cycle. Finally, given the very modest overloads during the summer peak conditions and the linkage to Helms generation during non-peak conditions, BAMx recommends that any increase in scope beyond reconductoring the existing *Bellota-Gregg 230 kV* line be treated as an economic project and required to undergo the CAISO assessment process for economically based project justifications. ***SDG&E Request Window Applications*** **1. San Diego Reactive Support 230 kV** At the September 27, 2012 CAISO Stakeholder's Meeting for the 2012-	

		2013 Transmission Planning cycle, SDG&E presented a group of projects collectively referred to as the *Reactive Support 230 kV*. Each of the four installations included in this project would install +/- 240 MVARs of reactive capability through the use of synchronous condensers and shunt reactors. The four installations would have a combined total cost of **$228M** to **$284M**. The driving factors for this project are identified as: • Meet NERC/WECC reactive margin criteria. • Dynamic reactive capability & inertia: – South Bay (Retired in 2010) – Encina (Possible 2017 retirement & OTC) – SONGS is currently OOS, possible future OTC Retirement • Need for improved voltage control pre and post contingency: – Maintains voltage stability, particularly with high system imports. – Regulates grid voltage for all system loading conditions. – Voltage/VAR control independent of unit commitment /dispatch. – NUC-001 requires following narrow voltage band at San Onofre bus. • Improves San Diego Import Capability. With regard to the need to meet NERC/WECC reactive margin criteria, there is no information presented in the CAISO assessment that suggests that there is a reactive margin deficiency in the San Diego area. Additional information is needed to identify the nature of any such alleged deficiency as well as alternative measures to mitigate it.	

		With regard to dynamic reactive capability and inertia, other devices such as such as SVCs can provide dynamic reactive support and are the more standard way of providing such capability. Synchronous condensers have higher initial capital costs, as well as higher maintenance costs and operating losses. As for inertia, synchronous condensers are not highly effective in providing inertia. The lack of a turbine and the lighter rotor construction of a synchronous condenser (due to the lack of the need to accommodate power transfer) result in a lower effectiveness in providing inertia. If inertia is indeed needed due to the shut down of South Bay and possibly Encina, other options should also be considered such as conversion of those units into synchronous condensers or procurement of local replacement generation. With regard to improved pre and post contingency voltage control, the assessment did identify a number of SDG&E 69 kV and a few 138 kV voltage violations. These are primarily due to light load normal conditions or contingency conditions on the 69 and 138 kV systems. As voltage issues are normally best corrected closest to the deficiency, it is unclear why device installation on the 230 kV was chosen. Solutions to these issues should be addressed through local system improvements rather than through bulk system upgrades. As for improving San Diego Import Capability, this should be addressed based on an economic evaluation rather than as a reliability upgrade. Given the above issues, the project as presented does not contain sufficient information to be justified for inclusion in the CAISO's 2012-13 Transmission Plan. **1. San Diego New 230kV Sycamore-Penasquitos line and Los**	

		Coches 230kV Expansion SDG&E also presented two large projects, the *New 230 kV Sycamore - Penasquitos* line and the *Los Coches 230kV Expansion*. The total cost of these two projects ranges between **$191M** and **$241M**. The *Sycamore - Penasquitos line* is represented as alleviating multiple *Category B* and *C* overloads. As most of the overloads in the CAISO assessment of the San Diego area were on the 69 kV system, it is not clear which overloads this project addresses. Both projects are identified as reducing congestion in the Sycamore area. No alternatives were provided for the *Sycamore - Penasquitos* line and the alternative to the *Los Coches 230kV Expansion* is to upgrade the 138 kV and 69 kV systems. There is insufficient information to assess the minimum project cost for simply addressing the *Category B* and *C* violations versus the expanded scope of these larger projects to reduce congestion and facilitate renewable generation integration. Any costs/scope above that necessary to address criteria violations should be treated as an economic project and required to undergo the CAISO assessment process for economically based project justifications. Given the above issues, these projects as presented do not contain sufficient information to be justified for inclusion in the CAISO Transmission Plan. BAMx appreciates the opportunity to comment on the CAISO 2012-13 Transmission Plan and acknowledges the significant effort of the CAISO staff to develop the plan to date.	
4	Chifong Thomas,	1) Comments on Valley Electric Association (VEA) assessment results:	VEA will be a participating transmission owner starting in January 2013. Any transmission mitigation needed to meet NERC planning standards in

	BrightSource Energy, Inc.	• During the stakeholder meeting, the CAISO presented study results for VEA's system because VEA is expected to become a Participating Transmission Owner (Participating TO) in early 2013. The study results identified several potential reliability issues, as well as potential solutions, on both the VEA and Southern California Edison Company (SCE) transmission systems. BSE would like additional information about how the VEA projects will be integrated into the TPP, since VEA is not yet a Participating TO. It is unclear whether the study results produced by the ISO are for information only and/or if the ISO anticipates that VEA and SCE will submit the projects during the Request Window. Moreover, BSE would like to understand the proposed timing of these upgrades and receive confirmation that the upgrades will not delay the integration of VEA into the CAISO's system. BSE requests the CAISO provide additional clarification concerning these questions, as well as next steps in the process. • The study results for both the VEA and SCE East of Pisgah areas recommended the modifications of SPS around Ivanpah and Crazy Eye Tap or curtailment of generation in the area as the solutions for potential problems triggered by outages in the VEA and SCE systems. While this approach is one of the possible solutions to mitigate the potential problems, however, because the majority or all of generators that may be curtailed are part of the renewable portfolio from the CPUC to meet the 33% RPS Goal, their curtailment can impact the ability to meet this RPS Goal. Therefore, BSE encourages the CAISO to explore other alternatives with less impact on the ability to meet the 33% RPS Goal. For example, if the main concerns are low voltages and large voltage deviations, adding reactive power	the VEA area will be included in the ISO transmission plan to be presented the ISO Board for approval in March 2013. The study results presented in September 2012 were based on the ISO reliability assessment which. The focus of the reliability assessment is generally to ensure reliable service to load customers. Studies presented to stakeholders by the ISO in December 2012 were based on our policy driven transmission need analysis. The focus of the policy driven need analysis was to ensure that the transmission system would be sufficient to deliver renewable generation output to customers. The ISO agrees that available reactive power support devices, including those available from generating facilities, and operating procedures should be utilized to mitigate voltage problems as much as possible. Any SPS or renewable generation curtailment recommended by the ISO would be for post-contingency conditions. Therefore the amount of curtailed renewable energy is expected to be negligible and not expected to impact the ability to meet our 33% RPS goal.

		sources, or utilizing the reactive power capabilities of the renewable generators in the area, or developing operating procedures to reconfigure the surrounding network connections may be viable solutions.	
5	Chifong Thomas, BrightSource Energy, Inc.	2) SDG&E New Imperial Valley – IID Flow Control Device: • For this upgrade, BSE encourages the CAISO and SDG&E to work with IID to ensure that the implementation of the Flow Control Device will not adversely impact power flow on other known system limitations. For example, it is unclear at this point what will be the impact from implementation this Flow Control Device on other transmission corridor such as West of Devers. In order to maintain Deliverability of generators that are located on other corridor(s), BSE encourages the CAISO and SDG&E to evaluate this potential impact prior to the approval of this project.	The ISO has not found a need for this project.
6	Chifong Thomas, BrightSource Energy, Inc.	3) "Congestion management" as a potential solution • To effectively evaluate the various alternative solutions to potential transmission problems, the cost and impacts of each alternative need to be indentified and, if possible, quantified. Therefore, to evaluate the viability of "congestion management" as a solution, more information on the general location(s), duration(s) and amounts of generation to be curtailed or be designated as "must run", and the system conditions under which this "congestion management" is implemented, will be needed. This information does not have to be elaborate. For example, descriptions of the conditions under which "congestion management" would be imposed can provide insight for the evaluation. Whether "congestion management" is in the form of	The level of analysis necessary to support each decision must take into account the specific circumstances being examined.

		generation curtailment or generation being placed on line, there is a difference in impacts if this "congestion management" is required only after a contingency has occurred, or if it is required before a contingency (i.e., in anticipation of the contingency). The former may only take place for a few hours during a year, while the latter could take place a few hours every weekday in summer. BSE therefore encourages the ISO to provide more specific information when "congestion management" is proposed as a solution so that its impacts can be fully understood and that it can be compared against other potential solutions.	
7	California Consumer Alliance	We consider some of the proposals, such as the "Barre - Ellis 230 kV Reconfiguration"project, to be needed and cost effective solutions for improving the reliability of the system and we are willing to support implementation of these projects. However, we question others; the CAISO has not yet provided enough data to support the conclusion that many of the proposed solutions are the least-cost solutions considering a reasonable range of feasible wires and non-wires alternatives. As required by FERC and NERC, CAISO uses a deterministic approach to its reliability studies—the likelihood of occurrence and the severity of outcomes does not come into play in identifying the contingencies that must be studied. Nor does likelihood of occurrence or severity of outcomes change the fact that under FERC and NERC reliability standards, mitigation must be identified where any violation of the standards is found. However, likelihood of occurrence and severity of outcomes are very relevant in determining what specific mitigation measures are sensible to pursue. For example, where the likelihood of a double contingency event is small and the resulting reliability standard violation is not too severe, load drop may be the	The ISO acknowledges the significant volume of transmission issues that have to be dealt with in each year's plans, and encourages stakeholders to participate throughout the 14 to 16 month span that comprises each planning cycle. By offering stakeholder updates and opportunities for input at multiple stages throughout the planning cycle, beginning with input on a draft study plan, we seek to distribute the workload over the year. Also regarding access to information, the base cases are published, and staff is available for questions at stakeholder sessions.

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		sensible solution to pursue since it is low cost, unlikely to ever be needed, and avoids the possibility of cascading outages. At the September 27, 2012 meeting, the PTOs presented their proposed mitigations to stakeholders for the first time. The PTOs have submitted a total of **57** transmission projects for CAISO approval in the 2012/13 TPP. In what amounts to just over two weeks time, stakeholders are being tasked with reviewing and responding to the CAISO's preliminary reliability results and the PTO's proposed mitigations. This is a daunting undertaking for stakeholders with limited resources. The CCA would like to fully understand and examine the cases where the proposed mitigation may result in an extraordinary burden for consumers and the environment as compared to feasible alternatives. At the September 26, 27 meetings, CAISO staff stressed the importance of consistent and early involvement of stakeholders. In tune with staff's recommendation, we point out that timely and transparent access to information plays a crucial role in facilitating stakeholders' early and meaningful involvement.	
8	California Consumer Alliance	**Central California Study** Central California has been the subject of numerous and nearly continuous transmission studies for at least the last seven years. When one includes Path 15 studies, the time span stretches back much further. The CCA notes that the current Central California Study distinguishes itself from its numerous predecessors in that the current analysis has not started as a project objective-based planning effort, but rather, it explicitly sets out to evaluate the transmission system in Central California to determine if need(s) exists in the first place. We believe this approach to be superior to previous study efforts in the area. Nevertheless, we have concerns. As the process unfolds, we request the CAISO consider the following:	The comment period for the completed draft 10 Year Plan to be released at the end of January is being extended to the maximum possible duration, yet still enable the schedule to be maintained.

		1) Durability of Preliminary Reliability Results. Three of the CAISO's September 26 presentations*: 1) PG&E Bulk Transmission System Preliminary Reliability Assessment Results, 2) Fresno & Kern Areas Preliminary Reliability Assessment Results, 3) Central California Study Area Preliminary Reliability Assessment Results,* and the corresponding *2012/13 ISO Reliability Assessment-Preliminary Study Result posted on August 15* indicate that the assessments for these reliability studies are ongoing and the *results* reflect 2017 cases and a few additional 2022 PG&E Bulk Transmission Assessment cases only. As we understand it, key assumptions and other factors that could significantly impact the 2022 cases that have not been incorporated into the 2017 assessments; not the least of which are accounting for updated generation portfolios and fully meeting the 33% RPS requirement. Since the currently posted *results* are subject to change in the 2022 assessment, stakeholders are currently tasked with reviewing and responding to an incomplete assessment. We urge the CAISO to provide stakeholders with extended time for examining the more complete ten-year assessment results and developing fully informed comments.	
9	California Consumer Alliance	**Central California Study** **2) Clarification of Base Case Parameters** The CAISO's *Preliminary Reliability Assessment Results* incorporated into the *Central California Study* includes several 2017 cases with various parameters that appear to be meant to "stress" grid elements in Central California. The CAISO also indicates that it has used historical data to set path flows used in the modeling. The 2017 cases have identified several normal overloads and numerous post contingency reliability concerns. The CCA understands that the stress cases that the CAISO has developed	In assessing reliability needs, the relevant reliability standards (NERC and WECC) call upon the system to be planned at demand levels over the range of forecast system demands to examine system performance test the boundary conditions under certain assumptions and not only including highest anticipated load levels, but also idealized conditions with the rest of the system in service. With this critical system conditions are assessed under normal and applicable contingencies. The Central

		may be an informative modeling exercise that simulates critical system conditions, however, we question whether the particular pre-contingency scenarios (a convergence of the parameters used in the various base cases) incorporated into the *Central California Studies* are reasonable to utilize. The reasonableness of the generation dispatch pattern is central to assessing whether the power flow results are truly indicative, or merely a matter of intellectual curiosity. Thus, we are compelled to ask the following: i. How often during a given year are the particular generation dispatch patterns and load levels likely to occur? ii. Are the generation dispatch patterns and load levels used in the pre-contingency power flow cases realistic? iii. Are we dealing with system conditions that could be present in a significant number of hours a year? iv. Or, are we dealing with system conditions that are highly unlikely to simultaneously occur? v. Could the identified reliability standard violations be avoided altogether by redispatching out-of-economic-merit order controllable fossil-fired generation? If so, what are the estimated annual costs of such redispatch? As one example, we note that some of the most severe 2017 reliability concerns in the Central California Study Area are identified in the ISO's *PG&E Bulk - Summer Light Load, Summer Off-Peak & Summer Partial Peak Study.* As we understand it, the base case for this study includes the simultaneous occurrence of following parameters: • Northern Cal Hydro – dry year historical data • Path 15 modeled according to dry year historical data for partial peak hours (25 MW South-to-North) • Path 66 stressed at maximum per dry year historical data for partial peak hours (4350 MW North-to-South)	California study also assesses the availability of adequate pumping times to have adequate water level available to generate as needed for area reliability needs. Details of the analysis will be included in the Transmission Plan. Details of the analysis will be included in the Transmission Plan.

		• North of Los Banos flow modeled at 800 MW North-to-South • Helms Off-line The CCA believes it would be instructive for the CAISO to test whether alternative generation dispatch patterns for the *Summer Off peak* and the *Summer Partial Peak* study conditions would result in the same, more severe or less severe reliability standard violations than those identified in the CAISO's published results. Different generation dispatch patterns—which could be achieved through the out-of-economic-merit order redispatch of generation (i.e., congestion management)–could change the Path 15, Path 66 and North of Los Banos flows and thereby post-contingency results. Another example where we seek clarification regarding the reasonableness of a utilized base case parameter is in the *2017 Fall/Winter Off-Peak--Dry Hydro Scenario.* Slide 9 of CAISO's presentation indicates *Helms pumping with two pumps* in the base case. For the reasons we explain below, the assumed simultaneous operation of two 300 MW pumps may not be a realistic scenario for Fall/Winter drought conditions in the Central Sierra Nevada. Nor is the parameter of *Helms pumping with two pumps* completely consistent with other "dry-hydro" cases that CAISO has put together for the Central California Study. The Helms' lower pool, Wishon reservoir, is situated in the watershed of the North Fork of the Kings River. The upper pool, Courtright reservoir, is situated in the adjacent tributary watersheds of Helms and Dusy Creeks. Both of these reservoirs are largely dependent upon annual precipitation, as are any users of water from the North Fork of the Kings River. During the fall and winter months of past drought years, it has not been all that uncommon to find Wishon reservoir to be significantly drained.	

		Furthermore, review of historic data from The Water Resources Division of the U.S. Geological Survey reveals extreme variation in annual runoff in the watershed of the North Fork of the Kings River. Ten year statistics published by the USGS show as much an 8 fold difference between the min and max fall/winter month inflows into the Helms lower pool, and that the period from Nov-Mar is when the reservoir tends to be at its lowest annual levels, While the Helms PSP essentially operates as a closed loop of sorts, the pools are not immune to *dry-hydro* conditions but are highly dependent on inflows and minimum levels to facilitate pumping and generation. Furthermore, it is our understanding that each of the three Helms units is capable of pumping at a rate of 2400 cubic feet per second. All told, it is less than clear that *Fall/Winter--Dry Hydro Scenario* conditions would regularly allow for the simultaneous operation of two Helms pumping units. Being a relative condition, drought has differing degrees of severity that would affect a *Dry-Hydro scenario*, and presumably the dispatch pattern of the hydro generation fleet that supplies energy to the Greater Fresno area. Nevertheless, we believe the *dry-hydro* base case should strive to account for supportable, hydrological data based conditions. Moreover, we believe *Dry-Hydro Scenarios* should be modeled in a consistent manner across all of the base cases. Lastly, we recognize some high level similarities in the *2017 Fall/Winter Off-Peak—Dry Hydro Scenario* to transmission studies of the past. We request the CAISO consider the generation dispatch and load assumptions utilized in this case as a means to eliminate the *normal (101%) overload on the Midway-Gates 500 kV line*, and the post contingency overloads.	
10	California	**Central California Study**	

	Consumer Alliance	**3) Potential Mitigation** It is noted that the *results* on Slide 7 of *Central California Study Area Preliminary Reliability Assessment Results/ 2017 Summer Partial Peak* presentation indicate that *dispatching Fresno Area internal peaking resources mitigates the identified normal overloads.* We have generally noticed that the CAISO has bulleted *potential mitigation*(s) throughout its September 26 presentations. However the CAISO presentations do not make clear what alternatives are actually being assessed in developing mitigation for identified reliability standard violations. The CCA requests that future study results clearly identify which alternative mitigation(s) are being analyzed for each reliability standard violation(s) and, the manner and level of detail at which the CAISO's analysis of the alternative mitigation(s) is being carried out.	After the ISO has completed the analysis of the area and system needs, the potential mitigations identified will be considered to develop the recommended transmission development required to addresses the identified needs to be recommended in the transmission plan.
11	California Consumer Alliance	**Central California Study** **4) Helms Pumped Storage.** The CCA observes that the Central California Study Scope shows, and the preliminary reliability results suggest, that the CAISO intends to perform the largest portion of evaluating the utilization of the Helms Pumped Storage Plant in the 2012/13 Economic Planning Study. The CCA recognizes that Helms PSP is a useful resource in certain system conditions. However, we are not aware of any studies that indicate it is necessary for grid reliability purposes, or for the integration of intermittent renewable resources, to have the 3 Helms units always available. If such studies exist, CCA requests that the CAISO make those studies available to stakeholders for their review and input. CCA requests that with respect to Helms, the CAISO explain what is meant	Within the study plan, the reference to: "The economic assessment will evaluate the cost and level of congestion and the benefit of any new transmission upgrade by including the potential importance of Helms Pump Storage Plant full participation in the ancillary services in order to facilitate the integration of renewable resources and supporting reliability of the greater Fresno area" was to identify the importance that Helms may have in renewable integration activities and, if economic analysis warrants and justifies, its participation in the ancillary services market at all times. The ISO will be assessing the area reliability concerns, capability of HELMs to support area reliability as well as the potential to enhance utilization for renewable integration. This analsyis will be included in the Transmission Plan.

		by *"full participation in ancillary services"* as the term is used in the *Central California Study* Scope. Should stakeholders assume it refers to the full pumping/generation capability of all three Helms units during all hours of a year? According to the *Pumped Storage Generating Statistics (Large Plant) Report* included in *the 2010 Annual Report of PG&E (Form 1) to the California Public Utilities Commission,* energy statistics for the Helms Pumped Storage Plant were reported as follows: • Generation, (exclusive of plant use) = 583, 877, 767 KWH. • Energy for Pumping = 899,144, 292 KWH • Net output for Load = (-315,263,525) KWH These 2010 statistics from *Form 1* indicate an efficiency factor of approximately 65%. Accounting for the installed capacities of the Helms turbines in pumping and generation modes, the statistics for the Helms PSP translate into **5.49 % & 11.4%** annual capacity factors for generators, and pumps, respectively. The CCA believes that the CAISO's 2012/13 economic studies related to the utilization of Helms PSP should precisely explain the rationale behind "full participation". We request that the production simulation modeling the CAISO intends to perform fully account for all operational limits of the facility. We understand the production simulation modeling will reflect the limitations of the existing transmission grid so that the effect of those limitations on the ability to operate the Helms facility up to each pumping/generating unit's full capability, if any, will be accounted for. Importantly, the CAISO needs to expand the scope of the economic study to include cases that incorporate possible transmission upgrades in the Fresno area. This will allow the CAISO to compare the cost of operating	

		the system as is, with the cost of operating the system with the transmission upgrades. The economic study should identify the most economical solution, considering both fixed and variable costs, for accommodating intermittent renewable resources.	
12	California Consumer Alliance	**Central California Study** **5) PG&E's proposed mitigations** Two PG&E proposals, (i) *Northern Fresno 115 kV Area Reinforcement* (ii) *Greater Fresno Area Upgrade Project* appear to be in response to preliminary reliability concerns identified in the cases completed to-date that comprise the *Central California Study*. Due to the scarcity of information provided in PG&E's presentations and through discussions with PG&E representatives regarding the proposals, it is virtually impossible to tell if the PG&E-proposed mitigations are effective or economical. Note that the only way to determine whether the PG&E-proposed mitigations are economical is to understand the alternative mitigation solutions that PG&E evaluated and rejected, and their respective costs. It is necessary to establish whether those alternative mitigation solutions included a reasonable range of options (other infrastructure solutions, Remedial Action Schemes, generation redispatch, etc.) Given the scant information made available in PG&E's presentation, it is impossible to formulate a worthwhile evaluation of the PG&E proposal. The only method of reaching a worthwhile evaluation is to compare the economic impact of PG&E's proposed solution to the economic impact of alternative solutions. The cost of the *Greater Fresno Area Upgrade Project* is subject to	The *Northern Fresno 115 kV Area Reinforcement* is a transmission project that has been identified to serve Fresno and address overloads and voltage collapse on the 115 kV system. It does not increase or improve the capability transfer power into the Fresno area. As the needs within the Central California area are determined, the *Greater Fresno Area Upgrade* project as well as other projects ISO has received through the open window additional alternatives developed by the ISO will be assessed to address the need. The need assessment, alternative analysis and recommended mitigation plan will be presented in the transmission plan.

		significant variables. For example, the uncertainty in the location of Path 15 terminations of the two 230kV lines emanating from the new *Raisin City Junction Substation* could lead to a near doubling of the length of these two lines. As it stands, PG&E's estimate of 40 miles appears to be erroneously based upon a straight-line distance from the *Raisin City Junction Substation* to the *Gates* and *Panoche Substations*. Moreover, a straight-line distance from *Raisin City* to the *Los Banos Substation* would be over 70 miles. We also note that the *Northern Fresno 115kV Area Reinforcement and Greater Fresno Area Upgrade Project* share overlapping elements, in particular, a new *North Fresno Substation.* The line drawings in the presentations for both PG&E proposals reveal the looping of the existing *Helms-Gregg 230kV* into the proposed *North Fresno Substation*, but in different configurations--single and double circuit. Neither of the PG&E presentation offers a text description of the modifications to the *Helms-Gregg DCTL*. Furthermore, it is not clear which of the proposals (if any) account for these significant modifications to these existing 230kV facilities. Assuming that CAISO's evaluation of these proposals moves forward, we request that uncertainties that cloud costs estimates be clarified, and realistic estimates be developed and utilized.	
13	California Consumer Alliance	**Other Non-Transmission Alternatives** The CCA appreciates the CAISO's decision to directly address the issue of *Non Transmission Alternatives*. We find that Neil Millar's presentation offers well-reasoned reference points to facilitate a discussion with stakeholders. First, the CCA recognizes that the CAISO already incorporates consideration of *Non Wires Alternatives (NWA)* in the transmission	The ISO does not agree with many of the characterizations applied to the presentation or discussion of September 26 regarding non-wires alternatives by the CCA, but appreciates that the comments provided here provide an opportunity to respond. The presentation addressed the conditions at the time of the presentation, and conditions taken into account in the 2012/2013 planning cycle which

		planning process. Contrary to a bullet point in Mr. Millar's presentation, we also believe that the ISO does have the authority to ensure that some non-wires alternatives are actually implemented. To make this point clear, throughout the CAISO September 26 *Preliminary Reliability Assessment Results* presentation, the CAISO has offered a number of examples of *potential mitigations* that are in fact *NWA*s--the examples include, operating solutions, congestion management, generation re-dispatch, SPS modifications, etc. Furthermore, there are numerous *NWA* solutions and mitigations that have been implemented by CAISO, and are in place today. These include, out of economic order re-dispatch of generation, remedial action/special protection schemes, re-rating of exiting facilities, under-voltage load shedding, etc., that are being used today. We view Mr. Millar's presentation as a matter of facts statement on how the CAISO views Preferred/Demand Side Resources in the TPP. Mr. Millar's presentation describes the significant technical requirements that a non-transmission alternative should meet in order for it to be given consideration as a potential solution to an ISO identified need. The technical requirements include, *providing necessary location specificity, operating characteristics and certainty*. Mr. Millar's presentation goes on by explaining that the burden of meeting the technical requirements largely rests upon advocating stakeholder(s). Finally, an advocate for non-transmission alternatives is presented with a caveat… *the ISO has no ability or authority to ensure that any proposed non-wires alternative is actually implemented.* The CAISO, however, must accept that other market participants do have the ability to ensure that proposed non-wires alternatives are actually	is reaching the conclusion of Phase II at the March Board of Governors meeting. While the ISO is optimistic that demand side management can play a much larger role in the future and has committed to industry to help advance the viability of demand side management, misconstruing the current situation would actually be detrimental, as it would lead to a lack of emphasis on the areas where progress needs to be made to better utilize non-transmission alternatives in the future. This is particularly the case where broader coordination is needed to implement non-transmission alternatives. The CCA points to what it characterizes as "non-wires alternatives" as an example of where the ISO has the "authority" to ensure non-wires alternatives are implemented, but this situation is not as the CCA sets out, and in fact reinforces the ISO point. In the transmission planning process, the ISO can and has identified solutions other than transmission capital projects such as special protection systems and operating procedures. However, the ISO does not have approval authority over those solutions; they are developed collaboratively with the particular Participating Transmission Owner, and provide an example of how coordination is necessary both to implement, and ensure that implementation takes place, for such solutions. If implementation of such measures proved infeasible for reasons not identified earlier, then another solution would need to be pursued. Broader coordination with stakeholders including end-use customers will be necessary to implement demand side management initiatives. There was additional discussion on the 26th of the steps the ISO is intending to take in both the development of the 2013/2014 planning cycle and other forums, and the clarifications provided there do not appear to have factored into the CCA's comments. The ISO provided an

		implemented. The CAISO should also acknowledge that in response to increasing electricity rates, consumers in growing numbers are providing for their energy needs, and, reducing their demand on the system; the market is providing means implement these preferred resources, in singular and aggregated levels of deployment. CCA notes that nearly all infrastructure alternatives, both wires and non-wires, are subject to regulatory permitting requirements so even the CAISO cannot "ensure" that any proposed wires alternative is implemented. The CAISO needs to change its mind-set; without which we are less than confident that preferred resources would be given meaningful consideration as alternatives to transmission.	explanation on the 26th of where energy efficiency and behind-the-meter distributed generation has been included in the2012/2013 planning cycle as well as the source of the forecasts for system-connected distributed generation. Further, in discussion on the 26th, it was indicated that the ISO is looking for input into the 2013/2014 planning assumptions, and is participating in the CPUC's LTPP proceedings both in reviewing forecast assumptions and also to help define and advance future demand response programs that will be viable alternatives to transmission reinforcement.
14	California Consumer Alliance	**Other Non-Transmission Alternatives** **1) Obstacles to integrating Preferred Resources into the TPP** Preferred resources (EE, DR, CHP, and DG) are demand side resources directly accessible to consumers that reduce load and correspondingly lower system needs. The CAISO TPP does little to accommodate and nothing to implement demand side resources. Conversely, the transmission planning process accommodates supply side resources advocated for by market participants, and essentially passes the costs of implementing these resources on to consumers, the net effect resembling oligarchy in action. Examples of how market participants are proactively accommodated include the CAISO's extensive infrastructure planning processes and approved upgrades to interconnect remote generators, and active advocacy for flexible resources in the form of conventional generation. In comparison, a demand side resource is confined to planning assumptions and not been given anything remotely resembling prospective planning treatment offered to supply side resources.	The actions the ISO is taking to provide further consideration of such resources in future planning cycles was discussed above. As noted in the presentation of September 26, energy efficiency programs and customer side of the meter generation is embedded in the adopted CEC forecast, and system-connected distributed generation is factored into the programs provided by the CPUC.

		Demand side resources should not be automatically discounted in mitigating identified reliability concerns. Analysis is needed to determine whether such resources are sufficiently reliable. Nor should ISO control be the deciding factor. A technology neutral comparative analysis should be performed as a means to inform the regulatory approval and procurement processes with jurisdiction. In developing and implementing the *Energy Action Plan Loading Order*, the CPUC & CEC prioritize demand side resources as the preferred means to meet energy needs. It is our impression that CAISO largely agrees with the CEC & CPUC deference to meeting needs with preferred resources but traditional roles and methods have stifled cooperation on the issue. While we appreciate the CAISO's concerns about certainty, again, it is critical for CAISO to consider the extent to which "certainty" is provided for by its decision-making processes alone. As it stands, resources that CAISO approves are often required to subsequently move through regulatory processes administered by other agencies.	
15	California Consumer Alliance	**Other Non-Transmission Alternatives** **2) Recommendations regarding preferred resources** The CCA suggests that the CAISO reset its perspective regarding the consideration of preferred resources in the TPP. Preclusive treatment of preferred resources is not helpful or instructive--It amounts to partiality, before the facts are established. Reducing the range of competing feasible alternatives impacts consumers. Removing impediments to the consideration of preferred resources would enhance the transmission planning process by broadening the range of alternatives to evaluate. In cases where preferred resources are determined to be the most cost effective solution, the analysis results will	The steps the ISO is pursuing to enhance opportunities for demand side resources in future planning cycles have been discussed above and in the discussion of September 26. The ISO fully supports adherence to the preferred resources when possible while providing reliable service to customers. However, the reference to FERC Order 1000 public policy requirements is inconsistent with the desired intent expressed by CCA. FERC Order 1000 calls for a means to advance transmission to achieve public policy requirements, as opposed to calling for public policy objectives to be met that do not require transmission development. However, this does not preclude

		serve to garner commitment to the state's policy priorities in meeting energy needs. The CCA propose a way forward. We believe that FERC Order No. 1000 provides a means to reconcile agency cooperation in the meeting energy needs with preferred resources. In compliance with FERC Order No. 1000, we note that the CAISO intends to provide a clearer path for the consideration of public policy requirements in its annual TPP. We believe that further progress on the issue of preferred resources hinges on a clear answer to this question**: Does the CAISO consider California's established EAP Loading Order a public policy requirement?** Assuming that the CAISO finds that the Loading Order is a public policy requirement, identifying the most successful strategies employed in CAISO's RPS policy driven planning processes would be constructive in developing a Loading Order public policy initiative. We believe a Loading Order initiative would ultimately help to reconcile differences and move the state closer to realizing its long-standing energy priorities—an accomplishment that would be highly supported by stakeholders, including consumers. Immediately, the CAISO TPP can provide better public service by providing a balanced analysis (e.g. *providing necessary location specificity, operating characteristics and certainty)* where and when preferred resources can efficiently meet identified needs. This would help to inform stakeholders, the market place, and the regulatory authorities that have jurisdiction over those preferred resources.	advancing public policy requirements regarding preferred resources, and the steps the ISO is pursuing in the 2013/2014 transmission planning cycle have been discussed earlier as noted above.
16	Staff, California Public Utilities	***1. CPUC Staff support broader use of benefit-cost (b/c) methodology for justifying reliability upgrades, combined with explicit explanation of how other factors not captured in b/c may influence decisions.*** We applaud PG&E's incorporation of b/c based on value of service by	The ISO appreciates the comments. The projects identified utilizing Benefit to Cost Ration (BCR) are based upon the application of the ISO Planning Standards for New Transmission vs. Involuntary Load Interruption Standard (Section VI – 4).

	Commission	customer class and probability of load loss, for some proposed transmission solutions. However, this method should be applied further, for all PTOs and for more types of transmission proposals especially where driven by Category C (multiple outage) contingencies. Value of service and probabilities of contingencies are not perfectly known, but b/c nevertheless provides a transparent and useful basis for understanding and discussing the rationale and need for transmission upgrades. For example, if value of service and probability of loss of load (and its magnitude, duration) yield a very high b/c, then the need for a proposed transmission (or non-transmission, if more economic) solution may be well established. On the other hand, a low b/c should indicate a need to carefully consider the strength of rationale other than loss of load-based b/c to justify a proposed project. Accompanying and essential for b/c assessments should be consistently reported estimates of the cost range for transmission upgrades being proposed. For projects exceeding $50 million, this should include the basis for high and low estimates. It is also critical that key assumptions (e.g. value of service and loss of load) be reasonable, but with that caveat CPUC strong supports b/c analysis of projects.	
17	Staff, California Public Utilities Commission	***2. Where substantial transmission investments are being justified to a significant extent based on alternative (non-TPP base case) risk scenarios, those scenarios, their rational and their impact on proposed investment decisions need to be fully identified.*** Based on SDG&E's presentation and accompanying discussion at the September 27 stakeholder meeting, proposed large investments in synchronous condensers and a new 230 kV line appear to be driven in part by alternative supply (and load?) scenarios, such as regarding SONGS, Encina and imports. The exact nature, rationale and implications of such scenarios, and their relationship to the TPP base case, should be more	Thanks for the comment. The ISO comprehensive transmission plan has more information on these topics to address this concern.

		fully explained, particularly as the ISO evaluates this proposal and shares its assessment and conclusions with stakeholders. CPUC Staff strongly supports analysis of alternative supply scenarios/contingencies, but this information is only useful when all key assumptions are fully understood.	
18	Staff, California Public Utilities Commission	**3. Assessment of PG&E's proposal for a new 230 kV line into San Francisco should be transparently based on benefit versus costs including marginal benefit relative to a non-wires solution.** Only a few years ago, major justifications for the Trans Bay Cable (TBC) included enabling retirement of local fossil generation while avoiding another AC import line that would itself be costly and challenging to site and permit. Now, we are told that after that retirement of local fossil generation, "catastrophic" (category D) outage of existing AC import lines would lead to inoperability of the TBC itself, unless another AC import line (that would need to avoid catastrophic outage affecting existing AC lines) is built, or perhaps if local generation is added that could energize the DC-AC converter at Potrero. The TBC presentation at the September 27 stakeholder meeting indicated that 3 MW of local generation could accomplish this energization. Considering the imposing prospect of building a new $0.5 billion (PG&E's estimate) AC transmission line into San Francisco with nontrivial siting and permitting implications, the ISO's evaluation of transmission needs and solutions for this situation must be thorough and clearly explained, including at least the following: • Reconciliation of the present assessment with the original evaluation and approval of the TBC, including what conditions and assumptions have	Thanks for the comment. The ISO comprehensive transmission plan will provide additional information on reliability concerns of the San Francisco Penisula area and the ISO will be continuing to assess these concerns.

		changed (if any) since that approval. • Explicit quantitative characterization of the risk that would be mitigated by building a new 230 kV AC line, including the nature of the transmission contingency and its probability, as well as the magnitude, duration and estimated cost of the load outage. This should include description of the outage impacts that would be experienced even if the AC line was built. • The ability and cost of non-wires alternatives, particularly non-emitting generation and storage, to maintain operability of the TBC under the catastrophic contingency in question should be fully explored and assessed. In particular, the options and costs for black starting the converter station with local power sources plus any needed modifications to the converter station itself should be thoroughly examined and reported. • The marginal benefit and cost of the proposed AC line vs. non-wires alternatives should be clearly analyzed and reported. The CPUC Staff strongly support conducting the additional analysis described above before considering an additional AC import line into San Francisco.	
19	Staff, California Public Utilities Commission	**4. To provide real opportunities for non-wires alternatives to transmission, it is essential to determine what granularity in DSM and DG planning cases is needed to provide real substitutes for specific transmission additions, and to define opportunities and needs for nonwires alternatives far enough in advance of transmission decisions.** There seems to be a disconnect between DSM and DG in cases developed through the CPUC and CEC versus what granularity of non-wires information is sufficient to avoid or delay specific transmission additions. The ISO's studies and its communications with stakeholders should explicitly identify situations where, within the TPP,	The ISO agrees considerable effort will be required in 2013 to address the issues identified and better enable demand side management and distributed generation to play a larger role in mitigating transmission needs in the 2013/2014 planning cycle. Further, the ISO anticipates in the 2012/2013 plan, as has occurred in past plans, that there will be cases where a need is identified as well as potential mitigations, but that the approval of a capital project is not necessary in this planning cycle; those cases are deferred to future planning cycles.

		potential deferral or avoidance of transmission investments is precluded by imprecision regarding the location, characteristics or timing of DSM and DG included in planning cases. Then, we need to address how this situation could be improved. If the state and its energy loading order place a high priority (and expend considerable effort) on DSM and DG, and this does not translate into comparable impacts on transmission planning, then changes are needed. More specifically and perhaps more immediately addressed, the TPP needs to clearly identify situations where non-wires solutions would be valuable to avoid or defer specific transmission additions that would otherwise be imminent. This needs to be done with sufficient specificity (needed locations and non-wires resource characteristics) to allow timely development of viable non-wires proposals and projects by market participants or even via regulatory initiatives. The short interval after posting of reliability studies (and even shorter interval after posting of proposed wires solutions) up to the deadline for submitting alternative reliability solutions is generally inadequate for development of appropriate, viable non-wires alternatives. Part of the answer is to identify and flag as transparently and comprehensively as possible those imminent transmission needs for which non-wires solutions are likely to be applicable - - at least a year in advance of when a transmission decision will have to be made. The recent proposal for an $0.5 billion new AC line into San Francisco is an example of where non-wires solutions may be very desirable, but may need sufficient time to be developed and tailored to the situation and risks of concern. Finally, until there is better advance identification of what characteristics,	

		locations and timing of non-wires solutions are eligible to substitute for (or at least compete with) wires solutions, there is very limited ability of market participants, innovators, and even state agencies to identify, develop or promote the appropriate nonwires solutions and investments. For example, when does the non-wires solution need to be available? How dispatchable does it need to be? What reactive support or inertia does it need to provide? What locations on the grid are critical? What timing is critical? We hope that efforts such as the new DG deliverability studies, Rule 21 reforms and operational flexibility studies will help clarify these questions, particularly for critical areas such as the L.A. Basin. Otherwise, the TPP is not providing sufficient information , sufficiently in advance, to achieve the State's goals for preferred resources (e.g. DSM and DG) and prevent unnecessary costs to the State's economy.	
20	Staff, California Public Utilities Commission	**5. The ISO should clearly identify and interrelate recommended near term transmission investments (next two years) driven by risk of continuing SONGs outage and the longer term value of these and other investments in the LA Basin and San Diego.** It is important that recommended near term investments as well as potential subsequent measures be evaluated on their longer term value with and without the return of one or both SONGS units. This must be done in the context of estimated overall longer term transmission needs in the L.A. Basin and San Diego local areas, to help provide a clearer picture of "least regrets" investments and the interaction of the transmission implications of the SONGS and OTC situations.	In the grid reliability assessment of the LA Basin and San Diego areas without SONGS scenario, the ISO evaluated a mid-term extended outage scenario for 2018 time frame, as well as a long-term (2022) evaluation for a potential retirement or relicensing scenario. These study results were presented to the ISO Board of Governors on December 14, 2012 (http://www.caiso.com/Documents/Board%208)%20briefing%20on%20nuclear%20generation%20studies%20preliminary%20results). In addition, the ISO also evaluated a 2013 scenario without SONGS and provided recommended mitigation measures earlier (http://www.caiso.com/Documents/Addendum-Final2013LocalCapacityTechnicalStudyReportAug20_2012.pdf). The mitigation measures recommended for 2013 without SONGS scenario were included in the starting study cases for the evaluation of additional mitigation considerations for 2018 mid-term scenario. The mitigation measures included for 2018 were included in the starting study cases for

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			the 2022 long-term evaluation, with the exception of the Huntington Beach synchronous condensers for 2022 time frame as there is current plan from AES Corporation to repower the entire Huntington Beach power plant with approximate capacity of the four steam units which would necessitate the removal of the Huntington Beach synchronous condensers by that time for the development of the second block of the combined cycle gas turbine (note: the repowering of the HB generation was also included in the assessment for the long-term assessment). In the evaluation of the nuclear generation absence studies, the ISO also included assumptions of OTC generation subject to the SWRCB's compliance schedule. The need for replacement or new power was included in the ISO preliminary study results as presented to the ISO Board.
21	Staff, California Public Utilities Commission	**6. Assessment of Fresno area transmission upgrades should utilize benefit-cost assessment for reliability (and economic) upgrades, identification of which specific planning objectives beyond reliability are being used to justify transmission upgrades, and analysis of RPS portfolios beyond the base portfolio.** The assessment should clarify both the need for and sufficiency of the set of proposed transmission additions to meet all stated objectives, as well as the likelihood and conditions for needing further transmission additions to meet the objectives within a few years.	Thanks for the comment. The ISO comprehensive transmission plan provides details for the projects recommended to address reliability concerns to meet the established reliability standards.
22	Staff, California Public Utilities Commission	**7. Any reliability transmission needs significantly or solely driven by the generator interconnection process should be clearly identified as such, and the generation in question should be identified to the extent permitted by confidentiality considerations.** This will be important to transparently link the planning of reliability-driven	Reliability transmission needs are generally not driven by the generator interconnection process.

		and other (especially policy-driven) transmission, consistent with the ongoing priority to better coordinate transmission and resource planning.	
23	Jeffrey L. Paul, CalPeak Power, LLC	CaiPeak Power, LLC ("CalPeak") respectfully submits the following comments to the California ISO ("CA!SO") for consideration in the current Transmission Planning Process ("TPP"). CalPeak Power strongly encourages CAISO's immediate approval of San Diego Gas & Electric's ("SDG&E") "Preferred Scope" Metro Area 69kV Rebuild Project# PI2XYZ and suggests changing the In Service Date ("ISD") from "2017/2022" to "ASAP". CalPeak supports this project because of the ongoing dispatch limitations placed upon the three Border-area generation resources: • CalPeak Power - Border LLC, Cal Peak Power Border Unit 1, BORDER_6_UNITA1, 48.98 MW (Pmax) • Wildflower Energy LP, Larkspur Peaker Unit 1, LARKSP _6_UNIT I, 46.1 MW (Pmax) • Wildflower Energy LP, Larkspur Peaker Unit 2, LARKSP 6_UNIT 2, 47.98 MW (Pmax) SDG&E refers to these resources simply as "Border Gens 1, 2, and 3" in their September 26-27,2012 presentation materials. These generators represent a trio of critical fast-start, flexible ramping gas-turbine resources with a combined capacity of nearly 150 megawatts. The resources are physically located within the incorporated limits of the City of San Diego. In the unprecedented absence of the San Onofi·e Nuclear Generating Station ("SONGS") Units 2 and 3, aU available existing generation resources in the San Diego sub-area are now required for Local Capacity Requirements ("LCR") per the Addendum to the 2013 Local Capacity Technical Analysis published by CAISO on August 20, 2012.	The ISO will take this comment into account while evaluating the 'Metro Area Rebuild' project. The comprehensive plan will have a discussion on this project.

		Given the above mentioned new change in 2013 LCR and continued absence of SONGS units, CalPeak requests the highest possible priority be given to e liminate the cw-rent dispatch limitations placed upon the Border-area generation resources. CalPeak also requests that CAISO and SDG&E ensure the full capacity of"Border Gens *1,* 2, and 3" is deliverable without any transmission constraint under both NERC Category B and C Contingency since no optional capacity is available for re-dispatch to meet the new LCR requirements.	
24	Barry Flynn or Meg Meal, City and County of San Francisco	There were two PTO Request Window (R/W) presentations made during the CAISO's September 27th stakeholder meeting that could potentially improve the reliability of electric service to the City. – **PG&E Project:** The construction of another major transmission line to San Francisco, this one a 230 kV AC cable from Moraga to Potrero Substation, estimated to cost **$450-$550M**. PG&E's proposal indicates that "The loss of AC transmission imports to San Francisco will result in inoperability of the DC Trans Bay Cable (TBC) and therefore result in the loss of all San Francisco demand." PG&E's assessment does not indicate which event/s could lead to "the loss of AC transmission imports to San Francisco." – **Trans Bay Cable (TBC) Project:** TBC's transmission project includes three options for energizing the SF end of the cable to allow returning the cable to service in the event of a full SF blackout, estimated to cost **$20M- $30M**. The problem statement of the TBC project indicates that the contingency of	Thanks for the comment. The ISO comprehensive transmission plan will provide additional information on reliability concerns of the San Francisco Peninsula area and the ISO will be continuing to assess these concerns.

		concern is "Loss of Martin substation – Loss of Service to San Francisco, including Potrero 115 kV Bus." CCSF encourages the CAISO to thoroughly investigate the above-mentioned projects and other methods to protect the City electric supply under extreme events like the ones cited above that exceed the standard contingency analysis conducted by the CAISO. Such analysis should be shared with interested stakeholders such as the City. In addition, we have some specific questions on the above-mentioned two R/W projects. 1. How much of the added reliability envisioned by the PG&E proposal is accomplished by the TBC proposal? 2. What are the results of the comparison to the other alternatives that PG&E has studied, such as the East Shore to Potrero 230kV line and the Newark to Potrero 230kV line? 3. PG&E's proposed Moraga-Potrero 230kV project would provide similar benefits as the SFPUC Transmission Project that CCSF submitted to the CAISO in the 2009 Request Window and that the CAISO rejected. Both projects would improve reliability to San Francisco by establishing a transmission connection to the East Bay and minimize San Francisco's reliance on the Peninsula transmission lines and the Martin substation. The CAISO did not identify sufficient reliability benefits at that time to approve the SFPUC project. It is not clear what changes to the system have transpired since that time to now find that such a project is needed. If the CAISO finds that such a project is needed it should include in any evaluation the SFPUC's Transmission Project as an alternative to PG&E's proposal.	

25	Barry Flynn or Meg Meal, City and County of San Francisco	<u>Other Issues</u> The CAISO reliability assessment discovered a Category C overload on the Potrero-Larkin 115kV cable, but no solution was proposed by the PTOs in their R/W applications. This issue was also identified in the CAISO 2011-2012 assessment. The CAISO should thoroughly investigate solutions to this problem and report back on such investigations. The CAISO assessment has also identified a TBC run-back scheme as a solution for several potential overloads and lists expansion of those run-back schemes as a mitigation for some other contingencies. The City requests more detailed information on the existing and future expansion of the TBC run-back schemes.	The overload of the Category C contingency will be assessed with mitigation plans identified in the draft Transmission Plan. The TBC Runback scheme is currently designed to mitigate overload condition of the Potrero-Mission 115kV AX cable during an outage of the Potrero-Larkin AY-2 115kV cable. Actuation of the scheme will ramp down, or "runback", the power flow of the TBC cable to a maximum of 300MW. This SPS is to be in service at all times.
26	Tony Braun & Kevin Smith, Imperial Irrigation District	IID is greatly concerned by a SDG&E proposal to study, through the CAISO Transmission Planning Process ("TPP"), the addition of a flow control device at or near the Imperial Valley ("IV") substation. This step is being taken without coordination with IID, in contravention of the CAISO Tariff, and in a manner inconsistent with contracts between IID and SDG&E. The description of the location of a proposed Imperial Valley-IID Flow Control Device (pages 26-28) is not precise. It could be proposed on IID facilities and within the IID Balancing Authority ("BA"), or on jointly owned facilities between IID and SDG&E. Either way, SDG&E cannot move forward on such a proposal that would affect the IID system, without consultation and agreement. IID has several concerns regarding this proposal:	The ISO has not found a need for the flow control device.

		A. The Proposal is Inconsistent with the CAISO Tariff Provisions Relevant to the TPP. As an initial matter, it is unclear why SDG&E is putting this proposal in the TPP. The slide provided by SDG&E does not clearly describe where the proposed phase shifter will be located. Section 24.4.3(b) of the Tariff requires that proposals for transmission additions or upgrades submitted into the TPP be within or connected to the CAISO BA or Controlled Grid. If the phase shifter is proposed to be located on IID's system, it is not properly studied in the TPP under any circumstances. Further, even if the proposed phase shifter is not completely on IID's system, it must be studied in collaboration with IID as a neighboring BA. When the TPP was modified, the CAISO and IID worked to craft language to avoid overlap and duplication of study processes and transmission development. As such, Section 24.2(c) of the Tariff requires that the TPP seek to avoid unnecessary duplication, ensure simultaneous feasibility with interconnected Balancing Authority Areas ("BAA"), and coordinate with regional, subregional, and interconnected BAA processes. Section 24.3.1(l) requires that inputs into its Unified Planning Assumptions and Study Plan include planned facilities in interconnected BAAs. Section 24.4.3(b)(iii) requires that all proposals affecting interconnected BAAs be reviewed in appropriate sub-regional or regional planning processes. Section 24.10 requires coordination and consultation among neighboring BAAs with respect to how proposed facilities will meet operational needs. None of these requirements have been met. To the contrary, and as	

		described below, SDG&E must be aware that their proposal runs counter to the purposes of planned upgrades on IID's system. In short, it appears that the SDG&E proposal may not even be eligible for submission and study in the CAISO TPP because it may not be within the CAISO BA. Even if it is on jointly owned facilities and operated as part of the CAISO BA, the proposal violates numerous requirements for coordination of facilities affecting neighboring BAAs, and the avoidance of duplication, as discussed further below.	
27	Tony Braun & Kevin Smith, Imperial Irrigation District	**B. The Proposal Conflicts with Well-Documented and Known Upgrades to the IID Transmission System to Facilitate the Export of Renewable Energy from the IID System to the CAISO BA.** The SDG&E flow control device proposal violates the numerous provisions in the Tariff to avoid duplication and to coordinate upgrades through relevant sub-regional and regional planning processes. IID has well developed upgrades plans to portions of its system that will allow for comprehensive deliverability of projected interconnecting generation to the CAISO BA. IID's upgrades were included in the Final Statewide Transmission Plan produced by the California Transmission Planning Group ("CTPG") (*see pages 47-55).* For ease of reference IID has excerpted portions a description of the facilities taken from the CTPG Conceptual Statewide Plan, which are the upgrades contemplated to increase deliverability to IV Substation, and which were considered Foundation Lines in the conceptual plan: *see comments for table*.	The ISO has not found a need for the flow control device.

		These and additional facilities were listed as high and medium priorities in the Final Statewide Plan produced by CTPG.[3] Even before CTPG, the build out of the IID system to deliver to the IV Substation was identified as part of the recommendations of the Imperial Valley Study Group, whose work was performed under the auspices of the California Energy Commission. In short, the SDG&E proposal overlaps with existing IID upgrades contemplated as part of statewide plan developed in collaboration with SDG&E, the CAISO, and other transmission owners through CTPG. This lack of coordination and potential duplication of facilities is inconsistent with the Tariff, and runs counter to FERC's clear desire through Order Nos. 890 and 1000 to enhance regional planning and coordination.	
28	Tony Braun & Kevin Smith, Imperial Irrigation District	**C. Phase Shifters are Not a True Solution to the Problem** There are approximately 2700 MW of generation proposed to be located at or electrically near to the IV substation, both within the IID generator interconnection queue process and being evaluated as part of affected system studies. Installation of a phase shifter cannot maximize deliverability of this generation to the CAISO BA and cannot serve as a comprehensive solution to mitigate adverse impacts on IID's system. Phase shifters come with several disadvantages, including the likelihood of increased losses. More specific to installation of a flow control device at	The ISO has not found a need for the flow control device.

[3] http://www.ctpg.us/images/stories/ctpg-plan-development/2012/2012-03-05_2011finalstatewidetransmissionplan.pdf

		this location, installation of one phase shifter could limit IID schedules over its S-Line, impacting power deliveries to IID customers. Further, given the contemplated generation and transmission development in the IV substation area, it is likely that several phase shifters, not just one, would be required to ensure that there are no limitations on delivery from IID. Thus, SDG&E's proposal for a stand-alone flow control device does not solve anticipate flow issues on the IID system.	
29	Tony Braun & Kevin Smith, Imperial Irrigation District	**D. At the End of the Day, SDG&E Cannot Make Unilateral Upgrades to IID's Facilities.** Based on IID's review of the presentation made by SDG&E at the CAISO stakeholder meeting, it is unclear whether the proposed flow control device would be completely on IID's transmission system and located within the IID BAA, or within the breaker yards joint owned by SDG&E and IID at the IV substation. In the former scenario, the CAISO tariff does not contemplate study of such a facility. In the later case, SDG&E has no unilateral right to place any equipment or construct upgrades on jointly owned facilities. IID and SDG&E are parties to the California Transmission System Participation Agreement ("Participation Agreement"), entered into by the parties in 1983. While IID has no wish at this time to drag the CAISO into a contractual issue involving IID and SDG&E, if the flow control device is covered within the subset of facilities governed by the Participation Agreement, all interconnections made by one party to the Participation Agreement are governed by the provisions of the agreement and require assent of the parties.	The ISO has not found a need for the flow control device.
30	Tony Braun	**E. SDG&E's Phase Shifters Do Not Appear to Meet the Criteria**	The ISO has not found a need for the flow control device.

	& Kevin Smith, Imperial Irrigation District	**for Approval as a Reliability Project.** In its presentation materials, the CAISO identified several Category A, B, and C contingencies in the service territories of the Participating Transmission Owners, and potential solutions as part of its preliminary reliability assessment. IID can see no "problem" identified in the CAISO's reliability assessment to which the SDG&E proposal responds. The more detailed materials provided by the CAISO, dated August 15th, similarly raise no contingencies associated with the IID system. SDG&E's proposal is simply "out of the blue." Without more information, the CAISO must reject the SDG&E phase shifter proposal as unresponsive to the reliability assessment performed by the CAISO, which is the sole purpose of this phase of the TPP. **F. Conclusion** IID is filing these comments on the very day the CAISO held a stakeholder meeting to implement Order No. 1000 requirements to improve coordination and collaboration in the transmission planning process. IID cannot think of a project less consistent with that policy direction. SDG&E has proposed a project that does not solve a reliability problem identified in the CAISO reliability assessment. The proposed flow control device may be outside of the parameters of the TPP because it is not clear whether it would be in the CAISO BA or directly connected to the CAISO Controlled Grid. Further, no coordination of this proposal was made by SDG&E, as required by the Tariff. The SDG&E proposal duplicates and overlaps planned IID facilities, and may impact the ability of IID to schedule	

		over its system. Finally, SDG&E has no ability to unilaterally place a flow control device on the IID system, nor on jointly owned facilities. The CAISO should not waste is valuable staff and analytical resources studying a proposal that is so fundamentally flawed.	
31	Larry Chaset, Interstate Renewable Energy Council, Inc.	IREC does not have any particular comments with respect to either the CAISO staff's technical analyses or the various reliability projects proposed by the PTOs. However, the final substantive presentation on Day One of this meeting, on Non-Transmission Alternatives was a highly welcome opening from the CAISO on an issue that, in the past, has been a matter of frustration for many CAISO stakeholders. Among the primary goals of IREC is the facilitation of wider deployment of renewable distributed generation (DG), especially residential and smaller-scale commercial solar photovoltaic (PV) systems. Until Neil Millar's presentation on September 26, it has been difficult for IREC – and others – to discern a path forward to engage the CAISO in a serious dialogue regarding how PV DG can play the significant role in meeting California's future energy needs that it clearly has the capacity to play. It was therefore encouraging that Mr. Millar stated affirmatively during his presentation that the CAISO's processes are intended to address non-transmission alternatives, that the CAISO wants to ensure that the <u>opportunities</u> for suggesting non-transmission alternatives are clear, and that the CAISO wants to ensure that the <u>methodology</u> for comparable evaluation of non-transmission alternatives is also clear. IREC has no doubt that the CAISO is willing to, and will, work with the non-wires stakeholders to identify precisely how non-transmission alternatives, including, but certainly not limited to, PV DG, will be able to be actively considered in the CAISO's transmission planning processes going forward. However, as the old expression goes, "the devil is in the details."	Thank you for the comments, and they will be considered in the steps the ISO plans to take in 2013.

		The CAISO needs to begin – as soon as possible -- an energetic and proactive engagement with stakeholders that will ultimately result in the CAISO's promulgation of a set of detailed guidelines that will inform stakeholders clearly and precisely what needs to be done in order for particular types of non-wires resources to be counted toward a PTO's resource adequacy requirements. Such guidelines currently do not exist, and it is a matter of urgency for the CAISO to roll up its sleeves and begin addressing how non-wires alternatives can play a real and effective role in meeting the state's energy needs. In his presentation, Mr. Millar stated that the CAISO has no ability or authority to ensure that any proposed non-wires alternative is actually implemented. That statement may be true in a narrow sense, but the fact is that the California Public Utilities Commission (CPUC) has undoubted authority over the actions of the PTOs under its jurisdiction (which PTOs serve the great majority of the customers within the CAISO's balancing area). The CPUC can direct the PTOs under its jurisdiction to take specific steps to expand their respective distribution systems' reliance on energy efficiency, demand-side resources and DG. The CPUC, working closely with the CAISO, will be able to (and should!) develop a set of detailed criteria and counting conventions that will direct the CPUC's jurisdictional utilities to account for such non-wires resources in a way that will allow the energy generated or saved by such resources to be credited to those utilities' resource adequacy requirements. In this regard, an existing problem faced by PV DG where such an effort will be able to make a major difference is the limited amount of "qualifying capacity" toward meeting resource adequacy requirements for which PV DG is currently credited. The current methodologies for assigning " capacity factors" to PV DG are uniformly backward looking, and simply do	

		not assign any significant amount of capacity credit for DG PV resources. This needs to change, and several well-respected studies, including one by Energy + Environmental Economics (E3),[4] have proposed methodologies which would allow for the development of a more reasonable capacity factor for PV DG by aggregating PV systems for which there are hourly generation data into groups with similar characteristics. Moreover, even though the actual capacity factor that should be assigned to PV DG is significantly higher than is currently the case, the CAISO also needs to recognize the fact that PV DG that is coordinated with distributed electricity storage would have a very high capacity factor, especially during peak periods of demand within the state. Moreover, such PV DG plus storage systems can be sited strategically, so as to dramatically assist in meeting local capacity requirements. Such systems, because of their inherent flexibility, will also overcome the utilities' traditional concern about the need for "limits" on the amount of PV that can be installed on any given distribution circuit. Most importantly, perhaps, such systems can be installed and brought into operation in a fraction of the time needed to design, permit and build a new transmission line. Specific, detailed criteria to facilitate and expand the opportunities for such advanced distributed resources need to be vetted with the CAISO's stakeholders. Ultimately, such criteria should be approved by the CPUC as directives to its jurisdictional utilities, and should also be incorporated into a chapter of the CAISO's Business Practice manual, so that all entities who seek to have California rely on a more robust set of local, renewable resources in order to help meet the state's clean energy goals will know exactly the steps to follow in order to help bring those goals into a reality.	

[4] See, *e.g.*, *Net Energy Metering (NEM) Cost-Effectiveness Evaluation*, prepared for the CPUC, January 2010.

		The key to this effort will be a thoroughgoing reform of the existing, somewhat opaque counting conventions that are used in connection with the evaluation of PV DG (as well as energy efficiency and many demand-side resources) as an "alternative" to transmission or to more traditional (although polluting) dispatchable resources. The pressing need for such reform is demonstrated by the comment in Mr. Millar's presentation to the effect that "[u]tility-connected distributed generation from CPUC/CEC provided renewable generation portfolios" is "currently difficult to model due to lack of certainty about location." Again, Mr. Millar's statement may be true in the narrow and limited sense of how things are done today. However, with the widespread deployment of "smart meters" throughout California, it should already be quite easy for the utilities to identify both the location and the extent of small-scale PV resources. The utilities also have sophisticated records of their customers' use of electricity over time. Given this existing information, it should be relatively easy to develop data sets, aggregated by the areas into which the utilities' service territories are divided, that can be modeled to show with a high degree of reliability the amount of PV DG that is actively serving load in those areas. Similarly, it should be reasonably easy for the CAISO, working with the utilities, to develop similar data sets to identify the capacity of PV DG at the nodes where the transmission system meets the distribution system and for the utilities to aggregate installed PV DG that is contributing to overall system capacity needs by node. Moreover, with the addition of distributed storage within the utility's service territories, the generation provided by PV DG should be able to treated as firm capacity, or something very close to it.	
32	Mark Higgins,	PG&E supports TBC's proposed solution, assuming that it is technically feasible, to address a Category D contingency resulting in a citywide	The ISO appreciates the comments and will give consideration of in the assessment of the San Francisco Peninsula area reliability concerns in

	Pacific Gas & Electric	blackout in San Francisco. Given the large population and economic importance of San Francisco to California's economy, it is critical that the city of San Francisco quickly regain power to ensure that vital public services can function in an emergency, and that the region's economy isn't harmed by a prolonged blackout. Given the important and urgent nature of the problem, PG&E urges the ISO to approve both the TBC Dead Bus Energization solution and the Moraga-Potrero solution in the 2012-2013 TPP Planning Cycle. Without additional transmission into the city, such as the proposed Moraga-Potrero solution, the TBC proposed solution is at best a partial interim fix because: • Re-energization of TBC would only provide enough power to serve less than half of San Francisco's load while the Category D contingency remains, which could be for a long period; • It's unclear how long re-energization of TBC, assuming it is technically feasible, could take without AC reference bus voltage and frequency support from PG&E's system; and • The technology proposed by TBC is not yet proven. Moreover, the two solutions are highly complementary: • Dead bus start capability for TBC provides an important interim solution to San Francisco's reliability problem, and PG&E's proposed Moraga-Potrero solution more comprehensively addresses the reliability problem in the long run. • AC support from Moraga-Potrero will ensure that TBC can operate at full capacity while the contingency remains. • When combined with TBC, PG&E's proposed Moraga-Potrero solution will allow almost all of San Francisco's load to be served under a Category D contingency. • Virtually all electric service to the city could be restored within	the development of the draft Transmission plan.

		hours once Moraga-Potrero is operational. In summary, due to the critical and urgent nature of the problem, PG&E urges the ISO to approve both an interim and comprehensive solution to the problem. Moreover, PG&E believes it is imperative that action is taken to approve both solutions in the current cycle of the Transmission Planning Process.	
33	Karen Shea & Garry Chinn, Southern California Edison	SCE submitted four projects in the CAISO request window and provided a presentation on these projects on September 27; the presentation may be found on the CAISO website at http://www.caiso.com/Documents/SCE2012-2013ProposedSolutions.pdf. These projects are designed to address reliability needs with Huntington Beach units 3 & 4 retired and the potential continued unavailability of San Onofre Nuclear Generating Station units 2 & 3. Per Section 24.4.10 of the CAISO Tariff, transmission upgrades and addition projects with capital costs of $50 million or less can be approved by CAISO management and may proceed to permitting and construction prior to CAISO Board approval of the transmission plan. SCE requests CAISO management approval of the three projects that are less than $50 million (Barre – Ellis 230 kV Reconfiguration, Johanna & Santiago 230 kV Capacitor Banks and Viejo 230 kV Capacitor Banks) as soon as practical so that SCE can proceed with these projects expeditiously to address reliability needs identified in 2013. SCE looks forward to reviewing the CAISO's posting of the draft transmission plan in January 2013 and working with the CAISO on any next steps regarding the projects SCE has proposed in the request window.	The ISO has included these projects in the 2012/2013 Transmission Plan for approval.
34	Huang Lin, San Diego Gas &	1) ISO presentation slide #190 indicated the TL 631 overloads for the contingency loss of TL 632 in year 2014. This reliability violation might have been a result of ISO's power flow case modeling incorrect line	The updated model was received from SDG&E and is now reflected in the updated study results.

	Electric	impedance for the TL631. SDG&E will provide updated line impedance data to the CAISO to verify the results.	
35	Huang Lin, San Diego Gas & Electric	2) ISO presents some system reliability reinforcement for the near term no-SONGS scenario, however did not exhibit any long term solution that would address the shortage of MW and MVAR if SONGS are permanently out-of-service. Is it ISO's vision that SONGS will only be out of service **temporarily**? If not, reliability projects that are urgently needed, such as synchronous condensers or bulk power transmission lines, all require long-lead time and need to have ISO's approval in a timely manner.	Comprehensive plan will include a discussion on this matter and will address the concerns.
36	Huang Lin, San Diego Gas & Electric	3) ISO typically limits its reliability study only to the compliance of NERC, WECC, and CAISO reliability criteria, and approves projects only to the extent of mitigating Category B violations **if** there is **no** generation re-dispatch available. SDG&E urge ISO to look beyond the minimum reliability criteria requirement and take into account: i) the possibility of loss of critical / major loads, value of service; ii) the cost and operation constraints associated with re-dispatch of generation; iii) the possibility that a single major improvement may mitigate the need for multiple small or incremental upgrades, avoid the risk of making multiple upgrades to the same facilities, and result in a net savings to ratepayers.	The ISO will consider this comment while finalizing the recommendations in the comprehensive plan.
37	Huang Lin, San Diego Gas & Electric	4) ISO presentation slide #224 indicated ISO's interest in examining non-transmission alternatives to address the transmission reliability issue; then on the following slide indicated "ISO has no ability or authority to ensure that any proposed non-wire alternative [NWA] is actually implemented". Question and comment are: i) How does ISO evaluate the level of the commitment that the NWA will actually materialize on time; ii) the ISO needs to provide the analysis supporting its determination that a NWA is preferable to a wires alternative. This analysis is needed to support the PTO's efforts to secure the applicable regulatory approvals of, and cost	The ISO relies on transmission planning standards and available information regarding project status while evaluating non-wire alternatives. The ISO would include documentation regarding the basis for all assumptions associated with any non-wire alternative.

		recovery for, the NWA.	
38	Huang Lin, San Diego Gas & Electric	5) Unlike last year, ISO no longer has a separate submission window for policy driven and economic projects. It appears all proposed projects have to go in the same reliability window. What are the criteria to differentiate the policy driven/economic projects from the reliability projects? Stakeholders need a clear definition.	In 2009, the ISO initiated a stakeholder process to design the needed changes, and in June 2010 filed tariff amendments with the Federal Energy Regulatory Commission (FERC) to implement the needed changes. The FERC approved RTPP tariff amendments on December 16, 2010, and the amendments went into effect on December 20, 2010. At this time, ISO solicitation for economic projects that have not been identified as needed in the comprehensive transmission plan, was eliminated. Section 4.4.1 of the ISO Transmission Planning BPM describes the projects that are accepted through the Request Window. In short they are proposed solutions to reliability problems identified and posted on the ISO website on August 15 every year. Policy and economically driven transmission elements are identified as needed in approximately March in the annual ISO comprehensive transmission plan. Then during Phase 3 of the ISO planning process, the ISO solicits proposals for policy and economically driven transmission projects identified as needed. Link to Transmission Planning BPM: http://bpmcm.caiso.com/Pages/BPMDetails.aspx?BPM=Transmission Planning Process
39	Huang Lin,	6) In order to comply with TPL-002 and TPL-003, SDG&E must present a	When the lead time for a transmission project identified as the expected

	San Diego Gas & Electric	project or operating procedure to remove identified overloads. The ISO has stated that they will re-evaluate certain projects in future planning cycles without stating what will be re-evaluated. To be compliant, the ISO should accept SDG&E's project and state that it will be re-evaluated in subsequent planning cycles.	mitigation plan is short and the need date is in the long-term horizon, the ISO concurs with the need for mitigation of such issues and will evaluate the final mitigation solution in future planning cycles. Detailed implementation plans for such projects are not needed, and can be developed in a subsequent planning cycle.
40	Robert Jenkins & Orville Plum, Silicon Valley Power (SVP)	At the September 27th CAISO Stakeholder's Meeting, PG&E presented a proposal for a project named ***NRS-Scott No. 1 115 kV Line Reconductoring***. SVP strongly supports this project. This circuit is one of the two circuits of the approximately two mile double circuit line 115 kV that terminates at Silicon Valley Power's Northern Receiving Station (NRS) and Scott Receiving Station (SRS). The CAISO's Annual Assessment indicates *Category B* loading violations for multiple single contingencies beginning in 2014. Additionally SVP has identified *Category C* contingencies that result in heavy overloads on this line that were not identified in the annual assessment.[5] Such *Category C* contingency violations lend further support for the need to upgrade this facility. This line has already been reconductored in 2005 with 477 ACSS conductor. As such, installing a higher capacity conductor may involve significant tower work. Additionally this line transverses a congested urban area and crosses Highway 101. Given the continued increase in line loading that has resulted in the need for new reinforcements so soon following the completion of the last upgrade and the challenging conditions surrounding this line, SVP highly recommends that the No. 2 circuit be	The ISO appreciates the comments and the ISO will consider this comment while finalizing the recommendations in the comprehensive plan. The ISO will continue to coordinate issues related to adjacent systems to assess overlapping outages in both areas.

[5] The most severe of these Category C overloads is the overlapping loss of the Los Esetros - Nortech 115 kV (branch 35658 to 35659) and the NRS 115/60 kV transformer (branch 35851 to 36892). This contingency causes flows on the NRS-SRS #1 115 kV line in excess of 139% of the emergency rating (1,144 amps). SVP recently notified the CAISO and PG&E of this discovery.

		upgraded at this time as well. Given the overloads identified in the 2014 CAISO base case associated with this line, SVP recommends that the operative date for these upgrades be advanced to Summer 2014. Lastly, SVP has been working with PG&E concerning potential improvements to the SVP transmission facilities in this area. We look forward to continued cooperation with both PG&E and the CAISO in coordinating the upgrades to both systems.	
41	John Yarbrough or Aseem Bhatia, California Department of Water Resources - State Water Project (SWP)	SWP believes the planning process; including inputs, studies, and results; needs to be consistent with the guiding principles of transparency, stakeholder participation, and clarity; and appreciates CAISO's attempt to apply these principles in the current planning process. SWP also supports CAISO's efforts to improve grid reliability through consideration of both physical transmission and transmission alternatives, such as RAS, in certain cases. With either alternative, CAISO should evaluate the short-term and long-term impacts to the affected systems, entities, and paths in order to assess and inform stakeholders of the benefits of each alternative. As part of CAISO's consideration of transmission alternatives, CAISO should also explore compensation mechanisms to support such alternatives. The September stakeholder meeting presented several Policy Driven Power Flow and Stability results with ovmeiererloads that could benefit from either physical transmission or transmission alternatives, and SWP supports CAISO's efforts to refine these studies and identify any supporting mechanisms in the Transmission Plan. During the stakeholder meeting CAISO staff indicated that, based on the results of PG&E's Bulk Power (Dynamic Stability) modeling for the 2017 and 2022 peak base cases, a 3-phase fault on the Midway 230 kV system	In the 2012-2013 Transmission Plan, the ISO assessment included studying contingencies per the reliability standards. Detailed evaluation of the ISO transmission system was needed due to continuous load growth that may bring some transmission facilities closer to their operational limits, as well as due to many renewable generation projects interconnecting to the ISO and replacing conventional generation. While three-phase faults on the 230 kV transmission system may appear less critical than 500 kV faults and probability of their occurrence is perceived to be low, the 2012-2013 Transmission Plan included transient stability studies of three-phase faults on the major facilities, including Midway 230 kV bus and transmission lines connected to this bus. The studies showed transient voltage and frequency concerns that may occur with three-phase faults at the Midway 230 kV bus or in its vicinity. The source of the issues is a large transient voltage dip at the Wind Gap # 2 pumps (Wind Gap pumping plant is located farther from the Midway Substation than the other pumping plants connected to it) that may lead to oscillations. This became an issue due to higher system load and lower voltages, especially when some of generation units connected to the Midway Substation are not generating, thus not providing much needed reactive support.

		could potentially cause multiple issues for CDWR's Wind Gap Pumping Plant's pumps. Because CDWR has not made any changes or increases to Wind Gap pump load since initial operation, CAISO needs to clarify the sources causing these issues so that they and the impact on SWP operations are better understood by CDWR. In clarification, CDWR also questions if these same or similar issues impacting CDWR's Wind Gap pumps been identified in previous Transmission Planning Process studies? If not, what new changes have occurred and/or different modeling assumptions have been made in the 2012/2013 studies that currently identify these new issues? CAISO indicated "no solar PV" in one of the plots for the 2022 peak case. If a photovoltaic solar facility was to be interconnected to the Midway 230 kV system, please clarify whether or not these issues could potentially occur sooner than PG&E anticipates by 2022.	Mitigation of these concerns will be assessed in the draft Transmission Plan. Regarding impact of the photovoltaic solar PV on the transient stability concerns at the Wind Gap pumps, the studies have indicated that these projects are not expected to exacerbate the issues; and on the contrarythe transient voltage dip was not as large with the solar PVdepending on howthe thermal plants at Midway are generating and providing dynamic reactive support.