California Wind Energy Association

CalWEA

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California Energy Commission
Docket Office, MS-4
1516 Ninth Street
Sacramento, CA 95814-5512
Via docket@energy.state.ca.us

Re: Docket No. 11-IEP-1G - *Draft Renewable Power in California: Status and Issues*

Dear Commissioners and Staff,

I appreciated the invitation to participate in the September workshop to discuss the staff draft report *Renewable Power in California: Status and Issues* ("Staff Draft Report"). These comments recount the remarks I made at the workshop, and elaborate on my responses to questions posed to me by two Commissioners. Our comments do not address the document comprehensively, only some of the areas in which we are currently focused.

1. **Water Impacts.** The report references all renewable energy technologies as posing concerns for water supplies and waterways (see, e.g., p. 8). Of course, wind energy projects require very little water, and the water requirements of solar photovoltaic projects are also limited (as indicated in footnote 111). This fact should be noted as a major benefit of these technologies.

2. **Technical Wind Potential.** It appears that the draft report has not sufficiently taken into account the low-wind-speed turbines that are already coming onto the market, which can economically tap lower wind speeds.[1] Accounting for lower wind speeds across the state, along with the new technologies, greatly expands the land area that is suitable for commercial development, and thus the technical potential for wind in California.

3. **Integration Issues.**

   (a) **Tell the good-news story that new resources, including storage, are not needed to integrate 33% renewables.** The timeframe that the staff report is addressing is not clear, although it appears to be aimed at least partially at the 2020 timeframe relevant to the 33% RPS goals. When the Staff

[1] See, e.g., http://www.nrel.gov/wind/pdfs/37934.pdf; http://www.windpowermonthly.com/news/1071446/GE-launches-16-100-low-wind-speed-turbine/; http://news.cnet.com/8301-11128_3-10233108-54.html; and http://business380.com/2011/07/01/low-wind-speed-turbine-being-developed-by-clipper/.

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Draft Report says, therefore, that "Maintaining a reliable electricity system while adding …variable resources will require energy storage" (among other things; emphasis added), it gives a false impression with regard to the 2020 timeframe that should be corrected. Likewise, statements such as "new technologies [supported by R&D] will be crucial to integrating renewable technologies into the grid" (emphasis added) exaggerate the situation in the 2020 timeframe, and potentially well beyond.

As the significant studies conducted this year by the California Independent System Operator (CAISO) and the utilities have shown, the gas plants operating on the system now can handle the integration of 33% renewables.[2] Indeed, we can safely retire a large fraction of the coastal once-through cooling units while we're at it. That's a "good news" story that should be told in this document. Although new storage and new technologies ultimately will be helpful to integrating high penetrations of renewables, the facts to not support the assertion that they must be developed in order to successfully integrate 33% renewables.

(b) Highlight the financial needs of existing gas resources to meet new circumstances. The report should also highlight the as-yet-unmet financial needs of the existing gas generators that will have to operate at much lower capacity factors as they provide the litany of integration services that the report discusses. (Describing the services in great detail without mentioning that the capability to provide these services exists also could leave the misimpression that additional capabilities are needed.) The report discusses an unfounded need to set goals for storage technologies within the 2020-timeframe -- and many related workshops have been held, but it does not address the relatively small and inexpensive steps that need to be taken to keep existing gas generators on line and the importance of addressing this issue soon.

It would be very inefficient to allow existing gas units to shut down for lack of payment for their integration services, while mandating new storage units that would be much more costly.[3] As we look toward adopting a new cost-containment approach for the 33% RPS, we must look to minimize all related costs. One way is to take advantage of the system resources we have, and use them efficiently. Currently, we are flush with gas-fired pipeline, storage and generating capacity -- we do not have any near-term need for electricity storage per se, which in any case should compete with gas resources to provide the integration services we need at least-cost.

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[2] A settlement among the parties in the CPUC's long-term planning proceeding states that the results of these studies "show no need to add capacity for renewable integration purposes above the capacity available in the four scenarios for the planning period addressed in this LTPP cycle (2012-2020)." See http://docs.cpuc.ca.gov/efile/MOTION/140823.pdf.

[3] This is not to say that the electric power industry could not have efficiently adopted storage resources decades ago to better utilize industry assets (asset utilization has traditionally been at around 40% only), instead of adding more fossil fuel generation capacity. Storage has important advantages in meeting system flexibility needs (whether due to integration of more renewables, increases in system load, or continued inflexibility of nuclear resources, etc.). However, given the fact that we have excess existing gas generation resources on the system, we can use these assets to address flexibility needs at significantly lower cost on a per-MW basis than adding new storage. When new resources are needed to address system flexibility needs, storage resources should be considered along with other options and may prove to be the best option.

(c) Highlight the need to efficiently operate the system overall (do not perpetuate the myth that intermittent resources "need back up"). In that same vein, the section on wind energy (p. C-8) continues to perpetuate the false notion that wind energy in particular "needs back up" or "needs storage". In this and other instances, the staff report should be reoriented to promote the accepted idea (as evidenced in the CPUC's LTPP proceedings) that the grid's resources can and should be operated together in an efficient and effective way. While clearly California needs to make relatively low-cost technical improvements in operations such as improving the accuracy of forecasting and creating markets that operate closer to real time – and the report does appropriately address these – they should be placed in the context of an integration challenge that is wholly manageable over the next 10 years and potentially beyond.

Another useful point of context that should be provided in the report is the fact that load, as well as all conventional generation resources, also require flexibility services – not the least being the nuclear power plants, one of which was shut down for nearly four days following the September 8, 2011, blackout triggered in Yuma, Arizona, and affecting the San Diego area. Meanwhile, renewable generators were producing.

(d) There is no need for substantial curtailment of renewable resources through 2020. The Staff Draft Report (at p. 129-130) quotes a CAISO proposal to limit future entry into its scheduling program for intermittent resources (the Participating Intermittent Resources Program, or PIRP) as stating that "[o]perational conditions that require curtailment of renewable energy are expected to increase in magnitude and frequency, particularly overgeneration in spring high hydro, light load conditions, but possibly other times as well" and that the "current self-scheduling rules of the PIRP do not favor economic dispatch that can accurately determine the most efficient amount of each resource to resolve overgeneration conditions…"

Since the Staff Draft Report was written, the CAISO has withdrawn its proposal to eliminate PIRP, apparently recognizing CalWEA's arguments that: (1) no need has been demonstrated for large quantities of curtailments through 2020; and (2) the small amount of curtailments that may be needed can be readily addressed through the physical and economic curtailment provisions in power purchase agreements (PPAs).

The CAISO's studies looking at the integration of 33% renewable energy scenarios (see footnote 2) did not demonstrate a need for large quantities of additional curtailments. As indicated in a CAISO staff memo to the CAISO board, the studies indicated a maximum need for up to 800 MW of downward flexibility under the CAISO's "High Load" scenario, and less (or none) under four CPUC scenarios studied.[4] This 800 MW is a very small amount of additional downward flexibility compared to the 15,800-19,100 MW of intermittent under the different scenarios considered. Moreover, even the High

[4] See August 18th, 2011, memo (Table 1 and footnote 2) to the Board from CAISO VP of Market and Infrastructure Development Keith Casey at http://www.caiso.com/Documents/110825BriefingonRenewableIntegration-Memo.pdf.

Load scenario shows the need for such large amounts of downward flexibility only for about 11 hours a year.

This need for downward flexibility can readily be met through the terms of the power-purchase agreements (PPAs) executed by the large investor-owned utilities (IOUs), if that need is not met by other resources. PPAs have always provided for physical curtailment when ordered by the CAISO, and the CAISO has such curtailment rights under the tariff (and through the Participating Generator Agreement that all generators have to sign) to maintain reliability regardless of their inclusion in any PPAs. In addition, the pro forma contracts recently approved by the CPUC in D. 11-04-030 (at pp. 13-20) for all three of the large investor-owned utilities include economic curtailment rights (i.e., ability for the IOU schedulers to offer economic bids in their RPS contracts). As requested by a Commissioner and by a CAISO representative at the workshop, we summarize these pro forma contract terms in the footnote below.[5]

Based on the estimated amount of renewable resources needed to comply with the 33% RPS requirement and the pro forma contract provisions adopted by the CPUC in 2010, CalWEA estimates that the IOUs will have at least 5,000 MW of renewable energy capacity under contracts that specifically provide the buyer with substantial rights to economically curtail deliveries. These curtailment rights – likely to be implemented through economic bids to the CAISO – are exercisable for many times the small number of hours that CAISO studies show additional flexibility to be needed.

The figure below presents these facts, demonstrating that the relatively small amount of curtailment anticipated to be required in 2020 can readily be met by the terms of the RPS contracts.

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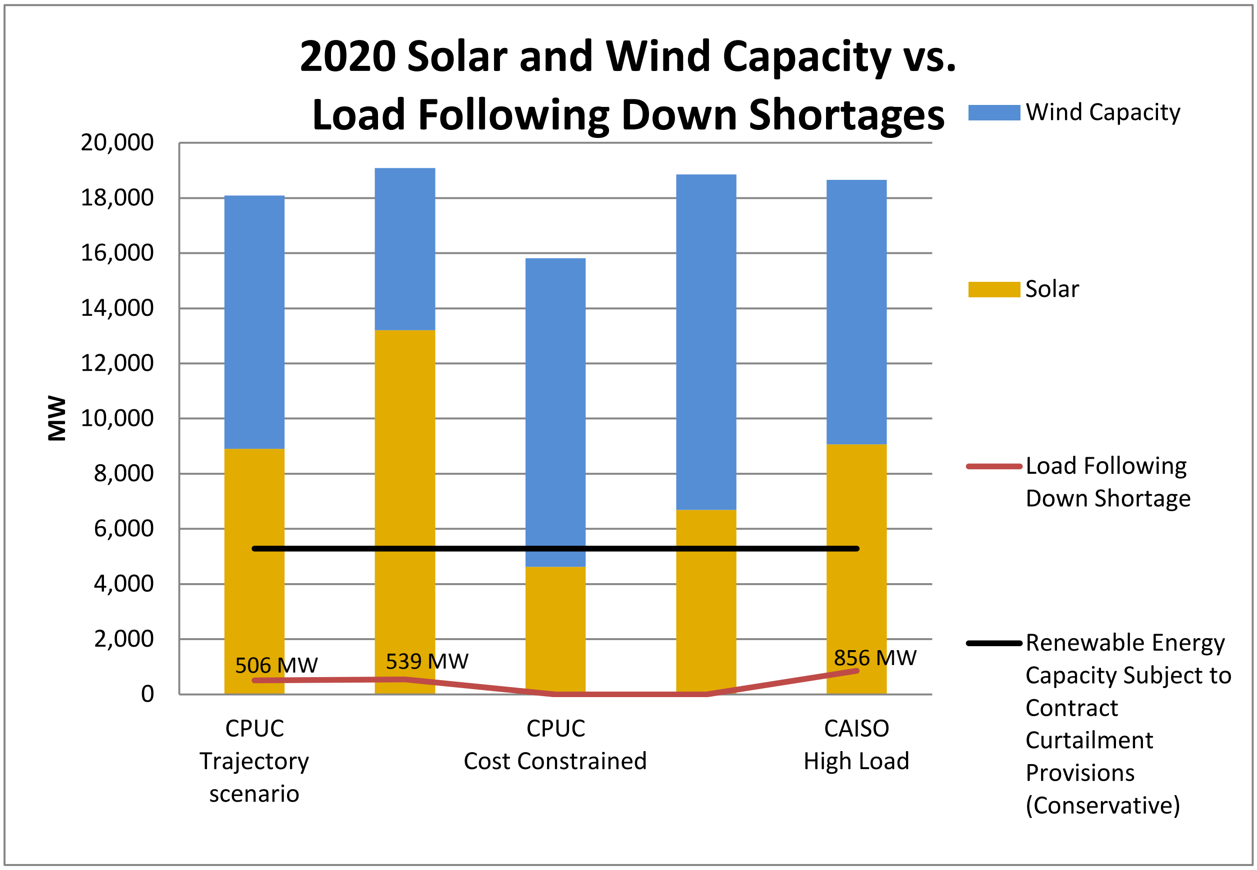
[5] Economic Curtailment Parameters Under 2011 pro forma RPS Power Purchase Agreements:

- PG&E has the right to curtail for any reason up to a negotiated number of hours (PG&E requests minimum of 250 hours), with Seller compensated for curtailed energy at negotiated prices for (1) the first 150 hours of curtailment (PG&E proposes this amount be capped at Contract Price), (2) 151st to 250th hours of curtailment, and (3) hours of curtailment in excess of 250, up to the negotiated cap.
- Seller is required to curtail if no schedule is awarded in either the Day-Ahead or the Real-Time CAISO markets, or if SCE issues an OSGC Order or RTOSGC Order (which is essentially an instruction to curtail output to the level specified in the CAISO Day-Ahead or Real-Time Schedule, respectively). There is no limit on the volume of curtailment; however, SCE will pay the TOD-adjusted Product Price (plus lost PTCs if elected by Seller in the PPA) for Curtailed Product, except that SCE will not pay for Curtailed Product when all three of the following conditions are met: (1) no schedule is awarded, (2) the applicable CAISO price is negative, and (3) the aggregate Curtailed Product for the year is less than the Curtailment Cap (a negotiated annual volumetric limit on "free" curtailment equal to the product of the Contract Capacity and 50, 100, or 150 hours).
- SDG&E has the right to curtail for any reason up to a cumulative curtailed energy volume of not more than 5% of the Contract Quantity (typically equal to the expected annual energy production) per Contract Year, with Seller compensated for curtailed energy at a rate equal to the sum of the TOD-adjusted Energy Price and the lost PTCs, less the Sales Price (i.e., the price for which Seller was able to re-sell the curtailed energy to a third party).



4. Transmission Planning Issues.

(a) A little proactive planning would go a long way. The staff report suggests that additional transmission capacity is not needed to meet the 33% RPS goals beyond that which is already being planned and built, such as the Tehachapi and Sunrise lines. That is no doubt technically true, but further strengthening the state's transmission infrastructure will promote much greater competition in the renewable energy market. Because transmission is a relatively small component of our electricity bill (or at least should be – see below), and generation a much larger component, promoting a more competitive market by removing transmission barriers will pay for itself, while also laying the groundwork to achieve RPS goals higher than 33%. (We believe that the soon-to-be-in-service Tehachapi, Sunrise and DPV2 lines significantly contributed to the very strong market response to the utilities' most recent RFOs.)

The report credits the CAISO's 2010-11 transmission plan as having produced "policy-driven upgrades," authorized by the FERC when it approved a new CAISO tariff provision in 2010 enabling pro-active transmission planning to facilitate the achievement of state policy goals. We disagree: virtually all of the upgrades included in the 2010-2011 plan were already being planned for – some were even under construction -- prior to development of the plan, so very few can be said to have been facilitated by the new policy planning tool.[6] The new tariff provision enables the CAISO to resolve traditional problems– insufficient reliability and economic bottlenecks -- in a way that simultaneously removes transmission barriers that exist under a variety of renewable energy development scenarios – so-called "least-regrets" planning.

Under a least-regrets plan, we would expect to see many of the transmission elements that were included in the 2010 Conceptual Transmission Plan produced by the Renewable Energy Transmission Initiative (RETI) because, while the RETI analysis did not simultaneously consider system reliability and economic needs, it did identify the transmission upgrades that are common to a variety of renewable development scenarios (rather than "prioritizing CREZs" as RETI was initially conceived). This important principle, and the RETI Conceptual Plan itself, should be included in the description of RETI on page 91. (We reproduce a portion of the plan, below.) The 2010-11 CAISO plan, however, had little in common with the RETI conceptual plan; in particular, the CAISO plan did not address north-south bottlenecks between load centers in central and northern California and desert renewable energy resource areas that are now the focus of the DRECP effort (see below).

These are the very upgrades that are now acting as giant market-entry barriers to generators seeking to interconnect to the CAISO's system (other than those interconnecting to previously planned upgrades – Tehachapi , Sunrise and DPV2, or generator-interconnection upgrades that a utility has otherwise chosen to upfront-finance). These fundamental transmission constraints need to be addressed in the transmission planning process so that financial and transmission-timeline burdens are taken off of interconnecting renewable resources all over the state, which would promote generation competition while resolving CAISO queue bottlenecks.

Unfortunately, it is looking like the CAISO is not going to use its new tool to accomplish this type of planning in 2011-2012, either. But we would like to see the staff report encourage them to do so. Otherwise, the opportunity to plan for upgrades that can be completed in the 2020 timeframe will be lost.

A Commissioner asked at the workshop whether we should re-start the RETI process. There is no need for that, as the conceptual transmission plan that was produced after an intensive, multi-year stakeholder process which included the CAISO and the utilities, remains relevant. Were the CAISO to conduct an appropriate least-regrets planning effort, we would expect it to produce a very similar plan.

(b) Planning standards for transmission should be rationalized. We completely agree with the comment made by CPUC Energy Division Director Julie Fitch at the workshop that the planning standards for transmission upgrades need to be optimized. This is particularly true in the generator interconnection process, where the CAISO currently designs "delivery network upgrades" to meet very rare system conditions – essentially, contingency conditions that might arise, literally, once every several thousand

[6] For more information, see CalWEA's comments at: http://www.calwea.org/pdfs/publicFilings2011/CalWEA_Comments_CAISO_2010-11_Transmission_Plan_(April_20_2011).pdf.

years. The result is that generators are being burdened with enormous market-entry barriers from over-designed, extremely expensive upgrades whose costs are ultimately paid for by utility customers.

Instead, the CAISO should seek as much as possible to address transmission system constraints posed by interconnecting generators with operational solutions (such as congestion management and system protection schemes), and plan major upgrades through the transmission planning process using least-regrets principles. In that process, reasonable contingency conditions should be applied using a probabilistic (vs. deterministic) approach.[7] This approach would save utility customers substantial amounts of money both directly in transmission upgrade costs and indirectly through the savings that would accrue from greater competition among generators.

Another example of setting unduly conservative standards is the "exceedance" approach that the CAISO proposed for determining the "net qualifying capacity" (NQC) of intermittent resources, which was subsequently adopted by the CPUC in modified form. The deterministic approach produces a much lower NQC value for intermittent resources than does the probabilistic "effective load carrying capacity" (ELCC) approach (which, unlike the "exceedance" approach, has a solid foundation in the literature and has been accepted by the North American Electric Reliability Corporation for purposes of counting the qualifying capacity of variable energy resources[8]). The exceedance approach results in greater capacity reserve requirements that consumers will pay for. Consumer and renewable energy stakeholders filed a request for rehearing of this decision[9] and, in SB 23, the 33% RPS legislation, the legislature directed the CPUC to use the ELCC approach.[10]

(c) Upsizing generation interconnections is not always the right approach. The staff report suggests (at pages 11 and 85) that upsizing the transmission upgrades that are identified in the generator interconnection process could allow greater utilization of the grid, and that the CAISO should be allowed to do this. While some upsizing (such as building a double circuit instead of a single circuit structure) may be efficient, upsizing in general is not the only or necessarily the best way to build transmission ahead of generation. The upgrades identified in the generation interconnection process are usually determined for a cluster of projects, not all of which will necessarily materialize. Upsizing from there absent any indication of commercial viability in renewable development could result in under-utilized transmission assets. Proactive planning in a "least regrets" fashion as described above would plan ahead of generation without pre-judging the worthiness of particular development areas and therefore promote competition among most or all such areas.

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7 This was the conclusion of a special report by the North American Electric Reliability Corporation (April 2009), *Accommodating High Levels of Variable Generation*, which stated: "The addition of significant amounts of variable generation to the bulk system changes the way that transmission planners must develop their future systems to maintain reliability. Current approaches are deterministic based on the study of a set of well-understood contingency scenarios. With the addition of variable resources, risk assessment and probabilistic techniques will be required to design the bulk power system."

8 *Ibid.*

9 See TURN/CalWEA/AWEA/Solar Alliance Application for Rehearing of CPUC Decision 09-06-028, available at: http://www.calwea.org/pdfs/publicFilings2009/Application-of-TURN-CalWEA-AWEA-SA-for-Rehearing-of-D-09-06-028-in-Phase-2-of-R-08-01-025.pdf.

10 See amended PU Code Section 399.26 (d).

5. **DRECP & Related Transmission.** CalWEA is an active participant in the Desert Renewable Energy Conservation Plan (DRECP) process and we have high hopes for this process preserving sensitive desert ecosystems while streamlining and expediting the permitting process for renewable energy projects, which can take up to 10 years and cost $10 million per project, uniquely in California. The goal of permit streamlining is not mentioned in the Executive Summary section on the DRECP, but should be, as it is one of the dual purposes of the plan.[11]

   With regard to developing transmission in conjunction with the DRECP effort, it is important to understand that strengthening the backbones of the state's grid, including areas well <u>outside</u> of the DRECP boundary, can facilitate development within the DRECP area by removing transmission constraints to load centers. As noted above, a very important principle that evolved out of the RETI process was that, in planning transmission, we need not, and indeed should not, attempt to predict or select particular areas for renewable energy development (because it is impossible to make such predictions accurately and fairly at such a high level). Rather, we should build up the foundation of the transmission system in a way that facilitates any one of a number of possible development scenarios.

   A similar principle seems to be taking shape in the DRECP process; namely, that the DRECP process should, for the most part, avoid dictating where renewable energy projects should or should not be built because it will not be possible, in a planning process that covers tens of thousands of square miles, to understand the many site-specific factors that will determine the ability to develop an energy project at a particular site. Instead, there seems to be growing agreement that the desert renewable energy plan should indicate areas of lesser and greater environmental sensitivity, along with associated conservation/mitigation ratios, which will provide incentives for developers to focus on the areas of lesser concern. If a developer should choose to pursue a higher-impact area, the higher mitigation requirements would be warranted by superior site characteristics (e.g., resource quality, proximity to transmission lines, avoidance of military radar interference, and willing land owners).

   Given what we have learned in the RETI process and are learning in the DRECP process, it is not necessary, as the Staff Draft Report states in Chapter 4 and elsewhere, to have "a fully coordinated" transmission and land use planning process. It is sufficient to coordinate enough to improve transmission access between the general areas of high-quality renewable resources and load centers. Beyond that, we can allow siting and transmission processes to play out separately.

   As it happens, the RETI conceptual plan would build up transmission in the Western Mojave area that the Commission expressed particular interest in based on the DRECP process.[12] See the RETI conceptual plan for Southern California, reproduced, below. We encourage the Commission to promote "least regrets" transmission planning broadly, as described above, rather than advocating the development of specific

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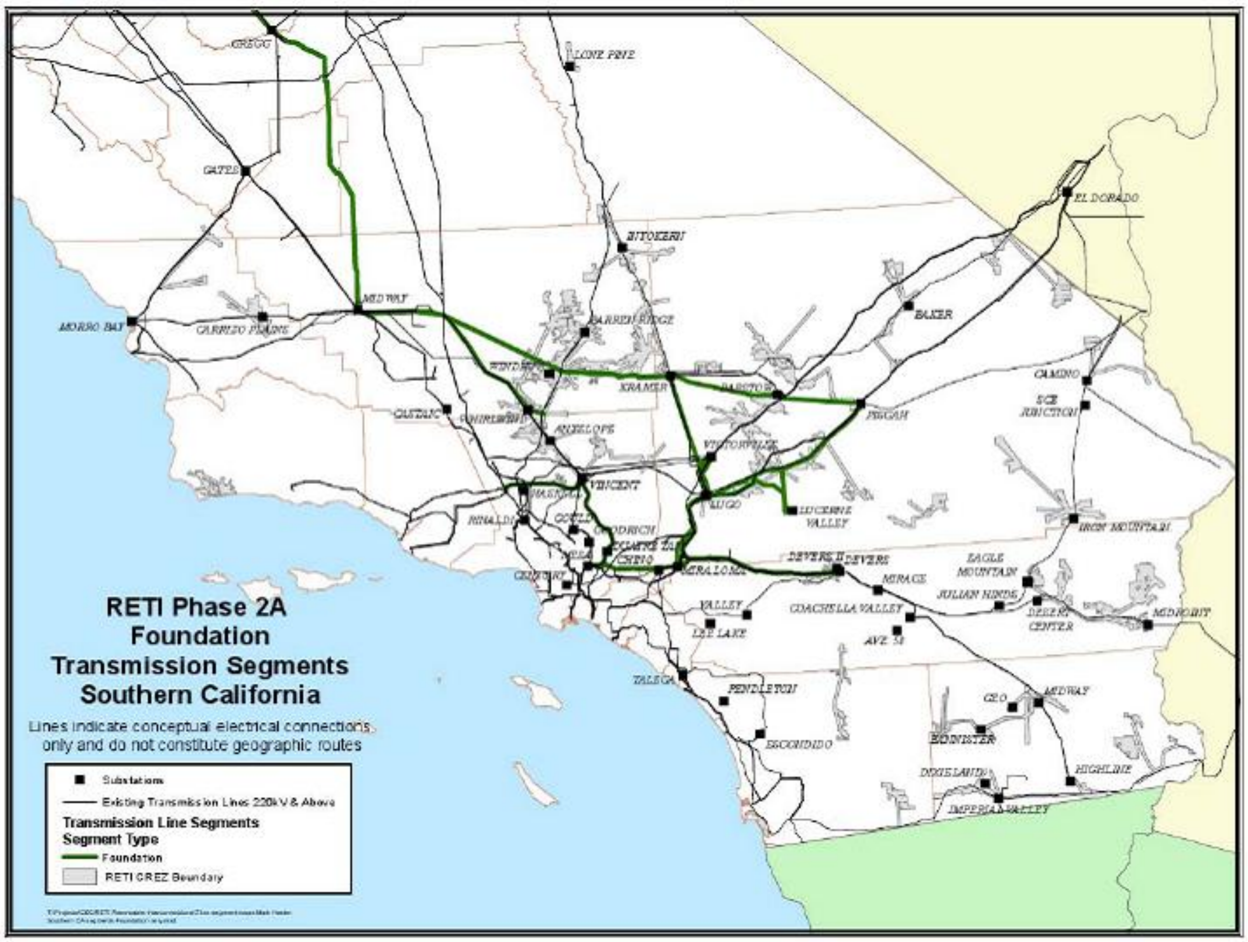
[11] See, e.g., the May 2010 DRECP Planning Agreement, which states "The REAT's primary mission is to streamline and expedite the permitting processes for renewable energy projects, while conserving endangered species and natural communities at the ecosystem scale. Executive Order S-14-08 directs the REAT to achieve these twin goals in the Mojave and Colorado Desert regions through the DRECP."

[12] See July 15, 2011, CEC letter to the CAISO referenced in Staff Draft Report footnote 55.

areas (particularly in the relatively early stage of the DRECP analysis process that we are still in). The state should "dust off" the RETI plan in which it invested significant resources, encourage the CAISO to integrate that plan as part of a robust least-regrets analysis, and then implement that plan within the 2020 timeframe.



Thank you again for inviting CalWEA to participate on a panel to discuss these issues. We would welcome any additional questions on these comments.

Sincerely,

Nancy Rader

Nancy Rader
Executive Director