Transmission and Renewable Energy Planning In California: Opportunities for Regional Stakeholder Engagement

WESTERN GOVERNORS' ASSOCIATION

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List of Acronyms

AB – Assembly Bill
ACR – Assigned Commissioner Ruling
ARRA – American Recovery and Reinvestment Act
BLM – Bureau of Land Management
BPA – Bonneville Power Administration
CAISO – California Independent System Operator
CARB – California Air Resources Board
CBA – California Balancing Authority
CEC – California Energy Commission
CEQA – California Environmental Quality Act
CPCN – Certificate of Public Convenience and Necessity
CPUC – California Public Utilities Commission
CREPC – Committee on Regional Electric Power Cooperation
CREZ – Competitive Renewable Energy Zone
CTPG – California Transmission Planning Group
DAWG – Demand Analysis Working Group
DFA – Development Focus Area
DG – Distributed Generation
DNU – Deliverability Network Upgrade
DOI – Department of the Interior
DRECP – Desert Renewable Energy Conservation Plan
EAP – Energy Action Plan
EIS – Environmental Impact Statement
FERC – Federal Energy Regulatory Commission
GHG – Greenhouse Gas
GIDAP – Generator Interconnection and Deliverability Allocation Procedure
GIP – Generator Interconnection Process
GW/GWh – Gigawatt/Gigawatt-hour
LSE – Load-serving Entity
LTPP – Long-term Procurement Plan
IEPR – Integrated Energy Policy Report
IOU – Investor Owned Utility
IRP – Integrated Resource Plan
ITC – Investment Tax Credit
LADWP – Los Angeles Department of Water and Power
MOU – Memorandum of Understanding
MW/MWh – Megawatt/Megawatt-hour
NCPA – Northern California Power Agency
NERC – North American Electric Reliability Corporation
OIR – Order Instituting Rulemaking
OTC – Once-through Cooling
PEIS – Programmatic Environmental Impact Statement
PG&E – Pacific Gas and Electric

POU – Publicly Owned Utility
PPA – Purchase Power Agreement
PTC – Permit to Construct; or Production Tax Credit
PV – Photovoltaic
RA – Resource Adequacy
REAT – Renewable Energy Action Team
REC – Renewable Energy Credit
RESA – Renewable Energy Study Area
RETI – Renewable Energy Transmission Initiative
RFO – Request for Offers
RNS – Renewable Net Short
ROD – Record of Decision
RPS – Renewable Portfolio Standard
SB – Senate Bill
SCE – Southern California Edison
SCPPA – Southern California Public Power Authority
SDG&E – San Diego Gas and Electric
SMUD – Sacramento Municipal Utility District
SPSC – State-Provincial Steering Committee
TEPPC – Transmission Expansion Planning Policy Committee
TPP – Transmission Planning Process
USFWS – U.S. Fish and Wildlife Service
WAPA – Western Area Power Administration
WECC – Western Electricity Coordinating Council
WGA – Western Governors' Association
WREZ – Western Renewable Energy Zone

1. Executive Summary

Western states and provinces are working to develop their abundant renewable energy resources, and nine states in the region require that renewable resources meet a significant portion of consumers' electricity needs. Conversations in the West about renewable energy typically turn toward California, its sizeable renewable energy targets, and the potential benefits associated with broader regional approaches to renewable resource and transmission development.

This report for the Western Renewable Energy Zones (WREZ) project,[1] an initiative of the Western Governors' Association, explains the renewable energy and transmission planning processes in California and where stakeholder input is likely to have the greatest impact on regional development of resources and transmission lines.

The report relies on a thorough review of documents produced by the California Public Utilities Commission (CPUC), the California Independent System Operator (CAISO), the California Energy Commission (CEC) and the state's largest utilities. In addition, the report aggregates information from interviews with renewable energy developers, utility regulators in California and elsewhere, utility representatives, transmission developers and environmental groups.[2]

Based on our analysis of rules, procedures and proceedings for California's renewable energy and transmission planning processes and drawing on the experiences of those interviewed, the report lays out opportunities for stakeholder engagement in these primary venues:

1. CPUC's Long Term Procurement Planning (LTPP) and scenario development process[3] (Chapter 3)
2. CPUC's Renewable Portfolio Standard (RPS) proceeding and annual procurement planning process (Chapter 5)
3. CAISO's Transmission Planning Process (TPP) (Chapter 4)
4. CEC's rulemaking on RPS compliance for the state's Publicly Owned Utilities (Chapter 6)
5. CEC's public workshops on energy demand forecasts developed for the Integrated Energy Policy Report (Appendix A)

Each of these forums yields multiple decisions yearly about where renewable energy will be procured both inside California and in the wider West, and they have an interlocking effect on one another. Tracking the wending nature of these decisions, and casting a spotlight on the most crucial junctures, is a key objective of this report.

The report also relates proposals by interviewees for changes to California's energy and transmission planning processes that could make it easier for stakeholders to

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[1] The WREZ initiative identified areas throughout the West with large quantities of high-quality renewable resources, as well as the transmission needed to deliver them to load centers. In addition, the WREZ initiative undertook an analysis of utilities' and regulators' interest in procuring renewable resources within those renewable energy areas and explored potential improvements to siting processes.

[2] Their views are not directly quoted in the report. Rather, interview subjects were told that information they offered would be used anonymously to help paint an accurate picture of California transmission and energy planning.

[3] Scenario planning in the LTPP process is not intended to be prescriptive of what renewable resources ultimately are procured. However, it may affect which resources are developed to the extent the portfolios are used for transmission planning and thus the ability for projects to meet deliverability requirements.

participate and allow for greater consideration of regional energy and transmission solutions. Chief among the recommendations are the following:

- More stakeholder involvement in particular aspects of the CPUC's LTPP process including the development of renewable resource portfolios
- Continued improvements in accurately valuing the benefits of energy products in a regional market context during the utilities' RPS procurement planning process
- Continued improvements to quantifying resource and transmission costs for the CPUC's RPS Calculator tool used to predict future renewable resource portfolios
- Continued focus at CAISO on regional coordination
- Greater clarity from California policymakers regarding the ability of out-of-state resources to participate in fulfilling the state's renewable energy requirements

2. Introduction

California's renewable energy demand and production are driven by the state's robust RPS, which at 33 percent of retail sales by 2020 is among the highest standards in the U.S.[4] When applied to the state's large retail electric load, California's RPS accounts for two-thirds of the renewable energy demand in the Western Interconnection.[5] This significant demand has attracted the attention of developers throughout the West. In addition, California Gov. Jerry Brown has indicated his view that the RPS is a floor rather than a ceiling on the amount of renewable energy the state could procure, expressing a desire for the state to eventually obtain as much as 40 percent of its electricity from renewable resources.[6]

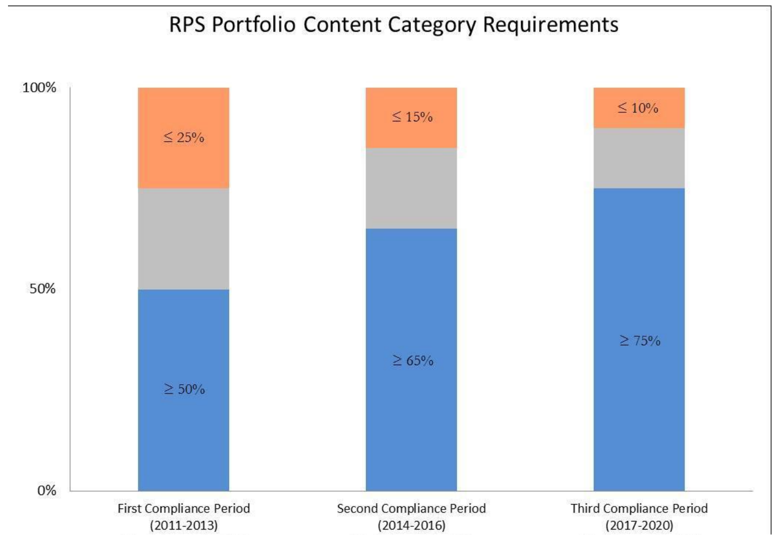

Figure 1. California's 33 percent RPS law places requirements on the amount of renewable energy that can come from each of three categories described in this section. This requirement changes for each of the three compliance periods. (Image Source: CPUC)

In April 2011, Gov. Brown signed into law SB 2 (1x), which increased the state's RPS from 20 percent to 33 percent by 2020.[7] The law for the first time covered all utilities in the state, going beyond Investor Owned Utilities (IOUs) like Pacific Gas and Electric (PG&E), Southern California Edison (SCE) and San Diego Gas & Electric (SDG&E) to include the Publicly Owned Utilities (POUs) such as Sacramento Municipal Utility District (SMUD) and the Los Angeles Department of Power and Water (LADWP), which had previously not formally come under the state's RPS requirements.[8]

SB 2 (1X) also instituted a number of new compliance structures and market rules. The new law set out three distinct, multi-year compliance periods for utilities under the RPS,[9] declared that the CPUC should establish cost containment requirements circumscribing the total amount of money that could be spent to meet the newly increased targets, and required that each utility plan for a "minimum margin" over-compliance of the RPS to ensure renewable energy targets are met.[10]

The most significant, and controversial, of these new features is the creation of three portfolio content categories, or "buckets," which in many respects impact utility

[4] See DSIRE Database of State Incentives for Renewables and Energy Efficiency, http://www.dsireusa.org/documents/summarymaps/RPS_map.pdf.
[5] See Western Electric Coordinating Council 10-year Regional Transmission Plan – Plan Summary, September 2011, Figure 8, http://www.wecc.biz/library/StudyReport/Documents/Plan_Summary.pdf.
[6] See Office of Gov. Jerry Brown, press release, April 12, 2011, http://gov.ca.gov/news.php?id=16974.
[7] See Cal. Pub. Util. Code §399.15; D.11-12-020.
[8] See §399.25.
[9] See §§399.15(a),(b).
[10] See §§ 399.13(a)(4)(D), 399.15(b)(5)(B)(iii).

procurement and in turn where renewable resource development occurs (Figure 1). Under this system, utilities must, by 2020, procure three-quarters of their renewable energy supplies from Category 1 generation projects, along with their renewable energy credits (RECs) – certificates that demonstrate ownership of the environmental and other attributes associated with the RPS-eligible generation. Category 1 projects include those that have their first point of interconnection with a California Balancing Authority (CBA)[11] or a distribution facility serving California customers – essentially projects that can deliver directly to the California transmission and distribution grid. Category 1 also takes in any project that has secured a dynamic transfer arrangement into a California CBA and projects that, while not directly interconnected, can deliver energy to a CBA without substituting any electricity from a source other than the renewable energy project.[13] Though the California grid does extend outside the state in several locations, the requirement that projects essentially have a first point of connection with a CBA means that much of California's RPS will eventually be met by renewable energy projects located within the state's borders.[14]

> **? What is a "Dynamic Transfer"[12]?**
>
> Dynamic transfers move in real-time a designated portion or all of the output of a generator to another area so that the receiving Balancing Authority can manage the intra-hour variability. For example, a wind generator in Montana could be dynamically transferred to California so that the larger CAISO Balancing Authority Area can use its resources for balancing.

After the Category 1 requirement is met, additional RPS energy can come from Category 2 and Category 3 resources. Category 2 includes resources procured from facilities located outside a CBA where firmed and shaped energy provides incremental electricity scheduled into a CBA – that is, resources that cannot be delivered to a CBA without substituting electricity from another source – together with the underlying RECs associated with the renewable generation. Category 3 consists of unbundled RECs– certificates that are procured without the associated renewable energy – or RECs that do not otherwise qualify for the other two categories.

The fraction of energy that must come from Category 1 increases steadily over the three compliance periods. Conversely, the fraction of energy that is permitted to come from Category 3 declines steadily over time (Figure 1).[15]

Pursuant to SB 2 (1X), utilities are directed to file annual RPS Procurement Plans at the CPUC, highlighting among other items how they intend to meet the RPS over the coming

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[11] Balancing Authorities are entities required to balance the generation and load within their control area. In many instances this function is served by a utility and the control area is synonymous with the utility's service territory. CAISO serves as the Balancing Authority for the three large California IOUs.

[12] For more details on dynamic transfer policy in the CAISO refer to http://www.caiso.com/Documents/FinalProposal-DynamicTransfers.pdf.

[13] For more details and examples of Portfolio Content Categories, see presentation by Sean A. Simon, CPUC, to the Committee for Regional Electric Power Cooperation (CREPC) and State-Provincial Steering Committee (SPSC), June 6, 2012, at http://www.westgov.org/wieb/webinars/2012/07-12-12CREPC-SPSC.pdf.

[14] The inclusion of dynamic transfers leads some to believe that more renewable energy from outside of California could come in under Category 1 than originally expected.

[15] See § 399.13, D.11-12-052. Category 1: 50 percent by December 2013, 65 percent by December 2016; 75 percent by December 2020 and beyond. Category 2: No maximum or minimum procurement amounts prescribed. Category 3: 25 percent by December 2013, 15 percent by December 2016, and 10 percent by December 2020 and beyond. See presentations by California Energy Commissioner Carla Peterman and Kate Zochetti to CREPC and SPSC, July 12, 2012, and Simon, *id.*, at http://www.westgov.org/wieb/webinars/2012/07-12-12CREPC-SPSC.pdf.

compliance period, discussing the rate impacts of their RPS compliance, detailing their "net short" – or how much renewable energy they will need to procure in order to meet the RPS, and providing project developers with a detailed description of their process for soliciting bids for new renewable resources to meet RPS obligations.[16]

All indications are that the state's utilities are well on the way to achieving California's RPS goals. According to the CEC, renewable energy generation totaled 16 percent of California's total retail electricity sales for all providers in 2010.[17] The large IOUs – SCE, PG&E and SDG&E – collectively served over 20 percent of their 2011 sales with renewable power.

Each company is on track for meeting their obligations under the 2011-2013 compliance period, the first under SB 2 (1X). PG&E reported in its 2012 RPS Procurement Plan that procurement under the contracts it has already secured will easily meet targets in the first compliance period and will "significantly exceed" procurement requirements for the second compliance period, 2014-2016.[18] PG&E indicated an appetite for additional renewable energy, but primarily in the 2019-2020 timeframe, or during the third compliance period and beyond.[19] Other utilities indicated similar success in securing contracts with sufficiently viable projects to meet their RPS requirements in the first two compliance periods.[20]

Despite early successes, California utilities and others have cautioned regulators about potential barriers to procuring cost-effective renewable energy supplies to meet the RPS. They point out that several federal tax incentives that have been a boon to renewable energy in the past few years are set to expire: the Production Tax Credit, crucial to wind, sunsets in 2012; the Investment Tax Credit, crucial to solar, will end in 2016; and funding through the American Recovery and Reinvestment Act, primarily in the form of federal loan guarantees, is concluding.[21] Others point to siting and construction challenges in California, which has more rigorous environmental policies than other jurisdictions,[22] as a hurdle that will add to the cost of meeting the RPS if projects are solely in California.

Some have suggested that greater regional coordination and cooperation on renewable energy could help California, as well as neighboring states, meet RPS obligations in a cost effective way. Specific improvements might include better recognition and more

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[16] See § 399.16, D.11-12-052.

[17] See presentation by California Energy Commissioner Carla Peterman and Kate Zochetti, to CREPC and SPSC, July 12, 2012, at http://www.westgov.org/wieb/webinars/2012/07-12-12CREPC-SPSC.pdf, detailing utility progress. In 2010, PG&E recorded 17.7 percent renewable energy; SCE 19.4 percent; SDG&E 11.9 percent; LADWP 20 percent; and SMUD 23 percent. The percentages increased in 2011. See CPUC RPS first and second quarter reports for 2012, http://www.cpuc.ca.gov/NR/rdonlyres/2060A18B-CB42-4B4B-A426-E3BDC01BDCA2/0/2012_Q1Q2_RPSReport.pdf.

[18] See Pacific Gas and Electric Company, Renewable Portfolio Standard 2012 Renewable Energy Procurement Plan (Draft Version), August 15, 2012, https://www.pge.com/regulation/RenewablePortfolioStdsOIR-IV/Other-Docs/PGE/2012/RenewablePortfolioStdsOIR-IV_Other-Doc_PGE_20120815_246695.pdf.

[19] *Id.* at pg. 57.

[20] Both SDG&E and SCE reported they do not need to procure additional renewable energy projects in the next compliance period. SDG&E indicated it would not likely need to procure again until the third compliance period, with solicitations in 2012, 2013 and 2014 directed at this timeframe. SCE did not conduct any renewable energy solicitations in 2012. See SDG&E Amended 2012 Draft Renewable Procurement Plan, Aug. 15, 2012, http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M027/K381/27381355.PDF, and SCE First Amended 2012 Renewable Portfolio Standard Procurement Plan, Aug. 15, 2012, http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M027/K131/27131904.PDF.

[21] See *Id.* at p. 31.

[22] See the California Environmental Quality Act (CEQUA), codified at California Public Resources Code, Section 21000, *et sec*, or http://ceres.ca.gov/ceqa/stat/.

detailed information about renewable resource development occurring in neighboring and remote jurisdictions. Additionally, more participation and information sharing by parties outside of CBA control areas in California processes could help enable joint transmission development, bolstering reliability and procurement opportunities WECC-wide. At the same time, some have concluded that there may be technical challenges associated with limiting procurement to particular geographies or balancing areas. That would restrict the diversity of project locations, technologies and balancing reserves, all of which are key ingredients for successful integration of renewable resources over the long term.

In previous interviews for the WREZ initiative, utilities and regulators indicated a desire for a more regional approach to renewable energy and transmission development, as well as interest in renewable energy hubs outside of their home states. However, they indicated that RPS in-state preferences, uncertainties surrounding permitting and cost recovery of long-haul transmission lines, and inconsistent policies among states have prevented a more regional approach. As a result, most utilities are currently procuring energy primarily from in-state sources, if not within their individual service territories.[23]

Responsibilities for implementing one of the nation's most ambitious RPS targets, and for planning the transmission necessary to bring renewable resources to where they are consumed, are housed within three California entities – the CPUC, CEC and CAISO:

- The CPUC handles the approval of annual RPS Procurement Plans for the state's IOUs, approves IOU contracts for renewable procurement, grants approval of new transmission projects, develops scenarios of future renewable resource development for transmission planning purposes, and determines whether the IOUs have met their RPS compliance requirements. The CPUC is a body of five Commissioners, appointed by the Governor, who set overall policy at the agency. Staff within the CPUC's Energy Division, working with the CPUC's Administrative Law Judge Division, carries out much of the development and implementation of that policy.
- The CEC, comprised of five Commissioners appointed by the Governor, is tasked with determining whether a particular renewable energy generator is eligible to produce energy for the RPS, verifying and tracking the retail sellers' procurement of RECs (using WREGIS),[24] developing forecasts of electricity retail sales, and developing regulations to implement and enforce the POUs' RPS efforts.
- CAISO manages 80 percent of California's transmission grid, conducts transmission planning for the state's IOUs, operates California's energy markets, and coordinates interconnection processes for generators wishing to interconnect to the CAISO transmission grid.

Efforts are underway to enhance the cooperation and synchronization of the renewable energy and transmission processes these agencies direct.

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[23] Lisa Schwartz, *et al.*, Regulatory Assistance Project, *Renewable Resources and Transmission in the West: Interviews on the Western Renewable Energy Zones Initiative*, prepared for Western Governors' Association, March 2012, http://www.westgov.org/component/joomdoc/doc_download/1555-wrez-3-full-report-2012.

[24] The Western Renewable Energy Generation Information System (WREGIS), launched in 2007, is a voluntary, independent renewable energy registry and tracking system using verifiable generation data for the area covered by the Western Electricity Coordinating Council (WECC). WREGIS is managed by WECC and its use is required for RPS verification in California as well as other Western states.

While POUs report to the CEC for compliance with the RPS, they do not need CEC approval for individual renewable energy contracts. Thus, planning for renewable energy resources and transmission for California POUs is driven largely by their boards of directors.

Several additional policy forums in California and elsewhere in the West play an important role in the administration of the state's RPS (Figure 2). In addition to administering RPS rules for POUs, the CEC produces the Integrated Energy Policy Report (IEPR) and the critical energy demand forecasts that become inputs to the state's various RPS processes. The CEC, the California Department of Fish and Game, U.S. Fish and Wildlife Service, and the Bureau of Land Management are also preparing the Desert Renewable Energy Conservation Plan (DRECP), a resource conservation and renewable energy plan designed to identify desert lands in Southern California for the development of renewable energy projects. Other state policy forums, including the California Transmission Planning Group (CTPG), a group of transmission providers primarily serving California that collaborate on a joint transmission planning process, and the California Renewable Energy Transmission Initiative (RETI) are now dormant, but could be re-activated.

Planning initiatives beyond California could result in more cohesion between the state and its Western neighbors in planning for renewable energy and transmission:

- In addition to CTPG, other sub-regional planning groups conduct detailed studies of the aggregate plans of affiliated transmission providers and jointly consider planning issues among members and stakeholders.
- The Western Electricity Coordinating Council (WECC) conducts Interconnection- wide planning studies with guidance from its Transmission Expansion Planning Policy Committee (TEPPC) and advice from states and provinces, utilities, independent resource and transmission developers, environmentalists and other stakeholders. Studies include 10- and 20- year transmission expansion plans that provide an interconnection- wide view of expected energy resources and transmission, as well as transmission requirements and alternatives under a variety of futures.[25]
- Transmission systems of the Western Area Power Administration (WAPA) and Bonneville Power Administration (BPA), federal power marketing agencies, are interconnected to the California transmission grid and plan transmission – including joint projects with California transmission providers – to meet load, transmission service requests and public policy directives. The California POUs are preference power customers of WAPA.
- The Federal Energy Regulatory Commission's (FERC's) Order 1000 requires jurisdictional transmission owners to form coordinated planning arrangements and methodologies for cost allocation for new transmission projects.[26]
- The Bureau of Land Management is undertaking a Programmatic Environmental Impact Statement (PEIS) that would streamline the permitting process for solar energy projects on suitable BLM lands.[27]

[25] WECC's most recently approved 10-year plan is available at http://www.wecc.biz/library/StudyReport/Wiki%20Pages/Home.aspx.

[26] CAISO will be its own FERC Order 1000 planning organization. Several California utilities that are not jurisdictional to CAISO are considering joining Order 1000 planning organizations *outside* of California.

[27] For more information on the BLM Solar PEIS, see http://solareis.anl.gov/.

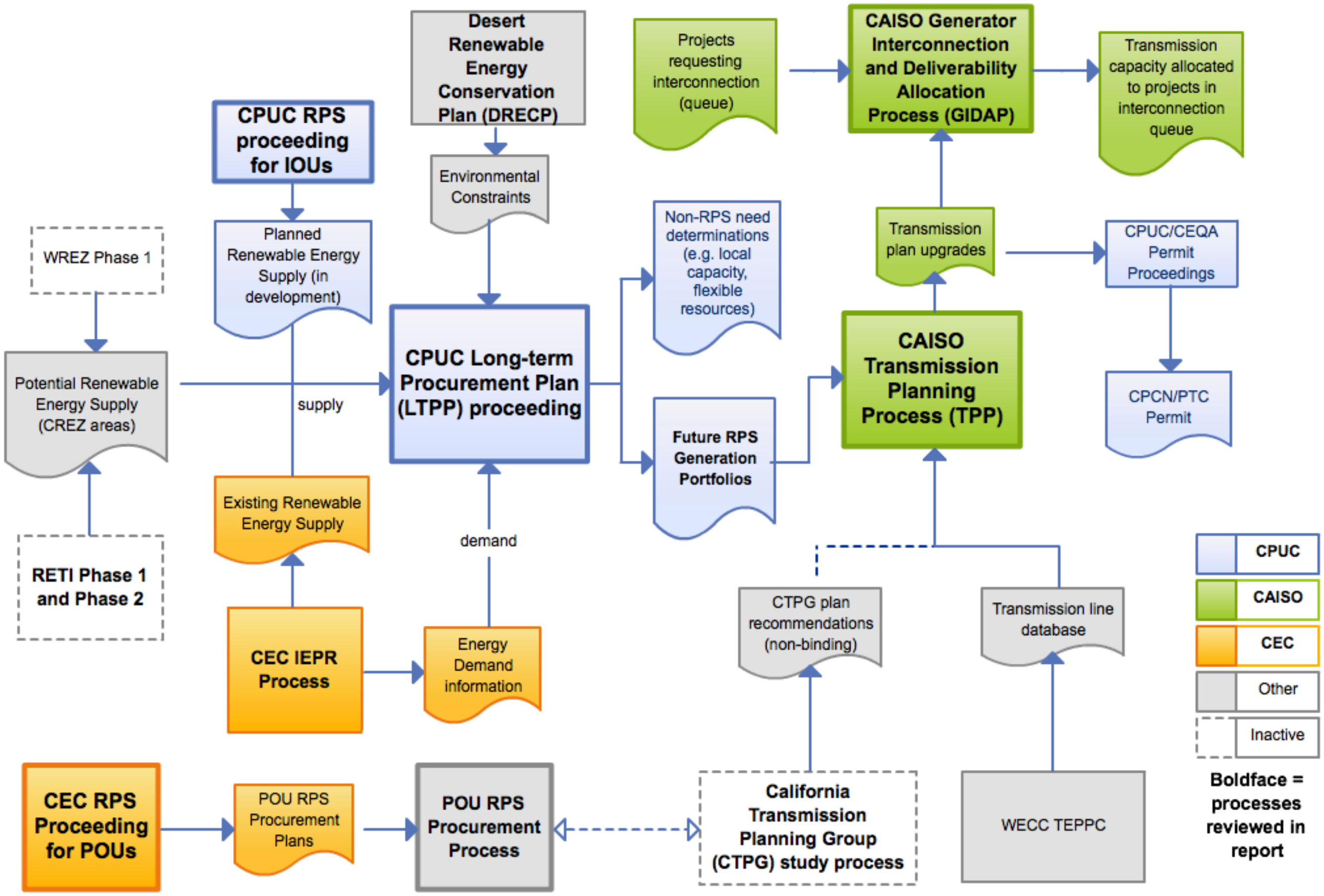

Figure 2. Flow chart depicting the complex interactions between various California proceedings related to renewable resource procurement and transmission.

3. CPUC Long- Term Procurement Planning Proceeding

In a nutshell:

- The biennial CPUC LTPP authorizes the IOUs' procurement plans for meeting future resource needs, except for resources needed to meet RPS requirements.
- Scenario-based planning is used to inform these authorization decisions. Each scenario considered in this process contains a portfolio of renewable energy projects that meet the state's RPS requirements.
- Renewable resource portfolios developed for the LTPP scenarios form the basis of "policy driven" transmission planning at CAISO.

Key documents/outcomes:

- CPUC Rulings on Standardized Planning Assumptions (2012-LTPP, 2010-LTPP) and Standardized Planning Scenarios (2012-LTPP)
- CPUC Decision on 2010 LTPP Scenarios (2010-LTPP)
- Renewable Resource Portfolios submittal letters from CPUC to CAISO (2011-12 TPP Letter & Attachment, 2012-13 TPP Letter)

3.1 Origins and purpose of the LTPP proceedings

a) Brief summary of the LTPP

The Long-term Procurement Planning (LTPP) proceeding overseen by the CPUC plays a foundational role in planning the state's electricity generation resources. Through this biennial process, the CPUC authorizes the amount and type of resources the state's IOUs can procure in order to meet future system needs. This process excludes resources needed to meet the RPS, which are determined in the RPS proceeding.[28] However, information about RPS resource procurement informs the LTPP process. The LTPP uses scenario-based planning to develop infrastructure plans and inform authorization decisions.[29] Earlier, the LTPP used a 10-year planning horizon. Starting with the 2012 process, the horizon has been extended to 20 years.[30] The CPUC establishes standardized assumptions and scenarios recognizing that the scenarios may influence the amount, location and timing of authorized procurement. These assumptions and scenarios include the impacts of the state's "loading order" for preferred resources, including energy efficiency, demand response, renewable energy and distributed generation.

In many ways, the LTPP process is analogous to integrated resource planning activities commonly conducted by other utilities. The LTPP process focuses on two areas. The first addresses infrastructure needs for all of California's largest IOUs simultaneously and specifies key assumptions and scenarios for the system as a whole. The second area is

[28] "System needs" in the LTPP process refers to physical resources needed to meet California's future load growth plus a planning reserve margin. System needs also include assessments of physical resources needed to meet local area planning criteria.
[29] For examples of prior plans see http://www.cpuc.ca.gov/PUC/energy/Procurement/LTPP/LTPP2010/LTPP_System_Plans.htm.
[30] See the June 27, 2012, Assigned Commissioner's Ruling which established the two planning periods, http://docs.cpuc.ca.gov/PublishedDocs/EFILE/RULINGS/169732.PDF.

establishing upfront rules and criteria for the large IOUs' procurement plans on behalf of bundled customers.[31]

b) AB 57 and the establishment of the LTPP process

In the aftermath of the 2000-2001 energy crisis, the state's legislature passed Assembly Bill 57.[32] This law reinstated the ability of California IOUs to procure electricity generation resources in order to maintain reliability. In the lead up to this crisis, California's efforts to deregulate its electricity sector included separating resource procurement from the incumbent IOUs. A primary focus of the law was to ensure that utilities could recover the costs of new infrastructure without being subject to "after-the-fact" reasonableness reviews of procurement decisions so long as the decisions were consistent with the procurement plans authorized by the CPUC. CPUC authorization of IOU procurement plans through the LTPP thereby provides California utilities with certainty of cost recovery for long-term procurement decisions.

Some stakeholders indicated that the LTPP has historically been seen as a forum for authorizing new fossil-fueled generation. Indeed, the LTPP may be the final opportunity to address any system needs that persist after energy efficiency and renewable resource options have been exhausted.[33] In any case, the LTPP process addresses a central question: What resources are needed to maintain a reliable and cost-effective energy system while meeting policy goals and avoiding stranded costs?[34]

Because a core aim of the process is to identify the need for and authorize procurement for new resources, it also represents one of the most important decision points for cost recovery for the IOUs. As a result these proceedings tend to be lengthy and complex. There is a general sentiment among many stakeholders that the LTPP process increasingly serves as an umbrella proceeding for policies affecting the California IOUs since it interacts with many other proceedings in important ways.

However, renewable resource procurement occurs within the RPS proceeding described in Chapter 5, not within the LTPP process. Nevertheless, assumptions about future renewable energy generation are a fundamental input to the LTPP process. As the CPUC stated in its 2010 LTPP Scoping Memo, "the pattern of renewable generation development over the

?	**What decisions are made in the LTPP proceeding vs. the RPS proceeding?**
•	The ***LTPP proceeding*** authorizes the procurement of all resources except for renewable resources. However, assumptions about renewable resources are a key input for determining remaining resource and transmission needs in the LTPP.
•	The ***RPS proceeding*** oversees renewable resource procurement through the development of RPS procurement plans, annual solicitations and CPUC approval of individual contracts.

[31] Customers who purchase electricity from the utility.
[32] See *Cal. Pub. Util. Code* §454.4, http://www.leginfo.ca.gov/cgi-bin/displaycode?section=puc&group=00001-01000&file=451-467.
[33] Through the adoption of California's Energy Action Plan, the CPUC and other state agencies have established a "loading order" for meeting system needs. This means that when considering authorization for resource procurement, the CPUC prioritizes energy efficiency and demand response first, followed by distributed and renewable resources and then clean fossil-fuel generation. See http://www.energy.ca.gov/2005publications/CEC-400-2005-043/CEC-400-2005-043.PDF.
[34] See *Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans,* http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/162752.PDF.

next ten years will be linked directly to when and where transmission gets built, to which areas of the state are determined to be appropriate for large generation installations, and to emerging information about renewable integration needs, as well as to commercial interest."[35]

3.2 Key steps in the LTPP process and interaction with other processes

a) Steps in the LTPP process

The LTPP process can be broken down into a sequence of steps described below that are similar to other resource planning efforts. Many key inputs and outputs are not established in the LTPP process, instead relying on other processes or entities in California. Figure 3 summarizes how the LTPP process interacts with these other California processes as it pertains to renewable energy resources.

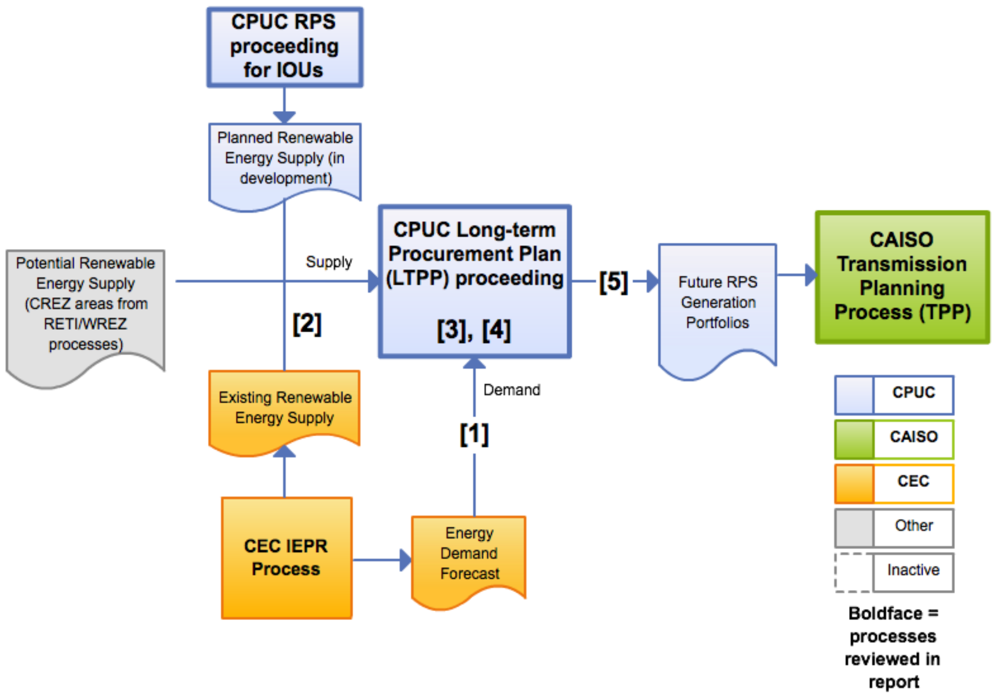

Figure 3. Illustration of how the LTPP process develops renewable resource generation portfolios for use in transmission planning. Numbers in brackets correspond to the following steps:

[1] The CEC leads development of an energy demand forecast (see Appendix A) and additional information that determine the quantity of renewable energy needed in the future.

[2] Current renewable energy supplies are accounted for, including existing generation and planned resource additions or retirements. The existing generation is determined from the CEC's annual RNS update report (www.energy.ca.gov/2013_energypolicy/documents/). Planned additions are largely derived from solicitations in the RPS proceeding (see Chapter 5).

[3] Additional resource needs are identified based on the demand forecast and existing generation inventory. For renewable resources, this need is referred to as the "renewable net short" (RNS). The RNS is the difference between the RPS requirement (33 percent of retail energy sales in 2020) and the expected delivered renewable energy.

[35] CPUC, *Assigned Commissioner and Administrative Law Judge's Joint Scoping Memo and Ruling*, R.10-05-006 (Filed Dec. 3, 2010), p 29, http://docs.cpuc.ca.gov/PublishedDocs/EFILE/RULC/127542.PDF.

[4] The CPUC develops assumptions and scenarios with stakeholder input to explore alternative resource procurement options that address any unmet system needs. An "RPS Calculator" tool uses inputs from the RETI process, and other data sources including WREZ, to predict future renewable resource additions (see Appendix B). Parties model these assumptions and scenarios and provide recommendations to the CPUC on how to meet shortfalls.

[5] The CPUC submits information about future renewable energy portfolios to CAISO for its Transmission Planning Process (TPP).

b) Interaction of the LTPP and CAISO

In May 2010, the CPUC and the CAISO signed a Memorandum of Understanding (MOU) to better coordinate the state's transmission planning efforts, particularly in relation to renewable resources.[36] According to the MOU, "The CPUC develops renewable generation portfolio scenarios as part of its Long Term Procurement Plan process that will assist the ISO in identifying transmission projects needed under various renewable generation location assumptions and developing a comprehensive transmission plan." In other words, the LTPP renewable portfolios form the basic renewable resource assumptions to be used in the CAISO's Transmission Planning Process (TPP).

The CPUC, working in conjunction with the CEC, provides portfolios to the CAISO via a submittal letter published each year.[37] CAISO uses these portfolios as inputs to conduct a sequence of studies to identify the need for any new transmission projects to accommodate RPS projects, identified as "policy driven" projects. Thus, the assumptions and methodologies in the LTPP proceeding affect which transmission upgrades CAISO approves through its planning process. However, assumptions other than for the RPS may differ between the two processes, since the CAISO develops these other assumptions through a different stakeholder process than the LTPP proceeding.

Although the LTPP process takes places every two years, CAISO conducts the TPP every year, so the CPUC submits portfolios based on the most recent proceeding. For example, the scenarios being developed in the 2012 LTPP proceedings are on track to provide input to the 2013-2014 CAISO TPP cycle. Since the signing of the MOU, many stakeholders agree that there has been improved coordination between the CPUC and CAISO for transmission planning.[38]

In addition to using the renewable generation portfolios for transmission planning, CAISO supports the LTPP process by performing integration studies, separate from the TPP. They assess the adequacy of the expected resource portfolios to meet the flexibility needs of the system. Flexibility refers to the ability for the generation fleet to respond to dispatch signals in order to maintain a balance between supply and demand. As utilities achieve higher RPS targets, supplies will be increasingly variable due the nature of renewable resources such wind and solar. The integration studies evaluate

> **? Why are the LTPP scenarios important?**
>
> For stakeholders interested in regionally coordinated renewable energy and transmission development in the West, LTPP scenarios important because they are a primary input to the CAISO Transmission Planning Process (see Chapter 4 for details).

[36] CPUC and CAISO Memorandum of Understanding, May 2010: http://www.caiso.com/2799/2799bf542ee60.pdf.

[37] Recent portfolio submittal letters sent from CPUC to CAISO:
--2011-12 TPP Portfolio Submittal Letter (PDF) & Attachment (DOC)
--2012-13 TPP Portfolios Submittal Letter (PDF)

[38] Some disagree with this assessment and are concerned about the disjointedness of various stakeholder processes in the state.

the ability of the system to respond to the minute-by-minute changes in load, net of the changes in supply from wind and solar resources. If shortages of flexibility are identified, potential options for meeting any flexibility shortages are evaluated.

c) Stakeholder participation in the LTPP process

In addition to the IOUs, a variety of stakeholders participate in the LTPP process by participating in workshops and filing formal comments and briefs. For example, in the current proceeding, numerous parties commented on the standardized planning assumptions. Views vary among stakeholders about whether there is sufficient participation in the LTPP process by out-of-state entities. On one hand, several transmission developers and renewable resource developers outside California have been active in recent LTPP proceedings. However, several of those interviewed for this report acknowledged that since California utilities already rely heavily on out-of-state energy providers, and *vice versa*, there would be value in heightened regional collaboration and additional stakeholder involvement in California's planning processes.

Stakeholder Opportunity
Stakeholders interested in participating in the LTPP or other CPUC proceedings may find it useful to consult the CPUC practitioner website, which contains information on how to become a party in a proceeding, subscribe to proceeding updates and more: http://www.cpuc.ca.gov/PUC/Practitioner/index.htm.

3.3 How are the LTPP scenarios developed?

a) Basics of scenario-based planning

A core task of the LTPP proceeding is to identify the system's future resource needs. In brief, these needs consist of a capacity supply sufficient to meet system demand, subject to policy constraints such as the RPS. Because the LTPP process assesses needs that extend well into the future, certainty in any of these elements, such as future supply or demand and policy constraints, cannot be guaranteed. Thus the CPUC uses a scenario-based planning method that explores various possible futures. These scenarios and associated system needs are ultimately used to inform the resource procurement authorization decisions at the CPUC and planning efforts elsewhere in California, most notably the renewable energy portfolio for CAISO's Transmission Planning Process. In the 2012 LTPP process, scenarios are being developed through Track 2 of the proceeding (Figure 4). The Scoping Memo[39] explicitly identifies the following issues to be addressed, among others:

- "Determination of specific scenarios to be developed to analyze long-term system reliability needs; these scenarios will form the basis for the Commission's submittal to the ISO for its 2013-2014 Transmission Planning Process."
- "How to inform other infrastructure planning processes, including the ISO Transmission Planning Process and other regional planning processes."

[39] R.12-03-014, Scoping Memo and Ruling of Assigned Commissioner and Administrative Law Judge, May 17, 2012, http://docs.cpuc.ca.gov/PublishedDocs/EFILE/RULC/166780.PDF.

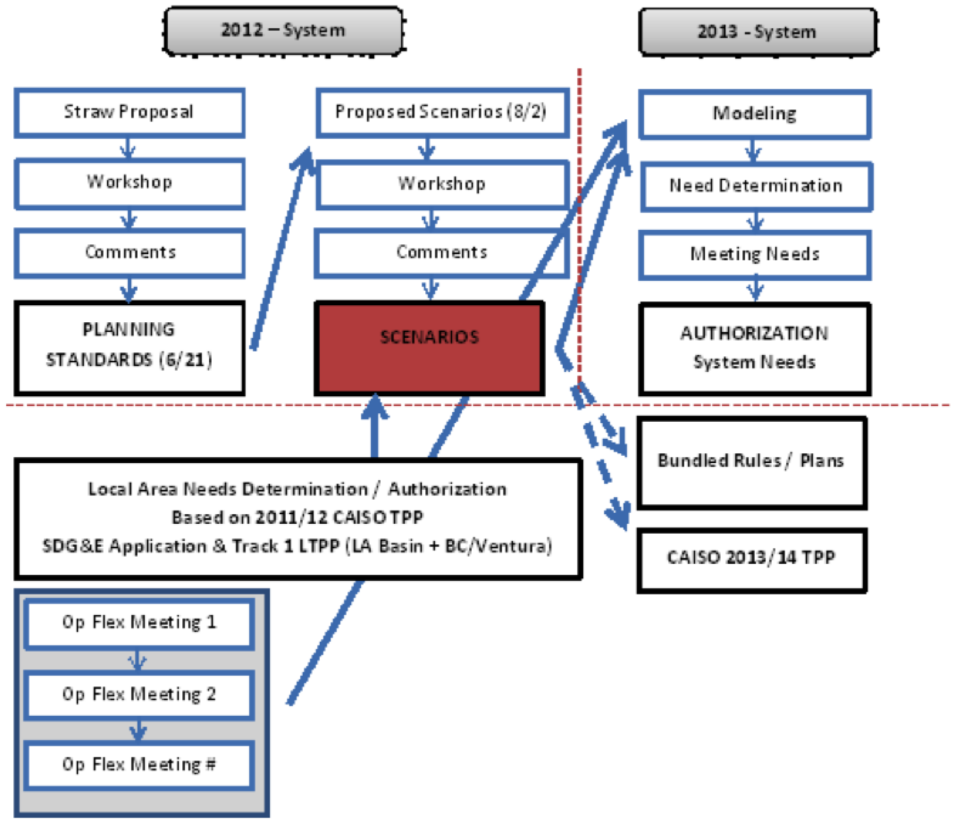

Figure 4. Key steps of the system needs portion of Track 2 in the 2012 LTPP proceeding, which focuses on standardized planning assumptions and scenarios. The process begins with a straw proposal drafted by the CPUC Energy Division on standardized planning assumptions. The Energy Division also drafts the initial scenarios. These scenarios and assumptions will be used in 2013 to determine system resource needs, including those associated with operating flexibility. The red box indicates the current proceeding status. Separately, in 2013, the IOUs will develop procurement plans to be authorized by the CPUC. Multiple opportunities for stakeholder engagement exist throughout the proceeding such as workshops and comment periods. (Image Source: Assigned Commissioner Ruling on Standardized Planning Scenarios in R.12-03-014).[40]

Each scenario developed through the LTPP process represents a distinct possible future. This future reflects assumptions about the energy supply and demand influenced by the stated policy preferences and market conditions. For example, one future scenario might anticipate reduced load growth associated with a high level of behind-the-meter distributed generation. Another might envision robust economic growth, accelerated adoption of electric vehicles and corresponding increases in energy demand, along with renewable resource development reflecting current commercial interests.

In the past, the CPUC used a 10-year planning period. In the 2012 proceeding, the CPUC is overseeing analysis of an additional 10 years (20 years total). However, the CPUC will only authorize procurement for the initial 10-year period. The second planning period has significant uncertainties. This period will inform the CPUC of long-term impacts of decisions made in the first period.

[40] See p. 6, Attachment to Assigned Commissioner Ruling on Standardized Planning Scenarios in R.12-03-014, Sept. 20, 2012, http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M028/K155/28155334.PDF. Image was refreshed to indicate current place in the proceeding.

b) LTPP Standardized Planning Assumptions

The CPUC determines a set of common inputs to the process known as the "Standardized Planning Assumptions" or "Planning Standards" to provide a consistent basis for evaluating the IOU procurement plans. The Standardized Planning Assumptions are first introduced through an Energy Division staff "straw proposal"[41] (see Figure 4, top left) consisting of two main components: 1) energy demand and 2) energy supply.

Stakeholder Opportunity
Provide comments on Standardized Planning Assumptions and Scenarios in future LTPP planning cycles. Use these comment opportunities to assist the CPUC in establishing "guiding principles" and assumptions that reflect regional interests and opportunities.

i) Identifying future energy demand (resource needs)

The LTPP uses planning assumptions for future energy demand based largely on the forecasting efforts of the CEC's IEPR process (see Appendix A). Three demand scenarios (high, medium and low) are included with additional sensitivity analysis for future policies, such as incremental energy efficiency and distributed generation measures. Since California's RPS target is a percentage of retail sales, the forecasted demand for energy is a key input for determining how much renewable energy procurement is needed. This unmet need is an amount known as the Renewable Net Short (RNS), which is defined differently depending on the context. In planning, the value of the RNS reflects the difference between the RPS target and the expected renewable energy from existing resources delivered to load. The CEC has published a standardized method[42] for calculating the RNS, which is used for LTPP process and transmission planning. However, due to timing issues, the LTPP RNS calculation and the CEC calculation may differ. Meanwhile, for RPS procurement purposes, the CPUC adopted a different RNS calculation methodology that the IOUs use in the RPS proceeding, which includes the contribution of expected future resources.[43]

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[41] 2012 LTPP, CPUC's Straw Proposal on Standardized Planning Assumptions, http://www.cpuc.ca.gov/NR/rdonlyres/502D2DA7-A160-4652-88E5-570AC9B0822B/0/2012LTPPStrawProposalvFinal2.doc.

[42] California Energy Commission, Proposed Method to Calculate the Amount of New Renewable Generation Needed to Comply With Policy Goals, November 2011, http://www.energy.ca.gov/2011publications/CEC-200-2011-001/CEC-200-2011-001-SF.pdf.

[43] CPUC Administrative Law Judge ruling adopting the RNS methodology in the RPS proceeding: http://docs.cpuc.ca.gov/PublishedDocs/EFILE/RULINGS/171999.PDF

ii) Future renewable energy supply

While the LTPP process considers all resources, including fossil-fueled resources, CPUC authorization of IOU procurement is heavily influenced by policies such as RPS requirements, once-through cooling (OTC) regulations, regulation of greenhouse gases, local resource adequacy requirements,[44] energy efficiency standards, demand response, distributed generation incentives and transmission import capabilities.[45] As such there is a major focus on renewable energy resources. Each LTPP scenario contains a renewable resource portfolio that reflects assumptions about which renewable energy projects are likely to be developed and thus contribute to the energy supply. The renewable resource portfolios contain a combination of anticipated projects currently under development and future projects yet to be developed. Details on anticipated projects are largely derived from the RPS proceeding's annual procurement process.

? What is the Renewable Net Short and how could it change?

The Renewable Net Short (RNS) is the difference between the RPS target (33% of retail sales in 2020) and the expected delivered renewable energy from existing supplies. Here's an illustrative RNS calculation, which also accounts for energy efficiency (EE) and distributed generation (DG):

300 TWh (energy demand in 2020)
- 30 TWh (future EE/DG)
270 TWh (retail sales)

* 33% (RPS requirement)
90 TWh (renewable energy needed)

- 40 TWh (from existing generation)
50 TWh of Renewable Net Short

The RNS reflects remaining resource needs to meet the RPS, so it also reflects the relative market size for developers interested in selling renewable energy to meet California's RPS. Factors that could alter actual RPS needs include:

- Unanticipated changes in load growth, which increases or decreases retail sales and in turn increases or decreases the RNS
- Aggressive EE or DG policies that decrease retail sales and reduce the RNS, or these programs not coming to realization
- Unanticipated failure rates for renewable energy projects, decreasing the renewable energy supply and increasing the RNS
- Legislative changes to the RPS requirement (for example, an increase to 40%)

[44] According to the CPUC's planning standards, in order for a resource to count towards meeting future system Resource Adequacy needs in the LTPP analysis it must either fit on an existing transmission line or be a baseload/flexible resource.
[45] Imports are assumed to be the Available Import Capability for loads in the CAISO control area: 13,308 MW for 2013. This is equal to the Maximum Imports value minus Existing Transmission Contracts outside the control area. Data from CAISO's table, 2013 Assigned and Unassigned Resource Adequacy Import Capability on Branch Groups.

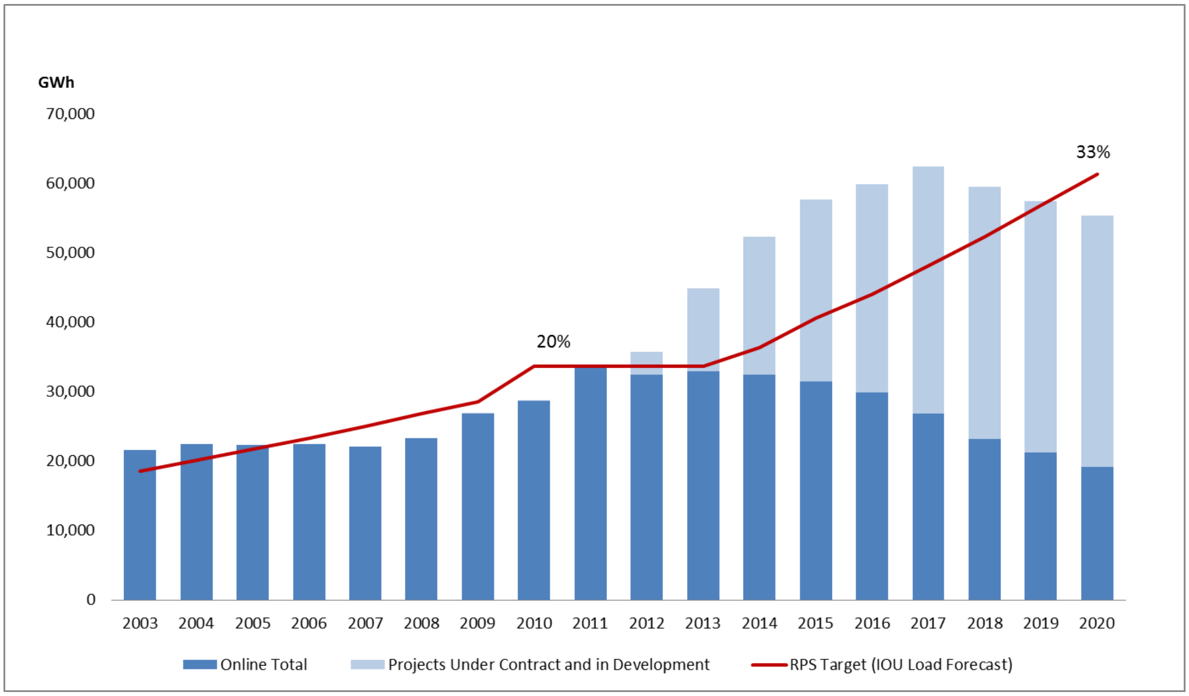

Figure 5. The Residual Renewable Net Short is the difference between the RPS requirement (red line) and the total generation currently under contract for delivery (dark blue bar). Additional projects to fill this gap are comprised of projects currently in development (light blue bar), re-contracted projects and new projects. (Source: CPUC, June 6, 2012, webinar, slide 11: http://www.westgov.org/wieb/webinars/2012/06-06-12CREPC-SPSC.pdf)

3.4 How does the CPUC select future renewable resource portfolios for its scenarios?

a) Background on renewable energy in the LTPP process

Since 2005, the CPUC has been intent on integrating renewable energy procurement into the LTPP process.[46] This began in earnest with the 2006 proceeding, which kicked off planning for the 33 percent RPS in response to the 2005 Energy Action Plan jointly adopted by the CPUC and CEC.[47] In recent years, the LTPP process has steered RPS development by predicting when and where resources will be procured, which in turn influences when and where transmission development is likely to occur to meet RPS needs, and ultimately which RPS resources are likely to be developed. The scenario planning in the LTPP process is not intended to prescribe the renewable resources that ultimately will be procured. However, it may affect which resources are

? What is a scenario vs. a portfolio?
• A resource ***scenario*** is a set of possible future conditions that incorporates assumptions about supply and demand. For example, an "environmentally constrained" scenario might be described as follows: Through 2020, environmental considerations will be paramount and steer RPS project development exclusively to specified, preferred areas. • A ***portfolio*** is the set of resources – by size and location and fuel type – established within a scenario as one of the planning assumptions.

[46] This follows specifically from the CPUC's decision on July 21, 2005, D.05-07-039.
[47] CEC/CPUC 2005 Energy Action Plan, http://www.energy.ca.gov/energy_action_plan/2005-09-21_EAP2_FINAL.PDF.

developed to the extent the portfolios are used for transmission planning and thus affect the ability of renewable energy projects to meet deliverability requirements.

b) Evolution of the renewable portfolio selection methodology

As part of the 2006 LTPP decision, the CPUC directed its Energy Division staff to develop a methodology for RPS planning based on the RETI initiative (see Appendix B). The Energy Division developed this methodology (in conjunction with consulting firm E3) through the 2008 LTPP proceeding and incorporated it into the 33 percent RPS Implementation Analysis report released in 2009.[48] The CPUC confirmed that the report met its intended direction and alluded to future refinements.[49] As such, the report's methodology represents the starting point for subsequent LTPP renewable resource planning methods. However, these methods have evolved significantly, incorporating several new layers of complexity and precision.

In particular, the CPUC thought some of the implementation scenarios (such as "High Out of State") were unlikely because they implied that 1) utilities could step out of existing contracts or 2) resources with signed contracts would fail to develop.[50] In reality, most of the IOUs have a large number of signed contracts for projects that are expected to reach commercial operation. In an effort to reflect this reality, the CPUC now groups the most certain projects into a "discounted core" of projects that are treated as sunk decisions for planning purposes. Identifying which contracts are treated as foregone decisions for compliance may reveal information that is considered confidential. Thus a different list of projects is used in the RPS proceeding versus the LTPP proceeding. The LTPP process relies upon a public list of contracts.

Some stakeholders in our interviews expressed skepticism about this outcome and suggested that higher-than-expected contract failures might emerge in the coming years. Developers of certain projects may have sought contracts with the IOUs on the expectation that PV prices would continue to fall, but lack the proper financing or project development expertise to fulfill their obligations under the power purchase agreement with the utility. Conversely, others claim that as developers and utilities become more experienced with the procurement process the failure rate will decline.

> **? What is the "Discounted Core"?**
>
> The "discounted core" represents renewable energy projects that have signed contracts with IOUs and are considered to be the most viable projects under development. The PUC considers these projects reliable and includes them in each LTPP scenario.

[48] 33% Renewable Portfolios Standard Implementation Analysis Report, June 2009, http://www.cpuc.ca.gov/NR/rdonlyres/1865C207-FEB5-43CF-99EB-A212B78467F6/0/33PercentRPSImplementationAnalysisInterimReport.pdf.

[49] Assigned Commissioners Ruling on July 1, 2009, in R.08-02-007, http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/RULINGS/103212.PDF.

[50] CPUC, *Assigned Commissioner and Administrative Law Judge's Joint Scoping Memo and Ruling*, R.10-05-006 (Filed Dec. 3, 2010), Attachment 2, "Standardized Planning Assumptions (Part 2 – Renewables) for System Resource Plans," http://docs.cpuc.ca.gov/PublishedDocs/EFILE/RULC/127544.PDF.

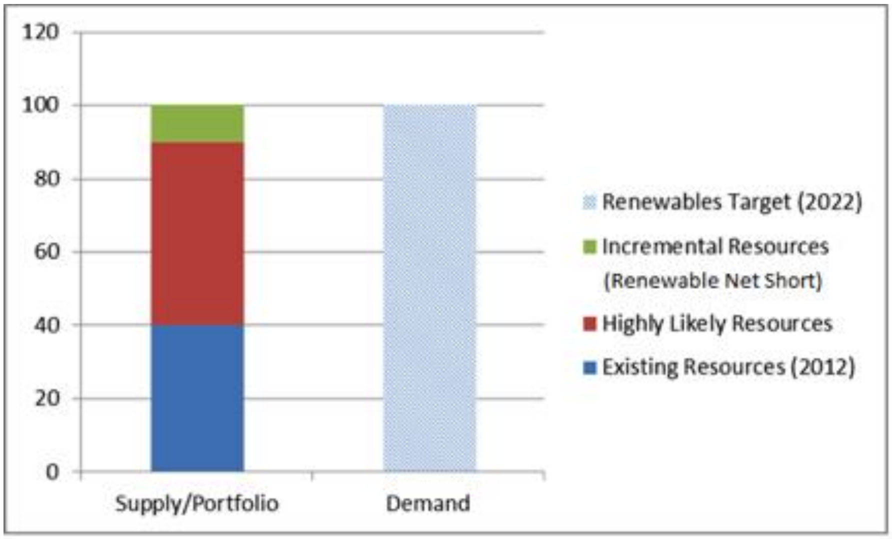

Figure 6. This graphic shows the construction of a portfolio according to the CPUC's methodology. First, the CPUC accounts for existing generation (blue). Next, the CPUC includes a "discounted core" of highly likely-to-be-developed projects (red). Finally, the Renewable Net Short, or incremental resources (green) are filled according to the preferred criteria of the scenario. (Source: CPUC, Energy Division Standardized Planning Assumptions Presentation, May 17, 2012, http://www.cpuc.ca.gov/NR/rdonlyres/DF0F45A3-18CC-406A-BC02-A6A53F62E722/0/2012LTPPStrawProposalPresentation.ppt)

Once existing generation and the discounted core[51] of likely to be developed projects are accounted for, additional RPS resources are then considered to fill the residual RNS. The CPUC studies different approaches to filling the RNS by developing a set of renewable resource portfolios that are then used as a component of the LTPP scenarios.

For the 2012 LTPP proceeding, the CPUC anticipates the generation needed to meet the residual RNS. After accounting for the discounted core, the RNS is approximately 1,600 MW for the base case scenario.[52] As such, the resulting portfolios will reflect a limited number of new supply choices.

Unanticipated events, such as extraordinarily high contract failure, could necessitate seeking new supply options for filling the RNS. However, there is a common consensus that this is unlikely because the IOUs have sought procurement levels assuming historic failure rates of about 30 percent to 50 percent. Some stakeholders expect this rate to increase while others expect it to decrease. In the most recent RPS procurement plan updates (see Chapter 5), PG&E anticipates a failure rate of 12 percent to 32 percent; SDG&E anticipates a 37 percent failure rate, and SCE expects an initial 36 percent failure rate, increasing to 50 percent by 2018.

c) RPS Calculator

The CPUC uses its scenario planning to predict which renewable energy resources

[51] Note that discounted core resources which require new transmission may not be included in the portfolio if the discounted core resource(s) make up less than 67 percent of the energy expected to be accommodated by the new transmission.

[52] See the Sept. 27, 2012, RPS Calculator Update – "Portfolios Summary" document, http://www.cpuc.ca.gov/NR/rdonlyres/A8B8B72A-B8D3-40A6-A978-0FB2635FCB95/0/portfolios_92712.xlsa, and the Sept. 20, 2012, CPUC Assigned Commissioner Ruling on Standardized Planning Assumptions in the 2012 LTPP, http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M028/K155/28155334.PDF.

the IOUs are likely to pursue using a methodology spun off from its initial 33 percent RPS Implementation Analysis. The CPUC's scenario planning results then form the basis of the scenarios the CAISO TPP process uses for transmission planning. Renewable resource portfolios are selected primarily through the "RPS Calculator" tool. The methodology underlying this tool is described in detail first in the 2010 LTPP proceeding[53] and then in subsequent updates in 2012.[54] In essence, the RPS Calculator is a screening tool designed to select which renewable resources should be included in a specific resource portfolio according to specific criteria defined by the LTPP scenario. This selection process involves a complex and exhaustive methodology. In brief, the process takes a large list of potential projects and narrows them down into a smaller list of likely-to-be-developed projects that are included in the portfolio. The following concepts are fundamental to understanding this selection process:

1. *Energy Division database:* Renewable resource portfolio selection for the LTPP process begins with a comprehensive list, maintained by the CPUC Energy Division, of potential renewable energy projects. This includes virtually all potential utility-scale projects in the Western Interconnection that could be used to meet California's RPS needs,[55] both renewable energy projects that are under development ("commercial interest") and those that could theoretically be developed ("generic"). The discounted core is a subset of "commercial interest" projects. From this initial list, the Energy Division uses the RPS Calculator to rank and select resources in steps to narrow the list down to a set of final resources to fill the portfolios.

2. *Local use:* A certain amount of out-of-state resources are set aside for "local use" and are not included in the list of potential California resources. The prevailing theory behind this is that the lowest cost, non-California resources will be used first and foremost to fulfill RPS obligations in other states in the Western Interconnection.

3. *CREZ, Non-CREZ and REC Resources:* Each resource is classified according to its location as CREZ, non-CREZ or REC-only. Projects in each CREZ are then assigned to transmission bundles. The best-ranking resources are assigned to transmission bundles in the following order according to their rank:
   - Existing transmission - projects that fit along existing transmission capacity
   - Minor upgrades - projects that can be accommodated with only minor transmission upgrades
   - New transmission - projects requiring construction of new transmission lines

> **? What is a CREZ?**
>
> Competitive Renewable Energy Zones in California are areas designated for potential renewable energy development because they have density of developable resources to justify building transmission lines and meet certain other criteria (for example, environmental sensitivity). CREZ areas were defined through the RETI process (see Appendix B for details).

[53] For a comprehensive explanation of the CPUC's Portfolio Selection Method (the RPS Calculator), a good starting place is the "Standardized Planning Assumptions (Part 2 – Renewables) for System Resource Plans" filed Dec. 3, 2010, for the 2010 LTPP proceeding, http://docs.cpuc.ca.gov/PublishedDocs/EFILE/RULC/127544.PDF.

[54] Recent updates to the RPS Calculator for the 2012 LTPP process and supporting documentation: http://www.cpuc.ca.gov/NR/rdonlyres/6E7C875F-3BF2-4A07-9D4C-A7A3FE3BB0A2/0/DescriptionofCalculatorUpdates20120323_corrected.docx; http://www.cpuc.ca.gov/NR/rdonlyres/EA89868E-4D4A-4458-ACFC-49B2E7B4B541/0/May2012Updates.doc.

[55] To see which projects are included in this database, download the RPS calculator (XLSM) and see tabs "i – CommProjData" and "j – GenericProjData."

4. *Ranking and sorting:* At various stages of the portfolio selection process, resources are ranked according to the criteria in the scenario. The weighting of each metric is defined by the specific scenario:

- Net cost - projects ranked according to the cost of delivered energy
- Environmental score - projects ranked based on the project location's environmental criteria, with DRECP information recently incorporated
- Commercial interest score - projects weighted according to the commercial interest of the utility and the status of a power purchase agreement
- Permitting score - projects weighted according to the progress toward securing major permits for development

Stakeholder Opportunity
Propose changes to the RPS Calculator that improve consideration of regional resources and associated transmission costs – in particular, the treatment of resources in WREZ hubs and resources that are dynamically transferred to a California Balancing Authority. Currently, a uniform transmission cost is estimated for each project in a CREZ based on the distance from the CREZ to a California interconnection point.

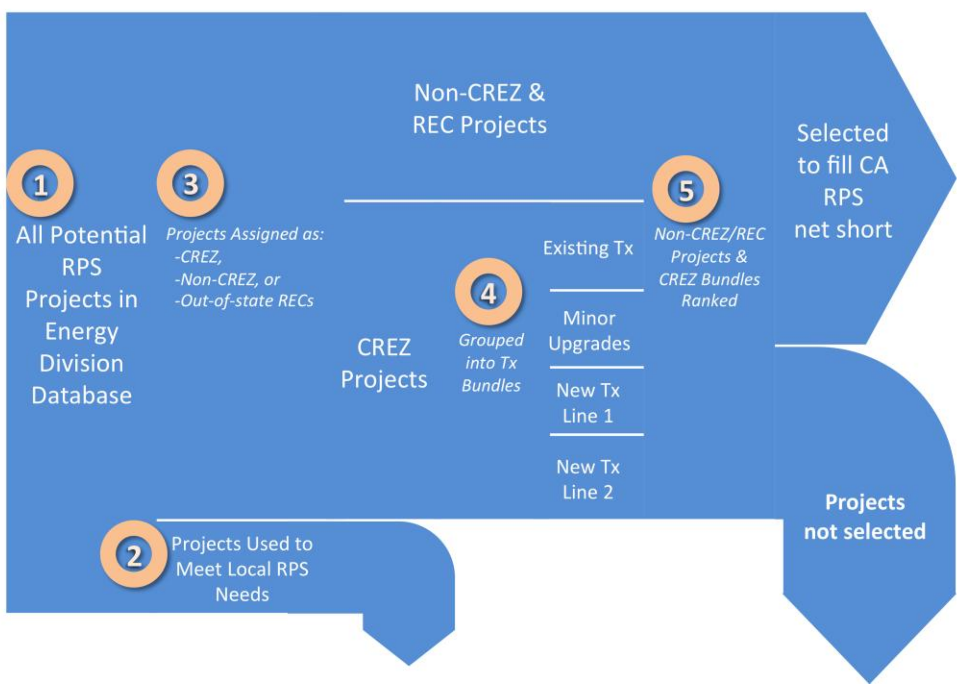

Figure 7. The RPS Calculator Resource Selection Methodology: (1) Compile a database of all potential RPS projects in the Western Interconnection. (2) Allocate lowest cost out-of-state theoretical projects to host states to satisfy all RPS targets for 2022 in states other than California. (3) Assign remaining projects to CREZ areas, or designate as non-CREZ or out-of-state REC-only. (4) Rank projects within each CREZ and sort into "transmission bundles." The most viable projects are assigned to "existing transmission" capacity, followed by "minor upgrades" and finally "new transmission" lines. (5) Rank each CREZ bundle, non-CREZ and REC-only resource according to scenario-specific criteria such as cost and environmental score. These projects then compete against each other for selection as an RPS project. Select best-ranking projects to fill California's 33 percent RPS target.

d) Recommended areas for regional stakeholder input

i) Operating flexibility and integration needs

Today, integration costs are not considered in the portfolio development process and are ascribed a value of zero. However, these integration costs are not likely to be zero or even uniform across the grid. New transmission could accommodate resources over a larger area to provide additional diversity, which could reduce some integration costs. Furthermore, transmission built to access out-of-state resources could provide additional benefits by providing access to much needed flexible capacity resources.[56] However, scheduling requirements across the interties may restrict out-of-state resource capacity to meet some types of operating flexibility needs.

Stakeholder Opportunity
Identify any potential system benefits for out-of-state renewable energy generation and transmission, such as reduced integration costs and greater diversity of resources, and make recommendations for evaluating these benefits in the portfolio selection process. Consider potential barriers at the state or federal level, such as intertie scheduling restrictions.

ii) Transmission costs

Both stakeholders and regulators acknowledge shortcomings in the RPS Calculator methodology for determining transmission costs. First and foremost, the method computes transmission costs for each CREZ area uniformly, without accounting for costs of individual projects. Second, all projects are assumed to be fully deliverable, which may distort transmission costs for projects that proceed without full capacity deliverability. Finally, the method does not specifically address options such as Dynamic Transfers that may use existing transmission more effectively.

iii) Updated project information

Several stakeholders we interviewed commented that some of the assumptions in the CPUC scenario development process are not up to date with market realities. For example, in the past CPUC portfolios have included generation in several CREZs that did not have significant commercial interest. At the same time, areas in other regions with significant commercial interest did not fall within the portfolios' preferred areas. Stakeholders have recently worked to address these problems in the portfolio development process.

Stakeholder Opportunity
The LTPP scenario process is an opportunity to provide information on projects of commercial interest in locations such as neighboring Balancing Authority Areas that may be less visible to California decision-makers than those being developed within the state.

[56] Flexibility refers to resources that are able to respond quickly to real-time changes in energy supply or demand. This characteristic is important for integrating variable renewable resources such as wind and solar.

3.5 Recent developments in the LTPP process

a) Recent LTPP cycles

While the fundamentals of the LTPP process were established in earlier cycles, new issues have emerged in recent years.[57] Most notably, the standardized planning assumptions and scenario development process have become a primary focus of the proceeding.[58] The 2010 LTPP proceeding[59] recently concluded with a Commission Decision[60] authorizing the IOU procurement plans.[61] The current LTPP proceeding[62] was initiated with a Commission Order Instituting Rulemaking on March 22, 2012. The 2012 LTPP Scoping Memo outlines what decisions will be made in this proceeding and identifies three tracks that are progressing according to the schedule shown in Appendix H. Future cycles may vary; however, because each LTPP builds upon the previous cycle, we expect future LTPP proceedings to adopt an approach and timeline similar to the current cycle.

b) 2010 LTPP renewable resource portfolios

Portfolios developed for the prior (2010) LTPP planning cycle informed the 2011-2012 CAISO Transmission Planning Process. The portfolios provide the baseline resource assumptions, outlined in the Scoping Memo:[63]

1. "Trajectory" (also called "commercial interest") - Intended to model a future similar to the utilities' current contracting and procurement activities. CAISO used this as the base portfolio.
2. "Cost-constrained" - Focuses on resources that can be procured at lowest cost.
3. "Time-constrained" - Focuses on resources that can come online most quickly.
4. "Environmental-constrained" - Focuses on resources that scored highest according to the environmental scoring methodology described in the planning assumptions.

> **? What is the Base Portfolio?**
>
> One of the LTPP portfolios is selected as the "base portfolio" used as the primary input for transmission planning. The 2012 LTPP process selected the "commercial interest" portfolio as the base portfolio. The 2010 LTPP process did not specify a base portfolio, but a variant of the "cost-constrained" portfolio was selected as the base for CAISO TPP purposes.

Procedurally, it is important to recognize the lag between the CPUC portfolio development process and the CAISO TPP. For instance, the 2011-2012 TPP stakeholder processes used RPS portfolios developed largely in the CPUC's 2010 LTPP proceeding.[64] To avoid having

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57 See Appendix G for a full listing of LTPP cycles to date.

58 Other primary focuses of the 2012 LTPP include local capacity needs (driven by analysis of scenarios created in the 2010 LTPP), procurement authorization which may occur based on the anticipated operational flexibility modeling of the completed 2012 LTPP scenarios, and updates to the three large IOUs' procurement plans.

59 See CPUC 2010 LTPP proceeding R.10-05-006.

60 See CPUC decision D.12-01-033, Jan. 12, 2012, on Track 2, bundled plans.

61 A separate decision (D.12-04-046) on April 19, 2012, addressed issues such as local area needs and operating flexibility needs. Parties agreed to a settlement and subsequent hearing process. This process is presently underway in Tracks 1 and 2 of the 2012 LTPP process. Some stakeholders believe the decision on local area needs should take place prior to determination of broader system needs that have more flexibility in terms of siting and procurement options.

62 See R.12-03-014.

63 CPUC, *Assigned Commissioner and Administrative Law Judge's Joint Scoping Memo and Ruling*, R.10-05-006 (Filed Dec. 3, 2010), p. 25, http://docs.cpuc.ca.gov/PublishedDocs/EFILE/RULC/127542.PDF.

64 Some stakeholders who became involved in the TPP were dismayed to learn that the portfolios had already been decided earlier through the CPUC process.

disjointed processes, some stakeholders even urged further consolidation of the LTPP and TPP processes so that transmission planning decisions were made by a single entity or process.

c) 2012 LTPP renewable resource portfolios

A straw proposal by the CPUC Energy Division first introduced the conceptual 2012 LTPP portfolios.[65] Notably, the CPUC selected a smaller set of resource portfolio choices, reflecting its view that the smaller RNS will limit the degree of flexibility in choosing new renewable resources to meet the RPS targets. The portfolios are as follows:

1. "Base" portfolio (also called "commercial interest") - Designed to be a best forecast of future RPS development using cost estimates as a proxy for future commercial interest.
2. "High DG" portfolio - Designed to represent a near- term policy shift to encourage significant development of distribution- interconnected resources near load. Some stakeholders view this portfolio as a proxy for Gov. Brown's stated goal of developing 12,000 MW of distributed generation in California.[66]
3. "Preferred location" portfolio (also called "environmentally constrained") - Assumes that additional RPS supply will be largely driven by environmental concerns with new RPS resources sited accordingly.

These three basic portfolio designs are reflected in the proposed scenarios of the Sept. 20, 2012, Assigned Commissioner Ruling.[67]

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[65] 2012 LTPP, CPUC's Straw Proposal on Standardized Planning Assumptions, May 2012, http://www.cpuc.ca.gov/NR/rdonlyres/502D2DA7-A160-4652-88E5-570AC9B0822B/0/2012LTPPStrawProposalvFinal2.doc.

[66] See http://www.jerrybrown.org/jobs-california%E2%80%99s-future.

[67] The "Base" portfolio is reflected in the following scenarios: Base, Replicating TPP, Early SONGS Retirement, Stress Case and Early Nuclear Retirement. The "High DG" portfolio is reflected in the High DG + High DSM and the High DG + High DSM, 40% RPS by 2030 scenarios. The "Preferred Location" portfolio is reflected in the Environmental scenario. The composition of the RPS portfolios varies due to differences in forecasted load embedded in each scenario. Forecasted retail sales are affected by Demand Side Resource assumptions, such as energy efficiency and combined heat and power resources. Retail sales are exclusive of pumped load.

4. CAISO Transmission Planning Process

In a nutshell:

- The CAISO transmission planning process (TPP) identifies transmission projects driven by needs for reliability, economics or policy.
- Policy-driven transmission projects include those needed to accommodate new renewable resources required to meet California's 33 percent RPS goal.
- Assumptions about which renewable resources will be developed are based on the portfolios developed through the CPUC's LTPP process.
- New transmission capacity from upgrades in the TPP is allocated to generators requesting interconnection through the Generator Interconnection and Deliverability Allocation Procedure (GIDAP, formerly Generator Interconnection Procedure).

Key documents/outcomes:

- Annual Transmission Plans (2011-12 Plan, 2010-11 Plan)
- Renewable Resource Portfolios submittal letters from CPUC to CAISO (2011-12 TPP Letter and Attachment, 2012-13 TPP Letter)
- FERC decision approving integration of TPP and GIP (Generator Interconnection Procedure) (PDF)

4.1 Overview of the CAISO

a) CAISO's role and responsibilities

CAISO is a nonprofit public benefit corporation that manages the transmission grid for approximately 80 percent of power sold in California. Several transmission owners have given control of their transmission system to CAISO, including California's three large investor-owned utilities (PG&E, SCE and SDG&E). The CAISO manages wholesale electricity markets and dispatches electricity generation and facilities. In managing the grid, the CAISO provides open access to the transmission system and performs long-term transmission planning. The CAISO is regulated by the Federal Energy Regulatory Commission (FERC), which has jurisdiction over the interstate transmission of electricity, among other areas. As a regulated entity, the CAISO operates under the terms and conditions of its FERC-approved tariff. CAISO's activities are strictly governed by its tariff obligations. Activities CAISO is responsible for include:

- Managing real-time and day-ahead markets for energy sold from generators to load serving entities (LSEs)
- Balancing generation and load to maintain grid reliability within the CAISO control area (Figure 8)
- Processing new generator interconnection requests to allow open-access to the CAISO transmission system
- Conducting long-term transmission planning activities to identify and prioritize new ratepayer-funded transmission projects

CAISO recently adopted a strategic plan with the following as one of its four core objectives: “Explore opportunities for regional collaboration and focused technological innovation.”[68]

Figure 8. This map illustrates the CAISO control area in yellow. Some CAISO-controlled transmission lines extend beyond these areas into neighboring states, as with Valley Electric Association beginning in 2013. Other examples are not shown here. (Source: CAISO, http://www.caiso.com/about/Pages/OurBusiness/UnderstandingtheISO/The-ISO-grid.aspx)

Stakeholder Opportunity
• California’s RPS law gives preference to renewable resources that are directly interconnected to California Balancing Authorities, including CAISO.[69] Regional entities wishing to develop renewable energy resources in other areas may want to consider opportunities to expand the CAISO footprint in other states. This may involve building new transmission lines that connect to the existing CAISO network. For example, Valley Electric Association in Nevada will be joining CAISO in 2013.

b) Navigating CAISO’s stakeholder processes

CAISO continually strives to improve its business practices through ongoing stakeholder processes and tariff revisions. For example, recent problems with the Generator Interconnection Procedures (GIP) led to a series of reforms to integrate the GIP with the Transmission Planning Process (TPP). While CAISO’s stakeholder processes are

[68] CAISO 2012-2016 Strategic Plan, http://www.caiso.com/Documents/2012-2016StrategicPlan.pdf.

[69] Preference also is given to resources that transfer output directly to a CBA in real time without substitution of energy from other sources, or dynamically transferred energy to a CBA.

numerous and can be difficult to track, they generally follow the sequence illustrated below (Figure 9):

1. CAISO introduces a potential policy or reform through an issue paper that is turned into a proposal for board approval.
2. CAISO submits an amendment to its tariff for FERC approval.
3. CAISO implements the change after FERC approval.

Throughout the sequence there are multiple opportunities for stakeholder input. Some processes, such as generator interconnection, require revision on a regular basis and are expected to have annual opportunities for stakeholder input and revision.

Figure 9. CAISO Stakeholder Process.
(Image Source: http://www.caiso.com/informed/Pages/StakeholderProcesses/Default.aspx)

c) Key transmission and reliability planning processes at CAISO

In recent years, two discrete planning processes[70] within CAISO have been central to its role in determining which transmission system investments are needed to meet California's RPS goals:

1. Generator Interconnection Procedures[71] (GIP)
2. Transmission Planning Process[72] (TPP)

The steps needed to accomplish each are parsed into annual cycles with discrete outcomes. For instance, each TPP cycle ultimately yields a comprehensive transmission plan that identifies new ratepayer-funded transmission upgrades necessary to meet various system needs. The CAISO Board of Governors adopted the most recent, 2011-2012 transmission plan in March 2012.[73] The current TPP cycle (2012-2013) is underway and will culminate with a comprehensive transmission plan to be presented for CAISO Board of Governors' approval in March 2013.

Meanwhile, through the GIP, CAISO has developed a parallel process whereby developers of energy projects, including renewable energy projects, can request interconnection to the CAISO grid during an annual request window and subsequent study process (or "Cluster"). Currently, the CAISO has accepted requests for new projects in "Cluster 5" which are to be studied over the coming months. A new request window for "Cluster 6" projects will be open in early 2013.[74] Until recently, transmission upgrades were largely driven by these generator interconnection requests. The following section describes how this process was recently reformed.

[70] In addition to these two processes, planning for renewable energy integration and flexible ramping has been another major focus of recent CAISO activities. However, that process is beyond the scope of this paper.
[71] GIP stakeholder process: http://www.caiso.com/planning/Pages/GeneratorInterconnection/Default.aspx.
[72] TPP stakeholder process: http://www.caiso.com/planning/Pages/TransmissionPlanning/Default.aspx.
[73] 2011-2012 ISO Transmission Plan, adopted March 2012, http://www.caiso.com/Documents/Board-approvedISO2011-2012-TransmissionPlan.pdf.
[74] See Appendix I for a visual depiction of the CAISO process timeline.

d) The role of the TPP and GIP in identifying new transmission upgrades

In restructured electricity markets, there are two general approaches to the challenging problem of identifying necessary transmission investments:

1. Generation leads transmission
2. Transmission leads generation

Both approaches have advantages and disadvantages,[75] but until recently CAISO typically prioritized the first approach whereby ratepayers refunded the cost of any transmission network upgrades needed to accommodate delivery of energy from new generation projects to load. Thus, the generation interconnection request process drove the bulk of large new transmission upgrades. Since start-up, the CAISO develops an annual TPP to identify projects for "system needs" commonly arising from reliability or economically driven concerns. However, this process has not been the primary driver of ratepayer-funded transmission.

This "generation leads" approach to transmission investment has led to a number of problems that have precipitated the need for GIP reform. For instance, in an open access environment, CAISO is required to maintain neutral treatment of all generators seeking interconnection. However, the inability to "pick winners" among applicants has also led to some undesired consequences. With the advent of California's 33 percent RPS and other major changes to the generator interconnection procedures, a large number of projects began to flood the CAISO interconnection queue, representing a significant amount of transmission upgrades, many for projects unlikely to be built.[76] Concerns arose about possible overinvestment in the transmission system at ratepayer expense and the delay of viable projects with later queue positions. Meantime, ratepayers were funding network upgrades to accommodate new projects without a way to make the process open and transparent due to the confidential nature of projects under development.

Once the problems were fully recognized, CAISO responded through several reforms intended to more accurately identify the transmission upgrades needed. Two major changes included:

1. Inclusion of "public policy" as a category for identification of new transmission projects in the TPP[77]
2. Integration of the GIP with the TPP process

In 2010, CAISO modified the TPP to add "public policy" as a category for ratepayer-funded upgrades in anticipation of FERC Order 1000.[78] While public policy encompasses a variety of possible network upgrades to accommodate new generation, to date it has largely been used to address RPS-related projects. An estimate of the sizes and locations of likely renewable energy projects is required to ensure enough transmission investment to

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[75] See "Opinion on the Integration of Transmission Planning and Generator Interconnection Procedures" by Members of the Market Surveillance Committee of the California ISO, March 2012, http://www.caiso.com/Documents/MSCFinalOpinion-Integration-TransmissionPlanning-GeneratorInterconnectionProcedures.pdf.

[76] According to some stakeholders interviewed, only about 14,000 MW of the approximately 40,000 MW of renewable generation in the interconnection queue may be needed to meet the state's RPS goals.

[77] *Cal. Indep. Sys. Operator. Corp.*, 133 FERC ¶ 61,224, Dec. 16, 2010, http://www.caiso.com/Documents/Dec16_2010Orderconditionallyacceptingtariffrevisionsandaddressingpet_docketER10-1401-000_ER10-2191-000_EL10-76-000.pdf.

[78] Public policy-driven transmission projects are also a fundamental part of the recent landmark FERC Order No. 1000.

accommodate the RPS. CAISO uses an estimate based upon the renewable generation portfolios developed by the CPUC for each scenario considered in the LTPP process.[79]

Additionally, the GIP was altered so that new generator interconnection customers were only granted ratepayer-funded transmission upgrades that aligned with the TPP. FERC recently approved the CAISO's tariff amendment reflecting this change,[80] known as the Generator Interconnection and Deliverability Allocation Procedures (GIDAP). Now, instead of being granted unlimited ratepayer-funded transmission upgrades, new interconnection customers compete for a limited pool of ratepayer-funded transmission upgrades (or "deliverability") that is predetermined by the TPP and in turn by the CPUC-created resource portfolios.

This signifies a shift towards a "transmission leads generation" investment philosophy. While CAISO had previously conducted a comprehensive transmission planning process parallel to the GIP, integrating these two processes ensures that the TPP is now the primary single venue for identifying ratepayer-funded transmission upgrades. Under the public policy-driven transmission category, the TPP identifies transmission needed for new generation in resource portfolio areas.

In essence, the TPP now decides *how much* and *where* these ratepayer-funded transmission investments for deliverability will be made based upon the generation portfolios determined by the CPUC. Meanwhile, the generator interconnection process determines how the transmission capacity associated with these upgrades will be allocated to projects that have requested interconnection with deliverability (versus energy-only projects). Thus, projects in areas favored by the CPUC portfolios may be more likely to receive ratepayer-funded transmission upgrades.

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[79] See Chapter 3 for a detailed discussion of the LTPP process.

[80] *Cal. Indep. Sys. Operator. Corp.*, 140 FERC ¶ 61,070, July 24, 2012, http://www.caiso.com/Documents/July242012OrderConditionallyAcceptingTariffRevisions-DocketNoER12-1855-000.pdf.

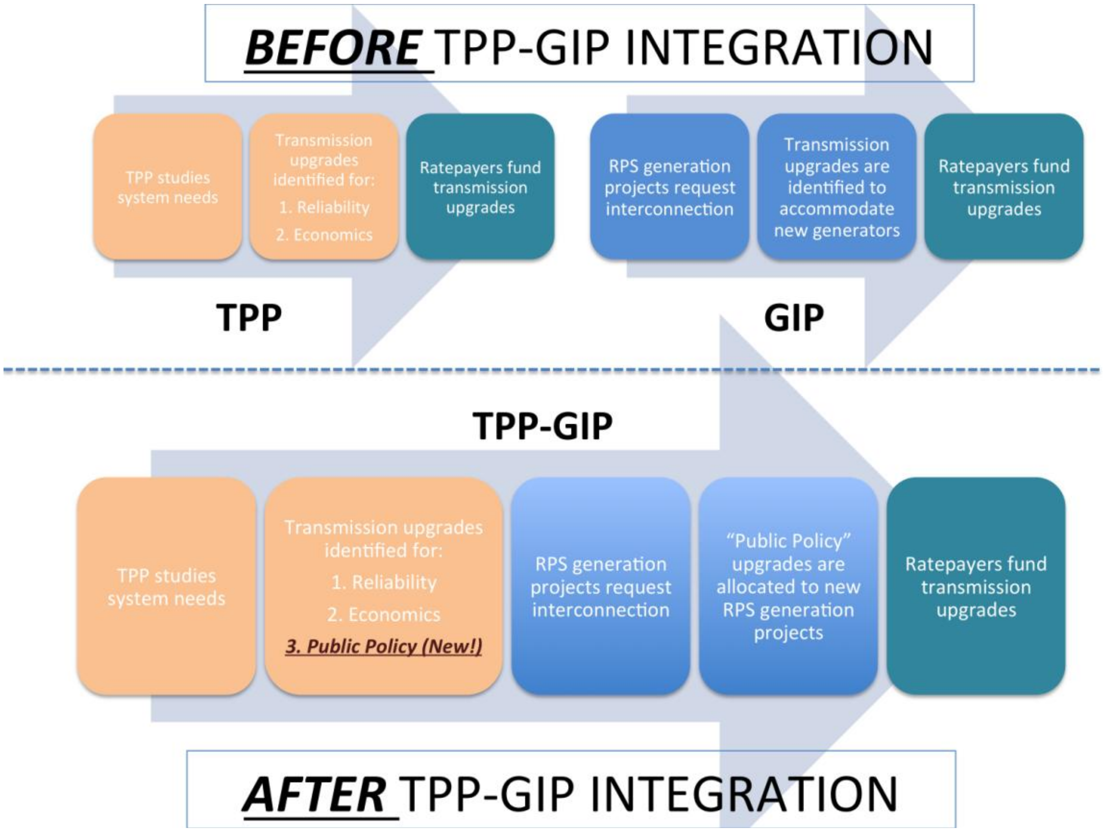

Figure 10. CAISO transmission planning process before and after integration of the GIP (approved by FERC in July 2012).

The provision of ratepayer-funded transmission capacity does not necessarily exclude projects from the market. Depending on location, not all projects may need transmission upgrades and many may be able to fit on existing transmission lines. Projects that need additional transmission capacity but receive no deliverability allocation can still participate by funding their own transmission upgrades for deliverability, although this is uncommon due to the expense. Finally, projects can proceed as "energy only" and forego providing any Resource Adequacy ("capacity") value to the utility. This occurs infrequently because utility procurement tends to give strong preference to projects with "full deliverability." Energy only projects will receive no Resource Adequacy payment from the utility, a significant benefit that is often necessary for a project's financial viability. Additionally, the developer assumes

> **? What is "full capacity deliverability" and "energy only"?**
>
> ***"Full capacity deliverability"*** projects are those capable of delivering the full capacity of energy production without the risk that transmission capacity will be unavailable during peak demand.
>
> ***"Energy only"*** projects are able to deliver energy when transmission capacity is available, but bear some risk of curtailment due to transmission lines being at full capacity during peak hours.

the risk that energy from the project could be curtailed in the event that transmission capacity is unavailable. Figure 11 illustrates possible scenarios a project may face under this regime.

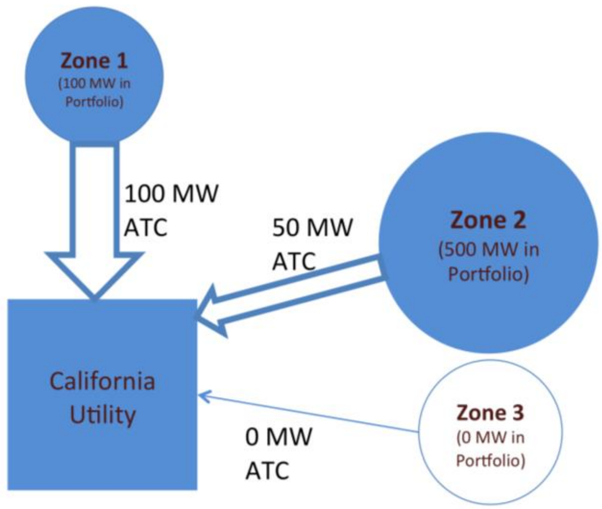

Figure 11. The following descriptions illustrate a few potential outcomes of the deliverability allocation procedure if the existing transmission network were similar to the diagram above (ATC = Available Transmission Capacity):

Case 1: 100 MW Project at Zone 1 -> Transmission capacity is sufficient for full deliverability along existing transmission capacity; no transmission upgrade required.

Case 2: 100 MW Project at Zone 2 -> Transmission capacity is insufficient for 500 MW of projects in portfolio; only 50 MW of ATC available. Project will compete with others at Zone 2 for a portion of the deliverability network upgrades needed to accommodate 500 MW of generation.

Case 3: 100 MW Project at Zone 3 -> Transmission capacity is insufficient for 100 MW project to attain "full deliverability" but project is ineligible for transmission upgrades (0 MW in portfolio at this location). Project can move forward as "fully deliverable" if it pays own transmission upgrade costs or it can elect to be "energy only."

4.2 Generator Interconnection and Deliverability Allocation Process

a) Overview

As part of its open-access transmission planning responsibilities,[81] CAISO handles all new generator requests for interconnection to its transmission system. This process is now known as the Generator Interconnection and Deliverability Allocation Procedures (GIDAP) and is intended to provide a non-preferential opportunity for any generator to connect to the system.

To understand the significance of the GIDAP for RPS project-related transmission, it is important to first understand how a renewable energy project progresses through the California procurement process. Generally, the RPS project development cycle is as follows:

1. A developer secures a location for a new project and performs initial design work.
2. The developer submits a request for interconnection to the CAISO and is added to the interconnection queue. In recent years, CAISO has created an annual "request window" for new projects in each cluster (see section 4.1.c for details).

[81] As mandated by FERC Order No. 890.

3. CAISO performs initial "Phase 1" interconnection studies for each project in the queue.
4. The developer submits the project to one or more utilities pursuant to annual RPS Request for Offers (RFO).
5. If the utility selects the project, it signs a power purchase agreement with the developer and sends an advice letter to the CPUC for approval.
6. CAISO completes additional "Phase 2" interconnection studies with the updated interconnection queue. In the past, Phase 2 studies have occurred after signing a power purchase agreement. However, due to the heavy competition in recent RFOs, utilities may only sign agreements with projects that have completed Phase 2 studies.
7. The CPUC assesses project costs and viability and may approve the power purchase agreement.
8. The project developer signs the interconnection agreement.
9. CAISO begins the transmission upgrades, if allocated to the project (see next section).

During the RPS resource procurement process, renewable energy developers are generally responsible for ensuring that energy from their projects can be delivered to the load-serving entities. Any renewable developer interconnecting directly to the CAISO system must go through the GIP to determine how much of the energy produced can be delivered to load. The generator interconnection procedures include studies of how the new generator will affect power flow and stability on the grid. Each new generator interconnection request is processed on a first-come, first-served basis, by cluster. Initially, the CAISO conducted the studies sequentially and managed them through a neutral interconnection queue. Interconnection requests have been extremely high in recent years. As a result, the interconnection queue has grown excessively long and there are ongoing efforts to address this problem. Some developers have expressed frustration with the process, particularly in earlier years when study process could take years to complete. More recently, many agree that the process has improved significantly. In particular, the cluster approach set study timelines, giving developers greater certainty in their ability to complete a project on schedule.

> **? What is the interconnection queue?**
>
> Because the transmission system controlled by CAISO is "open access," any generator can request to be interconnected to the system. CAISO processes requests on a non-discriminatory, first-come, first-served basis. Each new project is added to the interconnection queue so that its effects on the system, taking into account other projects ahead of it in the queue, can be studied before the request is granted.

b) Allocating deliverability

Due to reliability requirements, utility resource planners generally place a premium on resources that can offer Resource Adequacy benefits (capacity), in addition to energy delivered. In fact, many RPS projects are only economically viable if they are able to sell the Resource Adequacy value of the project to the utility seeking procurement. However, in order to provide the full Resource Adequacy value to the utility, the developer must ensure that the project has sufficient transmission capacity to ensure "full capacity deliverability."

Thus, one of the most critical steps for developers undergoing the GIP is the allocation of "deliverability network upgrades" or DNUs. This is the decision process through which CAISO selects which projects will be granted transmission deliverability capacity afforded by upgrades. Previously, generators initially funded GIP network upgrades, but these upgrades were refundable over a five-year period after the generators come online. Now, generators either receive ratepayer funded delivery network capacity or else fund such capacity without reimbursement. Therefore, if upgrades are necessary for a project to provide its full capacity value and contribute to Resource Adequacy, its economic viability may hinge on the allocation of DNU benefits.

Some project developers are fortunate to be located in places where transmission capacity is already available to allow energy to be fully delivered to the buyer. These projects do not need additional deliverability upgrades. Projects requiring transmission upgrades face the following possibilities:

1. CAISO allocates to the project a portion of the limited pool of ratepayer-funded deliverability upgrades, thereby granting the project "full deliverability."
2. Where CAISO does not allocate deliverability upgrades to the project, the developer can elect to pay for transmission on its own to ensure deliverability. This is not common given the narrow profit margins many projects face in the competitive utility procurement process.
3. The project can elect to move forward as an "energy only" project. The project does not receive any Resource Adequacy benefits from the buyer and could risk curtailment during times of peak transmission use.

Stakeholder Opportunity

- Recommend inputs and analytical methods for the RPS procurement process to appropriately assess "energy only" products and "partial deliverability" products. This may allow a broader variety of resources, including those without firm transmission capacity to access the California market.
- Identify any resource adequacy benefits that would accrue to California from a more regional portfolio of renewable resources – for example, due to geographic diversity that increases capacity value.
- Encourage a discussion between utilities, developers and stakeholders of who should bear the risk associated with the curtailment of renewable energy delivery. High levels of renewable resources on the system will ultimately necessitate some level of curtailment. Balancing Authorities can develop tools to reduce the need for curtailment, including cooperative actions across regions.[82] This could facilitate more energy-only projects that are not allocated transmission deliverability and help make the best use of existing transmission capacity.

[82] See Lisa Schwartz, Kevin Porter, Lori Bird, Mike Hogan, Brendan Kirby, Christina Mudd, Sari Fink, Jennifer Rogers and Dave Lamont, *Meeting Renewable Energy Targets in the West at Least Cost: The Integration Challenge*, prepared for Western Governors' Association, 2012, http://www.westgov.org/index.php?option=com_joomdoc&task=doc_download&gid=1610.

c) The status of the generator interconnection queue

There has been an extraordinary amount of competitive interest among generators requesting interconnection and being added to the queue. This interest is expected to persist in the upcoming Cluster 6 request window despite the fact that there is already more than double the generation in the queue than necessary to meet the 33 percent RPS. The motivations for this high degree of interest are not readily apparent. However, many of the stakeholders we interviewed believe that the continued drive to get projects in the queue is due to low barriers to entry and speculation on the part of some developers that the need for RPS projects will increase due to higher-than-expected contract failure or an increase in the RPS target. In either case, developers already in the queue would have an advantageous position.

CAISO has sought to remedy this problem by requiring security deposits for participants in the queue process. The vast majority of projects are seeking full capacity deliverability status, reflecting the perception that utility procurement interests heavily favor resource adequacy products. Additionally, developers may opt for full deliverability to avoid any possible curtailment risk. Since most major transmission network upgrades are associated with achieving full deliverability, procurement preferences should be considered carefully to avoid over-building transmission.

d) Future interconnection process reforms (GIP 3)

In addition to the TPP-GIP integration process, other GIP reforms have occurred and are expected to become routine. The latest of these reforms ("GIP 3") was initiated but deferred until late 2012 or early 2013. As part of the initial effort, CAISO conducted a survey to identify interest in specific reforms to the interconnection process. Some of the issues raised have implications for out-of-state stakeholders. For example, one suggestion was to allow allocation of deliverability to transmission projects external to the CAISO system. This would benefit transmission developers seeking to provide generation-tie transmission lines for remote wind and solar developers. The problem for these projects is that deliverability assurance is needed in order to secure generation developers, but under the current rules, CAISO can only provide deliverability upgrades to generators interconnecting to the CAISO system through the GIP. The proposed reform would allow external transmission line developers to receive a portion of deliverability upgrades. One question this reform raises, however, is whether a transmission developer without generation behind it can credibly commit to providing resources to the market such that it should be granted deliverability similar to a generator inside California.

Stakeholder Opportunity
Participate in CAISO stakeholder surveys on topics of interest for future reforms. Comment on issues affecting regional coordination such as deliverability network upgrades for External Transmission Lines.

4.3 Transmission Planning Process

a) Overview

Since FERC Order 890 was adopted in 2007, CAISO and other transmission owners have been required to conduct "open, coordinated and transparent planning on both the local and regional level."[83] CAISO's transmission planning process (TPP) has served as the focal point for these planning activities. The TPP's primary focus is developing an annual Transmission Plan, which encompasses all transmission projects identified to meet "system needs." Transmission system upgrades generally arise from at least one – and sometimes more than one – of the following:

- Reliability
- Economics (congestion)
- Policy (for example, RPS)

Any transmission system upgrades required to meet these needs are identified in the Transmission Plan and ultimately approved for reimbursement by ratepayers. A new TPP cycle begins each year and generally continues through the following year.[84]

b) How does CAISO develop the Transmission Plan?

The CAISO Transmission Planning Process occurs in three phases:

- Phase 1 - Planning assumptions and study plan
- Phase 2 - Technical studies and board approval of transmission plan
- Phase 3 - Competitive solicitation for transmission projects

i) Phase 1 – Planning Assumptions and Study Plan

This establishes all assumptions and forecasts including future resources and energy demand. The CAISO prepares a Draft Study Plan and offers it for stakeholder feedback. This feedback is key input to eventual publication of a Final Study Plan. An important step in this phase of the TPP cycle is establishing inputs about future renewable generation locations. These assumptions play a major role in identifying the transmission required to meet policy-driven needs.

Rather than develop its own assumptions about future renewable energy generation, CAISO defers to the CPUC and CEC to develop renewable resource portfolios through the LTPP proceeding. For other assumptions, such as future energy demand, CAISO relies on its own analysis or information sources other than the CPUC-created scenarios. In May 2010, the CPUC and the CAISO signed a Memorandum of Understanding[85] to better coordinate the state's transmission planning efforts.[86] As part of this agreement the CPUC and CEC jointly communicate their updated renewable resource portfolios to CAISO via a submittal letter

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[83] See Fact Sheet on FERC Order No. 890, http://www.ferc.gov/industries/electric/indus-act/oatt-reform/order-890/fact-sheet.pdf.
[84] Documents for the 2012-2013 TPP cycle are posted at http://www.caiso.com/planning/Pages/TransmissionPlanning/2012-2013TransmissionPlanningProcess.aspx.
[85] The document states, "The CPUC develops renewable generation portfolio scenarios as part of its Long Term Procurement Plan process that will assist the ISO in identifying transmission projects needed under various renewable generation location assumptions and developing a comprehensive transmission plan." CPUC and CAISO Memorandum of Understanding, May 2010, http://www.caiso.com/2799/2799bf542ee60.pdf.
[86] *Id.*, p. 1.

for each TPP cycle.[87] In return, to the extent CAISO uses the portfolios, the CPUC defers to CAISO's technical assessment of need. Stakeholders pointed out that this level of coordination is a relatively recent development and will undoubtedly improve in the coming years.

CAISO has, in the past, made minor adjustments to the final CPUC "base case" generation portfolio based on subsequent stakeholder feedback.[88] CAISO has emphasized that it is committed to working with the CPUC's portfolio development process rather than making unilateral changes to the portfolios based on input received later. Accordingly, stakeholders should be aware that the CPUC portfolio development process is the right time and place for effective input on renewable generation portfolios. In the 2012-2013 TPP, CAISO, CPUC and CEC jointly received stakeholder comments in the CAISO process in and made significant changes to the proposed portfolios before final portfolios were submitted by the CPUC and CEC in May 2012.

In addition to the portfolios proposed by the CPUC, CAISO may study additional portfolios. For example, CAISO has conducted studies on higher statewide load growth in the event that "uncommitted" energy efficiency policies assumed by the CPUC do not come to pass. The renewable resource procurement necessary to meet the RPS also would increase if load growth is higher than forecast, and additional transmission may be needed to deliver renewable energy. In addition, a higher load growth scenario could open the door for more out-of-state resources.

ii) Phase 2 – Technical analysis and board approval of transmission plan

This phase of the process conducts the primary analysis for reliability, economic and policy-driven transmission needs. These results are incorporated in the transmission plan, which then goes to the CAISO board for approval. Figure 12 shows the sequence of transmission planning studies.

[87] Recent portfolio submittal letters sent from CPUC to CAISO: 2011-12 TPP Portfolio Submittal Letter (PDF) and Attachment (DOC); 2012-13 TPP Portfolios Submittal Letter (PDF).

[88] For instance, in the 2011/2012 TPP cycle, changes were made in consultation with the CPUC to increase generation in some areas within California and decrease generation in other areas, such as Colorado and Wyoming.

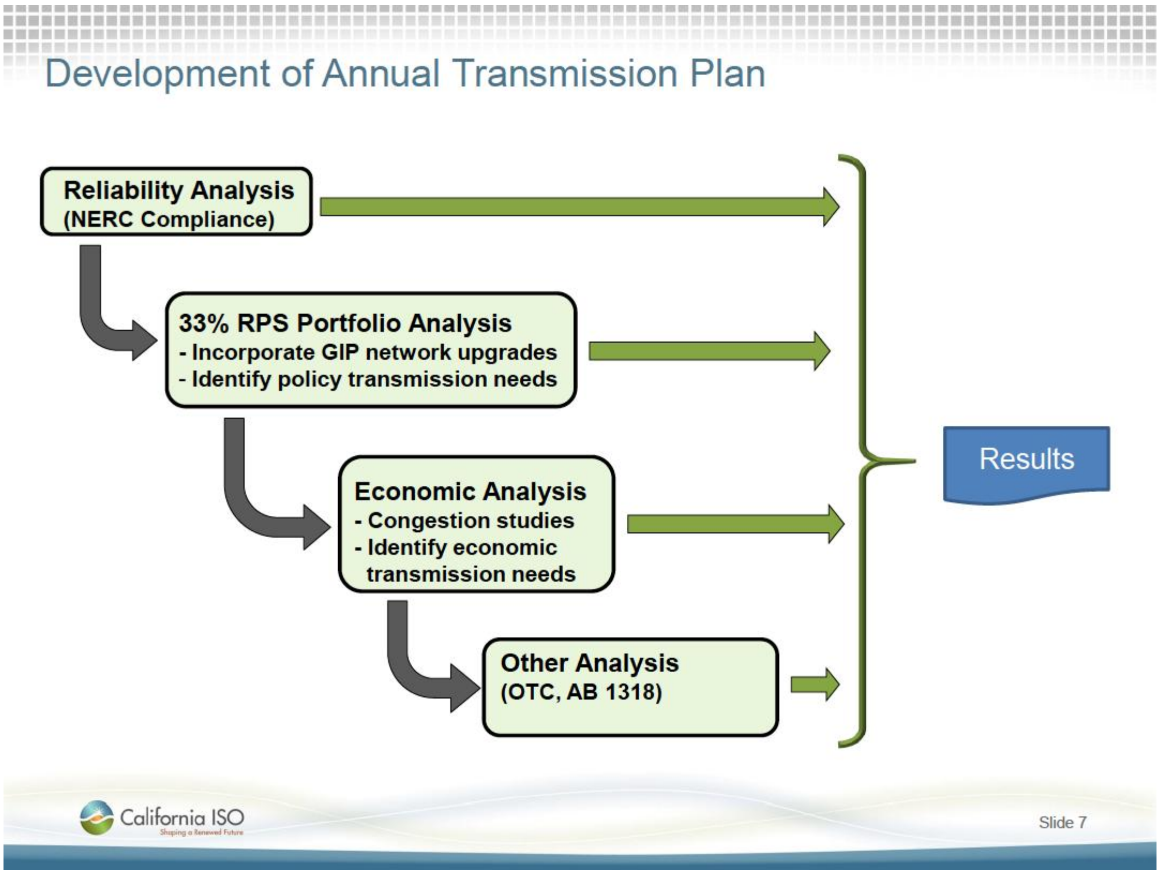

Figure 12. Sequence of analysis in the CAISO TPP study process. Reliability is considered first, followed by policy needs, then economic needs and finally other supplementary studies. (Image Source: CAISO, Webinar June 19, 2012, Slide 7: http://www.westgov.org/wieb/webinars/2012/06-19-12CREPC-SPSC.pdf)

The first stage of analysis ensures the system meets reliability criteria as set by the North American Electric Reliability Corporation (NERC), the Western Electricity Coordinating Council (WECC) and CAISO itself. Second, CAISO layers the reliability upgrades on to the current transmission system and performs additional analysis to see if further upgrades are needed to accommodate any policy-driven needs, including the 33 percent RPS.

Third, CAISO considers any economically driven upgrades needed to relieve transmission congestion. As part of the economic analysis, any party can request specific studies through a formal study request window. Finally, CAISO conducts other analysis such as transmission upgrades needed to accommodate upcoming retirement of once-through cooling (OTC) generation units.[89]

Public policy transmission elements are identified as either Category 1 or Category 2. Category 1 represents transmission upgrades approved with the current transmission plan, and Category 2 represents those that will be reevaluated in a later plan.

[89] Once-through cooling units discharge heated water into the local environment and can negatively impact marine life. California is implementing a policy adopted by the State Water Resources Board that will require most of these units to be retired or repowered. See http://www.caiso.com/1c58/1c58e7a3257a0.html.

iii) Phase 3 Competitive solicitations for transmission projects

Under current CAISO rules, after board approval of the transmission plan, CAISO assigns reliability-driven projects to the appropriate incumbent transmission owner and initiates a competitive solicitation process to procure transmission projects for Category 1 policy-driven or economically-driven upgrades. To date, there has not been a need to execute the competitive solicitation process. For example, the most recent Transmission Plan, for 2011-2012 (adopted March 2012), identified the need for several reliability driven projects, but no policy- or economically-driven upgrades. The 2010-2011 Transmission Plan identified one Category 1 policy driven upgrade, Path 42, but it was not open to competitive solicitation because it was a reconductoring project for an existing transmission line in an incumbent utility's service area.

Stakeholder Opportunity
Participate in the Transmission Planning Process: • Submit comments on study plan assumptions and the draft study plan, including any recommended adjustments to the LTPP renewable generation portfolios. • CAISO has a framework for accepting requests for economic (congestion) studies. Stakeholders can encourage neighboring Balancing Authorities to request that CAISO perform economic studies for transmission projects that may reduce current or forecast congestion, thus enabling regional energy transfers.

c) Current and future TPP issues

The lack of policy-driven projects identified by CAISO reflects its conclusion that transmission currently under development is sufficient for California to accommodate its 33 percent RPS goals, assuming the generation portfolios developed in the CPUC's LTPP process.

CAISO anticipates addressing a number of pressing challenges in upcoming TPP cycles. First and foremost is integration of higher levels of renewable energy. This is especially salient in light of the upcoming retirement of many OTC power plants that have flexibility to help integrate variable energy resources. Additionally, the CPUC will be incorporating new environmental and cost information in its generation portfolios. Finally, future CAISO transmission planning will address interregional transmission planning and cost allocation in compliance with FERC Order 1000.[90]

[90] For details on the implications of FERC Order No. 1000, see Appendix C.

d) Interaction of TPP with other stakeholder processes

The CAISO TPP interacts directly and indirectly with many other stakeholder and policy forums in California (Figure 13).

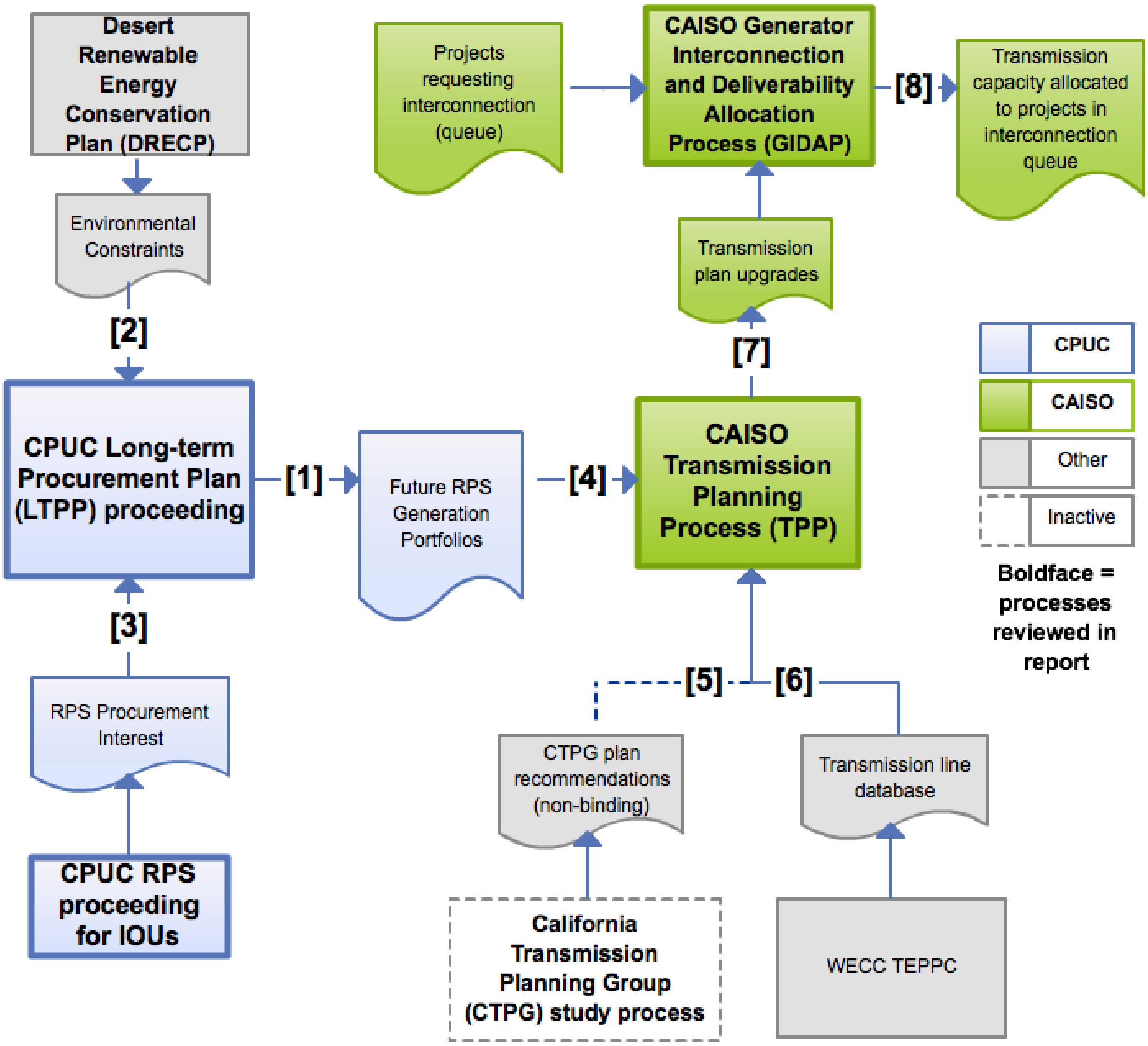

Figure 11. This diagram illustrates relationships between CAISO TPP and other California stakeholder processes. Numbers correspond to the descriptions below.

[1] The CPUC creates renewable generation portfolios in its LTPP proceeding specifying the locations and amounts of generation anticipated.

[2] RPS portfolios are created using the "RPS Calculator" incorporating environmental data from the DRECP process.

[3] RPS portfolio selection weights selection towards projects with procurement interest ("commercial interest") using information from the RPS proceeding.

[4] The RPS portfolios inform where generation is expected to occur, and thus where transmission is needed, in the TPP study process.

[5] The TPP considers recommendations for "high-potential" transmission upgrades from the CTPG studies to ensure the plan is coordinated with neighboring Balancing

Authority Areas. CTPG recommendations are non-binding as indicated by the dashed arrow.

[6] CAISO conducts TPP studies using information from WECC databases on transmission lines.

[7] CAISO selects transmission upgrades in the TPP process and includes them in its final transmission plan.

[8] CAISO allocates new transmission capacity available through any upgrades needed to meet RPS requirements to projects in the interconnection queue during the Generator Interconnection and Deliverability Allocation Process (GIDAP).

e) Opportunities and challenges for out-of-state resources

Several stakeholders commented that input on potential out-of-state resources should be brought forward as the CPUC develops renewable energy portfolios. Furthermore, to be useful, this input needs to focus on viable business interests of LSEs. In addition, parties will need to consider business and operational risk associated with mega-projects on California loads. The interregional process CAISO is developing in compliance with FERC Order 1000 will be helpful in addressing some of these issues.

Stakeholders in neighboring jurisdictions might also consider CAISO study requests that address common transmission planning needs. One source of ideas for such projects may be the California Transmission Planning Group. For instance, the CTPG (see Appendix C) identified upgrades within California associated with “high potential” transmission corridors likely to be driven by multiple procurement scenarios. These corridors reflect California utilities’ interest in more flexibility in resource locations, reducing development time and cost, providing greater resource diversity and preparing for future carbon reductions.

5. CPUC RPS Proceeding (Annual Procurement)

In a nutshell:

- The California RPS proceeding is an umbrella forum at the CPUC for implementation of RPS-related programs by the state's IOUs.**Error! Bookmark not defined.**
- The Annual RPS Procurement Plans, filed at the CPUC, detail each IOU's plans for renewable procurement pursuant to the RPS rules, and its methodologies for selecting winning bids proposed to each IOU via a competitive solicitation process.
- The CPUC is considering proposals to improve the solicitation process for renewable resources.

Key documents/outcomes:

- 2012 Renewable Energy Procurement Plans by SDG&E (PDF), SCE (PDF) and PG&E (PDF) and Proposed Decision Conditionally Accepting 2012 RPS Procurement Plans (PDF)
- Assigned Commissioner's Ruling Identifying Issues and Schedule of Review for 2012 Renewables Portfolio Standard Procurement Plans Pursuant to Public Utilities Code Sections 399.11 *Et Sec.* and Requesting Comments on New Proposals (PDF) and Second Assigned Commissioner's Ruling Issuing Procurement Reform Proposals (PDF)
- Amended Scoping Memo for RPS Proceeding Rulemaking R.11-05-005 (PDF)

5.1 Overview of RPS Procurement Planning

While the broad strokes of California's renewable energy policy are scoped out in SB2 (1X), the details of its implementation play out in annual Renewable Portfolio Standard Procurement Plans filed by IOUs at the CPUC in its RPS proceeding.[91] Lengthy documents filed at the direction of the Commission (typically in the spring) contain information ranging from calculation of the utility's Renewable Net Short for the coming years to preferences such as geographic location, product type and the years in which the utility prefers the procurement begin. As part of their Procurement Plans, the utilities must present a specific plan for how they will solicit renewable resources, called their bid solicitation protocols, as well as an explanation of how the utilities will choose the winning bids pursuant to a methodology called Least Cost, Best Fit. The 2012 annual Procurement Plans also included a description of the estimated cost impacts of renewable energy purchases on ratepayers and a forecast of utility's progress towards meeting RPS requirements based on signed renewable energy contracts.

The CPUC approves, modifies or denies the plans and uses them when determining whether to approve specific RPS contracts and, at the end of each Compliance Period, the utility has met RPS requirements.

After a utility conducts its solicitations, pursuant to its approved Procurement Plan, it must rank the bids it receives by the Least Cost, Best Fit methodology and shortlist its

[91] The current CPUC RPS proceeding is R.11-05-005, http://delaps1.cpuc.ca.gov/CPUCProceedingLookup/f?p=401:56:1499328284855901::NO:RP,57,RIR:P5_PROCEEDING_SELECT:R1105005.

choices based on the Least Cost, Best Fit results. The utilities then negotiate contracts with the winning bidders and submit the contracts to the CPUC, primarily through Advice Letters, for approval.

In the ruling ordering procurement plans for 2012, the CPUC called for comment on a set of proposals for changing the way the utilities conduct solicitations.[92] Of particular note are proposals to expand procurement authorizations from one year to two years, make Least Cost, Best Fit variables uniform across utilities, and require them to use the results of CAISO's Generator Interconnection Process in the utilities' Least Cost, Best Fit evaluations. The CPUC also is conducting a proceeding on Resource Adequacy, an issue that affects the value, types and locations of renewable energy projects that utilities procure each year.[93]

5.2 Portfolio Content Category 1 Procurement and Regulatory Uncertainties

In their 2012 RPS Procurement Plans, the IOUs have consistently stated that they will favor procurement Portfolio Content Category 1 ("bucket 1") resources. This is in part due to the higher anticipated resale value of Category 1 contracts as well as the potential risk of noncompliance if they do not procure sufficient Category 1 resources. This means that resources located outside a CBA that wish to be considered must either interconnect to transmission lines in the CAISO footprint that extend into neighboring states or be scheduled into a California Balancing Authority area without substituting energy from another source or through a dynamic transfer agreement.

Thus, while from a legal and technical standpoint the law creates opportunity for resources that are not located in a CBA to compete on an equal footing, some stakeholders we interviewed observed that, from a practical standpoint, this may not be the case. Because RPS compliance decisions, including determination of which category a resource falls into, occur after-the-fact, there is a great deal of uncertainty about how regulators may treat certain resources. Regardless of whether this regulatory compliance risk is real or perceived, it is more acute for resources that are not located in a CBA due to the additional complexities involved with dynamic transfers and other arrangements for scheduling into a CBA Area. A few projects under development with dynamic transfer arrangements may indicate the viability of this procurement pathway.[94]

Stakeholder Opportunity
Stakeholders interested in participating in implementation of the California RPS should consider commenting on the utilities' annual Renewable Energy Procurement Plans. Issues that could be raised in these proceedings include expanded use of dynamic transfers and valuation of regional energy products during the utilities' Least Cost, Best Fit bid evaluation process.

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92 See CPUC, "Assigned Commissioner's Ruling Identifying Issues and Schedule of Review for 2012 Renewables Portfolio Standard Procurement Plans…," filed April 5, 2012, http://docs.cpuc.ca.gov/PublishedDocs/EFILE/RULINGS/163513.PDF.

93 See CPUC Resource Adequacy proceeding R. 11-10-023, http://delaps1.cpuc.ca.gov/CPUCProceedingLookup/f?p=401:56:1499328284855901::NO.

94 For example, Mesquite Solar, Arlington Valley and Agua Caliente are three solar photovoltaic projects in Arizona that have or are seeking dynamic transfer agreements with California utilities. See also CAISO's stakeholder process regarding tariff changes to facilitate dynamic transfers: http://www.caiso.com/2476/24768d0a2efd0.html.

6. RPS Requirements for Publicly Owned Utilities

In a nutshell:

- California's RPS now covers publicly owned utilities in addition to investor-owned utilities and other retail sellers. Rulemaking is underway at the CEC.
- While the CEC oversees RPS compliance for the POUs, each utility's governing board makes decisions about procurement. The CEC forwards all notices of violation to the California Air Resources Board.

Key documents/outcomes:

- CEC Draft RPS Regulations, 2nd Draft, July 2012 (a 3rd draft will be available in late October or early November): http://www.energy.ca.gov/2012publications/CEC-300-2012-001/CEC-300-2012-001-SD2_clean.pdf

6.1 POU RPS requirements and the role of the CEC

In addition to the retail sellers, including the three large IOUs and about a dozen electric service providers, California is home to more than 40 publicly owned utilities (POUs) that comprise a significant share of the retail electricity sales in the state (Figure 14). The previous RPS law required only the retail sellers to meet a 20 percent renewable energy target, while the POUs were required to establish their own RPS programs and targets. The current 33 percent RPS law[95] adds POUs to the group of affected utilities required to meet the state's RPS.

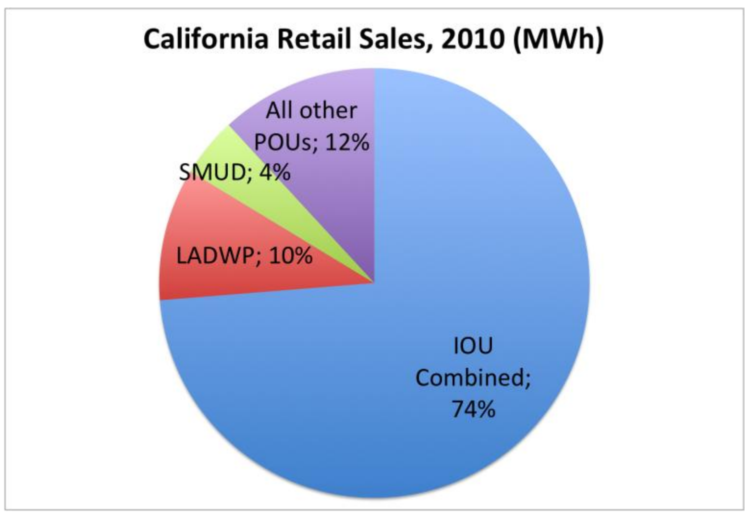

Figure 12. Publicly owned utilities such as LADWP and SMUD make up a significant share of the electricity retail sales in California. (Data Source: California Energy Commission, *Renewable Power in California: Status and Issues Report, December 2011*, as reported on July 16, 2012, Slide 17, http://www.westgov.org/wieb/webinars/2012/07-12-12CREPC-SPSC.pdf)

While the CPUC oversees these requirements for retail sellers, the California Energy Commission (CEC) oversees POU compliance.[96] The CEC released its first draft RPS regulations in February 2012 and the second in July 2012, and there have been several rounds of public comment and revision.[97] The CEC expects to set final rules in early 2013.

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[95] California Senate Bill 2 (1X) (Simitian, 2011).

[96] See *Calif. Pub. Util Code*, §399.30. The CEC is addressing RPS regulations for publicly owned utilities in Docket 11-RPS-01, http://www.energy.ca.gov/portfolio/index.html.

[97] CEC Draft RPS Regulations, February 2012, www.energy.ca.gov/2012publications/CEC-300-2012-001/CEC-300-2012-001-SD.pdf.

The CEC's draft regulations specify that each POU would be required to file a single RPS procurement plan by early 2013. More than 30 of the utilities already have filed procurement plans. While POUs are not subject to annual procurement plan filings like the IOUs, they would be subject to annual review of progress towards the RPS goals.

The CEC has attempted to make several other aspects of its RPS regulations similar to the CPUC's decisions – for instance, the portfolio content categories are intended to be largely the same. Some stakeholders we interviewed expressed a great deal of uncertainty about this aspect of the regulatory process. Due to past experiences with changing regulations, POUs expressed extreme caution in seeking out-of-state resources that might not count towards the Category 1 requirements. While prices for resources that do not qualify for Category 1 may be less expensive, some of those interviewed stated that the savings may not be enough to justify the compliance risk involved.

A major issue confronting the POUs as these regulations are developed is the treatment of excess renewable energy procured before 2011. For POUs that invested early in renewable resources, there is concern that certain short-term contracts will not carry forward to contribute towards the RPS goal.

Stakeholder Opportunity
Participate in development of the CEC's RPS regulations by submitting comments on the draft POU regulations. A final public hearing and comment period is likely to occur in late 2012 or early 2013.

6.2 POU Procurement Planning

In comparison to the IOUs, there is much less information published about progress of the POUs toward meeting RPS requirements and related procurement efforts. However, most of the largest POUs, notably SMUD and LADWP, have recently procured significant amounts of renewable energy. According to one report, the 10 largest POUs in the state had achieved approximately 19 percent of retail sales from renewable energy in 2010.[98]

The CEC has limited oversight over POU procurement decisions. The CEC will acquire information about procurement planning and progress towards the RPS target, but cannot steer procurement decisions towards any specific resources. Procurement planning is instead largely overseen by the POU governing boards.

While some POUs create procurement plans internally with little public documentation, other POUs develop integrated resource plans (IRPs) with extensive public outreach efforts.[99] For instance, LADWP has committed to conducting public outreach campaigns every two years, with its recently completed 2011 IRP using input gathered in 2010. LADWP is planning a new public outreach effort for the 2012 IRP process.[100]

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98 Union of Concerned Scientists, *The Clean Energy Race*, 2012, http://www.ucsusa.org/assets/documents/clean_energy/The-Clean-Energy-Race-Full-Report.pdf.

99 LADWP 2011 Integrated Resource Plan, https://www.ladwp.com/cs/idcplg?IdcService=GET_FILE&dDocName=QOELLADWP006035&RevisionSelectionMethod=LatestReleased.

100 For more information, see https://www.ladwp.com/ladwp/faces/ladwp/aboutus/a-power/a-p-integratedresourceplanning?_adf.ctrl-state=u71g2q2sf_73&_afrLoop=136812106519192.

Further, while the IOUs, which operate in a restructured electricity market, are typically required to purchase energy through purchase agreements, the POUs may build and own their own generation. Procurement is typically carried out on a regional basis through the two joint power authorities, Southern California Public Power Authority (SCPPA) and Northern California Power Agency (NCPA).

Stakeholder Opportunity
• Participate in board meetings of publicly owned utilities, SCPPA and NCPA and provide comments on proposed procurement decisions. • Participate in public outreach sessions for LADWP's Integrated Resource Planning process.

6.3 POU Transmission Planning

Today, the 10 largest POUs in California get more than half of their energy from out of state.[101] Even POUs that have already invested significantly in renewable energy may seek more remote resources in the long-term.

While many of the POUs are interconnected to the CAISO for reliability purposes, most of these utilities prefer not to rely on the CAISO transmission system if possible. This means that the POUs would likely seek resource procurement within their own service territories or use existing transmission lines first, but may then consider new lines to access renewable resources in other regions interconnected to CAISO.[102]

POUs operate within balancing authority areas separate from CAISO and participate in transmission planning efforts through a different set of processes than the IOUs. Opportunities for public participation in POU transmission planning processes vary. For example, SMUD coordinates transmission planning with WestConnect Sierra Subregional Planning Group and Imperial Irrigation District coordinates with the WestConnect Southwest Area Transmission Planning Group. Both of these groups host open planning processes with robust stakeholder participation and coordinate their efforts with WECC.

The California POUs also have participated in the transmission planning process of the CTPG, but this group is on hiatus while its members respond to FERC Order No. 1000 compliance requirements.[103] The future role of CTPG is yet to be determined. While POUs are not FERC-jurisdictional, many have indicated their intent to participate in Order 1000-related activities.

A particularly noteworthy issue for POU transmission planning is the imminent transition of LADWP's generation portfolio. A high percentage of its current generation resources are anticipated to retire in the coming years due to once-through cooling regulations and coal plant retirements. Furthermore, LADWP has significant transmission interconnection to locations outside of California, including several major, long-distance high-voltage DC lines that transport power from distant locations such as Navajo Generating Station in northern Arizona, the Intermountain Power Plant in Utah and BPA in

[101] Union of Concerned Scientists, The Clean Energy Race, 2012, http://www.ucsusa.org/assets/documents/clean_energy/The-Clean-Energy-Race-Full-Report.pdf.
[102] POUs do not have investors, so there is less incentive for these new infrastructure additions.
[103] For information about CTPG see Appendix C.

the Pacific Northwest. If any generators in these locations retire or reduce output, that could free transmission capacity along these lines to support delivery of renewable energy.

In addition, two federal Power Marketing Agencies – BPA and WAPA – serve the POUs. Their transmission systems already play an important role in delivering remotely interconnected renewable energy.

7. Conclusion

Efforts underway in California today to meet its renewable energy goals will have significant impacts throughout the West. Decisions by the CPUC, CAISO, the CEC and the utilities about where and how to procure resources to meet the California RPS will help determine what the renewable energy landscape looks like both within and outside California for decades to come. The Long Term Procurement Planning process at the CPUC, the Transmission Planning Process at the CAISO, and the CEC's RPS rulemaking for the POUs are fundamental drivers of California's transmission and renewable energy planning.

Stakeholders interviewed for this report generally agree that these processes have been uncoordinated in the past but that this situation is slowly improving. Some observers noted that coordination efforts are relatively new and need more time to mature. California is facing unprecedented challenges related to renewable resource integration, and interviewees believe more could be done to consider the holistic impacts renewable resource procurement has on the system. They pointed out that procurement decisions are heavily influenced by the RPS procurement planning process in the RPS proceeding. In particular, the application of the Least Cost, Best Fit evaluation of bids is a crucial step for determining when and where new renewable resources throughout the West will be developed.

While parties disagree whether the utilities will meet most of their RPS obligations under contracts that have already been signed, they acknowledge that dynamic scheduling provides a chance for renewable energy resources outside of California to contribute toward meeting the state's RPS objectives. Stakeholders we interviewed also agreed that it is likely that California will expand its renewable energy efforts, pointing to statements of high-profile California policymakers, including Gov. Brown, to increase the RPS to 40 percent or beyond.

Finally, while there may be limited opportunity for renewable resources outside of California to contribute towards the IOUs' current RPS requirements, significant opportunity may remain for some of the POUs. Now is the right time for stakeholders to engage on this issue because the rules for POUs are still being developed at the CEC.

And while stakeholders in our interviews expressed admiration for California's robust RPS and implementation procedures, some recommended areas for possible improvement in the state's renewable energy and transmission planning processes. First, the three resource categories established in SB 2 (1X) are generally seen as restrictive, and many question their policy merits. Despite legal and technical availability of bucket 1 categorization for some resources that are not located in a California balancing authority area, perceived regulatory uncertainty driven by after-the-fact compliance determinations disadvantage these resources. Some called for more upfront clarity on the matter, while others cautioned about being over-precise.

Utility procurement decisions are key to a more robust regional approach to resource acquisition to meet California's RPS. As such, some stakeholders point out the need for improved valuation of energy products from outside the state during the utilities' RPS procurement planning and Least Cost, Best Fit evaluation. Many also called for sustaining the momentum within CAISO to conduct planning activities for transmission and renewable resources on a more regional basis. They also point toward the need for broader participation in and understanding of CAISO stakeholder processes by non-California entities.

Most notably, observers we spoke with stated that the LTPP scenario development process could incorporate greater stakeholder input. As California continues to push forward on implementing its path-breaking renewable energy and transmission initiatives, many observers welcomed more robust and diverse participation by stakeholders from throughout the West. A more regional approach to renewable energy procurement and transmission could also reduce the cost of integration for California's RPS and will increase in importance if the state increases its renewable energy requirements to 40 percent.

Appendix A: California Energy Commission's Integrated Energy Policy Report

In a nutshell:

- The Integrated Energy Policy Report (IEPR) is an assessment of California's energy systems including, demand, supply, distribution and pricing.
- Demand forecasts and energy efficiency goals identified for the IEPR impact calculation are used to determine the renewable net short and long-term procurement and transmission needs.

Key documents/outcomes:

- 2011 IEPR Final Report (PDF)

SB 1389 established a statutory requirement for the California Energy Commission (CEC) to prepare an Integrated Energy Policy Report (IEPR) on a biennial basis.[104] Each report assesses the current state of California's energy system and addresses demand, supply, distribution and pricing. The IEPR also provides policy recommendations consistent with California's energy objectives in areas such as renewable energy, energy efficiency and climate change. In addition to the biennial report, the CEC undertakes a mid-cycle update that addresses significant changes affecting California energy policy.

Among the important areas addressed through the IEPR are demand forecasts and estimates of energy efficiency potential. By statute, the CEC, in consultation with the CPUC, is tasked with developing statewide energy efficiency estimates and targets. This work directly informs other California proceedings, including the Long Term Procurement Plan (LTPP) proceeding at the CPUC because it affects load forecasts and calculations of the renewable net short. The conclusions of the LTPP proceeding in turn affect procurement needs for the state's investor-owned utilities and CAISO's assumptions for transmission planning.

2011 IEPR

The 2011 IEPR summarized California's energy policies, discussed progress toward meeting objectives, and addressed topics such as infrastructure needs for meeting demand and clean energy goals, challenges to achieving varied policy goals and securing the benefits of a clean energy economy.

Policies identified in the IEPR include the 33 percent by 2020 RPS; Gov. Brown's Clean Energy Jobs Plan – targeting 20,000 MW of renewable energy capacity; the Loading Order identified in California's Energy Action Plan prioritizing energy efficiency; AB 2021, which requires identification of all potentially achievable cost-effective energy efficiency and goals for achievement; and AB 32, identifying energy efficiency as a key strategy for reducing greenhouse gas emissions.[105]

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[104] See CEC website on California's energy policies: http://www.energy.ca.gov/energypolicy/index.html.

[105] 2011 IEPR, page 51, http://www.energy.ca.gov/2011publications/CEC-100-2011-001/CEC-100-2011-001-CMF.pdf.

Renewable Energy

The IEPR estimated that California's 33 percent by 2020 RPS would require an additional 35,000 to 47,000 gigawatt hours (GWh) of renewable energy and procurement requirements of 55,000 to 85,000 GWh, depending on contract failure rates. The plan developed regional targets for achieving policy goals, incorporating transmission lines identified by CAISO and potential renewable capacity identified in CREZs through the RETI process.[106] In summarizing issues affecting renewable energy development in California, the IEPR noted permitting, transmission and integration among other key issues. Recommended strategies for renewable energy included:

- Prioritizing generation development in specific areas
- Evaluation of all costs of renewable energy projects, including transmission and integration, as part of a value assessment
- Minimization of interconnection costs
- Promotion of incentives for renewable energy technologies that create in-state jobs and industries
- Promotion and coordination of state and federal financing and incentive programs

Energy Efficiency

For energy efficiency, the IEPR summarized utility progress on energy efficiency program savings, a more detailed description of energy efficiency targets and policy recommendations. Policy recommendations included the need for improved data collection and submission.[107]

Demand Forecast

The demand forecast developed by the CEC within the IEPR is incorporated into a variety of proceedings including the CPUC's LTPP, CAISO's annual resource adequacy proceedings and transmission planning. The 2011 forecast developed three scenarios – high, mid and low – which looked at varying levels of economic/demographic growth, electric/natural gas rates, and the impact of energy efficiency and self-generation. Average growth rates for 2010-2020 were projected to be 1.41 percent, 1.10 percent and 0.91 percent for the high, mid and low demand scenarios, respectively. Peak demand was expected to grow from 69,700 GWh to 74,200 GWh by 2022. When energy efficiency forecasts are considered, statewide consumption ranged from 294,000 to 322,000 GWh, compared to 313,000 GWh to 332,000 GWh for unadjusted consumption.[108]

Renewable Net Short

The Energy Commission develops an annual update to the renewable net short for California load-serving entities.[109] This renewable net short methodology was first presented in the *2011 Integrated Energy Policy Report*. Estimates of renewable net short are needed to determine the amount of new renewable generation capacity that must be acquired to meet the RPS target, to evaluate the electricity infrastructure requirements for

[106] *Id.*, page 31.
[107] *Id.,* page 56.
[108] *Id.*, page 112.
[109] www.energy.ca.gov/2013_energypolicy/documents/.

integrating new generation additions, and to identify market mechanisms that may need to be modified to provide the ancillary services that would be required to maintain reliable system operations.

2010 Update

The 2010 update addressed impacts to California from the 2009 American Recovery and Reinvestment Act with respect to formula grants, direct awards from competitive solicitations, loan guarantees and clean energy tax credits. The update addressed benefits of Recovery Act funding and consistency with California energy policies. The CEC administered $315.5 million in formula grants through a variety of programs including energy efficiency retrofits, renewable energy development, appliance replacement and workforce training.

CEC formula-based funding focused on energy efficiency programs consistent with state policies identifying energy efficiency as the priority resource for meeting energy needs and the job impacts associated with energy efficiency investments.

Appendix B: Renewable Energy Transmission Initiative

In a nutshell:

- The California Renewable Energy Transmission Initiative (RETI) identified renewable resource zones and developed models for ranking them.
- RETI create a conceptual transmission plan for high-ranking renewable resource zones.
- RETI outcomes are incorporated into the LTPP, TPP and other processes.

Key documents/outcomes:

- Phase 1A (PDF) and 1B Reports (PDF) address identification and ranking of resource zones.
- Phase 2A addresses development of the conceptual transmission plan (PDF).

The Renewable Energy Transmission Initiative (RETI) was initiated as a joint effort between the CPUC, CEC, CAISO and stakeholders to identify and quantify renewable resources and transmission projects necessary to meet California's energy goals. Over a multi-phase process, RETI assessed and identified renewable energy resources and developed conceptual transmission plans to access the highest-ranking zones. In Phase 1, stakeholders examined available resources within a specified study area, recommended areas for further study and identified broad transmission requirements. In Phase 2, stakeholders closely examined generation and transmission and developed conceptual plans for transmission to the highest-ranking zones.

RETI Study Region.
Source: RETI Phase 1A Report

The work conducted by RETI supports ongoing processes including the CAISO Transmission Planning Process, CPUC renewable resource proceedings, and CEC energy policy development by identifying optimal resource areas for cost-effective and environmentally suitable generation development. The recommended scenarios for CAISO's 2012-2013 Transmission Planning Process incorporate resources and resource areas identified through the RETI process.

RETI Phase 1

Phase 1 was conducted in two steps. In Phase 1A, stakeholders conducted a high level review of renewable resources within a specified study area and made recommendations for which resources merited further examination. Phase 1B developed environmental criteria for ranking recommended zones.

Phase 1A

The initial RETI objectives were to identify renewable resources in California and adjoining areas that could deliver energy to California. The study area included California, Arizona, Nevada, Oregon, Washington, British Columbia and parts of Baja California. The study assessed nearly a dozen renewable energy technologies, including solid biomass, co-fired biomass, anaerobic digestion, landfill gas, solar thermal,[110] solar photovoltaic,[111] hydroelectric,[112] wind,[113] geothermal, marine current and wave.[114]

In reviewing potential resources, the RETI analysis incorporated assumptions of renewable energy demand, the transmission system, and generation information and costs. The base case, the starting point for the analysis, included existing renewable generating resources, renewable energy projects under construction and projects in pre-construction. The base case for transmission resources similarly included existing transmission, transmission under construction and approved transmission projects.[115] Resources were grouped into Competitive Renewable Energy Zones (CREZs) where projects shared a common transmission interconnection point, had similar development timeframes and the economics of the combined projects was higher than for individual projects alone.

RETI acknowledged the impact of uncertainties in its resource evaluations, highlighting variables including the calculation of the renewable net short, financing, technology costs and incentives. Specifically, RETI focused on uncertainty in assumptions which had the potential to change and impact CREZ rankings.

Resources with limited potential to serve California were eliminated from continued review in Phase 1B. Factors included the ability to cost-effectively deliver the resource, transmission need and technology maturity. Based on the initial review, several resources were recommended for Phase 1B analysis.[116]

Phase 1B

Phase 1B focused on developing a methodology for screening and ranking projects and CREZs based on economic and environmental assessments, development certainty and other considerations. CREZ groupings were built around geographic proximity, development timeframes, shared transmission constraints and potential economic benefits.

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110 Class 2 and higher, slope less than 1 percent, in Western Arizona and southern Nevada.
111 Only California resources.
112 Projects greater than 10 MW.
113 Class 4 and higher resources.
114 Primary sites, rated capacity.
115 New CAISO transmission included: Tehachapi 1-3, Tehachapi 4-11, Sunrise Powerlink and Devers-Palo Verde 2.
116 Biomass in California, Oregon, Washington and British Columbia. Solar thermal in California, southern Nevada and western Arizona. Solar photovoltaic in California. Wind in all regions except Arizona and northern Nevada. Geothermal in California, Oregon, Nevada and British Columbia.

Economic Assessment

The RETI economic assessment examined in-state and out-of-state resources, estimating costs for development and transmission to California consumers and the value of each energy resource considering time of production and capacity value. Individual CREZs were evaluated on the basis of their cost to value. The overall economic merits – or ranking costs – were determined for each CREZ area and used to develop resource supply curves.[117]

RETI used an incremental transmission cost approach that added transmission capacity based on potential generation production. The methodology did not account for potential reliability benefits or any load-flow effects. Capacity costs were based on the avoided costs of a combustion turbine. This method did not account for potential market revenues from dispatch of energy. The economic analysis did not include integration costs. RETI acknowledged that significant changes to certain assumptions would change CREZ rankings.[118]

Environmental Assessment

The RETI environmental assessment sought to identify renewable resource areas where development was prohibited or severely restricted and CREZs where energy development was expected to result in fewer environmental concerns. The environmental sensitivity of individual CREZs was analyzed using eight criteria that formed the basis for ranking each CREZ on their perceived level of environmental concern.[119]

Each CREZ received a scored for each of these criteria using a 1 to 5 scale. CREZs with lower total scores were perceived to have fewer environmental concerns. RETI estimated a net short requirement of 68,000 GWh/yr and identified 10 CREZ areas within California that could most cost-effectively meet the estimated need. RETI also found out-of-state resources in Oregon, Nevada, British Columbia and Baja California that were cost-competitive with California resources and could justify transmission costs.

Phase 2

Phase 2 of RETI focused on re-ranking of CREZs initially identified in Phase 1, developing a conceptual transmission expansion plan for California, and informing prioritization of future transmission projects. Energy flow, congestion, reliability and other operational issues were not evaluated.

Phase 2A

Under Phase 2A, RETI stakeholders developed a conceptual transmission plan identifying two groups of lines, Renewable Foundation Lines and Renewable Delivery Lines, that increased grid capacity and allowed for energy delivery to load centers. An additional category of Renewable Collector Lines was identified that would carry power to the Foundation and Delivery lines. Lines likely to be necessary regardless of future outcomes

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[117] For each CREZ, the overall economic merit, or ranking cost, was determined based on the following formula: generation cost + transmission cost – energy value – capacity value.

[118] These assumptions included renewable net short calculation, financing assumptions, incentives, technology, environmental impacts, transmission, energy value, capacity value, integration costs and development timeframe.

[119] Energy development footprint, transmission footprint, sensitive areas in CREZs, sensitive areas in CREZ buffer areas, significant species, wildlife corridors, important bird areas and land degradation.

were deemed least-regret lines. Proposed line segments were evaluated on their value for providing access to renewable energy resources, delivering energy to major load centers and enabling transfers between load centers. Planning assumptions included delivery of 100,000 GW per year and importing 15,000 GWh per year from out-of-state resources.

Phase 2B

Phase 2B of RETI updated earlier models, assumptions and analysis and accounted for changes in market conditions. The refreshed information informed updated technology costs, weighted average costs and CREZ rankings. RETI also incorporated data on out-of-state resources from the Western Governors' Association's Western Renewable Energy Zones (WREZ) initiative. Results were generally consistent with rankings in Phase 1B. RETI concluded that the results of the updated rankings showed that California had sufficient resources to meet its renewable energy goals, albeit at a higher cost.

Appendix C: California Transmission Planning Group

In a nutshell:

- The California Transmission Planning Group (CTPG) is a regional transmission planning entity that includes both investor- and consumer-owned utilities.
- After developing two transmission plans, CTPG activities are on hiatus pending FERC Order 1000 compliance in early 2013.
- Transmission upgrades that were identified in the plans focused heavily on importing renewable resources from out of state to achieve California's 33 percent RPS goals.

Key documents/outcomes:

- 2011 CTPG Statewide Transmission Plan (PDF)
- 2010 CTPG Statewide Transmission Plan (PDF)

C.1 History and Purpose of the CTPG

The California Transmission Planning Group (CTPG) is a regional group of transmission providers, primarily serving California, that collaborate on transmission planning. The CTPG was formed in 2009 in response to Order No. 890 issued by the Federal Energy Regulatory Commission (FERC), which required transmission providers under FERC jurisdiction to "participate in a coordinated, open and transparent planning process on both a local and regional level."[120] CTPG was also intended to be an evolution from prior transmission planning for renewable resources under the RETI process. CTPG developed statewide transmission plans for 2010 and 2011,[121] incorporating the findings of a technical study process. The studies identified transmission system upgrades that could help the state achieve its 33 percent RPS goals.

Members and others participate in the planning process. Members include California load-serving entities, both IOUs and POUs, an important virtue of the CTPG process.[122] Others participants include CAISO and Western Area Power Administration. CAISO participates in CTPG as a means to comply with FERC Order 890. While CAISO considers the CTPG recommendations, CAISO is not required to include them in its own transmission plans.

Other stakeholders also engage in the CTPG process. For instance, during the study plan development process in 2010, regional planning organizations and special interest groups provided feedback about renewable energy developed in Nevada and Arizona for delivery to California.

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120 See fact sheet on FERC Order No. 890: http://www.ferc.gov/industries/electric/indus-act/oatt-reform/order-890/fact-sheet.pdf.

121 CTPG 2011 California Transmission Plan: http://www.ctpg.us/images/stories/ctpg-plan-development/2012/2012-03-05_2011finalstatewidetransmissionplan.pdf; 2010 California Transmission Plan: http://www.ctpg.us/images/stories/ctpg-plan-development/2011/02-Feb/2011-02-09_final_statewide_transmission_plan.pdf.

122 CTPG members include Imperial Irrigation District, Los Angeles Department of Water and Power, Pacific Gas and Electric, Southern California Edison, Southern California Public Power Authority, San Diego Gas and Electric, Sacramento Municipal Utility District, Transmission Agency of Northern California and Turlock Irrigation District.

Several of CTPG's members are not under FERC's jurisdiction (notably, California's large municipal utilities such as LADWP and SMUD) and participate on a voluntary basis. Some of these entities have recently become concerned with their participation in the CTPG process in light of FERC Order No. 1000, issued in October 2011.[123] The apparent concern of the non-jurisdictional utilities is that CTPG might become the *de facto* regional transmission planning entity for compliance with the order. Because it requires regional transmission planning groups to establish methods for transmission cost allocation, these entities also are concerned that they might be required to enter into transmission cost allocation arrangements under the CAISO transmission planning process.

? What is FERC Order No. 1000?
Order No. 1000 is a landmark order adopted by FERC in October 2011. It requires transmission providers to engage in regional and interregional planning processes for new transmission development. The regional process must include a method for allocating costs among participants for projects included in a regional transmission plan. Transmission providers submitted compliance filings to FERC in October 2012 for regional transmission planning. They will submit plans in April 2013 for interregional plans.

CTPG activities have been on a hiatus while FERC-jurisdictional entities work toward meeting compliance deadlines. Future prospects for renewed CTPG activity are unknown at this time.

Stakeholder Opportunity
Explore potential interest of transmission providers outside California in joining CTPG, assuming the group's efforts continue, so they might have a voice in future statewide transmission planning efforts.

C.2 CTPG Study Process and Findings

a) Investigating Renewable Resource Scenarios

Renewable resource scenarios in the CTPG process are aimed at answering major "what-if" questions about regional energy generation and transmission futures. The studies investigate alternatives for future renewable resource build-outs that meet the California RPS. For each scenario, the Renewable Net Short[124] is filled first by including the Discounted Core and resources from Highly-Ranked CREZ areas. The remaining net short is filled with additional resources specific to the scenario (e.g., "out-of-state" or "central California").[125] New transmission projects identified in the study tend to represent large, long-term investments that would take significant time to develop.

Scenario selection was driven by the participation of stakeholders after significant deliberation. Taken together, the scenarios studied represent the wide variety of available

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[123] Fact sheet on FERC Order No. 1000: http://www.ferc.gov/media/news-releases/2011/2011-3/07-21-11-E-6-factsheet.pdf .

[124] For a full discussion of Renewable Net Short refer to Chapter 3.

[125] For details on scenarios and the scenario development process, see the 2011 CTPG Final Statewide Transmission Plan, §2, http://www.ctpg.us/images/stories/ctpg-plan-development/2012/2012-03-05_2011finalstatewidetransmissionplan.pdf.

build-out options for California's RPS and procurement preferences of participants. Examples of scenarios studied include "Pacific Northwest Import" and "West of River Import" (imports from Southern Nevada and Arizona).[126]

b) High Potential Transmission Corridors

The CTPG studies identified three "High Potential Transmission Corridors" intended to provide information about the viability of developing out-of-state renewable resources for import to California. Identification of these corridors is not necessarily connected to any particular scenario analysis. Instead, these corridors were generally understood by participants and other stakeholders to be areas of "least regrets;" that is, transmission investments in these locations are likely to be driven by multiple procurement scenarios. They reflect areas for "logical" transmission upgrades that planners would be remiss to exclude.

Specific reasons for identifying these import corridors include uncertainty about the precise location of renewable resources to be developed, potential insecurity of existing purchase power agreements, provision of additional procurement flexibility for California utilities, potential for resources to be developed in areas that could reduce development time and procurement cost for combined generation and transmission, potential for additional resource diversity, and potential future resource needs arising from future greenhouse gas reduction policies.[127]

One additional important finding worth noting is that, due to the physics of power flow on the system, many transmission upgrades to accommodate imports along the High Potential Transmission Corridors would need to occur within California itself rather than near the point of origin. For example, with high levels of power imported from solar in Arizona, there would likely need to be transmission upgrades on the Midway to Tesla transmission line in Central California.[128]

[126] *Id.* §2, p. 12.
[127] *Id.* §1.33, p 11.
[128] *Id.* §1, p. 2.

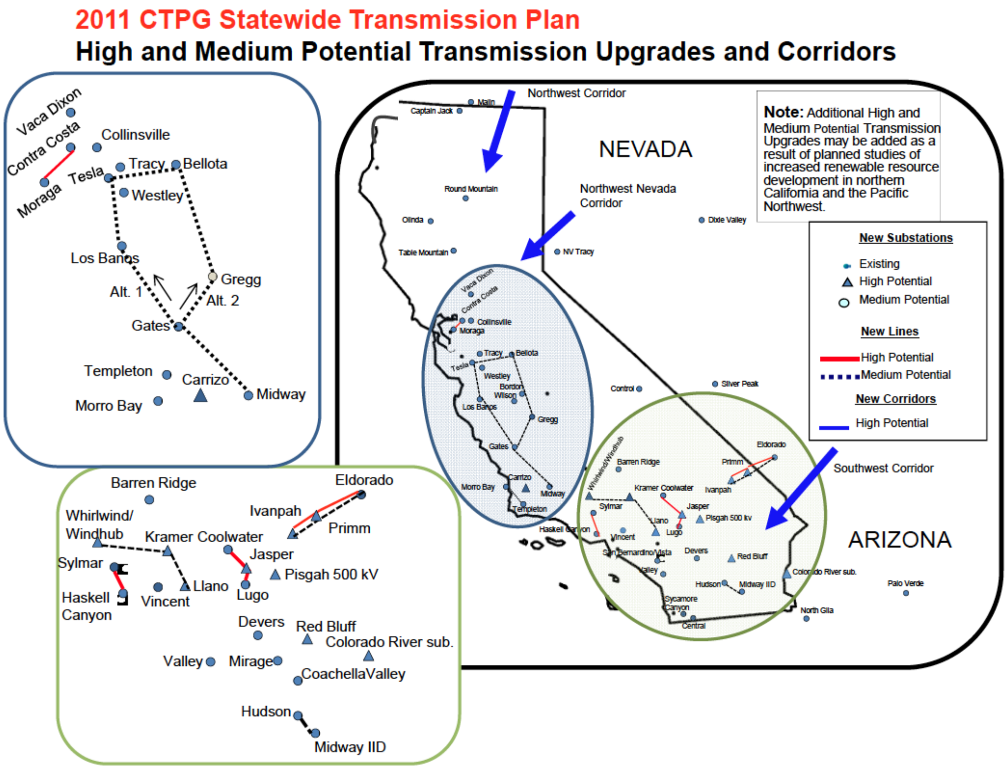

Figure 13. This map identifies the transmission upgrades included in the 2011 CTPG Statewide Transmission Plan. It includes both high and medium potential upgrades based on relative need as determined by scenario studies. The map also shows the three "High Potential Transmission Corridors" as indicated by the blue arrows. Source: 2011 CTPG Statewide Transmission Plan.[129]

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

Appendix D: Desert Renewable Energy Conservation Plan

In a nutshell:
- The Desert Renewable Energy Conservation Plan (DRECP) is a long-term habitat and natural community conservation plan and renewable energy development plan for desert ecosystems in southern California.
- Environmental sensitivity information from DRECP work is a major input to the RPS portfolio development process of the LTPP.

Key documents/outcomes:
- Preliminary Conservation Strategy, October 2011 (PDF)
- Environmental Impact Statement (EIS), Environmental Impact Report, Record of Decision (ROD) and Notice of Determination are forthcoming.

D.1 Overview of DRECP

In order for California to achieve its 33 percent RPS goal in a timely manner, it is expected that significant areas of land will need to be developed for new renewable energy generation facilities. California's desert areas present an opportunity for this development, particularly for solar. However, these desert habitats contain many endangered species, such as the desert tortoise. Gov. Schwarzenegger's Executive Order[130] to develop a Desert Renewable Energy Conservation Plan (DRECP)[131] is intended to provide both a long-term conservation management plan for the region as well as expedited permitting for renewable energy projects and transmission lines.

The DRECP is particularly noteworthy for its long-term outlook, with a 2040 planning horizon. This is by far the longest-term outlook of California's stakeholder processes and therefore may have an impact on where and when renewable energy is developed in California well into the future. To the extent that the DRECP identifies preferred areas for development and preferred areas for conservation, it could have an impact on the development of new transmission lines that may be necessary to deliver renewable energy from outside the state to California.

A core activity of the DRECP process is using GIS mapping tools and environmental data to delineate areas within DRECP boundaries that are either ecologically sensitive and require conservation management or low-sensitivity areas suitable for development. To date, this evaluation has identified several Development Focus Areas, areas where projects could be developed that result in fewer conflicts with biological resources.

[130] Executive Order S-14-08, http://gov.ca.gov/news.php?id=11072.
[131] See DRECP website: http://www.drecp.org/.

Figure 14. The DRECP Planning Area. Source:
http://www.drecp.org/whatisdrecp/docs/DRECP_Plan_Area_Map.pdf

D.2 What is the DRECP's current timeline?

So far, the DRECP process has produced a Preliminary Conservation Strategy[132] and maps of draft development focus and conservation areas.[133] These materials continue to be refined as a result of public comments and additional analysis. Public draft environmental review documents on the Plan – an Environmental Impact Statement and Environmental Impact Report – are anticipated in 2013. They will be subject to a minimum 90-day comment period. A significant remaining step for the DRECP process is acceptance of the final plan by local county governments.

D.3 How is DRECP information used in other CA proceedings?

The CPUC's Long-term Procurement Plan (LTPP) proceeding develops future renewable resource portfolios. Using an "RPS Calculator" the CPUC ranks renewable resources according to several criteria, including an environmental score.[134] Information from the DRECP work and analysis to date has recently been incorporated into this environmental scoring process. LTPP portfolios that are more heavily weighted towards environmental criteria will be more likely to avoid ecologically sensitive areas as defined by the DRECP analysis. Many California stakeholders have heralded integration of DRECP information into the LTPP process as a major step forward in assessing the viability of

[132] DRECP Preliminary Conservation Strategy, October 2011, http://www.drecp.org/documents/docs/preliminary_conservation_strategy/index.php.
[133] Background meeting materials for the July 25-26, 2012 Stakeholder Committee meeting, http://www.drecp.org/meetings/2012-07-25-26_workshop/background/.
[134] See Chapter 3 for a full discussion of the CPUC LTPP proceeding, the RPS Calculator, and how environmental scoring is used in portfolio development.

projects in the state. Some parties have suggested that DRECP could be further improved with a more focused goal of providing direct inputs to the transmission planning process.

D.4 Who is participating in the DRECP effort?

The DRECP process is managed by the Renewable Energy Action Team, a collaboration of state and federal agencies including:

- California Energy Commission
- California Department of Fish and Game
- Bureau of Land Management
- U.S. Fish and Wildlife Service

DRECP involves many stakeholders including local governments, renewable energy project developers and industry representatives, environmental groups, utilities, Native American tribes and government agencies.[135] DRECP's stakeholder committee meets regularly to provide input to member agencies. Some 13 county representatives are on the committee. Most are regular attendees and actively participate in meetings and workshops.

[135] See list of DRECP stakeholders: http://www.drecp.org/participants/stakeholder.html.

Appendix E: California Air Resources Board's Climate Change Scoping Plan

When Gov. Schwarzenegger first announced the goal of 33 percent renewable energy by 2020,[136] the objective was soon incorporated in the CEC and CPUC's joint 2005 Energy Action Plan II (EAP II).[137] In 2006, California passed its landmark Global Warming Solutions Act (AB 32),[138] which established a plan to reduce the state's greenhouse gas emissions. A major component of the law was the requirement that the California Air Resources Board (CARB) adopt a Scoping Plan "for achieving the maximum technologically feasible and cost-effective reductions in greenhouse gas emissions."[139] This Scoping Plan was adopted in December 2008 and included a number of measures for achieving the GHG reduction targets, including increasing the state's RPS to 33 percent.[140] In advance of the 2008 Scoping Plan, the CEC and CPUC conducted a joint workshop and proceeding as part of the Climate Action Team Energy Subgroup and issued a final opinion to CARB recommending the 33 percent RPS.[141]

Including this target in the AB 32 Scoping Plan became a key justification for the CPUC in seeking procurement of additional renewable resources in corresponding proceedings, well in advance of the higher target becoming law in 2011. For example, the 33 percent RPS goal and the AB 32 Scoping Plan were cited in the CPUC's approval of the 2009 RPS Procurement Plans.[142] Furthermore, the Scoping Plan and related records make explicit reference to the need for additional transmission infrastructure to accommodate new renewable resources to meet GHG targets. Accordingly, AB 32 and the inclusion of the 33 percent RPS in the Scoping Plan were primary justifications for the CPUC's decision to approve major new transmission lines such as Sunrise Powerlink.[143]

In addition to the original Scoping Plan, AB 32 requires that CARB "update its plan for achieving the maximum technologically feasible and cost-effective reductions of greenhouse gas emissions at least once every five years."[144] Some observers suggest that there may be an opportunity for stakeholders to address future RPS and transmission-related policies, including regionally oriented solutions, through the development of the Scoping Plan update due in December 2013. Before adoption of the original Scoping Plan, CARB held numerous stakeholder workshops and public comment sessions.

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[136] Gov. Schwarzenegger, letter to California Senate President Don Perata, Aug, 23, 2005, http://www.energy.ca.gov/energypolicy/2005-08-23_GOVERNOR_IEPR_RESPONSE.PDF.

[137] Energy Action Plan II, September 2005, http://www.energy.ca.gov/energy_action_plan/2005-09-21_EAP2_FINAL.PDF.

[138] California Assembly Bill 32 (2006).

[139] *Calif. Health & Safety Code* §38561(a).

[140] California Air Resources Board, "Climate Change Scoping Plan" (December 2008), http://www.arb.ca.gov/cc/scopingplan/document/adopted_scoping_plan.pdf.

[141] Joint Agency final opinion, publication # CEC-100-2008-007-F, adopted Oct. 16, 2008, by the California Energy Commission and Public Utilities Commission, http://www.energy.ca.gov/2008publications/CEC-100-2008-007/CEC-100-2008-007-F.PDF.

[142] Decision 09-06-018, at p. 7.

[143] Decision 08-12-058, Dec. 18, 2008, at p. 6.

[144] *Calif. Health & Safety Code* §38561(h).

Stakeholder Opportunity
Stay informed about opportunities for public participation in the 2013 Scoping Plan Update by subscribing to CARB’s Climate Change listserv: http://www.arb.ca.gov/listserv/listserv_grp.php?listtype=C0.

Appendix F: Summary Table of 2012 LTPP Scenarios

Renewable Resource Portfolios

		Demand				Supply								
	Scenario	Load	Inc EE	Inc PV	Inc CHP	Existing	Additions	Retirements	Solar + Wind & Hydro Retirements	Nuclear Retirement	RPS	Imports	Inc CHP	Inc DR
1	Base	Mid	Mid	Mid	Low	Base	Base	Mid	Low	Low	Commercial	Base	Low	Mid
1A	Environmental	Same as Base				Same as Base					**Enviro**	Same as base		
1B	Early SONGS Retirement	Same as Base				Same as Base				**Modified High (2015)**	Same as base	Same as base		
1C	Early Nuclear Retirement	Same as Base				Same as Base				**High (2015)**	Same as base	Same as base		
1D	Low Load	**Low**	**Low**	**Low**	Low	Same as Base								**High**
1E	High Load	**High**	**High**	**High**	Low	Same as Base								**Low**
2	No New DSM	Mid	None	None	None	Same as Base							None	None
2A	Replicating TPP	**Mid (1-in-5 Peak weather)**	Same as No New DSM			Same as Base							None	**Low**
3	High Distributed Generation	Same as Base		High	High	Same as Base					High DG	Base	High	High

Figure 15. In the 2012 LTPP, the CPUC developed multiple scenarios. This table summarizes the major inputs and assumptions that form the 2012 LTPP Scenarios including three RPS portfolios. (Image Source: Assigned Commissioner's Ruling on Standardized Planning Scenarios, at page 20 of Attachment A, Sept. 20, 2012, http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M028/K155/28155334.PDF)

Appendix G: Historical LTPP Proceedings

Proceeding	Title	Filed
R.01-10-024	Order Instituting Rulemaking (OIR) to Establish Policies and Cost Recovery Mechanisms for Generation Procurement and Renewable Resource Development	Oct. 29, 2001
R.04-04-003	OIR to Promote Policy and Program Coordination and Integration in Electric Utility Resource Planning	April 1, 2004
R.06-02-013	OIR to Integrate Procurement Policies and Consider Long-Term Procurement Plans	Feb. 16, 2006
R.08-02-007	OIR to Integrate and Refine Procurement Policies Underlying Long-Term Procurement Plans	Feb. 14, 2008
R.10-05-006	OIR to Establish Policies and Cost Recovery Mechanisms for Generation Procurement and Renewable Resource Development	May 6, 2010
R.12-03-014	OIR to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans (current)	March 22, 2012

Appendix H: Timeline for the 2012 LTPP proceeding

LTPP Proceeding Actions	Date	Documents
Order Instituting Rulemaking	March 22, 2012	PDF
Comments on Preliminary Scoping Memo	April 6, 2012	--
Scoping Memo	May 16, 2012	PDF
Track 1 -- Local Area Needs		
ISO Testimony	May 2012	
Other Testimony	June 2012	--
Prehearing Conference	July 2012	--
Reply Testimony	July 2012	--
Evidentiary Hearings	August 2012	--
Opening Briefs	September 2012	--
Reply Briefs	October 2012	
Proposed Decision	Nov./Dec. 2012	--
Track 2 -- System Needs		
Planning Standards Straw Proposal	May 10, 2012	DOC
Workshop on Straw Proposal	May 17, 2012	PPT
Comments on Straw Proposal	May 31, 2012	url
Reply Comments on Straw Proposal	Jun 11, 2012	url
Commissioner Ruling on Planning Standards	June 26, 2012	PDF
Draft Scenarios	Aug. 2, 2012	PDF
Workshop on Scenarios	Aug. 24, 2012	PPT
Assigned Commissioner Ruling on Scenarios Issued	Sept. 20, 2012	PDF
Comments on Scenarios	Oct. 5, 2012	--
Reply Comments on Scenarios	Oct. 19, 2012	--
Proposed Decision on Scenarios	November/ December 2012	--
Operating Flexibility and System Needs	2013	--
Proposed Decision on Operating Flexibility and System Needs	**Q4 2013**	**--**
Track 3 -- Bundled Procurement Plans		
Proposed Rules	November 2012	--
Proposed Decision on Rules	January 2013	--
IOUs File Bundled Procurement Plans	March 2013	--
Remainder of Schedule	TBD	

Appendix I: Timelines for Recent and Upcoming TPP and GIP Cycles

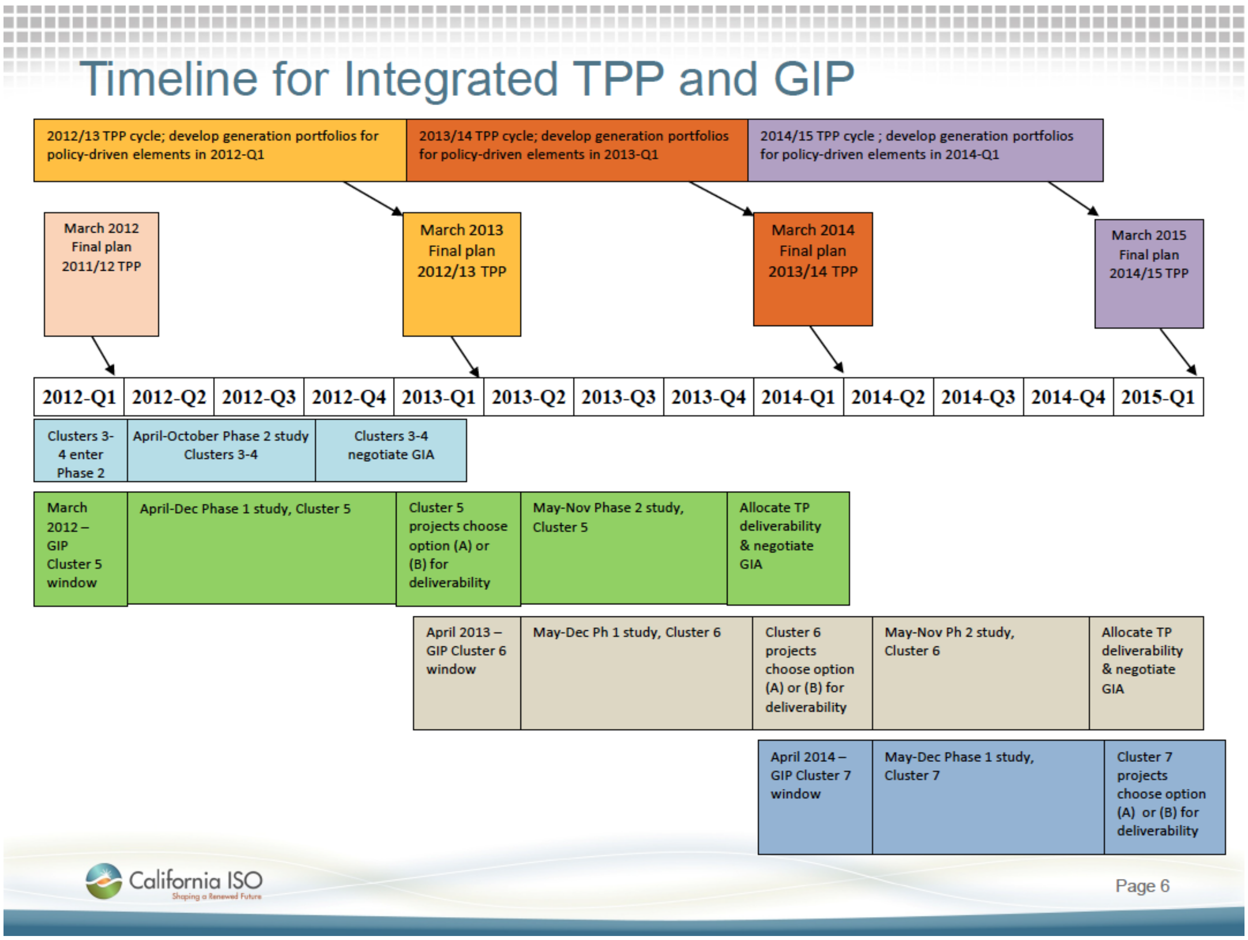

Image Source: CAISO, Webinar June 19, 2012, Slide 7: http://www.westgov.org/wieb/webinars/2012/06-19-12CREPC-SPSC.pdf.

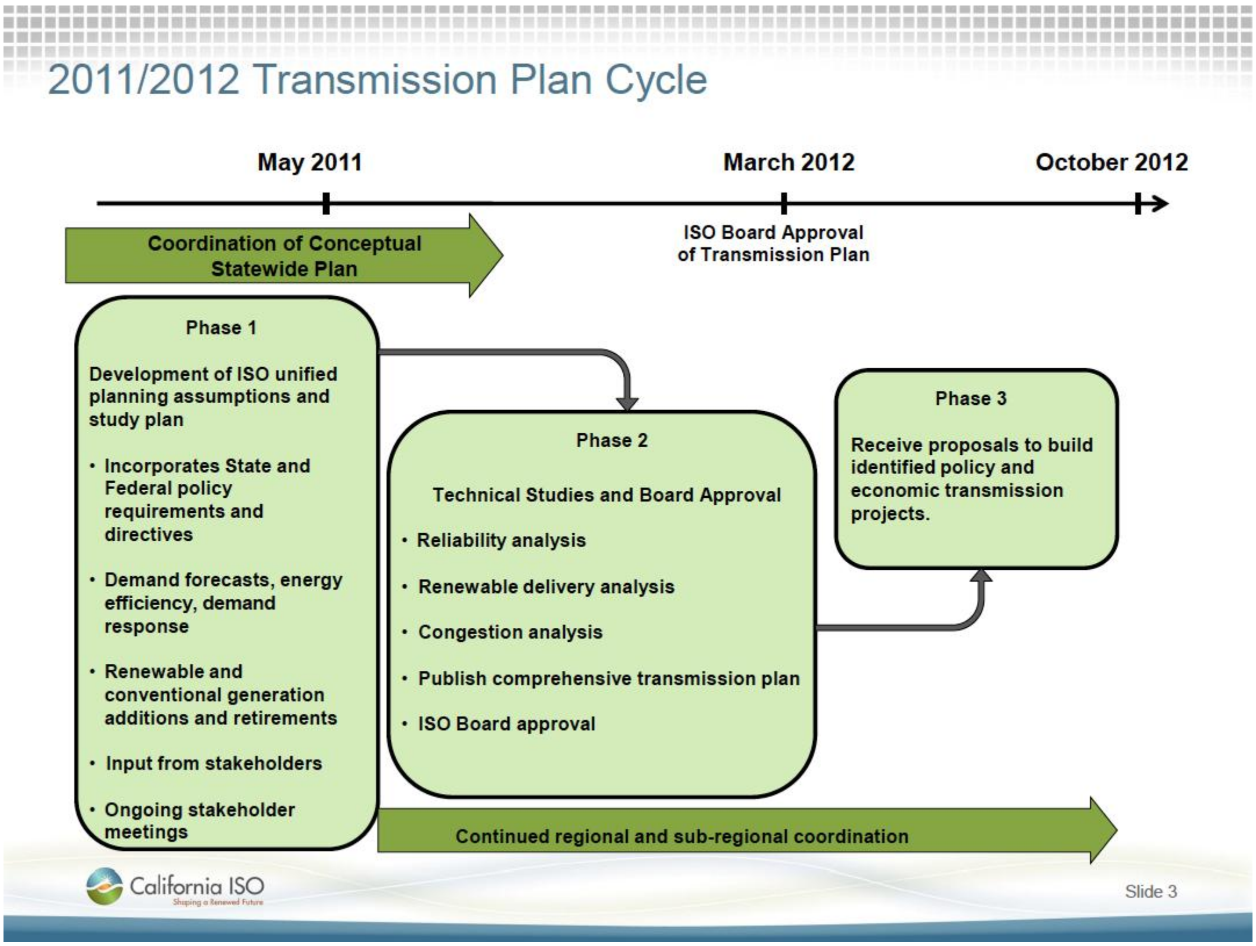

Image Source: CAISO, June 19, 2012, Webinar, Slide 7: http://www.westgov.org/wieb/webinars/2012/06-19-12CREPC-SPSC.pdf.