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January 25, 2012

The Honorable Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

Re: California Independent System Operator Corporation
Petition for Waiver of Tariff Revisions and Request for Confidential Treatment
Docket No. ER12-____-000

Dear Secretary Bose:

The ISO hereby submits a petition for waiver of tariff provisions and request for confidential treatment, plus the attachments referenced in the petition. The ISO attempted to file the petition by the close of Commission business on January 25, 2012, but was unable to do so due to software difficulties related to the Commission's eTariff system. Therefore, the ISO is filing the petition on January 25 after the close of Commission business, for Commission acceptance as of January 26, 2012. The ISO will serve the filing as stated in the petition on January 25.

Please contact the undersigned with any questions. Thank you for your assistance in this matter.

Respectfully submitted,

/s/ Sean A. Atkins
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PRIVILEGED AND CONFIDENTIAL INFORMATION HAS BEEN REMOVED PURSUANT TO 18 C.F.R. § 388.112

THE UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

California Independent System Operator Corporation	**)** **)**	**Docket No. ER12-____-000**

PETITION FOR WAIVER OF TARIFF PROVISIONS AND REQUEST FOR CONFIDENTIAL TREATMENT

The California Independent System Operator Corporation (ISO) hereby requests a limited, one-time waiver[1] of the requirement in Section 43.2.6(3) of the ISO Tariff that a Capacity Procurement Mechanism (CPM) designation for capacity at risk of retirement and needed for reliability purposes must be shown for "the end of the calendar year following the current RA [Resource Adequacy] Compliance Year."[2] The ISO requests this waiver to prevent the retirement in 2012 of the Sutter Energy Center (referred to hereinafter as the Sutter plant), an existing flexible, combined cycle facility owned by Calpine Corporation (Calpine) that will be needed to support the reliable operation of the ISO grid in 2017 and beyond.

Calpine has submitted a request for designation of the Sutter plant as CPM capacity for 2012 and stated that, absent a CPM designation, the Sutter

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1 The ISO submits this petition for tariff waiver pursuant to Rule 207 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.207.

2 Capitalized terms not otherwise defined in this petition for tariff waiver have the meanings set forth in the Master Definitions Supplement, Appendix A to the ISO Tariff. References in this petition for tariff waiver to numbered sections are references to sections of the ISO Tariff unless otherwise stated.

plant will retire as soon as May 2012. The ISO respectfully requests that the Commission issue an order in response to this petition by March 29, 2012 that will allow the ISO to timely designate the Sutter plant as a CPM resource during 2012, thereby avoiding closure of the facility.

Pursuant to Section 388.112 of the Commission's regulations, the ISO respectfully requests confidential treatment of Attachment B to this filing, certain tables of financial information provided to the ISO by Calpine which contain commercially-sensitive information that is not normally publicly available. In the public version of the Calpine request provided in Attachment A to this filing, the commercially-sensitive information has been redacted. The non-public materials in Attachment B have been marked "PROTECTED MATERIALS NOT AVAILABLE TO COMPETITIVE DUTY PERSONNEL." The ISO will provide copies of the non-public materials in Attachment B to parties that file to intervene in this proceeding, provided that such parties provide the ISO with executed versions of the attached non-disclosure certificates by qualified reviewing representatives of such parties agreeing to comply with the proposed protective order submitted by the ISO.

I. Executive Summary

The ISO submits this petition at a time when the California electric grid is undergoing a significant transformation. Under environmental regulations dictating the use of once-through cooling (OTC) technology at coastal power plants, 12,079 megawatts (MW) of generation resources are scheduled to retire over the next eight years. California is simultaneously implementing a renewable portfolio standard (RPS) which requires that 33 percent of retail energy sales be met by eligible renewable energy by 2020. The ISO anticipates that retirements of the OTC resources will create a capacity gap of more than 3,500 MW needed to serve load in the ISO's balancing authority area as early as the end of 2017, and the ISO projects this capacity gap to grow to 4,600 MW by 2020. The ISO's analyses identifying this capacity gap take into account new capacity additions, most of which will be variable resources. This tariff waiver is necessary to retain an air-cooled existing flexible resource that is not subject to OTC regulations in order to meet future system-wide reliability needs.[3] If the Sutter plant is retired, the capacity gap identified by the ISO will grow by an additional 525 MW, thereby aggravating an already challenging situation and posing further significant impediments to the reliable operation of the ISO grid starting in 2017.

As the system operator for most of the state, the ISO is keenly aware of its responsibility for maintaining reliability as cost-effectively as possible, particularly in light of the significant transformation that the electricity grid will undergo. Nothing, however, will undermine the state's policy goals more quickly than reliability issues, challenges with integrating renewable resources, or significant cost impacts. Ensuring that we have adequate flexible resources on the system enables us to avoid operations issues and mitigate cost impacts. Thus, this waiver petition is an indication of the urgency the ISO brings in meeting its obligation to maintain system reliability and enable successful implementation of

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[3] The Sutter plant operates under a pseudo-tie arrangement with the ISO and has valuable operating characteristics, including fast start and flexible ramping capability that allows the ISO to dispatch discrete portions of its capacity as needed to satisfy demand in the ISO balancing authority area.

the state's policy goals. Through this petition, which is extremely limited and targeted in nature, the ISO seeks to keep the Sutter plant operational through the end of 2012 in order to permit the ISO and its stakeholders to explore longer-term procurement options to address the risk of retirement of existing, flexible generation capacity that will be needed to support reliable operation of the grid in the coming years. In order to ensure that market participants do not incur more costs than necessary to keep the Sutter plant operational in 2012, the ISO expects to designate the Sutter plant as CPM capacity for a maximum of six months in 2012.

This filing satisfies the Commission's standards for tariff waivers. The waiver allowing the CPM risk-of-retirement designation for the Sutter plant is limited in scope given that it will only apply to the Sutter plant and will only apply to a 2012 designation. Granting the waiver will provide benefits to customers in California by ensuring that a needed resource remains in service. The potential adverse impact on third parties is limited given that the procurement will only apply for a maximum of six months, and is based on the CPM payment and cost allocation methodology applicable to Section 43.2.6 CPM risk-of-retirement designations which the parties have agreed to in a settlement filed with the Commission in the CPM proceeding.

The ISO has determined that Sutter is needed for reliability starting by the end of 2017 based on production studies it conducted in coordination with state regulators to assess the flexible resources needed to support a 33 percent RPS given the expected retirement rate of resources within the existing OTC fleet.

The ISO prepared these studies in connection with the California Public Utilities Commission's (CPUC) long-term procurement plan (LTPP) proceeding, which will drive the future long-term procurement obligations of the state's investor-owned utilities. The ISO's studies are based on plausible planning assumptions that reflect one of the potential scenarios within the scope of the CPUC's LTPP proceeding, namely the 33% RPS trajectory scenario with high load. The ISO based its determination of need on this specified CPUC scenario, referred to hereinafter as the "operations planning scenario" because the ISO determined that this was the most appropriate scenario to use for operations planning purposes in this instance. The operations planning scenario identifies a plausible set of load outcomes and assumptions which a prudent utility would anticipate for planning purposes to assess operational reliability needs several years into the future. In particular, this scenario is a more plausible scenario than the other scenarios specified in the LTPP proceeding for purposes of serving as the basis for assessing the future need for existing resources.

The load values in the scenario used by the ISO were based on the very reasonable assumption of the California Energy Commission (CEC) of a 1.3% annual load growth, which is consistent with historical trends prior to the recent recession. The operations planning scenario used by the ISO also included the CPUC assumptions on planned resources. Even with consideration of new developments since the studies were conducted, the ISO studies indicate that no other resource stands ready to mitigate for the identified capacity gap should the Sutter plant leave.

The ISO cannot prudently or adequately plan for future capacity requirements based on a set of scenarios that are overly optimistic and difficult to justify given what we know about the historical usage of the grid. In particular, the four other scenarios studied by the ISO in the LTPP proceeding are based on a CPUC-mandated assumption that peak system load in 2020 will be approximately 45,000 MW, which is more than ten percent lower than the ISO's historic peak load and is lower than the ISO's 2010 peak load of 47,350 MW or 2011 peak load of 45,545 MW (which occurred in the midst of a recession and during a very mild summer).

In addition to severe economic consequences, failure to rely on a plausible range of study assumptions could lead to electricity outages caused by a shortage of the flexible resources needed to operate the system reliably. The scenario relied on by the ISO to assess the need for the Sutter plant is consistent with good utility practice. Failure to rely on this realistic scenario (and reliance instead on a scenario that is not consistent with historic or reasonably anticipated grid usage, or which is based on unproven, high levels of participation in energy programs) could result in a situation starting in 2017 where an existing resource like the Sutter plant is needed in order to maintain reliability, but it is unavailable because it was forced to retire in 2012 due to unrealistic assumptions regarding future needs and system conditions. As the entity responsible for reliable grid operations, the ISO must not be placed in this untenable position. The study assumptions used by the ISO better account for future uncertainties regarding load growth and program performance, as well as demand response, energy efficiency and a plausible increase in electric vehicles in California, as embedded in the CEC's 2009 load forecast. The overall reasonableness of the ISO's studies is also supported by a joint analysis submitted by the California investor-owned utilities in the LTPP proceeding, which also identified a significant capacity gap by 2020 even with the assumption that the Sutter plant will remain in service.

This waiver request is the most appropriate option available to the ISO for ensuring that the Sutter plant will not retire permanently in 2012 and therefore be unavailable to meet system needs in future years. Because the ISO's analysis shows that the plant will only be needed for reliability and operational requirements as of the end of 2017, the ISO is precluded from procuring the resource under its current tariff authority to procure CPM capacity at risk of retirement.

The Sutter plant is uniquely situated as the only plant that has provided the ISO with notice of its intent to retire in 2012 absent a CPM designation. If any other resource requests similar treatment, the ISO is required under its tariff to conduct the same analysis, but the ISO does not expect another resource can support a comparable waiver request. There is no other resource as large and flexible as the Sutter plant that has not been procured through the annual CPUC resource adequacy process. More importantly, no other resource has requested the same treatment since the ISO issued its report on the Sutter request on December 6, 2011.

To address potential resource retirements in 2013 and beyond, the ISO has just launched a Flexible Capacity Forward Procurement stakeholder process which, among other things, will develop rules for the procurement of resources at risk for retirement in the current year but needed in future years. However, the new tariff provisions resulting from this stakeholder process cannot be developed, finalized, and approved in time to procure the Sutter plant before it is targeted for retirement. The ISO expects to file new risk-of-retirement tariff provisions with the Commission in the fall of 2012, which once approved by the Commission would potentially apply to the Sutter plant and any other similarly situated resources in years after 2012. In other words, the requested waiver only applies to the designation of the Sutter plant for 2012; it does not carry over into future years.

The ISO considered other potential alternatives to provide the Sutter plant with adequate compensation to remain online for the rest of 2012 but concluded that the alternatives were not feasible or justifiable. In particular, the ISO considered whether it could compensate Calpine for "mothballing" the Sutter plant until the resource is needed again in 2017. The ISO has no authorization for such action absent a tariff amendment that would require an appropriate stakeholder process and could not be developed, finalized, and approved in time to procure the Sutter plant by mid-2012. Further, the owner of the Sutter plant has stated in a sworn affidavit that it is unlikely that the resource feasibly could be mothballed and then returned to service by the end of 2017 due to environmental permitting requirements.

Moreover, the Sutter plant is a 525 MW resource that has operated at a 60-80 percent capacity factor during the summer and peak months and has provided significant energy and ancillary services to the ISO. Importantly, this resource can also be shut down and cycled at night, thereby allowing the ISO to avoid high off-peak minimum load energy costs if the ISO does not need the unit. Thus, removing such a large unit from service would adversely affect market efficiency and competition, to the detriment of ratepayers. The CPM option keeps the unit operational in 2012 and enables the ISO to continue to make use of this valuable resource. To the extent parties are more focused on the possibility that mothballing could result in lower overall payments to Sutter, the ISO notes that it has successfully and adequately addressed that issue by determining that it would only procure the Sutter plant for a maximum of six months, which is the bare minimum needed to keep the plant operational based on the data provided to the ISO.

The ISO also considered the use of its reliability must-run (RMR) process to procure the Sutter plant but determined that, because the Sutter plant does not address localized, long-term reliability needs, the ISO could not rely on an RMR process absent a tariff amendment to allow the ISO to procure Sutter to address system needs. In addition, the CPM designation, as previously approved by the Commission, provides greater benefits to the ISO and market participants given that it provides greater flexibility.

Granting this waiver request will not establish a general model for procuring capacity from resources to address long-term system needs in

California. Local regulatory authority programs will continue to establish the rules and requirements for procurement of new and existing resources to meet capacity needs. Where these programs fall short in meeting identified needs to operate the system reliably, however, the ISO must have the ability to step in and provide backstop mechanisms that ensure the ISO has sufficient capacity to meet the changing demands of the grid reliably. If the Sutter plant is procured under any of the CPUC resource adequacy related procedures, the CPM designation of the Sutter plant will not occur or will be rescinded consistent with the approved ISO Tariff. Thus, there is no possibility of the Sutter plant receiving duplicative payments.

The ISO acknowledges that the CPUC recently issued a draft resolution that, if adopted, orders the three largest investor-owned utilities in California to negotiate to enter into a contract with the Sutter plant to end no later than December 31, 2012.[4] Because this result is not assured, however, it is important that the ISO continue to seek this waiver so that it can stand prepared to procure the Sutter plant in a timely manner and prevent degradation of an already tenuous future reliability and operational outlook.

For all these reasons, the ISO submits that the requested limited, one-time waiver is the most expeditious and reasonable method for providing compensation to Sutter to ensure that the plant, which is needed for reliability in future years, is not retired in 2012. The Commission should grant this request in

[4] *See* Draft Resolution E-4471, available on the CPUC's website at http://docs.cpuc.ca.gov/WORD_PDF/COMMENT_RESOLUTION/157581.PDF.

order to protect against loss of the flexible capacity that the Sutter plant provides and that the ISO system will need.

II. Background

A. Request for CPM Designation for the Sutter Plant

In March 2011, the Commission authorized the ISO to modify the ISO Tariff to include provisions regarding CPM designations for capacity at risk of retirement.[5] Under these tariff provisions, the ISO may make CPM designations for capacity at risk of retirement if five specified requirements in Section 43.2.6 of the ISO Tariff are met.[6]

On November 22, 2011, the ISO received its first and so far only request for a CPM designation for capacity at risk of retirement. Calpine requested that the ISO grant a CPM designation for the Sutter plant because the plant must and will have to be retired in 2012 and will thus be unavailable for commercial operations in 2013 and later years, unless it receives a CPM designation.[7] The

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[5] *California Independent System Operator Corp.*, 134 FERC ¶ 61,211, at PP 124-44, Ordering Paragraph (C) (2011); Commission Letter Order, Docket No. ER11-2256-001 (June 21, 2011) (accepting ISO compliance filing in proceeding). The Commission accepted those ISO Tariff provisions effective April 1, 2011.

[6] Such capacity must also meet requirements set forth in Section 7.3.5.2 of the ISO's Business Practice Manual for Reliability Requirements.

[7] Calpine indirectly owns the Sutter plant through its subsidiary, Calpine Construction Finance Company. Calpine's request for CPM designation for the Sutter plant (November 22 Calpine request) is provided in Attachments A and B hereto. Attachment B has been designated as confidential because certain tables of financial information provided to the ISO by Calpine in support of the November 22 Calpine request contain commercially sensitive information that is not normally publicly available. Attachment C hereto contains supplemental information provided by Calpine on January 24, 2012 at the request of the ISO.

ISO issued a report regarding the November 22 Calpine request on December 6, 2011.[8]

The Sutter plant is an air-cooled, combined cycle gas turbine generating facility located near Yuba City in Sutter County, California. The plant has a net qualifying capacity for 2012 of between 500 and 525 MW.[9] It is interconnected to the transmission system operated by the Western Area Power Administration and operates in the ISO markets pursuant to a pseudo-tie arrangement with the ISO.[10] The Sutter plant can be dispatched by the ISO and has flexible ramping capability that allows discrete portions of its capacity to be dispatched as needed to satisfy demand.

B. Stakeholder Process

In accordance with Section 43.2.6, the ISO posted the December 6 ISO report on its website for review and written comment by stakeholders. The ISO hosted a stakeholder conference call on December 9, 2011 to discuss the December 6 ISO report. Written stakeholder comments were due by December 16, 2011. A total of 18 stakeholders submitted comments.[11] The issues raised

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[8] *See ISO Report on Basis and Need for CPM Designation for Sutter Energy Center*, at 5-9 (Dec. 6, 2011) (December 6 ISO report). This report is provided as Attachment D to this filing and also is available on the ISO website at http://www.ISO.com/Documents/Basis_Need_CapacityProcurementMechanismDesignation_SutterEnergyCenter.pdf. The report was issued pursuant to the requirement in Section 43.2.6 that, "prior to issuing [a] CPM designation [for capacity at risk of retirement], the CAISO shall prepare a report that explains the basis and need for the CPM designation."

[9] The net qualifying capacity of the Sutter plant is specified for each month and varies based on seasonal factors.

[10] *See* Pseudo Participating Generator Agreement between the ISO and Calpine Construction Finance Company, accepted by Commission letter order issued in Docket No. ER06-58-001 on March 1, 2006.

[11] The written stakeholder comments on the December 6 ISO report are available on the

by stakeholders are addressed in this filing and the attached declaration of Mark Rothleder, Executive Director of Market Analysis and Development for the ISO.[12] In addition, the ISO has provided a matrix of its responses to these stakeholder comments as Attachment F to this filing.

III. The ISO Has Determined the Need for Flexible Capacity to Satisfy Reliability Needs on the California Grid.

A. The ISO's Production Studies of Future System Conditions Indicate the Need to Retain the Sutter Plant.

Upon receipt of Calpine's request regarding the pending risk of retirement of the Sutter plant, the ISO evaluated the need for Sutter. The ISO's analysis used a series of production studies it developed and conducted over the past two years in anticipation of the changes to the California grid that will occur over the next several years. Using these studies, discussed further below, the ISO determined that the retirement of the Sutter plant will further reduce already-problematic projections of the ISO's ability to meet reliability and operational requirements by the end of 2017.

The ISO reviewed the November 22 Calpine request and determined that the Sutter plant meets all of the ISO Tariff requirements set forth in Section 43.2.6 to be designated as CPM capacity at risk of retirement, with one exception.[13] The ISO's determination of the need for the Sutter plant does not

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ISO website at http://www.ISO.com/informed/Pages/StakeholderProcesses/CapacityProcurementMechanismDesignation_SutterEnergyCenter.aspx.

[12] Mr. Rothleder's declaration is provided as Attachment E to this filing.

[13] The ISO also determined that the Sutter plant does not qualify for designation as CPM capacity under a designation other than capacity at risk of retirement. *See* ISO Tariff, Sections 43.2.1 to 43.2.5 (setting forth requirements for other CPM designations).

meet the tariff requirement that "CAISO technical assessments project that the resource will be needed for reliability purposes, either for its locational or operational characteristics, *by the end of the calendar year following the current RA Compliance Year*."[14] In this case, the relevant resource adequacy compliance year is 2012. Without the ISO's requested waiver, the ISO Tariff would require the ISO to identify a locational or operational need by the end of 2013. The ISO's analysis does not support such a need for the Sutter plant by 2013.

As the entity responsible for the reliability of the ISO controlled grid and a participant in the CPUC LTPP addressing long-term procurement plans for state investor-owned utilities,[15] the ISO has analyzed numerous factors that will affect the reliability of the ISO-controlled grid over a planning horizon from 2011-2020. Based on its analysis to date, the ISO has identified a significant concern that, under some scenarios, there will be a "gap" or shortage in the capacity needed to meet system-wide reliability needs in California by the end of this planning horizon. The attached declaration of Mr. Rothleder provides a more detailed discussion of the methodology employed and the results of that analysis.

As discussed by Mr. Rothleder,[16] this gap was identified in the context of the ISO's evaluation of the operations planning scenario which reflected the CPUC's 33 percent RPS integration by 2020. Concerns about this gap have led

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[14] ISO Tariff, Section 43.2.6(3) (emphasis added).

[15] CPUC Rulemaking 10-05-006. Filings and issuances generated in that proceeding are available on the CPUC website at http://www.cpuc.ca.gov/PUC/energy/Procurement/LTPP/ltpp_history.htm.

[16] Rothleder Declaration at 14-16.

the ISO to focus on the benefits of maintaining the availability of capacity currently on the system to enable successful operations during this time frame.

One of the objectives of the LTPP proceeding is to quantify the need for new resources to meet system or local resource adequacy over the 2011-2020 planning horizon, including issues related to long-term renewable integration planning and the need for replacement generation to eliminate reliance on OTC power plants, *i.e.*, power plants that are cooled using ocean or lake water and that are expected to be retired during that time frame due to regulations implemented by the State Water Resources Control Board. As part of the CPUC LTPP proceeding, the ISO also evaluated potential operational and resource capacity needs driven by the California RPS requirement that 33 percent of retail energy sales be met by eligible renewable energy by 2020. The scope of the LTPP proceeding is described in Section 3 of the "Assigned Commissioner and Administrative Law Judge's Scoping Memo and Ruling" (Scoping Memo), issued in the LTPP proceeding on December 3, 2010.[17]

Faced with the prospect of Sutter's retirement, the ISO leveraged its work in the CPUC LTPP proceeding to perform a supplemental sensitivity analysis in addition to its operational requirements 2020 study. As discussed further below and in Mr. Rothleder's declaration,[18] in its sensitivity analysis of the need for the Sutter plant the ISO made certain adjustments to the 2020 production analysis it conducted for the CPUC's LTPP proceeding to evaluate resource needs by the

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[17] The Scoping Memo is provided as Attachment 2 to Mr. Rothleder's declaration and is available on the CPUC website at http://docs.cpuc.ca.gov/EFILE/RULC/127542.htm.

[18] Rothleder Declaration at 25-27, 34.

end of 2017. A summary of the ISO's analysis is provided in the December 6 ISO report.[19]

The results of the ISO's prior studies conducted for the CPUC using the operations planning scenario, which also assumed the presence of the Sutter plant, indicated a capacity gap of 4,600 MW by 2020. These results reflected the retirement of 12,079 MW of OTC resources. Based on the OTC retirement schedule, the ISO determined that the end of 2017 or 2018 was the first time that the OTC retirement exceeded 4,600 MW and therefore would likely be the first time when a significant capacity gap would occur. The ISO's sensitivity analysis factored in this expectation.[20] The ISO's study of the need for the Sutter plant also adjusted the total level of renewable generation. Under assumptions to achieve the 33 percent RPS, the level of anticipated renewable capacity on the system is expected to be 2,000 MW less in 2018 than in 2020. Based on the assumptions included in the Scoping Memo, the 2,000 MW of renewable capacity to be added to the system between 2018 and 2020 is primarily comprised of approximately 1,100 MW of new solar thermal resources and 700 MW of new geothermal resources.[21]

As explained by Mr. Rothleder, the ISO's analysis of future needs identified an estimated 3,570 MW capacity gap by the end of 2017. The removal of 525 MW of capacity assumed to be available in the ISO's analysis – *i.e.*, the

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19 *See* December 6 ISO Report at 5-9.

20 Rothleder Declaration at 25.

21 *Id.* at 27.

maximum net qualifying capacity of the Sutter plant – would exacerbate reliability and operational issues on the ISO grid and would result in a further capacity need in addition to the identified 3,570 MW as early as the end of 2017.[22]

No stakeholder has objected to the ISO's use of the production studies to identify the capacity gap, but some stakeholders disagree with the ISO as to the projections of future load that the ISO should consider in making decisions to procure resources at risk of retiring, such as the Sutter plant. As discussed by Mr. Rothleder, although the ISO did not conduct a full-year, hourly interval production simulation analysis as was performed for the 2020 cases in the LTPP proceeding, a rerun of the production simulation for July 2018 was performed incorporating the adjustments in assumptions described above to reflect 2018 conditions.[23] The sensitivity analysis is sufficiently robust to determine how the capacity requirements are likely to change based on the results of the actual production runs. An additional rerun of the production studies was not expected to provide additional useful information.

B. Good Utility Practice Necessitates Reliance on the Operations Planning Scenario to Plan for Future Capacity Deficiencies.

As indicated above, the ISO appropriately based its analysis of the potential long-term need for the Sutter plant on the operations planning scenario used in the CPUC LTPP proceeding. While some stakeholders have challenged the use of this scenario, arguing that the ISO should have used the lower-load scenarios defined by the CPUC through the LTPP proceeding, the ISO's use of

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22 *Id.* at 36.

23 *Id.* at 29-30.

the operations planning scenario for its Sutter analysis is consistent with good utility practice and is necessary to ensure system reliability, particularly given the optimistic and unproven assumptions underlying the other scenarios and their significant divergence from historic grid usage.

There were a number of scenarios identified in the LTPP proceeding that were based on varying assumptions of projected load, renewable integration, the performance of state level efficiency and demand response programs, and general conditions. In this regard, the Scoping Memo stated that the purpose of establishing the required scenarios was to "model potential outcomes of a wide variety of policy choices using common assumptions to allow plans developed by each IOU [investor-owned utility] to be compared together."[24] As described in Mr. Rothleder's declaration,[25] the Scoping Memo initially required the IOUs to study the following seven scenarios: four different renewable portfolio standard scenarios that assume achievement of a 33 percent RPS by 2020; a scenario that assumes achievement of a 20 percent RPS by 2020; and two scenarios that include sensitivities regarding a 33 percent RPS trajectory scenario – one scenario assuming high load and the other scenario assuming low load.[26] The scenarios were intended to represent a wide practical range of common value assumptions that could be used to uniformly compare procurement proposals across the various IOU jurisdictions so that the CPUC could create a more

[24] *See* Attachment 2 to Rothleder Declaration, Scoping Memo at 7.

[25] Rothleder Declaration at 14-15.

[26] *See* Attachment 2 to Rothleder Declaration, Scoping Memo at 24-25.

meaningful overall system resource plan.[27] The seven required scenarios included the scenario used by the ISO in its evaluation of the need for Sutter.

Through its participation in the LTPP proceeding, the ISO studied only five of the seven required scenarios due to timing constraints. Of the five scenarios the ISO studied, four were designated by CPUC staff as "priority scenarios" that the ISO should study first in the interest of maximizing the study results in the time allotted in the LTPP proceeding, not because any inherent value was ascribed to these particular scenarios.[28] These consist of the 33 percent trajectory base load, environmentally constrained, cost constrained, and time constrained scenarios.[29]

In the LTPP proceeding, the ISO has indicated the inadequacy of these four scenarios for identifying plausible outcomes that the ISO must use for designing its own market products and planning to meet future operational and reliability needs.[30] As explained in the testimony provided by Mr. Rothleder in the LTPP docket, the ISO cannot conclude from the results of these four scenarios "whether sufficient flexible capability would exist to meet the simultaneous energy, operating reserve, regulation and load following requirements if the

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27 *See id.* at 7.

28 *See* LTPP Testimony of Mr. Rothleder at 7-8, which is provided as Attachment 1 to Mr. Rothleder's declaration in this proceeding and is available on the CPUC's website at http://www.caiso.com/Documents/2011-08-10_ErrataLTPPTestimony_R10-05-006.pdf. In addition to the five CPUC scenarios, the ISO also studied an "All Gas" scenario in support of development of metrics by the IOUs, and conducted a sensitivity analysis assuming all three Helms pumps are available year round. *Id.* at 7.

29 Rothleder Declaration at 14-15. *See also* Attachment 1 to Rothleder Declaration, LTPP Testimony of Mr. Rothleder at 6.

30 Attachment 1 to Rothleder Declaration, LTPP Testimony of Mr. Rothleder at 44-45.

available generation capacity was not in excess of the 15-17% PRM [required planning reserve margin]."[31]

The ISO also joined a settlement agreement (Settlement Agreement) filed in the LTPP proceeding on August 3, 2011 that addressed a number of the LTPP Track 1 issues.[32] As acknowledged in the Settlement Agreement, although the results of the ISO's analysis of these four scenarios "show no need to add capacity . . . above the capacity available in the four scenarios for the planning period addressed in this LTPP cycle (2010-2020)," the results of the ISO's analysis of the operations planning scenario "did show need."[33] The Settlement Agreement goes on to state that "[t]he Settling Parties have differing views on the input assumptions used in, and conclusions to be drawn from the modeling. There is general agreement that further analysis is needed before any renewable integration resource need determination is made."[34] Therefore, contrary to the allegations of some stakeholders, the record in the LTPP proceeding does not discredit the use of the operations planning scenario for purposes of determining future system needs.

But more importantly, as discussed by Mr. Rothleder, the ISO must base its determination of future need for the Sutter plant on the fifth scenario it studied

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31 *Id.*

32 The Settlement Agreement is provided as Attachment 3 to Mr. Rothleder's declaration in this proceeding and is available on the CPUC website at http://docs.cpuc.ca.gov/efile/MOTION/140823.pdf. This Settlement Agreement will not become effective until it is approved by the CPUC.

33 Attachment 3 to Rothleder Declaration, Settlement Agreement at 4.

34 *Id.* at 5.

– the operations planning scenario – because to do otherwise would be imprudent and contrary to good utility practice. This is because, when considering issues of and planning system reliability, it is generally appropriate to apply a more realistic approach and not rely on potentially overly optimistic assumptions and expectations that are not factually based or reasonably extrapolated from historic performance, or that are not clearly supported and justified based on tangible evidence.[35] The operations planning scenario, which is intended to reflect future uncertainties in forecast demand, reflects a plausible analysis of longer-term system needs. Indeed, the main difference between the first four scenarios and the operations planning scenario is due to the load assumptions involved. The operations planning scenario differs from the other four scenarios in that it anticipates generally higher load demands, due in part to more positive economic conditions or lower realization of new demand response and energy efficiency measures. In fact, Mr. Rothleder explains that the operations planning scenario assumes that load levels will remain closer to previous system conditions than do the four other scenarios.[36]

All five LTPP scenarios include an expectation that the performance of energy efficiency and demand response programs in the future will substantially exceed the energy efficiency and demand response experienced today. As Mr. Rothleder explains, these scenarios include over 5,100 MW of demand response and over 5,600 MW of incremental uncommitted energy efficiency programs. For

[35] Rothleder Declaration at 17-19.

[36] *Id.* at 15, 20-21.

2012 the total expected demand response expected for July is approximately 2,600 MW. Expected incremental energy efficiency for 2012 is a total of 192 MW for the combined investor-owned utility areas.[37] The ISO's study of the need for the Sutter plant in July 2018 used assumptions from the operations planning scenario and therefore more than tripled expected demand response and energy efficiency as compared with the anticipated performance of existing programs. Moreover, actual performance of these resources has been significantly lower than expected. The ISO believes that it is prudent to plan based on an expectation of reasonable performance of such programs and not projections of performance that exceed past trends. The ISO's use of the operations planning scenario is not an indictment of the state efficiency and demand response goals, which are among the most important and least-cost steps that California can take to successfully integrate the expected levels of new renewable generation. However, the consequences of having insufficient resources to reliably operate the grid are much more significant than the consequences of over-procurement. In addition to severe economic consequences, electricity outages caused by a shortage of the flexible resources needed to reliably operate the system would put renewable goals themselves at risk. As the system operator, the ISO must focus on the potential adverse consequences of having insufficient resources to reliably operate the grid.

Any claims by stakeholders that the operations planning scenario represents an exaggerated prediction of future conditions are misguided. The

[37] *Id.* at 15-16.

reasonableness of the load assumptions in the operations planning scenario that indicated the need for the Sutter plant is illustrated simply by looking at the relative load assumptions in the first four scenarios as compared with the operations planning scenario. As discussed by Mr. Rothleder, the first four scenarios all shared the same load assumptions, which incorporated more than 10,000 MW of load reduction by 2020 as compared with what would have been the load based on the latest projections of expected load growth provided by the California Energy Commission's projections of expected load. These low load projections are largely driven by the assumptions that the energy efficiency and demand response performance will more than triple the actual performance to date during that time frame.[38]

These four scenarios include a forecasted peak ISO demand of approximately 45,000 MW in 2020 (net of expected energy efficiency, demand response, and combined heat and power). For the operations planning scenario, the CPUC prescribed a 10 percent higher peak load than the other four scenarios, which resulted in a forecasted peak ISO demand of 50,672 MW for 2020 and 50,881 MW for 2018 (again, net of expected energy efficiency, demand response, and combined heat and power). Use of the higher peak ISO demand levels under the operations planning scenario is appropriate to capture plausible increases in demand by the 2018-2020 time frame. In contrast, the forecasted peak ISO demand in 2020 under the four scenarios is lower than the historical ISO peak demand of 50,270 MW in 2006, the ISO peak demand of 47,350 MW in

[38] *Id.* at 14-16.

2010, and even the ISO peak demand of 45,545 MW that occurred in 2011 in the midst of a recession and during a mild summer.[39]

The operations planning scenario is therefore based on plausible load projections. After evaluating the potential for a significant gap in capacity under the operations planning scenario, the ISO determined that good utility practice requires it to take all appropriate actions today to address the potential for future system conditions that may threaten system reliability.

Assertions that the operations planning scenario is not a CPUC-approved scenario are false and misleading. Most notably, the operations planning scenario was included in the Scoping Memo as one of the scenarios that the IOUs were directed to use in their sensitivity studies to drive their procurement decisions. The ISO's use of the operations planning scenario is fully consistent with the Settlement Agreement. The purpose of Track 1 of the LTPP proceeding is for the CPUC to identify needs for new resources to meet system or local resource adequacy and to consider authorization of its jurisdictional IOUs' procurement to meet that need, including issues related to long-term renewables planning and a need for replacement generation infrastructure to eliminate reliance on power plants using once-through cooling.[40] In response to the rulings of the presiding Administrative Law Judge in the LTPP proceeding, the IOUs and the ISO developed and analyzed system resource plans using the other four scenarios studied by the ISO to fulfill the standardized planning assumptions

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[39] *Id.* at 14-15. In analyzing these scenarios, the ISO employed the assumptions prescribed by the CPUC.

[40] *See* Attachment 2 to Rothleder Declaration, Scoping Memo at 4-5.

established by the CPUC. In addition, the IOUs developed three scenarios (IOU common scenarios) and a further sensitivity analysis. On the issue of a system needs determination, the ISO agreed that additional study work should continue before any decisions on procurement of new resources should be made in the LTPP proceeding. All of the analyses in that proceeding, however, assumed that the Sutter plant would be available, and the ISO's stipulations in that proceeding are fully consistent with the ISO's current conclusion that the Sutter plant will continue to be needed in the 2018 time frame.[41]

Further, as explained in the Settlement Agreement, the IOUs applied the same methodology for the IOU common scenarios using assumptions that differ from the operations planning scenario but also differ from those used in the first four scenarios. The results of the IOUs' modeling "show need for additional capacity for renewable integration purposes under certain circumstances."[42] Thus, the IOUs' own studies, like the study conducted by the ISO for the operations planning scenario, show a future need for additional capacity in the specified circumstances, also assuming that the Sutter plant would remain available to meet system needs in 2020.

Although the first four scenarios did not indicate a need to add new capacity, the first four scenarios all assumed that certain generation would be in place, which included the Sutter plant.[43] Therefore, one cannot conclude based

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41 Rothleder Declaration at 39-40.

42 *See* Attachment 3 to Rothleder Declaration, Settlement Agreement at 5.

43 This is consistent with the assumptions for the first four scenarios as set forth in the LTPP proceeding. *See* Attachment 1 to Rothleder Declaration, LTPP Testimony of Mr. Rothleder at Exhibit 1, Slides 39, 78.

on the results of analyses using the first four scenarios that the Sutter plant is not needed in the 2020 time frame. The ISO has not conducted any sensitivity analysis based on the first four scenarios to determine whether removal of the Sutter plant would cause any reliability issues. However, as explained in Mr. Rothleder's declaration, the operations planning scenario, which is a more prudent and appropriate scenario for planning future reliability needs, definitively shows that a capacity gap will exist by the end of 2017 that cannot be filled by planned generation and that would only be exacerbated by removal of the Sutter plant.[44]

C. The Additional Capacity Gap Caused by the Loss of Sutter Cannot Be Addressed by Another Existing Resource or Planned New Resources.

1. The Sutter Plant Has Proven to Provide Benefits That Would Assist in Mitigating the Identified Capacity Gap.

Losing 525 MW of capacity assumed to be available in the ISO's analysis – *i.e.*, the maximum net qualifying capacity of the Sutter plant – would exacerbate reliability and operational issues on the ISO grid and would result in a further capacity need in addition to the identified capacity gap of 3,570 MW at the end of 2017. The absence of the Sutter plant would increase the needed flexible capacity for the July 2018 production simulation examined in the ISO's analysis. The Sutter plant's flexible capacity of up to 525 MW would be unavailable to meet system needs in the ISO balancing authority area if the plant were to be

44 Rothleder Declaration at 30-39.

retired. Therefore, the Sutter plant is needed to meet the 2017/2018 operational needs identified by the ISO.[45]

The ISO's production and sensitivity analyses considered details regarding the specific operating characteristics of the Sutter plant, and all other plants considered to be available to the ISO in the applicable time frame. Thus, the results of the ISO studies are informed by how each resource specifically contributes to ISO system needs and the identified capacity gap is based on a full consideration of the production capabilities of the fleet. Moreover, as discussed by Mr. Rothleder, the Sutter plant is a particularly valuable resource to the ISO that contributes to the ISO's operations and market efficiency.[46] The Sutter plant was specifically observed to provide energy, operating reserves, and flexibility in the ISO's July 2018 production simulation. In the July 2018 production simulation, the Sutter plant was observed to have a 69.91 percent capacity factor. The relatively high capacity reflects that the Sutter resource was needed to meet load and/or be online providing operational flexibility for a significant amount of the study period. This is further supported by the observation that the resource provided 280.89 GWh of energy, 8.86 GWh of Spinning Reserve, 0.36 GWh of Non-Spinning Reserve, 5.20 GWh of Regulation, 30.84 GWh of load following up, and 64.38 GWh of load following down in the July 2018 production simulation.[47]

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45 December 6 ISO report at 7-9.

46 Rothleder Declaration at 33-34.

47 *Id.*

The Sutter plant is an air-cooled power plant with 525 MW of installed capacity and is not at risk for retirement due to the OTC requirements, which means it could be available in 2018 provided there is sufficient compensation to keep the plant operational in the intervening years. The Sutter plant can be dispatched by the ISO and has relatively fast start and relatively fast, flexible ramping capability that allows discrete portions of its capacity to be dispatched as needed to satisfy demand. These operating characteristics make the Sutter plant especially valuable in serving demand. Therefore, there is value in retaining the resource. The Sutter plant is particularly attractive to the ISO because its flexible nature makes it valuable in serving demand in the real-time. The Sutter plant also has automatic generation control capability, allowing it to provide Regulation service. In sum, the Sutter plant is among the most flexible resources serving needs in the ISO balancing authority area today and allowing the loss of the facility in the advent of a potential gap in flexible capacity only six years out is contrary to good utility practice.[48]

2. No Other Existing or Planned Resource Can Address the Need for the Sutter Plant Within the Identified Time Frame.

The ISO's 2017/2018 analysis identified a 2,535 MW deficiency in flexible capacity requirements, resulting in an estimated 3,570 MW of additional capacity needs. The removal of 525 MW capacity of capacity would result in a need for additional capacity as early as the end of 2017. Any additional generation that can be installed by 2017 will be needed to address the over 3,500 MW shortfall

48 *Id.*

which is projected even if the Sutter plant remains in operation. To put it simply, when one finds oneself in a hole, the first step is to stop digging. In light of the coming capacity shortfall, the ISO believes it is important to find ways to keep existing generation in operation, particularly generation facilities like the Sutter plant that have valuable operational characteristics.

The ISO's analysis included a set of embedded assumptions regarding the planned addition of new generation. As discussed in Mr. Rothleder's declaration,[49] the ISO adopted the same assumptions for resource additions adopted in the CPUC's LTPP proceeding as set forth in the Scoping Memo. Therefore, consistent with the Scoping Memo, the ISO's studies assume planned additions of new generation based on whether or not the resource received a CPUC-approved contract. The ISO adopted these assumptions because, as explained by Mr. Rothleder, including a generator in the ISO's interconnection queue provides no guarantee that all the generation will be brought online. To the contrary, the ISO's experience, particularly in recent years, has been that the level of proposed generation projects that submit interconnection requests substantially exceeds the level of generation that will actually be placed in service. In making projections of future generation, it is more reasonable to use objective criteria, such as whether or not the planned project has received a CPUC-approved power purchase agreement.[50]

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[49] *Id.* at 22-24.

[50] *Id.*

Mr. Rothleder explains that the ISO accepted the criteria put forth in the Scoping Memo because resources that already have CPUC-approved contracts demonstrate a degree of financial security that will enable the resources to come online. To the extent the ISO made adjustments in preparing its studies, it was to add resources not assumed in the LTPP study assumptions, but that the ISO concluded based on later developments would satisfy the criteria for inclusion in the LTPP study assumptions.[51] Specifically, as explained by Mr. Rothleder, the Coolwater 3 and 4 units were assumed to be retired in the LTPP planning assumptions, but, based on the best information available to the ISO at the time it prepared its 2020 study for the LTPP proceeding, no retirement of Coolwater 3 and 4 is expected in the planning horizon. Even with this adjustment to reflect the once-anticipated retirement of the Coolwater units that are now expected to remain in service, the ISO determined that the Sutter plant will be needed by 2018.

Some stakeholders have questioned whether the procurement, siting, and construction process for new generation could accommodate a new power plant before 2017. It would be imprudent for the ISO to assume that additional resources not already assumed to be available under the ISO's analysis will complete the procurement, siting, and construction process by then. Significant risk awaits a proposed generation project. Each such project must meet all federal and state environmental permitting requirements and successfully reach power purchase agreement terms with a load serving entity that are acceptable

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51 *Id.* at 23-25.

to appropriate regulatory authority and financing entities. Rather than make unwarranted assumptions, the ISO adopted the assumptions set forth in the Scoping Memo to determine the generation expected to be available by 2017. Consistent with this conservative approach to analyzing reliability impacts, the ISO has determined that no additional new capacity with the needed flexibility is expected to come online in time to meet the capacity need identified by the ISO.

As Mr. Rothleder explains, the ISO is aware of one planned resource, the Oakley unit, which was not included in the LTPP planning assumptions and therefore was not included in the ISO's analysis. This planned resource has now satisfied additional regulatory milestones and appears to be likely to add 623 MW by 2016. However, based on the study results, 623 MW would not be sufficient to eliminate the need for Sutter based on the observed shortfalls in the 2018 scenario. Moreover, the additional generation anticipated from the Oakley unit is more than offset by greater amounts of generation that were included in the Scoping Memo but are now expected to be unavailable by 2018. Specifically, the Scoping Memo assumed the additions of the Avenal unit (600 MW) and potentially the Victorville Hybrid unit (563 MW), which have subsequently been determined to likely be unavailable by then. Therefore, the 2018 case actually assumed more generation than is now anticipated to be available by 2018.[52]

In addition, the ISO had preliminarily identified a need of approximately 2,000 MW of replacement generation in the Los Angeles Basin to meet local reliability needs based on OTC retirements. More recently, the ISO has prepared

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52 *Id.* at 36-37.

updated local capacity study results for 2021. These results do indicate higher local resource needs than the previous 2,000 MW, including 2,370 MW of local resource needs in the Los Angeles Basin.[53] However, these resource needs do not appear until 2021.[54]

Further, the ISO's analysis did not consider the up to 415 MW of potential generation that is the subject of a San Diego Gas & Electric Company application before the CPUC. This proposed generation has not been the subject of a CPUC-approved contract and has not received siting approval. Because of the uncertainty about this proposed generation, it does not now satisfy the criteria established in the LTPP proceeding for inclusion in the ISO's study.[55]

IV. Absent the Requested Waiver, the ISO Is at Risk of Losing the Sutter Plant, Thereby Reducing Its Ability to Mitigate for the Anticipated Capacity Gap.

The ISO has concluded that, based on the information provided in the November 22 Calpine request and supplemental information provided by Calpine, the Sutter plant will be unavailable to meet the 2017/2018 operational needs discussed above if the plant does not receive a CPM designation (or some other form of capacity compensation) for 2012.

The Sutter plant satisfies all of the requirements of Section 43.2.6 of the ISO Tariff and the applicable requirements of the Business Practice Manual

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53 *See Once-Through Cooling & AB1318 Study Results* at Slide 11 (page 148 of the combined presentations document). The combined presentations document containing this presentation is available on the ISO website at http://www.caiso.com/Documents/Presentation%20-%2020112012_TransmissionPlanningProcessDec8_2011.pdf.

54 Rothleder Declaration at 35.

55 *Id.* at 37.

(other than the requirements in Section 43.2.6(3) for which the ISO submits this tariff waiver filing). In this regard, Section 43.2.6(5) obligates the resource to provide an affidavit and supporting financial information and documentation that attests that it will be uneconomic for the resource to remain in service in the current RA Compliance Year and that the decision to retire is definite unless CPM procurement occurs. Calpine has provided an affidavit and supporting financial information and documentation that meet the tariff requirements.[56] Thus, Calpine has made the required showing that it will be uneconomic for the Sutter plant to remain in service in the current resource adequacy compliance year (*i.e.*, 2012) and that the Sutter plant will definitely be retired unless it is procured through CPM or receives some other form of capacity compensation. This showing by Calpine is sufficient to satisfy the requirements of the ISO Tariff.

Further, in the order accepting Section 43.2.6 for filing, the Commission explained that the "CAISO's proposal contains multi-layered safeguards and stringent requirements that will adequately protect against the possibility that resource owners will manipulate the system to receive CPM designations."[57] The Commission also found that, "[b]ased on the fact that a market participant is prohibited from submitting false or misleading information to CAISO, the affidavit should be sufficient to establish that a resource cannot continue to operate economically. If the [ISO's] Department of Market Monitoring has reason to suspect that a resource submitted false, inaccurate, or otherwise misleading

56 *See* Attachments A through C hereto.

57 *California Independent System Operator Corp.*, 134 FERC ¶ 61,211, at P 134.

information in its affidavit, the CAISO tariff requires such a suspected violation to be referred to the Commission for appropriate sanction."[58] Thus, the Commission found that the tariff requirements and other existing safeguards are sufficient to ensure that a resource owner's assertions of a need for CPM designation pursuant to Section 43.2.6 are valid.

In the November 22 Calpine request, Calpine asserts that if the Sutter plant is retired in 2012, the plant may not return to commercial operations in future years because, under Environmental Protection Agency policy, the plant would likely need to undergo New Source Review and obtain a new air quality permit. Even if the Sutter plant could meet then-current best available control technology (BACT) requirements and otherwise satisfy all of the new air quality permitting requirements that have gone into effect since the plant was first permitted, the permitting process is often lengthy and subject to an extended and unpredictable appeals process. Further, Calpine stated that future requirements to meet then-current BACT requirements could necessitate substantial new investments, making the return of the Sutter plant to service uneconomic.[59] These considerations suggest that there is a very high risk that, if the Sutter plant shuts down in 2012, it will not return to operation by 2017. As explained in the discussion in Section V below, even if mothballing were a viable option for the Sutter plant, the ISO has no tariff authority to compensate Calpine for mothballing the Sutter plant.

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58 *Id.* at P 132.

59 November 22 Calpine request at 5-6.

V. Granting the Waiver Requested Herein Is the Most Appropriate Means of Providing the Sutter Plant with Sufficient Compensation to Prevent Its Shutdown.

As explained below, the Commission should grant the waiver requested in this petition by March 29, 2012. No viable alternative for providing appropriate compensation for the Sutter plant can be implemented by the ISO prior to May 2012. May 2012 is the earliest that Calpine can retire the Sutter plant under the November 22 Calpine request. As explained further below, Calpine also has requested a notice of the ISO's decision on the CPM designation by April 2012 to allow for needed maintenance at the Sutter plant while keeping the plant in service for at least six months of 2012.

As discussed in more detail below, the CPUC is conducting its own proceeding that has the potential to result in a contract that could avert the shutdown of the Sutter plant. It is unclear what the outcome of that CPUC proceeding will be or when it will conclude. Therefore, the most appropriate course is for the Commission to grant this petition for tariff waiver, based on the possibility that the CPUC proceeding will not avert the shutdown of the Sutter plant. Taking into account these timing issues, the ISO respectfully requests that the Commission grant this petition for tariff waiver by March 29, 2012, in order to prevent a May 2012 shutdown.

A. CPM Designation Is the Only Viable Approach.

The ISO has determined that there are no viable alternatives to granting a CPM designation for the Sutter plant. First, the ISO has concluded that the Sutter plant does not qualify for designation as CPM capacity under a designation other than capacity at risk of retirement.[60]

Further, contrary to the suggestions of some stakeholders, ISO action to mandate or ensure the “mothballing” or temporary retirement of the Sutter plant until it is needed in 2017 is not a viable option. The ISO Tariff contains no provisions addressing mothballing of resources or the compensation to be provided to resources that are mothballed. Thus, the ISO has no authority to compensate Calpine for mothballing the Sutter plant or to pass the costs of such mothballing compensation on to market participants absent a future tariff amendment preceded by a stakeholder process to determine the appropriate conditions and rate for that service. Such authority will be evaluated in the ISO’s stakeholder process this year examining longer-term capacity procurement mechanisms. However, it is not feasible for the necessary tariff amendment to be developed, filed with the Commission, approved, and implemented prior to the planned retirement of the Sutter plant by mid-2012.

Moreover, as explained at page 9 above, the Sutter plant has provided significant energy and ancillary services to the ISO, and a CPM designation keeps the unit operational in 2012 and enables the ISO to continue to make use of this valuable resource. A narrow focus on whether mothballing could result in lower overall capacity payments to Sutter than some other approach ignores the market value that the resource provides. In any event, the ISO has already successfully and adequately addressed the concern that “excessive” capacity payments will be made to Sutter by determining that it will only procure the Sutter

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[60] *See* ISO Tariff, Sections 43.2.1-43.2.5 (setting forth requirements for other CPM designations).

plant for a maximum of six months in 2012. This will result in capacity payments that are the bare minimum needed to keep the plant operational based on the data provided to the ISO.[61] Specifically, the ISO's proposed approach will result in CPM capacity payments of only approximately $17.4 million.[62]

Nor is the Sutter plant eligible for an RMR designation. The Commission has previously recognized that the CPM risk-of-retirement designation addresses situations that cannot be addressed by the existing RMR provisions of the ISO Tariff.[63] The Sutter plant is in exactly that situation.

As part of its analysis, the ISO considered whether the Sutter plant could qualify as an RMR resource, but determined that such a designation would not be appropriate because the need for the Sutter plant is not a locational need, whereas the *pro forma* RMR contract set forth in the ISO Tariff and the related tariff provisions concerning RMR cost allocation are for local reliability needs.[64] The ISO's existing RMR contract authority therefore does not provide an alternative to ensure that the Sutter plant will be available to meet operational and reliability needs by the end of 2017. In this regard, the Commission has explained that a CPM retirement designation can address a need that can be entirely different from a need for an RMR designation:

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[61] Market revenues resulting from the sale of energy and ancillary services from the Sutter plant are expected to make up the additional revenue needed to keep the plant operational.

[62] This amount of CPM capacity payments is substantially less than the payments of up to $29.5 million for the Sutter plant contemplated in the draft resolution issued by the CPUC on January 17, 2012, and discussed in the next section of this petition.

[63] *California Independent System Operator Corp.*, 134 FERC ¶ 61,211 at P 125.

[64] *See* ISO Tariff, Section 41.7 and Appendix G (setting forth RMR cost allocation provisions).

> The Commission also rejects protestors' assertions that the risk of retirement category is duplicative of CAISO's authority to contract with at-risk resources under its reliability must-run authority. The risk of retirement CPM designation provides more flexibility to address reliability needs beyond local constraints. In addition, we note that reliability must-run contracts only apply for the current year, whereas CAISO proposes to use the risk of retirement category to designate resources needed in the following year. Therefore, a situation may arise in which a resource at risk of retirement, but needed for reliability, is deemed ineligible for a reliability must-run contract. For these reasons, the Commission finds that CAISO has demonstrated a need for the risk of retirement category that is not met by CAISO's reliability must-run authority.[65]

Moreover, an RMR designation provides for the recovery of return on equity. In contrast, as explained in the affidavit provided in the November 22 Calpine request, the revenue requirement data provided in support of Calpine's request shows that the Sutter plant would not "obtain a return of or on invested capital during 2012 and subsequent years."[66]

Further, the Sutter plant has not been procured via a resource adequacy contract for 2012.[67] As with RMR, the Commission has expressly recognized that the CPM risk-of-retirement designation concerns situations that have not been addressed by the resource adequacy regime.[68] In this regard, the attached

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65 *California Independent System Operator Corp.*, 134 FERC ¶ 61,211 at P 128.

66 November 22 Calpine request, Affidavit of Alexandre B. Makler at 2.

67 Even if the Sutter plant does not receive a resource adequacy contract for 2012, it could possibly receive one for 2013. In this regard, on January 13, 2012, the ISO filed with the CPUC a proposal to establish a flexible capacity procurement requirement for the 2013 resource adequacy compliance year. To implement this proposal, the ISO plans to establish a stakeholder process to develop tariff revisions to ensure that the proposal applies to all load-serving entities, not just those jurisdictional to the CPUC. See California Independent System Operator Corporation Proposal on Phase 1 Issues, CPUC Rulemaking 11-10-023 (Jan. 13, 2012). This ISO filing is available at http://www.caiso.com/Documents/2012-01-13_Phase1Proposal_FlexCap.pdf.

68 *California Independent System Operator Corp.*, 134 FERC ¶ 61,211, at P 125.

November 22 Calpine request explains that Calpine sought a resource adequacy contract for the Sutter plant but was unable to obtain such a contract. The ISO also has not identified any deficiencies in the resource adequacy plans of any load-serving entity that would result in a resource adequacy designation for the Sutter plant. Also, the Sutter plant does not satisfy locational resource adequacy requirements.[69]

Because these alternatives are not viable, the ISO concluded that the immediate and time-sensitive issues associated with the potential risk of retirement for the Sutter plant would best be addressed through a limited, one-time tariff waiver filing. Preventing the Sutter plant's retirement will avoid the reliability issues associated with the permanent loss of the Sutter plant in 2012.

B. It Is Uncertain When the CPUC Proceeding on the Sutter Plant Will Conclude or What the Outcome of That Proceeding Will Be.

On January 17, 2012, the CPUC established a proceeding regarding the potential shutdown of the Sutter plant. CPUC staff issued a draft resolution (CPUC Draft Resolution) for public comment that would order Pacific Gas and Electric Company, Southern California Edison Company and San Diego Gas & Electric Company to negotiate to enter into a contract to procure the Sutter plant for a time period to end no later than December 31, 2012.[70] The CPUC Draft Resolution, if adopted, would require those IOUs to complete the negotiations

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69 Issues regarding resource adequacy are discussed further in Section V.B, below.

70 *See* Draft Resolution E-4471, available on the CPUC's website at http://docs.cpuc.ca.gov/WORD_PDF/COMMENT_RESOLUTION/157581.PDF.

and submit a tier 3 advice letter within 30 days of the effective date of the resolution.

The ISO believes the issuance of the CPUC Draft Resolution is a positive development. Depending on the outcome of the proceeding regarding the CPUC Draft Resolution, and when that outcome is reached, the CPUC proceeding could conceivably enable the Sutter plant to avoid retirement this year. However, because it is uncertain what the outcome of the CPUC proceeding will be or when that outcome will be reached, this CPUC proceeding does not obviate the need for the tariff waiver the ISO is requesting.

The CPUC's Energy Division has stated that the CPUC will not consider the draft resolution before its February 16, 2012 business meeting.[71] At that time, the CPUC may vote on the draft resolution or it may postpone a vote until a later meeting.[72] When the CPUC votes on a draft resolution, the CPUC may adopt all or part of it as written, amend it, modify it, or set it aside and prepare a different resolution.[73] Even assuming that the CPUC does direct this procurement and the IOUs comply within 30 days of the resolution's effective date, additional time will be required for CPUC approval of the IOUs' compliance filing. The CPUC Draft Resolution specifically requires the IOUs to submit a negotiated contract via a tier 3 advice letter, which requires additional CPUC

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[71] See letter dated January 17, 2012 from the CPUC Energy Division to parties in Rulemaking 10-05-006; Rulemaking.11-10-023. A copy of the letter is appended to the CPUC Draft Resolution.

[72] *Id.*

[73] *Id.*

approval before the advice letter is effective.[74] Based on the CPUC's business meeting schedule, it appears that the earliest the CPUC would be in a position to approve an IOU advice letter would be at the April 19, 2012 meeting.[75]

Given these uncertainties, the most appropriate course is for the Commission to act on this petition for tariff waiver, based on the possibility that the CPUC proceeding will not avert the shutdown of the Sutter plant.

C. A Commission Order on This Waiver Request by March 29 Is Justified.

The ISO requests a Commission order granting this petition for tariff waiver by March 29, 2012. Obtaining an order by this date will provide the needed certainty for the ISO to issue a CPM designation to prevent the retirement of the Sutter plant.

The ISO determined the requested March 29 order date as follows. Under Section 43.2.6 of the ISO Tariff, issuance of a CPM report such as the December 6 ISO report would normally trigger the start of a period of no less than 30 days for a load-serving entity to procure capacity from a resource before the ISO may issue a CPM risk-of-retirement designation. Because the ISO's authority to issue a risk-of-retirement designation for the Sutter plant is dependent upon Commission approval of this request for tariff waiver, the ISO does not intend to commence the 30-day procurement period until after the Commission acts on the

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[74] Tier 3 advice letters are generally subject to rule 7.6.2 of General Order 96-B, which requires the reviewing Industry Division to prepare and place on the CPUC's meeting agenda a resolution approving, rejecting, or modifying the advice letter. More information on the advice letter process and industry-specific rules is available in General Order 96-B, which is available on the CPUC's website at http://docs.cpuc.ca.gov/word_pdf/GENERAL_ORDER/100177.pdf.

[75] The CPUC's business meeting schedule is available on the CPUC website at http://www.cpuc.ca.gov/PUC/aboutus/2012meetings.htm.

request for tariff waiver. The ISO will issue a market notice announcing the start of the time period set forth in Section 43.2.6 for a load-serving entity to procure resource adequacy capacity from the Sutter plant after the Commission issues an order granting the request for a tariff waiver.[76] Therefore, if the Commission issues an order granting tariff waiver by March 29, the 30-day procurement period will end on or about April 30.

As reflected in the November 22 Calpine request, Calpine intends to retire the Sutter plant as early as May 2012, absent a capacity contract or a CPM designation.[77] Further, in the event Calpine obtains a capacity contract or CPM designation for the Sutter plant by May 1, 2012, Calpine states in the supplemental information it provided on January 24 that it will then require a 30-day outage to conduct needed maintenance at the plant.[78] Calpine states that it requires 30 days of lead time to obtain the necessary equipment and materials to perform the maintenance during the outage. Under these circumstances, the ISO would need to notify Calpine of its intent to designate the Sutter plant as capacity at risk of retirement by April 1, 2012 to allow Calpine the 30-day lead time (*i.e.*, until approximately June 1, 2012) required to secure the necessary equipment and materials.[79] Calpine states that the Sutter plant would then be

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[76] December 6 ISO report at 12.

[77] November 22 Calpine request (stating that the expected Participating Generator Agreement termination date for the Sutter plant is at least 180 days after the date of the request).

[78] January 24 supplemental information, Supplemental Affidavit of Alex Makler at 11-12.

[79] This notice can be concurrent with the notice announcing the 30-day procurement period.

subject to an outage during the entire month of June 2012.[80] The Sutter plant would then be able to resume operations pursuant to a capacity contract or CPM designation on or about July 1, 2012.[81] Calpine states that this schedule permits only "a bare minimum of slippage time."[82]

Resumption of plant operations on or about July 1 would allow the Sutter plant to receive compensation as a CPM resource for six months. The ISO has determined that six months of compensation for the Sutter plant at the Section 43.2.6 CPM risk-of-retirement price set forth in the settlement pending in Docket No. ER11-2256 should provide Calpine with sufficient revenues to keep the Sutter plant in service.

Although it is appropriate for the Commission to issue an order granting the ISO's petition for tariff waiver by March 29, the ISO recognizes that events regarding the Sutter plant may unfold in different ways. The ISO is prepared to address each of those contingencies in an appropriate manner. If, before a CPM retirement designation is issued for the Sutter plant, Calpine obtains an approved contract pursuant to the parallel CPUC proceeding or a load-serving entity procures capacity from the Sutter plant pursuant to Section 43.2.6, then the ISO will not issue a CPM designation for the Sutter plant. Alternatively, if either of those events happens after a CPM designation is issued for the Sutter plant, the ISO will rescind the CPM retirement designation for any applicable months

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80 January 24 supplemental information, Supplemental Affidavit of Alex Makler at 12.

81 *Id.*

82 *Id.*

pursuant to Section 43.3.7 of the ISO Tariff.[83] However, the ISO and the Commission cannot reasonably count on any of those events happening. Therefore, as explained above, the Commission should issue an order granting the ISO's petition for tariff waiver by March 29, 2012.

VI. No Market Participant Other than Calpine Has Requested or Is Anticipated to Request a Comparable CPM Retirement Designation.

The Sutter plant is the only facility that has submitted a CPM risk-of-retirement designation request. To the best of the ISO's knowledge, there are no similarly situated generating plants that are at risk of retirement in 2012 and that are likely to be the subject of a CPM risk-of-retirement designation request in the near future. As explained in Mr. Rothleder's declaration,[84] the CPM tariff provisions went into effect in April 2011, and load-serving entities and suppliers made their resource adequacy showings in December 2011. No resource other than the Sutter plant requested a risk-of-retirement designation.

Mr. Rothleder explains that the ISO has conducted a review of gas-fired resources within the ISO's balancing authority area that have flexible, dispatchable capacity and that have other characteristics comparable to the Sutter plant, including the ability to provide Regulation service. The vast majority of these resources, other than the Sutter plant, have resource adequacy contracts for 2012. Specifically, of the 29,306 MW of flexible resources (excluding resources that are either dynamic resources or OTC resources), there

[83] Section 43.3.7 requires the ISO to "rescind the CPM designation for any month during which the resource is under contract with an LSE [load-serving entity] to provide RA Capacity."

[84] Rothleder Declaration at 40.

are only 1,256 MW of flexible resources that have not been included in resource adequacy showings. At 525 MW, the Sutter plant represents the largest portion of this capacity. In addition, based on additional information, approximately another 500 MW of the 1,256 MW of flexible resources not making a showing in the annual showing is expected to make a showing in monthly resource adequacy showings and a further 188 MW of capacity is the subject of a contract for capacity expansion and is expected to be available over the applicable time frame. This leaves less than 50 MW of flexible, dispatchable capacity that has characteristics comparable to the Sutter plant. Based on this review, even if a request for risk-of-retirement designation was submitted to the ISO, the ISO would not expect its analysis to support a capacity procurement mechanism designation for any other resource for reasons comparable to the ISO's analysis of the Sutter plant.[85]

As explained above, the ISO has concluded that there is a need to develop a capacity procurement mechanism that addresses longer-term system needs than the ISO's CPM provisions. The ISO anticipates that the stakeholder process on this subject will include discussion of appropriate pricing based on a multi-year forward assessment, including different pricing options for generators with differing needs. However, any new or modified tariff provisions resulting from this stakeholder process will not be finalized and approved by the Commission in time to address the proposed retirement of the Sutter plant in 2012. The ISO expects to file new risk-of-retirement tariff provisions with the

[85] *Id.* at 40-41.

Commission in the fall of 2012. After the tariff provisions to implement the longer-term capacity procurement mechanism go into effect, the ISO expects that continued operation of the Sutter plant and any other resources with similar issues will be assessed under that mechanism. As such, the ISO's request for a waiver in this proceeding is limited to a one-time waiver applicable only to the pending CPM designation request for the Sutter plant.

VII. The ISO's Request Satisfies the Commission's Requirements for Waiver Requests.

The ISO requests waiver of the provisions of Section 43.2.6(3) discussed above that would otherwise subject the Sutter plant to the requirement that CPM capacity at risk of retirement and needed for reliability purposes must be shown for the end of the calendar year following the current RA Compliance Year.

The Commission has historically granted requests for tariff waivers by public utilities where an emergency situation or an unintentional error was involved.[86] However, the Commission has stated that waiver is not limited to those circumstances. The Commission has also found good cause to grant tariff waiver requests where the waiver (1) is of limited scope, (2) has no undesirable consequences, and (3) results in evident benefits to customers.[87]

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[86] *See, e.g.*, *California Independent System Operator Corp.,* 118 FERC ¶ 61,226, at P 24 (2007), *citing ISO New England Inc.*, 117 FERC ¶ 61,171, at P 21 (2006); *Great Lakes Gas Transmission Ltd. Partnership*, 102 FERC ¶ 61,331, at P 16 (2003); *TransColorado Gas Transmission Co.*, 102 FERC ¶ 61,330, at P 5 (2003).

[87] *See, e.g.*, *Pacific Gas and Electric Co. and Southern California Edison Co.*, 136 FERC ¶ 61,243, at P 8 (2011); *California Independent System Operator Corp.*, 136 FERC ¶ 61,107, at P 7 (2011); *California Independent System Operator Corp.*, 118 FERC ¶ 61,226, at P 9 (2007).

In this case, all three of these elements under Commission precedent for granting a tariff waiver are satisfied. Therefore, good cause exists to grant the ISO's requested waiver of Section 43.2.6(3).

A. The Tariff Waiver Is of Limited Scope

The ISO's requested tariff waiver is of limited scope. As explained above, the Sutter plant is the only resource for which any market participant has requested or is anticipated to request a CPM designation due to a risk of retirement. The ISO's stakeholder process to develop and implement a capacity procurement mechanism that addresses longer-term needs will not be finalized in time to address the operational issues related to the mid-2012 retirement of the Sutter plant. The ISO expects that continued operation of the Sutter plant beyond 2012 and the proper treatment of any other comparable resources at risk of retirement in the future will be assessed under the longer-term capacity procurement mechanism to be implemented after the mechanism is developed and receives any necessary regulatory approval.

As noted above, the ISO has determined that if the Sutter plant shuts down in 2012, it will exacerbate a capacity gap of over 3,500 MW by the end of 2017, which will pose significant challenges to the reliable operation of the ISO controlled grid. The ISO believes that the interests of ensuring the reliable operation of the grid in the long run warrant a CPM designation for the Sutter plant on a limited one-time basis while the longer-term capacity procurement mechanism is being developed. Therefore, the ISO is requesting a one-time waiver of limited scope that applies only to the treatment of the Sutter plant under Section 43.2.6(3) in 2012.

B. The Tariff Waiver Has No Undesirable Consequences

The ISO's requested tariff waiver will have no undesirable consequences. Granting the tariff waiver will not unfairly disadvantage any market participant, because no other market participant has requested a CPM designation due to risk of retirement of a resource. Therefore, it is not possible that the Sutter plant might be unfairly advantaged over any other similarly situated resources. In the future, both the Sutter plant and any potential similarly situated resources will be assessed under the longer-term capacity procurement mechanism to be developed.

Further, although the ISO acknowledges that the waiver will result in the allocation of significant costs to ratepayers, the ISO respectfully submits that this is not an undesirable consequence that might arise from granting the tariff waiver, particularly in light of the consequences if the tariff waiver is not granted. Although the costs of CPM procurement for the Sutter plant will be borne by ISO market participants,[88] the Commission has already determined that it is appropriate for market participants to pay CPM procurement costs where the ISO has made a determination that a resource at risk of retirement will be needed in the future for reliability purposes, either for its locational or its operational characteristics. The specific CPM costs for procurement of the Sutter plant will

[88] Because the need for the Sutter plant is based on operational needs in all Transmission Access Charge (TAC) Areas rather than any locational needs, the costs of the proposed CPM designation for the Sutter plant will be allocated to all scheduling coordinators for load-serving entities that serve load in all ISO TAC Areas, consistent with Section 43.8.7 of the ISO Tariff.

be based on the applicable tariff-based rate determined to be just and reasonable by the Commission.[89] The sole purpose of this waiver request is to permit the ISO's analysis of reliability needs to look forward a period of five years rather than the two-year period currently contemplated by Section 43.2.6 of the ISO Tariff.

The ISO has taken the cost of procuring the Sutter plant into consideration in its decision to procure Sutter at this time and has weighed carefully the fact that Sutter is being kept online this year for a need identified in the future. As discussed above, the ISO intends to procure the Sutter plant for no more than six months. Based on the financial assessment provided to the ISO by Calpine, this procurement by the ISO should provide the bare minimum amount of compensation needed to keep the Sutter plant online through the end of 2012. The ISO recognizes that this payment does not suffice to guarantee that the Sutter plant will be online at the end of 2017, when the ISO expects to need the Sutter plant. Consistent with the current CPM risk-of-retirement procurement provisions of the ISO Tariff, under which a resource can be procured for more than one year, it will be necessary to evaluate whether the Sutter plant will be needed again in later years if and when Calpine submits a statement of risk of retirement (or a submittal pursuant to similar procedures) under the ISO's new proposal for a longer-term capacity procurement mechanism to be developed in

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[89] *See* ISO Tariff, Section 43.7.1 (setting forth applicable tariff-based rate). A settlement agreement concerning this rate was filed with the Commission on December 23, 2011 and is currently pending Commission action in Docket No. ER11-2256.

an ISO stakeholder process this year. This future evaluation also will ensure that the ISO does not impose unnecessary costs on market participants.

The ISO also believes the costs of procuring the Sutter plant as a result of the waiver must be compared with the potential costs that California could incur if the ISO needs a resource to maintain reliability in 2018, but that resource is not available then because it was allowed to retire in 2012. As Mr. Rothleder notes, a failure to maintain the ongoing operation of resources with operating characteristics like the Sutter plant that will be needed by the 2018 time frame could lead to other increased costs, such as the costs associated with exceptional dispatch, increased ability to exercise market power and even the costs associated with load shedding events.[90] On the whole, given the demonstrated need for capacity by 2018, the ISO believes that the cost of procuring the Sutter plant is appropriate.

C. The Tariff Waiver Results in Benefits to Customers

The ISO's requested tariff waiver will provide benefits to customers in California. Granting the tariff waiver will allow the ISO to designate the Sutter plant as CPM capacity and thus will permit the plant to continue commercial operation in 2012. This addresses the risk of retirement for the Sutter plant in 2012, allowing a plant needed to address long-term system needs to remain in operation. As explained above, if the Sutter plant is retired, the ISO's analysis indicates that there will be insufficient generation in operation for 2017/2018 that has the required flexible operational characters and will meet the identified

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[90] Rothleder Declaration at 38-39.

reliability need. Therefore, the retirement of the Sutter plant would harm customers in California. In light of Calpine's explanation that it definitely will retire the Sutter plant in 2012 if the plant does not receive a CPM designation, the ISO has determined that there is a sufficient risk of the loss of needed resources by the 2017/2018 time frame to justify taking the steps required to permit the Sutter plant to remain in operation for 2017/2018.

Although the ISO's analysis does not show a need for the Sutter plant in 2012, as discussed above, the designation of the Sutter plant as a CPM resource will increase the reliability of power supply and price competition in the ISO markets. The Sutter plant has a net qualifying capacity for 2012 of between 500 and 525 MW. All of that capacity will benefit customers by remaining available to meet system needs in the ISO balancing authority area if the Sutter plant continues to operate.

As explained in Section V above, the issue of the retirement of the Sutter plant in 2012 cannot reasonably be addressed through some means other than the designation of the plant as CPM capacity at risk of retirement. In order to permit that CPM designation, the Commission should grant the instant request for tariff waiver. There is not sufficient time to take the alternative course of developing a long-term capacity procurement mechanism and obtaining Commission approval of a tariff amendment to implement the new mechanism prior to the planned retirement of the Sutter plant in 2012 as attested to by Calpine. As a result, granting the ISO's requested tariff waiver is necessary to allow the Sutter plant to provide continued benefits to customers and to keep the Sutter plant available to address reliability needs in California in the long-term.

VIII. Request for Confidential Treatment

Pursuant to Section 388.112 of the Commission's regulations, the ISO respectfully requests confidential treatment of Attachment B to this filing, certain tables of financial information provided to the ISO by Calpine which contain commercially-sensitive information that is not normally publicly available. In the public version of the Calpine request provided in Attachment A to this filing, the commercially-sensitive information has been redacted. The non-public materials in Attachment B have been marked "PROTECTED MATERIALS NOT AVAILABLE TO COMPETITIVE DUTY PERSONNEL." The ISO will provide copies of the non-public materials in Attachment B to parties that file to intervene in this proceeding, provided that such parties provide the ISO with executed versions of the attached non-disclosure certificates by qualified reviewing representatives of such parties agreeing to comply with the proposed protective order submitted by the ISO. A proposed protective order and non-disclosure certificate that includes a restriction of the ability of competitive duty personnel to view the confidential material are included as Attachment G to this filing.[91] The

[91] The proposed protective order contained in Attachment G is a variant on the Commission's model protective order that is similar to such variants that have been adopted in prior Commission proceedings. *See, e.g.*, *California Independent System Operator Corp.*, "Order of Chief Judge Adopting Protective Order," (Docket No. ER10-188-000) (Feb. 2, 2010); *ALLETE, Inc. v. Midwest Independent Transmission System Operator, Inc.*, 117 FERC ¶ 61,090, at P 6 (2006). In this regard, the Commission has explained that, "[a]lthough the Commission has a model protective order, protective orders are to be drafted in light of the facts in a particular case." *Westar Energy, Inc.*, 115 FERC ¶ 61,034, at P 9 (2006).

ISO requests that the Commission issue an order adopting this protective order when it accepts this waiver filing.

IX. Attachments

In addition to this petition for tariff waiver, the following attachments support this filing:

Attachment A	November 22 Calpine request (public portions)
Attachment B	November 22 Calpine request (confidential portions)
Attachment C	January 24 Calpine supplemental information
Attachment D	December 6 ISO report
Attachment E	Declaration of Mark A. Rothleder
Attachment F	Matrix of ISO responses to stakeholder comments
Attachment G	Draft protective order and non-disclosure certificate

X. Service

The ISO has service copies of this filing upon the California Public Utilities Commission and all parties with effective Scheduling Coordinator Service Agreements under the ISO Tariff. In addition, the ISO has posted this filing on its website.

XI. Correspondence

The ISO requests that all correspondence, pleadings, and other communications concerning this filing be served upon the following:

Nancy Saracino
General Counsel
Anthony Ivancovich
Assistant General Counsel
Anna A. McKenna
Senior Counsel
The California Independent System
Operator Corporation
250 Outcropping Way
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XII. Conclusion

The ISO respectfully requests that the Commission grant a limited, one-time waiver of the requirement in Section 43.2.6(3) of the ISO Tariff that a Capacity Procurement Mechanism designation for capacity at risk of retirement and needed for reliability purposes must be shown for the end of the calendar year following the current Resource Adequacy Compliance Year. For the reasons explained above and in the materials supporting this filing, failure to grant this waiver request could result in significant adverse consequences for California reliability in the future.

Respectfully submitted,

<u>/s/ Sean A. Atkins</u>
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The California Independent System Operator Corporation
250 Outcropping Way
Folsom, CA 95630

Dated: January 25, 2012

Attachment A

CALPINE CORPORATION

NYSE CPN

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DUBLIN, CA 94568
925.557.2224 (M)
925.479.9560 (F)

November 22, 2011

Steve Berberich
President and Chief Executive Officer
California Independent System Operator Corporation
250 Outcropping Way
Folsom, CA 95630

Re: <u>Confidential Request of Calpine Corporation for CPM Designation of the Sutter Energy Center under CAISO Tariff Section 43.2.6</u>

Dear Mr. Berberich:

Calpine Corporation ("Calpine"), which, through its subsidiary Calpine Construction Finance Company, L.P., ("CCFC") indirectly owns the Sutter Energy Center ("Sutter"), hereby requests that the California Independent System Operator Corporation ("the CAISO") designate, under CAISO Tariff section 43.2.6, the full net qualifying capacity of the Sutter Energy Center as CPM Capacity for the 2012 RA Compliance Year.[1] Absent such designation as CPM Capacity (or comparable bilateral capacity procurement) for 2012, Sutter must and will be retired in 2012. In this letter, Calpine submits the information required of Sutter under the provisions of Tariff section 43.2.6 and the CAISO Business Practice Manual implementing that provision.[2]

In addition to this letter, and in support thereof, Calpine submits the affidavit of Alexandre B. Makler, an executive officer of Calpine, which has the legal authority to bind its

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1 For purposes of this request, the term "current RA Compliance Year" as used in Tariff section 43.2.6 means the 2012 RA Compliance Year.

2 References to the "Business Practice Manual" in this request are to the *BPM for Reliability Requirements,* version 10, § 7.3.5.2, as revised September 14, 2011.

DSMDB-3000326v6

subsidiary CCFC, which owns Sutter. Mr. Makler attests, as required under Tariff section 43.2.6(5) and the Business Practice Manual, that Calpine has determined that it will be uneconomic for Sutter to remain in service in 2012 and that Calpine has made the definite decision to retire Sutter in 2012, unless CPM procurement (or comparable bilateral capacity procurement) occurs.

As attachments to this letter, Calpine is submitting certain confidential and proprietary financial information. Pursuant to Tariff section 20.2, Calpine requests that these confidential attachments be treated by the CAISO as confidential information, which would not be disclosed as part of the report that the CAISO would issue pursuant to Tariff section 43.2.6.

Description of Sutter Energy Center

Sutter is a modern, efficient, ultra-low water consumption, natural gas-fired combined-cycle generating facility located near Yuba City in Sutter County. Sutter has a net qualifying capacity for 2012 of between 500 and 525 MW.[3] When Sutter commenced commercial operation in 2001, Sutter was interconnected to facilities within the CAISO control area and the project was designed, constructed and financed for the purpose of providing energy, capacity and ancillary services within the CAISO markets. At that time, Sutter was the first major combined-cycle facility built in California in over a decade.

Sutter is interconnected to the Western Area Power Administration's ("Western") transmission system at the O'Banion substation, but because of Western's departure from the CAISO in 2005, Sutter now operates in CAISO markets pursuant to a pseudo-tie arrangement

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[3] Sutter's net qualifying capacity is specified for each month, varying based on seasonal factors.

with the CAISO.[4] Sutter has applied to the CAISO for a direct interconnection with the CAISO Controlled Grid at a new substation on the Pacific Gas & Electric Table Mountain transmission line. The CAISO has not completed its interconnection study process for the cluster that includes Sutter's application for direct interconnection.[5]

<u>Sutter's Continued Operation Is Uneconomic</u>

Current and expected wholesale market conditions in 2012 and in subsequent years are not expected to provide reasonable opportunities for Sutter to secure sufficient revenue streams to continue operation. Calpine has not received and does not expect that Sutter will receive RA capacity contracts in the ordinary course or other type of annual CPM contract (*i.e.*, CPM designations under Tariff section 43.2, other than section 43.2.6) for the 2012 RA Compliance Year that would provide sufficient revenue for Sutter to remain in operation. Facing these economic prospects, Calpine has decided to retire Sutter in 2012, unless it obtains designation as CPM Capacity under Tariff section 43.2.6, in the amount of its net qualifying capacity, or it receives RA or other capacity contracts for the same quantity of capacity on comparable terms for 2012. Mr. Makler's Affidavit and the supporting information and documentation attached hereto confirm Calpine's decisions, fully satisfying the requirement of Tariff section 43.2.6(5), as described in the Business Practice Manual.

<u>Sutter Meets the Requirements for CPM Designation under Tariff Section 43.2.6 and the Business Practice Manual</u>

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4 Sutter's pseudo-tie arrangement with the CAISO enables Sutter to provide Resource Adequacy capacity to the CAISO as if it were directly interconnected to the CAISO grid. As such, Sutter can also provide and is eligible for designation as CPM capacity.

5 This request should have no immediate effect on the CAISO's continued processing of Sutter's pending interconnection request.

§ 43.2.6(1). Sutter is not contracted as RA Capacity for the 2012 RA Compliance Year, nor does it have a capacity contract despite substantial marketing efforts and extensive market analysis. In fact, Calpine submitted an open RFO for any and all capacity or energy products to an extensive list of possible off-takers including PG&E, SMUD, Western and more than one dozen other local customers. No energy or capacity offers were received of sufficient value to warrant continuing operation of Sutter in 2012. Sutter also bid into PG&E's RFP for 2012 RA Capacity and was not selected. Sutter is not aware of other IOU or LSE procurement programs into which it could have bid or participated and been expected to receive an RA contract for 2012.

§ 43.2.6(2). No information from Sutter is required.

§ 43.2.6(3). Calpine herewith describes Sutter's operational characteristics that could be taken into account by the CAISO in conducting its requisite technical assessments that Sutter will be needed for reliability purposes.[6]

Sutter is a modern, flexible, natural gas-fired, air-cooled, combined-cycle facility that is capable of providing the CAISO cycling, fast ramping, quick starts, low heat rates and other advantageous operational characteristics. The operational parameters of the resource are in the CAISO's Master File. In addition to its existing operational characteristics, the potential exists at Sutter to make incremental investments in performance upgrades that would further shorten start times, accelerate ramp rates, allow for greater cycling, and lower heat rates.

[6] The Business Practice Manual describes the diverse set of tools that the CAISO intends to use to make its technical assessments of its reliability needs for a Resource. Calpine is not required or expected to submit its own technical assessment.

Sutter has other operational characteristics that provide flexibility potential to the CAISO. Sutter is an air-cooled unit and, thus, will not be forced to retire or repower to comply with State and federal water policies and regulations. Hence, with the requested CPM designation, Sutter will be available to the CAISO in 2012 and, in future years, with adequate compensation, Sutter's operational flexibility would likely remain available to the CAISO. In addition, Sutter can and does provide Automatic Generation Control to the CAISO that meets requirements for providing regulation service to the CAISO. Sutter could also provide Multi-Stage Generation capability to the CAISO.

If Sutter retires in 2012, its distinctive operational characteristics as an air-cooled flexible resource may be permanently lost, because, under EPA policy, the resource would quite possibly need to obtain a new air permit and to undergo New Source Review ("NSR") prior to being reactivated in a later year.[7] Even if Sutter could meet then-current BACT requirements and otherwise satisfy all of the new air quality permitting requirements that have gone into effect since it was first permitted, the permitting process is often lengthy, highly contentious, and subject to an extended and unpredictable appeals process. Further, although not entirely predictable today, the future requirements to meet then-current BACT could require substantial new investments, further challenging project economics. Thus, if Sutter retires in 2012, there is

[7] Current EPA policy on reactivation provides that any shutdown of a resource for more than two years is presumed to constitute a permanent shutdown, triggering NSR prior to recommencing operations. Further, Calpine is aware of no instance where a California power plant has been shut down for any extended, indefinite period of time and then started up again at a later date without triggering NSR. In light of this, Calpine has been advised that there is a substantial risk that Sutter could be exposed to New Source Review, including the requirements to meet then-current "best available control technology" ("BACT") standards and other new permitting requirements that have gone into effect, if it retires in 2012 and seeks to recommence commercial operations in a later year.

no practical assurance that Sutter and its flexible operating characteristics would again be permitted and available in future years. An indefinite shutdown, or "mothballing" of the resource with no definitive plan to restart in the foreseeable future, would also be subject to these same EPA policies and, therefore, create similar New Source Review and permitting uncertainties for Sutter.

Sutter commits to providing the CAISO with any additional information it may request concerning Sutter's operational characteristics. Sutter will also provide, upon request, information regarding its potential upgrades and enhancements to its operational characteristics, which would be foregone if Sutter were to retire in 2012. These upgrades and enhancements could be a cost-effective option for the CAISO to procure incremental flexible capacity to meet future reliability needs within a much shorter time frame and at a lower per-MW capital cost than investment in new generation. If Sutter is retired, the opportunity for cost-effective upgrades in flexible capacity would be lost.

§ 43.2.6(4). No information is required from Sutter.

§ 43.2.6(5). Calpine submits to the CAISO and the Department of Market Monitoring the affidavit of Alexandre B.. Makler, an executive officer of Calpine, which has the legal authority to bind CCFC, which owns Sutter. Mr. Makler's affidavit attests that, after conducting economic analyses, Calpine management determined that it would be uneconomic for Sutter to remain in service in 2012 and that Calpine has made a definite decision to retire Sutter in 2012, unless CPM procurement occurs or Sutter is provided a comparable annual bilateral capacity contract for 2012. These attestations satisfy the content requirements of Tariff section 43.2.6(5).[8]

The Business Practice Manual specifies that additional supporting information and documentation be provided in implementation of Tariff section 43.2.6(5). Calpine herewith provides the supporting information and documentation itemized in the Business Practice Manual.

1. Expected PGA termination date. Calpine states that its expected PGA termination date will be at least 180 days after the date of this request for a risk of retirement CPM designation.[9]

2. Description of current power purchase agreement and capacity contracts. Sutter has multiple contracts with multiple entities to provide Resource Adequacy (but not energy), all of which expire no later than December 31, 2011. The total revenues expected from these RA contracts are shown in the attached table described below under item (4). Sutter has no Resource Adequacy contracts for 2012. Sutter has no power purchase agreements to supply third-parties with energy in 2011, 2012, or later years.

3. Description of existing fuel supply contracts. Sutter has no project-specific fuel supply contracts with non-affiliated third parties. Calpine purchases gas and hedges its fuel requirements on a portfolio basis for its plants. A Calpine affiliate supplies gas to Sutter and other Calpine owned or operated plants on an as-needed basis.

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8 *See* CPM Order at P 132.

9 A specific termination date would be noticed in accordance with the notice of termination provisions in the applicable PGA.

4. Economic analyses. Mr. Makler's Affidavit explains that Calpine conducted extensive analysis of the economics of Sutter were it to remain in service in the 2012 RA Compliance Year and subsequent years. Mr. Makler's Affidavit further explains that the company's analysis considered a range of assumptions for projected market revenues in 2012 and later years, and that, under those assumptions, Sutter would sustain cash flow losses and be unable to recover its going forward costs in 2012 and subsequent years. Sutter would also not obtain a return of or on its capital investment in those years. Mr. Makler also states that Calpine's determination that it would be uneconomic for Sutter to remain in service in 2012 and the company's decision to retire Sutter unless CPM procurement (or comparable bilateral capacity procurement) occurs were not made on the basis of any single economic calculation or analysis and were made in consideration of various risks and uncertainties that Sutter would not recover its going forward costs or meet its cash and investment requirements in 2012.

In satisfaction of the Business Practice Manual's requirement for analyses to support the company's affidavit, Calpine provides two tables that illustrate the analyses that the company considered. Table 1 (captioned Sutter Project Economics) presents Sutter's actual and projected cash flow for the period 2010 through 2015. Energy margins in 2012 and future years are projected based on forward price curves. No Resource Adequacy revenues are projected for 2012 and future years. Going forward costs, including fixed Western transmission expense, are based on company projections. Table 1 demonstrates the failure of Sutter to meet its going forward costs and cash flow requirements in 2012 and subsequent years.

Table 2 (captioned Sutter Schedule F) presents Sutter's annual revenue requirement and fixed revenue requirement for 2012 and 2013 calculated as prescribed in Schedule F of the

CAISO's pro forma RMR contract. These calculations demonstrate, in combination with the projected revenues in Table 1, that Sutter would not obtain a return of or on its capital investment in 2012 or 2013.

5. <u>Documents confirming the company's decision to retire Sutter unless CPM (or comparable bilateral) procurement occurs</u>. Mr. Makler's Affidavit attests to Calpine's definite decision to retire Sutter in 2012, unless CPM (or comparable bilateral) procurement occurs. Calpine also provides an Officer's Certificate verifying that the company's decision to retire Sutter, unless CPM (or comparable bilateral) procurement occurs was authorized by Calpine's Board of Directors.

If CAISO determines that additional supporting information and documentation is required under the Business Practice Manual, Calpine respectfully requests an opportunity to supplement this request for CPM designation, without delay in the issuance of the CAISO report.

Conclusion

Calpine wishes to underscore that its decision to shut down the modern Sutter electric generating facility for economic reasons was not reached lightly, nor without due consultation with both the CAISO and the California Public Utilities Commission. Calpine did not make this important business decision to retire Sutter based on application of a single economic calculation that it would not recover its going forward costs or obtain a return of or on its capital investment, although the economic analyses attached to this letter confirm such calculations for 2012 and subsequent years. Properly and significantly, Calpine considered not only its expected failure to recover Sutter's going forward costs, but also the uncertainties and risks that Sutter might incur other non-compensable costs during those years, such as the risk of a major outage and the need for additional capital investment in order to meet environmental requirements or to maintain operational characteristics. Calpine is also mindful of consequences to its employees and to the local communities of its decision. Based on Calpine's analysis, the company decided that it is uneconomic for Sutter to remain in service in 2012 and to retire Sutter if it does not obtain CPM designation or comparable bilateral capacity procurement for 2012.

In conclusion, Calpine requests that the CAISO designate the full net qualifying capacity of Sutter as CPM Capacity for the 2012 RA Compliance Year. Please address any questions or requests for additional information to the undersigned or to Mark Smith (at 925-557-2231).

Sincerely,

Rosemary Antonopoulos
Vice President and Assistant General Counsel,
Calpine Corporation

cc. Eric Hildebrand, Director
CAISO Department of Market Monitoring

PRIVILEGED INFORMATION REMOVED
PURSUANT TO 18 C.F.R. § 388.112

AFFIDAVIT OF ALEXANDRE B. MAKLER IN SUPPORT OF CALPINE CORPORATION'S REQUEST FOR CPM DESIGNATION OF THE SUTTER ENERGY CENTER UNDER CAISO TARIFF SECTION 43.2.6

My name is Alexandre B. Makler. I am the Vice President –Strategic Origination and Development, West Region, of Calpine Corporation ("Calpine"), which, through its subsidiary Calpine Construction Finance Company, L.P. ("CCFC"), indirectly owns the Sutter Energy Center ("Sutter"). My business address is 4160 Dublin Blvd., Suite 100, Dublin, CA 94568.

1. This Affidavit is submitted in support of Calpine's confidential request, on behalf of Sutter, under CAISO Tariff section 43.2.6, for CPM designation of the full net qualifying capacity of Sutter for the 2012 RA Compliance Year. This Affidavit is submitted in satisfaction of the attestations required in Tariff section 43.2.6(5).

2. I am an executive officer of Calpine. Calpine has the legal authority to bind its subsidiary CCFC, which owns Sutter. I attest that Calpine management has determined that it will be uneconomic for Sutter to remain in service in the 2012 RA Compliance Year and that the company has made the definite decision to retire Sutter in 2012, unless CPM procurement (or comparable bilateral capacity procurement) occurs.

3. Calpine conducted extensive analyses of whether it would be uneconomic for Sutter to remain in service in the 2012 RA Compliance Year. I participated in Calpine management's consideration of these analyses. Calpine's economic analyses showed that, under a range of assumptions for projected market revenues in 2012 (assuming either flat prices from 2011 to 2012, or increased 2012 prices, reflective of some forward price curves), Sutter would sustain cash flow losses and be unable to recover its going forward costs in 2012 and subsequent

years. Sutter would also not obtain a return of or on invested capital during 2012 and subsequent years.

4. Calpine's determination that it would be uneconomic for Sutter to remain in service in 2012 and its decision to retire Sutter unless CPM procurement (or comparable bilateral capacity procurement) occurs, is not based on any single economic calculation or analysis. The analyses that Calpine conducted indicate an unacceptable level of risk that Sutter would not recover its going forward costs or meet its cash and investment requirements in 2012 and subsequent years. Calpine considered not only its risk of failure to recover Sutter's going forward costs under reasonable scenarios, but also the uncertainties and risks that it might incur other non-compensable costs during 2012 and later years, such as the risk of a major outage and the need for additional capital investment in order to meet environmental requirements or to maintain operational characteristics. Based on its analyses, Calpine has decided that it is uneconomic for Sutter to remain in service in 2012 and that Sutter should be retired if it does not obtain CPM designation or comparable bilateral capacity procurement for 2012.

5. This concludes my Affidavit.

I, Alexandre B. Makler, certify under penalty of perjury that the foregoing is true and correct to the best of my knowledge.

Executed on November 22, 2011.

Calpine Corporation Officer's Certificate

The undersigned, W. Thaddeus Miller, Executive Vice President and Chief Legal Officer of Calpine Corporation, a Delaware corporation (the "Company"), is an officer of the Company and hereby certifies on behalf of the Company that the decision by the management of the Company to retire the Sutter Energy Center ("Sutter") in 2012, unless Sutter obtains CPM designation under CAISO Tariff section 43.2.6 (or comparable bilateral capacity procurement occurs), has been duly authorized by the Board of Directors of the Company.

IN WITNESS WHEREOF, the undersigned has executed this Officer's Certificate on behalf of the Company as of this 22nd day of November, 2011.

Calpine Corporation

By W. Thaddeus Miller

Name: W. Thaddeus Miller
Title: Executive Vice President
and Chief Legal Officer

Attachment C

CALPINE CORPORATION

NYSE CPN

4160 DUBLIN BOULEVARD
SUITE 100
DUBLIN, CA 94568
925.557.2224 (M)
925.479.9560 (F)

January 24, 2012

Mr. Steve Berberich
President and Chief Executive Officer
California Independent System Operator Corporation
250 Outcropping Way
Folsom, CA 95630

Re: Authorization for Submission to FERC of Confidential Request of Calpine Corporation for CPM Designation of the Sutter Energy Center under CAISO Tariff Section 43.2.6, <u>including Supplemental Affidavit of Alex Makler and Request for Protective Order</u>

Dear Mr. Berberich:

Calpine Corporation ("Calpine") submitted a confidential letter request, dated November 22, 2011, for CPM designation of the Sutter Energy Center ("Sutter") under CAISO Tariff section 43.2.6, including two attached Tables, a supporting Affidavit of Alex Makler and an Officer's Certificate (the "CPM Request"). Calpine designated and requested confidential treatment for the entirety of its CPM Request under CAISO Tariff section 20.2.

In connection with the CAISO's planned filing of a request with FERC for a limited waiver of one requirement in Tariff section 43.2.6 (the "Waiver Request"), Calpine herewith submits as a supplement to its CPM Request, a Supplemental Affidavit of Alex Makler. This Supplemental Affidavit addresses Calpine's economic analysis and decision making in more detail than was pertinent to, or included in, Mr. Makler's original Affidavit. Calpine requests that the Supplemental Affidavit of Alex Makler be included as part of Calpine's CPM Request.

Calpine hereby authorizes the CAISO to include Calpine's CPM Request in its entirety, including the Supplemental Affidavit of Alex Makler, as one or more exhibits to the CAISO's filing with FERC of its Waiver Request, provided that the CAISO request privileged treatment of certain confidential financial information, as described herein, under FERC regulations, 18 CFR § 388.112. The confidential financial information that Calpine requests be submitted under the foregoing FERC rule consists of the two tables of financial information attached to Calpine's confidential letter request. These tables are captioned Sutter Projected Economics and Sutter Schedule F (collectively, the "Confidential Tables").

Calpine requests that, pursuant to 18 CFR § 388.112, in filing its Waiver Request with FERC, the CAISO redact the Confidential Tables from its public filing of the exhibit containing Calpine's CPM Request, and that the CAISO request that the Confidential Tables be maintained in a non-public file, accessible only to non-competitive duty personnel that execute the model FERC Protective Order, modified to exclude disclosure to Competitive Duty Personnel. The CAISO should make clear in its Waiver Request that parties that choose to intervene in the proceeding would have access to the Confidential Tables, provided that qualified

Reviewing Representatives of such parties execute and provide Non-Disclosure Certificates, thereby agreeing to comply with the proposed Protective Order.

Other than the Confidential Tables, the balance of Calpine's CPM Request, including the Supplemental Affidavit of Alex Makler, may be submitted publicly without redaction and without being subject to disclosure under the proposed Protective Order.

Should you or your staff have any questions concerning the foregoing, please do not hesitate to contact the undersigned. We would also be pleased to assist your staff in its preparing the proposed FERC protective order that would be applicable to disclosure of both Confidential Tables.

Sincerely,

Rosemary Antonopoulos,
Vice President and Assistant General Counsel,
Calpine Corporation

Attachment: Supplemental Affidavit of Alex Makler

SUPPLEMENTAL AFFIDAVIT OF ALEX MAKLER
IN SUPPORT OF CALPINE CORPORATION'S
REQUEST FOR CPM DESIGNATION OF THE
SUTTER ENERGY CENTER UNDER CAISO TARIFF SECTION 43.2.6

My name is Alex Makler. I am the Vice President-Strategic Origination and Development, West Region, of Calpine Corporation ("Calpine"), which, through its subsidiary Calpine Construction Finance Company, L.P. ("CCFC"), indirectly owns the Sutter Energy Center ("Sutter"). My business address is 4160 Dublin Blvd., Suite 100, Dublin, CA 94568.

I. Introduction

1. On Nov. 22, 2011, Calpine submitted a confidential request to the CAISO seeking designation, under CAISO Tariff section 43.2.6 (applicable to capacity at risk of retirement), of Sutter's full net qualifying capacity as CPM Capacity in 2012 (the "Request").[1] In support of the Request, I submitted an affidavit in satisfaction of the two attestations required in Tariff section 43.2.6(5). I attested that Calpine management has determined that it will be uneconomic for Sutter to remain in service in 2012, and that Calpine has made the definite decision to retire Sutter in 2012, unless CPM procurement (or comparable bilateral capacity procurement) occurs.

2. On December 6, 2011, in response to Calpine's Request, CAISO issued a *Report on Basis and Need for CPM Designation for Sutter Energy Center* (the "*Report*") in which it stated that Calpine's Request satisfied all of the requirements for CPM designation of capacity at risk of retirement, except for the requirement that Sutter be needed for reliability purposes, either for its locational or operational characteristics, in the year after the current RA Compliance Year, i.e.

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[1] For purposes of Calpine's request, the term "current RA Compliance Year" as used in Tariff section 43.2.6 means the 2012 RA Compliance Year. For purposes of simplification, we refer to the 2012 RA Compliance Year, as that term is used in the Tariff, as the calendar year 2012.

in 2013 (referred to herein as the "year-after requirement"). The *Report* stated that CAISO determined that "the Sutter plant will be needed for reliability purposes for its operational characteristics in the 2017/2018 time frame."[2] The *Report* stated further that, if Sutter retires in 2012, the CAISO will face a capacity gap and significant reliability issues by the end of 2017. The *Report* concluded that CAISO has determined that, "to avoid these reliability and operational issues in the future," the CAISO will make a filing at FERC requesting a waiver of the existing Tariff's year-after requirement, as applied to Calpine's Request for CPM designation of Sutter in 2012.

3. Calpine has authorized the CAISO to submit Calpine's confidential Request as an attachment to its filing requesting waiver of the year-after requirement.[3] I have prepared this Supplemental Affidavit to accompany the Request attached to the CAISO waiver filing. My Supplemental Affidavit addresses Calpine's economic analysis and decision making in more detail than was pertinent to, or included, in my November 22 Affidavit. This Supplemental Affidavit also explains a timeline for Sutter to initiate and complete scheduled, necessary major maintenance that would only be undertaken if the plant is certain it will receive capacity compensation (either as a result of CPM designation or comparable bilateral procurement).

II. Calpine Determined It Will Be Uneconomic for Sutter To Remain in Service in 2012

4. CAISO Tariff section 43.2.6(5) requires that a request for CPM designation for capacity at risk of retirement be accompanied by an executive officer's affidavit attesting that "it will be uneconomic for the resource to remain in service in the current RA Compliance Year and

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2 *Report* at 2.

3 Calpine has requested that two tables attached to Calpine's Request (referred to there and herein as Tables 1 and 2) be redacted from the public filing that the CAISO makes at FERC, but be made available to non-Competitive Duty Personnel that execute a FERC Protective Order.

that the decision to retire is definite unless CPM procurement occurs." In its March 17, 2011 Order, FERC rejected the CAISO's proposal that, in reviewing a request for a CPM designation under Tariff section 43.2.6, it make an assessment of the resource's financial condition. FERC held that CAISO should rely instead on the officer's attestations.[4] My original Affidavit attested that Calpine determined that it will be uneconomic for Sutter to remain service in 2012 and that the company made the definite decision to retire Sutter in 2012, unless CPM procurement (or comparable bilateral capacity procurement) occurs.[5] Calpine also submitted to the CAISO confidential economic analyses that supported the company's determination. The CAISO's *Report* found that Calpine's attestations and its supporting economic analyses met the Tariff's requirement in Section 43.2.6(5). Although we believe Calpine is not required under the March 17 Order or the Tariff to justify its Request with additional analyses, in this Supplemental Affidavit, I further explain how Calpine determined that it would be uneconomic for Sutter to remain in service in 2012, absent CPM designation or comparable bilateral capacity procurement.

5. Neither the Tariff nor the Commission's March 17 Order prescribes evaluative criteria that a company must use in determining whether it is economic or uneconomic to continue operation of a resource seeking designation as CPM capacity at risk of retirement. Calpine used its business judgment in conducting relevant analyses and in weighing those analyses and other factors and considerations in making its determinations that it will be uneconomic for Sutter to remain service in 2012 and that Sutter will be retired in 2012, absent

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4 *Calif. Indep. Sys. Operator Corp.*, 134 FERC ¶ 61,211, P 132 (2011) ("March 17 Order"). Calpine's submission and its attestations are subject to Department of Market Monitoring review that the information submitted is not false, inaccurate or misleading. *Id.*

5 Makler Aff. at P 2.

CPM designation as capacity at risk of retirement (or comparable bilateral capacity procurement). Calpine's exercise of its business judgment was not based on any single economic analysis or calculation. Calpine conducted analyses, under reasonable scenarios, that indicated an unacceptable level of risk that Sutter would not recover its going forward costs or meet its cash and investment requirements in 2012 and subsequent years. In addition to its assessment of the risk of failure of recovering its going forward costs and the risk of not meeting cash and investment requirements, Calpine considered the uncertainties and risks that contingencies might occur that would cause the company to incur other non-compensable costs during 2012 and later years. These risks include items such as the risk of a major equipment failure, the substantial risks of deferring maintenance, and the need for additional capital investment in order to meet environmental requirements or to maintain operational characteristics. These contingencies were not explicitly accounted for in the "models" and quantitative analyses used in assessing the risk of failure of recovering the company's going forward costs and the risk of not meeting its cash and investment requirements. Calpine's assessment of these contingency-related uncertainties and risks was informed by the company's business experience and its objectives in allocating limited and discretionary funds among investment alternatives.

6. In short, Calpine's business judgment as to whether it would be economic to operate Sutter in 2012 is not based exclusively on a single analysis showing substantial and sustained losses such as that attached to the Request. Nonetheless, the analyses that Calpine conducted, which are discussed below in sections II.A and II.B that follow, showed, respectively, that Sutter would sustain cash flow losses and would not recover its going forward costs in 2012 and

subsequent years, and that Sutter would not obtain a return of or on invested capital during 2012 and subsequent years.

A. Going-Forward Cost Analysis

7. In its Request, Calpine presented results of a going forward cost analysis for Sutter in 2012 and subsequent years conducted by Calpine. These results are shown in Table 1 (captioned Sutter Project Economics), attached to the Request. Table 1 shows that Sutter's estimated energy margins (energy market revenues less fuel costs) for 2012 and 2013 are substantially lower than Sutter's estimated non-fuel going forward costs (variable and fixed O&M, transmission expense, property taxes, insurance, and major maintenance costs). This results in substantial cash flow losses from operation in 2012 and 2013. In particular, Table 1 shows that Sutter will sustain cash flow losses of $19.7 million in 2012.[6] Calpine recognizes that Table 1 reflects only one set of estimates for both net revenues (energy margins) and non-fuel costs. In this section II.A, I explain why Calpine's business judgment was that these results are robust and a strong indication (confirmed by the entirety of Calpine's analysis) that operation of Sutter in 2012 would be uneconomic.

8. <u>Energy margins</u>. Predicting future energy margins is a staple of Calpine's business, used in budgeting, financial forecasting, marketing, and strategic planning, among other functions. The estimated energy margins shown in Table 1 reflect Calpine's use, in the ordinary course of its business and not just for purposes of the Request, of commercial software analytic tools purchased from a reputable vendor (Ventyx) that are widely used and accepted in the

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6 Notwithstanding public disclosure of this figure, Calpine requests that the CAISO seek from FERC confidential treatment of Tables 1 and 2, which contain confidential, proprietary estimates of margins and other cash flow components. Such confidential information should only be available pursuant to a FERC protective order.

industry. These analytic tools enable a user such as Calpine to undertake a robust stochastic analysis of energy margins. As the user of the software tools, Calpine first uploads its estimates of future prices for energy and natural gas. Calpine, as with all major generating companies, maintains proprietary forecasts of monthly electricity and natural gas prices. The software tools generate a statistical distribution of energy margins, reflecting the effects of random shocks to both energy prices and fuel costs. The distribution of possible outcomes is reduced by statistical means to an "expected value." Table 1 shows the expected value of energy margins estimated using the commercial software analytic tools and Calpine's proprietary electricity and natural gas price price curves.

9. The estimated or expected value of energy margins would change over time as forward price curves change for both energy and fuel. For this and other reasons, Calpine regularly (at least monthly) uses its commercial software analytic tools and new price curves to update near-term estimated energy margins for each of its electric generating plants, including Sutter. As stated above, those estimates are used in a variety of business functions. In addition to regular monthly "runs" of the analytic software, Calpine from time to time (typically every six months or so) uses the tools to estimate longer term trends in energy margins applicable to its California portfolio. Table 1 shows the expected value of energy margins for 2012 and 2013 that were generated applying the stochastic analytical tools to the company's proprietary price curves. Management judged the proprietary price curves and the resulting stochastic determination of expected energy margins to be fairly reflective of the economic outlook for Sutter in 2012 and 2013. Alternative scenarios, such as assuming flat energy and fuel prices from 2011 through 2013, did not improve the economic outlook for energy margins in 2012 and 2013.

10. I note that Calpine's energy margin estimates are based on price curves for CAISO NP 15 spot markets, as adjusted for Sutter-specific factors (such as transmission costs and transmission losses). This reasonably reflects the fact that Sutter had and has no long-term bilateral contracts to supply energy to third parties in 2011, 2012, or later years. Sutter also has no project-specific fuel supply contracts with non-affiliated third parties. Calpine purchases gas and hedges its fuel requirements on a portfolio basis for its California plants and an affiliate supplies gas to Sutter and other Calpine owned or operated plants on an as-needed basis. Hence, the Table 1 inputs for fuel costs reflect monthly price curves for natural gas. I note also that the only non-fuel cost included in the energy margin estimates is for SO2 and CO2 emissions expenses. The estimates of emissions expense are based on expected generation output (proportionate to fuel burn, based on heat rate), Calpine's view of the State's implementation of its carbon reduction program (known as AB32) and proprietary price curves for emissions allowances.

11. <u>Other revenue sources</u>. Table 1 assumes that Sutter will earn no ancillary services revenues or RA revenues in 2012 or 2013. Over the last three years Sutter's gross ancillary services revenues have been insignificant. Consequently, in projecting forward in 2012 and 2013, management considered it reasonable to treat estimated ancillary services revenues as immaterial. In 2011, Table 1 shows that Sutter had some RA revenues, which contributed to a modest, expected value of positive cash flow. Those RA contracts have expired as of the end of 2011. Sutter has no RA contracts for 2012, despite exercising commercially reasonable efforts to market Sutter's capacity through participation in utility RFOs, and issuing a reverse RFO for Sutter, among other capacity marketing efforts. Management judged it reasonable to assume that

Sutter will not receive bilateral RA or other capacity revenues in 2012 and 2013 (unless the Request for designation of CPM capacity at risk of retirement is granted).

12. Non fuel costs. The non-fuel costs shown on Table 1, which represent going forward cash costs of operations, are based on company budgeted amounts. These estimates have been developed in the ordinary course of company budgeting, and were included in the analyses of the economics of continued operation of Sutter in 2012.

13. The largest category of non fuel costs is for estimated major maintenance work previously scheduled to be performed in 2012. These costs have been estimated based upon industry-standard run-hour intervals and the observations of plant personnel. Three specific maintenance procedures comprise 75 percent of the anticipated expenditures in 2012. First, under normal operations, the turbines would require significant interval-based preventative maintenance, triggered upon reaching 12,000 hours of run-time, including a combustion inspection. The other two major maintenance procedures and costs are driven by equipment degradation and include a significant boiler (heat-recovery steam generator) Low Pressure Evaporator Harp replacement, and reliability based upgrades to control system software and hardware. Given the risks of collateral equipment damage, lost opportunity and lost availability, the company did not consider these to be discretionary maintenance expenditures for 2012 that could be postponed under normal operating conditions until a following year.

14. The second largest non-fuel cost is transmission expense. This reflects charges due under Sutter's transmission arrangement with the Western Area Power Administration (WAPA) pursuant to a long-term Network Integration Transmission Service agreement and the WAPA tariff. These monthly charges are ratcheted based on historic use and create an obligation to pay for the following 12 months if there is transmission use in the current month.

15. The other categories of non fuel costs are variable and fixed O&M, property taxes and insurance. Calpine used budgeted amounts, which generally reflect a combination of historical costs and professional judgment.

16. Cash flow results. Table 1 shows negative cash flows in 2012 and 2013. The expected values of these negative cash flows are large, statistically significant, and unsustainable, as determined in the company's business judgment.

B. Annual Revenue Requirements Analysis

17. In exercising its business judgment on continued operation of Sutter, Calpine evaluated, as one criterion, whether such operation would be likely to result in recovery of capital investment, including a rate of return on that investment. Calpine does not generally consider it reasonable to invest in a resource that is not likely to result in recovery of and on capital investment. Complementary to its analysis of recovering going-forward costs, Calpine prepared an annual revenue requirements analysis for 2012 and 2013 using the accounting framework prescribed in Schedule F of the CAISO's pro forma RMR contract. This Schedule F is required for use by RMR units that are compensated on a full cost of service basis, taking account of projected net operating revenues (from sales of energy, ancillary services and capacity). Schedule F includes both returns of and on investment as part of a resource's fixed annual revenue requirement.

18. Calpine prepared Sutter's Schedule F using the accounting rules and framework prescribed for use by RMR units. Using company data on gross plant investment, depreciation expense, O&M and other line items, the Tariff-prescribed 12.25% rate of return on capital investment (which is not necessarily the rate of return that Calpine would consider an economic return on its investment) and taking account of the expected value of projected energy margins, Sutter's Schedule F shows that continued operation of the resource in 2012 and 2013 would not

result in any recovery of, or on, fixed capital investment. Indeed, it shows a substantial annual revenue requirement shortfall. Moreover, the Schedule F results underscore that the facility would not be able to recover any new capital expenditures required during that period as a result of unexpected contingencies or environmental upgrade requirements.

III. Calpine's Decision To Retire Sutter, Absent CPM or Comparable Bilateral Procurement, Is Definite and Well-Considered

19. Calpine's decision to retire Sutter in 2012, absent CPM or comparable bilateral capacity procurement, is definite and well-considered. This decision was made by the company exercising its business judgment, taking into account not only the economic analyses that show that it would not be economic to operate Sutter in 2012, as described in Part II, above, but also an extensive array of other factors and considerations. Among these factors and considerations, Calpine assessed: (i) future market and regulatory uncertainties and risks; (ii) whether future decisions (discretionary and non-discretionary) to invest capital can be expected to be justified were Sutter to remain in operation; (iii) the need for near-term, non-discretionary or discretionary Major Maintenance; (iv) environmental risks associated with the future applicability of the plant's air permit; (v) the feasibility of non-operating alternatives to retirement (e.g., mothballing); (vi) the impacts of retirement or alternatives on highly trained, professional employees and the community where Sutter is located; (vii) alternative uses of equipment that could be salvaged and redeployed were Sutter retired; and (viii) other less quantitative considerations (e.g., effect on goodwill) that company management normally considers in exercising business judgment regarding major decisions such as consideration of retirement of a modern electric generating facility.

20. All of the foregoing analyses, assessments, factors, and considerations were subsumed in Calpine's exercise of its business judgment and its determinations that it would be

uneconomic to operate Sutter in 2012 and future years, and that the company would retire Sutter in 2012, absent CPM or comparable bilateral capacity procurement. Calpine conducted its review of Sutter over an extended period of time and does not take lightly the consequences of its definite decision to retire Sutter in 2012 unless capacity procurement is obtained. Calpine is mindful of the consequences of Sutter's retirement to its valued employees and to the local communities that would be affected by plant retirement. Nonetheless, Calpine's decision to retire Sutter in 2012 (absent CPM or comparable bilateral capacity procurement) is definite, as I have previously attested.

IV. Sutter's 2012 Maintenance Activities Are Contingent on Timely Resolution of Its CPM Request

21. Prior to Calpine's decision to retire Sutter in 2012, (absent CPM or comparable bilateral capacity procurement), Sutter had scheduled major maintenance work in 2012. As described above in paragraph 13, the largest categories of major maintenance involve interval maintenance (based on hours of cumulative run-time), including a combustion inspection, and other major maintenance activities including Low Pressure Evaporator Harp replacement and reliability based upgrades to control system software and hardware. Sutter will not undertake these major maintenance activities absent designation under its CPM Request (or comparable bilateral capacity procurement). In order for Sutter to be available to the CAISO for the peak months beginning July 1, 2012, it must initiate and complete its interval-driven major maintenance before that date. Sutter's operational staff's professional judgment is that the following timeline needs to be followed to have the major maintenance work completed ahead of July 1, 2012. Management approval and initiation of the interval-based major maintenance activities will occur only after realization of sufficient revenues is deemed likely, and must occur by April 1, 2012, which will allow sufficient time for Sutter to procure and ship parts to the plant

site and to notify and mobilize skilled workers needed to support and carry out the maintenance work. Initiation by April 1, 2012 should allow the maintenance to be carried out during a planned outage that would begin around June 1, 2012,[7] which we would expect to be completed prior to a July 1, 2012 availability date. This schedule contains a bare minimum of slippage time. This schedule will also permit initiation of ordering of equipment needed for the other major maintenance activities. If notice of CPM designation is not obtained by April 1, 2012, Sutter may not be able to initiate and complete its major maintenance in sufficient time for the facility to be returned to service from a planned outage by July 1, 2012.

22. Calpine remains receptive to bilateral capacity procurement that is comparable to CPM designation. Accordingly, while its request for CPM designation is pending, Calpine is and will continue commercial efforts to sell Sutter energy and capacity products. However, Calpine has no assurance that commercial transactions, including possible RA procurement for portions of 2012 will be offered on terms sufficient to warrant Sutter's continued operation. Calpine is aware that the California Public Utilities Commission ("CPUC") is considering action under its General Order 167. Calpine will closely follow such action and immediately notify the CAISO if the CPUC's action results in comparable procurement sufficient to allow withdrawal of its request for CPM designation. However, it is Calpine's business judgment that, as of this date, CPM designation for Sutter is the last resort alternative to retirement.

23. This concludes my Affidavit.

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[7] This presumes that a planned outage in this time frame can be accommodated by the CAISO. Calpine will seek such a modification to its currently scheduled spring planned outage.

I, Alex Makler, certify under penalty of perjury that the foregoing is true and correct to the best of my knowledge.

Executed on January 24, 2012.

Attachment D

California ISO
Shaping a Renewed Future

California ISO Report on Basis and Need for CPM Designation for Sutter Energy Center

December 6, 2011

California ISO Report on Basis and Need for CPM Designation for Sutter Energy Center

I. Executive Summary

This report addresses the basis and need for the California ISO (CAISO) to designate the Sutter Energy Center (Sutter plant) as capacity at risk of retirement, pursuant to the provisions of the CAISO Tariff regarding the Capacity Procurement Mechanism (CPM).[1]

On November 22, 2011, Calpine submitted to the CAISO a request, and all required supporting documentation, for designation of the Sutter plant as CPM Capacity for 2012 (November 22 Calpine request). The November 22 Calpine request stated that, absent such a CPM designation, the Sutter plant must and will be retired in 2012 and thus will not be available for commercial operations in 2013 and later years.[2]

Section 43.2.6 of the CAISO Tariff states that the CAISO may issue a CPM designation for capacity at risk of retirement if all five requirements specified in the tariff section are met. In this case, the CAISO has determined that the Sutter plant satisfies four of the five requirements but does not meet the requirement that "the resource will be needed for reliability purposes, either for its locational or operational characteristics, by the end of the calendar year following the current RA Compliance Year." The CAISO's analysis shows that the Sutter plant will be needed for reliability purposes for its operational characteristics in the 2017/2018 time frame. As explained below, based on information provided by Calpine, the CAISO has determined that the Sutter plant will not be available to meet reliability needs in the CAISO balancing authority area in the 2017/2018 time frame. In accordance with Section 43.2.6, the CAISO requests that stakeholders provide any written comments on this report to the CAISO by December 16, 2011. Please submit comments to Phil Pettingill at ppettingill@caiso.com.

Because the CAISO analysis shows that the plant will only be needed for reliability and operational requirements as of 2017/18, the CAISO is precluded from procuring the resource under the current tariff authority. The ISO has determined that if the Sutter plant shuts down in 2012, there will be a capacity gap of 3570 by the end of 2017, which will pose significant challenges to the reliable operation of the CAISO grid. The CAISO has determined that it must take immediate action to avoid these reliability

[1] Capitalized terms not otherwise defined in this report have the meanings set forth in the Master Definitions Supplement, Appendix A to the CAISO Tariff. References in this report to numbered sections are references to sections of the CAISO Tariff unless otherwise stated.

[2] Certain information submitted in support of the November 22 Calpine request is subject to the confidentiality provisions of Section 20.2 of the CAISO Tariff.

and operational issues in the future. Specifically, the CAISO will be making a filing with the Federal Energy Regulatory Commission requesting waiver of existing tariff provisions that currently limit the procurement of capacity at risk of retirement to cases in which such capacity is needed the next resource adequacy compliance year. The waiver if granted will enable the ISO to procure the Sutter capacity for 2012 based on the CAISO's determination of need by the end of 2017.

II. Background

A. Applicable CAISO Tariff Provisions

Section 43.1.2 of the CAISO Tariff authorizes the CAISO to designate Eligible Capacity to provide CPM Capacity services in order to address six listed types of circumstances. One of the CPM categories consists of the procurement of capacity at risk of retirement within the current Resource Adequacy (RA) Compliance Year that will be needed for reliability by the end of the calendar year following the current RA Compliance Year. Section 43.2.6 of the CAISO Tariff states that the CAISO may issue a CPM designation for such capacity at risk of retirement in the event that all of the following requirements apply:

(1) the resource was not contracted as RA Capacity nor listed as RA Capacity in any Load Serving Entity's (LSE) annual RA Plan during the current RA Compliance Year;

(2) the CAISO did not identify any deficiency, individual or collective, in an LSE's annual RA Plan for the current RA Compliance Year that resulted in a CPM designation for the resource in the current RA Compliance Year;

(3) CAISO technical assessments project that the resource will be needed for reliability purposes, either for its locational or operational characteristics, by the end of the calendar year following the current RA Compliance Year;

(4) no new generation is projected by the CAISO to be in operation by the start of the subsequent RA Compliance Year that will meet the identified reliability need; and

(5) the resource owner submits to the CAISO and the Department of Market Monitoring (DMM), at least 180 days prior to terminating the resource's Participating Generator Agreement (PGA) or removing the resource from PGA Schedule 1, a request for a CPM designation under Section 43.2.6 and the affidavit of an executive officer of the company who has the legal authority to bind such entity, with the supporting financial information and documentation discussed in the Business Practice Manual (BPM) for Reliability Requirements, that attests that it will be uneconomic for the

resource to remain in service in the current RA Compliance Year and that the decision to retire is definite unless CPM procurement occurs.[3]

Section 43.2.6 further provides that if the CAISO determines that all five of these requirements have been met, prior to issuing the CPM designation, the CAISO will prepare a report that explains the basis and need for the CPM designation and will provide stakeholders at least seven (7) days to review and submit comments on the report.[4] Section 43.3.7 of the CAISO Tariff also states that a CPM designation for capacity at risk of retirement under Section 43.2.6 will have a minimum commitment term of one (1) month and a maximum commitment term of one (1) year, based on the number of months for which the capacity is to be procured within the current RA Compliance Year.

B. The Sutter Plant

The Sutter plant is a combined cycle gas turbine (CCGT) generating facility located near Yuba City in Sutter County, California. Calpine Corporation (Calpine) indirectly owns the Sutter plant through its subsidiary, Calpine Construction Finance Company, L.P. (CCFC). The Sutter plant relies on air cooling rather than once-through cooling (OTC) using ocean or lake water.[5]

The Sutter plant has a net qualifying capacity for 2012 of between 500 and 525 MW.[6] It is interconnected to the transmission system operated by the Western Area Power Administration and operates in the CAISO markets pursuant to a pseudo-tie arrangement with the CAISO.[7] The Sutter plant can be dispatched by the CAISO and has flexible ramping capability that allows discrete portions of its capacity to be dispatched as needed to satisfy demand.

III. Demonstration of Basis and Need to Designate the Sutter Plant as Capacity at Risk of Retirement

As explained below, Sutter meets four of the five requirements to be issued a CPM designation for capacity at risk of retirement pursuant to Section 43.2.6 and the related provisions of the BPM for Reliability Requirements and will meet the fifth

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3 Section II of this report addresses the application of these CAISO Tariff provisions and related provisions of the BPM for Reliability Requirements to the Sutter plant.

4 Section 43.2.6 also states that the CAISO will allow no fewer than thirty (30) days for an LSE to procure Capacity from the resource. If an LSE does not, within that period, procure sufficient RA Capacity to keep the resource in operation during the current RA Compliance Year, the CAISO may issue the risk of retirement designation; provided that the CAISO determines that the designation is necessary and that all other available procurement measures have failed to procure the resources needed for reliable operation.

5 Because the Sutter plant is air-cooled, it is not subject to the OTC regulations discussed in Section III.C below.

6 The Sutter plant's net qualifying capacity is specified for each month and varies based on seasonal factors.

7 *See* Pseudo PGA between the CAISO and CCFC, accepted by FERC letter order issued in Docket No. ER06-58-001 on March 1, 2006.

requirement upon FERC approval of a request to waive the tariff provision requiring the reliability and operational need for the plant to be "by the end of the calendar year following the current RA Compliance Year." A FERC waiver of this tariff provision will allow the CAISO to designate the Sutter Plant as CPM Capacity at risk of retirement based on longer-term reliability and operational needs.

A. The Sutter Plant Was Not Contracted or Listed as RA Capacity

The CAISO's review confirms that the Sutter plant was not contracted as RA Capacity nor listed as RA Capacity in any LSE's annual Resource Adequacy Plan during the current RA Compliance Year, *i.e.*, during 2012.

B. The CAISO Identified No Deficiency in an LSE's Annual Resource Adequacy Plan that Resulted in a CPM Designation for the Sutter Plant

The CAISO did not identify any deficiency, individual or collective, in an LSE's annual Resource Adequacy Plan for the current RA Compliance Year (*i.e.*, 2012) that resulted in a CPM designation for the Sutter plant in the current RA Compliance Year.

C. CAISO Technical Assessments Project that the Sutter Plant Will Be Needed for Reliability Purposes

1. Overview of the CAISO's Analysis and Methodology

The CAISO has conducted analysis, including technical assessments, that project that the Sutter plant will be needed for reliability purposes, specifically for its operational characteristics, in the 2017/2018 time frame.[8]

The CAISO conducted its analysis regarding the Sutter plant in accordance with Section 7.3.5.2 of the BPM for Reliability Requirements, which explains that the CAISO will use a diverse set of tools and follows a multi-step process whereby the generating facility is studied for its impact on local and system reliability and operational flexibility, given the best available information regarding future grid conditions and the assumed availability of RA resources procured for the current RA Compliance Year (including other known generator retirements) and any new generation that will achieve commercial operation to meet future needs. In the case of the 2017/2018 assessment the assumed availability of resources is based on the California Public Utilities Commission (CPUC) Long-Term Procurement Plant (LTPP) planning assumptions rather than the RA resource procurement.

Section 7.3.5.2 of the BPM for Reliability Requirements also explains that the CAISO's analysis must consist of one several listed types of studies that include a

[8] The CAISO recognizes that Section 43.2.6 states that the technical assessments are to be conducted for the end of the calendar year following the current RA Compliance Year. That subject is addressed in Section III.C(3) below.

production simulation. As explained below, the CAISO's analysis in this case consists multi-step process that includes quantification of the expected flexibility requirements to meet load and supply variability and uncertainty and an assessment of fleet of resources expected to be available to simultaneously meet the load plus operating reserves requirements, plus flexibility using a production simulation conducted in accordance with the study assumptions and scope of study established by the CPUC/LTPP proceeding, with certain adjustments. Further, pursuant to the BPM requirements, the CAISO's analysis evaluates the adverse effects on the transmission system as well as operational flexibility requirements, and also considers the characteristics of the individual resources in the fleet and will be able to highlight resources that are needed for locational and system reliability or have non-generic resource flexibility required to operate the integrated grid and have not been secured through the procurement process. As explained below, the CAISO's analysis does address operational flexibility requirements with specific consideration to the non-generic operating characteristics of the Sutter plant and how that plant is needed for system reliability.

The CAISO's analysis is based on the study assumptions and scope of study developed for the rulemaking proceeding established in 2010 by the CPUC/LTPP for California.[9] The LTPP proceeding will determine the future long-term procurement obligations of the state's investor-owned utilities. As part of that proceeding, the CAISO evaluated potential operational and resource capacity needs driven by the requirement of the state of California that LSEs implement the state's 33 percent renewable portfolio standard (RPS) by 2020.[10]

In accordance with the parameters established in the LTPP proceeding, the CAISO's analyzed 2020 scenarios. The CPUC authorized several scenarios for analysis in that proceeding. The CAISO has based its analysis of the potential need for the Sutter plant based on the CPUC's 33 percent trajectory high load (high load) scenario, which is intended to reflect future uncertainties in forecast demand. The CAISO determined that use of the high load scenario is appropriate because it reflects plausible uncertainties in which higher load growth and/or demand programs underperform[11]

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9 CPUC Rulemaking 10-05-006. Filings, orders, and other documents generated in that proceeding are available at http://www.cpuc.ca.gov/PUC/energy/Procurement/LTPP/LTPP2010/index_2010.htm, http://docs.cpuc.ca.gov/Published/proceedings/R1005006_doc.htm, and http://www.cpuc.ca.gov/PUC/energy/Renewables/100824_workshop.htm.

10 An overview of the CAISO's evaluation in the LTTP proceeding is provided in a briefing memorandum from Keith Casey, Vice President, Market and Infrastructure Development for the CAISO, to the CAISO Board of Governors dated August 18, 2011 (Board memorandum). The Board memorandum is available at http://www.caiso.com/Documents/110825BriefingonRenewableIntegration-Memo.pdf. More detailed information regarding the CAISO's evaluation is provided in the Track I Direct Testimony of Mark Rothleder on behalf of the CAISO, CPUC Rulemaking 10-05-006 (as corrected on August 12, 2011) (Rothleder testimony). The Rothleder testimony is available at http://www.caiso.com/Documents/R1005006_CAISO_LTPP_TestimonyErrata08102011_clean_final.pdf.

11 CPUC Scoping LTPP Scoping Memo Section 3.1.2.3.3 Need: In the sensitivity analysis for demand levels for both gigawatt hour (GWh) and MW, the investor owned utilities shall use high and low demand levels that reflect a 10% variance from the demand forecast value for each year. This value is reflective of any combination of future uncertainties (e.g., increased or decreased load growth or programmatic performance).

consistent with CPUC assumptions. While load forecast and other assumptions may vary over time, the CAISO must plan and account for probable scenarios in its back-stop procurement of capacity to ensure reliable operations of the CAISO grid.

The CAISO's analysis uses the generating resource retirement schedule from the scoping memorandum issued by the CPUC in the LTPP proceeding, in order to determine the extent to which there is the potential for resource flexibility shortages from 2011 to 2020.[12] In particular, the analysis takes into account the MW quantity of generating capacity that is expected to retired during that time frame due to regulations implemented by the State Water Resources Control Board to curb the use of once-through cooling (OTC) in coastal power plant plants.[13]

2. Results of the CAISO's Analysis

The CAISO's analysis indicates that the Sutter plant will be required for reliability purposes, specifically for its operational characteristics, in the late 2017 or early 2018 time frame.[14] Based on information provided in the CPUC scoping memo, it is expected that plant retirements due to the OTC regulations will amount to 8,099 MW by the end of 2017. An additional 3,980 MW of retirement will occur between from the end of 2017 to 2020.[15] The CAISO's analysis also indicates that, under the high load scenario, the need for new capacity in addition to the expected resource additions will be 4,600 MW by 2020. To project the needs for the 2017/2018 period, 3980 MW of capacity was added to the original 2020 high load scenario to reflect the OTC resources that will not be retired by the end of 2017. Load was not adjusted as the forecast load in 2018 and 2020 remain almost the same due to an assumption that projected load growth will be offset by increased energy efficiency, demand response and demand combined heat and power resources.

Other than the adjustments made to OTC resources expected to be available in 2018 no other supply adjustments were made to the 2020 high load scenario. Renewable supply was adjusted to reflect 2018 capacity levels. No local resources have assumed to be added by 2018 to satisfy local capacity requirement because by 2018, with 3980MW of unretired OTC all reside in SCE area and therefore are assumed to satisfy local capacity requirements. Consistent with the CPUC planning assumptions for the 2020 simulations, the Sutter plant, 525 MW of installed capacity, was assumed

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[12] Assigned Commissioner and Administrative Law Judge's Joint Scoping Memo and Ruling, CPUC Rulemaking 10-05-006 (May 6, 2010) (CPUC scoping memo). The CPUC scoping memo and attachments thereto are available at http://docs.cpuc.ca.gov/EFILE/RULC/127542.htm.

[13] *See* Board memorandum at 2; CPUC scoping memo at 18-19 (setting forth study assumptions regarding OTC retirements). Information regarding the OTC regulations is available at http://www.swrcb.ca.gov/water_issues/programs/ocean/cwa316/.

[14] Because the Sutter plant is a pseudo-tie generating resource and thus is located outside of the CAISO balancing authority area, the Sutter plant will not be needed for its locational characteristics.

[15] The CAISO calculated the 3,980 MW amount based on the difference between the expected retirement or repowering of 8,099 MW of OTC plant by 2018 and 12,079 MW of OTC plant by 2020 (12,079 MW – 8,099 MW = 3980 MW). *See* Board memorandum at 2.

available in 2017/2018 case. With these assumptions, a production simulation was performed for July to assess whether operational requirements could be met. This simulation identified a 2535 MW deficiency in flexible capacity requirements resulting in an estimated 3,570MW of additional capacity needs. The removal of 525 MW capacity of capacity identified as needed by the study would result in reliability and operational issues on the CAISO grid and would reflect as additional needs to identified 3,570MW as early as the end of 2017. Thus, there will be a need for additional capacity as early as the end of 2017. The absence of Sutter would increase the needed flexible capacity for the 2017/2018 case. Table 1 compares the load, supply and flexibility needs for the 2018 and 2020 case.

	Case Assumptions			**Differences**	
CPUC-LTPP High Load Scenario	2020 LTPP Assumptions (MW)	2018 Sensitivity (Developed from 2020 Case) (MW)	2018 LTPP Assumptions (MW)	2018 Senstivity-2018 LTPP Assumptions (MW)	2020 LTPP-2018 Senstivity (MW)
Demand					
CAISO Demand Forecast	62,324	62,324	60,754	1,570	-
Incremental Energy Efficiency (EE)	5,688	5,688	4,167	1,521	-
Load Net EE	56,636	56,636	56,587	49	-
Demand Response (DR)	5,145	5,145	5,051	94	-
Demand Side CHP	819	819	655	164	-
Load net (EE, DR, CHP)	50,672	50,672	50,881	(209)	-
Supply (incremental/decremental)					
OTC	19,292	19,292	19,292	-	-
OTC Retirement	12,079	8,099	8,099	-	3,980
OTC Net OTC Retirements	7,213	11,193	11,193	-	(3,980)
RPS Additions (Note 1)	6,049	Note 1 4,118	4,118	-	1,931
Other Additions	2,797	2,797	2,797	-	-
Total Supply Changes	16,059	18,108	18,108	-	(2,049)
Flexibility					
HE15 Load Following Requirements	2,935	2,827	N/A	N/A	108
Upward A/S and load following shortages	Note 3 3,266	2,535	N/A	N/A	731
Need (Note 2)	4,600	Note 2 3,570	N/A	N/A	1,030
Note 1: Renewable production in 2020 scenario was adjusted to reflect expected 2018 RPS capacity					
Note 2: The need of in the 2018 senstivity was estimated based on the quantity of shortage observed and 2020 observed shortages and needs (2,535MW x 4,600MW/3,266MW = 3,570MW)					
Note 3: 2020 shortages occur both load following and non-spin					

Table 1: Comparison of 2020 and 2018 Case

The CAISO has determined that there is no additional new capacity with needed flexibility projected to come online in time to meet the identified need. In the production simulation, Sutter was observed to have a 69.91% capacity factor. Sutter was observed to provide energy, operating reserves and flexibility in the 2017/2018 production simulation.[16] The retirement of existing capacity that embodies the required flexible characteristics would pose a significant risk to reliability.

[16] July energy production 280.89 GWh, spinning reserve = 8.86 GWh, non-spinning reserve = 0.36 GWh, Regulation = 5.20 GWh, load following Up = 30.84 GWh, load following down = 64.38 GWh.21

The Sutter plant is needed to meet these 2017/2018 operational needs identified by the CAISO. The plant provides a significant amount of net qualifying capacity – between 500 and 525 MW. That capacity will not be available to meet system needs in the CAISO balancing authority area if the plant is retired. Moreover, the Sutter plant has valuable flexible ramping capability that allows the CAISO to dispatch discrete portions of its capacity as needed to satisfy demand. This flexible capacity will also be lost if the Sutter plant is retired in 2012.

Based on the information provided to the CAISO in the November 22 Calpine request, the Sutter plant will be unavailable to meet the 2017/2018 operational needs discussed above if the plant does not receive a CPM designation for 2012. Calpine explained that if the Sutter plant is retired in 2012, the plant may not return to commercial operations in future years because, under Environmental Protection Agency policy, the plant would likely need to undergo New Source Review and obtain a new air quality permit. Even if the Sutter plant could meet then-current best available control technology (BACT) requirements and otherwise satisfy all of the new air quality permitting requirements that have gone into effect since the plant was first permitted, the permitting process is often lengthy and subject to an extended and unpredictable appeals process. Further, Calpine stated that future requirements to meet then-current BACT could require substantial new investments, making the return of the Sutter plant to service uneconomic.

3. Planned CAISO Request for Tariff Waiver

Because the Sutter plant is needed to meet the 2017/2018 operational needs discussed above, the CAISO has determined that it is appropriate to file a request with FERC for waiver of the tariff requirement in Section 43.2.6 of the CAISO Tariff that the reliability need for a risk of retirement CPM designation must be shown for "the end of the calendar year following the current RA Compliance Year." The CAISO plans to file the request for waiver no later than January 2012, after the CAISO receives stakeholder comments on this report.

4. Stakeholder Process on Longer-Term Capacity Procurement Mechanism

The Sutter plant request highlights the benefits of developing a capacity procurement mechanism than address longer-term system needs than the CAISO's CPM provisions. The CAISO will be initiating a stakeholder process in January 2012 to develop such a longer-term mechanism. The CAISO anticipates that the stakeholder process will take approximately six months to complete. Any requisite filings would be made shortly after the completion of the stakeholder process. Given this schedule, that stakeholder process will not be finalized in time to address the proposed retirement of the Sutter plant during 2012. Because the Sutter plant is uniquely situated as the only plant with its operating characteristics that has informed the CAISO of its intent to retire in 2012 absent a CPM designation, the CAISO intends to seek a waiver to allow a CPM designation of the Sutter plant in 2012. After 2012, the CAISO expects that continued operation of the Sutter plant and any other resources with similar issues will be assessed under the longer-term capacity procurement mechanism to be developed.

D. The CAISO Projects No New Generation that Will Meet the Identified Reliability Need

The CAISO has reviewed the best available information on projected generation additions to the system and has determined that, even with projected generation additions, there will be insufficient generation in operation by the start of 2017/2018 that have the needed operational characteristics to meet the identified reliability need. In light of Calpine’s statement that it definitely will retire the Sutter plant in 2012 if the plant does not receive a CPM designation (or comparable bilateral capacity compensation) it is reasonable for the CAISO to provide a CPM designation to the Sutter plan in 2012 that will allow the Sutter plant to remain in operation in 2017/2018.

E. Calpine Has Submitted the Required Information to the CAISO

The Calpine request, submitted on November 22, 2011, satisfies the CASO Tariff requirements that the resource owner must submit, at least 180 days prior to terminating the PGA for the resource or removing the resource from PGA Schedule 1, a request for a CPM designation and the affidavit of an executive officer of the company who has the legal authority to bind the company, with the supporting financial information and documentation discussed in the BPM for Reliability Requirements, that attests that it will be uneconomic for the resource to remain in service and that the decision to retire is definite unless CPM procurement occurs. The November 22 Calpine request included an affidavit from Alex Makler, Vice President –Strategic Origination and Development, West Region, of Calpine Corporation, stating that Calpine has conducted extensive analyses of whether it would be economic for the Sutter plant to remain in service in the 2012 RA Compliance Year, and the company has made the definite decision to retire Sutter in 2012, unless CPM procurement (or comparable bilateral capacity procurement) occurs.

The supporting financial information and documentation required under Section 7.3.5.2 of the BPM for Reliability Requirements includes the following:

- The expected PGA termination date for the resource. This date must be a least 180 days after submission of the request for a risk of retirement CPM designation. Calpine states that its expected PGA termination date will be at least 180 days after the November 22Calpine request, bur prior to the end of 2012.

- A description of power purchase agreements and capacity contracts currently in effect (if any), including the term length, volume, and pricing provisions. Calpine states that the Sutter plant has multiple contracts with multiple entities to provide

Resource Adequacy (but not energy), all of which expire no later than December 31, 2011. Calpine further states that the Sutter plant has no Resource Adequacy contracts for 2012 and no power purchase agreements to supply third-parties with energy in 2011, 2012, or later years.

- A description of the term, length, volume, and pricing provisions of existing fuel supply contracts. Calpine states that the Sutter plant has no project-specific fuel supply contracts with non-affiliated third parties. The November 22 Calpine request indicates that Calpine purchases gas and hedges its fuel requirements on a portfolio basis for its plants and that a Calpine affiliate supplies gas to Sutter and other Calpine owned or operated plants on an as-needed basis.

- Any analyses the resource owner performed, or had performed, to determine whether it is economic for the resource to remain in service during the current year including supporting documents. Calpine has provided economic analyses in a confidential attachment submitted in support of the November 22 Calpine request.

- Any documents confirming the formal decision of the Board of Directors, officers, or management of the resource owner, as appropriate, that the resource will be retired unless CPM procurement occurs. Calpine has provided appropriate certificates from its management that reflect the requisite formal decisions.

The CAISO has reviewed the November 22 Calpine request and has determined that the request includes each of these pieces of supporting financial information and documentation.

IV. Proposed Designation of the Sutter Plant as Capacity at Risk of Retirement

Following the receipt of FERC-approval of the requested tariff-waiver, the CAISO anticipates a CPM designation for any of the remaining months of 2012 as necessary. The CAISO has determined that a designation for this period should be sufficient to ensure that the Sutter plant will remain operational through 2012. As noted above, after 2012, the CAISO expects that continued operation of the Sutter plant will be assessed under the longer-term capacity procurement mechanism to be developed in the stakeholder process discussed above.

In accordance with Section 43.6.2 of the CAISO Tariff, the price for the proposed CPM designation for the Sutter plant will be as approved by the Federal Energy Regulatory Commission in Docket ER11-2256, currently pending the outcome of settlement negotiations.

Because the need for the Sutter plant is based on operational needs in all Transmission Access Charge (TAC) Areas rather than any locational needs, the costs of the proposed CPM designation for the Sutter plant will be allocated to all Scheduling

Coordinators for LSEs that serve Load in all CAISO TAC Areas, consistent with Section 43.8.7 of the CAISO Tariff.

In accordance with Section 43.2.6, the CAISO has posted the instant report on its website and will provide stakeholders seven days (*i.e.*, until December 16, 2011) to submit any written comments on the report.

Under Section 43.2.6 of the CAISO Tariff, issuance of this report normally triggers the start of a period of no less than thirty (30) days for an LSE to procure Capacity from a Resource before the CAISO may issue the risk of retirement designation. Because the CAISO's authority to issue a risk of retirement designation for the Sutter plant is dependent upon FERC approval of the planned waiver request defined above, the CAISO does not intend to commence this procurement period until after FERC acts on the waiver request. The CAISO will issue a market notice announcing the start of the time period set forth in Section 43.2.6 for an LSE to procure RA Capacity from the resource after FERC issues an order granting the CAISO's request for a tariff waiver.

Attachment E

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

California Independent System Operator Corporation	**))**	**Docket No. ER12-____-000**

DECLARATION OF
MARK A. ROTHLEDER
ON BEHALF OF THE
CALIFORNIA INDEPENDENT SYSTEM
OPERATOR CORPORATION

I. Introduction

Q. Please state your name, title, and business address.

A. My name is Mark A. Rothleder. I am Executive Director of Market Analysis and Development for the California Independent System Operator Corporation (ISO). My business address is 250 Outcropping Way, Folsom, California 95630.

Q. What are your duties and responsibilities at the ISO?

A. As Executive Director of Market Analysis and Development, I play a lead role in the design and implementation of market rules and operating procedures for the ISO. In this position, I also play a significant role in the ISO's efforts, in conjunction with state regulators, to consider long-term system and resource adequacy needs in the State of California. Prior to serving as Executive Director of Market Analysis and Development, I was a Principal Market Developer for the ISO in the lead role in the implementation of market rules and software modifications related to the ISO's Market Redesign and Technology Upgrade. Since joining the ISO over thirteen years ago, I have worked extensively on implementing and integrating the approved market rules for California's competitive energy and ancillary services markets and the rules for congestion management, real-time economic dispatch, and real-time market mitigation into the operations of the ISO balancing authority area. I have also held the position of Director of Market Operations. For the past two years, I have also been responsible for leading the ISO's analysis and efforts to determine operational requirements and resource needs to support integration of renewable resources to satisfy California's 20 percent and 33 percent renewable portfolio standard (RPS).

Q. Please describe your educational and professional background.

A. I am a registered Professional Electrical Engineer in the State of California. I hold a B.S. degree in Electrical Engineering from the California State University, Sacramento. I have taken post-graduate coursework in Power System Engineering from Santa Clara University and earned an M.S. degree in Information Systems from the University of Phoenix. I have co-authored technical papers on aspects of the California market design in professional journals and have frequently presented to industry forums. Prior to joining the ISO in 1997, I worked for eight years in the Electric Transmission Department of Pacific Gas and Electric Company, where my responsibilities included Operations Engineering, Transmission Planning and Substation Design.

Q. **As you testify, will you be using any specialized terms?**

A. Yes. Unless otherwise indicated, capitalized terms in my declaration have the meanings set forth in the Master Definitions Supplement, Appendix A of the ISO tariff.

Q. **Please briefly describe your role in the ISO's determination of a need to procure capacity from the Sutter Energy Center as a result of that plant's risk of retirement in 2012.**

A. I was responsible for directing and conducting the ISO analysis that resulted in the determination that the Sutter Energy Center (Sutter plant) is needed to meet the long-term operational needs of the ISO. I was chosen to undertake this assessment because of my extensive work in evaluating long-term capacity procurement needs for the State of California in light of the state's 33 percent RPS. As I will explain later in my declaration, the California Public Utilities Commission (CPUC) has established a long-term procurement plan proceeding (CPUC Rulemaking 10-05-006) to determine those capacity procurement needs over the 2011-2020 planning horizon. I provided the ISO's direct testimony and supporting documentation in the CPUC long-term procurement plan proceeding.

Q. What is the purpose of your declaration?

A. My declaration will explain why the ISO has determined that there is a need to designate the Sutter plant as capacity at risk of retirement in 2012 and that the ISO should procure capacity from the Sutter plant under the provisions of the ISO tariff regarding the capacity procurement mechanism (CPM) with the additional authority the Commission authorizes in this waiver proceeding. First, I will discuss the methodology that the ISO used in analyzing the need for the Sutter plant for reliability purposes. As I will explain, the ISO's methodology is based on the planning assumptions set forth in the CPUC long-term procurement plan proceeding. These assumptions were applied to a study scenario established in that proceeding that the ISO has determined is the most appropriate of the studied scenarios, consistent with good utility practice, to reflect future uncertainties in system conditions, including uncertainties in forecast demand. In the CPUC proceeding, that scenario was sometimes called the 33% RPS trajectory scenario with high load. I will refer to that scenario as the "operations planning scenario" because the ISO determined that this was the most appropriate scenario to use for operations planning purposes in this instance.

Next, I will discuss the results of the ISO's analysis. I will explain why the ISO determined that it needs to designate the Sutter plant as capacity at risk of retirement in 2012, and why alternatives to procuring capacity from the Sutter plant are not viable. I will also explain why the ISO has concluded that other resources comparable to the Sutter plant are unlikely to request a designation as capacity at risk of retirement in 2012. In addition, I will explain that, based on the ISO's analysis, a failure to prevent the retirement of the Sutter plant could lead to adverse consequences for system reliability when the Sutter plant is needed in the 2018 time frame, including the potential for load shedding events.

II. Methodology of the ISO's Analysis Regarding the Need for the Sutter Plant for Reliability Purposes

Q. Did the ISO evaluate whether the Sutter plant will be needed for its locational or operational characteristics by the end of 2013?

A. Yes. The ISO evaluated both whether the Sutter plant will be needed for its locational or operational characteristics by the end of 2013 and whether a need for the Sutter plant will exist in years after 2013. Based on its prior production studies, which I describe further below, the ISO was able to conclude that, although the Sutter plant has many beneficial operational characteristics and the ISO has received market benefits from the plant, the ISO is not likely to need the Sutter plant for its locational or operational reliability benefits by the end of 2013.

Q **Why did the ISO further analyze whether the Sutter plant will be needed for its locational or operational characteristics in years after 2013?**

A. As the entity responsible for the reliability of the ISO controlled grid, the ISO evaluates projected future system conditions and market trends to determine whether there are actions which the ISO should undertake to ensure that the system can be operated in a reliable manner. As explained in greater detail later in my declaration, in its capacity as a participant in the CPUC long-term procurement plan (LTPP) proceeding, the ISO has analyzed a number of factors which will affect the reliability of the ISO controlled grid over a planning horizon in 2020. Based on its analysis to date, the ISO has identified a significant concern that, under the operations planning scenario defined by the CPUC, there will be a "gap" or shortage in the capacity needed to meet system-wide needs in California by the end of this planning horizon in 2020. As I discuss further below, while certain assumptions underlying that scenario are different from the other scenarios relied on by the CPUC in its long-term procurement plan proceeding, it is the only scenario the ISO can rely on consistent with good utility practice as it is the only scenario that considers a sufficient range of assessments of future needs for reliable operations during this planning horizon.

In light of the ISO's previous 2020 planning analyses and the resulting concerns that there is a gap in the capacity available to meet system needs by 2020, the ISO determined that it would be prudent to consider the longer-term impact of the planned retirement of the Sutter plant. This is prudent because, if the Sutter plant retires from service in 2012 and it is needed to maintain reliability in future years, the ISO would not have sufficient capacity, and there will be insufficient time to build new generation resources to meet the shortage in system-wide capacity and to replace the Sutter plant. By taking this action for 2012, the ISO is taking the appropriate steps to ensure that viable operations can be maintained in the foreseeable future. Otherwise, the ISO would be taking on an increased, unjustified risk of not being able to maintain reliability in future years.

Q. What methodology did the ISO use to perform its analysis of the need for the Sutter plant in later years?

A. The ISO conducted its analysis regarding the Sutter plant in accordance with Section 7.3.5.2 of the Business Practice Manual for Reliability Requirements addressing the analysis of capacity at risk of retirement. This portion of the Business Practice Manual states that the ISO will use a diverse set of tools and follow a multi-step process whereby the generating facility is studied for its impact on local and system reliability and operational flexibility, given the best available information regarding future grid conditions and the assumed availability of resource adequacy resources procured for the current resource adequacy compliance year (including other known generator retirements) and any new generation that will achieve commercial operation to meet future needs. Normally, consistent with Section 43.2.6 of the ISO tariff, the ISO would evaluate the need for the end of 2013. However, in the ISO's analysis of longer-term needs for capacity, the assumed availability of resources is based on the planning assumptions set forth in the CPUC long-term procurement plan proceeding.

Q. **Has the ISO conducted prior assessments of such need under the risk of retirement CPM category and is this assessment consistent with any prior assessments?**

A. Since the CPM risk of retirement tariff provisions became effective on April 1, 2011, this is the first instance in which the ISO has been asked to evaluate its need for a resource seeking CPM designation as a result of its declared risk of retirement. Therefore, there are no prior studies conducted under this section of the tariff to compare with the assessment of the Sutter Energy Center.

Q. **How does the study conducted for the Sutter Energy Center compare with the types of studies that you believe the ISO originally had contemplated for the risk of retirement CPM category?**

A. The studies the ISO conducted for the 2020 assessments are more sophisticated than the studies the ISO originally had contemplated conducting for a risk of retirement designation. As required by the current Business Practice Manual for Reliability Requirements, once a CPM request is made, the ISO must complete its assessment of whether the retirement of the generating unit would affect the reliability of the transmission system within 30 days. This does not provide sufficient time to conduct a full-year, hourly interval production simulation analysis as was performed for the 2020 cases in the CPUC long-term procurement plan proceeding. However, the ISO's prior work in evaluating future needs in light of the changing landscape of the ISO fleet over time due to environmental regulation requirements and the integration of renewable resources on the system provides a useful framework for the evaluation of future needs when faced with the possible retirement of resources.

Q. Why did the ISO decide to analyze the retirement of the Sutter plant based on the planning assumptions set forth in the CPUC long-term procurement plan proceeding rather than the assumptions underlying other studies, such as those used for resource adequacy procurement?

A. One of the objectives of the CPUC long-term procurement plan proceeding is to quantify the need for procurement of new resources to meet system or local resource adequacy needs in the 2020 planning horizon, including issues related to long-term renewable integration planning and the need for replacement generation to eliminate reliance on once-through cooling (OTC) power plants, *i.e.*, power plants that are cooled using ocean or lake water and that are expected to be retired during that time frame due to regulations regarding OTC implemented by the State Water Resources Control Board. The CPUC long-term procurement plan proceeding will address the future long-term procurement obligations of the state's investor-owned utilities, and the planning assumptions for the long-term procurement plan proceeding include assumptions regarding the retirement schedule for OTC resources. As part of the CPUC proceeding, the ISO also evaluated potential operational and resource capacity needs driven by the requirement of the state of California that load-serving entities implement the state's 33 percent RPS, which requires that 33 percent of retail energy sales be met by eligible renewable energy by 2020. This longer-term planning horizon is more consistent with the ISO's forward-looking approach for evaluating system needs and designing market products intended to send proper market signals for adequate investment in resources with operational requirements.

By comparison, the resource adequacy resource procurement examines a shorter-term set of procurement needs and does not factor in California's evolving fleet resulting from the 33 percent RPS or OTC retirement. Thus, the CPUC LTPP planning assumptions permit a more comprehensive analysis of anticipated generation needs, both in terms of examining procurement needs further into the future and of taking the 33 percent RPS into account.

Q. **Please describe the evaluations the ISO conducted of potential operational and resource capacity needs in the CPUC long-term procurement plan proceeding.**

A. To assist the CPUC in making long-term procurement decisions, the ISO conducted a preliminary study of system needs in 2020 assuming 33 percent renewable resources and presented the study results during workshops held in the summer and fall of 2010. The ISO then agreed to evaluate potential system needs using new resource portfolio assumptions developed by the CPUC energy division staff that were made available in December 2010. As the ISO incorporated the new assumptions into the study, the ISO presented results and sought feedback in workshops held in the spring of 2011. The updated ISO study results were submitted to the CPUC in testimony and supporting documentation that I provided in the long-term procurement plan proceeding in July and August 2011.[1] A copy of this CPUC testimony is provided as Attachment 1 to my declaration.

[1] *See* http://www.caiso.com/Documents/2011-08-10_ErrataLTPPTestimony_R10-05-006.pdf.

Q. What methodology did the ISO employ in performing the study submitted in the CPUC long-term procurement plan proceeding?

A. The ISO's evaluation of 2020 system needs employed an industry state-of-the-art methodology developed over four years in collaboration with industry experts. The study methodology is divided into various steps. In the first step, the ISO developed detailed one-minute load consumption profiles, wind power profiles, and solar production profiles for every minute of the year. The load and existing wind and solar power profiles are based on actual operational data. The wind and solar power profiles for future resources are synthesized based on location, time, resource characteristics, wind variation, and solar irradiance conditions. The profiles are then used as inputs into a statistical analysis conducted in the next step to calculate operational balancing requirements for regulation and load following. These requirements, along with hourly load and other operating reserves, are then used as inputs to the last step of running a production simulation to assess the ability of the resource fleet to simultaneously meet the hourly load, operating reserve, regulation, and intra-hour balancing requirements for each hour of the year, while respecting resources' operational characteristics and import capabilities.

Although the intra-hour balancing requirements are sometimes referred to as load following requirements, these requirements in fact reflect the flexible capacity required to be available for dispatch to balance the system differences between hourly average net load conditions and average five-minute net load conditions within an hour. Regulation is the balancing service that is responsible for balancing the difference between actual net load and the average five-minute net load.

The ISO's methodology also takes into account the MW quantity of generating capacity that is expected to retire during that time frame due to regulations implemented by the State Water Resources Control Board to curb the use of once-through cooling in coastal power plant plants. The ISO's planning assumptions reflect the State Water Resources Control Board environmental protection goal that will result in the retirement or repowering of 8,099 MW of OTC plants by 2018 and the retirement or repowering of 12,079 MW of such plants by the end of 2020.

Q. Did the ISO apply this study methodology to different scenarios established in the CPUC long-term procurement plan proceeding?

A. Yes. The ISO studied a number of scenarios for 2020 in accordance with the parameters established in the CPUC long-term procurement plan proceeding. In particular, the ISO studied a number of scenarios in the "Assigned Commissioner and Administrative Law Judge's Scoping Memo and Ruling" (Scoping Memo) issued in the long-term procurement plan proceeding in December 2010.[2]

[2] *See* http://docs.cpuc.ca.gov/EFILE/RULC/127542.htm.

Q. What is the Scoping Memo?

A. The Scoping Memo is an issuance by the Assigned Commissioner and Administrative Law Judge that set forth issues to be considered in the CPUC long-term procurement plan proceeding and established a procedural schedule for steps to be taken in that proceeding. The Scoping Memo was issued following consideration of input from CPUC staff and parties to the proceeding.[3] A copy of this Scoping Memo is provided as Attachment 2 to this declaration.

Q. What scenarios included in the Scoping Memo did the ISO study?

A. Due to the CPUC's procedural schedule in the long-term procurement plan proceeding, the CPUC prioritized and the ISO agreed to study four out of a total of seven CPUC-defined scenarios with different renewable build-out assumptions to achieve the 33 percent RPS. Those four scenarios share the same load assumption of more than 10,000 MW of load reduction as compared to what would have been the load based on the latest projections of expected load growth provided by the California Energy Commission. The resultant ISO forecast peak demand in 2020 for these scenarios is a peak load level of approximately 45,000 MW (net of expected energy efficiency, demand response, and combined heat and power), which is lower than the ISO historical peak load level of 50,270

[3] *See* http://docs.cpuc.ca.gov/EFILE/RULC/127542.htm.

MW in 2006, the ISO peak load level of 47,350 MW in 2010, and even the ISO peak load level of 45,545 MW in 2011 that occurred in the midst of a recession and during a mild summer. The ISO also studied a fifth CPUC-defined scenario in order to establish a range of analyses which is more reflective of a combination of future uncertainties that should be considered for its study results of system reliability needs. As explained above, I will refer to this scenario as the "operations planning scenario" in my declaration.

Q. **In what ways is the operations planning scenario more reflective of the combination of future uncertainties regarding system reliability needs?**

A. The operations planning scenario assumes 10 percent higher peak load than the other four scenarios to reflect any combination of future uncertainties, including the possibility that load in 2020 would continue to be closer to the historical peak load level. This results in a forecasted peak ISO demand under the operations planning scenario of 50,672 MW for 2020 and 50,881 MW for 2018 (again, net of expected energy efficiency, demand response, and combined heat and power). The operations planning scenario also includes over 5,100 MW of demand response and over 5,600 MW of incremental uncommitted energy efficiency programs. As such, although the operations planning scenario is more conservative in certain respects than other scenarios, this scenario continues to reflect substantial growth in both demand response and energy efficiency programs over current system conditions. For 2012 the total expected demand response expected for July is approximately 2,600 MW. Expected incremental energy efficiency for 2012 is a total of 192 MW for the combined investor-owned utility areas. The ISO's study of the need for the Sutter plant in July 2018 used assumptions from the operations planning scenario and therefore more than tripled demand response and energy efficiency as compared to existing programs. Thus, the study results based on the operations planning scenario reflect that these higher levels of demand response and energy efficiency are relied upon to meet system needs during the most constrained conditions. As discussed later in my declaration, the identification of a capacity gap under the operations planning scenario studied by the ISO is mirrored in studies issued by the investor-owned utilities in the long-term procurement plan proceeding that also show a gap in the capacity required to meet system-wide needs in California by the end of the planning horizon in 2020.

Q. Is the CPUC long-term procurement plan proceeding study an appropriate type of study to be used as the basis for the ISO's analysis of the need for the Sutter plant?

A. Yes. Section 7.3.5.2 of the Business Practice Manual for Reliability Requirements states that the ISO's analysis will consist of one of several listed types of studies that include a production simulation. The ISO's analysis in this case consisted of a multi-step process that included quantification of the expected flexibility requirements to meet load and supply variability and uncertainty and an assessment of the fleet of resources expected to be available to simultaneously meet the load plus operating reserve requirements, plus flexibility using a production simulation conducted in accordance with the study assumptions and scope of study established by the CPUC long-term procurement plan proceeding, with certain adjustments.

Q. Which one of the CPUC long-term procurement plan proceeding scenarios that you have described did the ISO use in its analysis of the Sutter plant?

A. The ISO based its analysis of the potential need for the Sutter plant on the operations planning scenario from the CPUC proceeding.

Q. Why did the ISO base its analysis on the operations planning scenario?

A. When considering issues of system reliability, it is generally appropriate to apply a conservative approach. The ISO concluded that good utility practice best supported the use of a reliability study that is more reflective of a combination of future uncertainties for its Sutter analysis. The operations planning scenario, which is intended to reflect future uncertainties in forecast demand due primarily to potential for higher load growth, provides the basis for the most credible analysis available to the ISO of longer-term system needs. The ISO determined that use of this operations planning scenario is appropriate because it reflects plausible uncertainties in future load conditions consistent with CPUC assumptions. Indeed, the other scenarios studied by the ISO in the long-term procurement plan proceeding all included load assumptions that are less than historical peak system load and peak load in recent years.

In this regard, the CPUC Scoping Memo (at 22) directed that, “[i]n the sensitivity analysis for demand levels for both gigawatt hour (GWh) and MW, the IOUs [investor-owned utilities] shall use high and low demand levels that reflect a 10% variance from the demand forecast value for each year. This value is reflective of any combination of future uncertainties (e.g., increased or decreased load growth or programmatic performance).” Thus, the Scoping Memo required the investor-owned utilities to conduct their sensitivity analyses in the long-term procurement plan proceeding for demand levels using the operations planning scenario. For the same reasons, it was also appropriate for the ISO to use the operations planning scenario in its analysis regarding the Sutter plant. While load forecast and other assumptions may vary over time, the ISO must plan and account for probable scenarios in its backstop procurement of capacity to ensure reliable operations of the ISO grid. This planning assumption also reflects the most up-to-date assumptions regarding renewable resource scenarios and expectations about existing resources, including OTC retirement. The Sutter plant is an existing resource not subject to OTC retirement and was assumed to remain as an available resource as part of the planning assumptions in the CPUC long-term procurement plan proceeding.

Q. Are there other analyses submitted in the long-term procurement plan proceeding that produced results comparable to the ISO's study results under the operations planning scenario?

A. Yes. On July 1, 2011, Southern California Edison Company, Pacific Gas and Electric Company, and San Diego Gas and Electric Company (collectively the investor-owned utilities) submitted their "Joint Investor Owned Utilities Supporting Testimony" in the long-term procurement plan proceeding.[4] The investor-owned utilities' studies utilized higher load assumptions in their "IOU Common Assumptions" than did the four scenarios from the Scoping Memo studied by the ISO other than the operations planning scenario. At page 2-2 of their joint testimony, the investor-owned utilities explained that "the IOUs modified some variables in the input databases to reflect alternative assumptions that align with the IOUs' expectations, including a higher load forecast and an updated renewable generation build-out." The summary of the investor-owned utilities' "Joint Analysis" provided in Table 3-1 of their joint testimony shows needs for combustion turbine resources by 2020 of as much as

[4] See http://www.cpuc.ca.gov/NR/rdonlyres/070BF372-82B0-4E2B-90B6-0B7BF85D20E6/0/JointIOULTPP_TrackI_JointIOUTestimony.pdf.

8,200 MW in a temperature peak sensitivity analysis. A summary of the differences in assumptions is provided in testimony submitted on behalf of the IOUs in the long-term procurement plan proceeding.[5] In this analysis, even when the investor-owned utilities accounted for 2,000 MW of additional local resources, they identified residual needs for combustion turbine resources of 1,700 MW by 2020. The IOU Common Assumptions and the joint analysis of the investor-owned utilities also assumed that the Sutter plant would be available through 2020. Thus, the joint analysis of the investor-owned utilities in the long-term procurement plan proceeding also shows a significant gap in the capacity needed to meet system-wide requirements in California by the end of the planning horizon in 2020, even before one factors in the potential retirement of the Sutter plant.

Q. Are there other reasons why the ISO concluded it was reasonable to base its Sutter analysis on the operations planning scenario?

A. Under an operations planning scenario that anticipates increased economic productivity and higher energy usage, it is also reasonable to assume that load levels will remain closer to or above current system conditions. This is appropriate given that the assumed 5,600 MW of incremental energy efficiency under the operations planning scenario is

[5] *See* http://www.google.com/url?q=http://www.cpuc.ca.gov/NR/rdonlyres/174CF631-3B79-4AD8-8685-A0FD1BB30547/0/E3_testimony_LTPP2010OIRTI_DR_ED_IOUPGE005Q01Atch01.docx&sa=U&ei=Gz0XT7vnNoqciQL_gO3XCw&ved=0CBAQFjAG&client=internal-uds-cse&usg=AFQjCNHCd5oUJqAi1HAeqdNXYNfnmj1VdQ (testimony of Arne Olson, Energy and Environmental Economics, Inc., on behalf of the IOUs) (July 1, 2011).

based on uncommitted energy efficiency programs. While the ISO cannot predict the future, it is prudent in utility practice to plan for contingencies and scenarios that may require greater investments now to ensure adequate operational flexibility to meet load reliably and efficiently in the future.

In these circumstances, there is asymmetric risk of being wrong. In other words, while there is a cost for additional certainty that sufficient capability exists to balance the system over a range of conditions, the cost and potential disruption of electricity has significantly more impact in the event that prudent measures are not taken.

Faced with the risk of retirement of the Sutter plant, it is important to consider the long-term potential impact on the system at this important juncture of changing composition of resources on the grid. Higher expected load, combined with the changes in the flexibility characteristics of the fleet in the future as I discuss further below, creates significant risks for meeting load reliably. Therefore, it is more prudent to plan the ISO system with these conservative assumptions, which result in higher expected demand and generation needs. Also, it is important to note that the ISO is not proposing to procure the Sutter plant every year through 2018 but rather the ISO proposes to procure the Sutter plant only during the 2012 resource adequacy compliance year. Going forward beyond

2012, the ISO will incorporate new information, as it becomes available, into future studies, and reassess the need for generating resources such as Sutter.

This year, the ISO intends to develop and propose tariff provisions that would allow the ISO to procure, in the current resource adequacy compliance year, resources that the ISO determines are needed two or more years out into the future. Under these tariff provisions, the ISO anticipates that it will have to re-evaluate the need for the Sutter plant in each subsequent year and determine whether there are other resources that can meet any demonstrated need at the time of the evaluation, thereby obviating the need to procure the Sutter plant. Use of a more conservative approach is particularly justified under these circumstances, especially where the ISO is seeking to avoid the untenable situation where a resource turns out to be needed, but it retired years earlier, because the ISO and market participants were too shortsighted to procure it then and keep it available.

Q. Are the assumptions about resource additions and retirements in the ISO's Sutter analysis corroborated by other entities?

A. Yes. The Scoping Memo included assumptions regarding planned additions and retirements. In particular, system resource additions are considered "Known or High Probability" if they have CPUC-approved contracts in place, have been permitted, and are under construction. As an alternative, the Scoping Memo also treated as high probability those projects outside of an investor-owned utility with an approved Application for Construction (AFC). “Utility Probable Planned Additions” are additions with CPUC-approved contracts in place where the resources have not yet begun construction, or additions with an approved AFC. ”Other Planned Additions” are resources with CPUC-approved contracts, but that currently do not have approved AFC permits. The Scoping Memo specified an approach to plant retirement assumptions for required scenarios in the investor-owned utilities’ resource plans, consistent with implementation of the state’s OTC policy. The CPUC Scoping Memo also made certain assumptions about economic non-OTC retirements. Notably, the Sutter plant was not one of the resources assumed to retire. All resource additions and retirements in this analysis are based on a reasonable forecast, but are only an estimate of what resources may come on- or off-line during the planning horizon established in the long-term procurement plan proceeding. All of the planned additions included in the CPUC categories were also included in the studies conducted by the ISO, which assumed a minimum requirement that the resources had CPUC-approved contracts in place.

Q. Given the large number of generation interconnection requests in the ISO queue, why was it appropriate to base the analysis of the need

for the Sutter plant on generation addition assumptions based on the Scoping Memo?

A. Based on its experience, the ISO has concluded that these assumptions about expected generation additions are appropriate, consistent with a conservative approach to analyzing reliability impacts. The ISO's experience, particularly in recent years, has been that the level of proposed generation projects that submit interconnection requests substantially exceeds the level of generation that will actually be placed in service. Indeed, significant risk awaits a project beyond the ISOs interconnection queue. Each project will need to meet all federal and state environmental permitting requirements and successfully reach terms with a load serving entity that are acceptable to appropriate regulatory authority and financing entities. Therefore, not every generator that signs an interconnection agreement will be placed into commercial operation.

Q. Did the ISO's analysis in the long-term procurement plan proceeding deviate from the Scoping Memo planning assumptions in some respects?

A. Yes. As noted in the ISO's testimony in the long-term procurement plan proceeding, there are a few situations where the ISO has deviated from the Scoping Memo planning assumptions based on later developments. Specifically, the Coolwater 3 and 4 units were assumed to be retired in the planning assumptions, but, based on the best information available to the

ISO at the time it prepared its 2020 study, no retirement of Coolwater 3 and 4 is expected in the planning horizon.

Q. Is the ISO's determination of need for the Sutter plant based on the ISO's 2020 study?

A. No. The ISO evaluated the need for the Sutter plant based on the results of the 2020 study but made some changes to the assumptions in the 2020 study to determine how soon the resource will be needed.

Q. Why did the ISO evaluate the need for the Sutter plant by 2018?

A. The ISO's 2020 study indicated that 4,600 MW of additional resources may be needed in 2020 to offset the retirement of 12,079 MW of OTC resources. Based on the OTC retirement schedule, the ISO next determined that the end of 2017 or 2018 was the first time that the OTC retirement would exceed 4,600 MW and therefore would likely be the first time when the capacity gap previously identified by the ISO would occur.

Q. What adjustments were made to the ISO's 2020 study to evaluate the need for the Sutter plant by 2018?

A. It is important to note that the ISO's analysis of 2018 system needs was not just an interpolation of the 2020 study. While some of its assumptions are interpolated from analyses prepared for the CPUC proceeding, the

ISO's Sutter analysis is based on a full production simulation for July 2018.

First, the ISO adjusted the retirement of resources subject to the OTC regulations. It was assumed that, by 2020, 12,079 MW of capacity would be retired due to the OTC regulations. Based on information provided in the Scoping Memo, the CPUC staff assumes a plant retirement schedule that indicates that retirements due to the OTC regulations will amount to 8,099 MW by the end of 2017. An additional 3,980 MW of retirement will occur between the end of 2017 and 2020. The ISO calculated the 3,980 MW amount based on the difference between the expected retirement or repowering of 8,099 MW of OTC plant by 2018 and 12,079 MW of OTC plant by 2020 (12,079 MW – 8,099 MW = 3,980 MW). Working backwards from the 2020 results, the ISO evaluated when the retirement schedule would result in a need for the Sutter plant. The ISO's analysis used the generating resource retirement schedule from the Scoping Memo, in order to determine the extent to which there is the potential for flexible resource shortages from 2011 to 2020. In particular, the ISO's analysis took into account the MW quantity of generating capacity that is expected to be retired during that time frame due to regulations implemented by the State Water Resources Control Board to curb the use of OTC in power plants.

Q. Why is it reasonable to use that resource retirement schedule?

A. This is the best information currently available to the ISO about potential OTC retirements. While it is possible that fewer resources will retire due to OTC requirements, use of this schedule is consistent with a conservative approach to evaluating the reliability impacts of retirement of the Sutter plant. Indeed, because this schedule does not reflect the significant possibility of additional retirements of non-OTC units over the planning horizon due to economic considerations, the schedule used by the ISO in its analysis is far from a "worst case" assumption.

Q. What other assumptions from the 2020 study did you modify in evaluating the need for the Sutter plant?

A. The ISO also adjusted renewable supply to reflect 2018 capacity levels. In the 2020 study, there is an assumption that 33 percent of the ISO energy supply will be sourced from renewable resources. That amounts to 15,670 MW of capacity. Based on the Scoping Memo assumptions, the 2,000 MW of additional renewable capacity between 2018 and 2020 is primarily comprised of an approximately 1,100 MW (25 percent) reduction of new solar thermal resources and a 700 MW (84 percent) reduction of new geothermal resources from 2020 levels. Therefore, to reflect 2018 conditions, the energy produced from new solar resources was reduced by 25 percent and the energy produced from new geothermal resources was reduced by 84 percent from the 2020 levels.

Q. What specific characteristics of the Sutter plant did the ISO's analysis take into account?

A. The 2020 production study on which the ISO's 2018 study is based incorporates the operational characteristics of supply resources as reflected in the Western Systems Coordinating Council Transmission Expansion Planning Policy Committee base case. The Sutter plant can be dispatched by the ISO and has relatively fast start and has a relatively fast ramping capability that allows discrete portions of its capacity to be dispatched as needed to satisfy demand. These operating characteristics were considered in the production analysis, which evaluates the operational requirements of the ISO controlled grid based on operational characteristics of the available fleet of resources. This means that the study results are based on the actual characteristics that the resources can provide.

Q. Is the ISO in the process of conducting an updated study using the CPUC long-term procurement plan proceeding scenarios?

A. Yes. The ISO is conducting an updated study for submission in the CPUC long-term procurement plan proceeding but does not anticipate that the updated study will be completed until at least March 31, 2012. Calpine, the owner of the Sutter plant, has stated that, without a capacity procurement mechanism designation or comparable capacity payment, the Sutter plant may retire as soon as May 2012. In order to obtain necessary Commission authorization through this waiver petition prior to the pending retirement, the ISO concluded it must file this petition by January 2012. Therefore, the ISO is unable to incorporate the results of the updated study into the ISO's analysis regarding the need for the Sutter plant.

Q. What other factual circumstances and requirements did the ISO's analysis take into account?

A. Pursuant to the requirements of Section 7.3.5.2 of the Business Practice Manual for Reliability Requirements, the study methodology used in the ISO's 2020 studies evaluated the adverse effects on the transmission system as well as operational flexibility requirements, and also considered the characteristics of the individual resources in the fleet and was able to highlight resources that are needed for locational and system reliability or have non-generic resource flexibility required to operate the integrated grid and that have not been secured through the procurement process. The ISO's methodology embodied an evaluation of operational flexibility requirements with consideration of the specific operating characteristics of the Sutter plant and how that plant is needed for system reliability.

Q. Did the ISO re-run the production studies using the adjustments in the assumptions you describe above?

A. Yes. Although the ISO did not conduct a full-year, hourly interval production simulation analysis as was performed for the 2020 cases in the CPUC long-term procurement plan proceeding, a rerun of the production simulation for July 2018 was performed incorporating the adjustments in assumptions described above to reflect 2018 conditions.

III. Results of the ISO's Analysis Regarding the Need for the Sutter Plant for Reliability Purposes

Q. What does the ISO's analysis conclude regarding the need for the Sutter plant?

A. As I will explain, the ISO's analysis concludes that, under an analysis using the assumptions described above consistent with good utility practice, there will be a shortage or gap of 3,570 MW for meeting system-wide capacity needs in California by the end of 2017. This shortage would pose significant challenges to the reliable operation of the ISO grid. The results of the ISO's analysis are provided in Table 1 below, which compares the load, supply, and resource flexibility needs in California for the 2018 and 2020 cases relevant to the ISO's analysis:

Table 1

	Case Assumptions			Differences	
CPUC-LTPP High Load Scenario	2020 LTPP Assumptions (MW)	2018 Sensitivity (Developed from 2020 Case) (MW)	2018 LTPP Assumptions (MW)	2018 Senstivity- 2018 LTPP Assumptions (MW)	2020 LTPP- 2018 Senstivity (MW)
Demand					
CAISO Demand Forecast	62,324	62,324	60,754	1,570	-
Incremental Energy Efficiency (EE)	5,688	5,688	4,167	1,521	-
Load Net EE	56,636	56,636	56,587	49	-
Demand Response (DR)	5,145	5,145	5,051	94	-
Demand Side CHP	819	819	655	164	-
Load net (EE, DR, CHP)	50,672	50,672	50,881	(209)	-
Supply					
OTC	19,292	19,292	19,292	-	-
OTC Retirement	12,079	8,099	8,099	-	3,980
OTC Net OTC Retirements	7,213	11,193	11,193	-	(3,980)
RPS Additions (Note 1)	6,049	Note 1 4,118	4,118	-	1,931
Other Additions	2,797	2,797	2,797	-	-
Total Supply	16,059	18,108	18,108	-	(2,049)
Flexibility					
HE15 Load Following Requirements	2,935	2,827	N/A	N/A	108
Upward A/S and load following shortages	Note 3 3,266	2,535	N/A	N/A	731
Need (Note 2)	4,600	Note 2 3,570	N/A	N/A	1,030

Note 1: Renewable production in 2020 scenario was adjusted to reflct expected 2018 RPS capacity

Note 2: The need of in the 2018 senstivity was estimated based on the quantity of shortage observed and 2020 observed shortages and needs (2,535MW x 4,600MW/3,266MW = 3,570MW)

Note 3: 2020 shortages occur both load following and non-spin

Q. What did the ISO's analysis regarding the Sutter plant indicate as to expected plant retirements in the 2017/2018 time frame?

A. Based on information provided in the Scoping Memo, it is expected that plant retirements due to the OTC regulations will amount to 8,099 MW by the end of 2017. (See the row in Table 1 above entitled "OTC Retirement," at the columns entitled "2018 Sensitivity (Developed from 2020 Case)" and "2018 LTPP Assumptions.") The Sutter plant is air-cooled and therefore will not be retired due to the OTC regulations issued by the State Water Resources Control Board. An additional 3,980 MW of plant retirements will occur from the end of 2017 to 2020. The ISO calculated this 3,980 MW amount based on the difference between the expected retirement or repowering of 8,099 MW of OTC plant by 2018 and 12,079 MW of OTC plant by 2020 (12,079 MW – 8,099 MW = 3,980 MW). (See the rows in Table 1 above entitled "OTC Retirement" and "OTC Net OTC Retirements," at the column entitled "2020 LTPP – 2018 Sensitivity.")

Q. What did the ISO's analysis indicate regarding the need for new capacity in addition to expected plant additions?

A. The ISO's analysis indicates that the need for new capacity in addition to expected resource additions will be 4,600 MW by 2020. (See the row in Table 1 above entitled "Need," at the column entitled "2020 LTPP Assumptions.") To project the needs for the 2017/2018 period, the 3,980 MW of capacity I discussed earlier was added to the original 2020 operations planning scenario to reflect the OTC resources that will not be retired by the end of 2017. Load was not adjusted as the forecast load in 2018 and forecast load in 2020 remains almost the same due to an assumption that projected load growth will be offset by increased energy efficiency, demand response, and demand combined heat and power resources.

Q. Is there any additional new capacity with the needed flexibility that is expected to come on-line in time to meet the identified need?

A. No. As discussed above, the 2020 study and the 2018 sensitivity analysis incorporate the generation expected to come on-line consistent with planning assumptions in the long-term procurement plan proceeding. Pursuant to these planning assumptions, the ISO's studies assume that all generators that have signed CPUC-approved contracts where the resources have not yet begun construction or additions approved for siting will thus be available. Therefore, one can conclude there is no additional new capacity with the needed flexibility that the ISO can assume will come on-line in time to meet the capacity need identified by the ISO. As a result, the retirement of any existing capacity that embodies the required flexible characteristics would pose a significant risk to the reliability of the ISO grid.

Q. Does the Sutter plant provide needed flexibility to meet the capacity need identified by the ISO?

A. Yes. The Sutter plant was observed to provide energy, operating reserves, and flexibility in the ISO's July 2018 production simulation. In this regard, the Sutter plant was observed to have a 69.91 percent capacity factor. The relatively high capacity reflects that the Sutter resource was needed to meet load and or be online providing operational flexibility for a significant amount of the study period. This is further supported by the observation that the resource provided 280.89 GWh of energy, 8.86 GWh of Spinning Reserve, 0.36 GWh of Non-Spinning

Reserve, 5.20 GWh of Regulation, 30.84 GWh of load following up, and 64.38 GWh of load following down. The Sutter resource is particularly attractive to the ISO because its flexible nature makes it valuable in serving demand in the real-time. The Sutter resource also has automatic generation control capability, allowing it to provide Regulation service. Overall, the Sutter plant is among the most flexible resources serving needs in the ISO balancing authority area today.

Moreover, the Sutter plant is an air-cooled power plant with 525 MW of installed capacity that is not subject to the OTC regulations. This means there is no risk that the Sutter resource will be gone in 2018 due to the OTC regulations. Therefore, the ISO can count on having the Sutter plant available to meet reliability needs but for the risk of retirement of that plant.

Q. Did the ISO's analysis include any adjustments regarding supply?

A. Other than the adjustments discussed above, including adjustments made for OTC resources expected to be available in 2018, no other supply adjustments were made to the 2020 operations planning scenario. As I have explained, renewable supply was adjusted to reflect anticipated 2018 renewable capacity levels.

Q. Were any resources assumed to be added to meet local reliability requirements as a result of OTC retirement?

A. The ISO had preliminarily identified a need of approximately 2,000 MW of replacement generation in the Los Angeles Basin to meet local reliability needs based on OTC retirements. More recently, the ISO has prepared updated local capacity study results for 2021. These results do indicate higher local resource needs than the previous 2,000 MW, including 2,370 MW of local resource needs in the Los Angeles Basin.[6] However, these resource needs do not appear until 2021. No local resources have been assumed to be added by 2018 to satisfy such local capacity requirements, because by 2018 there will be 3,980 MW of unretired OTC resources. All of that unretired OTC generation will reside in the Southern California Edison Company service area. Therefore, the unretired OTC resources are assumed to satisfy local capacity requirements in the 2018 time frame and thus no additional local capacity resources were assumed by 2018. Consistent with the CPUC planning assumptions for the 2020 simulations, the Sutter plant, which consists of 525 MW of installed capacity, was assumed to be available in the 2018 case.

6 *See Once-Through Cooling & AB1318 Study Results* at Slide 11 (page 148 of the combined presentations document). The combined presentations document containing this presentation is available on the ISO website at http://www.caiso.com/Documents/Presentation%20-%2020112012_TransmissionPlanningProcessDec8_2011.pdf.

Q. Based on the study assumptions you have described, what did the ISO determine about a potential retirement of the Sutter plant in 2012?

A. The ISO's analysis identified a 2,535 MW deficiency in flexible capacity requirements, resulting in an estimated 3,570 MW of additional capacity needs. (See the rows in Table 1 above entitled "Upward A/S and load following shortages" and "Need," at the column entitled "2018 Sensitivity (Developed from 2020 Case).") The removal of 525 MW capacity of capacity identified as needed by the analysis – *i.e.*, the maximum net qualifying capacity of the Sutter plant – would exacerbate reliability and operational issues on the ISO grid and would be reflected as additional needs to the identified 3,570 MW as early as the end of 2017. Thus, there will be a need for additional capacity as early as the end of 2017. The absence of the Sutter plant would increase the amount of needed flexible capacity for the 2018 case.

Q. Did the ISO also consider whether additional generation with the needed operational flexibility could be constructed by 2017?

A. Yes. The ISO is aware of one planned resource, the Oakley unit, which was not included in the LTPP planning assumptions and therefore was not included in the ISO's analysis. This planned resource has now satisfied additional regulatory milestones and appears likely to add 623 MW of capacity by 2016. However, based on the study results, 623 MW would not be sufficient to eliminate the need for the Sutter plant based on the observed shortfalls in the 2018 scenario. Moreover, the additional generation anticipated from the Oakley unit is more than offset by greater amounts of generation that were assumed in the Scoping Memo but are now expected to be unavailable by 2018. Specifically, the Scoping Memo assumed the additions of the Avenal unit (600 MW) and potentially the Victorville Hybrid unit (563 MW), which have subsequently been determined to likely be unavailable by then. Therefore, the 2018 case actually assumed more generation than is now anticipated to be available by 2018.

Q. Did the ISO's analysis consider the up to 415 MW of potential generation that is the subject of a San Diego Gas & Electric Company application before the CPUC?

A. This proposed generation has not been the subject of a CPUC-approved contract and has not received siting approval. Because of the uncertainty about this proposed generation, it does not now satisfy the criteria established in the LTPP proceeding for inclusion in the ISO's study planning assumptions.

Q. Did the ISO consider what would occur if some of the OTC plants were repowered prior to retirement?

A. Depending on how much repowering was to occur, this in theory could offset some of the capacity gap identified by the ISO in 2018. But it would require approximately 3,570 MW of OTC repowering to eliminate the observed shortages. There is no certainty at this time that such repowering would occur by 2018.

Q. Did the ISO consider the option of allowing the Sutter plant to retire and addressing the capacity gap with either another existing resource or a new resource that could be constructed by 2018?

A. The ISO concluded that neither approach would be prudent. Since the Sutter plant is among the most flexible resources serving needs in the ISO balancing authority area today, it might take more than 525 MW of another existing resource to address the same operational needs that can be addressed by the Sutter plant. The ISO considered the possible retirement of Sutter but determined that the observed insufficiency in 2018 demonstrates that Sutter is needed.

In addition, a failure to maintain the ongoing operation of resources with operating characteristics like those of the Sutter plant that will be needed by the 2018 time frame could lead to other increased costs, such as costs associated with exceptional dispatch, increased ability to exercise market power, and even load shedding events. On the whole, given the demonstrated needs for capacity by 2018, the ISO believes the most reasonable approach is to promote the continued operation of existing flexible resources until and unless there is confidence of alternative flexible capacity being developed in a time frame that would fill the observed gap.

Q. Didn't the ISO stipulate in the long-term procurement plan proceeding that no decisions to procure new resources should be made based on the analyses conducted to date?

A. The ISO is a party to a Settlement Agreement pending CPUC approval in the long-term procurement plan proceeding.[7] A copy of this Settlement Agreement is provided as Attachment 3 to my declaration. In this agreement, the ISO did agree to stipulations recommending that no decision regarding new resource needs should be made based on the analyses conducted to date in that CPUC proceeding. Specifically, the ISO agreed that additional study work should continue before any decisions on procurement of new resources should be made in that proceeding. All of the analyses in that proceeding, however, assumed that the Sutter plant would be available, and the ISO's stipulations in that proceeding are fully consistent with the ISO's current conclusion that the Sutter plant will continue to be needed in the 2018 time frame. There is a significant difference between deciding whether and how to procure new resources and determining that existing resources will be needed based

[7] *See* http://docs.cpuc.ca.gov/efile/MOTION/140823.pdf.

on analyses demonstrating a system-wide need for flexible resources in the near future.

Q. Does the ISO anticipate that any other generation plant owner will request a CPM risk of retirement designation for its plant in 2012?

A. The ISO has no reason to expect that any other plant owner will request a CPM risk of retirement designation in 2012. The CPM provisions went into effect in April 2011, and load serving entities and suppliers made their Resource Adequacy showings in December 2011. No resource other than the Sutter plant requested a risk of retirement designation.

The ISO has conducted a review of natural gas resources within the ISO's balancing authority area that have flexible, dispatchable capacity and that have other characteristics comparable to the Sutter plant, including the ability to provide Regulation service. The vast majority of these resources have resource adequacy contracts for 2012. Of the 29,306 MW of these flexible resources (and excluding resources that are either dynamic resources or OTC resources), there are only 1,256 MW of flexible resources that have not been included in resource adequacy showings. At 525 MW, the Sutter plant represents the largest portion of this capacity. In addition, based on additional information, approximately another 500 MW of the 1,256 MW of flexible resources not making a showing in the annual showing is expected to make a showing in monthly resource adequacy showings and a further 188 MW of capacity is the subject of a contract for capacity expansion and is expected to be available over the applicable time frame. This leaves less than 50 MW of flexible, dispatchable capacity that has characteristics comparable to those of the Sutter plant. Based on this review, even if a request for risk of retirement designation was submitted to the ISO, the ISO would not expect its analysis to support a capacity procurement mechanism designation for any other resource for reasons comparable to the ISO's analysis of the Sutter plant.

Q. Thank you. I have no further questions.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

California Independent System Operator Corporation	))	Docket No. ER12-____-000

DECLARATION OF WITNESS

I, Mark A. Rothleder, declare under penalty of perjury that the statements contained in the Direct Testimony of Mark A. Rothleder on behalf of the California Independent System Operator Corporation in this proceeding are true and correct to the best of my knowledge, information, and belief.

Executed on this 25 day of January, 2012.

Mark A. Rothleder

Attachment 1

Application No.:	R.10-05-006
Exhibit No.:	
Witness:	Mark Rothleder

Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans.	)))	Rulemaking 10-05-006

TRACK I DIRECT TESTIMONY OF MARK ROTHLEDER ON BEHALF OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION (CORRECTED)

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans.	)))	Rulemaking 10-05-006

TRACK I DIRECT TESTIMONY OF MARK ROTHLEDER ON BEHALF OF THE CALIFORNIAINDEPENDENT SYSTEM OPERATOR CORPORATION

I. BACKGROUND

Q. What is your name and by whom are you employed?

A. My name is Mark A. Rothleder and I am employed by the California Independent System Operator Corporation (ISO) as Director, Market Analysis and Development.

Q. Please describe your educational and professional background.

I am the Director of Market Analysis and Development for the ISO. Prior to this role, I was a Principle Market Developer for the ISO in the lead role in the implementation of market rules and software modifications related to the ISO's Market Redesign and Technology Upgrade ("MRTU"). Since joining the ISO over ten years ago, I have worked extensively on implementing and integrating the approved market rules for California's competitive Energy and Ancillary Services markets and the rules for Congestion Management, Real-Time Economic Dispatch, and Real-Time Market Mitigation into the operations of the ISO Balancing Authority Area ("BAA"). I also have held the position of Director of Market Operations. I am a registered Professional Electrical Engineer in the state State of

California. I hold a B.S. degree in Electrical Engineering from the California State University, Sacramento. I have taken post-graduate coursework in Power System Engineering from Santa Clara University and earned a M.S. in Information Systems from the University of Phoenix. I have co-authored technical papers on aspects of the California market design in professional journals and have frequently presented to industry forums. Prior to joining the ISO in 1997, I worked for eight years in the Electric Transmission Department of Pacific Gas & Electric Company, where my responsibilities included Operations Engineering, Transmission Planning and Substation Design.

Q. **What is the purpose of your testimony?**

I will describe the results of the ISO's evaluation of potential operational and resource capacity needs driven by the state of California's requirement that load serving entities (LSEs) develop 33% renewable resource portfolios by 2020. For the purposes of this testimony, I will refer to this requirement as "33% RPS" and the ISO's study of operational requirements and market impacts at 33% RPS in 2020, using its renewable integration model, as the ISO's "33% integration study."

Q. **Why does the ISO conduct renewable integration studies?**

A. As part of the ISO's continuing effort to understand and prepare for increasing levels of renewable integration consistent with California's energy and environmental policy objectives, the ISO performs renewable integrations studies to 1) identify operational requirements necessary to support increased variability and uncertainty in supply with increasing renewable penetration; 2) assess the expected generation fleet needed to meet simultaneously both the operational requirements for renewable energy integration and the forecasted demand for energy; and 3) identify any additional operational needs for integration of renewable resources.

The ISO released a study of grid impacts associated with a 20% RPS level in 2012 on August 31, 2010.[1] In support of this renewable integration study work, the ISO produced a technical appendix[2] that explained in detail the technical methodology. Also starting in 2010, the ISO performed some preliminary studies of operational requirements and needs to meet the 33% renewable integration objective in 2020. The 33% integration study builds on the work done in the 20% RPS analysis and was intended to accomplish the following four objectives:

- Provide information for the long-term procurement docket that could be used to identify potential planning needs, costs or other options.
- Inform other CPUC and state agency regulatory decisions.
- Inform ISO transmission planning decisions regarding the need for additional infrastructure to integrate renewable resources.
- Inform the ISO in potential energy and ancillary services market enhancements for needed renewable integration capabilities.

Q. How has the ISO participated in this proceeding?

A. The preliminary 33% integration study work was performed in coordination and support of this Long Term Procurement Plans (LTPP) proceeding using assumptions from the prior LTPP assumptions (Docket No. R. 08-02-007 and predecessor dockets). In the context of this case, in 2010 the 33% study work was primarily used to familiarize parties and gain agreement regarding the renewable integration study methodology. During the third and fourth quarters of 2010, the ISO conducted Step 1 modeling and Step 2 production simulation using 2009 vintage scenarios developed by the CPUC's Energy Division (ED) staff. The ISO described its 33% integration model at a workshop on August 24, 2010; the Step 1 modeling at a workshop on October 22, 2010; and the Step 2 results at a workshop on November 30, 2010. In addition, the ISO reviewed the Lawrence Berkeley National Lab's

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[1] See *Integration of Renewable Resources-Operational Requirements and Generation Fleet Capability at 20% RPS* at http://www.caiso.com/2804/2804d036401f0.pdf

[2] Draft Technical Appendices for Renewable Integration Studies - Operational Requirements and Generation Fleet Capability http://www.caiso.com/282d/282d85c9391b0.pdf

(LBNL) report and responded to comments and questions submitted by parties to the proceeding following each workshop.

On December 3, 2010, the CPUC issued a scoping memo in which new assumptions and scenarios were identified. The ISO has now revised its 33% integration study consistent with the CPUC's new assumptions and scenarios identified in the scoping memo. At the same time, the ISO has incorporated other identified data updates and methodological refinements to the 33% integration study. The preliminary study results based on these new assumptions and scenarios were distributed to the parties in this proceeding on April 29, 2011 and presented at a May 10, 2011 workshop. Here I describe the updates and refinements to the input data and methodology used for the 33% integration study to produce final study results, including the changes made to the preliminary study results.

Q. Do the 33% integration study methodology and the renewable portfolio scenarios that the ISO studied and that you describe in your testimony provide sufficient information to make procurement and infrastructure decisions?

A. As I describe in detail in this testimony, the study results show the flexibility requirements to support a 33% RPS result in a range of possibilities, from no additional capacity needs to the need for substantial capacity additions depending on the scenario assumptions. For this reason, the ISO believes that the study results should only be used making least regrets procurement decisions considering the lead time needed for such development . The study work that the ISO will be performing this year may provide additional insights to the plausible range of resource needs under different assumptions, which can also inform incremental procurement decisions. For example, the ISO, along with the CPUC, the CEC and other agencies, is in the process of conducting power flow and stability studies to evaluate local area capacity needs created by once through cooling (OTC) environmental restrictions. These study results will likely impact capacity input assumptions for future renewable scenarios that the ISO intends to run and will make available in the next LTPP proceeding.

In future studies, assumption areas needing further validation are the levels of energy efficiency and demand response captured in some of the renewable portfolio scenarios because such levels may take many years to achieve. Forecast error improvements should also be considered in future study work.

Because of the uncertainty around many of the study assumptions, the ISO believes that infrastructure decisions regarding the resources needed to support renewable integration is best determined on an incremental basis over the course of several years. For now it is important that the programs needed to achieve the levels of energy efficiency and demand response load reduction assumptions must be put in place as soon as possible. As the OTC study results become available, decisions about repowering or new generation siting must be considered. At the same time, the ISO will be developing market rules and integration policies that will align the operational and environmental objectives.

Q. Please describe how your testimony is organized.

A. The ISO's April 29, 2011 preliminary results were provided in the form of a slide deck. Those results now have been updated to account for the changes in modeling assumptions described in the May 31, 2011 ALJ ruling on the joint motion for extension of time to file testimony, and the ISO has updated the slide deck accordingly. In addition, the ISO has added summary information about the additional sensitivity scenarios that were modeled to test the results of the four scenarios. The updated slides are attached as Exhibit 1 and I describe them in this testimony. In the sections that follow, I will describe the 33% integration study methodology, input assumptions and the CPUC's renewable scenarios, study results, and how these results can be interpreted.

II. MODELING THE REQUIRED CPUC RENEWABLE PORTFOLIO SCENARIOS AND OTHER CASES

Q. You stated that the ISO ran the 33% integration model using 2009 vintage renewable scenarios, and these results were presented during workshops in 2010. What was the ISO's role with respect to the updated renewable scenarios described in the December 3, 2010 Scoping Ruling?

A. The ISO 33% integration study was updated to reflect the latest scenario assumptions developed by the ED staff and described in the December 3, 2010 scoping ruling[3]. Seven scenarios were specified:

1. 33% Trajectory Base Load
2. 33% Environmentally Constrained
3. 33% Cost Constrained
4. 33% Time Constrained
5. 20% Trajectory
6. 33% Trajectory High Load
7. 33% Trajectory Low Load

The assumptions for load and renewable resources vary depending on the scenario. There are a set of assumed resources that are common to all scenarios. This common assumption is referred to as the "discounted core." The discounted core consists of projects with signed power purchase agreements and filed applications for major permits. As a general observation, the load assumed in the 2010 scenarios is lower than the 2009 vintage scenarios. The ISO studied five of the seven 2010 scenarios: 33% Trajectory Base Load, Environmentally Constrained, Cost Constrained, Time Constrained, and 33% Trajectory High Load. Of these five, the first four were prioritized by the CPUC and are referred to in this testimony as the four priority scenarios. The preliminary results from modeling and production simulation runs for the four priority scenarios were provided to the parties on April

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[3] http://www.cpuc.ca.gov/PUC/energy/Procurement/LTPP/LTPP2010/2010+LTPP+Tools+and+Spreadsheets.htm

29, 2011 and discussed at the workshop held on May 10, 2011. In addition to the five CPUC scenarios, the ISO also studied an "All Gas" scenario in support of development of metrics by the IOUs, and conducted a sensitivity analysis assuming all three Helms pumps are available year round. I discuss in this testimony the results of those studies.

Q. **Please provide a general description of the five scenarios and the All Gas scenario?**

A. The four priority scenarios described in the scoping memo and modeled by the ISO all have the same load assumption based on the 2009 California Energy Commission (CEC) load forecast. The priority scenarios differ with respect to the assumptions about the type and location of renewables needed to achieve 33% RPS. Of these scenarios, the Environmentally Constrained scenario relies more heavily on distributed solar (about 9000 MW), which includes small to medium sized solar photovoltaic (PV) plants selling their entire output to utilities. The Cost Constrained and Time Constrained scenarios have higher levels of out of state renewables. The fifth CPUC scenario studied, the 33% Trajectory High Load scenario, has a 10% higher load assumption than the four priority scenarios to reflect any combination of future uncertainties (*e.g.*, increased load growth and programmatic performance). The Trajectory High Load scenario also had 1,497MW of additional renewable resource versus the Trajectory Base Load scenario. Slide 5 in Exhibit 1 contains a list of the load and renewable assumptions for the five CPUC scenarios that the ISO ran. The All Gas scenario uses similar base load assumptions but does not include new renewable resources. The All Gas scenario does include existing renewables and 1750 MW of expected customer PV.

Q. **How do these scenarios differ from the 2009 vintage scenarios?**

A. The five CPUC scenarios assumed higher quantities of energy efficiency, behind the meter combined heat and power (CHP) and different assumptions about renewable portfolio build-out than the vintage scenarios. The increased energy efficiency and

CHP assumption reduce the peak load from the 70,180MW statewide peak in the vintage scenarios to a 63,755MW statewide peak for the 2010 scenarios. Slide 6 of Exhibit 1 compares assumptions between the two sets of scenarios.

Q. How did the ISO work with the utilities to model all the scenarios?

A. The ISO collaborated with the three investor-owned utilities (IOUs) - PG&E, SDG&E and SCE - and their consultant, Environmental Energy and Economics, Inc. (E3), through the working group. As I describe later in this testimony, the ISO conducted the Step 1 modeling and Step 2 production simulation for the five scenarios. Additionally, the ISO ran the All Gas scenario to support the cost metrics that E3 was retained to provide for the IOUs. E3 also assisted with reconciling the Step 2 model and the portfolio assumptions from the scoping memo.

Q. How did the ISO use the input assumptions in the December 3, 2010 Scoping Ruling (as modified in later rulings) to develop the database to run the renewables scenarios you described?

A. The ISO found that the input assumptions (or, at times, lack thereof) in the scoping memo fell into four general categories. Some of the assumptions could be used directly in developing the database. Other assumptions needed to be clarified with Energy Division staff in order to be consistent with the scoping memo. The third category consisted of input assumptions that were needed to successfully model and run the scenarios but were not in the scoping memo. Finally, some assumptions were simply incorrect and required revisions. For the last two categories, the ISO used its independent judgment and operational experience, supplemented by expertise from Nexant (the ISO's consultant), to develop the needed assumptions or to make the necessary changes.

Q. What was the basis for the changes made to the input assumptions?

A. Slides 36-39 set forth the changes to the assumptions in the scoping memo for accuracy.

Q. Did the ISO make additional input assumptions and clarifications?

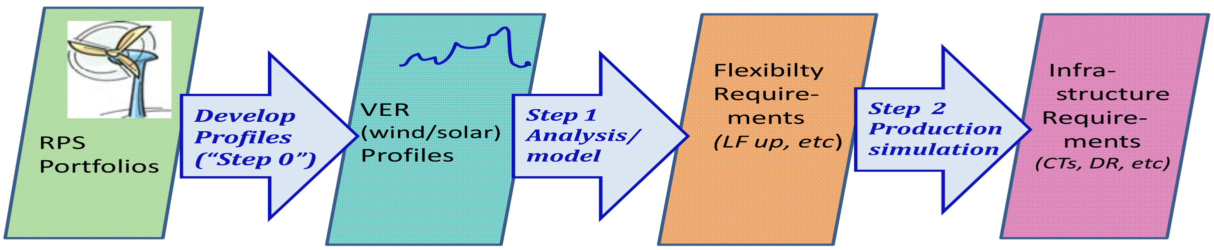
A. Yes. As I noted above, following the release of the preliminary study results on April 29, 2011, the ISO, in collaboration with the IOUs, developed a list of input assumption modifications required to finalize the studies. These assumption modifications were described in the May 31, 2011 ALJ ruling in this proceeding.

III. STUDY METHODOLOGY

Q. Can you provide an overview of the 33% integration model, and the study methodology steps followed by the ISO, to develop the results summarized in Exhibit 1?

A. Yes. The study methodology is divided into stages: Steps 0, 1 and 2, conducted by the ISO, and Step 3, undertaken by E3 and the IOUs. The first stage, Step 0, is the development of load, wind and solar profiles, based on the resource assumptions in each portfolio. The profiles are then used as inputs into the Step 1 statistical analysis to calculate regulation and load following requirements. These requirements, along with hourly load and other operating reserves, are then used as inputs to a production simulation in Step 2. Figure 1 illustrates the study process. The results of production simulation were then provided to the IOUs to develop integration metrics referred to as Step 3.

Figure 1: Renewable Integration Study Process



RPS-Renewable Portfolio Standard

VER-Variable Energy Resources

LF=Load Following

CT-Combust Turbine
DR-Demand Response

Q. What modeling tools and resources were used to conduct the study?

A. For Step 0, the ISO consulted with Nexant and used National Renewable Energy Laboratory (NREL) data and tools such as the Solar Advisory Model (SAM). To develop solar data, the ISO used 2005 Solar Anywhere satellite solar irradiance data. For the Step 1 analysis the ISO used Pacific Northwest National Laboratories' (PNNL) statistical analysis software. For Step 2, the ISO used PLEXOS Solutions production simulation package and also consulted with PLEXOS Solutions to assist in running the production simulation.

Q. How were out-of-state renewable resources considered in the study?

A. Four categories of out-of-state resources were considered: 1) 15% assumed to be import into California as a dynamic transfer, 2) 15% assumed to be import into California as a 15 minute intra-hour scheduled, 3) 40% assumed to be import into California as an hourly schedule, and 4) 30% assumed to be unbundled renewable energy credit (REC).

Q. How were the different categories of out-of-state renewable resources treated in the different steps of the study process?

A. Table 1 summarizes how the different categories were reflected in the study steps**.**

Table 1: Modeling of Out-of-State Renewable Resources

Type of Out-of-State Renewable	Step 1	Step 2	Post Processing Costs and Emissions
Dynamic Schedule/Pseudo Tie (15%)	Use 1 minute profiles as if the plant is in CA. Forecast error included.	Hourly profiled production should be modeled using import lines to carry this flow.	Zero production costs and emissions should all be attributed to CA related to imports.
15 minute intra-hour scheduled (15%)	Average 1 minute data over 15 minutes with appropriate schedule ramps. Forecast error not included.	Hourly profiled production should be modeled using import lines to carry this flow. (same as above).	Zero production costs and emissions should all be attributed to CA related to imports.
Hourly Schedule Type 2[4] (40%)	Not used in Step 1	Hourly production is modeled as if the plant's production will be injected in the bubble that the plant resides in and will have only an indirect impact on CA through any possible re-dispatch in the region the plant is located in.	Zero production costs and emissions should all be attributed to CA related to imports.
Unbundled RECs (30%)	Not used in Step 1	Hourly production is modeled as if the plant's production will be injected in the bubble that the plant resides in and will have only an indirect impact on CA through any possible re-dispatch in the region the plant is located in.	RECs should be attributed to CA. Imports would be at costs and emissions of the WECC.

[4] It is assumed that the schedule for these projects are such that the yearly production from the plant is scheduled into California without any other constraints on hourly, weekly, or monthly schedules. Within the hour balancing, and any additional balancing and shaping, is not supplied by California.

A. STEP 0 - IDENTIFYING RESOURCE CHARACTERISTICS TO BE USED IN EACH SCENARIO

Q. What is the purpose of Step 0?

A. The purpose of Step 0 profile development is to produce a series of 1 minute and hourly generation production profiles for each minute and hour of the of the year based on the resource location, quantity and a capacity factor identified in the CPUC scoping memo. The ISO has summarized the plant locations used in each CPUC scenario and capacity factors by technology in support used for this analysis at Exhibit 2 attached to this testimony. This information can also be found on the ISO website at http://www.caiso.com/23bb/23bbc01d7bd0.

Q. How did the ISO develop the Step 0 profiles?

A. As I discuss below, wind and solar 1 minute and hourly profiles were developed using different methods. In addition, the solar method was further refined to develop profiles for small-scale photovoltaic (PV), defined in the CPUC scoping memo as small distribution solar at the wholesale level. Four types of small-scale PV were specified depending on size and location: 1) large rooftop (0-2MW), 2) large ground (5-20MW), 3) mid ground (2-5MW), and 4) small ground (0-2MW). Due to the relatively small quantity and size of mid and small ground, the ISO combined the mid and small ground into the large ground profile development. The ISO modeled customer-side PV as supply in order to capture the intermittent nature of these facilities. The ISO and Nexant consulted with ED staff and E3 to clarify information provided in the scoping memo prior to developing the profiles.

Q. Please provide additional detail about how the ISO developed the Step 0 wind profiles.

A. For existing wind plant, the ISO used actual historical wind production from 2005. Aggregate data for existing wind resources is available at http://www.caiso.com/2b53/2b53c0f95d330.csv

For new wind resources, the ISO used wind generation profiles that were developed based upon NREL mesoscale wind data for 2005.[5] For new plants, wind plant production modeling was based on NREL 10 minute data production data from the year 2005 for 21 distinct locations in California and 22 distinct locations throughout the remainder of the WECC where wind plants were identified in the CPUC study scenarios.[6]

Q. What steps did the ISO take to develop profiles for new wind resources?

A. The 1 minute wind data used for all new wind plants was developed using a methodology that included the following steps or processes:

First, a representative number of plants and their geographical locations were developed, whose total capacities (MW) matched the MW in each Competitive Renewable Energy Zone (CREZ), based on the resources included in each of the scenarios developed by the CPUC. To identify the number of units and locations for the projected additions the CPUC used data from the IOU procurement processes as a starting point and generic plant information from the Renewable Energy Transmission Initiative (RETI) process and other sources. The number of plants that were ultimately used to represent the wind generation were chosen so that no one plant represented more than about 5% of the total wind generation.

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[5] Data for the year 2005 was used in the ISO 33% RPS Studies because 2005 was designated as a normal hydro year. Thus load, wind, solar and hydro run of river profiles were based on conditions (wind speeds, solar irradiance, and hydro flows) that existed in 2005.

[6] NREL production data is based upon a wind farm using Vestas V-90 3 MW generators.

Second, geographic information system (GIS) software was used to find one or more appropriate NREL data sites for each CREZ to represent wind plants in that CREZ . Multiple NREL data sets within a CREZ were used to capture the diversity within a CREZ where there were multiple plants within a CREZ in the study definition. In selecting the NREL points to use from among the many NREL mesoscale points available, wind sites that represented likely sites for wind farms (ridge location, etc.) and that had capacity factors that were as close as possible to the plants specified in the scenario definitions were carefully selected.

Third, the 10 minute production data sets for the selected sites were downloaded from the NREL website. These data sets were then shifted in time to Pacific Standard Time and then the days of the week were shifted to match the days of the week for the study year – 2020. Fourth, necessary if there were any capacity factors that did not closely match the study definition plant capacity factors, the resulting data was adjusted as necessary. These adjustments were minimal since the data sets were chosen to closely match the desired capacity factors.

Fifth, the 10 minute production data for each site was curve fit with a cubic spline curve fit function to produce 1 minute data without 1 minute variability.

Sixth, a statistical model was developed using historical ISO data from several existing wind farms to capture the 1 minute variability (compared to a 10 minute average) as a function of the size of the plant/wind farm. This statistical model captures the standard deviation of the 1 minute variability as it varies with wind farm size.

Finally, using this 1 minute statistical model, variability was then added to each 1 minute splined set of data using a process that adds variability randomly as a function of the wind farm size. The final data set of 1 minute wind farm data for each plant, which includes 1 minute variability, was then used for the Step 1 statistical model to determine operational regulation and load following requirements. The hourly wind generation profiles were developed by averaging the 60 - 1 minute production data over each hour of the year.

Q. How did the ISO develop the Step 0 profiles for solar resources?

A. The solar profiles were developed based on upon satellite irradiation data. The 1 minute solar data used for all new large solar plants was developed using a methodology that includes the following steps or processes:

First, a representative number of plants and their geographical orientation were developed whose totals match the technology and number of megawatts in each CREZ[7] in the CPUC study definition. The process to identify the number of units, types, and locations for the projected additions uses as a starting point the renewable additions identified as per the renewable portfolios being modeled and assumptions about the renewable net short. Similar to wind, solar plants have a maximum size to ensure that no single profile represented more than 10% of the total solar generation to capture diversity properly.

Second, selected representative half-hourly satellite solar irradiance data points available in the 2005 Solar Anywhere solar data set were identified for each plant to be modeled. Table 2, below, shows the number of square miles of land needed by a solar plant that produces from 60-80 MWs, depending on the technology and location. Thus for a plant of 140 MWs two 1 km square areas that are adjacent to each other would be selected from the Solar Anywhere irradiance data set.

[7] Used solar CREZ info from RETI study http://www.energy.ca.gov/reti/documents/index.html

Table 2: Plant Area by Technology

Plant Technology	Area Required in Square Miles for 10 MW Facility
Solar Thermal	0.0855 Square Miles[8]
Solar PV without Tracking	0.093 Square Miles
Solar PV with Tracking	0.093 Square Miles

Third, using this information about the land area needed for specific technologies, the third step was to download the half-hourly irradiance data from the Solar Anywhere[9] website for all of the 1 square kilometer areas needed to model all of the large solar plants.

Fourth, hourly production data was developed for the plant for the appropriate technology in each CREZ using hourly average Solar Anywhere irradiation data sets for 2005 for each plant as input to the NREL SAM. The SAM model was used to develop production data for six types of technologies – Solar PV with tracking, Solar PV without tracking and Solar Thermal using a Trough, Central Tower, Central Tower with Storage, or Stirling engine.

Fifth, 1 minute production data was synthesized from the plant hourly production data using a smooth cubic spline curve fitting function. This data did not yet represent the minute to minute production variability that can be present in the output of solar plants due to clouds or other factors. What it does represent is a plant that captures the hourly variation of irradiance over its full plant footprint.

Sixth, Clear Sky profiles were developed for each plant by calculating the maximum production for each hour for each month under clear skies (without clouds, fog, or

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[8] Average of solar thermal tower and trough technology.
[9] The Solar Anywhere satellite solar irradiance data can be found at: https://www.solaranywhere.com/Public/About.aspx

other factors that would reduce the amount of irradiance that falls on earth's surface).

Seventh, variability was introduced into the smoothed 1 minute plant production data using a process that inserted the variability captured from historical 1 minute irradiance data from measurements collected by NREL's Measurement and Instrumentation Data Center (MIDC)[10] at the SMUD Anatolia site in Rancho Cordova, CA, Loyola Marymount University in Los Angeles, and the SolarCAT station in Phoenix, AZ. At this stage in the process, the 1 minute data captures the variability of a plant that occupies the full plant footprint. This step is discussed in more detail below.

Eighth, to reflect the fact that certain technologies have inherent time delays in their response to changes in irradiance, the data described in step 7 was processed in an inertial delay algorithm to arrive at the final 1 minute production data. This step was applied only to solar thermal plants as it is believed that solar PV plants have negligible time delay in their response to changes in irradiance. For the three types of solar thermal technologies (trough, tower and Stirling) three different characteristics were used as shown in Figure 22.

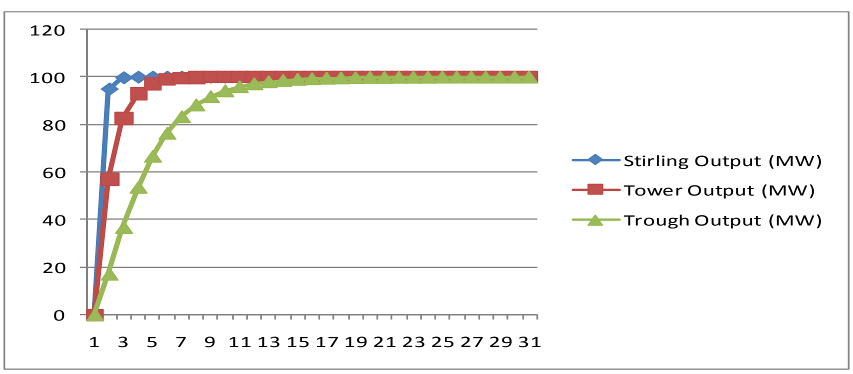


Figure 2: Response to Step Increase in Irradiance by Solar Thermal Technology v, Time in Minutes

[10] www.nrel.gov/midc

Q. Please provide additional detail about how the variability was introduced into the Step 0 solar profiles.

A. One minute variability is introduced into the smoothed 1 minute production data in Step 7 above. This step in turn is made up of several steps.

First, a Data Library was developed of 1 minute variability from historical 1 minute irradiance data collected by Sacramento Municipal Utility District (SMUD) in Sacramento, Loyola Marymount University in Los Angeles, and the SolarCAT in Phoenix, AZ. A summary plot of the raw historical irradiance data (in W/M^2) for the Sacramento sites for a single month is shown in Figure 3.

Second, this 1 minute data was converted to a normalized derate value by dividing the 1 minute actual irradiance data by the irradiance measurement that would have existed had there been no clouds in that minute (clear sky). The resulting data was a set of 1 minute historical per unit irradiance derate values that ranged from 0 to 1.0, with 0 representing full reduction from a clear sky level to a zero irradiance level and 1.0 representing no reduction from a clear sky level. Six different sets of this 1 minute derate data were developed for solar thermal and solar PV for the various sizes of plants (number of 1 kilometer squares in the plants footprint). A moving average was applied to each of the libraries, based on the number of 1km irradiance grids, to represent the 1 minute variability over the full footprint of the plant. Thus six libraries are developed for use in the subsequent steps.

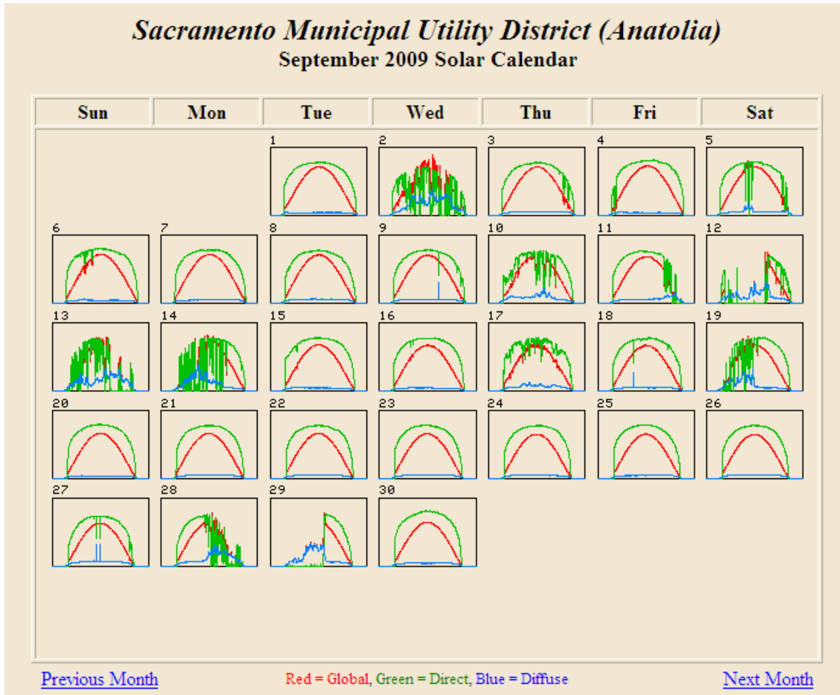


Figure 3: SMUD 1 Minute Irradiance Data for September 2009

The data plotted in the diagrams in Figure 3demonstrates that some days have little variability and other days have significant variability. Figure 4 shows the variability of a single day.

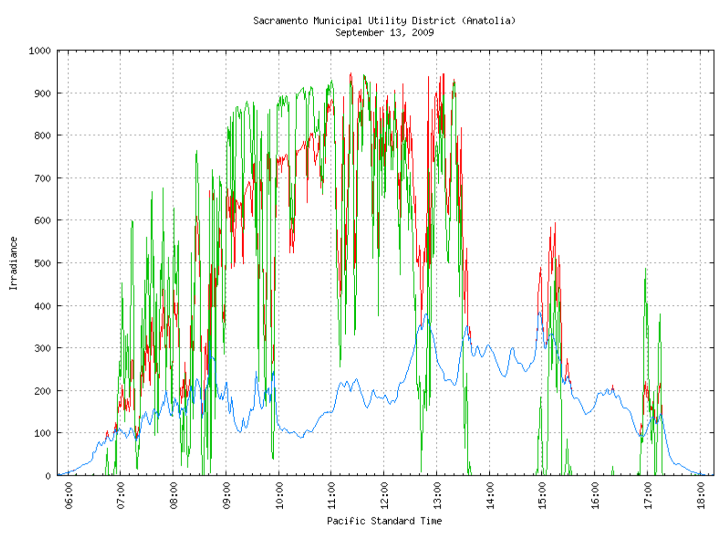


Figure 4: 1 Minute Irradiance for September 13, 2009

To capture the fact that some hours are cloudless and other hours have clouds which reduce the irradiance below its clear or cloudless sky level, variability was added to only those hours of production which show cloud cover impacts. The process first converted the 1 minute smoothed production data for the plant into 1 minute derate values that ranged from 0 to 1.0 similar to the 1 minute derate values in the irradiance data library discussed earlier. This was accomplished by dividing the smoothed 1 minute generation by the 1 minute generation that would have been produced if there were no clouds in that minute (clear sky).

Next, average production derate values were calculated on an hourly basis from the 1 minute derate values. Then for each hour of the year that had a derate value lower than 0.95, the 1 minute production derate values were replaced by an hour of irradiance derate values from the library developed that had the same hourly derate value. Which of the six libraries was used for this substitution depended on the plant size (number of 1 Kilometer squares in the plant footprint). This step added variability based upon historical data to the 1 minute production derate values while maintaining the average derate over the hour at the same level as in the production data.

Q. Did the ISO validate the variability results before finalizing the solar profiles?

Yes, we performed the following checks:

- To ensure that there were no significant step changes caused by the derate data substitution, the start minute and end minute derate values were tested to make sure they were within 1% of the minute before and the minute after the starting and ending minutes, respectively.

- To ensure that historical data was as representative as possible, substitution data was required to come from hours in the library that were within +/- 2 hours. For example, afternoon variability would not be applied to morning hours.

- To increase the number of library “hours” available for substitution, sets of 60 1 minute values (library hours) were created by shifting the start of the 60 minute period by 1 minute. For example, data from 2 hours could be used to construct 60 library hours.

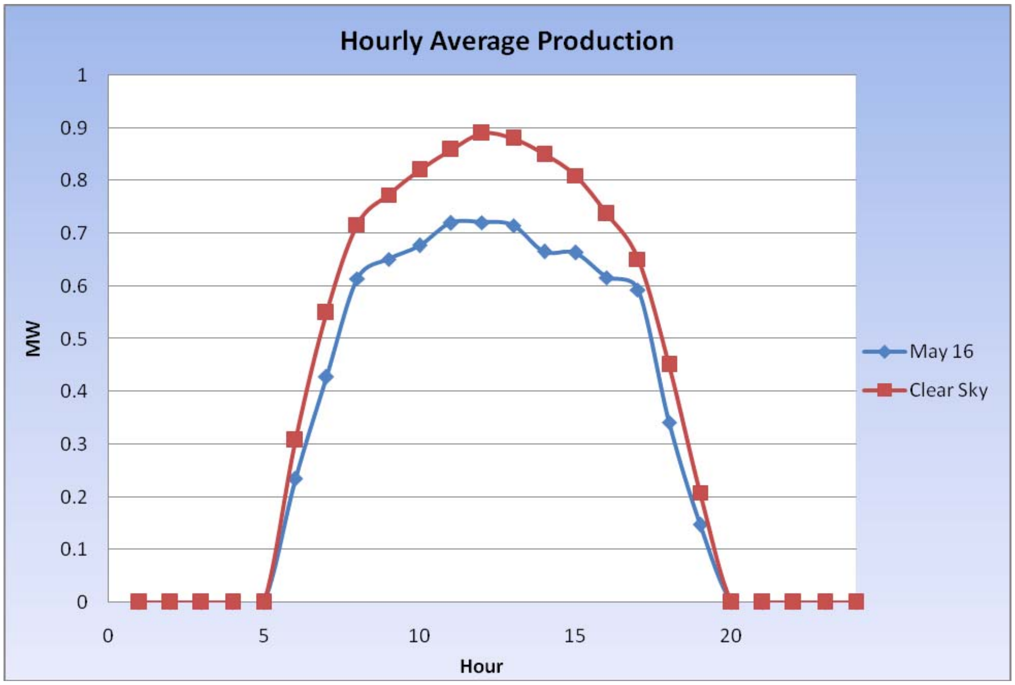
- To ensure that a bias was not introduced in the substitution process, a random selection process was used to find the derate data that met the end effects tolerances. This hourly process proceeded through the entire year to develop a full year of 1 minute production derate values.

Q. What was the final step in developing the variability results?

A. The final step converted the derate values into 1 minute production values by multiplying the derate values by the 1 minute production expected from a plant under clear sky conditions.

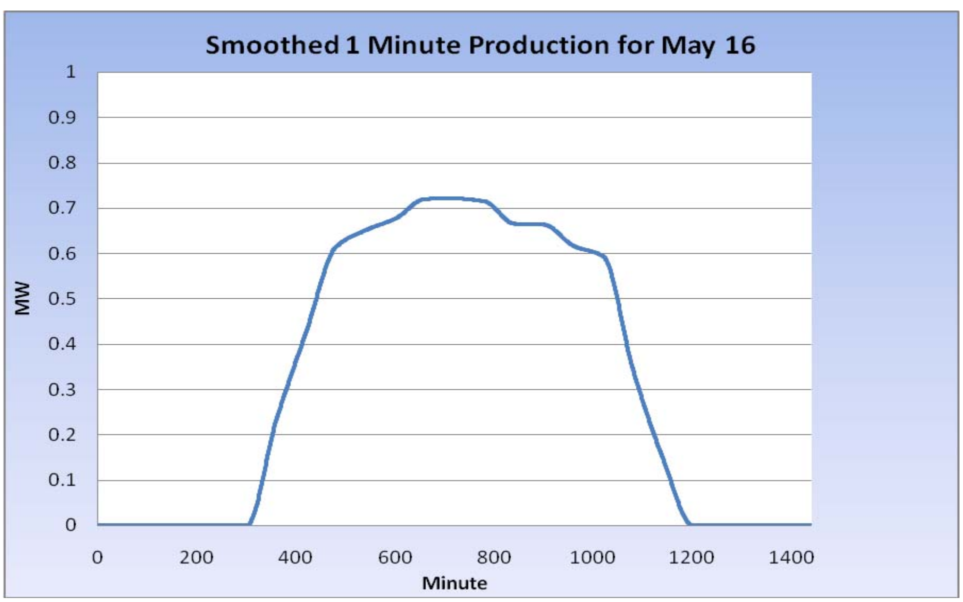
Q. Can you provide an example of the results of the variability process?

A. Yes. The results of this process are shown graphically in the figures below. Figure 5 shows the hourly production data output of the SAM for May 16, 2020. Figure 6 shows the smoothed 1 minute production data and Figure 7 shows the production data after historical variability has been added.



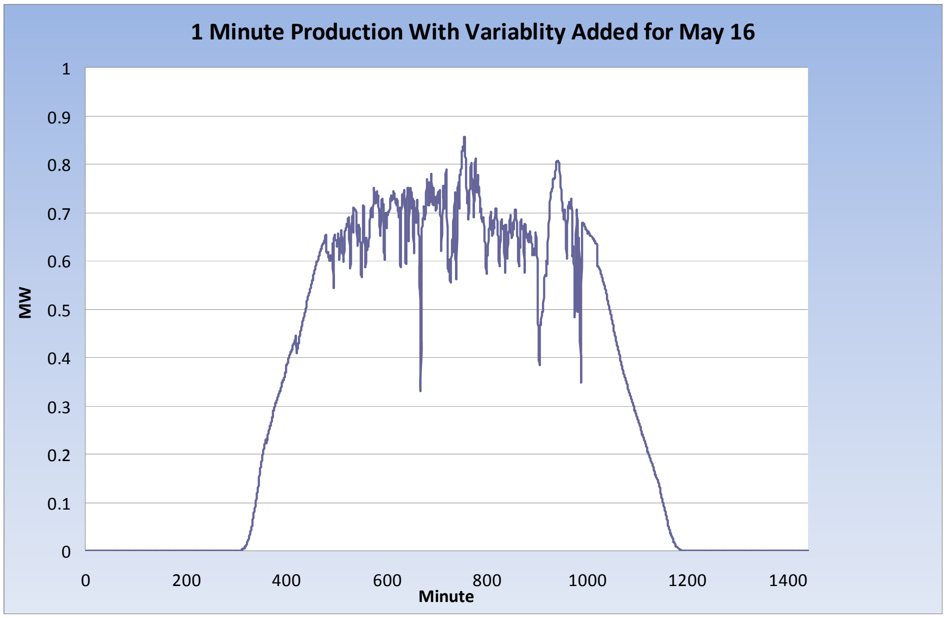
1 Minute Smoothed Production Data for a Tracking PV in the Mountain Pass/Tehachapi for May 16, 2020

Figure 5: Hourly Production Data Output from SAM Model



1 Minute Smoothed Production Data for a Tracking PV in the Mountain Pass/Tehachapi for May 16, 2020

Figure 6: Hourly Production Data Output from the SAM After Spline Fit



1 Minute Production Data With Historical Variability Added for a Tracking PV in the Mountain Pass/Tehachapi for May 16, 2020

Figure 7: Hourly Production Data Output from the SAM After Variability Is Added

Q. How did the ISO develop the Step 0 profiles for small solar PV?

A. Developing profiles for small solar PV resources presented a challenge. There are approximately 9000 MW of various types of small solar PV in the Environmentally Constrained Scenario and either 1000 MW or 2000 MW in the other scenarios. In addition, there are approximately 2000 MW of small PV on the customer side of the meter in all scenarios. The number of these plants is in the thousands, which precludes these plants from being analyzed or modeled on an individual plant basis. In addition, because of data confidentiality limitations, the supply side projects are not easily located geographically.

Q. What was the ISO's approach to modeling the small solar profiles?

A. Due to numbers, geographic and size diversity, and other factors, we decided to model these projects at an aggregate level.

For the supply side, we defined a number of rectangular geographical areas as shown in Table 3 below to cover about 4-500 MWs of generation in each rectangle. (The use of a predetermined shape allowed more efficient coding and data processing).

The numbers in the column labeled "Number of Sites" is not the actual number of sites, which are in the thousands, but the number of projects selected from RPS Calculator, each of which would be distributed over many sites. The first five columns of the Table contain clarifying information provided to Nexant by ED staff as the profiles were being developed. The last two columns, "grids" and "MWs/ grid," were developed by Nexant as part of their modeling effort.

Table 3: Small Supply Solar Projects as Defined by the CPUC

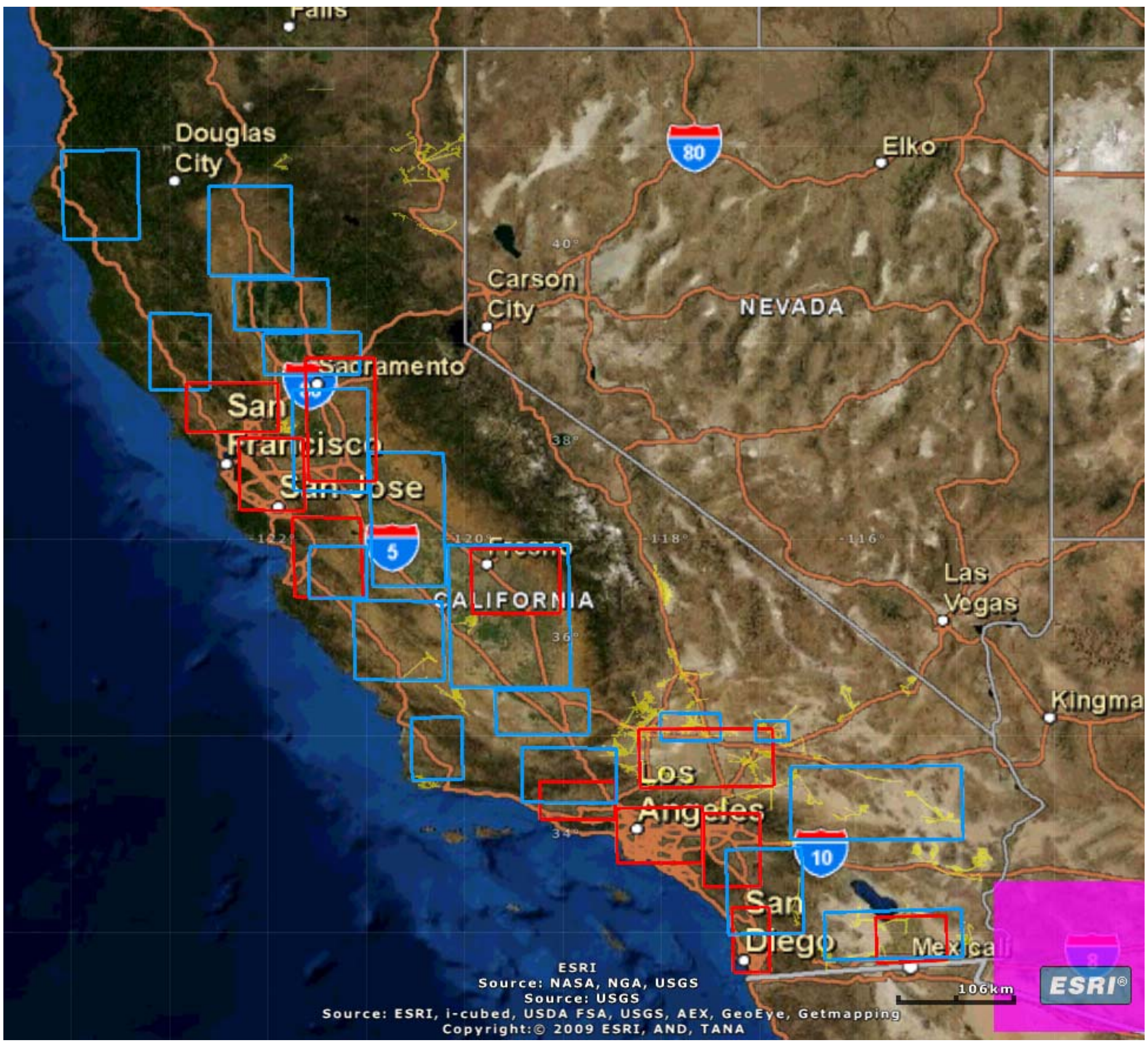
Location	Sub-Type	Number of Sites	Total MW	Capacity Factor	Grids	MWs/Grid
Central Valley	Large Ground	52	2677.7	23.56%	6	446
	Large Roof	7	710	20.37%	2	355
	Mid Ground	22	132.9	23.56%		Combine
	Small Ground	21	26.1	25.57%		Combine
Mojave	Large Ground	46	836.1	26.68%	2	418
	Large Roof	19	513.7	22.68%	1	514
	Mid Ground	21	12.5	26.68%		Combine
	Small Ground	21	3	29.36%		Combine
North Coast	Large Ground	31	725.2	21.87%	2	363
	Large Roof	19	929.9	19.56%	2	465
	Mid Ground	15	48.4	21.87%		Combine
	Small Ground	14	13.1	23.71%		Combine
South Coast	Large Ground	27	923.1	24.34%	2	462
	Large Roof	24	1517.7	21.17%	3	506
	Mid Ground	14	6.7	24.34%		Combine
	Small Ground	14	1.1	26.09%		Combine
Total		367	9077.2	Total	20	

For each square grid, we assumed that the plants are uniformly distributed over the grid. For the categories (rows) with relatively small amounts of generation, we decided that accuracy would not suffer if they were combined with other categories that had similar technologies and capacity factors. For example, under Central Valley there is 133 MW of Mid Ground and 26 MW of Small Ground. We determined that for modeling purposes these projects should be added to others in the same region with the same or similar characteristics.

Q. How were the grids distributed geographically?

Figure 8 shows the grids that are used for the 9000 MWs of solar PV.

Figure 8: Distributed Solar Geographic Areas



In this geographic representation, blue squares are for large ground projects and red squares are for large roof projects.

Q. Once the geographic boundaries were determined, what process did you follow to develop the profiles?

We selected 25 1 km by 1 km satellite irradiance data that was evenly distributed over the grid. For some grids this might be one every 5 km and others might be one every 20 km. That data was averaged on an hourly basis for each rectangle.

Next, we processed the averaged irradiance data in the SAM to develop hourly production for the MWs represented by the group. Using a cubic spline curve fit function on the hourly production, we then developed 1 minute profiles for each geographic area, which has no 1 minute variability.

We added 1 minute variability to the 1 minute production data using algorithms similar to those described above used for developing large solar plant profiles and, as the final step, we developed clear sky production for each geographic area in the same manner as with the large solar – by selecting the maximum production in each hour for each month.

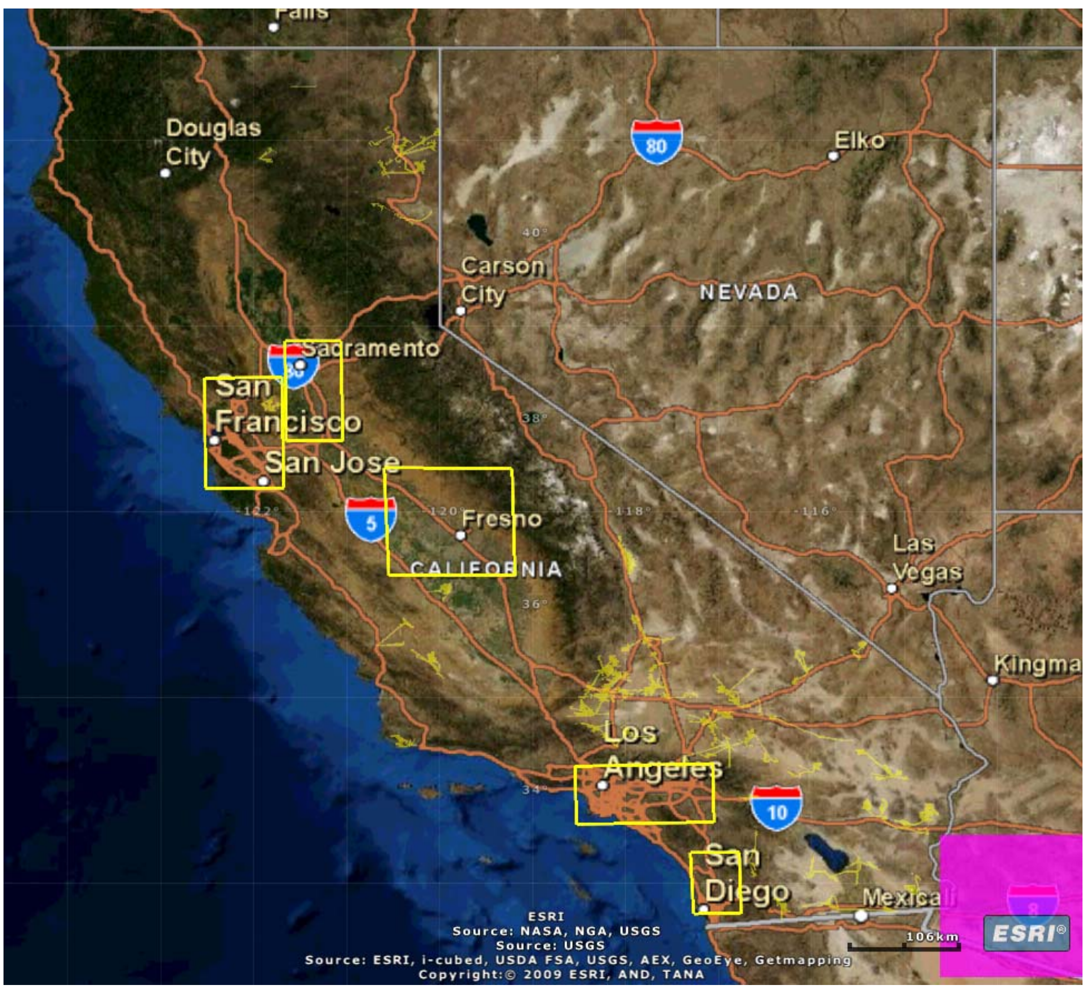
Q. What was the process used for developing small customer-side PV?

A. The process for small PV on the customer side of the meter was similar to the process used for small supply PV plants. Five grids were used, as presented on Figure 9. Table 4 provides the location, size and capacity factor planning assumptions for these customer side solar resources.

Table 4: Aggregated Customer Side Distributed Solar

Location	Profile Name	Size MW	Type	Capacity Factor
Central Valley	Distributed_Solar_1	349.9	fixed tilt	21.00%
Central Valley	Distributed_Solar_2	349.9	fixed tilt	21.00%
North Coast	Distributed_Solar_3	349.9	fixed tilt	21.00%
South Coast	Distributed_Solar_4	349.9	fixed tilt	21.00%
South Coast	Distributed_Solar_5	349.9	fixed tilt	21.00%

Figure 9: Customer Side PV Geographic Areas



Q. How were the 1-minute and hourly load profiles developed?

A. The 1-minute load profiles were developed from actual 1-2005 actual load data. The total system load was scaled up to match the hourly peak load in the CPUC defined scenarios. The 1-minute hourly data was then averaged over 60-minutes to produce an hourly load profile. The hourly load profiles were further adjusted to ensure the total energy over the year was consistent with the CPUC planning assumptions.

These load profiles were posted to the ISO website as the ISO conducted its Step 0 modeling: 1-minute load http://www.caiso.com/2b3e/2b3ed83725ee0.csv and hourly load: http://www.caiso.com/2b41/2b41d086444a0.zip.

B. STEP 1- MODELING LOAD FOLLOWING AND REGULATION REQUIREMENTS

Q. How did the ISO develop the Step 1 load following and statistical regulation requirements?

A. The Step 1 load following and regulation requirements were developed from the load, wind and solar 1 minute profiles developed in Step 0 along with distributions of load, wind and solar forecast errors. This step in the study uses a stochastic process developed by the ISO and PNNL that employs Monte Carlo simulation, a sampling over multiple trials or iterations used to estimate the statistical characteristics of a mathematical system. The simulation is designed to model aspects of the daily sequence of ISO operations and markets in detail, from hour-ahead to real-time dispatch. The objective is to measure changes in operations at the aggregate power system level, rather than at any particular location in the system. The model provides realistic representations of the interaction of load, wind, and solar forecast errors and variability in those time frames and evaluates their possible impact on operational requirements through a very large number of iterations. A summary of the regulation and load following requirements produced by Step 1 analysis is provided on Slides 3 and 4 of Exhibit 1. The detailed Step 1 hourly results for the following scenarios are available at:

Scenario	Step 1 Results
Trajectory	http://www.caiso.com/2b49/2b4980da2f1e0.xls
Environmentally Constrained	http://www.caiso.com/2b49/2b49906560a70.xls
Cost Constrained	http://www.caiso.com/2b49/2b4980da2f1e0.xls
Time Constrained	http://www.caiso.com/2b4c/2b4c96c04f880.xls
Trajectory High Load	http://www.caiso.com/2b59/2b59ed4521ce0.xls

Q. Are the load, wind and solar forecast errors inputs into the Step 1 stochastic modeling process you described above?

A. Yes. As I describe below, the ISO developed distributions of forecast errors that are defined by the standard deviation and correlation of error from time interval to the next based on actual forecast and load data for load and based on a T-1 persistence method using the wind and solar profiles developed in Step 0.

Q. What are forecast errors and why is this data important to the Step 1 determination of grid operating characteristics?

A. Forecast errors quantify the magnitude of uncertainty one can expect when forecasting load or generation production from variable resources such as wind and solar resources. To ensure the ISO can balance supply and demand in real-time, the ISO must consider the difference between supply and demand that can arise in case actual conditions differ from forecasted conditions.

Q. Did you observe differences in the level of forecast errors between the 2009 vintage scenarios and the priority scenarios?

A. Yes. These differences are depicted on Slide 59 of Exhibit 1. For the load forecasts, we observed a significant reduction in hour ahead load forecast error. This reduction is because our forecast is now based on forecasts that are produced 75 minutes prior to actual operating hour. The load forecast errors in the vintage scenarios were based on load forecast that was produced 2 hours prior the operating hour. In addition, the ISO has made improvements to its load forecasting tools.

However, the 5 minute ahead forecast errors have increased some from prior analysis. The 5-minute ahead forecast errors affect regulation more than load following requirements.

The wind forecast errors determined using the T-1 persistence method discussed above resulted in modest reduction in forecast when compared the wind forecast error used in vintage scenarios. However, the forecast errors observed in the T-1 persistence method have the level observed when compared to current Participating Intermittent Resource Program (PIRP) resource wind forecast errors.

Depending the technology and clear sky index, the solar forecast errors are in some cases lower and other cases higher than the forecast errors used in the 2009 vintage scenarios.

Q. **How did the changes in forecast errors affect the Step 1 regulation and load following requirements?**

A. The lower hour ahead and wind forecast errors contributed to a reduction in the load following requirements observed in these priority scenarios when compared to the vintage scenarios results. Only modest reductions in regulation requirements were observed in part due to the offsetting effects of the high 5 minute load forecast errors.

Q. How were the load forecast errors determined?

A. The load forecast errors were determined for two different timeframes, the hour ahead and each 5-minute interval within the operating hour. For each timeframe, the forecast errors were calculated by taking the difference between the forecast demand for that timeframe and the actual average demand for the corresponding timeframe. Four probability density functions were approximated using a truncated normal distribution that is defined by using the mean and standard deviation for the forecast errors for each season. The hour ahead and 5-minute aggregated load forecast errors were calculated using actual and forecast data for 2010.

Q. What were the load forecast errors that were calculated?

A. The hour-ahead and 5-minute load forecast errors determined are presented on Slide 59 of Exhibit 1.

Q. How were the wind forecast errors determined?

A. The hour ahead wind forecast errors are based on a T-1 persistence analysis.

Q. What is T-1 persistence analysis?

A. T-1 persistence analysis compares the average production for an hour “t” with the actual production from the previous hour “T-1 hour.” The basis for this approach is that a forecasting approach should be able to at least be no worse than an assumption that what is produced in one hour will persist and reflect what is produced the next hour.

Q. Why was a 1 hour comparison used?

A. 1 hour is used because currently the market structure and scheduling timelines in the west require occurring on an hourly basis and are determined approximately 1 hour ahead of the actual operating hour.

Q. What were the wind forecast errors that were calculated using the T-1 hour persistence method?

A. The hour-ahead wind forecast errors we determined are presented on Slide 61 of Exhibit 1.

Q. How were the solar forecast errors determined?

A. The solar forecast errors were determined based on a T-1 persistence analysis of the clearness index for hours 12 though 16, separately for different solar technologies- PV, solar thermal, distributed solar and customer side PV- using the profiles developed in Step 0, and broken down into 4 different clearness index categories.

Q. Why were the solar forecast errors separated into the technology and clearness index groupings you described above?

A. The solar forecast error analysis was separated due to different solar technology production patterns and variability as a function of solar irradiance. As a result, separating the forecast error analysis by solar technology and clearness index allows the ISO to better reflect the impacts of the relative quantity of different solar technology.

Q. Why was the solar forecast error analysis limited to hours 12-16?

A. The forecast error analysis was limited to hours 12-16 to avoid introducing errors that result from sunrise and sunset which would distort T-1 persistence error analysis. Hours 12-16 are hours where the clear sky solar irradiance is relatively stable from one hour to the next and better reflects forecast conditions.

Q. Did the methodology for developing forecast error consider dispatch or thermal inertial capabilities of solar thermal resources?

A. No. In the analysis of solar forecast errors conducted so far, the ISO recognized that there is further research needed to refine the impact on forecasting modeling of plant-scale effects, operational properties and performance characteristics and capabilities of different solar technologies, including startup-up in the morning and shutdown-down during the evening hours.

Q. Did you consult with others to develop the application of T-1 persistence forecast error analysis method?

A. Yes, this method was developed in collaboration with Andrew Mills, Principle Research Associate with LBNL, who provided consultation services to ED staff.

Q. What were the solar forecast errors that were calculated using the T-1 hour persistence method?

A. The hour-ahead solar forecast errors determined are presented on Slide 65 of Exhibit 1.

Q. Please provide additional details about how the Step 1 modeling process was used to calculate operational requirements.

A. A detailed description of the statistical analysis methodology is found in the technical appendix to the ISO's 20% RPS integration study that I discussed earlier in my testimony. The basic method is as follows: First, the load and renewable production data is aggregated from the 1-minute data set to create averaged hour-ahead and 5-minute dispatch schedules for each hour of the year. Second, the probability distributions of forecast errors, and other statistical properties, such as autocorrelation, for load, and wind and solar production in the hour-ahead and 5-minute-ahead timeframes are constructed. Both wind and solar forecast errors are used in the hour-ahead random draws. However, in the 5-minute time frame, the ISO uses a wind persistence forecast, which is the basis for the simulation. Hence, in the 5-minute sampling, the wind variability is preserved but the forecast error is static for the period of the persistence model. For the solar resources, the 5-minute forecast errors are modeled explicitly because of the more extreme morning and evening ramp periods for solar in which persistence would not be an appropriate assumption.

Third, the Monte Carlo sampling then conducts random draws from the load, wind and solar forecast errors, with consideration of autocorrelations between the errors, to vary the initial hour-ahead and 5-minute schedules. The Monte Carlo sampling is done on each hour in the sequence individually.[11]

Each simulation of a seasonal case includes 100 iterations over all hours in the season to capture a large number of randomly generated values. Of these simulated values, five percent are eliminated as extreme points, using a methodology that considers all dimensions being measured in the analysis (capacity, ramp and ramp duration).

C. STEP 2 - USING PRODUCTION SIMULATION TO EVALUATE THE NETWORK AND DETERMINE OPERATIONAL NEEDS

Q. Please describe how the Step 2 production simulation analysis is used to determine grid needs.

A. Step 2 production simulation is an hourly deterministic production simulation of the WECC, including California hourly dispatch with the objective of minimizing cost while meeting the hourly load, spinning reserves, non-spinning reserves, regulation requirements and load following requirements, subject to resource and inter-regional transmission constraints. The regulation and load following requirements are determined in the Step 1 analysis. If the production simulation is not able to meet one or more of these requirements, a shortfall is identified and generic resource capacity is introduced to resolve the shortfall. The generic resource additions are identified as “needs” because additional resource capacity was needed to meet the simultaneous requirements. A more detailed description of the production

[11] However, the twenty (20) minute ramps that characterize the boundary between actual hourly schedules are represented in the model to ensure that in those periods, deviations between the underlying schedules and the random draws do not exaggerate the result.

simulation and its formulation can be found in Section D of the Integration of Renewable Resources: Technical Appendix for California ISO Renewable Integration Studies[12]

Q. What model was used in the production simulation?

A. The Step 2 underlying model is a Plexos Solutions representation of the WECC Transmission Expansion Planning Policy Committee (TEPPC) model version PC0 dated March 21, 2011.

Q. Was this TEPPC PC0 model modified in any way to support these studies?

A. Yes, the California portion of the model had to be reconciled and modified to comply with the assumptions for the renewable scenarios described in the December 3, 2010 scoping memo.

Q. What specific modifications to the TEPPC model were made to comply with the scoping memo?

A. The load pattern in California was modified to reflect assumptions in the scoping memo including accounting for energy efficiency and demand response. Supply resources and patterns were modified to reflect the renewable resource build out as well as planned retirement additions specified in scoping memo including expected retirements of once through cooled (OTC) resources. The maximum import capability into California was modified to reflect expected condition. The natural gas prices in California were modified to reflect Market Price Referent (MPR) method specified in the CPUC scoping memo. The natural gas prices used in California can be found on slide 42 of Exhibit 1. CO_2 price assumptions were used. The details of these changes can be found at slides 32-43 of Exhibit 1.

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[12] http://www.caiso.com/282d/282d85c9391b0.pdf

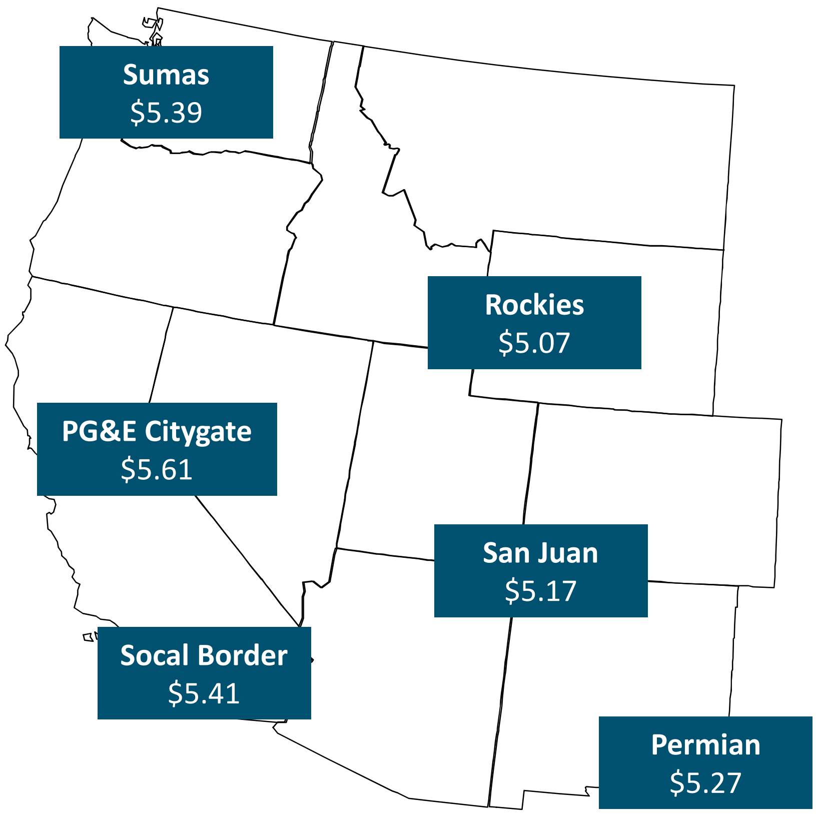
Q. Were there any other modification made to the model that were not specified in the CPUC LTPP scoping memo?

A. Yes. The allocation of regulation and load following reserves were distributed between ISO and municipal load. Generator operating characteristics, profiles and outage profiles were updated to reflect ISOs operational experience. Southern California Import Transmission (SCIT) and Path 26 interface limits were modified. Gas prices outside of California were updated to utilize a similar methodology used to develop the California gas prices. Coal resource assumptions, including planned retirements outside of California, were updated to reflect publicly available information about planned retirements. Details of these changes can be found at Slides 45-55 of Exhibit 1.

Q. Do you have any more detail regarding how the gas prices outside of California were developed?

A. Yes, the ISO found it necessary to extend the MPR methodology to develop natural gas prices for generators located outside of California. While the TEPPC PC0 case does have pre-loaded fuel prices for all generators, it was important to ensure that the natural gas prices used outside of California were consistent with those used inside of California in order to avoid introducing bias into the model's dispatch calculations. E3 assisted the ISO in developing these natural gas prices by obtaining basis spread prices from the New York Mercantile Exchange (NYMEX) for pricing points outside of California that are contemporaneous with the Henry Hub natural gas prices and basis spread prices used for California pricing points. The basis spread prices represent locational price differences between Henry Hub, Louisiana (the delivery location for the benchmark NYMEX natural gas futures contracts) and local market pricing points throughout the West: Sumas, Permian, San Juan, and Rockies. These basis spread prices are established through bilateral trading of basis "swaps," which are then cleared through the NYMEX Clearport clearing system. Figure 10, below, shows the wholesale natural gas prices derived using this methodology.

Figure 10: 2020 Average Wholesale Natural Gas Prices for Major Western Pricing Points (2010 Dollars per MMBtu, based on a Henry Hub price of $5.61/MMBtu)



E3 then applied the natural gas delivery charges from the TEPPC PC0 case, with two modifications to better reflect actual market conditions: (1) eliminated the TEPPC delivery charge for natural gas in British Columbia, and (2) established SoCal Border instead of Permian as the reference pricing point for Arizona. The table below shows the delivery charges applied in 2020.

Table 5: Natural Gas Delivery Charges in 2020 (2010 $/MMBtu)

Generator Location	Natural Gas Hub	Natural Gas Delivery Point	Delivery Charge (2010 $/MMBtu)
AESO	Rockies	AECO_C	-
APS	SoCal Border	Arizona	0.303
AVA	Sumas	Pacific_NW	0.094
BCTC	Sumas	Sumas	-
BPA	Sumas	Pacific_NW	0.094
CFE	SoCal Border	Baja	-
EPE	San Juan	San_Juan	-
IID	SoCal Border	SoCal_BurnerTip	0. 438
LDWP	SoCal Border	SoCal_Border	-
LDWP	SoCal Border	SoCal_BurnerTip	0.438
NEVP	SoCal Border	SoCal_Border	-
NWMT	Rockies	Idaho_Mont	0.512
PACE_UT	Rockies	Utah	0.271
PACW	Sumas	Pacific_NW	0.094
PG&E_BAY	PG&E Citygate	PGE_Citygate BB	0.069
PG&E_BAY	PG&E Citygate	PGE_Citygate LT	0.230
PG&E_VLY	SoCal Border	Kern_River	0.359
PG&E_VLY	PG&E Citygate	PGE_Citygate BB	0.069
PG&E_VLY	PG&E Citygate	PGE_Citygate LT	0.230
PG&E_VLY	SoCal Border	SoCal_BurnerTip	0.359
PGN	Sumas	Pacific_NW	0.094
PNM	San Juan	San_Juan	-
PSC	Rockies	Colorado	0.553
PSE	Sumas	Pacific_NW	0.094
SCE	SoCal Border	SoCal_BurnerTip	0.438
SDGE	SoCal Border	Baja	-
SDGE	SoCal Border	SoCal_BurnerTip	0.438
SMUD	PG&E Citygate	PGE_Citygate BB	0.069
SMUD	PG&E Citygate	PGE_Citygate LT	0.230
SPP	PG&E Citygate	Sierra_Pacific	0.167
SRP	SoCal Border	Arizona	0.303
TEP	SoCal Border	Arizona	0.303
TIDC	PG&E Citygate	PGE_Citygate LT	0.281
TREAS VLY	Rockies	Idaho_Mont	0.512
UT S	Rockies	Utah	0.271
WACM	Rockies	Wyoming	0.553
WALC	SoCal Border	SoCal_Border	-

In addition to the delivery charges, electric generators must pay state or local taxes in some areas. The following table lists these additional charges applied for the ISO's Step 2 analysis.

Table 6: Additional Natural Gas Costs (2010 $/MMBtu)

Natural Gas Delivery Point	Charge	Description
Arizona	5.6%	State excise tax
SoCal_BurnerTip	1.5%	Municipal Surcharge
PGE_Citygate BB	0.9%	Municipal Surcharge
PGE_Citygate LT	0.9%	Municipal Surcharge

The Natural Gas Prices in 2020 (2010 $/MMBtu) for locations external to California locations can be found on slide 52 of Exhibit 1.

Q. Were there any other modifications made to the model after the presentation of the preliminary results at the workshop May 10, 2011?

A. Yes. As I have previously described, certain proposed changes to the model were the basis for the ISO and IOU motion for extension of time to submit testimony and were described in the May 31, 2011 ALJ ruling. Details of these changes are presented in Slides 77-80 of Exhibit 1.

Q. Were there any production simulation methodology improvements incorporated into running these scenarios?

A. Yes. Based on what the ISO learned from running the 2009 vintage scenarios, the ISO worked with Plexos to develop improvements to the production simulation methodology to enhance performance. These improvements are presented in Slides 67-75 of Exhibit 1.

Q. How was the production simulation run used to produce results?

A. The production simulation was conducted for an 8760 hour/year long run using hourly time step intervals. The production simulation was first run to determine any shortfalls and incremental resource needs to resolve identified shortfalls. This run is referred to as the "need" run. For this "need" run, monthly maximum requirements for regulation and load following were used for each hour to ensure that the fleet had sufficient capability to meet a wide range of expected conditions for each month. After the "need" run was completed, a second production simulation run was performed to determine production costs, annual fuel burn, emissions and capacity factors. This second run is referred to as a "cost" run. For the "cost" run, the hourly regulation and load following requirements were used to better reflect the expected knowledge of requirements based on operational conditions.

Q. What was the ISO's involvement in Step 3?

A. The ISO provided the production simulation results to E3, who was consulting for the IOUs to perform the Step 3 metrics. The ISO did not independently perform or review the Step 3 metric analysis. As a working group member, E3 also performed reconciliation of the model and the resource planning assumptions, as well as developing the gas prices described above in my testimony. Because E3 produced its work product as part of the working group, the ISO had an opportunity to review the results and verify the reasonableness of the data before adopting it into the ISO's studies.

Q. Was the same load profile and distribution methodology used for the four priority scenarios?

A. Yes. For the peak demand calculation, Nexant consulted with ED staff and developed load profiles, based on the Statewide Net Peak Demand (70,964 MW) from Form 1.4[13] of the CEC's 2009 IEPR. Exhibit 3 attached to my testimony sets forth the load profile energy and demand assumptions and adjustments made to the Form 1.4 peak quantities:

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[13] Form 1.4, Second Edition, http://www.energy.ca.gov/2009publications/CEC-200-2009-012/adopted_forecast_forms/Chap1Stateforms-Adopted-09.xls
Statewide Revised Demand Forecast Forms

- 1,131 MW of upward adjustment were made to account for behind the meter PV that was modeled as supply.
- 7005MW of downward adjustment was made to account for incremental energy efficiency.
- 1008MW of downward adjustment were made to account for behind the meter CHP.
- 327MW of downward adjustment was made to account for demand side programs.

Q. How was the load distributed in the model?

A. For the four priority scenarios, the load (hourly demand) was distributed on a pro-rata basis to the eight bubbles using allocation factors based, in part, on the energy data set forth on Exhibit 4 to this testimony. Exhibit 4 contains a set of data developed by the CEC which contains annual peak energy and demand data for each of the eight bubbles modeled in California. The peak energy values for each bubble were used after an adjustment for the customer side PV energy to calculate allocation factors for each of the eight bubbles used in the production simulation analysis. These allocation factors were then used to allocate the hourly California demand to the eight bubbles modeled. The customer side PV energy adjustment was made by allocating 52% of the total customer side PV energy to the Northern California bubbles and 48% to the Southern California bubbles based upon CEC historical data.

Q. Was the same load profile and distribution methodology used for the All Gas scenario?

A. No. For the All Gas scenario, the non-coincident peak demand for each bubble from Form 1.5b[14] was used. The total state wide, non-coincident peak demand in Form 1.5b is 70,799 MW. The load was adjusted to account for energy efficiency, CHP, demand response and customer side PV, using the same adjustments contained in Exhibit 3. Using this approach for the All Gas scenario resulted in a slightly lower total statewide load of 166MW versus the total load in the four CPUC priority scenarios discussed in the previous question.

Q. How was the Helms Pumps storage facility modeled?

A. The model contains the following assumptions about the Helms pumps:

- There are three pumps that can operate simultaneously from January to May and from October to December. There will be only one pump available for the rest of year 2020.
- PG&E provided the following pump and usage targets. The storage should reach reservoir maximum volume at the end of May.

Pump/Usage Target	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Pump (GWh)				30.2	29.9							
Usage (GWh)						13.5	18.0	18.0	10.6			

- Based on that, the monthly initial and end storage volumes are set as follows:

Reservoir Storage	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Initial Volume (GWh)	120	120	120	124	154	184	171	153	135	124	120	120
End Volume (GWh)	120	120	124	154	184	171	153	135	124	120	120	120

[14] Form 1.5b, Second Edition, http://www.energy.ca.gov/2009publications/CEC-200-2009-012/adopted_forecast_forms/Chap1Stateforms-Adopted-09.xls

Q. What was the basis for restricting Helms pumps in the scenarios?

A. Based on ISO transmission planning studies and planned transmission upgrades for 2020, the ISO determined that the Helms pumping window would be restricted to one pump due to the load level in the Fresno area.

IV. STUDY RESULTS

Q. Please describe the 33% integration study results for the four priority scenarios.

A. No upward incremental shortfalls were identified for the four priority scenarios, and, thus, no incremental needs of resources beyond capacity already planned were identified in any of these scenarios. However, the results show 506MW and 539MW shortfalls in downward load-following capacity in the Trajectory and Environmentally Constrained scenarios, respectively. No downward load-following shortfalls were observed in the Cost and Time Constrained scenarios. No regulation shortfalls were observed in any of the four priority scenarios. Slides 10 and 11 of Exhibit 1 provide additional details about these observations.

Q. Do you anticipate any resource needs resulting from the observed shortfalls in downward load following capacity?

A. No, not necessarily for these particular scenarios. Based on the magnitude and frequency of the observed shortfalls, storage or curtailment opportunities should be considered in lieu of additional capacity.

Q. Were any shortfalls or needs identified in the All Gas or Trajectory High Load scenarios that the ISO ran?

A. Yes. We observed 1400MW capacity need in the All Gas scenario and 4600MW capacity need in the High Load Trajectory scenario to resolve shortfalls in upward ancillary service and load following. No downward load following shortfall was observed in the All Gas. Downward load following shortfalls up to 856MW were observed in the Trajectory High Load scenario. Slides 10 and 11 of Exhibit 1 contain additional details about these observations.

Q. Can you explain why shortfalls are observed in the All Gas scenario and Trajectory High Load scenarios?

A. In the All Gas scenario, all new renewable resources were removed (except for 1750MW of customer side solar) while no additional resources were added from the base scenario. Due to the removal of such capacity, the flexible fleet capacity is being used to meet the load and does not remain available to meet the load following and regulation upward requirements. What this indicates is that qualified capacity in excess of the planning reserve margin in the four priority scenarios provides sufficient unloaded flexible capacity to meet the load following and regulation needs while the renewable resource capacity is meeting the load. In the All Gas scenario the planning reserve margin is significantly reduced while still maintaining the required planning reserve margin. In the Trajectory High Load scenario, the load was increased by 10% over Trajectory Base Load scenario. At these high load levels the flexible fleet capacity needs to produce energy to meet the load during higher load periods. As a result, remaining flexible capacity is insufficient to simultaneously meet the load following requirements.

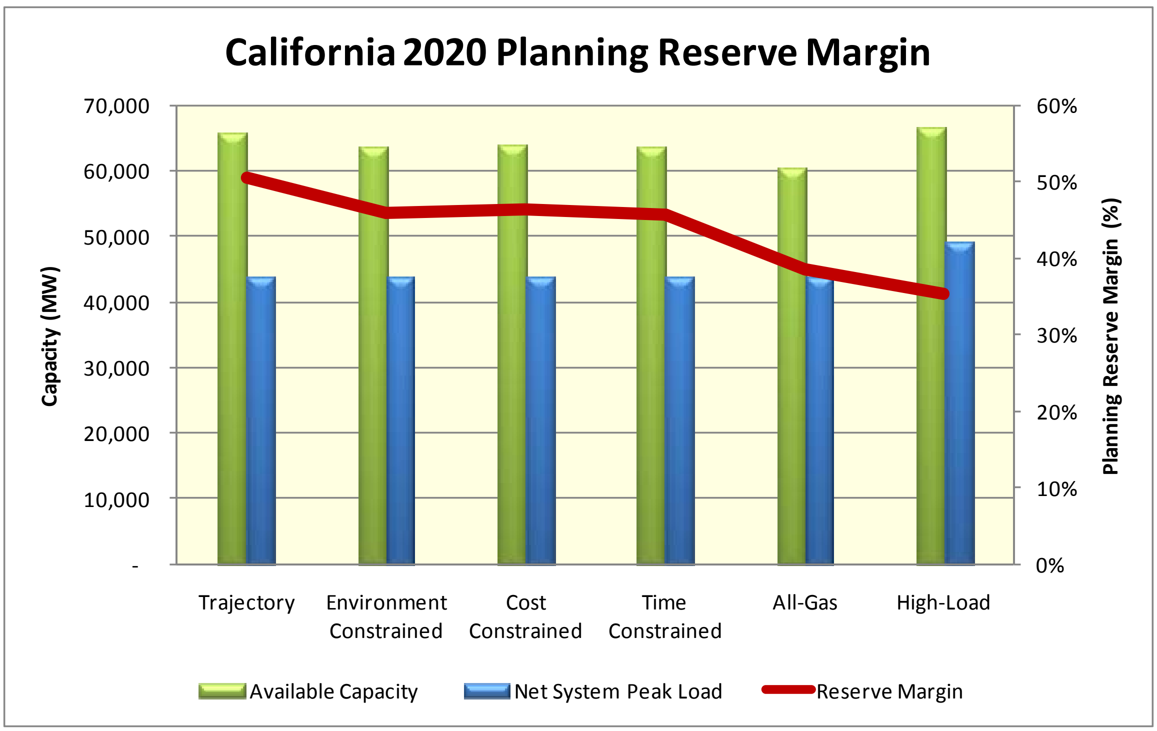
Q. Can you conclude from the four priority scenarios that no needs above planning reserve margin exist to meet renewable integration?

A. No. The four priority scenarios reflect scenarios with resource capacity in excess of the required planning reserve margin (PRM) of 15%-17%. Table 7 and Figure 11, below, show the planning reserve margin of the different scenarios as calculated by E3. As a result, the excess capacity above PRM provides sufficient flexible capacity to meet the simultaneous energy, operating reserve, regulation and load following requirements of these four scenarios. However, we cannot conclude from these results whether sufficient flexible capability would exist to meet the simultaneous energy, operating reserve, regulation and load following requirements if the available generation capacity was not in excess of the 15-17% PRM. For example, if the utilities contract for less import qualifying capacity, just meeting their PRM of 117%, the ISO may need to dispatch the capacity that is currently unloaded and providing flexibility services in these cases, and therefore may be short the needed flexible capacity. The four priority scenarios were not analyzed assuming the PRM would just be met but not exceeded.

Table 7: Planning Reserve Margin Calculated by E3

	Trajectory-Base Load	Environmentally Constrained	Cost Constrained	Time Constrained	All Gas	Trajectory-High Load
Planning Reserve Margin	51%	46%	46%	46%	39%	35%

Figure 11: Planning Reserve Margin



Q. Do the results of the Trajectory High Load scenario reflect a realistic bookend?

A. Not necessarily. As stated in the scoping memo, while the Trajectory High Load scenario may be more reflective of any combination of future uncertainties, such as increased load growth or programmatic performance, the scenario also does not account for the possible local capacity resources that may be needed due to retiring OTC resources and therefore may reflect an overly conservative supply scenario. Once the ISO's OTC studies are completed, it may be appropriate to consider repowering or scenarios that consider local capacity resources to assess what if any needs may exist in a higher load scenario.

Q. How did the total WECC-wide production cost compare among the scenarios?

A. The total production cost of the four priority scenarios are all within 0.3% of each other, with WECC wide production costs ranging from $18.85 billion for Environmentally Constrained scenario to $18.89 billion for the Cost Constrained scenario. The production costs to meet WECC load in the All Gas scenario were $ 20.79 billion. The production costs to meet WECC load in the Trajectory High Load scenario were $19.63 billion. This information can be found on Slide 14 of Exhibit 1.

Q. How did the production costs to meet California load compare among the scenarios?

A. The total production costs to meet the California load of the four priority scenarios were within 4% of each other. The Time Constrained scenario had the highest costs to meet California load ($7.45 billion), while the Environmentally Constrained scenario had the lowest cost to meet California load ($7.17 billion). The production costs to meet California load in the All Gas scenario were $8.37 billion. The production costs to meet California load in the Trajectory High Load scenario were $8.07 billion. This information can be found on Slide 18 of Exhibit 1.

Q. How did the total WECC-wide fuel usage compare among the scenarios?

A. The total WECC fuel usage for the four priority scenarios ranged from 5.366 billion MMBtu in the Time Constrained scenario to 5.375 billion MMBtu in the Environmentally Constrained scenario. The total WECC fuel usage in the All Gas scenario was 5.810billion MMBtu. The total WECC emission in the Trajectory High Load scenario was 5.544billion MMBtu. This information can be found on Slide 19 of Exhibit 1.

Q. How did the California fuel usage compare among the scenarios?

A. The total California fuel usage for the four priority scenarios ranged from 1.326 billion MMBtu in the Environmentally Constrained scenario to 1.341 billion MMBtu in the Time Constrained scenario. The total California fuel usage in the All Gas scenario was 1.417 billion MMBtu. The total WECC emission in the Trajectory High Load scenario was 1.437billion MMBtu. This information can be found on Slide 20 of Exhibit 1.

Q. How did the total WECC-wide emissions compare among the scenarios?

A. The total WECC emissions for the four priority scenarios ranged from 364,684 million metric tons at a cost of $13.238 billion in the Time Constrained scenario to 366,059 million metric tons at a cost of $13.287 billion in the Environmentally Constrained scenario. The total WECC emission in the All Gas scenario was 398,089 million metric tons at a cost of $14.450 billion. The total WECC emission in the Trajectory High Load scenario was 377,070 at a cost of $13.687 billion. This information can be found on Slides 21 and 22 of Exhibit 1.

Q. How did the emissions attributable to meet California load compare among the scenarios?

A. The Environmentally Constrained scenario reflects the lowest emissions of 76,101 million metric tons while the Time Constrained scenario had the highest among the four priority scenarios of 80,987 million metric tons. The Trajectory High Load scenario had 85,822 million metric tons attributable to meet California load. The all gas scenario has a 92,299 million metric tons meet California load. This information can be found on Slide 24 of Exhibit 1.

Q. How did the California net import compare between the scenarios?

A. The maximum imports between the four priority scenarios had similar maximum California net import of approximately 12,000MW. The Cost and Time Constrained scenarios had the highest average net imports due the higher imports renewable capacity. Slide 17 of Exhibit 1 provides a comparison of California average net import for the different scenarios.

Q. Did the Step 2 results provide any insight into start-ups and capacity factors of the fleet?

A. A higher average number of annual starts on California gas turbines of approximately 80-100 starts/year are observed versus 40-55 starts/year observed for the WECC. A lower average number of starts on California combined cycle resources of 40 starts/year versus 70-80 starts/year observed for the WECC. The capacity factor of WECC coal resources is approximately 60% in the scenarios. The capacity factor for combined cycle resources in California and WECC are both in the range of 40%. The capacity factor for gas turbines in California are approximately 6.4% versus 8% for WECC. Slides 25 and 26 of Exhibit 1 provide a comparison of start-up and capacity factors for California and WECC for the different scenarios.

Q. Were there any sensitivity runs performed assuming Helms could pump with 3 pumps year round?

A. Yes. As I discussed earlier in my testimony, the ISO performed a sensitivity run on the Trajectory Base Load scenario assuming Helms could pump with 3 pumps year round. The total annual production costs to meet California load was reduced by $2.3 million when Helms was not restricted. However, additional scenarios and benefit considerations are needed to fully evaluate the incremental benefit of having greater access to Helms pumping capabilities.

Q. How will these sensitivity results be used by the ISO?

A. These results, plus additional simulations and benefit analyses, will be provided to ISO transmission planning engineers for consideration in the 2011/2012 planning cycle.

V. NEXT STEPS

Q. Will the ISO continue to work on the 33% integration study?

A. Yes. The ISO recognizes that these 33% integration studies are based on a set of planning assumptions that will continue to evolve. The ISO intends to run additional scenarios and sensitivities that are relevant to the ISO's operational responsibilities. For example, as I discussed above, the ISO believes it is operationally relevant to consider a case with local capacity resources needed to meet local reliability needs to offset the retirement of OTC resources, once the ISO completes the OTC studies. In addition, the ISO expects to perform assessments of the resource adequacy fleet to assess whether the capacity and characteristics of the current resource adequacy fleet will be adequate to meet the changing flexibility needs of the system. Importantly, this resource adequacy assessment will consider only the generation under resource adequacy contract in order to capture the potential reality that generation capacity not under a resource adequacy contract will not be available due to lack of sufficient revenues. As the ISO completes these and potentially other operational scenarios, the ISO will make the results available and can provide updates in the next LTPP case.

Q. Does this conclude your testimony?

A. Yes, it does.

Exhibit 1

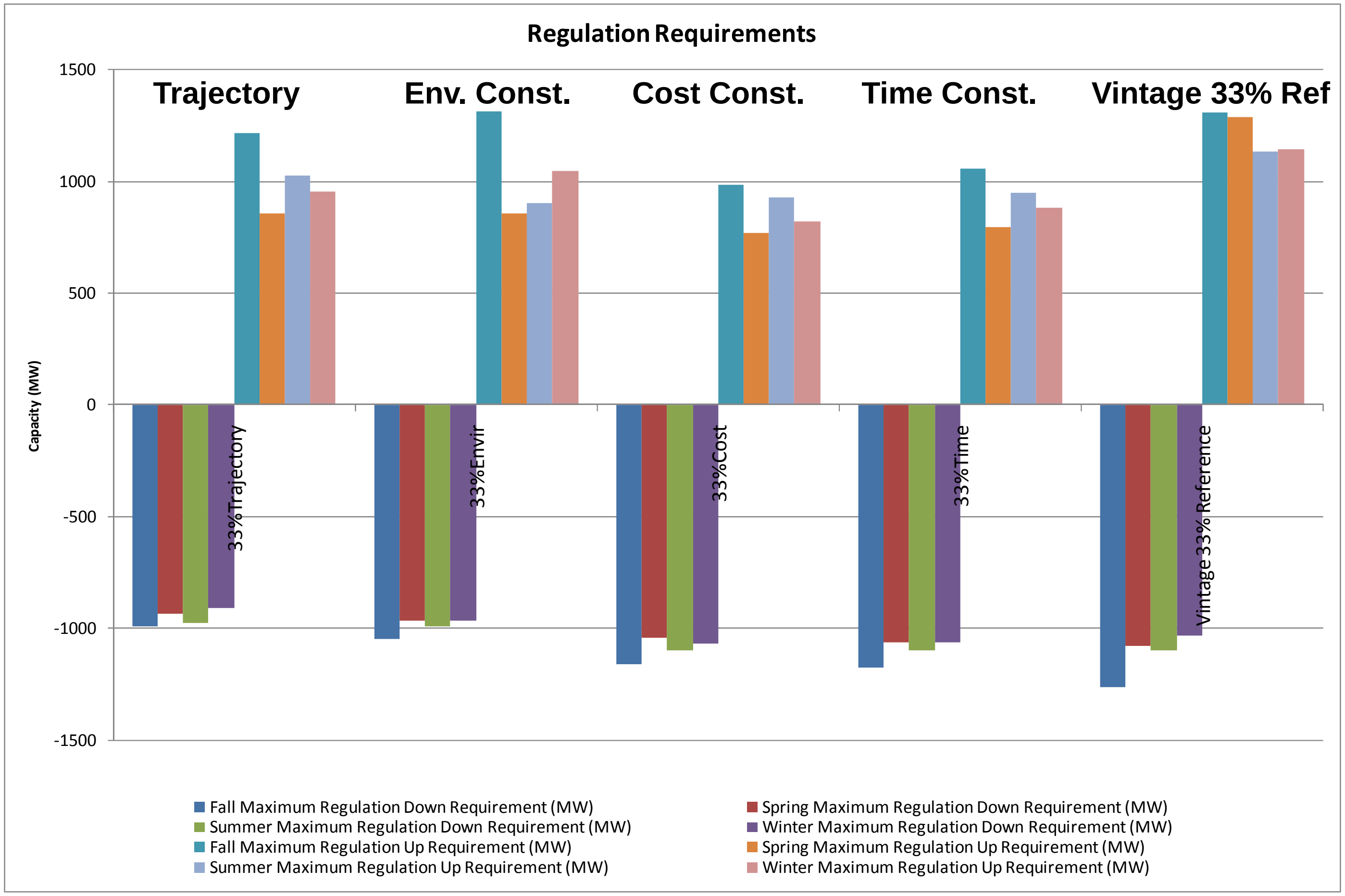
Exhibit 1– 2010 CPUC LTPP Docket No. R.10-05-006

July 1, 2011

Step 1 Operational requirement results

- Regulation and load following requirements determined 2010 CPUC-LTPP scenarios
- New load, wind and solar profiles were developed
- Updated load, wind and solar forecast errors were used to calculated requirements
- Refer to appendix for changes to profile and forecast error
- Load following requirement reduced from vintage cases due to reduced forecast errors
- Regulation requirements increased in some hours due to increase in 5 minute load forecast

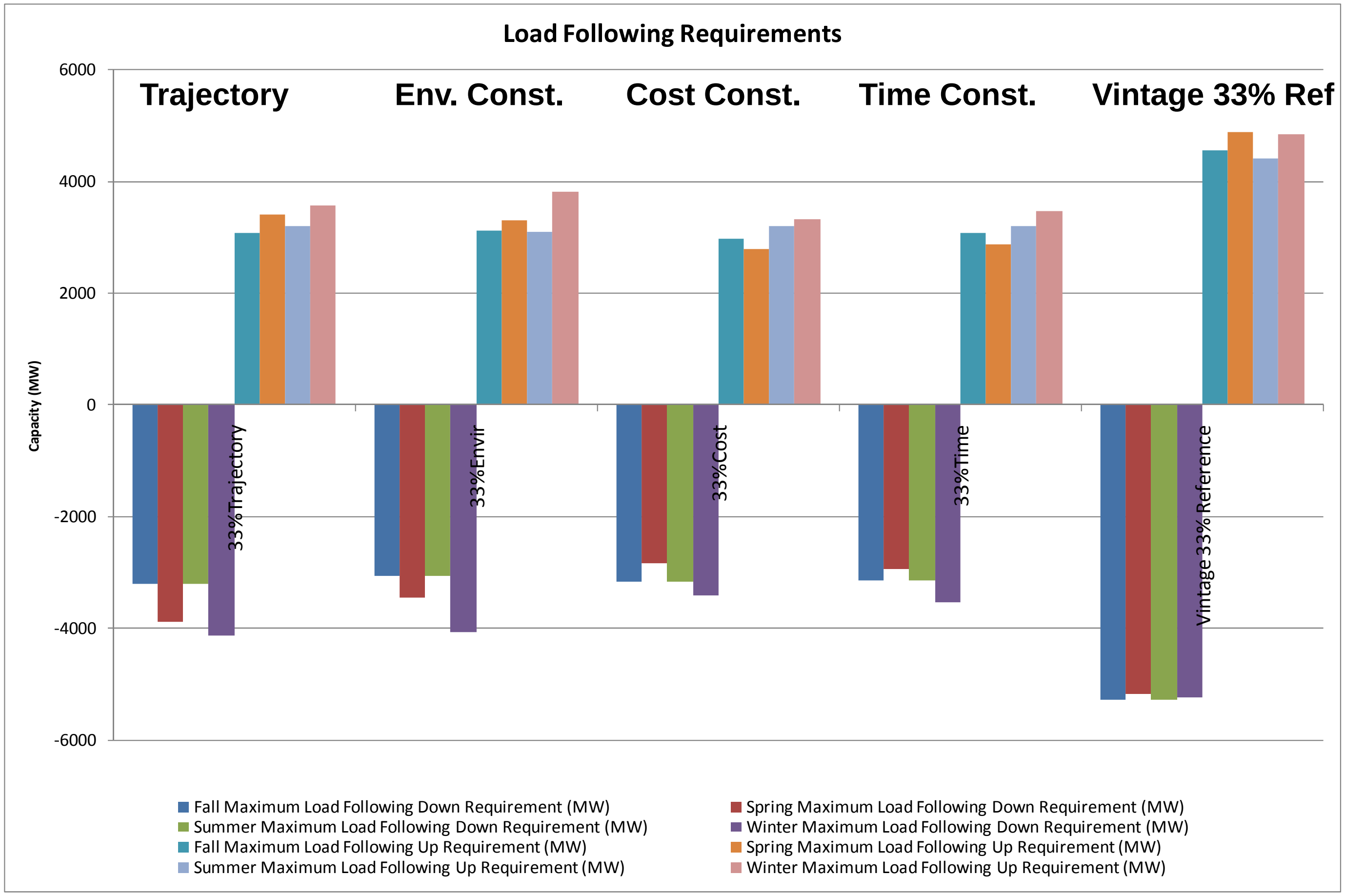
Step 1: Hourly regulation capacity requirements, by scenario



Notes:

- For purposes of comparison, the figures show the single highest hourly seasonal requirement from Step 1 for each season (using the 95th percentile)
- The actual cases use the maximum monthly requirement by hour for need determination and hourly value for production cost and emissions
- Discussion of sensitivity in Section 3

Step 1: Hourly load-following capacity requirements, by scenario



Notes:

- For purposes of comparison, the figures show the single highest hourly seasonal requirement from Step 1 for each season (using the 95th percentile)
- The actual cases use the maximum monthly requirement by hour for need determination and hourly value for production cost and emissions
- Discussion of sensitivity in Section 3

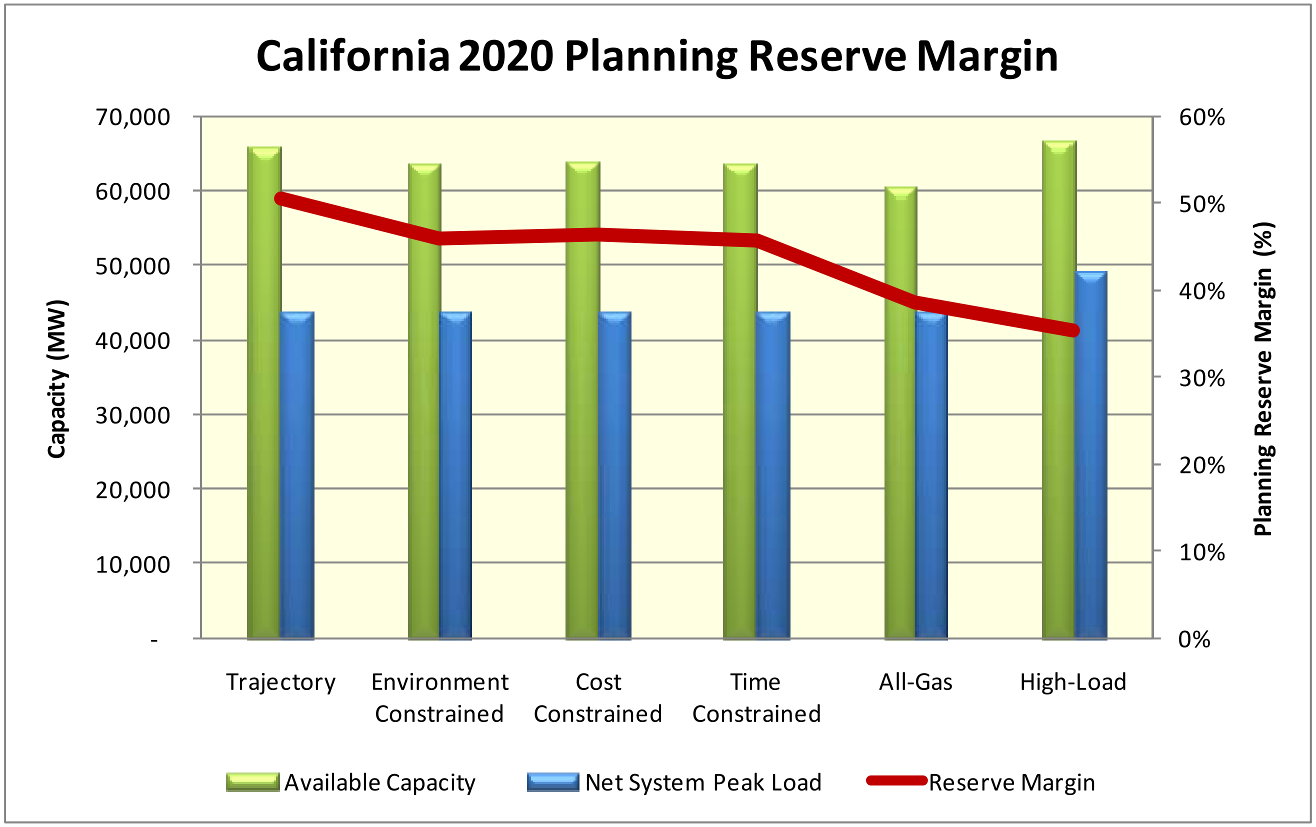
Renewable portfolios for 2020: 2010 LTPP Scenarios

Scenario	Region	Biomass/ biogas	Geothermal	Small Hydro	Solar PV	Distributed Solar	Solar Thermal	Wind	Total
Trajectory	CREZ-North CA	3	0	0	900	0	0	1,205	**2,108**
	CREZ-South CA	30	667	0	2,344	0	3,069	3,830	**9,940**
	Out-of-State	34	154	16	340	0	400	4,149	**5,093**
	Non-CREZ	271	0	0	283	1,052	520	0	**2,126**
	Scenario Total	338	821	16	3,867	1,052	3,989	9,184	**19,266**
Environmentally Constrained	CREZ-North CA	25	0	0	1,700	0	0	375	**2,100**
	CREZ-South CA	158	240	0	565	0	922	4,051	**5,935**
	Out-of-State	222	270	132	340	0	400	1,454	**2,818**
	Non-CREZ	399	0	0	50	9,077	150	0	**9,676**
	Scenario Total	804	510	132	2,655	9,077	1,472	5,880	**20,530**
Cost Constrained	CREZ-North CA	0	22	0	900	0	0	378	**1,300**
	CREZ-South CA	60	776	0	599	0	1,129	4,569	**7,133**
	Out-of-State	202	202	14	340	0	400	5,639	**6,798**
	Non-CREZ	399	0	0	50	1,052	150	611	**2,263**
	Scenario Total	661	1,000	14	1,889	1,052	1,679	11,198	**17,493**
Time Constrained	CREZ-North CA	22	0	0	900	0	0	78	**1,000**
	CREZ-South CA	94	0	0	1,593	0	934	4,206	**6,826**
	Out-of-State	177	158	223	340	0	400	7,276	**8,574**
	Non-CREZ	268	0	0	50	2,322	150	611	**3,402**
	Scenario Total	560	158	223	2,883	2,322	1,484	12,171	**19,802**
High Load	CREZ-North CA	3	0	0	900	0	0	1,205	**2,108**
	CREZ-South CA	30	1,591	0	2,502	0	3,069	4,245	**11,437**
	Out-of-State	34	154	16	340	0	400	4,149	**5,093**
	Non-CREZ	271	0	0	283	1,052	520	0	**2,126**
	Scenario Total	338	1,745	16	4,024	1,052	3,989	9,599	**20,763**

Renewable portfolios for 2020: 2010 LTPP Scenarios

Capacity (MW)	33% Trajectory		33% Env Constrained		33% Cost Constrained		33% Time		33% Trajectroy Low		33% Trajectory High		20% Trajectory		2009 Vintage 33%	
	In-State	Out-of-State	In-State	Out-of-State	In-State	Out-of-State	In-State	Out-of-State	In-State	Out-of-State	In-State	Out-of-State	In-State	Out-of-State	In-State	Out-of-State
Biogas	178	0	178	66	168	73	172	73	178	0	178	0	178	0	1409	
Biomass	126	34	404	156	291	129	212	103	126	34	126	34	126	34		
Geothermal	667	154	240	270	797	202	0	158	617	154	1,591	154	113	154	2598	
Hydro	0	16	0	132	0	14	0	223	0	16	0	16	0	16	680	
Large Scale Solar PV	3,527	340	2,315	340	1,549	340	2,543	340	3,147	340	3,684	340	1,509	340	5432	534
Small Scale Solar PV	1,052	0	9,077	0	1,052	0	2,322	0	1,052	0	1,052	0	1,052	0		
Solar Thermal	3,589	400	1,072	400	1,279	400	1,084	400	1,790	400	3,589	400	1,034	400	6902	
Wind	5,034	4,149	4,426	1,454	5,559	5,639	4,895	7,276	4,006	4,149	5,450	4,149	3,877	1,454	11291	3302
Total	14,173	5,093	17,711	2,818	10,696	6,798	11,228	8,574	10,916	5,093	15,670	5,093	7,889	2,398	28312	

Planning Reserve Margin for 2020 Portfolios: 2010 LTPP Scenarios



Note: Planning reserve margin calculated by E3

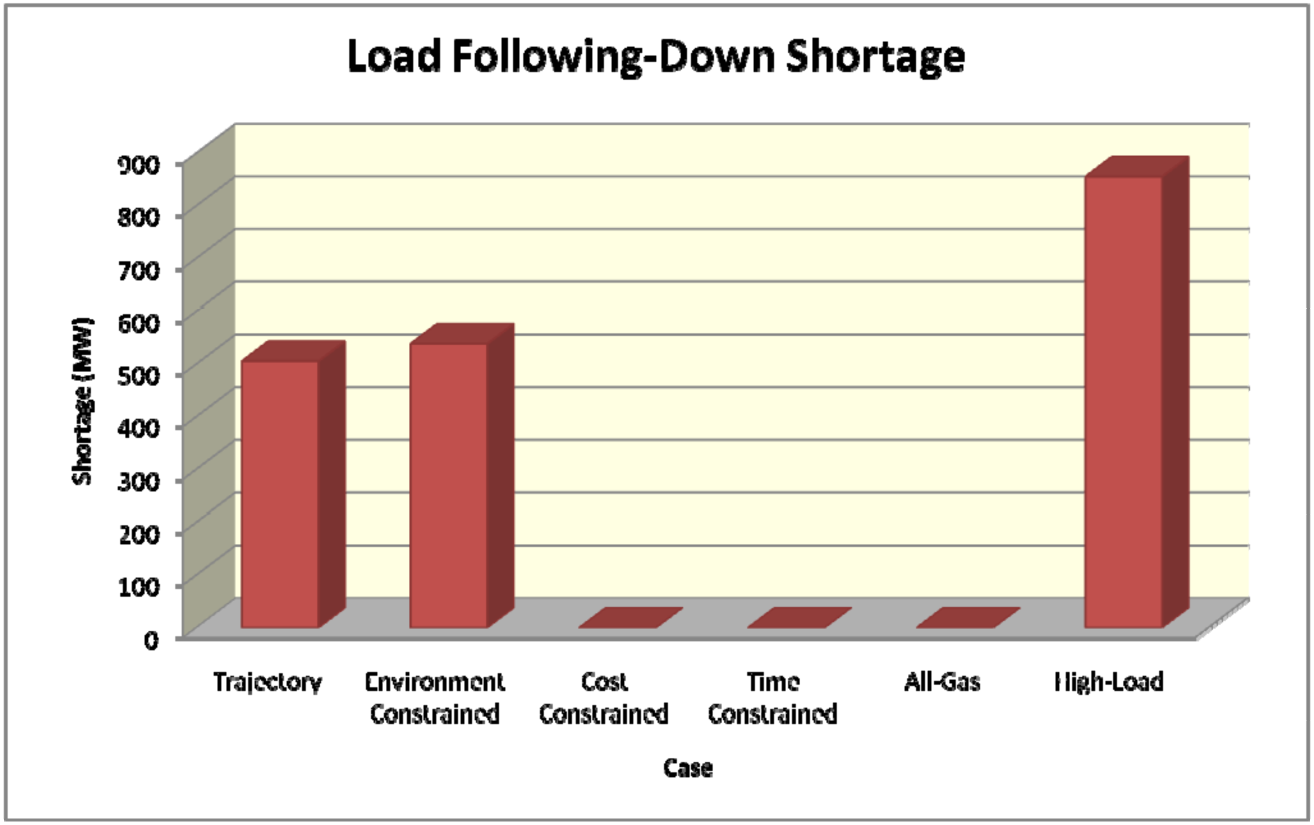
Production simulation results in this section reflect certain assumptions

- Intra-hourly operational needs from Step 1 assume monthly maximum requirements for each hour
  - Regulation, load-following
- Additional resources are added by the model to resolve operational constraints (ramp, ancillary services); this process determines potential need.
- Renewable resources located outside California to serve California RPS will create costs that will be paid for by California load-serving entities – see Step 3 results completed by California IOUs

The analysis adds resources above the defined case resource level to resolve an observed operational violations.

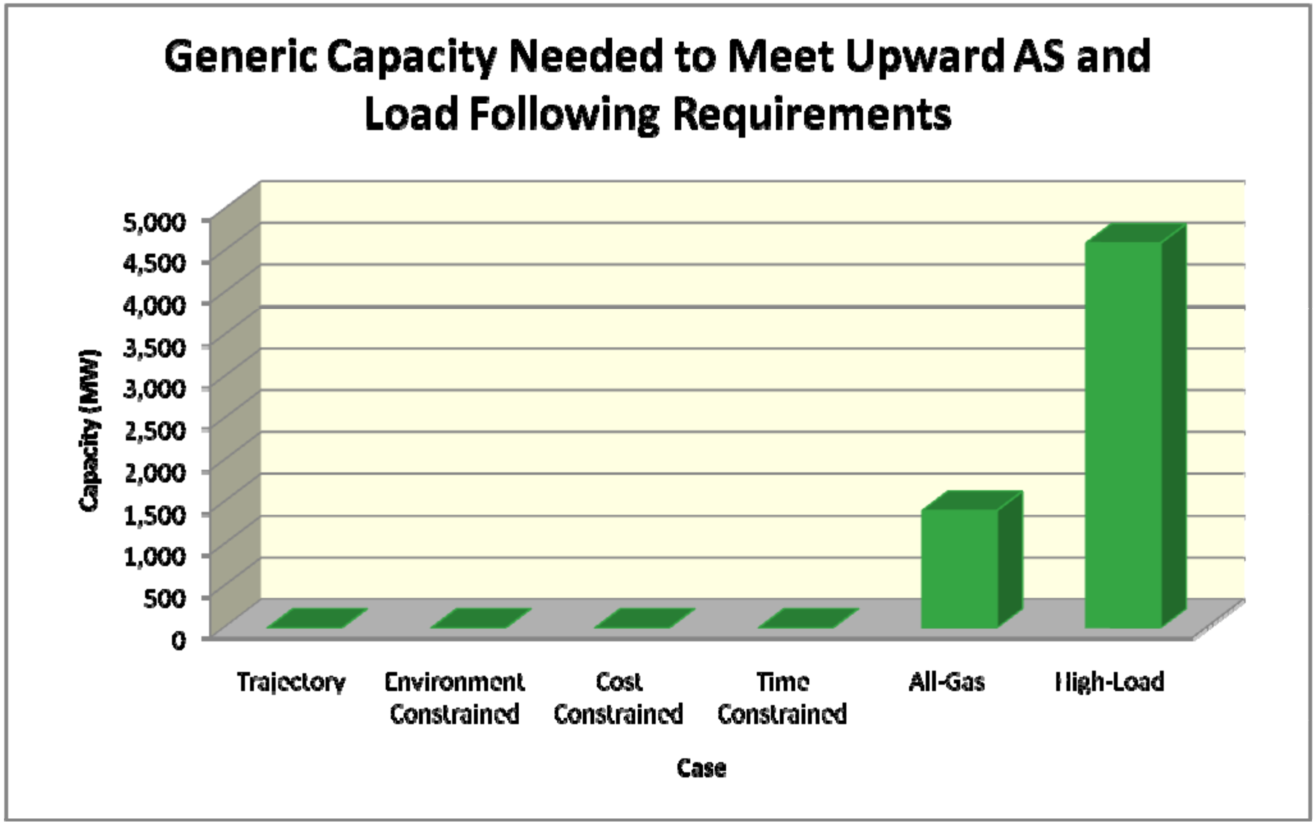
- LTPP analysis did not require adding any generic units to meet PRM because CPUC scoping memo assumptions create a 2020 base dataset that has a significant amount of capacity above PRM
- Next slide shows operational requirement shortages (constraint violations)
- Results for production costs, fuel use and emissions by scenario assume that these resources are added to generation mix

Under CPUC Scoping Memo assumptions, there are some hours with load following down shortages.



Note: No generic capacity is added to meet load following down shortage. Other measures, such as generation curtailment should be able to address this issue

Generic resources are added to meet upward ancillary services and load following requirements in the two additional cases.



Note: There is no upward ancillary service and load following shortage under CPUC Scoping Memo assumptions

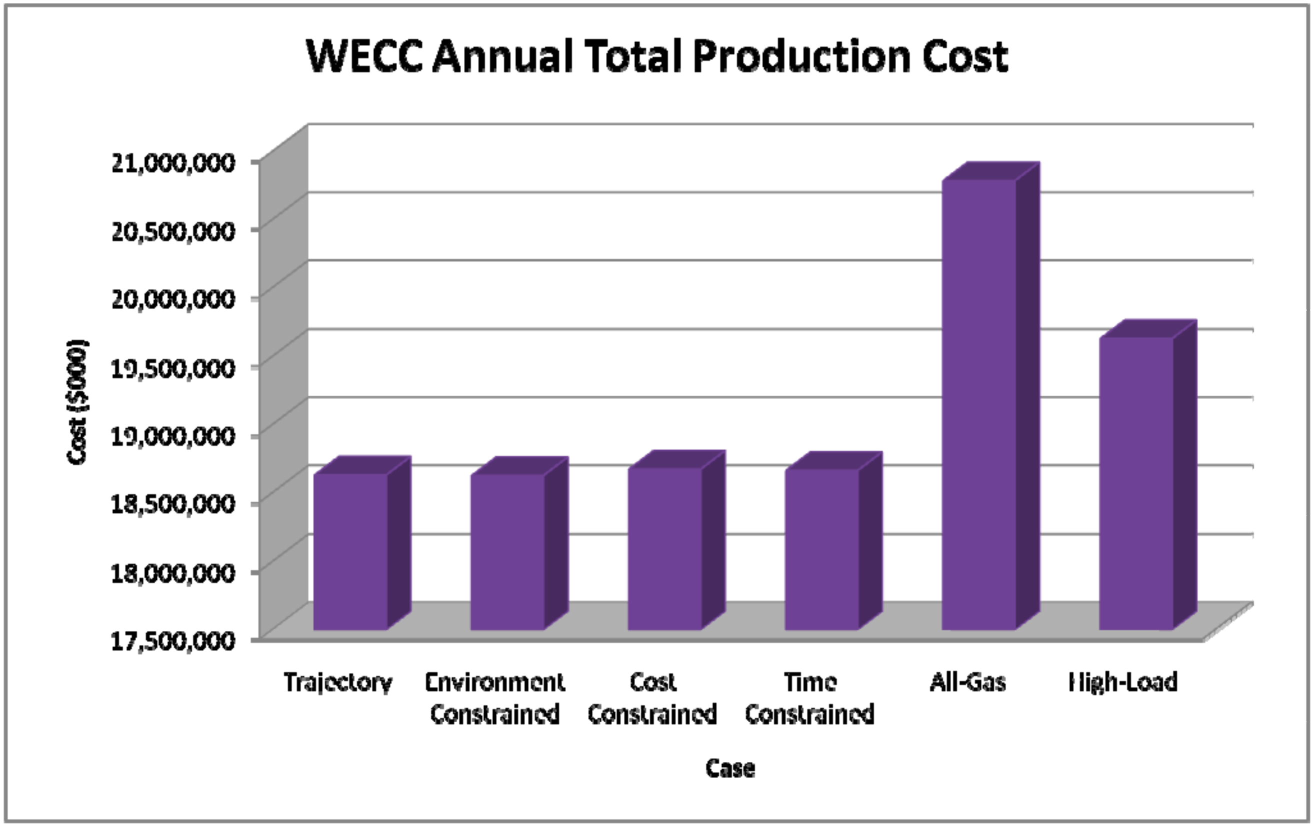
Discussion of results on additional resources

- No upward violations identified in the 2010 Trajectory, Environmental, Cost Constrained and Time Constrained scenarios due to combination of lower loads and reduced requirements
- Limited number of hours and magnitude of load following down violations warrant curtailment or other measures to resolve
- Results are sensitive to assumptions about load level, requirements based on forecast error, mix of resources, and maintenance schedules

Production costs and fuel consumption by scenario

- Production costs based primarily on generator heat rates and assumptions about fuel prices in 2020
- Trends in production costs related to fuel burn and variable O&M (VOM) costs are thus closely related
- Production costs have to be assigned to consuming regions by tracking imports and exports
- Costs associated with emission are tracked separately from fuel and VOM costs

WECC (including California) annual production costs (in 2020 dollars) by case



Notes: production cost includes generation cost and startup cost

Components for calculating California production costs

CA GENERATION COSTS

+

(**CA IMPORTS** – **CA EXPORTS**)

CA IMPORTS

- Dedicated Resources
  - Renewables
    - Firmed
    - Non-Firmed
  - Conventional Resources
    - *i.e.,* Hoover, Palo Verde
- Undesignated (or non-dedicated) Resources
  - Marginal resources in various regions

CA EXPORTS

- Undesignated (or non-dedicated) Resources
  - Marginal resources within CA regions

Calculating total California production costs

+ CA Generation Costs

- Costs to operate CA units (fuel, VOM, start costs)

+ Cost of Imported Power (into CA)

- Dedicated Import Costs
- Undesignated (or non-dedicated) Import Costs
- Out of State renewables (zero production cost)

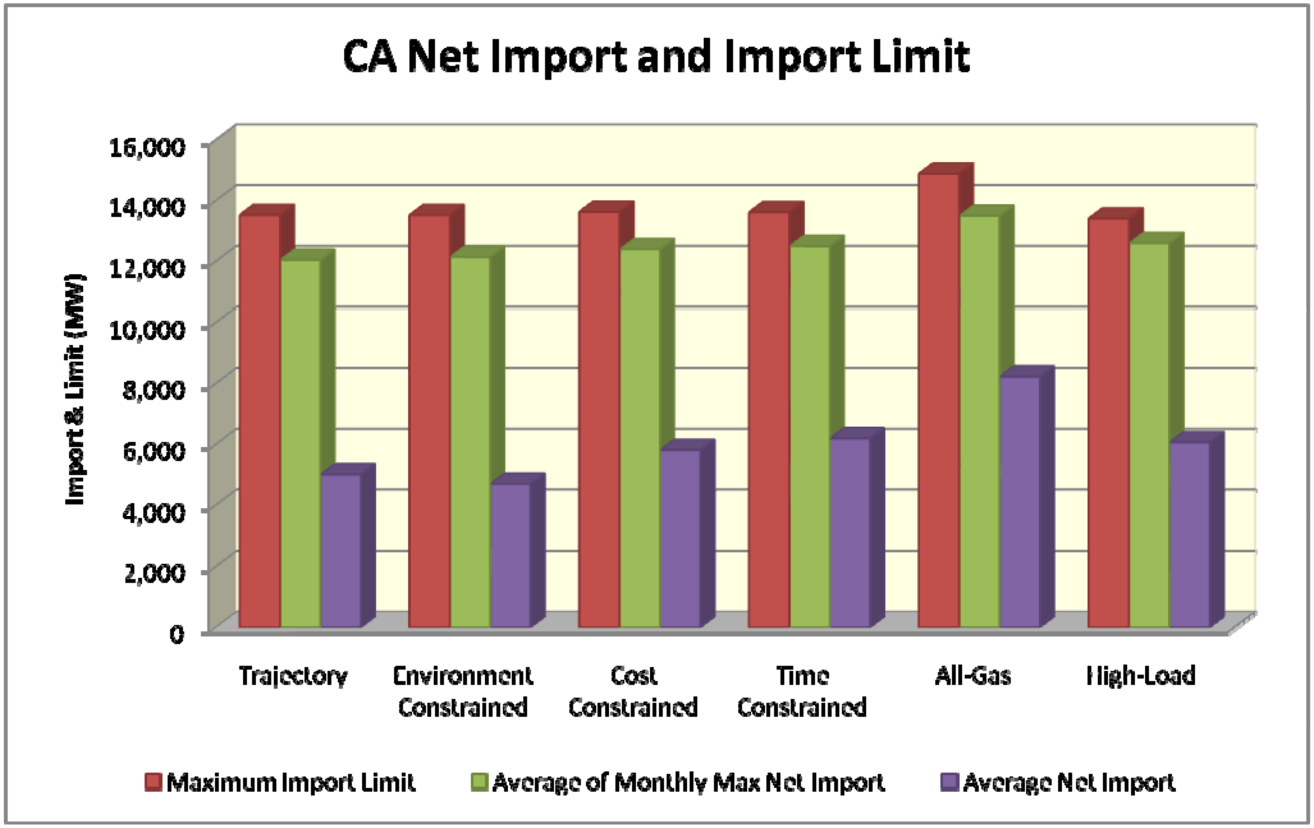
– Cost of Exported Power (out of CA)

- Undesignated (or non-dedicated) Export Costs

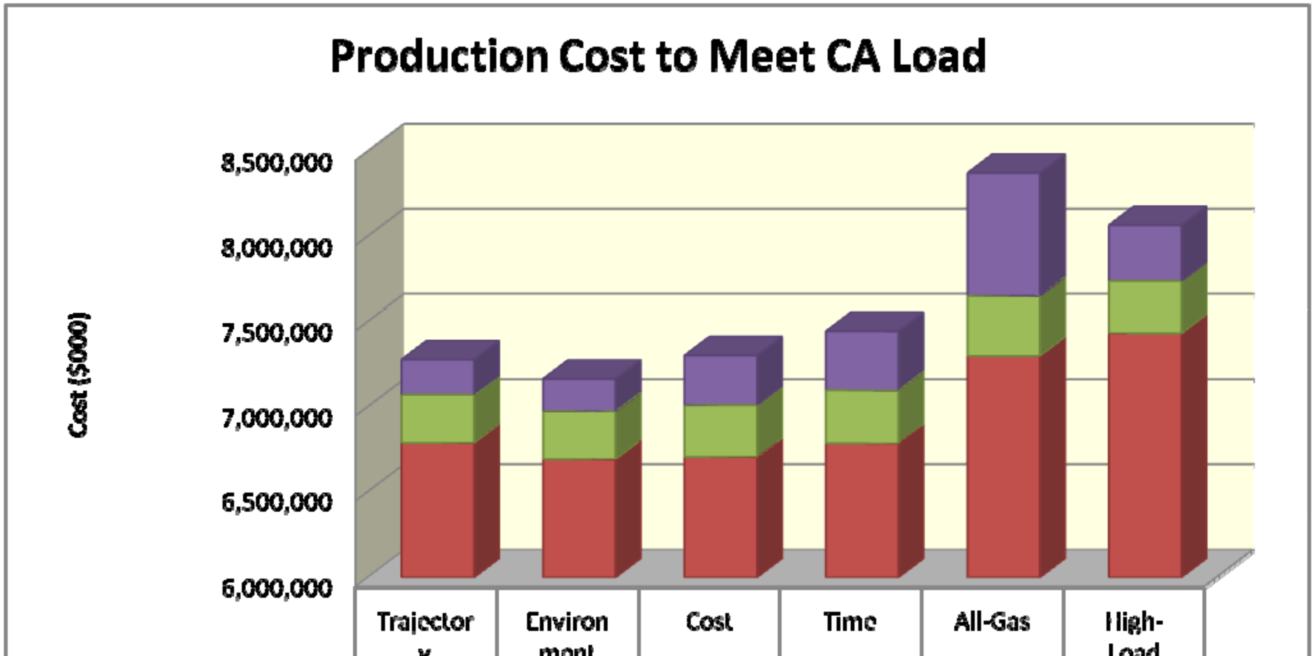
= Total Production Cost of meeting CA load

Note: Dedicated vs. Non-dedicated may also be known as specified or non-specified

California annual net import results by case



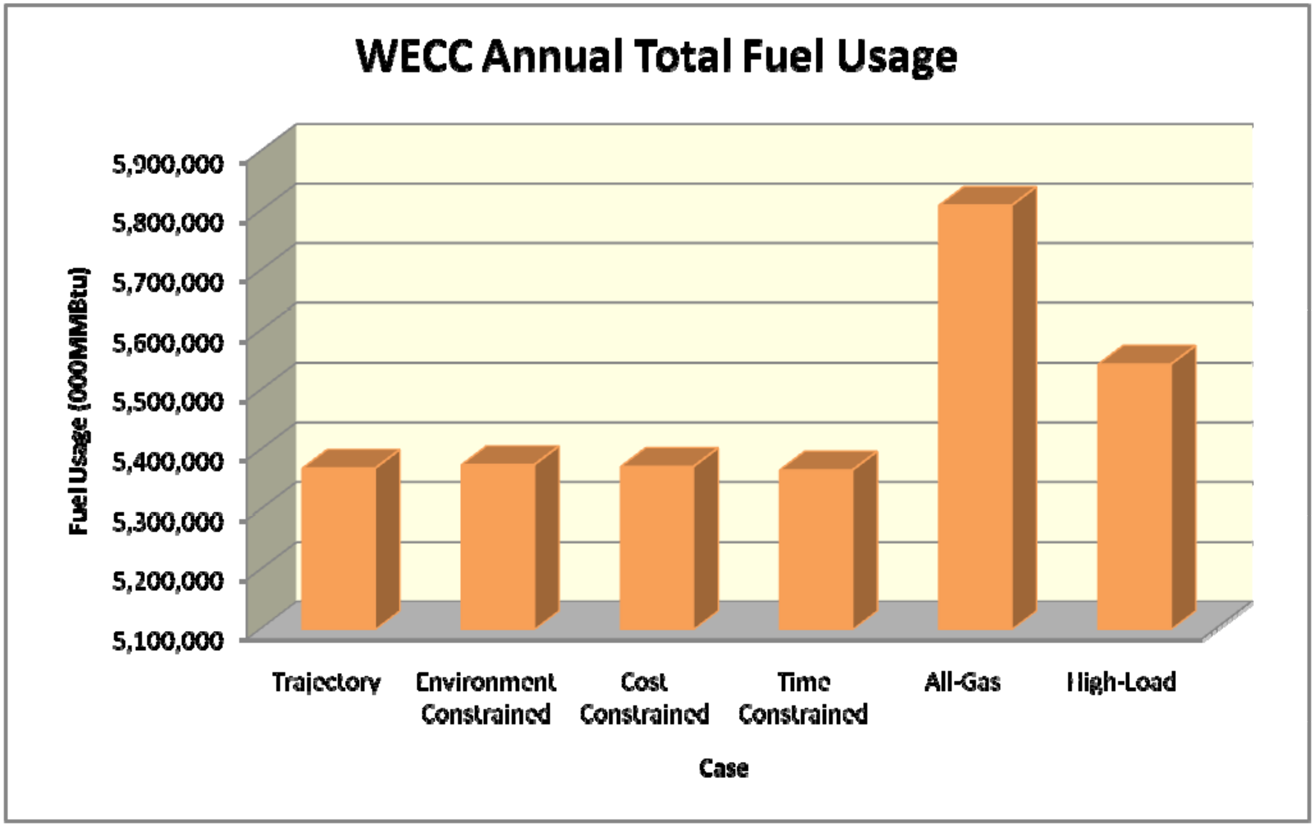
Annual production costs associated with California load (accounting for import/exports), by case



	Trajectory	Environment	Cost	Time	All-Gas	High-Load
Non-Dedicated Import	206,096	190,467	292,175	346,793	722,367	327,348
Dedicated Import	285,028	282,620	305,414	312,970	350,287	306,667
CA Generation	6,787,502	6,691,967	6,705,361	6,785,267	7,300,579	7,432,088

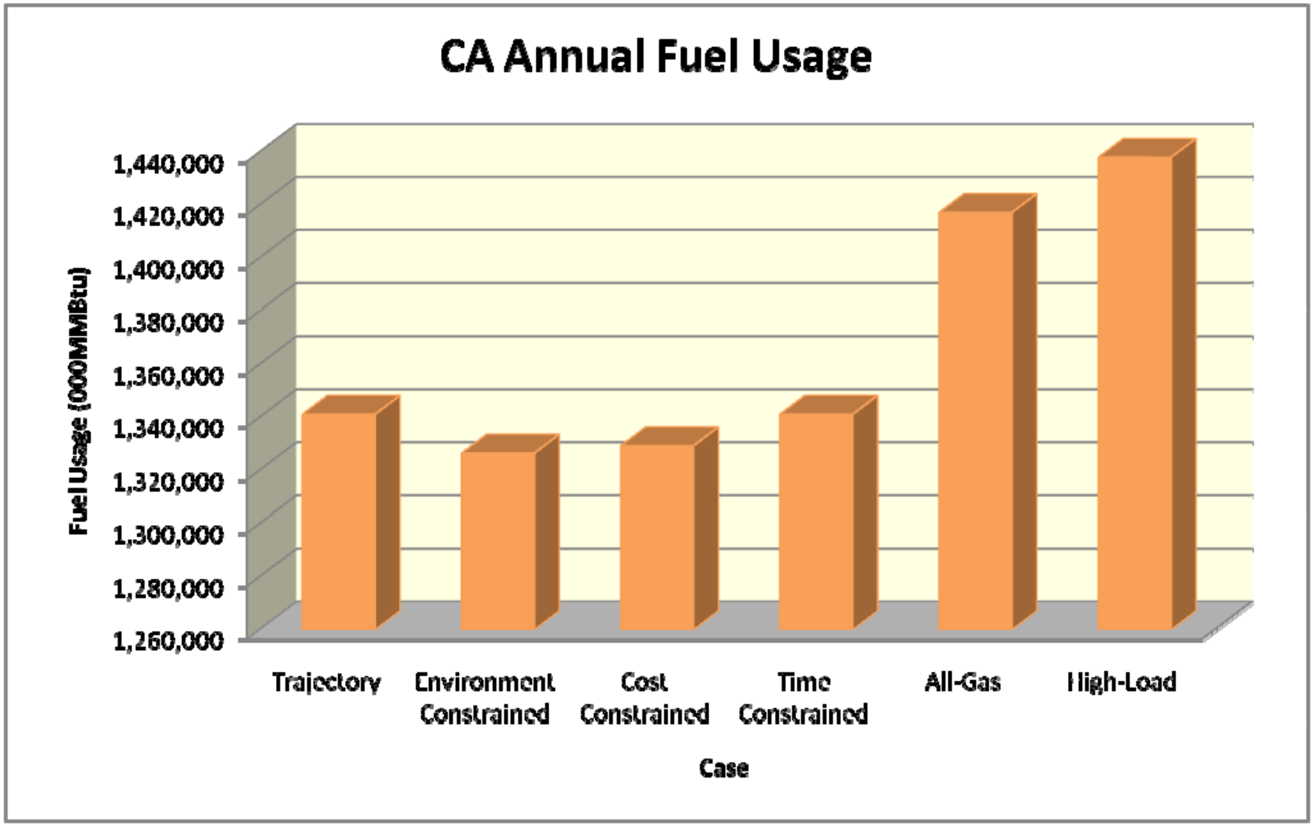
Note: Production cost associated with non-dedicated import is calculated based on the average cost ($/MWh) of each of the regions the energy is imported from; for dedicated import it is based on the actual production cost of each of the dedicated resource and its energy flows into CA

WECC (including California) annual fuel usage (MMBtu), by case



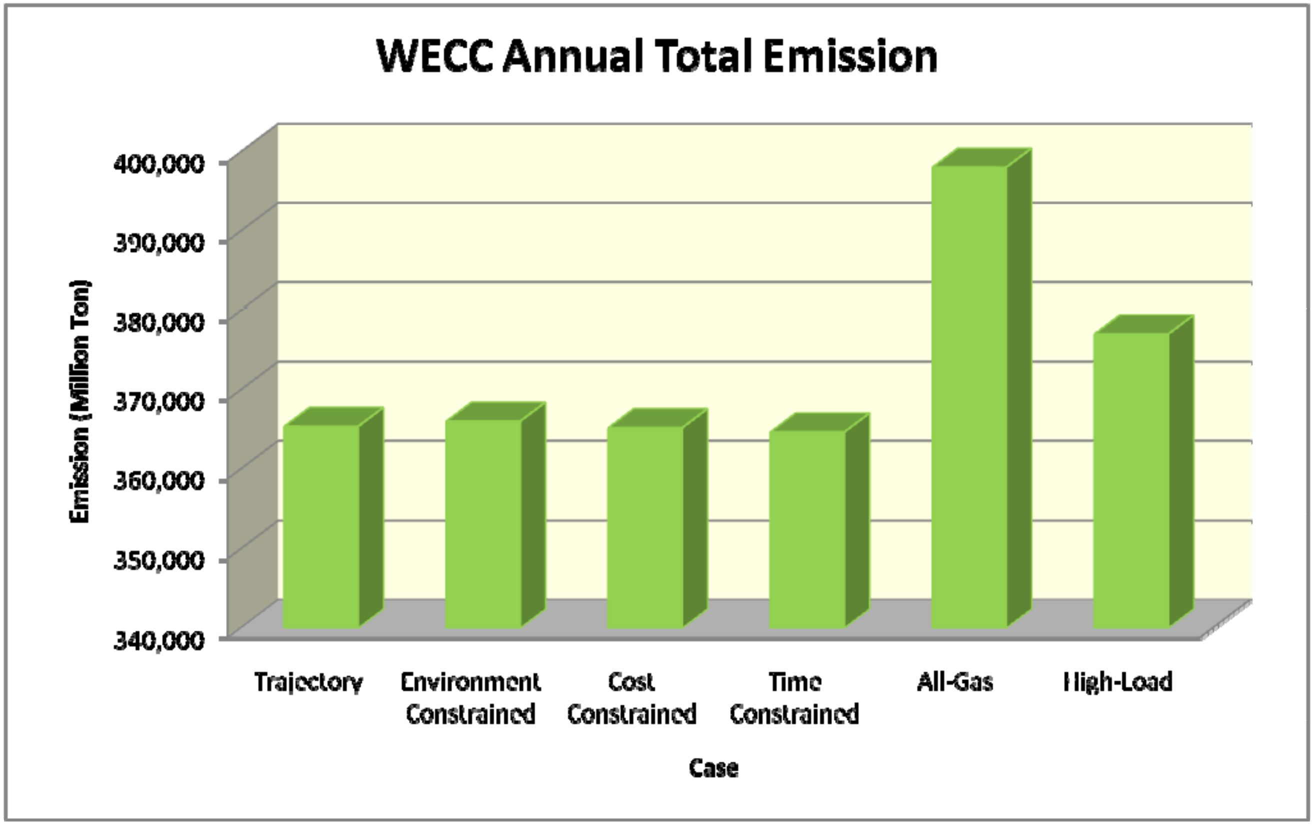
MMBtu = million BTU for conventional/fossil resources

California annual in-state generation fuel usage by case

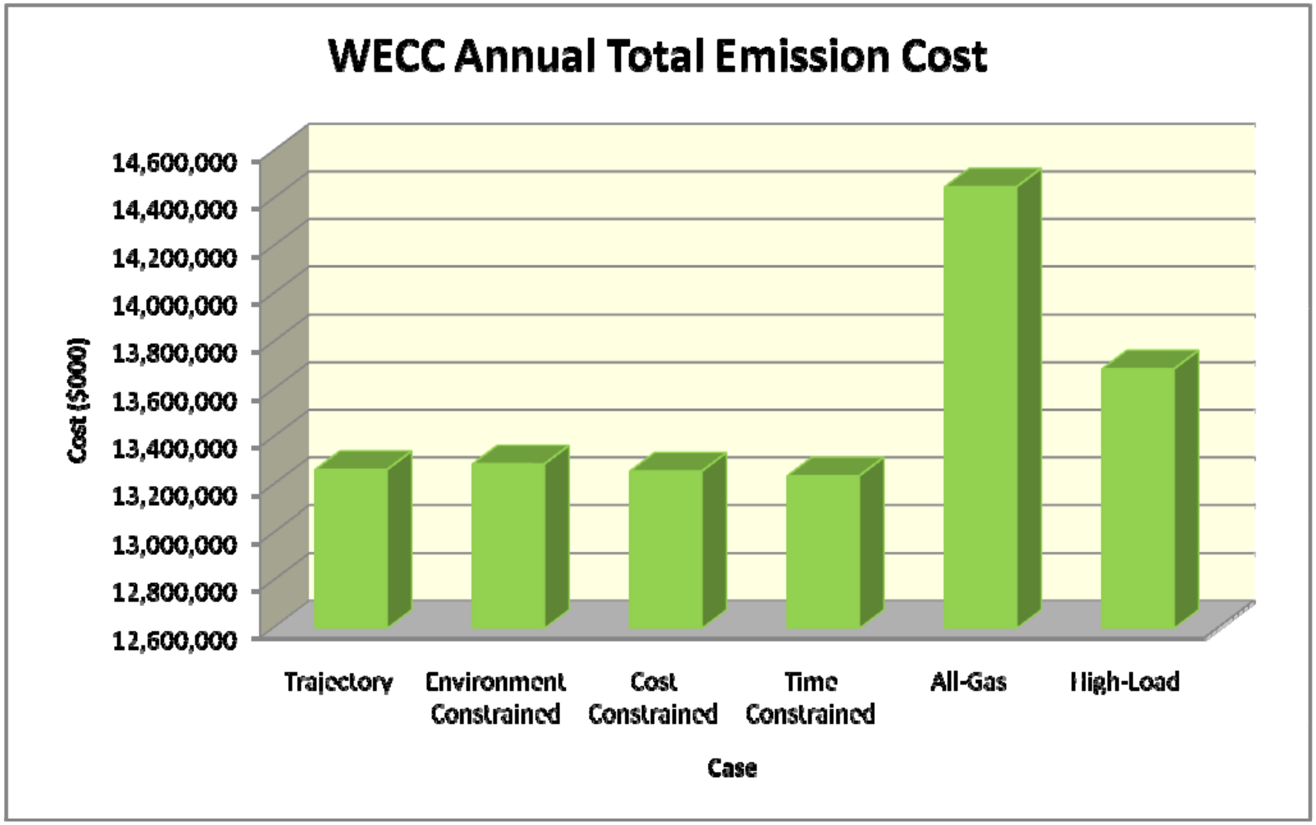


MMBtu = million BTU for conventional/fossil resources

WECC (including California) annual emissions by case



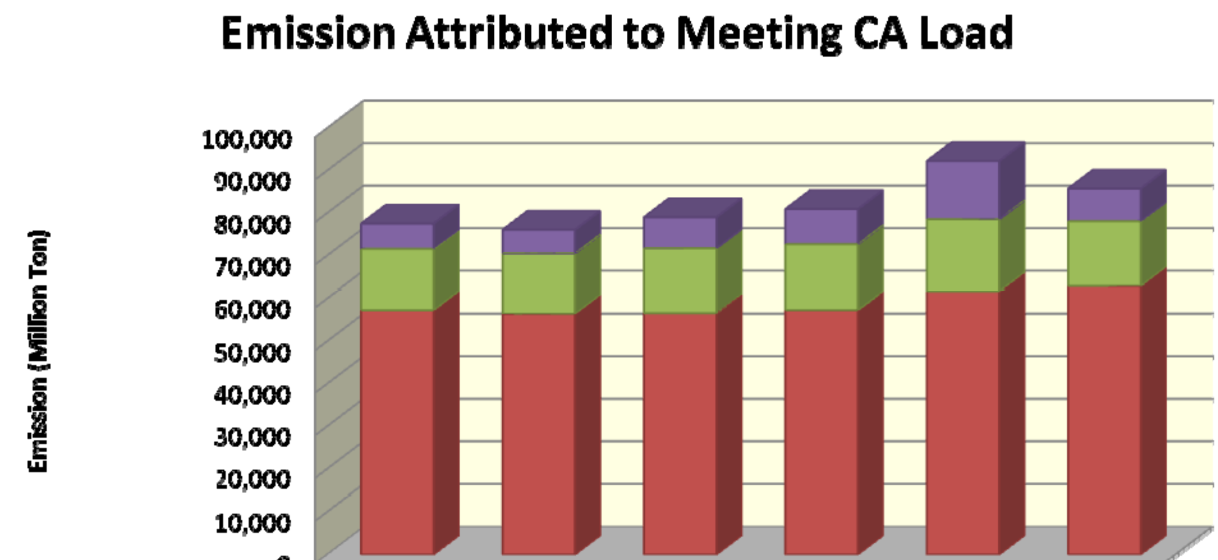
WECC (including California) annual emission costs by case



Calculation of emissions associated with California

- Production simulation modeling output includes GHG emissions (tons) per generator to capture WECC-wide emissions reductions, but:
  - The model solves production simulation for the WECC without considering contractual resources specifically dedicated to meet California load
  - Not all out of state (OOS) RPS energy dedicated to CA may “flow” into CA for every simulated hour as it could in actual operations (thus reducing emissions in CA)
- The emissions benefit of OOS RPS energy dedicated to California is counted towards meeting California load, the study uses an *ex post* emissions accounting method (next slide)

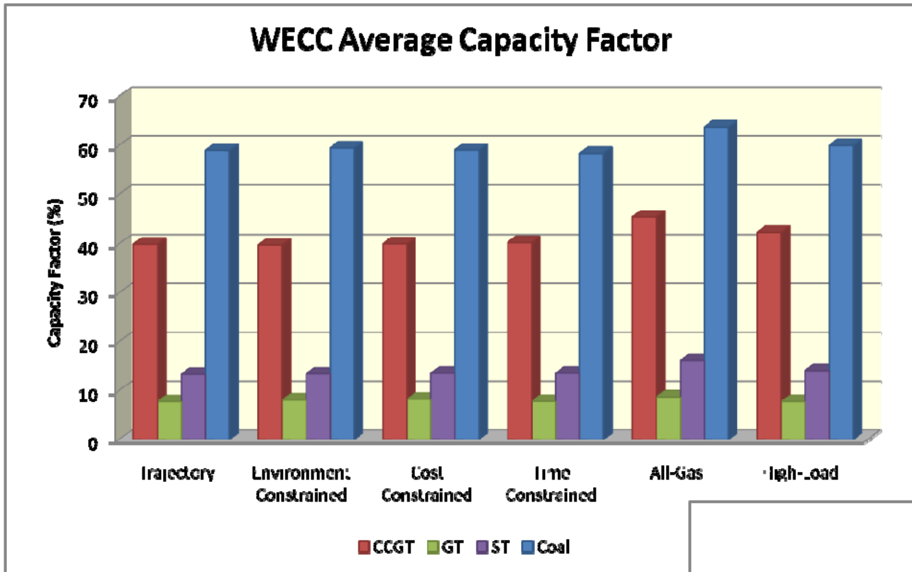
Emissions attributed to meet California load (accounting for Import/Exports), by scenario and emissions source

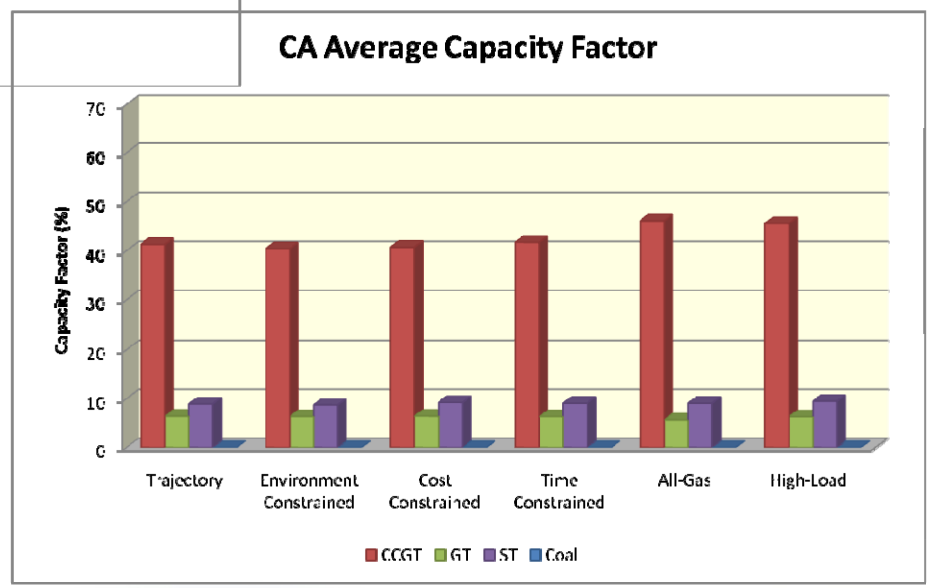


	Trajectory	Environment	Cost	Time	All-Gas	High-Load
Non-Dedicated Import	5,959	5,529	7,273	8,218	13,700	7,666
Dedicated Import	14,293	14,095	15,187	15,461	16,889	15,191
CA Generation	57,322	56,478	56,614	57,309	61,710	62,965

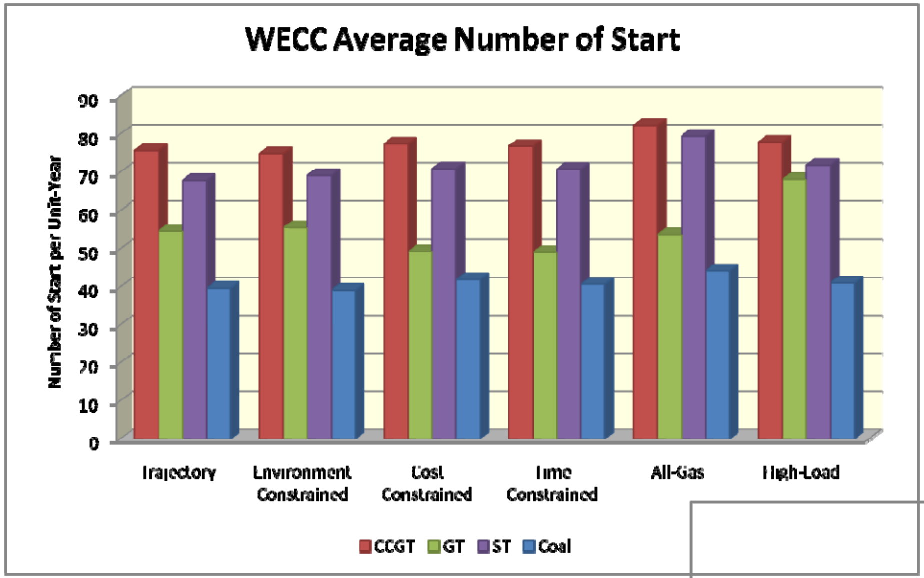
Note: Emissions associated with non-dedicated import is calculated based on the average emission rate (ton/GWh) of each of the regions the energy is imported from; for dedicated import it is based on the actual emission of each of the dedicated resource and its energy flows into CA

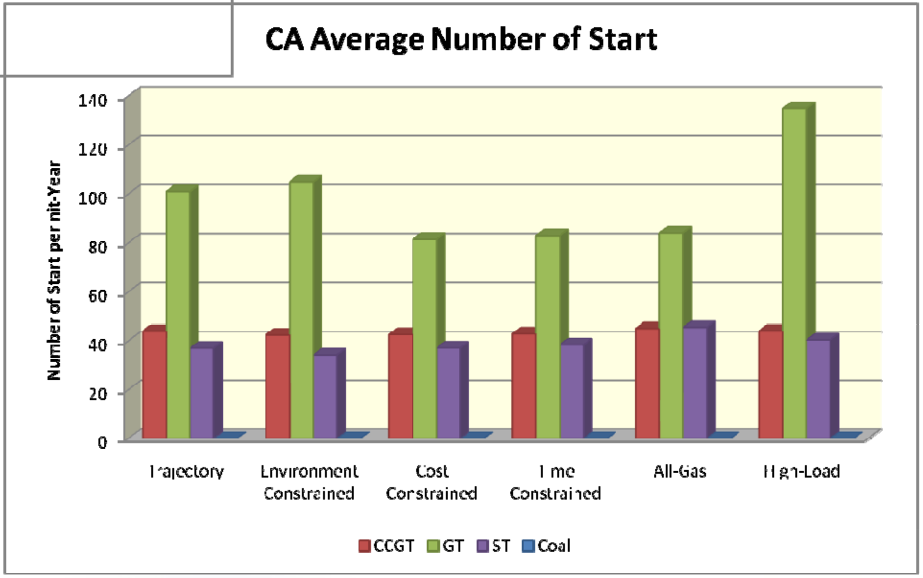
WECC and California annual average capacity factors by case





WECC and California annual average number of startup by case





Comparison of WECC (including CA) and CA results

Case	Trajectory	Environment	Cost	Time	All-Gas	High-Load
Annual Average Capacity Factor (%)						
WECC						
CCGT	39.9	39.8	40.0	40.3	45.5	42.3
GT	7.7	8.1	8.2	7.8	8.7	7.7
ST	13.3	13.4	13.5	13.5	16.1	14.1
Coal	59.0	59.5	59.0	58.4	63.7	60.0
CA						
CCGT	41.3	40.4	40.7	41.7	46.1	45.5
GT	6.4	6.3	6.4	6.3	5.6	6.3
ST	8.9	8.7	9.2	9.1	9.1	9.5
Coal	N/A	N/A	N/A	N/A	N/A	N/A
Number of Start per Unit per Year						
WECC						
CCGT	75.7	74.9	77.4	76.8	82.2	77.9
GT	54.7	55.6	49.3	49.0	53.8	68.1
ST	67.9	69.1	70.9	70.7	79.4	71.8
Coal	39.7	39.2	41.9	40.7	44.2	41.1
CA						
CCGT	43.9	42.3	42.6	42.8	44.9	44.0
GT	100.9	104.9	81.4	82.9	84.0	134.8
ST	37.0	34.2	37.1	38.4	45.5	40.4
Coal	N/A	N/A	N/A	N/A	N/A	N/A

APPENDIX:
PRODUCTION SIMULATION MODEL CHANGES

Overview of Step 2 Database and Modeling

- To conduct the LTPP Step 2 analysis, an up-to-date PLEXOS database was required
- ISO used the 33% operational study PLEXOS database as a starting point
- Input data from this database were changed to align with the assumptions in the CPUC scoping memo
- Non-specified assumptions were updated by the ISO to reflect operational feasibility and to include the best publically available data
- To ensure the April 29th deadline was met, PLEXOS implemented several modeling enhancements to improve simulation efficiency

Key Inputs

- Two sets of key inputs: CPUC specified assumptions and non-specified assumptions updated by the ISO
- Assumptions stated in the CPUC Scoping Memo
  - Load forecast that includes demand side reductions
  - Renewable resource build-out
  - Existing, planned and retiring generation
  - Maximum import capability to California
  - Gas price methodology for California
  - CO_2 price assumption
- Non-specified assumptions updated by the ISO
  - Allocation of reserve requirements between ISO and munis
  - Generator operating characteristics and profiles
  - Operational intertie limits
  - Loads, resources, transmission and fuel prices outside of California

CPUC SPECIFIED ASSUMPTIONS

Load – Load Profiles

- Nexant created a load profile that was consistent with the CPUC's forecasted load for the analysis of the four LTPP scenarios
- Load profile adjustment made to the CPUC specified demand side resources
  - Energy efficiency
  - Demand side CHP
  - Behind-the-meter PV – modeled as supply
  - Non-event based demand response

Generation - CPUC Generation Dataset

- CPUC provided data on existing, planned and retiring generation facilities
- Existing resources specified by the CPUC were drawn from two resources:
  - 2011 Net Qualifying Capacity (NQC) as of August 2^{nd}, 2010
  - ISO master generation list
- Additions and non-OTC retirements are drawn from the ISO OTC scenario analysis tool; other additions are resources with CPUC approved contracts that do not have AFC permits approved
  - Combined cycle resources in CPUC planned additions were modeled with generic unit operating characteristics taken from the MPR
- OTC retirements taken from the State Water Board adopted policy with several CPUC modifications

CPUC Supply Side CHP and DR Specifications

- Existing CHP and DR bundles in the 33% operational study PLEXOS database were scaled to match the incremental supply side CHP and DR goals in the CPUC scoping memo
- 761 MW of incremental supply side CHP was assumed to be online in 2020 with a heat rate of 8,893 Btu/kWh per the CPUC scoping memo
- 4,817 MW of incremental DR was modeled as supply in 2020 (including line losses)
  – Non-event based DR was included in the load profiles and not in the Step 2 database as supply side resource

Load and Resource Balance with CPUC assumptions

- The CPUC Scoping Memo assumptions estimate a 17,513 MW surplus above Planning Reserve Margin in 2020 in the ISO

Load and Resource Balance in the ISO using CPUC Resource Assumptions (MW)

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Load										
ISO Summer Peak Load	49,143	49,902	50,678	51,283	51,913	52,555	53,246	53,905	54,571	55,298
Total Demand Side Reductions	(3,432)	(4,712)	(5,650)	(6,374)	(7,187)	(8,036)	(8,936)	(9,874)	(10,776)	(11,651)
Net ISO Peak Summer Load	45,711	45,190	45,028	44,909	44,726	44,519	44,310	44,031	43,795	43,647
Resources										
Existing Generation	52,435	52,435	52,435	52,435	52,435	52,435	52,435	52,435	52,435	52,435
Retiring Generation	(1,260)	(1,425)	(1,425)	(2,434)	(4,694)	(5,646)	(10,378)	(11,329)	(12,280)	(14,357)
Planned Additions (Thermal, RPS, CHP)	1,747	4,388	6,728	7,336	10,558	11,280	12,207	12,283	13,471	13,547
Net Interchange (Imports - Exports)	16,955	16,955	16,955	16,955	16,955	16,955	16,955	16,955	16,955	16,955
Summary										
Total System Available Generation	69,877	72,353	74,693	74,292	75,254	75,024	71,219	70,344	70,581	68,580
Total System Capacity Requirement (PRM)	53,482	52,872	52,683	52,544	52,329	52,087	51,843	51,516	51,240	51,067
Surplus	**16,395**	**19,480**	**22,010**	**21,748**	**22,924**	**22,936**	**19,376**	**18,827**	**19,340**	**17,513**

Updating Generation Data in 33% Operational Database

- **The generation data in the 33% operational database were updated to reflect the specified existing, planned and retiring facilities in the CPUC scoping memo**
- **ISO also solicited feedback from the working group, stakeholders via ISO market notice and also all parties on the LTPP service list on generator operating characteristics which was incorporated into the Step 2 database**
- **ISO found some discrepancies in the CPUC generation assumptions which it has corrected in its Step 2 database and accounting:**
  - Double-counting of the Ocotillo facility
  - Renewable resource capacity additions above what is chosen in the 33% RPS calculator
  - Double counting of several resources as both imports and resources

Ocotillo/Sentinel Generation

- CPUC scoping memo includes two separate facilities in its planned additions for Ocotillo (455 MW) and Sentinel (850 MW)
- Ocotillo is a subset of the Sentinel facility (units 1-5)
  - SCE signed a contract with Sentinel for an additional three units in 2008
- ISO Step 2 database only includes eight Sentinel units (850 MW) because Ocotillo (455 MW) is already accounted for in Sentinel's nameplate capacity

RPS Resources above 33%

- CPUC included 287 MW of RPS resources in its planned additions that are not included in the 33% RPS scenarios:
  - CalRENEW-1(A) (5 MW)
  - Copper Mountain Solar 1 PseudoTie-pilot (48 MW)
  - Vaca-Dixon Solar Station (2 MW)
  - Blythe Solar 1 Project (21 MW)
  - Calabasas Gas to Energy Facility (14 MW)
  - Chino RT Solar Project (2 MW)
  - Chiquita Canyon Landfill (9 MW)
  - Rialto RT Solar (2 MW)
  - Santa Cruz Landfill G-T-E Facility (1 MW)
  - Sierra Solar Generating Station (9 MW)
  - Celerity I (15 MW)
  - Black Rock Geothermal (159 MW)
- If included, these resources will create RPS scenarios that are above 33% RPS
- These resources were not profiled in the Step 1 analysis
- ISO did not include these resources in the Step 2 database

Existing Generation/Imports Discrepancies

- The 2011 NQC list includes 2,626 MW of resources that are imports to the ISO
  - APEX_2_MIRDYN (505 MW)
  - MRCHNT_2_MELDYN (439 MW)
  - MSQUIT_5_SERDYN (1,182 MW)
  - SUTTER_2_PL1X3 (500 MW)
- The CPUC's original L&R tables counted the capacity of these resources twice:
  1. Directly, as specified resources with NQC capacity
  2. Indirectly, by assuming full transmission capability into the ISO
- For accounting purposes and to avoid double accounting, ISO has removed these resources from the available generation but maintains the assumption of full transmission capability into the ISO
- Modeled Coolwater 3 and 4 instead of assumed retired.

Load and Resource Balance After Assumption Modifications

- Accounting for all of these modifications, the load and resource balance has a surplus of 14,144 MW above PRM in 2020, compared to 17,513 MW above PRM using the CPUC assumptions

Load and Resource Balance in the ISO using CAISO Resource Modifications (MW)

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Load										
Summer Peak Load	49,143	49,902	50,678	51,283	51,913	52,555	53,246	53,905	54,571	55,298
Total Demand Side Reductions	3,432	4,712	5,650	6,374	7,187	8,036	8,936	9,874	10,776	11,651
Net Peak Summer Load	45,711	45,190	45,028	44,909	44,726	44,519	44,310	44,031	43,795	43,647
Resources										
Existing Generation	49,809	49,809	49,809	49,809	49,809	49,809	49,809	49,809	49,809	49,809
Retiring Generation	(1,260)	(1,425)	(1,425)	(2,434)	(4,694)	(5,646)	(10,378)	(11,329)	(12,280)	(14,357)
Planned Additions (Thermal, RPS, CHP)	1,618	4,259	6,440	7,048	9,815	10,537	11,464	11,540	12,728	12,804
Net Interchange (Imports - Exports)	16,955	16,955	16,955	16,955	16,955	16,955	16,955	16,955	16,955	16,955
Summary										
Total System Available Generation	67,122	69,598	71,779	71,378	71,885	71,655	67,850	66,975	67,212	65,211
Total System Capacity Requirement (PRM)	53,482	52,872	52,683	52,544	52,329	52,087	51,843	51,516	51,240	51,067
Surplus Above PRM with CAISO Modifications	13,640	16,726	19,096	18,834	19,556	19,568	16,007	15,459	15,972	14,144
Surplus Above PRM with CPUC Assumptions	16,395	19,480	22,010	21,748	22,924	22,936	19,376	18,827	19,340	17,513
Difference in Surplus between CPUC and CAISO	***2,755***	***2,755***	***2,914***	***2,914***	***3,369***	***3,369***	***3,369***	***3,369***	***3,369***	***3,369***

MPR Gas Forecast Methodology

- CPUC Scoping Memo specifies that the LTPP proceeding use a gas forecast calculated using the same methodology as the Market Price Referent (MPR) using NYMEX data gathered from 7/26/2010 – 8/24/2010
  - MPR methodology provides a transparent framework to derive a forecast of natural gas prices at the utility burner-tip in California
  - In the near term (before 2023), the forecast is based on:
    1. NYMEX contract data for natural gas prices at Henry Hub and basis point differentials between HH and CA
    2. A municipal surcharge, calculated as a percentage of the commodity cost
    3. A gas transportation cost based on the tariffs paid by electric generators

CA Gas Forecast

- 2020 natural gas forecast for CA delivery points (2010$/MMBtu)

Zone	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Gas - PGE_Citygate	$ 5.95	$ 5.92	$ 5.75	$ 5.31	$ 5.29	$ 5.34	$ 5.41	$ 5.45	$ 5.47	$ 5.54	$ 5.79	$ 6.04
Gas - PGE_Citygate_BB	$ 6.07	$ 6.04	$ 5.87	$ 5.43	$ 5.41	$ 5.46	$ 5.53	$ 5.57	$ 5.59	$ 5.66	$ 5.92	$ 6.17
Gas - PGE_Citygate_LT	$ 6.23	$ 6.20	$ 6.03	$ 5.59	$ 5.57	$ 5.62	$ 5.69	$ 5.73	$ 5.75	$ 5.82	$ 6.08	$ 6.33
Gas - SoCal_Border	$ 5.74	$ 5.70	$ 5.54	$ 5.13	$ 5.11	$ 5.16	$ 5.23	$ 5.27	$ 5.29	$ 5.36	$ 5.58	$ 5.83
Gas - SoCal_Burnertip	$ 6.18	$ 6.15	$ 5.98	$ 5.57	$ 5.54	$ 5.60	$ 5.67	$ 5.71	$ 5.72	$ 5.80	$ 6.02	$ 6.28

CO_2 Price

- A \$36.30/short ton of CO_2 (2010\$) cost was used in the PLEXOS simulations per the CPUC scoping memo

NON-SPECIFIED ASSUMPTIONS UPDATED BY ISO

Allocation of Reserves Between ISO and Munis

- Step 1 analysis created statewide load following and regulation requirements
- Step 2 is an ISO-wide analysis that requires an allocator to split the load following and regulation requirements between the IOUs and Munis
- Allocator calculated using two parts:
  - 50% of allocator = ratio of peak load between the ISO (83%) and Munis (17%)
  - 50% of allocator = fraction of wind and solar resources delivered to California that are integrated by the ISO (94%) and Munis (6%)
- This results in the following allocation of the reserve requirements: 88.5% to the ISO and 11.5% to the Munis

Update of Generator Operating Characteristics

- ISO received feedback from 4 stakeholders on information in the 33% operational study PLEXOS database
  - Comprehensive list of changes came from SCE and included updated information on individual generator operating characteristics and SP15 hydro dispatch
  - Calpine submitted a new start profile for CCGTs
- CT planned additions and generic units were mapped to the operating characteristics of an LMS100 or LM6000 depending on plant size

Helms modeling

- PG&E updated the maximum capacity of the Helms reservoir to 184.5 GWh
- PG&E provided end of spring reservoir energy storage target and summer monthly energy usage schedules
- ISO consulted with PG&E to develop the appropriate pumping windows in 2020
  - availability in the summer months, Helms pumping was restricted to 1 pump between May and September
  - 3 pumps were assumed to be available for October through April
- Continued discussions with PG&E suggest that three pump capability in 2020 in non-summer months may not be possible; may warrant additional sensitivities

Transmission Import Limits to CA

- ISO defined simultaneous import limits to CA
- ISO used a model developed by the ISO to estimate the Southern California Import Transmission (SCIT) limit based on
  - planned thermal additions
  - OTC retirements
  - renewable resources additions
  - neighboring transmission path flows into and around the SCIT area

Import Limits by Scenario and Time

Transmission Limits (MW)	Summer Pk	Summer Off Pk	Winter Pk	Winter Off Pk
Trajectory Case				
S. Cal Import Limit to be used for study	12,726	10,290	11,331	8,405
Total California Import Limit	13,526	11,090	12,131	9,205
Environmental Case				
S. Cal Import Limit to be used for study	12,724	10,224	11,349	8,340
Total California Import Limit	13,524	11,024	12,149	9,140
Cost Case				
S. Cal Import Limit to be used for study	12,833	10,186	11,457	8,302
Total California Import Limit	13,633	10,986	12,257	9,102
Time Case				
S. Cal Import Limit to be used for study	12,819	10,224	11,427	8,340
Total California Import Limit	13,619	11,024	12,227	9,140
All-Gas				
S. Cal Import Limit to be used for study	14,086	10,735	12,110	8,851
Total California Import Limit	14,886	11,535	12,910	9,651
High-Load				
S. Cal Import Limit to be used for study	12,610	10,237	11,270	8,352
Total California Import Limit	13,410	11,037	12,070	9,152

Assumptions of Gas Forecast Outside of CA

- The MPR methodology provides a forecast of gas prices for generators inside of California
- In order to avoid skewing the relative competitive position of gas fired generators inside and outside of California, WECC-wide gas prices outside of California must be updated to reflect the same underlying commodity cost of gas embedded in the MPR forecast

Gas Forecast Outside of CA (cont'd)

- Created an MPR-style forecast for gas prices elsewhere in the WECC drawing upon available NYMEX contract data over the same trading period (7/26/10 – 8/24/10):
  - In addition to the California gas hubs (PG&E Citygate and Socal Border), forecast hub prices at Sumas, Permian, San Juan, and Rockies hubs using the NYMEX basis differentials
  - For each bubble (geographic area), add appropriate delivery charges (based on TEPPC delivery charges) to the appropriate hub price to determine the burnertip price
- Two specific changes were made to this methodology based on IOU feedback:
  - Arizona gas hub was moved from Permian to SoCal Border
  - Delivery charge was removed from Sumas hub to British Columbia

Gas Forecast Outside of CA

- 2020 natural gas forecast for delivery points outside of California (2010$/MMBtu)

Zone	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Gas - AECO_C	$ 5.49	$ 5.46	$ 5.29	$ 4.72	$ 4.69	$ 4.75	$ 4.82	$ 4.86	$ 4.88	$ 4.95	$ 5.34	$ 5.59
Gas - Arizona	$ 6.06	$ 6.02	$ 5.85	$ 5.42	$ 5.39	$ 5.45	$ 5.52	$ 5.57	$ 5.58	$ 5.66	$ 5.89	$ 6.16
Gas - Baja	$ 5.74	$ 5.70	$ 5.54	$ 5.13	$ 5.11	$ 5.16	$ 5.23	$ 5.27	$ 5.29	$ 5.36	$ 5.58	$ 5.83
Gas - Colorado	$ 6.08	$ 6.04	$ 5.88	$ 5.42	$ 5.39	$ 5.45	$ 5.52	$ 5.56	$ 5.57	$ 5.65	$ 5.92	$ 6.17
Gas - Idaho_Mont	$ 6.00	$ 5.97	$ 5.81	$ 5.23	$ 5.21	$ 5.26	$ 5.33	$ 5.37	$ 5.39	$ 5.46	$ 5.85	$ 6.10
Gas - Kern_River	$ 5.74	$ 5.70	$ 5.54	$ 5.13	$ 5.11	$ 5.16	$ 5.23	$ 5.27	$ 5.29	$ 5.36	$ 5.58	$ 5.83
Gas - Malin	$ 5.98	$ 5.95	$ 5.79	$ 5.10	$ 5.07	$ 5.13	$ 5.20	$ 5.24	$ 5.26	$ 5.33	$ 5.83	$ 6.08
Gas - Pacific_NW	$ 6.11	$ 6.08	$ 5.91	$ 4.98	$ 4.95	$ 5.01	$ 5.08	$ 5.12	$ 5.14	$ 5.21	$ 5.96	$ 6.21
Gas - Permian	$ 5.58	$ 5.54	$ 5.38	$ 5.01	$ 4.99	$ 5.04	$ 5.11	$ 5.15	$ 5.17	$ 5.24	$ 5.42	$ 5.67
Gas - Rocky_Mntn	$ 5.49	$ 5.46	$ 5.29	$ 4.72	$ 4.69	$ 4.75	$ 4.82	$ 4.86	$ 4.88	$ 4.95	$ 5.34	$ 5.59
Gas - San_Juan	$ 5.52	$ 5.49	$ 5.32	$ 4.86	$ 4.84	$ 4.89	$ 4.96	$ 5.00	$ 5.02	$ 5.09	$ 5.37	$ 5.62
Gas - Sierra_Pacific	$ 6.12	$ 6.08	$ 5.92	$ 5.48	$ 5.46	$ 5.51	$ 5.58	$ 5.62	$ 5.64	$ 5.71	$ 5.96	$ 6.21
Gas - Sumas	$ 6.02	$ 5.98	$ 5.82	$ 4.89	$ 4.86	$ 4.92	$ 4.99	$ 5.03	$ 5.04	$ 5.11	$ 5.86	$ 6.11
Gas - Utah	$ 5.76	$ 5.73	$ 5.56	$ 4.99	$ 4.97	$ 5.02	$ 5.09	$ 5.13	$ 5.15	$ 5.22	$ 5.61	$ 5.86
Gas - Wyoming	$ 6.05	$ 6.01	$ 5.85	$ 5.27	$ 5.25	$ 5.30	$ 5.37	$ 5.41	$ 5.43	$ 5.50	$ 5.89	$ 6.14

TEPPC PC0 Case

- PC0, a recent TEPPC database, was used to populate the PLEXOS database with loads, resources and transmission capacity for zones outside of California
- Embedded in this case were several coal plant retirements
- ISO incorporated several adjustments to this case:
  - Included several additional coal plant retirements that were announced but not included in PC0
  - Excluded the resources assumed to contribute to California's RPS portfolio that are located outside of California

Exclusion of RPS Resources from PC0

- TEPPC's PC0 case includes enough renewables to meet RPS goals in California and the rest of the WECC
  - The portfolio for California is very similar to the Trajectory Case specified for the LTPP, which includes out-of-state renewables
- To develop consistent scenarios for LTPP, the RPS builds for CA in PC0 must be adjusted according to the following framework:

	WECC-Wide RPS Resources in PC0
–	PC0 RPS Resources in CA
–	PC0 OOS RPS Resources Attributed to CA
+	CPUC RPS Portfolio (Traj/Env/Cost/Time)
=	**RPS-Compliant LTPP Scenario**

State	Resource	MW	GWh
New Mexico	Biomass	39	231
Idaho	Geothermal	27	198
Nevada	Geothermal	76	561
Utah	Geothermal	120	885
British Columbia	Small Hydro	90	442
Oregon	Small Hydro	13	50
Nevada	Solar Thermal	285	933
Arizona	Solar PV	319	737
Nevada	Solar PV	23	41
Alberta	Wind	1,565	4,843
Colorado	Wind	517	1,298
Montana	Wind	262	818
Oregon	Wind	871	2,373
Washington	Wind	1,252	3,004
Wyoming	Wind	86	344
Total		5,544	16,760

OOS resources to remove from PC0

Coal retirements by 2020

- PC0 includes the following coal plant retirements:
  - **AESO:** Battle Units 3 & 4 and Wabamun Unit 4 **(586 MW)**
  - **NEVP:** Reid Gardner Units 1-3 **(330 MW)**
  - **PSC:** Arapahoe Units 3 & 4 and Cameo Units 1 & 2 **(216 MW)**
- Based on conversations with Xcel and announced retirements, ISO included the following retirements:
  - Arapaho Unit 4 repowers as a natural gas combined cycle **(109 MW)**
  - Cherokee Units 1-4 retire **(722 MW)**; unit 4 repowers as a natural gas combined cycle **(351 MW)**
  - Four Corners Units 1-3 retire **(560 MW)**
  - Valmont Unit 5 retires **(178 MW)**

REFINEMENTS OF THE STATISTICAL MODEL OF OPERATIONAL REQUIREMENTS (STEP 1)

Step 1 inputs and analysis of the four scenarios results are available

- Aggregate minute and hourly profile data
- Load, wind and solar forecast error
- Monthly and daily regulation and load following requirements
- Data available at: http://www.caiso.com/23bb/23bbc01d7bd0.html

Refinements to load profiles

- Load peak demand and energy adjusted to conform to CPUC scoping memo based on 2009 CEC IEPR
- LTPP net load reduction of approximately 6,500 MW in 2020 relative to “vintage” 33% reference case due to demand side programs specified in the CPUC scoping memo
- Statewide peak load in CPUC Trajectory Case is 63,755 MW versus 70,180 MW in vintage 33% ISO Operational Study reference case

Refinements to load forecast error

- Updated load forecast error based on 2010 actual load and forecast data
- Hour ahead forecast data based on T-75 minutes in updated LTPP analysis versus T-2 hours in vintage case
- 5-minute data shows increased forecast error based on actual load data

Comparison of Load Forecast Errors

LTPP Analysis

Season	HA STD 2010 ADJUSTED For PEAK (based on 2010 data)	RT (T-7.5min) STD 10% Improve 2020 (based on 2010 data)	HA autocorr	RT Autocorr
Spring	545.18	216.05	0.61	0.86
Summer	636.03	288.03	0.7	0.92
Fall	539.69	277.38	0.65	0.9
Winter	681.86	230.96	0.54	0.85

Vintage Analysis

Season	HA STD 10% Improve 2020 (based on Vitage 2006 data)	RT (T-7.5min) STD 10% Improve 2020 (based on Vitage 2006 data)
Spring	831.11	126
Summer	1150.61	126
Fall	835.11	126
Winter	872.79	126

Refinements to wind profiles

- Wind sites were expanded to include quantity and locations consistent with CPUC scoping memo
- For new plants, wind plant production modeling based upon NREL 10 minute data production was expanded to include 21 distinct locations in California and 22 locations throughout the rest of WECC.

Refinements to wind forecasting errors

- Recalibrated wind forecast errors using profiled data
- Applied a *T-1hr* persistence method for estimating forecast errors

Comparison of Wind Forecast Errors (Std Dev)

Region	Case	Technology	MW	Persistent	Hour	Spring	Summer	Fall	Winter
CA	33%Base	Wind	9436	T-1	All	0.040	0.038	0.032	0.031
					Vintage Cases	0.050	0.045	0.044	0.041

Note: Actual wind forecast error based on existing PIRP resources is higher than forecast *T-1hr* based on profiles

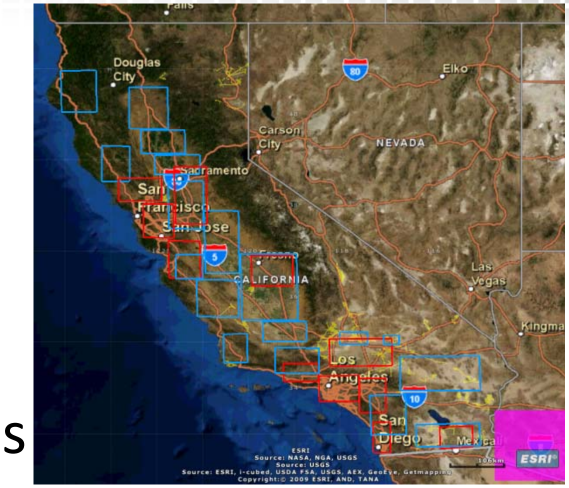
PIRP Forecast Error								
Region	Tech	MW	Persistent	Hour	Spring	Summer	Fall	Winter
CA	Wind	1005	T-2	All	11.1%	10.8%	8.1%	6.0%
CA	Wind	1005	T-1	All	8.4%	7.1%	5.3%	3.9%
CA	Wind	1005	PIRP	All	10.5%	8.9%	8.4%	6.7%

Refinements to solar profiles

- Profiles for 2010 scenarios are developed based on satellite irradiation data[1] rather than rather than NREL land based measurement data used previously.
- Variability was introduced based on a plant footprint rather than a single point
- Better represents diversity of resources
- Expanded use of 1 minute irradiance data to use three locations:
  – Sacramento Municipal Utility District (SMUD) in Sacramento
  – Loyola Marymount University in Los Angeles, and
  – in Phoenix, AZ

[1] The Solar Anywhere satellite solar irradiance data can be found at: https://www.solaranywhere.com/Public/About.aspx

Extended approach to profile small solar



- Extended method to profiling of small solar
- Define geographic boundaries of the 20 grids in Central, North, Mojave, and South area
- Choose each rectangular grid to represent an appropriate area. Each grid will have a different size rectangle
- Average the data on an hourly basis for each rectangle
- Follow similar process for developing solar profiles and adding 1-minute variability

Refinements to solar forecast errors

- Determined errors by analyzing 1-minute "clearness index" (CI) and irradiance data using *T-1 hr* persistence
- To address issues that arise using the *T-1 hr* persistence during early and later hours of the day, use 12-16 persistence to determine solar forecast error
- Results on next slide
  - CI persistence method for Hours 12-16 similar in outcome to "improved" errors
- Recommendations:
  - Since forecast errors are based on profiles and not actual production data, recommend calibrating the simulated to the actual forecast errors when more solar data is available
  - Continue to develop forecasting error for early and later hours of the day

Comparison of solar forecast error with persistence

Comparison of Solar Forecast Errors

Region	Case	Technology	MW	Persistent	Hour	0<=CI<0.2	0.2<=CI<0.5	0.5<=CI<0.8	0.8<=CI<=1
CA	33%Base	PV	3527	T-1	Hour12-16	0.035	0.069	0.056	0.023
CA	33%Base	ST	3589	T-1	Hour12-16	0.060	0.109	0.108	0.030
CA	33%Base	DG	1045	T-1	Hour12-16	0.022	0.047	0.039	0.018
CA	33%Base	CPV	1749	T-1	Hour12-16	0.016	0.033	0.031	0.016
		All			Vintage Cases	0.05	0.1	0.075	0.05

California ISO
Shaping a Renewed Future

IMPROVEMENTS TO SIMULATION EFFICIENCY

Modeling Improvements

- The model was modified to improve accuracy of modeling and efficiency of simulation while not compromising quality of results
- The major modifications implemented are:
  - Separation of spinning and non-spinning requirements
  - Generator ramp constraints for providing ancillary services and load following capacity
  - Simplified topology outside of California
  - Mixed integer optimization in California only
  - Tiered cost structure in generic resources in determining need for capacity

Separation of spinning and non-spinning requirements

- In the previous model, non-spinning includes spinning in both requirements and provision
- Spinning and non-spinning are separated in this model
  - The requirements for spinning and non-spinning are all 3% of load
  - The provision of non-spinning of a generator does not include its provision of spinning
- The separation is consistent with the ISO market definition and is needed to implement the ramp constraints as discussed below

Generator ramp constraints for providing ancillary services and load following capacity

- 60-minute constraint
  - The sum of intra-hour energy upward ramp, regulation-up, spinning, non-spinning, and load following up provisions is less than or equal to 60-minite upward ramp capability of the generator
  - The sum of intra-hour energy downward ramp, regulation-down, and load following down provisions is less than or equal to 60-minite downward ramp capability of the generator

Generator ramp constraints for providing ancillary services and load following capacity (cont.)

- 10-minute check constraint
  - The sum of upward AS and 50% of load following up provisions is less than or equal to 10-minite upward ramp capability
  - The sum of regulation-down and 50% of load following down provisions is less than or equal to 10-minite downward ramp capability

Generator ramp constraints for providing ancillary services and load following (cont.)

- 10-minute AS constraint
  - The sum of upward AS provisions is less than or equal to 10-minute upward ramp capability
  - Regulation-down provision is less than or equal to 10-minute downward ramp capability
- 20-minute constraint
  - The sum of upward AS and load following up provisions is less than or equal to 10-minute upward ramp capability
  - The sum of regulation-down and load following down provisions is less than or equal to 10-minute downward ramp capability

Simplified topology outside of California

- The topology was simplified by combining transmission areas (bubbles) outside CA according to the following rules:
  - The areas have no direct transmission connection to CA
  - The areas are combination by state or region (Pacific Northwest)
- There will be no transmission congestion within each of the combined areas

Mixed integer optimization in California only

- Model has mixed integer optimization in CA only
  - Mixed integer optimization applies to all CA generators and generators as dedicated import to CA only
  - These generators are subject to unit commitment decision in the optimization
  - Other generators outside CA are not subject to unit commitment decision
  - These generators are available for dispatch at any time (when they are not in outage)

California ISO
Shaping a Renewed Future

Tiered cost structure in generic resources in determining need for capacity

- In the run to determine need for capacity, generic resources have high operation costs set up in a tiered structure such that:
  - The generic resources will be used only when they are absolutely needed to avoid violation of requirements
  - The use of generic resources will be in a progressive way (fully utilizing the capacity of one generic unit before starting to use the next one)
- The model using this method can determine the need for capacity in one simulation

Tiered cost structure in generic resources in determining need for capacity (cont.)

- The VOM cost and the cost to provide AS or load following of the generic resources are set up as

  Tier 1 – $10,000/MW   Tier 2 - $15,000/MW

  Tier 3 – $20,000/MW   Tire 4 - $25,000/MW

- In the run to determine the need for capacity startup costs of all generators are not considered for the method to work properly
- The run uses the monthly maximum regulation and load following requirements for each hour

ADDITIONAL CHANGES TO MODEL ASSUMPTIONS

Additional changes were implemented based on May 31, 2011 ALJ ruling

- Corrected the calendar year for load profile, renewable profiles, and Step 1 requirements
- Reset heat rate of El Segundo plant and the minimum capacity of the LMS100 and LM6000 units based on public available information
- Added CoolwtrS3 and CoolwtrS4 units according to ISO transmission planning assumptions
- Disallowed existing GT to provide off-line non-spinning, new GT is allowed
- Created a generic unit reflective of storage or curtailment to absorb load following down shortage

Additional changes were implemented based on May 31, 2011 ALJ ruling (cont.)

- Updated transmission wheeling rates as follows:
  - Using TEPPC PC0 Case non-zero rate for paths outside CA
  - Using vintage rates for paths in CA and for paths outside CA where PC0 Case has zero rates
- Separated BC and AESO and applied a $48/MW wheeling rate (based on PC0 Case) to prevent large quantity of energy from flowing into AESO
- Switched the following dynamic resources to providing load following and ancillary services to meet the ISO requirements

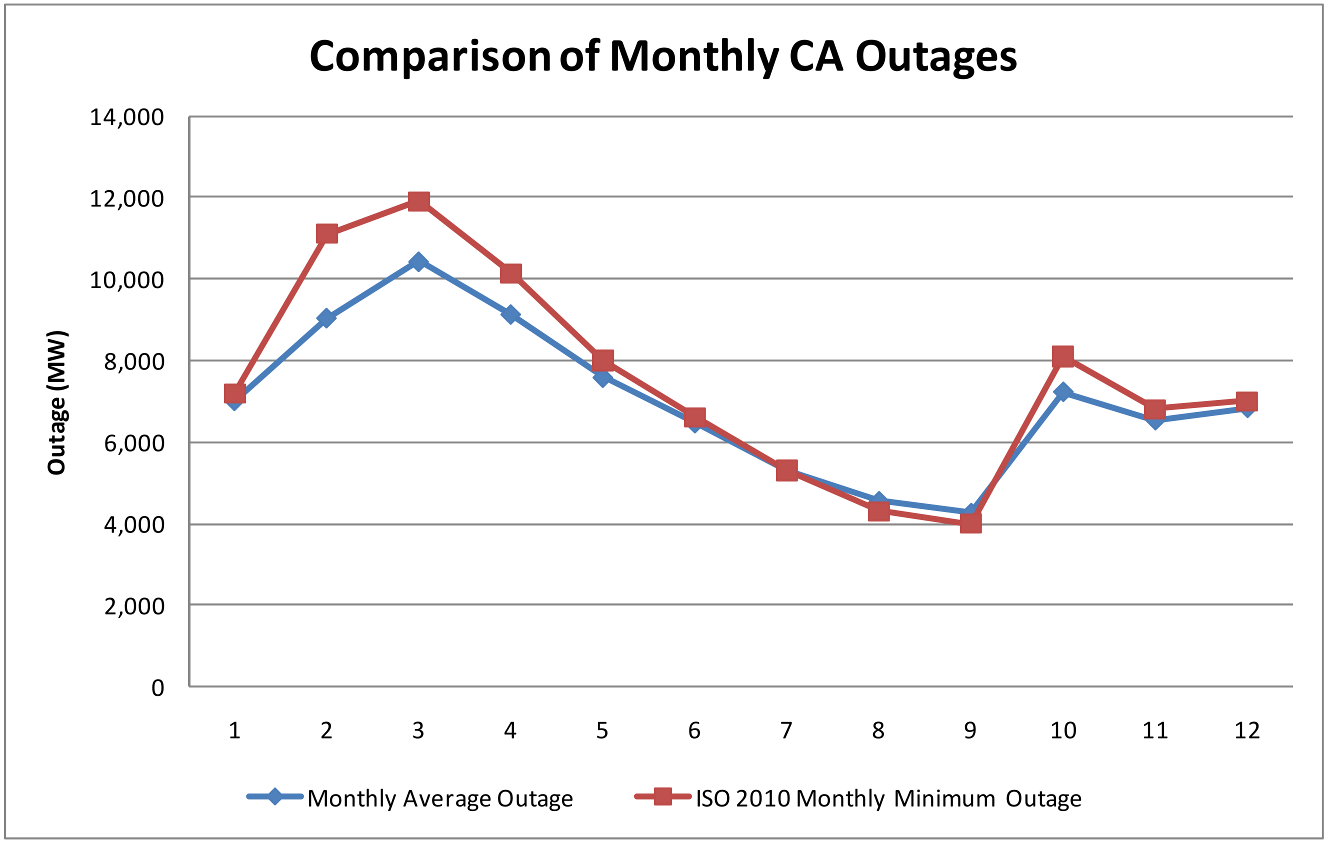
  - APEX_2_MIRDYN (505 MW) - MRCHNT_2_MELDYN (439 MW)

  - MSQUIT_5_SERDYN (1,182 MW) -SUTTER_2_PL1X3 (500 MW)

Additional changes were implemented based on May 31, 2011 ALJ ruling (cont.)

- Changed modeling of coal units with capacity greater than 300 MW to subject to commitment decision (integer variable)
- Updated SCIT and CA import limits based the revised SCIT model
- Revised generator outage rates to match monthly average outage (MW) with the ISO 2010 monthly minimum outage , no maintenance from Nov to Feb in Humboldt area

Outage profile used compared with actual outage profile



Attachment 2

MP1/VSK/PVA/oma 12/3/2010

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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans.	Rulemaking 10-05-006 (Filed May 6, 2010)

ASSIGNED COMMISSIONER AND ADMINISTRATIVE LAW JUDGE'S JOINT SCOPING MEMO AND RULING

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ASSIGNED COMMISSIONER AND ADMINISTRATIVE LAW JUDGE'S JOINT SCOPING MEMO AND RULING

1. Overview

This scoping memo and ruling, which follows a prehearing conference held on June 12, 2010, affirms the preliminary categorization of this proceeding as "ratesetting," sets forth the scope and procedural schedule for the proceeding, including evidentiary hearings, pursuant to the requirements of Section 1701.1,[1] and assigns Administrative Law Judge Victoria S. Kolakowski and Peter V. Allen as the presiding officers. It also addresses discovery, service, and other procedural issues for the proceeding. Parties can appeal this ruling only as to the category of this proceeding under the procedures in Rule 7.6.[2]

2. Background

This long-term procurement proceeding (LTPP) was initiated by an Order Instituting Rulemaking (OIR) to continue the Commission's efforts to ensure a reliable and cost-effective electricity supply in California through integration and refinement of a comprehensive set of procurement policies, practices and procedures underlying long-term procurement plans, and to provide the appropriate forum in to consider the Commission's electric resource procurement policies and programs and how to implement them.[3]

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[1] Unless otherwise stated, all section references are to the California Public Utilities Code.

[2] Unless otherwise stated, all references to a "Rule" or to "Rules" are to the Commission's Rules of Practice and Procedure.

[3] This is the successor proceeding to Rulemaking (R.) 08-02-007, R.06-02-013, R.04-04-003, and R.01-10-024, the rulemakings initiated by the Commission to ensure

Footnote continued on next page

The OIR established a multi-track proceeding separately addressing several issues.

In Track I, we shall consider issues related to the overall long-term need for new system and local reliability resources, including adoption of "system" resource plans[4] for each of the three utilities' service area that will inform the next available cycle of bundled procurement plans. These resource plans will allow the Commission to comprehensively consider the impacts of state energy policies on the need for new resources.

In Track II, we shall consider adoption of "bundled" procurement plans[5] pursuant to AB 57 (Stats. 202, ch. 83, Sec. 3) (codified as Pub. Util. Code § 454.5) for the three major electric IOUs, i.e., Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E), and Southern California Edison Company (SCE) to authorize their procurement needs for their bundled customers.

In Track III, we shall also consider a number of rule and policy issues related to procurement plans. Track III will be split into two phases. Phase 1

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that California's major investor-owned utilities (IOUs) could resume and maintain procurement responsibilities on behalf of their customers.

[4] We define "system" as pertaining to the loads and resources in each IOU's service area. "Service area" generally corresponds to the IOUs' respective distribution service territories, inclusive of bundled, direct access, and community choice aggregator loads, but exclusive of embedded publicly-owned utility loads. To distinguish filings related to system reliability needs from bundled Assembly Bill (AB) 57 procurement plans, we will refer to these as "resource plans."

[5] We define "bundled" as pertaining to an IOU's load and resources in its role as a Load Serving Entity (LSE). To distinguish filings related to bundled AB 57 obligations from separate filings related to system reliability needs (e.g., the resource plans), we will refer to these as "procurement plans."

covers issues requiring immediate resolution and includes convergence bidding and amendments to the Cost Allocation Mechanism. Phase 2 will consist of all other matters detailed in the Track III discussion below.

While the three tracks shall be conducted concurrently, any interim decisions and rulings from one track may inform future activities in the other tracks as described below.

All resource and procurement planning in this proceeding will be done in the context of the Energy Action Plan II (EAP II)[6] and other state energy policies.

The OIR includes a preliminary scoping memo which identified issues that are in the scope of this proceeding, as well as some issues which are not within the scope of this proceeding.[7] Any issue identified in the preliminary scoping memo as being within the scope of this proceeding is affirmed herein to the extent that this Scoping Memo does not clearly modify or supersede its provisions, and any issue identified in the preliminary scoping memo as being outside the scope of this proceeding is excluded unless specifically noted herein.

3. Scope of the Proceeding

3.1. Track I

As noted in the OIR, the purpose of the "system" planning track, Track I, is to identify California Public Utilities Code (CPUC)-jurisdictional needs for

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[6] Energy Action Plan I (EAP I) was issued jointly on May 8, 2003, by the Commission, the California Energy Commission (CEC) and the California Consumer Power and Conservation Financing Authority. EAP I was updated with the adoption of EAP II, as a joint policy plan of the Commission and the CEC, in October 2005. *See* www.energy.ca.gov/energy_action_plan/2005-09-21_EAP2_FINAL.PDF.

[7] OIR at 11-19.

new resources to meet system or local resource adequacy over the 2011-2020 planning horizon, including issues related to long-term renewables planning and need for replacement generation infrastructure to eliminate reliance on power plants using Once Through Cooling (OTC). In addition to maintaining an adequate reserve margin, we anticipate that system requirements to: 1) integrate renewables; 2) support OTC policy implementation; 3) maintain local reliability; and 4) meet greenhouse gas (GHG) goals will be primary drivers for any need for new resources identified in this proceeding. Furthermore, we may address or reassess the Energy Efficiency (EE) and Demand Response (DR) assumptions utilized in determining future need.[8]

Finally, the Commission will need comprehensive information on which to base resource policy choices applicable to all jurisdictional LSEs. While 33% renewables portfolio standards (RPS) implementation scenarios will likely be a central focus of this proceeding, additional information may be required to assess other cost-effective strategies to achieve GHG goals, including considering GHG adders, transmission, distributed generation, and OTC may also be considered.

3.1.1. General Process for Developing System Resource Plans

Administrative Law Judge (ALJ) Victoria S. Kolakowski issued a ruling on May 28, 2010 (May 28 Ruling) setting forth the initial schedule and process for

[8] We will not consider new EE goals in this proceeding. However, we may review the energy efficiency planning assumptions adopted in Decision (D.) 08-07-047 for procurement purposes. Additionally, we may consider any new information about EE projections after parties file proposals in response to a subsequent ruling served in both this proceeding and R.09-11-014.

discussing the various elements of Track I. The May 28 Ruling announced that system resource plans[9] would be developed based upon plans generated by the IOUs based upon a variety of scenarios[10] to be described in this Scoping Memo. IOUs and other parties may prepare alternative proposed resource plans or other analyses relevant to developing such plans. More specifically, the May 28 Ruling stated:

- Required renewable portfolios shall be initially proposed by Energy Division staff (Staff).
- Required non-renewable inputs shall be initially proposed by the IOUs (or any party, in the case of energy efficiency inputs).
- Any party or respondent may comment on any proposal and make any alternative proposal; Staff may, however, establish guiding principles for alternative proposals.
- Following this series of Staff, IOU and party proposals, the Scoping Memo shall establish standardized planning assumptions for the system resource plans conducted by the IOUs, consistent with the direction in the OIR.
- The IOUs shall complete and file system resource plans that fulfill the standardized planning assumptions set forth in the Scoping Memo.

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[9] Resource Plan: A filing before the Commission containing information and analysis on all portfolios developed and evaluated, including complete documentation of each portfolio's performance under required evaluation criteria.

[10] Scenario: A possible future state of the world encompassing assumptions about policy requirements, market realities and resource development choices.

- In filed testimony, the IOUs or any other party or respondent may submit supplemental analyses based on alternative assumptions.[11]

The required standardized planning assumptions to be used in developing the studied system resource plans were released in three separate parts, each of which was the subject of a separate workshop and round of comments and reply comments. We have reviewed these comments, and standardized planning assumptions are contained in Attachments 1 and 2 to this ruling and are discussed in further detail below.

Ultimately, the purpose of these required scenarios is to model potential outcomes of a wide variety of policy choices using common assumptions to allow plans developed by each IOU to be compared together. While not exhaustive, Staff intends these scenarios to represent a wide practical range of potential resource futures. Absent such pre-established assumptions, each IOU would likely develop proposals for their service territory based upon incompatible assumptions which could not be readily compared and combined to create a meaningful overall system resource plan.

The appropriate use for these system resource plans is within the scope of this proceeding, and has been the source of comment by parties. We shall not seek definitive resolution of these questions in this Scoping Memo. However, the system plans utilized in this proceeding may be utilized or modified in other proceedings as deemed appropriate by the ALJ or assigned Commissioner's office for the proceeding in question.

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[11] May 28 Ruling at 5-6.

To the extent that such questions arise regarding specific elements of the system resource plans, they are discussed in further detail below.

3.1.2. Standardized Planning Assumptions (Part 1)

The first part of the Resource Planning Assumptions was released with the May 28 Ruling. It sought to establish a number of common value[12] assumptions and definitions, including: evaluation criteria related to cost, risk and GHG emissions; base case assumptions for each scenario including load and resource (L&R) variables and cost variables as well as standardized L&R tables. Additionally, it recommended requiring sensitivity analysis regarding natural gas prices; carbon dioxide (CO_2) prices; need levels; and technology costs. The Planning Standards attachments to the May 28 Ruling have been revised and are attached hereto as Attachment 1 - Standardized Planning Assumptions (Part 1).

3.1.2.1. Evaluation Criteria

3.1.2.1.1. Cost

Some parties, including Cogeneration Association of California (CAC), Energy Producers and Users Coalition (EPUC), PG&E, and SDG&E,[13] commented that cost calculations for a wide range of renewable scenarios are too difficult and time consuming to model in production simulations in the LTPP proceeding. The Commission's procurement policies are not envisioned to

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[12] Common value: A set of input assumptions and parameters that represent the expected or most likely values for each scenario. All required scenarios shall have the same common value assumptions, whereas supplemental scenarios may consider alternative assumptions.

[13] CAC June 21st Comments at 5-6; EPUC June 21st Comments at 5-6; PG&E June 11th Comments at 5; and SDG&E June 21st Comments at 8.

include an exhaustive list of possible scenarios. The required scenarios described in this scoping memo have been selected to narrow the cost modeling burden on parties in this proceeding.

3.1.2.1.2. Risk

Risk analysis in the context of the LTPP proceeding raises issues related to the efficacy of Time to Expiration for the Value at Risk (TEVaR) over a 10 year horizon. In comments both SDG&E and PG&E opposed the utilization of TEVaR, while Jan Reid proposed utilities risk management plans must change over time with the "dynamics of both energy markets and risk management practices." (June 4th 2010, 1-2.) In opposing Reid's position, SDG&E argues "Track I addresses risk by examining multiple scenarios and sensitivities" (June 25th 2010, 6) and should not utilize TEVaR to otherwise measure long term risk exposure. SDG&E is correct that relative risks can be examined by comparing and contrasting multiple scenarios and sensitivities, but TEVaR remains the leading, although not the only, metric for measuring risk in IOU positions in the LTPP proceeding. In light of these concerns, the Commission will give each metric, including TEVaR, its appropriate weight in its assessment of risk.

3.1.2.1.3. GHG Emissions

See Section 3.A.2b.3 below for discussion of all GHG issues.

3.1.2.1.4. Other Potential Criteria

Natural Resources Defense Council (NRDC) and Union of Concerned Scientists (UCS) argue in comments[14] that the proposed GHG metrics capture

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[14] NRDC and UCS June 21st Comments at 4.

many of the state's objectives, but do not capture all of them. NRDC and UCS suggests that an environmental impact assessment (EIA) be an additional required portfolio metric. The EIA would measure the environmental impacts of different procurement portfolios based on criteria determined by the Commission.

The scenarios required herein are built upon indicative portfolios, and meet the state's environmental goals, such as the RPS, and OTC retirements. Given that, along with the nature of the process at issue here, and the uncertainty about what will ultimately be built, it is unnecessary and premature to attempt the detailed level of analysis suggested by NRDC and UCS.

3.1.2.2. Common Assumptions

3.1.2.2.1. Loads & Resources

The L&R tables are designed to provide guidance on the forecast of system demand and supply between 2011 and 2020. The assumptions underlying these tables are based upon numerous publicly available data sources, including the demand forecast, taken from the CEC, forecasts of demand-side programs, and forecasted retirements and additions.

3.1.2.2.1.1. Physical Location of Generation

Since the IOUs are not directed to create a single, system-wide plan, allocation of resources by their physical location is the easiest way to deal with the individual footprint. Existing, planned, and retiring generation will be allocated to North of Path 26 (NP26), South of Path 26 (SP26), or San Diego based on its physical location, regardless of the contracting entity. This allocation is derived from the physical siting location of units in the system in Track I, rather than the contractual obligations of units. Contractual obligations are considered in the bundled plans.

The impacts of dividing all resources by their physical path location will greatly alter the landscape of RPS-eligible resource capacity. For example, RPS-eligible resources are location-dependent, which means most of the capacity value from a given scenario might be assigned to SP26. Similarly, RPS-tagged imports from outside of California Independent System Operator Corporation (CAISO) service area will also be associated with either NP26 or SP26.

By comparison, the allocation of RPS-eligible resources from a contractual, or bundled, perspective will see much more equal distribution since the ability to contract (within Commission and State rules and policy) is much more flexible than physically siting the resources themselves.

3.1.2.2.1.2. Net Interchange

Net Interchange represents the firm amount of capacity in megawatts (MW) that is expected to be delivered into a particular service territory or balancing authority net of exports and taking into account path limits on transmission lines. For the System Resource Plans, the Net Interchange for each service territory will be established from the sum of two values. These values are derived from a physical perspective of the system, and not a contractual perspective. It is expected that the results presented for the PG&E, SCE, and SDG&E service areas will differ from the contractual plans presented in Track II due to the different types of analyses performed in the different tracks.

3.1.2.2.1.2.1. Imports/Exports from Outside the CAISO Control Area

The Maximum Import Capability will be determined by summing import capability of intertie lines into the CAISO control area that deliver into PG&E's service territory, SCE's service territory, or SDG&E's service territory based on the transmission resource's Maximum Available Import Capability for purposes of the Import Allocation process.[15]

3.1.2.2.1.2.2. Net Interchange of In-State Resources Across Paths

The net transfer of resources on peak across Paths between IOU service areas is recommended to be considered as part of any eventual final decision outcome, and will be included in the calculation of the residual net short or long in the service areas. In light of the physical look, we must address differences in location of physical resources or we are implicitly adopting a cross-subsidy between IOU ratepayers. To address this issue, we adopt a mechanism that calculates transfers across the path based on excess resources being transferred to areas with too few resources. As part of this calculation, there is the presumption that there are no exports across the Paths from a capacity-scarce service area during the time of that service area's peak.

Transfers across the path will be calculated based on excess existing resources in a capacity-rich side of the path[16] to the capacity-scarce side[17] of the

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[15] Maximum Import Capability posted to the Commission website here: http://www.caiso.com/27c6/27c675b81c230.pdf.

[16] Greater than 117% of the demand forecast.

path. This calculation would be capped in one of three cases. First, is when the maximum resource adequacy (RA) value of the Path's transmission capacity rating at peak is reached. Second, is when the transfers reduce the capacity-rich side of the path's residual net long position to 117% of the demand forecast. Third, is when the capacity-scare side of the path's residual net short position meets the Planning Reserve Margin (PRM) of 115%.

3.1.2.2.2. Prices

3.1.2.2.2.1. Natural Gas

The 2009 Market Price Referent (MPR) model incorporates the 22-day (22 trading days for one month from July 27, 2009 to August 25, 2009) average of New York Mercantile Exchange (NYMEX) closing prices for year 2010 to 2021. PG&E raises the issue during the Planning Standard Part 1 workshop and via its written comments that the MPR model should be updated with more recent quote dates.[18] We agree that the NYMEX gas price inputs should be updated to capture the most up-to-date gas futures. Therefore, the IOUs should utilize the 2009 MPR gas price methodology, with the NYMEX future price inputs based on the 22 trading day average over one month, from July 26, 2010 to August 24, 2010.

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[17] Less than 115% of the demand forecast.

[18] PG&E June 21 Comments at 8.

3.1.2.2.2.2. CO_2

The IOUs shall use the latest MPR methodology to determine CO_2 prices, for the same time period as employed for the gas price.[19]

3.1.2.2.3. GHG-Related Issues

This proceeding has a number of GHG related issues which we will consider in this section.

3.1.2.2.3.1. Carbon Offset Prices

On October 28, 2010 the Air Resources Board (ARB) released a proposed mechanism to implement a cap and trade program with an expected vote on the proposal on December 2, 2010. Until ARB releases its final carbon regulations, the utilities shall assume that offsets will be valued at the same price of carbon allowances for each year. After ARB finalizes its offset policies, parties shall discuss with Staff how to revise the offset assumptions to more appropriate outcomes expected under regulations under AB 32, stats.2006, ch 488.

3.1.2.2.3.2. GHG Cost Containment

In its OIR comments, PG&E encouraged the Commission to include cost containment policies in its GHG assumptions. We agree that these assumptions are important; however, the ARB has not finalized what cost containment policies it will be using in its regulation. The ARB released a draft version of these policies on October 28, 2010. In accordance with that draft at this time we

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[19] The 2009 MPR model is available at: http://www.cpuc.ca.gov/NR/rdonlyres/1406475F-6F1E-4A3F-85AF-6EA53419BA01/0/2009_MPR_Model.xls.

require the IOUs to base their analysis upon the carbon cost schedule provided in Attachment 1, Appendix B.

3.1.2.2.3.3. Allocation Policy Assumptions

In comments on the OIR, several parties[20] expressed an interest in receiving specific guidance from the Commission regarding assumptions that should be used for GHG allowance allocation policy. We recommend that portfolios be designed under the assumption that no allowances will be provided to utilities. The allocation policy will be determined by the ARB and included in their final draft carbon regulation. ARB has not provided any public announcements regarding specific electricity sector allocation proposals, but it has indicated an interest in auctioning some allowances and giving utilities some of the revenue from these sales to support their GHG-reduction efforts.

The ARB released its draft regulation October 28, 2010. Following the release of ARB's allowance allocation proposal, utilities should update their portfolios to reflect the value of the allowances or allowance revenue that they receive. The value of these allowances should be consistent with the allowance prices provided in this Scoping Memo.

In addition, IOUs should include in their portfolios information regarding how allowance allocation revenue will be used to support GHG mitigation efforts. As stated in the CPUC CEC Joint Recommendation to ARB on allowance

[20] PG&E June 11th Comments at 5; CAC June 25th Comments at 4-5; and EPUC June 25th Comments at 4-5.

allocation policy (R.04-06-009),[21] the Commission expects that all allowance value will be used to support GHG mitigation efforts. Procurement portfolios should include specific documentation outlining how much allocation value is used for different mitigation efforts.

Because of the opportunity costs associated with any allocation, the amount of free allocation that each utility receives should not impact the carbon cost of its procurement decisions. This is because the GHG costs associated with procurement will relate to the carbon cost passed on by generators and the carbon costs associated with utility-owned generation. The primary drivers of these costs are the allowance price and the procurement method. Neither of these factors is influenced by the allocation of allowances – whether allowances are allocated by auction or freely distributed. The price of allowances is determined by supply and demand for allowances, which is not affected by the allowance allocation schemes being considered by ARB.[22]

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[21] Interim Opinion on GHG Regulatory Strategies available at: http://docs.cpuc.ca.gov/efile/PD/78643.pdf.

[22] As discussed in the Commission Staff paper on allowance allocation in the electricity sector, an output-based allocation could impact the price of allowances, but only in the case that it was used for a significant portion of total allowances and used over a long period of time. We do not anticipate that ARB will use this approach to allowance allocation in the electricity sector. Available at: http://www.climatechange.ca.gov/eaac/documents/state_reports/CPUC-CEC_Staff_Paper_on_Allocation.pdf.

3.1.2.2.3.4. Allocation of GHG Emissions from Combined Heat and Power Facilities

While it is difficult to determine a precise system average heat rate (HR) for combined heat and power (CHP) expected to come online in the next decade, the CEC's CHP Market Assessment[23] provides some guidance. This report assesses the technical potential for CHP in the State and compares this capacity with various market scenarios. The sum of these market scenarios, or the "All-In" case in the report, includes a mix of large and small CHP providing on-site and exported electricity. The weighted average HR for CHP systems in the All-In case is 8,893 British thermal units (Btu) / kilowatt-hours (kWh) without line losses. (For supply-side resources, a line loss factor may be added to the HR to account for less efficient electricity delivered to the grid.)

We believe the weighted average HR provided in the CEC report's All-In market scenario represents an appropriate estimate for new CHP in the next decade. While the overall market penetration of CHP is higher in the All-In case than what is proposed in this proceeding, the characteristics of the market are reflective of we expect to see develop. That is, we expect a CHP build out roughly evenly split between new CHP above and below 20 MW, with exports to the grid dominated by large systems and a carbon payment that will stimulate the CHP market based on the social, environmental and economic benefits of emissions reductions provided by CHP-generated power that is more efficient than the displaced grid electricity.

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[23] Combined Heat and Power Market Assessment is available at: http://www.energy.ca.gov/2009publications/CEC-500-2009-094/CEC-500-2009-094-D.PDF.

3.1.2.2.3.5. Time of Use and Seasonal Marginal Emissions

We recommend that IOUs develop their own assumptions regarding the emissions of the marginal generator during different time periods and seasons. These assumptions are used to calculate the carbon cost associated with sales of self-owned generation, market purchases from other LSEs, bilateral purchases from other LSEs, purchases from Qualifying Facilities (QFs) and market purchases from the CAISO market.

3.1.2.2.3.6. Average Emissions of the CAISO Market Pool

Staff recommends that the emissions associated with CAISO market pool purposes should reflect the average emissions of all of the CAISO market pool during a particular time period and season. However, we will not direct IOUs to use specific assumptions regarding average emissions from CAISO pool purposes. Instead, IOUs are encouraged to discuss their proposed assumptions with the Staff prior to submitting their portfolio results.

3.1.2.2.3.7. Allocation of GHG from CHP Facilities

IOUs and parties will follow the methodology in the Standardized Planning Assumptions (Part 1) for allocating the proportion of GHG emissions from CHP to the electric industry.

3.1.2.2.4. OTC and Non-OTC Retirements

We adopt a set of assumptions about OTC retirements. These assumptions are based upon the State Water Resource Control Board (SWRCB) adopted policy, with the following modifications: (i) certain OTC plants with permit restrictions or repowering agreements that would become active before the SWRCB adopted policy schedule are placed in earlier years, due to publicly known arrangements; (iii) OTC in Los Angeles Basin remaining as of 2016 and slated to become compliant in 2020 was evenly spread over 2016 – 2019; (iii) several plants were assumed to not retire, such as the nuclear units and Moss Landing units 1 and 2. The 15 MW South Bay Gas Turbine is counted under OTC units retiring, although it itself is not an OTC unit.

As to non-OTC aging plants, this scoping memo directs use of the forecast retirements listed in the CAISO's OTC scenario analysis tool, under Category 10.

3.1.2.2.5. Demand Response

The common values used in the required scenarios should reflect the reasonable levels of DR resources that the Commission has authorized funding, directed in its DR policy decisions, and relied on the benefits for approving funding for other projects.

Specifically, the levels of DR assumed in the required scenarios shall reflect currently adopted 2009-2011 DR programs in D.09-08-027 and DR programs approved through other Commission proceedings. The Common Value should also include load impact from reasonably anticipated DR programs/resources such as those enabled by the IOUs' Advanced Metering Infrastructure (AMI) systems ("AMI Enabled DR"), of which the estimated benefits were included in the Commission approved AMI decisions.

The forecasted values shall include AMI-enabled DR, such as price-responsive programs adopted or directed by the Commission, but yet to be implemented,[24] and any default and optional dynamic rates expected in the forecast period. In addition, the forecasts should include the PTR program and

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[24] These include, for example, PG&E's Peak Time Rebate (PTR).

the Programmable and Communicating Thermostat program underling the AMI related DR benefit assumptions in the Commission AMI decisions.[25]

The estimated ex-ante load impact forecast filed in this proceeding shall be based on the April 1, 2010 Load Impact Report Compliance Filing pursuant to Ordering Paragraph (OP) 4, D.08-04-050. The utilities should report DR portfolio load impact forecast (2011-2020) for the 2010 LTPP using the August Monthly System Peak Load Day under a 1-in-2 Weather Condition.

Pursuant to the Commission orders in PG&E's and SCE's AMI decisions,[26] we anticipate that the IOUs would include the ex-ante load impact forecasts for the AMI Enabled DR in their April 1 Load Impact Reports (April filings). However, except for SDG&E, some of these programs have not been implemented; therefore, PG&E and SCE did not include any ex-ante forecast for these programs in their April 2010 filings. Neither PG&E nor SCE provided the information in their initial comments on the OIR neither in June 2010 nor in the supplemental comments in July 2010.

In absence of the IOU inputs, it is reasonable to rely on the load impact forecast adopted in the AMI decisions to develop the AMI Enabled DR values for this ruling. The common value also includes the ex-ante DR portfolio load impact forecast for other programs provided in the IOUs' April 2010 filings.

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[25] D.09-03-026 (PG&E), D.08-09-039 (SCE), and D.07-04-043 (SDG&E).

[26] D.09-03-026, OP 10 and D.08-09-039, OP 3.

3.1.2.2.6. Local Need Requirements

A number of parties, from SCE to The Utility Reform Network (TURN),[27] indicated the importance of locally constrained areas. As such, we are requiring the IOUs to conduct a needs analysis for locally constrained areas. The needs analysis shall include a methodology for the most appropriate and cost effective ways to address the shortages. As part of this analysis, we expect that the IOUs will not use simple L&R spreadsheets, instead they shall use modeling techniques such as power flow analyses to demonstrate the results of their methodology.

These analyses shall be completed according to the schedule laid out herein and in subsequent ALJ rulings.

3.1.2.3. Sensitivities

3.1.2.3.1. Natural Gas

In the sensitivity analysis for natural gas prices, the IOUs shall use low and high natural gas prices of $2 per million British thermal units (MMBtu) and $10 per MMBtu respectively based on feasible extremes of long-term gas prices. These values are established based on the current status of the natural gas industry.

3.1.2.3.2. CO_2

In the sensitivity analysis for CO_2 prices, the IOUs shall use low and high carbon prices that reflect a 25% variance from the MPR value for each year.

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[27] SCE June 11th Comments at 4-5; TURN June 25th Comments at 6; and WPTF June 4th Comments at 7.

3.1.2.3.3. Need

In the sensitivity analysis for demand levels for both gigawatt hour (GWh) and MW, the IOUs shall use high and low demand levels that reflect a 10% variance from the demand forecast value for each year. This value is reflective of any combination of future uncertainties (e.g., increased or decreased load growth or programmatic performance).

3.1.2.3.4. Technology Cost

Staff initially proposed consideration of a technology cost sensitivity. However, there are a number of distinct technologies used for different resources procured by IOUs. Because differences between technology costs adjustments can shift the resource allocation, use of distinct sensitivities for different technologies would be appropriate. This would require the use of numerous sensitivities, which would introduce complexities that would outweigh the benefits of the analysis. Additional discussion on photovoltaic costs is included later in this scoping memo. Therefore, we will not require use of a technology cost sensitivity in this proceeding.

3.1.2.4. Other Issues

3.1.2.4.1. CHP Assumptions

The common values regarding CHP were based on parties' comments. The Cogeneration Association of California (CAC) and the Energy Producers and Users Coalition (EPUC)[28] recommended that 4,596 MW of existing CHP should be retained by the IOUs. Additionally, CAC and EPUC recommended between 2,000 and 4,000 MW of new incremental CHP between now and 2020. SCE

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[28] CAC June 11th Comments at 2 and EPUC June 4th Comments at 2.

replied,[29] amongst other comments related to CHP, that the Commission has a QF, not a CHP policy, and that existing capacities are required only through 2016.

The common values assumptions developed by Staff and adopted herein anticipates increases in CHP in IOU service territories at the midpoint between no incremental CHP and the IOUs' portion of the nearly 4,000 MW of incremental state-wide CHP that ARB targets in its AB 32 Scoping Plan. This assumption is an attempt to balance current state policy goals, including AB 32 and AB 1613, Stats. 2007, ch. 713[30](which fosters new, small and highly efficient CHP facilities) with reliability concerns that could result from under-procurement if these CHP goals are not fully achieved by 2020. We will re-evaluate our CHP adoption assumptions in future LTPP proceedings, after review of actual incremental CHP capacity adoption rates.

Additionally, we make several assumptions for CHP. First, existing CHP capacity will be maintained through 2020. Second, incremental CHP growth is evenly split between on-site use and exports to the grid. Third, the ratio of capacity between the IOUs’ territories remains constant at the 2010 percentages for supply-side and demand-side CHP. Fourth, the 2020 values are evenly distributed back to 2010.

3.1.2.4.2. PRM

We are using existing assumptions regarding the PRM as adopted in D.04-01-050. R.08-04-012 was closed without altering the PRM.

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[29] SCE June 25th Comments at 8-11.

[30] Codified as Cal. Pub. Util. Code §§ 2840 through 2845.

3.1.3. Standardized Planning Assumptions (Part 2 - Renewables)

The second part of the Planning Standards were issued in a ruling mailed June 22, 2010 (RPS Ruling) and related to RPS assumptions, including proposals for the four RPS portfolios/scenarios to be included in developing the required system resource plans.

3.1.3.1. Required Scenarios:

We require that the IOUs study four different RPS scenarios that achieve a 33% RPS by 2020, as well as a 20% by 2020 scenario. Additionally, two sensitivities around the 33% trajectory scenario with high and low load are required. Staff and its consultants, Energy and Environmental Economics, Inc. (E3) and Aspen Environmental Group, sized these portfolios based upon: the CEC's 2008 Net Systems Power Report, as updated by Staff records of newly online resources;[31] the CEC's 2009 Integrated Energy Policy Report process for load forecasts;[32] and modifications to the load forecasts based upon assumptions regarding demand-side programs.

Each portfolio includes a "discounted core" consisting of projects with signed power purchase agreements and filed applications for major permits. To fill the remaining gap between the "discounted core" and the total RPS need in 2020, staff and E3 considered renewable potential identified in: the Energy Division database of projects under contract and negotiation; the Renewable Energy Transmission Initiative's Phase 2B database; E3's GHG calculator; and

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[31] CEC, *2008 Net System Power Report*. CEC-200-2009-010.

[32] CEC, *California Energy Demand 2010-2020, Adopted Forecast*. CEC-200-2009-012-CMF.

E3/Black & Veatch estimates of statewide distributed generation (DG) potential.[33] Cost, environmental concern, and time factors were assigned to resources,[34] and portfolios were developed by varying the weight given to these factors in the project ranking and portfolio selection process.

The following portfolios were developed:

(1) Trajectory: Intended to model a future similar to the IOU's current contracting and procurement activities. It weights commercial rankings at 60% and costs and environment rankings at 20% each, giving no weight to the time factor. Three versions of the trajectory scenario will be studied: the first assuming high demand, the second assuming the common value demand and the third assuming low demand. These changes to demand are consistent with the need sensitivity, and the changes to both demand and additional required RPS-eligible resources are located in the corresponding L&R Table.

(2) Time Constrained: Focuses on resources that can come online most quickly, weighting the time factor at 95% and the environmental factor at 5%. The environmental score is included as a tie-breaker, given the limited differentiation between the timing scores, which depend only upon first full year of commercial operation. The environmental criterion was chosen as the tie-breaker because of the impact that environmental concerns could have on a project's permitting and construction timelines.

(3) Cost Constrained: Focuses on resources that are lowest cost, weighting the cost factor at 100%.

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[33] RPS Ruling, Attachment 1 at 10-11.

[34] The weighting process is described in detail in the attached Standardized Planning Assumptions (Part 2 - Renewables).

(4) Environmentally Constrained: Focuses on the resources that scored highest according to the environmental scoring methodology described in the attached Standardized Planning Assumptions (Part 2 - Renewables), weighting the environmental factor at 100%.

Parties commented on the definitions assigned and values calculated regarding each of the foregoing inputs into these four portfolios.

3.1.3.2. High DG

Pacific Environment, Sierra Club California, and California Energy Storage Alliance (CESA) request that the Commission specifically adopt a "High DG" scenario as one of the required scenarios for the 2010 plans. We decline to adopt such a scenario as required, for several reasons.

First, the Environmentally-Constrained Scenario is in fact already a "High DG," though not "All DG," scenario, as it includes over 9,000 MW of wholesale distributed photovoltaic (PV) – system-side projects each less than or equal to 20 MW. This represents an approximately 200-fold increase over the current installed capacity of these types of projects in California. In fact, through the inclusion in the discounted core of 1,052 MW of wholesale DG, all of the required scenarios assume a significant acceleration in the installation of small-scale wholesale PV, relative to past trends in California.

Second, we agree with the comments by parties that more information is needed regarding the feasibility of such high levels of PV penetration, from both a system impact and project development perspective. Parties offered little comment on the staff-proposed timing assumptions for the deployment of wholesale DG (Table 6 of the draft Long-Term Renewable Resource Planning Standards), and these assumptions drive the amount of PV that is selected in the

Environmentally-Constrained and Time-Constrained Scenarios, where cost has little impact on portfolio selection.

We thus agree with comments from parties including Sierra Club California, that work is needed to identify and address the barriers that today constrain DG deployment. The CPUC is developing the Renewable Distributed Energy Collaborative (Re-DEC) for this purpose, and we hope to soon have better information on development time-frames. We encourage parties interested in this issue to contribute to the Re-DEC's work as it develops.

Should any party believe that a scenario with higher levels of DG would in fact meet the guiding principle of "reasonably feasible," that party may submit the complete scenario and justification for consideration by all parties according to the schedule laid out in this Scoping Memo.

3.1.3.2.1. Storage

CESA, Green Power Institute (GPI), NRDC and UCS, and Pacific Environment commented on the need for a storage scenario, particularly in relation to renewables integration.[35] While energy storage can potentially provide grid services to help integrate renewables, it is not the only technology type that can do so. The IOUs should choose the most environmentally-sound and cost-effective resources for procuring to the level of identified need.

The Commission has already approved ratepayer funding for storage research and demonstration projects in a number of proceedings,[36] and is

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[35] CESA July 9 2010 Comments at 2, GPI July 16 2010 Reply Comments at 1, NRDC and UCS July 9 2010 Comments at 3 and 6, and PE July 9 2010 Comments at 5.

[36] D.10-01-025 authorized PG&E to recover up to $24.9 million in ratepayer funding to study the feasibility of a Compressed Air Energy Storage facility. Resolution 4355-E

Footnote continued on next page

currently investigating the economic and operational benefits associated with energy storage.[37] Until these investigative efforts provide the Commission with better information regarding storage technologies' commercial viability and benefits, we agree with SCE that "it is premature to foreclose other alternatives based on the current state of energy storage development."[38]

Thus, we do not require storage in a separate scenario, nor order its inclusion across all portfolios.

3.1.3.3. Employment of Scenarios

Many parties requested clarity about the proposed use of the RPS scenarios in this proceeding. Specifically, all three IOUs, the Center for Energy Efficiency and Renewable Technologies (CEERT), GPI, the Large-Scale Solar Association and others requested that the Commission not use the scenarios to constrain or proscribe RPS procurement in any way. This Scoping Memo clarifies for parties the Commission's intended use of these scenarios.

Given the uncertainty in long term planning, it is prudent to use the best information available at the time to develop a plan. Using the best information available to both the Commission and the public, the Commission has selected 5

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approved SCE's request to construct a battery demonstration facility at Tehachapi. D.09-08-027 also approved funding for permanent load shifting technologies.

[37] *See* CPUC Policy and Planning Division Staff White Paper, *Electric Energy Storage: An Assessment of Potential Barriers and Opportunities*, at: http://www.cpuc.ca.gov/NR/rdonlyres/71859AF5-2D26-4262-BF52-62DE85C0E942/0/CPUCStorageWhitePaper7910.pdf.

Also, AB 2514 was enacted on September 29, 2010, which requires the CPUC to initiate a proceeding to consider energy storage policies.

[38] SCE July 16th 2010 Comments at 3.

scenarios, representing various policy objectives. While certainly not exhaustive or definitive, the required scenarios represent a reasonable subset of possible renewable development outcomes for which the IOUs would have to build conforming renewable integration plans in this planning cycle.

RPS procurement authority is not an outcome of this proceeding, and any Commission decisions about RPS procurement would be considered in the appropriate RPS proceedings – R.06-02-012, R.08-08-009, or its successor. However, long-term renewable resource planning is within the scope of this proceeding. The RPS analysis presented in this Scoping Memo is the Commission's first attempt at this long-term RPS planning, which also includes renewable integration. As parties are aware, the pattern of renewable generation development over the 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.

The plans submitted by the IOUs will provide this Commission with extremely valuable information about the extent to which the state's residual net short or long, transmission, and integration needs vary in response to alternative forecasts of renewable development. If the need for new integration resources varies significantly across renewable generation scenarios – and the procurement authorizing resulting from the 2010 LTPP may thus accommodate one particular set or range of RPS resources but not another – then it would be appropriate to consider with parties the implications for RPS procurement. Any such implications could be addressed as appropriate in other proceedings at the Commission. Similarly, the scenarios utilized in this proceeding may be utilized or modified in other proceedings as deemed appropriate by the ALJ or assigned Commissioner's office for the proceeding in question.[39]

3.1.3.4. Specific Elements of Scenario Proposal

3.1.3.4.1. Discounted Core

While most parties agreed with the idea of holding a "discounted core" of resources constant across scenarios for RPS planning, several parties commented on the makeup of and criteria for inclusion in the discounted core. Division of Ratepayer Advocates (DRA), for example, suggests that all signed contracts should be included in the discounted core, while GPI, UCS and NRDC, FiT Coalition, and SCE suggest that the Commission apply some discount factor to all projects in addition to, or in place of, the deterministic approach proposed by Staff, which includes or excludes each individual project based on certain criteria.

No party provided justification for use of specific alternative discount factors for evaluation. Therefore, in the attached updated standardized assumptions (Attachment 2), the discounted core is essentially unchanged from the one provided to parties in the Staff proposed Planning Standards (Part II).

3.1.3.4.2. Photovoltaic Costs

Several parties recommended that the RPS analysis consider cost reductions for photovoltaic and, to a more limited extent, other technologies – either as a base case assumption or as a sensitivity. Given long-term trends and uncertainty regarding what portion of recent PV cost

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[39] The scenarios utilized in this proceeding are also expected to be used by the CAISO in its transmission planning process, which may in turn result in applications for specific projects before this Commission.

declines can be attributed to changes in fundamentals, rather than to short-term shifts in supply and demand, we do not share the optimism of some parties regarding the extent to which PV prices may decline over the next 10 years.

We continue to find it most prudent to use current cost estimates for all technologies, but parties are welcome to test lower PV costs in the 33% RPS Calculator and to submit alternative scenarios as they believe warranted.

We note that cost does not affect resource selection for either the Environmentally-Constrained or the Time-Constrained scenario, and contributes only very slightly to resource selection in the Trajectory Scenario. Thus, a change in assumptions about the cost of PV would significantly affect the amount of PV in only 1 of the 4 required scenarios.

3.1.3.4.3. Timing Assumptions

In response to comments by several parties that the development timing assumptions in the RPS analysis were overly ambitious, we have revised some of the assumptions, as noted on the cover page to the updated standardized assumptions (Attachment 2). Staff also noted that the lack of obvious new, major transmission lines in most of the cases has a significant impact on the overall timing of the scenarios, and we anticipate revisiting the results of the timing analysis when the CAISO completes its high-level analysis of the transmission needs associated with each of the RPS scenarios.

Much of the work done by Staff in the June 2009 Implementation Analysis[40] to estimate the overall impact of "external risks" on the state's ability

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[40] http://www.cpuc.ca.gov/NR/rdonlyres/1865C207-FEB5-43CF-99EB-A212B78467F6/0/33PercentRPSImplementationAnalysisInterimReport.pdf.

to achieve a 33% RPS involved applying challenges and delays to transmission lines, technologies, and zones that were chosen relatively at random. This analysis was informative, as it attempted to illustrate whether a particular risk was likely to materialize as a delay *somewhere* in the state, with implications for the state's achievement of a 33% RPS.

However, applying such a methodology in the LTPP is more difficult – we know that certain risks are real, but zones and technologies should not be chosen at random for delay, given the potential real impacts for planning.

Here, we agree with parties including the California Wind Energy Association (CalWEA) and the Large-scale Solar Association (LSA) that a key goal of LTPP must be to identify major areas of uncertainty and risk, and to use that information to develop "robust long-term procurement principles designed to allow procurement and transmission planning to respond adroitly no matter how the uncertainties are resolved."[41]

3.1.3.4.4. Environmental Scoring

The environmental scoring methodology proposed in an appendix to the RPS Ruling received a great deal of comment, though most parties agreed that environmental concerns could significantly affect renewable generation development over the LTPP's planning horizon and should thus be considered in long-term planning. We have performed several changes to the methodology in response to comments and these changes are reflected in the Standardized Planning Assumptions (Part 2 - Renewables).

Parties including LSA, CEERT and GPI expressed concern about the extent to which the proposed methodology diverged from, without improving upon, the one developed by the Renewable Energy Transmission Initiative (RETI). In the revised standards, the new Disturbed Lands criterion remains, the High Desert and Air Quality criteria included in the draft have been removed, and RETI's measures of sensitive lands within and near a competitive renewable energy zone (CREZ) are now included.

Further, the technology-specific weightings proposed in the draft have also been removed, and are replaced by a calculation of acres/unit of energy/year that is specific to each technology and CREZ.[42]

Comments by CEERT, GPI and LSA raised the issue of the need to evaluate a renewable resource's effect on overall system dispatch and emissions when considering the true environmental concern associated with any portfolio of renewable resources. We hope to address this issue, to some extent, through review of the integration needs associated with each scenario and the GHG emissions metric used to evaluate each plan.

3.1.3.4.5. Capacity Value

In response to party comments about the capacity valuation methodology employed in the RPS analysis, we agree with SCE and PG&E that consistency with the Commission-adopted net qualifying capacity methodology is warranted

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[41] LSA Comments, July 9 2010 at 4.

[42] This approach mimics RETI's convention of "normalizing" each CREZ's score on each criterion by the total amount of energy in that CREZ, but accounts for the fact that the 33% RPS Calculator ranks projects individually and then sorts them into transmission "bundles" that may not reflect the overall resource mix of that CREZ. The energy metric that RETI used to normalize each CREZ's environmental score was specific to that CREZ's resource mix, so staff and its consultants developed an approach that maintained the intent of the RETI methodology, but reflected the appropriate new resource mix.

for the present analysis. However, we also understand the limitations of the reliance on capacity only as a methodology for long term planning as expressed by PG&E, LSA, CalWEA, Zephyr and Pacific Environment. We note, for example, that preliminary results from the work on renewables integration done by PG&E and CAISO raise questions about the capacity value of incremental resources as the "net" system peak shifts at very high levels of renewable penetration. This issue is not in scope in the current proceeding, but the Commission may address it in another proceeding, as appropriate.

3.1.3.4.6. Renewables Integration Modeling

The CAISO, with input from a working group of a number of stakeholders and PG&E are developing two independent models for addressing Renewables Integration in California for use in the LTPP proceeding. The CAISO and PG&E have presented methodologies and assumptions for a portion of the models in workshops held on August 24 and 25, 2010. Parties have commented on the information presented at those workshops. On October 22, 2010 PG&E presented the remainder of the model methodologies and assumptions, in addition to initial completed results, at a workshop. Parties are expected to comment on PG&E's model shortly. At the same workshop, CAISO presented on its model methodologies and assumptions. An additional workshop is expected on the remainder of CAISO's model during the last quarter of 2010. The renewables integration models are expected to be rerun with the planning assumptions detailed in this scoping memo with an initial release of information as detailed in the schedule. While the schedule details a release date for this information, we would encourage CAISO and PG&E to file results as they become available.

The results of these updated planning assumptions runs are expected to be presented according to the time line in the schedule. Parties will have had the opportunity to utilize the PG&E model, which is freely available, or any other model of their choice to develop other renewables scenarios for discussion at the February workshop as addressed below. Because of the extensive use of models in this proceeding, parties are reminded that access to computer models and related databases and documentation is required to be consistent with Rules 10.3 and 10.4 and Pub. Util. Code § 1822.

3.1.4. Planning Standards Part 3 – EE Assumptions

The third part of the Resource Planning Assumptions, related to EE, was issued in a ruling that mailed June 22, 2010 (EE Ruling). This ruling sought party inputs into EE inputs in two main areas: appropriate base case assumptions; and appropriate high and low sensitivity case assumptions.[43]

Two specific questions were: (1) whether to deviate from the Commission's policy of using one hundred percent of Total Market Gross as the base case scenario; and (2) whether to deviate from the Commission's policies requiring utilities replace fifty percent of measure decay.[44]

Most parties supported the Mid Case with variations. PG&E, SDG&E, TURN, NRDC, and DRA used the Mid Case as their recommendation for the starting value. By comparison, the Sierra Club of California (SCCA) supported using the High Case, and SCE the Low Case or the 2008 EE Goals. Reid

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[43] EE Ruling at 4.

[44] *Id.* at 5.

indicated that the 2008 EE Goals should serve as the starting point, with changes to known variants such as the Title 20 and Title 24 Codes and Standards.

Parties are split on how much of the Big Bold Energy Efficiency Strategies (BBEES) savings to include in the analysis. The IOUs, recommended against including any savings from BBEES in the analysis. However, the IOUs already have programmatic designs in place for the 2010 - 2012 EE program cycle which will provide savings in this category.[45] In contrast, other parties[46] recommended using 100% of the BBEES savings.[47] Given the uncertainties raised by parties over BBEES in particular, we have decremented the savings attributed by BBEES by employing the low case values from the CEC's final Committee Report on Incremental Uncommitted Energy Efficiency (Incremental Uncommitted EE Report).[48]

The CEC, in its final Committee Report on Incremental Uncommitted Energy Efficiency, recommended that the Commission adopt the EE savings decay for the committed period as a downward adjustment to the base Integrated Energy Policy Report (IEPR) forecast. The CEC conducted this additional analysis once it better understood the CPUC's policy on decay

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[45] PG&E July 2nd Comments at 6-7; SCE July 2nd Comments at 11; and SDG&E July 2nd Comments at 13.

[46] DRA July 2nd Comments at 8-9; NRDC July 2nd Comments at 9; SCCA July 2nd Comments at 8; and TURN July 9th Comments at 2-3.

[47] Forecast peak savings attributable to BBEES, in the CEC's Incremental Uncommitted EE mid goals care in 2020, are 2,056 MW; Energy savings are 2,167 GWh.

[48] Forecast peak savings attributable to BBEES, in the CEC's Incremental Uncommitted EE low goals case in 2020 are 1,552 MW; Energy savings are 1,809 GWh.

replacement; however this analysis came after the adoption of the 2009 IEPR and thus was not included in the base forecast.

DRA, TURN, SCCA, NRDC, and Reid all support the inclusion of savings decay replacement, while the three IOUs oppose including savings decay replacement.

We have revised the Planning Standards (Part 3) and the resulting assumptions are contained in the Standardized Planning Assumptions (Part 1). For the common values, parties will use the Mid Case Incremental Uncommitted results, with the exception of the Low Case results for BBEES. Additionally, the demand forecast will be further reduced by the inclusion of the CEC's recommended decrement for EE measure savings decay.

3.1.5. Alternative Scenarios Portfolios

Aside from the Commission required scenarios, parties are encouraged to file their own alternative scenarios and portfolios. We expect that all alternative scenarios and portfolios filed in this proceeding will conform to the Guiding Principles:

A. Assumptions should take a realistic view of expected policy-driven resource achievements in order to ensure reliability of electric service and track progress toward resource policy goals.

B. Assumptions should reflect the behavior of market participants, to the extent possible.[49]

C. Resource plans should be informed by an open and transparent process.[50]

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[49] A possible exception is confidential market price data, which may be reasonably substituted with public engineering- or market-based price data.

D. Resource plans should consider whether substantial new investment in transmission and flexible resources would be needed to reliably integrate and deliver new resources to loads.

E. Resource scenarios should provide useful information and resource portfolios should be substantially unique from each other.

F. Filed plans should include "active" or "live" spreadsheets for the metrics and portfolio results.

To this end, we anticipate that parties will file documentation in a clear manner, including providing their own alternative load and resource tables, justification for changes from the standardized planning assumptions, and stating where they have left the common value assumptions unchanged. As stated earlier, we encourage use of the E3 calculator. To the extent that an alternative methodology is used, we expect that it will: explain why the E3 calculator is insufficient and present an equal depth of analysis. Alternative methodologies will be weighed individually on their own merit. Parties must explain any departures from the common value assumptions. Portfolio information must also conform to the "Portfolio Evaluation Criteria" established in the Standardized Planning Assumptions (Part 1). Alternative scenarios and portfolios will be filed concurrently with the scenarios detailed in this scoping memo run by the CAISO and PG&E, based on the schedule discussed herein.

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[50] We believe that the renewable generation scenarios developed by Energy Division have been developed according to a transparent and vetted methodology. However, as stated in Guiding Principle B, there are benefits to having commercial activity reflected in renewable generation portfolios. These scenarios thus include some aggregated confidential information from the IOUs' RPS solicitations. Access to disaggregated market data may be restricted to non-market participants who sign a non-disclosure agreement, pursuant to D.06-06-066 and its successors.

3.2. Track II – IOU Bundled Procurement Plans

The OIR noted that Track II will consider individual IOU procurement plans pursuant to § 454.5, in light of any guidance derived from Tracks I and III adopted no later December 31, 2010. The selection of a date certain for incorporation of Track III changes into Track II filings was reasonable when the range of possible action in Track III was broad. However, we delineate two distinct phases of Track III. The first phase is sufficiently limited in scope that we expect a date no later than the end of the year for Track III, Phase 1 issues to be incorporated in Track II. We expect no decision on Track III, Phase 2 issues prior to the filing of the Track II IOU bundled procurement plan. Each IOU shall file its individual bundled plan consistent with the schedule included in Section 5 below or as modified by the Track II Scoping Memo. Additional guidance will be provided in a subsequent Track II Scoping Memo. We anticipate that Track II will begin no later than January 2011.

In this track, we anticipate that the IOUs shall file their bundled plans and associated testimony, to be followed by intervenor testimony. Evidentiary hearings are anticipated, followed by a round of post-hearing briefs and reply briefs. Regardless of any modifications to the above schedule, we anticipate issuance of one or more proposed decisions on the IOU bundled plans no later than December 2011.[51]

Based on the record in R.08-02-007, we find it reasonable to direct the IOUs' filing of bundled LTPPs to be based on a limited set of standardized

[51] The Commission is aware that the authorizations granted in D.07-12-052 only extend through 2016, and that the IOUs may need some decision on procurement authority by December 2011.

planning assumptions, consistent with those adopted here, using the best information available as described in the Track II Scoping Memo. While we envision that Track II plans will be based on currently effective conformed LTPP plans, our intent is to ensure that the IOUs' plans can be more easily compared to each other and to maintain consistency across utilities to the extent possible. Additional guidance will be provided by ALJ Rulings and/or by issuance of a revised Scoping Memo.

3.3. Track III – Procurement Rules

The OIR identified a number of issues that may be addressed in Track III, and noted that some must be resolved prior to the initiation of Track II of this proceeding.[52] We prioritize several issues for resolution, including those issues that will be addressed in a second phase of Track III later in the proceeding, time permitting. We expect proposed decisions on the issues of Phase 1 of Track III by the end of the year and modify the schedule in the May 6, 2010 OIR with regard to the November 19, 2010 deadline as described above.

3.3.1. Phase 1

3.3.1.1. Updates to Procurement Rules to Comply with SB 695 and Refinements to the D.06-07-029 Cost Allocation Methodology

Senate Bill (SB) 695 (Stats. 2009, ch. 337, effective October 11, 2009) addresses many of the same issues addressed in the Cost Allocation Methodology (CAM) which we adopted in D.06-07-029. SB 695 applies to both Utility Owned Generation (UOG) and Independent Power Producer-owned

[52] OIR at 14-17.

(IPP) generation, and provides that a cost allocation must be "on a fully nonbypassable basis consistent with departing load provisions as determined by the Commission."[53]

Thus, this proceeding will consider any necessary modifications to the CAM-related rules needed to implement SB 695 and also address refinements to the CAM process. Modifications to CAM-related rules to ensure statutory compliance do not raise disputed issues of fact, and will be resolved by concurrent briefs and reply briefs, as detailed in an ALJ Ruling issued September 14, 2010. CAM issues that are broader than those related to SB 695 are expected to be addressed in the 2nd phase of Track III.

3.3.1.2. CAISO Corporation Market-Related Procurement Implementation Issues

The CAISO instituted a new market structure in 2009, previously known as the Market Redesign and Technology Upgrade. This proceeding will consider LTPP issues that arise from the new CAISO market design, with a particular focus on the upfront standard for IOU procurement activity in congestion revenue rights (CRR) and convergence bidding markets.

Due to the complexity of the issues involved and the need to reach a resolution this year, ALJ Kolakowski issued a ruling (First Convergence Bidding Ruling) on July 1, 2010 regarding IOU participation in the CAISO's planned convergence bidding market. The First Convergence Bidding Ruling set forth a schedule for IOU proposals, comments and reply comments, and workshops. The First Convergence Bidding Ruling also asked a series of questions directed to parties' analysis of the risks and benefits of IOU participation in the CAISO

[53] Section 365.1(c)(2)(A).

convergence bidding market, as well as any potential limitations on that participation.

In response to a July 9, 2010 motion from PG&E, DRA and TURN, ALJ Kolakowski issued a Second Convergence Bidding Ruling on July 16, 2010, modifying the schedule.

Parties have provided comments and reply comments related to the questions from the First Convergence Bidding Ruling, and PG&E, SCE, and SDG&E have filed their individual proposals for participation. An additional round of comments concluded by September 7, 2010. These issued were included in a Proposed Decision which issued on November 15, 2010.

Issues regarding CRR procurement activities and any other CAISO market related issues shall be considered in the 2nd phase of Track III of this proceeding if conditions merit it.

3.3.2. Phase 2

3.3.2.1. Procurement Rules to Comply with OTC Policies

This proceeding will consider a number of procurement policies related to IOU-owned or contracted OTC generation units.[54] Examples of such policies include, but are not limited to, policies encouraging retirement of OTC units; Request for Offer (RFO) design to procure new greenfield or repowered projects for local RA, while minimizing market power; and RFO bid evaluation protocols

[54] We anticipate that changes to procurement rules may be necessary to ensure that IOU procurement activity is in accordance with any adopted OTC policy.

to allow comparison of retrofitting projects.[55] To the extent possible, these issues shall be resolved as part of the 2nd phase of Track III, as informed by the concurrent development of Track I.

3.3.2.2. Clarification / Refinement of Existing Procurement-Related Requirements in Support of the Development of a Procurement Requirements Summary Document (a.k.a. "Rulebook")

A Staff draft of a procedural requirements summary document or "Rulebook" was attached to a June 2, 2010 ruling (Rulebook Ruling) by ALJ Kolakowski. While this document is known informally as the "Rulebook," its final implementation may be in one of several different forms. A workshop was held on the Rulebook on June 11, 2010, and comments and reply comments were filed by parties.

One of the key issues discussed by the parties in comments was whether the Rulebook would serve as a compendium of existing rules and policies, or whether it would replace prior Commission action and serve as a single comprehensive governing document, much like a General Order. Other than SCE, all commenting parties favored treating this document as a compendium. This issue will be addressed in the 2nd phase of Track III.

[55] Retrofitting refers to a modification of an existing plant through the installation of a cooling system that complies with an adopted OTC policy. Retrofitting projects do not add new capacity to the system.

3.3.2.3. Refinements to Bid Evaluation in Competitive Solicitations (particularly with respect to UOG Bids)

D.07-12-052 identified several concerns related to the process for evaluating UOG bids against Power Purchase Agreements bids. These concerns focus on the need to ensure that the bid evaluation process is fair, just and reasonable, and include the need to determine whether and how bid criteria can be developed to improve head-to-head comparisons of UOG and IPP bids. Issues which may be considered include:

- How IOU bid development costs would be addressed ("at-risk" or ratepayer-guaranteed);
- The extent to which penalty and reward components are or should be added to UOG bids to make them consistent with IPP bids;
- What measures should be taken to prevent sharing of sensitive information between utility staff involved in developing utility bids and staff who create bid evaluation criteria and that select the winning bids;
- How failed contracts should be handled within the IOU RFO/procurement process; and
- Whether parties might agree on a common set of risk factors better managed by IOUs as compared to IPPs, to simplify the standard terms and conditions in the IOUs' pro forma contracts and subsequent counterparty contract negotiations.

As with the broader range of SB 695 issues, these issues may benefit from the developments of Track I and shall be considered later in Phase 2 of Track III.

3.3.2.4. GHG Compliance Products and Risk Management Strategies

This proceeding will also consider the GHG compliance products that IOUs will be authorized to procure to meet their anticipated California GHG compliance obligations. Included in this authorization will be the GHG risk management approaches the IOUs plan to employ to manage this new risk.[56] Due to the timing of the ARB's schedule for announcing the details of their proposed GHG regulations, this issue shall be addressed later in the proceeding after an ALJ ruling setting a process and schedule for review.

3.3.2.5. Refinements to the Timelines Associated with IOU RFOs for RA Products

D.06-06-064 instructs the IOUs to develop "least cost/best fit" portfolios and to sell contracted resources that are not needed. To meet this obligation, IOUs need to provide the excess resources to the market with sufficient time that other LSEs have an opportunity to purchase them to meet their resource obligations. We shall evaluate potential schedule milestones that IOUs can adopt to allow for smoother LSE compliance with RA filing deadlines.

3.3.2.6. Other Procurement Rule Changes

Staff has identified several issues in the Quarterly Compliance Report approval process: (1) net debtor IOU transactions with non-investment grade counterparties and collateral requirements; (2) refinements to Independent Evaluator (IE) guidelines (e.g., restrictions on IEs engaging in other business with the utility while being an IE); (3) clarifications related to the timing and availability of public information related to the Procurement Review Groups;

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[56] The Commission may also authorize in Track III interim IOU authority to procure a limited amount of these products, since the adoption of final ARB Cap and Trade Program regulations is anticipated in advance of the Track II decision in which bundled procurement authority will be addressed.

and (4) acceptable timeframes for IOU procurement staff to sign their codes of conduct.

These issues shall be addressed in the 2nd phase of Track III in this proceeding.

4. Evidentiary Hearings

Evidentiary hearings are anticipated in Track I. Evidentiary hearings may be held in Track II of this proceeding on appropriate issues (if necessary), to be set forth in subsequent rulings by the assigned Commissioner or ALJ.

5. Schedule

Track I

Date	Item
November 30, 2010	Workshop on step 2 results for CAISO model (a separate ruling will set dates for workshop comments.)
March 11, 2011	PG&E files renewables integration (RI) results for all runs, CAISO files RI results for runs completed to date[57]
March 18, 2011	Parties file alternative scenarios, metrics and common values; IOUs also file required scenarios and metrics
Late March 2011	Workshops presenting completed scenarios and outputs from updated RI runs
April 1, 2011	Requests for hearings due
April 8, 2011	Comments due on RI results
April 15, 2011	Reply comments due on RI results

57 To the extent individual runs are available before a particular due date, results should be distributed to all parties.

April 22, 2011	Comments due on data adequacy of required and alternative scenarios and metrics filed by parties
April 29, 2011	Reply comments due on data adequacy of required and alternative scenarios and metrics filed by parties
May 2011	Ruling on data sufficiency of filings
May 31, 2011	Supplemental data filings on scenarios and metrics (if necessary)
June 2011	Filed Testimony
July 2011	Hearings (if necessary)
July 15, 2011	Comments due on possible Commission actions
July 22 2011	Reply comments due on possible Commission actions
August 2011	Briefs and Reply Briefs
November 2011	Track I proposed decision

Track II

Date	Item
January 14, 2011	Utilities file bundled procurement authority plan and supporting testimony
February 18, 2011	Non-IOU Party testimony
March 18, 2011	Reply testimony
March 31, 2011	Request for hearings due
April 2011	Hearings (if necessary) or workshops
May - June 2011	Opening briefs on bundled procurement authority plan
May - June 2011	Reply briefs on bundled procurement authority plan

September 2011	Track II proposed decision

Date	Item
Spring 2011	Scoping, workshops (if necessary) and briefing of Phase 2 of Track III issues
Fall 2011	Track III, Phase 2 proposed decision

6. Attachments

We direct the use of the attached Standardized Planning Assumptions documents, Attachment 1 - Standardized Planning Assumptions (Part 1) for System Resource Plans, Attachment 2 - Standardized Planning Assumptions (Part 2 - Renewables) for System Resource Plans. The original Staff proposed Planning Standards have been updated based on party comments and the workshops held on June 2010 on the 11th, 18th, and 25th and are now replaced with this Scoping Memo's Standard Planning Assumptions.

7. Discovery

A party of which a discovery request has been made shall provide a complete response within 10 working days of each request. If the responding party needs clarification of the request, it shall seek that clarification within two working days of receiving the request. If the responding party cannot provide a complete response within 10 working days, it shall communicate that fact to the requesting party within four working days, along with providing a firm date for a complete response. A party issuing a discovery request shall simultaneously provide a copy of that request to all other parties. A responding party shall provide a copy of its discovery response to each party that makes a request for that specific response. Electronic copies of discovery requests and discovery responses are sufficient unless the receiving party requests a paper copy.

Parties shall undertake a "meet and confer" process in a good faith effort to resolve any discovery dispute. The meeting may occur telephonically if that is more convenient than an in-person meeting. If that attempt does not resolve the dispute, the parties shall so inform the ALJ. If there is not a timely opportunity to use that forum, the disputing parties may send an e-mail to the ALJ regarding the dispute. The assigned ALJ may schedule a conference call, ask for written motions, refer the discovery dispute to the Law and Motion ALJs, or take other steps as deemed appropriate. The assigned ALJ's e-mail address is vsk@cpuc.ca.gov.

8. Filing, Service, and Service List

All formally filed documents in this proceeding must be filed with the Commission's Docket Office and served on the service list for the proceeding. Article 1 of the Rules contains all of the Commission's filing requirements. Parties are encouraged to file electronically whenever possible as it speeds processing of the filings and allows them to be posted on the Commission's website. More information about electronic filing is available in Rule 1.13 and at http://www.cpuc.ca.gov/PUC/efiling. We will follow the electronic service protocols adopted by the Commission in Rule 1.10 of the Commission's Rules of Practice and Procedure for all documents, whether formally filed or just served. This Rule provides for electronic service of documents, in a searchable format, unless the appearance or state service list member did not provide an e-mail address. If no e-mail address was provided, service should be made by United States mail. In this proceeding, we require concurrent e-mail service to ALL persons on the service list for whom an e-mail address is available, including those listed under "Information Only." Parties are expected to provide paper copies of served documents upon request.

E-mail communication about this case should include, at a minimum, the following information on the subject line of the e-mail: R.10-05-006-2010 LTPP. In addition, the party sending the e-mail should briefly describe the attached communication; for example, *Brief*. Paper format copies, in addition to electronic copies, shall be served on the assigned Commissioner and the ALJ.

The official service list for this proceeding is available on the Commission's web page. Parties should confirm that their information on the service list is correct, and serve notice of any errors on the Commission's Process Office, the service list, and the ALJ. Prior to serving any document, each party must ensure that it is using the most up-to-date service list. The list on the Commission's web site meets that definition.

Any person interested in participating in this proceeding who is unfamiliar with the Commission's procedures or who has questions about the electronic filing procedures should contact the Commission's Public Advisor at (866) 849-8390 or in San Francisco at (415) 703-2074, or (866) 836-7825 (TTY-toll free), or send an e-mail to public.advisor@cpuc.ca.gov.

9. Intervenor Compensation

The prehearing conference in this matter was held June 12, 2010. Pursuant to § 1804(a)(1), a customer who intended to seek an award of compensation but has not done so already should have already filed and served a notice of intent (NOI) to claim compensation. In one or more separate ruling(s), the ALJ will address eligibility to claim compensation for the pending NOIs.

10. Categorization, Need for Hearings, *Ex Parte* Rules, and Designation of Presiding Officer

The Commission preliminarily categorized this proceeding as "ratesetting" as defined in Rule 1.3(e) and determined that the matter should be set for hearing. No party has disputed the Commission's preliminary categorization of this proceeding as "ratesetting." We affirm that preliminary determination. This ruling, as to category, is appealable pursuant to Rule 7.6.

In a ratesetting proceeding, Rule 13.2 defines the presiding officer as the person designated as such by the assigned Commissioner prior to the first hearing in the proceeding. The assigned Commissioner has designated ALJ Victoria S. Kolakowski and ALJ Peter V. Allen as the presiding officers. The provisions of § 1701.3(a) apply. The applicable *ex parte* rules are set forth in Rule 8.2(c).

IT IS RULED that:

1. This ruling confirms the Commission's preliminary finding that the category for this proceeding is ratesetting, and finds that hearings will be necessary. This ruling, only as to category, is appealable under Rule 7.6.
2. Administrative Law Judge (ALJ) Victoria S. Kolakowski and ALJ Peter V. Allen are the presiding officers for this proceeding.
3. The scope of this proceeding is as set forth in Section 3 of this ruling.
4. The schedule for this proceeding is as set forth in Section 5 of this ruling.
5. The assigned ALJ may make any revisions or provide further direction regarding the scope of this proceeding and the manner in which issues shall be addressed, as necessary for a full and complete development of the record.
6. The ALJ may modify the schedule adopted herein as necessary for the reasonable and efficient conduct of this proceeding.

7. Parties shall serve all filings as set forth in Section 8 of this ruling.

Dated December 3, 2010, at San Francisco, California.

/s/ MICHAEL R. PEEVEY
Michael R. Peevey
Assigned Commissioner

/s/ JANET A. ECONOME for
Victoria S. Kolakowski
Administrative Law Judge

/s/ JANET A. ECONOME for
Peter V. Allen
Administrative Law Judge

INFORMATION REGARDING SERVICE

I have provided notification of filing to the electronic mail addresses on the attached service list.

Upon confirmation of this document's acceptance for filing, I will cause a Notice of Availability of the filed document to be served upon the service list to this proceeding by U.S. mail. The service list I will use to serve the Notice of Availability of the filed document is current as of today's date.

Dated December 3, 2010, at San Francisco, California.

/s/ OYIN MILON

Oyin Milon

N O T I C E

Parties should notify the Process Office, Public Utilities Commission, 505 Van Ness Avenue, Room 2000, San Francisco, CA 94102, of any change of address to ensure that they continue to receive documents. You must indicate the proceeding number on the service list on which your name appears.

* *

The Commission's policy is to schedule hearings (meetings, workshops, etc.) in locations that are accessible to people with disabilities. To verify that a particular location is accessible, call: Calendar Clerk (415) 703-1203.

If specialized accommodations for the disabled are needed, e.g., sign language interpreters, those making the arrangements must call the Public Advisor at (415) 703-2074 or TDD# (415) 703-2032 five working days in advance of the event.

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ATTACHMENT 1

Standardized Planning Assumptions (Part 1) for System Resource Plans

Table of Contents

Standardized Planning Assumptions (Part 1) for System Resource Plans

The resource plans filed by the IOUs, or any other respondent shall conform with the standardized planning assumptions in this document. In general, standardization addresses (I) definitions, (II) guiding principles, (III) portfolio evaluation criteria; (IV) common value assumptions, and (V) sensitivity analysis, as specified below. Additionally, L&R Tables are provided in (VI), and supplemental explanation for metrics calculation or more detailed information on values in the L&R Tables are provided in the attached Appendices.[1]

I. Definitions

System Plan – The system plans take a physical look at supply and demand, rather than the contractual look conducted in the bundled plans. System plans are exclusive of SMUD and LADWP, except as noted for imports and exports.

Bundled Plan – The bundled plans are assessed based on the needs of the IOUs' bundled customers. It is a contractual look, rather than a physical look, that is exclusive of departing load, such as CCAs and DA customers.

Scenario - A possible future state of the world encompassing assumptions about policy requirements, market realities and resource development choices. *Required scenarios* are those specified in the Scoping Memo. *Alternative scenarios* are any additional scenarios provided by parties, and evaluated in addition to those required in the Scoping Memo.

Portfolio - A set of electric resources, both supply-side and demand-side, that provides electric service to all system ratepayers, under a given scenario. *Utility-Preferred Portfolio* is a resource portfolio identified by the IOU as a preferred resource portfolio and submitted to the Commission for consideration and possible adoption.

Resource Plan – A filing before the Commission containing information and analysis on all portfolios developed and evaluated, including complete documentation of each portfolio's performance under required evaluation criteria.

Case – A set of input assumptions and parameters (e.g., gas price, or electricity demand) under a given scenario that drives the selection of a given portfolio of resources.

Common Values – A set of input assumptions and parameters that represent the expected or most likely values for each scenario. All required scenarios shall have the same common value assumptions, whereas supplemental scenarios may consider alternative assumptions.

[1] Appendix A contains information on GHG-related calculations, Appendix B information on assumptions, and Appendix C more detailed spreadsheets on values used in the L&R Tables.

Sensitivity Analysis - A test to measure the change in output variable (e.g., cost, resource need) due to a change in input assumptions and parameters. Sensitivity analysis is conducted by changing one or more input assumptions from the common value to an alternative value.

II. Guiding Principles for Resource Plans

Resource plans filed in this proceeding shall follow these guiding principles:

A. Assumptions should take a realistic view of expected policy-driven resource achievements in order to ensure reliability of electric service and track progress toward resource policy goals.
B. Assumptions should reflect the behavior of market participants, to the extent possible.[2]
C. Resource plans should be informed by an open and transparent process.[3]
D. Resource plans should consider whether substantial new investment in transmission and flexible resources would be needed to reliably integrate and deliver new resources to loads.
E. Resource scenarios should provide useful information and resource portfolios should be substantially unique from each other.
F. Filed plans should include "active" or "live" spreadsheets for the metrics and portfolio results.

III. Portfolio Evaluation Criteria

Reliability shall be treated as a modeling input constraint, rather than as a separate evaluation metric. The Planning Reserve Margin (PRM), in conjunction with the resource adequacy (RA) program, is the mechanism by which the Commission ensures system reliability levels are maintained. In the system analysis, each resource portfolio should include sufficient levels of resources in order to meet the PRM requirement, currently 15-17% of peak demand.[4] While the IOUs may also choose to calculate and report a reliability metric (e.g. loss of load probability), or qualitatively assess the reliability benefits of a given portfolio above the PRM, the Commission discourages assessments of reliability benefits outside the PRM proceeding (R.08-04-012 or its successor).

All resource plans filed by the IOUs, or any other respondent shall evaluate and document the performance of each portfolio filed in terms of cost, risk, and GHG emissions metrics. These

[2] A possible exception is confidential market price data, which may be reasonably substituted with public engineering- or market-based price data.
[3] We believe that the renewable generation scenarios developed by Energy Division have been developed according to a transparent and vetted methodology. However, as stated in Guiding Principle B, there are benefits to having commercial activity reflected in renewable generation portfolios. These scenarios thus include some aggregated confidential information from the IOUs' RPS solicitations. Access to disaggregated market data may be restricted to non-market participants who sign a non-disclosure agreement, pursuant to D.06-06-066 and its successors.
[4] See D.04-01-050.

three categories of evaluation criteria are summarized in Table 1 and described in more detail below.

Table 1: Required Evaluation Criteria for Resource Plans

Criteria	Description
1. Cost	(a) Net Present Value Revenue Requirement (utility cost) (b) System average rate (c) Total Resource Cost (customer and utility cost) (d) Average, per ton cost of GHG emissions reductions (e) Total GHG-related Costs
2. Risk	Robust scenario and sensitivity analysis
3. GHG Emissions	(a) Total GHG emissions during each year of the planning horizon (b) Qualitative assessment of long-term GHG implications

<u>1. Cost</u>

Portfolios shall be evaluated on the basis of at least the following cost metrics: the net present value revenue requirement (PVRR), system average rate, PVRR plus customer cost, average, per ton cost of GHG emissions reduction, and the total GHG-related costs.

<u>(a) Net Present Value Revenue Requirement:</u> The PVRR includes all costs required to meet service area demand that are expected to enter into utility rates. The PVRR includes generation costs as well as transmission, distribution, and all other utility costs. To calculate PVRR, the total, utility revenue requirements are summed for each year of the planning horizon, and then discounted back to base year dollars using an appropriate discount rate.

A forecast of CO_2 allowance costs must be included in the PVRR calculation. (See Table 3 and discussion below for CO_2 price forecast methodology and GHG policy assumptions used to calculate the effect of CO_2 prices on generation costs and costs to utilities.)

Because fossil fuel and CO_2 allowance prices may continue to rise after the end of the normal 10-year planning period, cost metrics shall be calculated over 20 years, at a minimum. If a 20-year time period is selected, additional analysis to capture "end effects" after the end of the 20-year period should be done. A "salvage value" approach that credits ratepayers with the remaining market value of the resource, given appropriate assumptions for CO_2 price and natural gas price forecasts, is acceptable. We encourage the IOUs to work together to develop a common methodology; however, that methodology should incorporate the market value of the plant and not just the remaining book value.

(b) System Average Rate: The system average rate shall be calculated for each year of the model period as the revenue requirement of each portfolio divided by total sales in that year. A present value of the average rate shall also be calculated (present value of the revenue requirement divided by the present value of the total sales).

(c)PVRR Plus Customer Cost[5]: Many of California's policy goals are aimed at increasing the deployment of distributed energy resources such as EE, DR and renewable DG. Development of these resources often requires substantial customer contributions in addition to utility support. The PVRR Plus Customer Cost criteria includes both utility and net customer contributions toward the resource cost, but excludes any incentives that the utility pays to the customer. It is not necessary to calculate customer and utility costs for programs that are administered outside of the utility sector, such as building codes and standards. Customer and utility costs should be calculated for all utility-sector programs administered by the Commission, including EE, DR, CSI, CHP, and others.

(d) Average, Per-ton Cost of GHG Emissions Reduction: Resource plans shall calculate the average, per ton cost of CO_2 emissions reductions for each portfolio, relative to a benchmark portfolio constructed by meeting all resource needs with new natural gas fired resources. The "All-Gas" portfolio is similar to other portfolios submitted for the Commission's review, but is developed for benchmarking purposes only. To calculate the average cost of CO_2 emissions reduction, the change in PVRR relative to the All-Gas portfolio cost is divided by the change in total GHG emissions relative to the All-Gas portfolio. This metric shall be calculated for each year of the forecast period, and discounted to present day values using an appropriate discount rate. This is a useful evaluation criterion because it provides an indication of a portfolio's cost-effectiveness in reducing GHG emissions.

(e) Total GHG-related Costs: The total GHG-related costs metric will measure the carbon cost incorporated in each energy transaction. We expect that GHG costs will not simply be a function of the GHG emissions in a given procurement portfolio. Instead, GHG costs will be a function of both the embedded emissions in generation and the method of procurement. Under market purchases, GHG costs shall reflect the embedded GHG emissions of the marginal (price-setting) generator, rather than the emissions embedded in the power purchased. During periods in which the marginal generator has a compliance obligation (i.e. is a carbon-emitting resource), non-emitting generators that sell into the market will have a GHG cost embedded in their purchase price, despite having no direct emissions associated with generation.

[5] In this proceeding, this criteria refers to the sum of the utility cost and customer cost of the entire resource portfolio. This criteria is closely related to, but not precisely the same as, the Total Resource Cost criteria used in the context of cost-effectiveness determinations of individual EE and other demand-side resource programs.

2. Risk

Robust scenario and sensitivity analyses shall be conducted to assess a variety of risks associated with a given set of resource portfolios. More detailed guidance on scenarios and sensitivities is provided below in Sections III and V, respectively.

3. Greenhouse Gas Emissions

(a) Total GHG Emissions: Resource plans shall report the total GHG emissions associated with each portfolio during each year of the planning horizon. Since the Air Resources Board (ARB) has released a draft set of Global Warming Potential values on October 28, 2010 for GHGs, the evaluation criteria for Total GHG Emissions should be adjusted to comply with the draft ARB policy and its eventual final form.

(b) Qualitative Assessment of Long-Term GHG Implications: Resource plans shall include a qualitative assessment of the impacts of each portfolio on the ability of the state to meet long-term GHG reduction goals of 80 percent below 1990 levels by 2050 and the potential impact of portfolio resource choices to influence long-term technology transformation. Portfolios that rely heavily on existing, mature technologies would score poorly under this criterion, while portfolios that include emerging technologies with long-term potential for GHG benefits and substantial cost reductions and would score highly. We do not intend this assessment to be highly specific and quantitative in nature; rather, we are interested in the perspective of the IOUs' and parties as to which technologies hold the most promise for cost-effective, long-term, electric sector GHG reductions and whether increased investment in those technologies now would have long-term benefits for electric ratepayers in California.

IV. Required Scenarios

The Energy Division proposed a minimum set of four 33% renewable generation scenarios[6] in its draft report in June 2010. We have revised these scenarios, based on parties' comments, and the final RPS scenarios are included in the Standardized Planning Assumptions (Part 2 - Renewables) for System Resource Plans. The IOUs or any other party may propose alternative scenarios that the Commission should consider to achieve the goals of this proceeding. Alternative portfolios shall accompany the alternative scenarios, pursuant with the schedule in the Scoping Memo. The required scenarios and portfolios shall be consistent with the guiding principles set forth in Section II.

[6] The four 33% RPS scenarios presented were: Trajectory, Environmentally-Constrained, Cost-Constrained, and Time-Constrained.

<u>1. Required Common Value Assumptions for Each Required Scenario</u>

Tables 2 and 3 below summarizes our requirements for common value assumptions in required scenarios evaluated in the IOUs' resource plans. In general, these requirements apply to two categories of assumptions: (1) **load and resource variables** underlying assessments of need for new resources; and (2) **cost variables** underlying computations of total portfolio cost. See discussion below for more detailed descriptions of these requirements.

> **<u>(a) Load and Resource Variables:</u>** Table 2 below summarizes our requirements for common value load and resource assumptions in the minimum set of required scenarios evaluated in the IOUs' resource plans. We note that preferred resources (e.g., CHP) not already identified in Table 2 shall be reflected in the IOUs' resource plans, as specified in Scoping Memo or its attachments.

Table 2: Requirements for common value assumptions: load and resource assumptions

Variable	Source for Common Value Assumptions
Load and Resource Assumptions	
Load forecast (energy and capacity)	For system RA need assessments, use the most recent IEPR base case 1-in-2 load forecast. For local RA need assessments, use local area forecasts that are consistent with the most recent IEPR base case 1-in-10 load forecast.
Energy efficiency (EE)	**Committed EE**[7] - Embedded utility EE program savings in the most recent IEPR base case load forecast.
	Uncommitted EE[8] – Assumed levels of EE savings that are incremental to the most recent IEPR base case load forecast, as specified below.
Demand response (DR)	The estimated ex-ante load impact forecast filed shall be based on the April 1, 2010 Load Impact Report Compliance Filing pursuant to Ordering Paragraph 4, D.08-04-050. The utilities should report DR load impact forecast for LTPP using the August Monthly System Peak Load Day under a 1-in-2 Weather Condition.

[7] In this OIR, we define *committed EE* as savings from IOU programs implemented in the 2006-2012 period. These are considered committed savings and are embedded in the CEC's 2009 IEPR demand forecast.
[8] In this OIR, we define *uncommitted EE* as savings from IOU and non-utility programs implemented in the 2013-2020 period to achieve the Commission's EE savings goals adopted in D.08-07-047, as modified by D.09-09-047 and subsequent decisions.

Variable	Source for Common Value Assumptions
Customer-side DG, including California Solar Initiative (CSI)	Embedded levels of self-generation in the most recent IEPR base case load forecast.
Existing Resources	Net Qualifying Capacity (NQC) values per the RA proceeding.[9]
Resource Additions and Retirements	IOUs propose assumptions on resource additions and retirements beyond what has been included in the L&R tables and Attachments B & C.
Planning Reserve Margin	15%-17% of peak demand, or as modified in R.08-04-012.

[9] The updated NQC list is published at www.cpuc.ca.gov/PUC/energy/Procurement/RA/ra_guides_2008-09.htm.

(b) Load Growth: Pursuant to D.07-12-052, the IOUs are directed to use energy and peak demand forecasts based on the forecast developed for the CEC's 2009 IEPR and subsequent reports. As part of the IEPR, the CEC documents the amount of EE and other behind-the-meter resources such as solar PV, CHP and other DG that are assumed to be embedded in the forecast.

(c) Energy Efficiency: Decision 08-07-047 states that "energy utilities shall use one hundred percent of the interim Total Market Gross [TMG] energy savings goals for 2012 through 2020 in future [LTPP] proceedings, until superseded by permanent goals."[10] However, the Commission has deferred to the CEC's IEPR process to generate load forecasting information necessary to interpret the impacts of TMG energy savings goals on procurement. Specifically, CEC and Commission staffs collaborated in the 2009 IEPR proceeding to develop forecasts of uncommitted EE (i.e., TMG energy savings not embedded in the forecast.)[11]

In this proceeding, common value assumptions for EE reflect the sum of (1) utility EE program savings embedded in the most recent IEPR demand forecast including savings decay , and (2) incremental EE savings reasonably expected to occur from implementing the IOUs' EE goals, relative to the most recent IEPR load forecast. For this proceeding, this value is the mid-case results for all values except Big Bold EE Strategies, for which the low-case results shall be used.

(d) Demand Response: The common values shall reflect the reasonable levels of DR resources that the Commission has authorized funding, directed in its DR policy decisions, and relied on the benefits for approving funding for other projects.

Specifically, the common value levels of demand response (DR) assumed in the required scenarios reflect currently adopted 2009-2011 DR programs in D.09-08-027 and DR programs approved through other Commission proceedings. The common value also includes load impacts from reasonably anticipated DR programs/resources such as those enabled by the IOUs' Advanced Metering Infrastructure (AMI) systems ("AMI Enabled DR"), of which the estimated benefits were included in the Commission-approved AMI decisions.

The estimated ex-ante load impact forecasts are based on the April 1, 2010 Load Impact Report Compliance Filing pursuant to Ordering Paragraph 4, D.08-04-050. These forecasts use the August Monthly System Peak Load Day under a 1-in-2 Weather Condition.

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[10] D.08-07-047, OP 3, at p. 39.

[11] See CEC Committee Report, *Incremental Impact of Energy Efficiency Policy Initiatives Relative to the* 2009 Integrated Energy Policy Report *Adopted Demand Forecast.* http://www.energy.ca.gov/2010publications/CEC-200-2010-001/index.html.

The forecasted values include AMI-enabled DR, such as price-responsive programs adopted or directed by the Commission, but yet to be implemented,[12] and any default and optional dynamic rates expected in the forecast period. In addition, the forecasts include the Peak Time Rebate (PTR) program and the Programmable and Communicating Thermostat (PCT) program underling the AMI related DR benefit assumptions in the Commission AMI decisions.[13]

Pursuant to the Commission orders in PG&E's and SCE's AMI decisions[14], we anticipated that the IOUs would include the ex-ante load impact forecasts for the AMI Enabled DR in their April 1 Load Impact Reports (April filings). However, except for SDG&E, some of these programs have not been implemented; therefore, PG&E and SCE did not include any ex-ante forecast for these programs in their April 2010 filings. Neither PG&E nor SCE provided the information in their initial comments on the OIR neither in June 2010 nor in the supplemental comments in July 2010.

In absence of the IOU inputs, we believe that it is reasonable to rely on the load impact forecast adopted in the AMI decisions to develop the common value for the AMI Enabled DR for this ruling. The common value also includes the ex-ante DR portfolio load impact forecast for other programs provided in the IOUs' April 2010 filings.

(e) Resource Additions and Retirements: System resource additions are considered "Known or High Probability" if they have a Commission approved contract in place, have been permitted, and are under construction. An alternative is projects outside of an IOU with an approved Application for Construction (AFC). "Utility Probable Planned Additions" are additions with an approved contract in place, but have not yet begun construction, or additions with an approved AFC. "Other Planned Additions" are resources with CPUC approved contracts, but currently do not have approved AFC permits.

The Scoping Memo specifies an approach to plant retirement assumptions for required scenarios in the IOUs' resource plans, consistent with implementation of the state's OTC policy.

All resource additions and retirements are a forecast, and are an estimate of what resources may come on- or off-line during the LTPP planning horizon. Generation owners have a variety of options when it comes to retiring plants. For example, they could repower instead of retiring the facility.

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12 These include, for example, PG&E's Peak Time Rebate (PTR).
13 D.09-03-026 (PG&E), D.08-09-039 (SCE), and D.0704-043 (SDG&E).
14 D. 09-03-026, Ordering Paragraph (OP) 10 and D. 08-09-039, OP 3.

2. Cost Variables

Table 3 below summarizes our requirements for common value cost assumptions in the minimum set of scenarios evaluated in the IOUs' resource plans. See discussion below for more detailed descriptions of these requirements.

Table 3: Requirements for common value assumptions: cost assumptions

Variable	Source for Common Value Assumptions
Cost Assumptions	
Renewable resource availability	As in the Standardized Planning Assumptions (Part 2 - Renewables) for System Resource Plans.
Renewable resource cost	As in the Standardized Planning Assumptions (Part 2 - Renewables) for System Resource Plans.
Conventional and other resource cost and performance *	MPR values for CCGT. IOUs propose a single common value for others.
New generation tax and financing assumptions *	For new renewables, use assumptions in the Standardized Planning Assumptions (Part 2 - Renewables) for System Resource Plans. For other technologies, IOUs propose a single common value.
Transmission cost assumptions *	For transmission to access new renewables, use assumptions in the Standardized Planning Assumptions (Part 2 - Renewables) for System Resource Plans. For other transmission, IOUs propose a single common value.
Distribution cost assumptions	Most recent EE Avoided Cost methodology
Natural Gas Price	Most recent MPR methodology
CO_2 Price	Most recent MPR methodology
GHG Policy Assumptions	Utilities ensure that the carbon cost schedule provided embeds the draft cost containment mechanisms developed by ARB, and that they revise their portfolios to reflect ARB's actual cost containment policies when they are available. We encourage the utilities to coordinate with Energy Division staff and each other to devise assumptions that appropriately

Variable	Source for Common Value Assumptions
	reflect ARB's AB 32 regulations.
* Includes inputs or assumptions for which the IOUs shall file initial proposals in Q4 2010, pursuant to the Preliminary Schedule in the OIR, or as modified by subsequent ruling.	

(a) Natural Gas Fuel Price Forecast: Subject to change by the Commission in subsequent MPR decisions, the IOUs shall use the MPR gas price forecasting methodology (not actual values) for the common value gas price forecast in the LTPP. We direct this in order to avoid re-litigating an issue that the Commission has already decided in another procurement-related proceeding.

The IOUs shall use the quote date specified in the Scoping Memo. It is expected that each IOU will have different gas forecast values due to each utility's unique basis differentials and gas delivery costs.

(b) CO_2 Price Forecast: When the IOUs file their 2010 resource plans, neither California nor the Western Climate Initiative, is expected to have a fully-functioning CO_2 market. Likewise, in the event that the federal government pursues a nation-wide cap and trade program, it is unlikely that such a program would be operational by this time. Therefore, the Commission does not expect that relevant, real price data will be available when the IOUs file their 2010 resource plans. With this in mind, the IOUs' common value analysis shall use the CO_2 price forecast methodology applied in the most recent MPR decision.

(c) GHG Policy Assumptions: The ARB announced draft GHG policies in the regulation on October 28, 2010. At this time, we expect the utilities rely on the ARB's draft carbon cost containment policy assumptions to the extent that the carbon cost schedule provided above embeds any cost containment mechanisms developed by ARB. Utilities should revise their portfolios to reflect ARB's final cost containment policies when they are available. Since ARB's cost compliance policies were just released, we encourage the utilities to coordinate with Energy Division staff and each other to devise assumptions that appropriately reflect ARB's AB 32 regulations.

V. Required Sensitivity Analysis

The IOUs shall test the robustness of the common value portfolio against changes in a limited and influential set of variables. IOUs may assume that the resource portfolios would not change under the sensitivity analysis. For example, sensitivity analysis of total portfolio cost would simply apply different gas or CO2 cost assumptions to a fixed resource portfolio. The demand level sensitivity will allow both portfolio and dispatch changes. The IOUs shall run six sets of sensitivities: two sets for each of the three variables. During the course of the proceeding, the IOUs may be directed to run additional combinations of sensitivities. Table 4 below specifies the required sensitivity analyses.

Table 4: Requirements for required sensitivity analysis

Variable	Requirement
1. Natural Gas Prices *	Each portfolio shall be evaluated using a "High Gas Price" and "Low Gas Price" sensitivity analysis, corresponding to feasible extremes of natural gas prices. The Scoping Memo establishes values to be used for sensitivity analysis, based on initial IOU proposals for High- and Low-Gas Price assumptions and parties' comments and/or alternative proposals.
2. CO_2 Prices *	Each portfolio shall be evaluated using a "High CO_2 Price" and "Low CO_2 Price" sensitivity analysis, corresponding to feasible extremes of CO_2 price. The Scoping Memo establishes values to be used for sensitivity analysis, based on initial IOU proposals for High- and Low-CO_2 Price assumptions and parties' comments and/or alternative proposals.
3. Demand Level *	The utility-preferred portfolio shall be evaluated using a "High-Demand" and "Low-Demand" sensitivity analysis, corresponding to levels of uncertainty in the achievements of policy-driven demand-side programs. The "Low-Demand" sensitivity should reflect more optimistic assumptions about policy-driven resource achievements (e.g., EE, DR, customer-side DG, and CHP). These sensitivities are designed to reflect total need adjustments, not as permutations of a single policy-driven resource assumption. The "High-Demand" sensitivity should reflect more conservative assumptions about policy-driven resource achievements. The Scoping Memo establishes values to be used for sensitivity analysis, based on initial IOU proposals as well as parties' comments and/or alternative proposals.
* Includes inputs or assumptions for which the IOUs shall filed initial proposals in June and July 2010, pursuant to the Preliminary Schedule in the OIR, or as modified by subsequent ruling.	

VI. Load and Resource Tables

This section contains the L&R Tables, by IOU service area and by scenario. The line notes apply to each individual table.

NOTES (by Line number):

1	System peak demand represents peak demand in CAISO's control area, for the region indicated. This includes the IOU service area and participating publicly owned utilities in the Path 26 region served by the CAISO.
3	The existing resource NQC for each IOU's system planning area was drawn from the following resources: 1) the most current available 2011 NQC as of August 2; and 2) the CAISO master generation list as of July 12.
10	NQC of forecast OTC retirements.
11	NQC of any announced retirements, exclusive of OTC.
12	Known/High Probability Additions are plants under construction (Category 3) in the CAISO OTC scenario analysis tool. This total includes all CAISO balancing authority POU plants.
13	Other Utility Probably Planned Additions are resources with Contracts (Category 1) or have approved AFC's (Category 2) according to the CAISO OTC scenario analysis tool.
14	Those resources listed with CPUC approved contracts but do not currently have AFC permits approved AFC permits according to the CEC "Status of all Projects" list. These resources do not appear in the CAISO's OTC scenario analysis tool, since these resources did not have approved CPUC contracts or approved AFC permits as of the development of the OTC scenario analysis tool.
15	NQC of RPS Additions, as defined by the scenario.
16	Forecast of incremental CHP additions.
17	Sum of all physical imports and exports into service area, exclusive of imports and exports over Path 26.
18	The import/export capacity will be determined by allocating transmission from outside of the CAISO control area into either NP26 or SP26 based on the transmission resource's initial intertie location into the CAISO control area and its RA value.
20	Service Area Portion of System Resources = Total System Resources * (Service Area Demand/System Demand)
21	Service Area peak demand represents the service area's forecasted peak load, at the time of the CAIOS coincident peak, in the IOU service area, independent of LSE providing service. Service area peak demand includes bundled and direct access (DA) customer peak demand, and excludes publicly owned utility (POU) peak demand.
23	Incremental EE savings, beyond those embedded in the 2009 IEPR Demand Forecast. For the 2010 LTPP, this also includes additional savings from measure replacement decay, which typically would have been embedded in the base IEPR demand forecast.
24	DR savings based on the April 2010 Load Impacts, as well as load impact from reasonably anticipated DR programs/resources such as those enabled by the IOUs' Advanced Metering Infrastructure (AMI) systems ("AMI Enabled DR"), of which the estimated benefits were included in the Commission approved AMI decisions.
25	Forecast of incremental demand-side CHP savings. These savings are grossed up for line losses.
26	Residual Service Area Demand is based on the Commission's "managed forecast" which takes into account the incremental forecast savings from programs such as EE or DR.

	PG&E Physical North of Path 26 (NP26) Capacity Need Scenario: 33% Trajectory										
Line		MW									
	SYSTEM AND SERVICE AREA LOAD FORECASTS:	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
1	**System** 1-in-2 Peak Summer Demand	21,988	22,329	22,668	22,924	23,185	23,454	23,750	24,030	24,310	24,626
2	**Total System Resources** (Sum Lines 3, 8, 11 through 16)	**33,132**	**34,866**	**35,764**	**35,271**	**34,812**	**35,199**	**32,564**	**32,604**	**32,645**	**32,686**
	SYSTEM RESOURCES:										
3	Existing Generation (Sum of Lines 4 through 7)	26,623	26,623	26,623	26,623	26,623	26,623	26,623	26,623	26,623	26,623
4	*Existing Renewables (Excludes Hydro)*	1,426	1,426	1,426	1,426	1,426	1,426	1,426	1,426	1,426	1,426
5	*Existing Hydro (Includes RPS-eligible Hydro)*	6,461	6,461	6,461	6,461	6,461	6,461	6,461	6,461	6,461	6,461
6	*Existing CHP*	1,888	1,888	1,888	1,888	1,888	1,888	1,888	1,888	1,888	1,888
7	*Existing OTC*	7,064	7,064	7,064	7,064	7,064	7,064	7,064	7,064	7,064	7,064
8	*Other Generation*	9,784	9,784	9,784	9,784	9,784	9,784	9,784	9,784	9,784	9,784
9	Retirements (Includes Lines 10 & 11)	(497)	(662)	(662)	(1,336)	(1,986)	(1,986)	(4,807)	(4,807)	(4,807)	(4,807)
10	*OTC Retirements*	341	341	341	1,015	1,665	1,665	3,804	3,804	3,804	3,804
11	*Retirements*	156	321	321	321	321	321	1,003	1,003	1,003	1,003
12	Known/High Probability Additions	878	1,733	1,733	1,733	1,733	1,733	1,733	1,733	1,733	1,733
13	Utility Probable Planned Additions	0	784	784	784	784	784	784	784	784	784
14	Other Planned Additions	0	145	973	973	973	973	973	973	973	973
15	RPS Additions (In Service Territory)	20	94	123	263	414	760	904	904	904	904
16	Additional CHP	41	82	123	164	204	245	286	327	368	409
17	Net Interchange (Sum of Lines 18 & 19)	6,067	6,067	6,067	6,067	6,067	6,067	6,067	6,067	6,067	6,067
18	*Imports*	6,067	6,067	6,067	6,067	6,067	6,067	6,067	6,067	6,067	6,067
19	*Exports*	0	0	0	0	0	0	0	0	0	0
20	**Service Area Portion of System Resources (Line 2 * 92%)**	**30,481**	**32,077**	**32,903**	**32,450**	**32,027**	**32,383**	**29,959**	**29,996**	**30,034**	**30,071**
	SERVICE AREA SPECIFIC LINE ADJUSTMENTS:										
21	**Service Area** 1-in-2 Peak Summer Demand	20,193	20,510	20,829	21,071	21,318	21,572	21,851	22,117	22,383	22,683
22	Total Demand-Side Reductions	(1,492)	(1,836)	(2,178)	(2,496)	(2,839)	(3,237)	(3,657)	(4,090)	(4,501)	(4,898)
23	*Incremental Uncommitted EE*	98	128	388	620	871	1,180	1,511	1,857	2,184	2,496
24	*Total DR*	1,354	1,627	1,670	1,715	1,767	1,816	1,865	1,911	1,956	2,001
25	*Incremental Demand-Side CHP*	40	80	120	161	201	241	281	321	361	401
26	**Residual Service Area Peak Demand (Line 21 minus Line 22)**	**18,701**	**18,675**	**18,651**	**18,576**	**18,480**	**18,335**	**18,194**	**18,028**	**17,881**	**17,786**
	SERVICE AREA RESERVES:										
27	Amount of Available Resources Exceeding Demand (Line 20 minus Line 26)	11,780	13,402	14,252	13,874	13,548	14,049	11,764	11,968	12,152	12,286
28	Percentage of Available Resources Exceeding Demand (Line 20 / Line 26)	163.0%	171.8%	176.4%	174.7%	173.3%	176.6%	164.7%	166.4%	168.0%	169.1%
	1-in-2 SERVICE AREA SURPLUS (DEFICIT):										
29	Lower Bound of Planning Reserve Requirement (Line 26 * 15%)	21,506	21,476	21,448	21,362	21,251	21,085	20,923	20,732	20,564	20,453
30	Upper Bound of Planning Reserve Requirement (Line 26 * 17%)	21,880	21,849	21,821	21,734	21,621	21,452	21,287	21,092	20,921	20,809
31	Upper Bound 1-in-2 Service Area Surplus (Deficit)	8,975	10,601	11,455	11,088	10,776	11,299	9,035	9,264	9,470	9,618
32	Lower Bound 1-in-2 Service Area Surplus (Deficit)	8,601	10,227	11,082	10,716	10,406	10,932	8,671	8,904	9,112	9,262

	SCE Physical South of Path 26 (SP26) Capacity Need Scenario: 33% Trajectory										
Line		MW									
	SYSTEM AND SERVICE AREA LOAD FORECASTS:	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
1	**System** 1-in-2 Peak Summer Demand	23,785	24,142	24,518	24,823	25,149	25,482	25,833	26,169	26,509	26,875
2	**Total System Resources** (Sum Lines 3, 8, 11 through 16)	**30,618**	**31,355**	**32,633**	**32,578**	**33,696**	**33,051**	**32,837**	**31,916**	**32,066**	**30,019**
	SYSTEM RESOURCES:										
3	Existing Generation (Sum of Lines 4 through 7)	21,404	21,404	21,404	21,404	21,404	21,404	21,404	21,404	21,404	21,404
4	*Existing Renewables (Excludes Hydro)*	916	916	916	916	916	916	916	916	916	916
5	*Existing Hydro (Includes RPS-eligible Hydro)*	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470
6	*Existing CHP*	1,489	1,489	1,489	1,489	1,489	1,489	1,489	1,489	1,489	1,489
7	*Existing OTC*	9,250	9,250	9,250	9,250	9,250	9,250	9,250	9,250	9,250	9,250
8	*Other Generation*	8,279	8,279	8,279	8,279	8,279	8,279	8,279	8,279	8,279	8,279
9	Retirements (Includes Lines 10 & 11)	(452)	(452)	(452)	(787)	(2,398)	(3,349)	(4,300)	(5,251)	(6,202)	(8,280)
10	*OTC Retirements*	452	452	452	787	1,122	2,073	3,024	3,975	4,926	7,004
11	*Retirements*	0	0	0	0	1,276	1,276	1,276	1,276	1,276	1,276
12	Known/High Probability Additions	717	917	1,997	1,997	1,997	1,997	1,997	1,997	1,997	1,997
13	Utility Probable Planned Additions	0	500	500	500	1,854	1,854	1,854	1,854	1,854	1,854
14	Other Planned Additions	0	0	0	0	0	0	0	0	0	0
15	RPS Additions (In Service Territory)	0	6	174	423	1,768	2,043	2,749	2,749	3,819	3,819
16	Additional CHP	31	61	92	123	153	184	215	245	276	307
17	Net Interchange (Sum of Lines 18 & 19)	8,918	8,918	8,918	8,918	8,918	8,918	8,918	8,918	8,918	8,918
18	*Imports*	8,918	8,918	8,918	8,918	8,918	8,918	8,918	8,918	8,918	8,918
19	*Exports*	0	0	0	0	0	0	0	0	0	0
20	**Service Area Portion of System Resources (Line 2 * 90%)**	**27,557**	**28,219**	**29,370**	**29,320**	**30,327**	**29,746**	**29,554**	**28,725**	**28,859**	**27,017**
	SERVICE AREA SPECIFIC LINE ADJUSTMENTS:										
21	**Service Area** 1-in-2 Peak Summer Demand	21,305	21,634	21,981	22,262	22,561	22,867	23,189	23,497	23,810	24,146
22	Total Demand-Side Reductions	(1,721)	(2,634)	(3,118)	(3,458)	(3,856)	(4,228)	(4,624)	(5,042)	(5,449)	(5,850)
23	*Incremental Uncommitted EE*	44	60	325	565	834	1,171	1,530	1,912	2,283	2,648
24	*Total DR*	1,641	2,502	2,685	2,749	2,842	2,842	2,842	2,842	2,842	2,842
25	*Incremental Demand-Side CHP*	36	72	108	144	180	216	252	288	324	360
26	**Residual Service Area Peak Demand (Line 21 minus Line 22)**	**19,584**	**19,000**	**18,863**	**18,805**	**18,705**	**18,639**	**18,565**	**18,456**	**18,361**	**18,296**
	SERVICE AREA RESERVES:										
27	Amount of Available Resources Exceeding Demand (Line 20 minus Line 26)	7,973	9,219	10,507	10,516	11,621	11,107	10,988	10,269	10,499	8,721
28	Percentage of Available Resources Exceeding Demand (Line 20 / Line 26)	140.7%	148.5%	155.7%	155.9%	162.1%	159.6%	159.2%	155.6%	157.2%	147.7%
	1-in-2 SERVICE AREA SURPLUS (DEFICIT):										
29	Lower Bound of Planning Reserve Requirement (Line 26 * 15%)	22,521	21,850	21,692	21,625	21,511	21,435	21,350	21,224	21,115	21,041
30	Upper Bound of Planning Reserve Requirement (Line 26 * 17%)	22,913	22,230	22,070	22,001	21,885	21,807	21,721	21,593	21,482	21,407
31	Upper Bound 1-in-2 Service Area Surplus (Deficit)	5,035	6,369	7,677	7,695	8,816	8,312	8,204	7,501	7,745	5,976
32	Lower Bound 1-in-2 Service Area Surplus (Deficit)	4,644	5,989	7,300	7,319	8,441	7,939	7,832	7,132	7,377	5,610

	SDG&E										
	Physical Border Capacity Need										
	Scenario: 33% Trajectory										
Line		**MW**									
	SYSTEM AND SERVICE AREA LOAD FORECASTS:	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
1	**System** 1-in-2 Peak Summer Demand	4,578	4,658	4,738	4,797	4,856	4,911	4,973	5,032	5,094	5,157
2	**Total System Resources** (Sum Lines 3, 8, 11 through 16)	**6,127**	**6,130**	**6,291**	**6,437**	**6,737**	**6,765**	**5,808**	**5,810**	**5,856**	**5,859**
	SYSTEM RESOURCES:										
3	Existing Generation (Sum of Lines 4 through 7)	4,410	4,410	4,410	4,410	4,410	4,410	4,410	4,410	4,410	4,410
4	*Existing Renewables (Excludes Hydro)*	21	21	21	21	21	21	21	21	21	21
5	*Existing Hydro (Includes RPS-eligible Hydro)*	4	4	4	4	4	4	4	4	4	4
6	*Existing CHP*	136	136	136	136	136	136	136	136	136	136
7	*Existing OTC*	1,271	1,271	1,271	1,271	1,271	1,271	1,271	1,271	1,271	1,271
8	*Other Generation*	2,978	2,978	2,978	2,978	2,978	2,978	2,978	2,978	2,978	2,978
9	Retirements (Includes Lines 10 & 11)	(311)	(311)	(311)	(311)	(311)	(311)	(1,271)	(1,271)	(1,271)	(1,271)
10	*OTC Retirements*	311	311	311	311	311	311	1,271	1,271	1,271	1,271
11	*Retirements*	0	0	0	0	0	0	0	0	0	0
12	Known/High Probability Additions	55	55	55	55	55	55	55	55	55	55
13	Utility Probable Planned Additions	0	0	159	159	159	159	159	159	159	159
14	Other Planned Additions	0	0	0	0	0	0	0	0	0	0
15	RPS Additions (In Service Territory)	0	0	0	143	440	465	465	465	508	508
16	Additional CHP	3	6	8	11	14	17	20	22	25	28
17	Net Interchange (Sum of Lines 18 & 19)	1,970	1,970	1,970	1,970	1,970	1,970	1,970	1,970	1,970	1,970
18	*Imports*	1,970	1,970	1,970	1,970	1,970	1,970	1,970	1,970	1,970	1,970
19	*Exports*	0	0	0	0	0	0	0	0	0	0
20	**Service Area Portion of System Resources (Line 2)**	**6,127**	**6,130**	**6,291**	**6,437**	**6,737**	**6,765**	**5,808**	**5,810**	**5,856**	**5,859**
	SERVICE AREA SPECIFIC LINE ADJUSTMENTS:										
21	**Service Area** 1-in-2 Peak Summer Demand	4,578	4,658	4,738	4,797	4,856	4,911	4,973	5,032	5,094	5,157
22	Total Demand-Side Reductions	(219)	(242)	(353)	(421)	(492)	(570)	(655)	(743)	(825)	(903)
23	*Incremental Uncommitted EE*	3	4	66	121	179	247	321	398	471	544
24	*Total DR*	210	226	270	277	285	289	293	298	302	302
25	*Incremental Demand-Side CHP*	6	12	17	23	29	35	41	46	52	58
26	**Residual Service Area Peak Demand (Line 21 minus Line 22)**	**4,359**	**4,416**	**4,385**	**4,376**	**4,363**	**4,340**	**4,318**	**4,289**	**4,269**	**4,254**
	SERVICE AREA RESERVES:										
27	Amount of Available Resources Exceeding Demand (Line 20 minus Line 26)	1,768	1,714	1,906	2,061	2,374	2,425	1,490	1,521	1,587	1,606
28	Percentage of Available Resources Exceeding Demand (Line 20 / Line 26)	140.6%	138.8%	143.5%	147.1%	154.4%	155.9%	134.5%	135.5%	137.2%	137.7%
	1-in-2 SERVICE AREA SURPLUS (DEFICIT):										
29	Lower Bound of Planning Reserve Requirement (Line 26 * 15%)	5,013	5,079	5,043	5,032	5,018	4,991	4,966	4,932	4,909	4,892
30	Upper Bound of Planning Reserve Requirement (Line 26 * 17%)	5,100	5,167	5,131	5,120	5,105	5,078	5,052	5,018	4,994	4,977
31	Upper Bound 1-in-2 Service Area Surplus (Deficit)	1,114	1,051	1,248	1,405	1,719	1,774	842	878	947	968
32	Lower Bound 1-in-2 Service Area Surplus (Deficit)	1,027	963	1,160	1,317	1,632	1,687	756	792	862	883

PG&E
Physical North of Path 26 (NP26) Capacity Need
Scenario: 33% Time-Constrained

Line		MW									
	SYSTEM AND SERVICE AREA LOAD FORECASTS:	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
1	**System** 1-in-2 Peak Summer Demand	21,988	22,329	22,668	22,924	23,185	23,454	23,750	24,030	24,310	24,626
2	**Total System Resources** (Sum Lines 3, 8, 11 through 16)	**33,132**	**34,880**	**35,843**	**35,302**	**34,788**	**35,158**	**32,378**	**32,419**	**32,459**	**32,500**
	SYSTEM RESOURCES:										
3	Existing Generation (Sum of Lines 4 through 7)	26,623	26,623	26,623	26,623	26,623	26,623	26,623	26,623	26,623	26,623
4	*Existing Renewables (Excludes Hydro)*	1,426	1,426	1,426	1,426	1,426	1,426	1,426	1,426	1,426	1,426
5	*Existing Hydro (Includes RPS-eligible Hydro)*	6,461	6,461	6,461	6,461	6,461	6,461	6,461	6,461	6,461	6,461
6	*Existing CHP*	1,888	1,888	1,888	1,888	1,888	1,888	1,888	1,888	1,888	1,888
7	*Existing OTC*	7,064	7,064	7,064	7,064	7,064	7,064	7,064	7,064	7,064	7,064
8	*Other Generation*	9,784	9,784	9,784	9,784	9,784	9,784	9,784	9,784	9,784	9,784
9	Retirements (Includes Lines 10 & 11)	(497)	(662)	(662)	(1,336)	(1,986)	(1,986)	(4,807)	(4,807)	(4,807)	(4,807)
10	*OTC Retirements*	341	341	341	1,015	1,665	1,665	3,804	3,804	3,804	3,804
11	*Retirements*	156	321	321	321	321	321	1,003	1,003	1,003	1,003
12	Known/High Probability Additions	878	1,733	1,733	1,733	1,733	1,733	1,733	1,733	1,733	1,733
13	Utility Probable Planned Additions	0	784	784	784	784	784	784	784	784	784
14	Other Planned Additions	0	145	973	973	973	973	973	973	973	973
15	RPS Additions (In Service Territory)	20	108	202	294	390	719	719	719	719	719
16	Additional CHP	41	82	123	164	204	245	286	327	368	409
17	Net Interchange (Sum of Lines 18 & 19)	6,067	6,067	6,067	6,067	6,067	6,067	6,067	6,067	6,067	6,067
18	*Imports*	6,067	6,067	6,067	6,067	6,067	6,067	6,067	6,067	6,067	6,067
19	*Exports*	0	0	0	0	0	0	0	0	0	0
20	**Service Area Portion of System Resources (Line 2 * 92%)**	**30,481**	**32,089**	**32,975**	**32,478**	**32,005**	**32,345**	**29,788**	**29,825**	**29,863**	**29,900**
	SERVICE AREA SPECIFIC LINE ADJUSTMENTS:										
21	**Service Area** 1-in-2 Peak Summer Demand	20,193	20,510	20,829	21,071	21,318	21,572	21,851	22,117	22,383	22,683
22	Total Demand-Side Reductions	(1,492)	(1,836)	(2,178)	(2,496)	(2,839)	(3,237)	(3,657)	(4,090)	(4,501)	(4,898)
23	*Incremental Uncommitted EE*	98	128	388	620	871	1,180	1,511	1,857	2,184	2,496
24	*Total DR*	1,354	1,627	1,670	1,715	1,767	1,816	1,865	1,911	1,956	2,001
25	*Incremental Demand-Side CHP*	40	80	120	161	201	241	281	321	361	401
26	**Residual Service Area Peak Demand (Line 21 minus Line 22)**	**18,701**	**18,675**	**18,651**	**18,576**	**18,480**	**18,335**	**18,194**	**18,028**	**17,881**	**17,786**
	SERVICE AREA RESERVES:										
27	Amount of Available Resources Exceeding Demand (Line 20 minus Line 26)	11,780	13,415	14,325	13,902	13,525	14,011	11,593	11,797	11,981	12,115
28	Percentage of Available Resources Exceeding Demand (Line 20 / Line 26)	163.0%	171.8%	176.8%	174.8%	173.2%	176.4%	163.7%	165.4%	167.0%	168.1%
	1-in-2 SERVICE AREA SURPLUS (DEFICIT):										
29	Lower Bound of Planning Reserve Requirement (Line 26 * 15%)	21,506	21,476	21,448	21,362	21,251	21,085	20,923	20,732	20,564	20,453
30	Upper Bound of Planning Reserve Requirement (Line 26 * 17%)	21,880	21,849	21,821	21,734	21,621	21,452	21,287	21,092	20,921	20,809
31	Upper Bound 1-in-2 Service Area Surplus (Deficit)	8,975	10,614	11,527	11,116	10,754	11,260	8,864	9,093	9,299	9,447
32	Lower Bound 1-in-2 Service Area Surplus (Deficit)	8,601	10,240	11,154	10,744	10,384	10,894	8,500	8,733	8,941	9,091

	SCE Physical South of Path 26 (SP26) Capacity Need Scenario: 33% Time-Constrained										
Line		MW									
	SYSTEM AND SERVICE AREA LOAD FORECASTS:	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
1	**System** 1-in-2 Peak Summer Demand	23,785	24,142	24,518	24,823	25,149	25,482	25,833	26,169	26,509	26,875
2	**Total System Resources** (Sum Lines 3, 8, 11 through 16)	**30,618**	**31,355**	**32,633**	**32,606**	**33,771**	**33,126**	**32,403**	**31,482**	**30,562**	**28,515**
	SYSTEM RESOURCES:										
3	Existing Generation (Sum of Lines 4 through 7)	21,404	21,404	21,404	21,404	21,404	21,404	21,404	21,404	21,404	21,404
4	*Existing Renewables (Excludes Hydro)*	916	916	916	916	916	916	916	916	916	916
5	*Existing Hydro (Includes RPS-eligible Hydro)*	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470
6	*Existing CHP*	1,489	1,489	1,489	1,489	1,489	1,489	1,489	1,489	1,489	1,489
7	*Existing OTC*	9,250	9,250	9,250	9,250	9,250	9,250	9,250	9,250	9,250	9,250
8	*Other Generation*	8,279	8,279	8,279	8,279	8,279	8,279	8,279	8,279	8,279	8,279
9	Retirements (Includes Lines 10 & 11)	(452)	(452)	(452)	(787)	(2,398)	(3,349)	(4,300)	(5,251)	(6,202)	(8,280)
10	*OTC Retirements*	452	452	452	787	1,122	2,073	3,024	3,975	4,926	7,004
11	*Retirements*	0	0	0	0	1,276	1,276	1,276	1,276	1,276	1,276
12	Known/High Probability Additions	717	917	1,997	1,997	1,997	1,997	1,997	1,997	1,997	1,997
13	Utility Probable Planned Additions	0	500	500	500	1,854	1,854	1,854	1,854	1,854	1,854
14	Other Planned Additions	0	0	0	0	0	0	0	0	0	0
15	RPS Additions (In Service Territory)	0	6	174	451	1,843	2,118	2,315	2,315	2,315	2,315
16	Additional CHP	31	61	92	123	153	184	215	245	276	307
17	Net Interchange (Sum of Lines 18 & 19)	8,918	8,918	8,918	8,918	8,918	8,918	8,918	8,918	8,918	8,918
18	*Imports*	8,918	8,918	8,918	8,918	8,918	8,918	8,918	8,918	8,918	8,918
19	*Exports*	0	0	0	0	0	0	0	0	0	0
20	**Service Area Portion of System Resources (Line 2 * 90%)**	**27,557**	**28,219**	**29,370**	**29,346**	**30,394**	**29,813**	**29,163**	**28,334**	**27,506**	**25,664**
	SERVICE AREA SPECIFIC LINE ADJUSTMENTS:										
21	**Service Area** 1-in-2 Peak Summer Demand	21,305	21,634	21,981	22,262	22,561	22,867	23,189	23,497	23,810	24,146
22	Total Demand-Side Reductions	(1,721)	(2,634)	(3,118)	(3,458)	(3,856)	(4,228)	(4,624)	(5,042)	(5,449)	(5,850)
23	*Incremental Uncommitted EE*	44	60	325	565	834	1,171	1,530	1,912	2,283	2,648
24	*Total DR*	1,641	2,502	2,685	2,749	2,842	2,842	2,842	2,842	2,842	2,842
25	*Incremental Demand-Side CHP*	36	72	108	144	180	216	252	288	324	360
26	**Residual Service Area Peak Demand (Line 21 minus Line 22)**	**19,584**	**19,000**	**18,863**	**18,805**	**18,705**	**18,639**	**18,565**	**18,456**	**18,361**	**18,296**
	SERVICE AREA RESERVES:										
27	Amount of Available Resources Exceeding Demand (Line 20 minus Line 26)	7,973	9,219	10,507	10,541	11,689	11,175	10,597	9,878	9,145	7,367
28	Percentage of Available Resources Exceeding Demand (Line 20 / Line 26)	140.7%	148.5%	155.7%	156.1%	162.5%	160.0%	157.1%	153.5%	149.8%	140.3%
	1-in-2 SERVICE AREA SURPLUS (DEFICIT):										
29	Lower Bound of Planning Reserve Requirement (Line 26 * 15%)	22,521	21,850	21,692	21,625	21,511	21,435	21,350	21,224	21,115	21,041
30	Upper Bound of Planning Reserve Requirement (Line 26 * 17%)	22,913	22,230	22,070	22,001	21,885	21,807	21,721	21,593	21,482	21,407
31	Upper Bound 1-in-2 Service Area Surplus (Deficit)	5,035	6,369	7,677	7,720	8,883	8,379	7,813	7,110	6,391	4,623
32	Lower Bound 1-in-2 Service Area Surplus (Deficit)	4,644	5,989	7,300	7,344	8,509	8,006	7,441	6,741	6,024	4,257

SDG&E
Physical Border Capacity Need
Scenario: 33% Time-Constrained

Line		MW									
	SYSTEM AND SERVICE AREA LOAD FORECASTS:	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
1	**System** 1-in-2 Peak Summer Demand	4,578	4,658	4,738	4,797	4,856	4,911	4,973	5,032	5,094	5,157
2	**Total System Resources** (Sum Lines 3, 8, 11 through 16)	**6,127**	**6,130**	**6,291**	**6,308**	**6,371**	**6,374**	**5,417**	**5,419**	**5,422**	**5,425**
	SYSTEM RESOURCES:										
3	Existing Generation (Sum of Lines 4 through 7)	4,410	4,410	4,410	4,410	4,410	4,410	4,410	4,410	4,410	4,410
4	*Existing Renewables (Excludes Hydro)*	21	21	21	21	21	21	21	21	21	21
5	*Existing Hydro (Includes RPS-eligible Hydro)*	4	4	4	4	4	4	4	4	4	4
6	*Existing CHP*	136	136	136	136	136	136	136	136	136	136
7	*Existing OTC*	1,271	1,271	1,271	1,271	1,271	1,271	1,271	1,271	1,271	1,271
8	*Other Generation*	2,978	2,978	2,978	2,978	2,978	2,978	2,978	2,978	2,978	2,978
9	Retirements (Includes Lines 10 & 11)	(311)	(311)	(311)	(311)	(311)	(311)	(1,271)	(1,271)	(1,271)	(1,271)
10	*OTC Retirements*	311	311	311	311	311	311	1,271	1,271	1,271	1,271
11	*Retirements*	0	0	0	0	0	0	0	0	0	0
12	Known/High Probability Additions	55	55	55	55	55	55	55	55	55	55
13	Utility Probable Planned Additions	0	0	159	159	159	159	159	159	159	159
14	Other Planned Additions	0	0	0	0	0	0	0	0	0	0
15	RPS Additions (In Service Territory)	0	0	0	14	74	74	74	74	74	74
16	Additional CHP	3	6	8	11	14	17	20	22	25	28
17	Net Interchange (Sum of Lines 18 & 19)	1,970	1,970	1,970	1,970	1,970	1,970	1,970	1,970	1,970	1,970
18	*Imports*	1,970	1,970	1,970	1,970	1,970	1,970	1,970	1,970	1,970	1,970
19	*Exports*	0	0	0	0	0	0	0	0	0	0
20	**Service Area Portion of System Resources (Line 2)**	**6,127**	**6,130**	**6,291**	**6,308**	**6,371**	**6,374**	**5,417**	**5,419**	**5,422**	**5,425**
	SERVICE AREA SPECIFIC LINE ADJUSTMENTS:										
21	**Service Area** 1-in-2 Peak Summer Demand	4,578	4,658	4,738	4,797	4,856	4,911	4,973	5,032	5,094	5,157
22	Total Demand-Side Reductions	(219)	(242)	(353)	(421)	(492)	(570)	(655)	(743)	(825)	(903)
23	*Incremental Uncommitted EE*	3	4	66	121	179	247	321	398	471	544
24	*Total DR*	210	226	270	277	285	289	293	298	302	302
25	*Incremental Demand-Side CHP*	6	12	17	23	29	35	41	46	52	58
26	**Residual Service Area Peak Demand (Line 21 minus Line 22)**	**4,359**	**4,416**	**4,385**	**4,376**	**4,363**	**4,340**	**4,318**	**4,289**	**4,269**	**4,254**
	SERVICE AREA RESERVES:										
27	Amount of Available Resources Exceeding Demand (Line 20 minus Line 26)	1,768	1,714	1,906	1,932	2,008	2,034	1,099	1,131	1,154	1,172
28	Percentage of Available Resources Exceeding Demand (Line 20 / Line 26)	140.6%	138.8%	143.5%	144.1%	146.0%	146.9%	125.5%	126.4%	127.0%	127.5%
	1-in-2 SERVICE AREA SURPLUS (DEFICIT):										
29	Lower Bound of Planning Reserve Requirement (Line 26 * 15%)	5,013	5,079	5,043	5,032	5,018	4,991	4,966	4,932	4,909	4,892
30	Upper Bound of Planning Reserve Requirement (Line 26 * 17%)	5,100	5,167	5,131	5,120	5,105	5,078	5,052	5,018	4,994	4,977
31	Upper Bound 1-in-2 Service Area Surplus (Deficit)	1,114	1,051	1,248	1,275	1,354	1,383	452	487	513	534
32	Lower Bound 1-in-2 Service Area Surplus (Deficit)	1,027	963	1,160	1,188	1,266	1,296	365	401	428	449

PG&E
Physical North of Path 26 (NP26) Capacity Need
Scenario: 33% Cost-Constrained

Line		MW									
	SYSTEM AND SERVICE AREA LOAD FORECASTS:	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
1	**System** 1-in-2 Peak Summer Demand	21,988	22,329	22,668	22,924	23,185	23,454	23,750	24,030	24,310	24,626
2	**Total System Resources** (Sum Lines 3, 8, 11 through 16)	**33,132**	**34,866**	**35,764**	**35,286**	**34,757**	**35,144**	**32,512**	**32,553**	**32,594**	**32,635**
	SYSTEM RESOURCES:										
3	Existing Generation (Sum of Lines 4 through 7)	26,623	26,623	26,623	26,623	26,623	26,623	26,623	26,623	26,623	26,623
4	*Existing Renewables (Excludes Hydro)*	1,426	1,426	1,426	1,426	1,426	1,426	1,426	1,426	1,426	1,426
5	*Existing Hydro (Includes RPS-eligible Hydro)*	6,461	6,461	6,461	6,461	6,461	6,461	6,461	6,461	6,461	6,461
6	*Existing CHP*	1,888	1,888	1,888	1,888	1,888	1,888	1,888	1,888	1,888	1,888
7	*Existing OTC*	7,064	7,064	7,064	7,064	7,064	7,064	7,064	7,064	7,064	7,064
8	*Other Generation*	9,784	9,784	9,784	9,784	9,784	9,784	9,784	9,784	9,784	9,784
9	Retirements (Includes Lines 10 & 11)	(497)	(662)	(662)	(1,336)	(1,986)	(1,986)	(4,807)	(4,807)	(4,807)	(4,807)
10	*OTC Retirements*	341	341	341	1,015	1,665	1,665	3,804	3,804	3,804	3,804
11	*Retirements*	156	321	321	321	321	321	1,003	1,003	1,003	1,003
12	Known/High Probability Additions	878	1,733	1,733	1,733	1,733	1,733	1,733	1,733	1,733	1,733
13	Utility Probable Planned Additions	0	784	784	784	784	784	784	784	784	784
14	Other Planned Additions	0	145	973	973	973	973	973	973	973	973
15	RPS Additions (In Service Territory)	20	94	123	278	359	704	853	853	853	853
16	Additional CHP	41	82	123	164	204	245	286	327	368	409
17	Net Interchange (Sum of Lines 18 & 19)	6,067	6,067	6,067	6,067	6,067	6,067	6,067	6,067	6,067	6,067
18	*Imports*	6,067	6,067	6,067	6,067	6,067	6,067	6,067	6,067	6,067	6,067
19	*Exports*	0	0	0	0	0	0	0	0	0	0
20	**Service Area Portion of System Resources (Line 2 * 92%)**	**30,481**	**32,077**	**32,903**	**32,463**	**31,976**	**32,332**	**29,911**	**29,949**	**29,986**	**30,024**
	SERVICE AREA SPECIFIC LINE ADJUSTMENTS:										
21	**Service Area** 1-in-2 Peak Summer Demand	20,193	20,510	20,829	21,071	21,318	21,572	21,851	22,117	22,383	22,683
22	Total Demand-Side Reductions	(1,492)	(1,836)	(2,178)	(2,496)	(2,839)	(3,237)	(3,657)	(4,090)	(4,501)	(4,898)
23	*Incremental Uncommitted EE*	98	128	388	620	871	1,180	1,511	1,857	2,184	2,496
24	*Total DR*	1,354	1,627	1,670	1,715	1,767	1,816	1,865	1,911	1,956	2,001
25	*Incremental Demand-Side CHP*	40	80	120	161	201	241	281	321	361	401
26	**Residual Service Area Peak Demand (Line 21 minus Line 22)**	**18,701**	**18,675**	**18,651**	**18,576**	**18,480**	**18,335**	**18,194**	**18,028**	**17,881**	**17,786**
	SERVICE AREA RESERVES:										
27	Amount of Available Resources Exceeding Demand (Line 20 minus Line 26)	11,780	13,402	14,252	13,887	13,497	13,997	11,717	11,921	12,105	12,238
28	Percentage of Available Resources Exceeding Demand (Line 20 / Line 26)	163.0%	171.8%	176.4%	174.8%	173.0%	176.3%	164.4%	166.1%	167.7%	168.8%
	1-in-2 SERVICE AREA SURPLUS (DEFICIT):										
29	Lower Bound of Planning Reserve Requirement (Line 26 * 15%)	21,506	21,476	21,448	21,362	21,251	21,085	20,923	20,732	20,564	20,453
30	Upper Bound of Planning Reserve Requirement (Line 26 * 17%)	21,880	21,849	21,821	21,734	21,621	21,452	21,287	21,092	20,921	20,809
31	Upper Bound 1-in-2 Service Area Surplus (Deficit)	8,975	10,601	11,455	11,101	10,725	11,247	8,988	9,217	9,423	9,570
32	Lower Bound 1-in-2 Service Area Surplus (Deficit)	8,601	10,227	11,082	10,729	10,355	10,881	8,624	8,856	9,065	9,215

	SCE Physical South of Path 26 (SP26) Capacity Need Scenario: 33% Cost-Constrained										
Line		MW									
	SYSTEM AND SERVICE AREA LOAD FORECASTS:	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
1	**System** 1-in-2 Peak Summer Demand	23,785	24,142	24,518	24,823	25,149	25,482	25,833	26,169	26,509	26,875
2	**Total System Resources** (Sum Lines 3, 8, 11 through 16)	**30,618**	**31,355**	**32,633**	**32,582**	**33,076**	**32,431**	**31,708**	**30,787**	**29,867**	**27,820**
	SYSTEM RESOURCES:										
3	Existing Generation (Sum of Lines 4 through 7)	21,404	21,404	21,404	21,404	21,404	21,404	21,404	21,404	21,404	21,404
4	*Existing Renewables (Excludes Hydro)*	916	916	916	916	916	916	916	916	916	916
5	*Existing Hydro (Includes RPS-eligible Hydro)*	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470
6	*Existing CHP*	1,489	1,489	1,489	1,489	1,489	1,489	1,489	1,489	1,489	1,489
7	*Existing OTC*	9,250	9,250	9,250	9,250	9,250	9,250	9,250	9,250	9,250	9,250
8	*Other Generation*	8,279	8,279	8,279	8,279	8,279	8,279	8,279	8,279	8,279	8,279
9	Retirements (Includes Lines 10 & 11)	(452)	(452)	(452)	(787)	(2,398)	(3,349)	(4,300)	(5,251)	(6,202)	(8,280)
10	*OTC Retirements*	452	452	452	787	1,122	2,073	3,024	3,975	4,926	7,004
11	*Retirements*	0	0	0	0	1,276	1,276	1,276	1,276	1,276	1,276
12	Known/High Probability Additions	717	917	1,997	1,997	1,997	1,997	1,997	1,997	1,997	1,997
13	Utility Probable Planned Additions	0	500	500	500	1,854	1,854	1,854	1,854	1,854	1,854
14	Other Planned Additions	0	0	0	0	0	0	0	0	0	0
15	RPS Additions (In Service Territory)	0	6	174	427	1,148	1,423	1,620	1,620	1,620	1,620
16	Additional CHP	31	61	92	123	153	184	215	245	276	307
17	Net Interchange (Sum of Lines 18 & 19)	8,918	8,918	8,918	8,918	8,918	8,918	8,918	8,918	8,918	8,918
18	*Imports*	8,918	8,918	8,918	8,918	8,918	8,918	8,918	8,918	8,918	8,918
19	*Exports*	0	0	0	0	0	0	0	0	0	0
20	**Service Area Portion of System Resources (Line 2 * 90%)**	**27,557**	**28,219**	**29,370**	**29,324**	**29,768**	**29,188**	**28,537**	**27,709**	**26,881**	**25,038**
	SERVICE AREA SPECIFIC LINE ADJUSTMENTS:										
21	**Service Area** 1-in-2 Peak Summer Demand	21,305	21,634	21,981	22,262	22,561	22,867	23,189	23,497	23,810	24,146
22	Total Demand-Side Reductions	(1,721)	(2,634)	(3,118)	(3,458)	(3,856)	(4,228)	(4,624)	(5,042)	(5,449)	(5,850)
23	*Incremental Uncommitted EE*	44	60	325	565	834	1,171	1,530	1,912	2,283	2,648
24	*Total DR*	1,641	2,502	2,685	2,749	2,842	2,842	2,842	2,842	2,842	2,842
25	*Incremental Demand-Side CHP*	36	72	108	144	180	216	252	288	324	360
26	**Residual Service Area Peak Demand (Line 21 minus Line 22)**	**19,584**	**19,000**	**18,863**	**18,805**	**18,705**	**18,639**	**18,565**	**18,456**	**18,361**	**18,296**
	SERVICE AREA RESERVES:										
27	Amount of Available Resources Exceeding Demand (Line 20 minus Line 26)	7,973	9,219	10,507	10,519	11,063	10,549	9,972	9,253	8,520	6,742
28	Percentage of Available Resources Exceeding Demand (Line 20 / Line 26)	140.7%	148.5%	155.7%	155.9%	159.1%	156.6%	153.7%	150.1%	146.4%	136.8%
	1-in-2 SERVICE AREA SURPLUS (DEFICIT):										
29	Lower Bound of Planning Reserve Requirement (Line 26 * 15%)	22,521	21,850	21,692	21,625	21,511	21,435	21,350	21,224	21,115	21,041
30	Upper Bound of Planning Reserve Requirement (Line 26 * 17%)	22,913	22,230	22,070	22,001	21,885	21,807	21,721	21,593	21,482	21,407
31	Upper Bound 1-in-2 Service Area Surplus (Deficit)	5,035	6,369	7,677	7,698	8,257	7,753	7,187	6,485	5,766	3,998
32	Lower Bound 1-in-2 Service Area Surplus (Deficit)	4,644	5,989	7,300	7,322	7,883	7,381	6,816	6,116	5,398	3,632

Line	SDG&E Physical Border Capacity Need — Scenario: 33% Cost-Constrained										
		MW									
	SYSTEM AND SERVICE AREA LOAD FORECASTS:	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
1	**System** 1-in-2 Peak Summer Demand	4,578	4,658	4,738	4,797	4,856	4,911	4,973	5,032	5,094	5,157
2	**Total System Resources** (Sum Lines 3, 8, 11 through 16)	**6,127**	**6,130**	**6,291**	**6,339**	**6,639**	**6,670**	**5,761**	**6,254**	**6,257**	**6,260**
	SYSTEM RESOURCES:										
3	Existing Generation (Sum of Lines 4 through 7)	4,410	4,410	4,410	4,410	4,410	4,410	4,410	4,410	4,410	4,410
4	*Existing Renewables (Excludes Hydro)*	21	21	21	21	21	21	21	21	21	21
5	*Existing Hydro (Includes RPS-eligible Hydro)*	4	4	4	4	4	4	4	4	4	4
6	*Existing CHP*	136	136	136	136	136	136	136	136	136	136
7	*Existing OTC*	1,271	1,271	1,271	1,271	1,271	1,271	1,271	1,271	1,271	1,271
8	*Other Generation*	2,978	2,978	2,978	2,978	2,978	2,978	2,978	2,978	2,978	2,978
9	Retirements (Includes Lines 10 & 11)	(311)	(311)	(311)	(311)	(311)	(311)	(1,271)	(1,271)	(1,271)	(1,271)
10	*OTC Retirements*	311	311	311	311	311	311	1,271	1,271	1,271	1,271
11	*Retirements*	0	0	0	0	0	0	0	0	0	0
12	Known/High Probability Additions	55	55	55	55	55	55	55	55	55	55
13	Utility Probable Planned Additions	0	0	159	159	159	159	159	159	159	159
14	Other Planned Additions	0	0	0	0	0	0	0	0	0	0
15	RPS Additions (In Service Territory)	0	0	0	45	342	370	418	909	909	909
16	Additional CHP	3	6	8	11	14	17	20	22	25	28
17	Net Interchange (Sum of Lines 18 & 19)	1,970	1,970	1,970	1,970	1,970	1,970	1,970	1,970	1,970	1,970
18	*Imports*	1,970	1,970	1,970	1,970	1,970	1,970	1,970	1,970	1,970	1,970
19	*Exports*	0	0	0	0	0	0	0	0	0	0
20	**Service Area Portion of System Resources (Line 2)**	**6,127**	**6,130**	**6,291**	**6,339**	**6,639**	**6,670**	**5,761**	**6,254**	**6,257**	**6,260**
	SERVICE AREA SPECIFIC LINE ADJUSTMENTS:										
21	**Service Area** 1-in-2 Peak Summer Demand	4,578	4,658	4,738	4,797	4,856	4,911	4,973	5,032	5,094	5,157
22	Total Demand-Side Reductions	(219)	(242)	(353)	(421)	(492)	(570)	(655)	(743)	(825)	(903)
23	*Incremental Uncommitted EE*	3	4	66	121	179	247	321	398	471	544
24	*Total DR*	210	226	270	277	285	289	293	298	302	302
25	*Incremental Demand-Side CHP*	6	12	17	23	29	35	41	46	52	58
26	**Residual Service Area Peak Demand (Line 21 minus Line 22)**	**4,359**	**4,416**	**4,385**	**4,376**	**4,363**	**4,340**	**4,318**	**4,289**	**4,269**	**4,254**
	SERVICE AREA RESERVES:										
27	Amount of Available Resources Exceeding Demand (Line 20 minus Line 26)	1,768	1,714	1,906	1,963	2,276	2,330	1,443	1,965	1,988	2,006
28	Percentage of Available Resources Exceeding Demand (Line 20 / Line 26)	140.6%	138.8%	143.5%	144.9%	152.2%	153.7%	133.4%	145.8%	146.6%	147.2%
	1-in-2 SERVICE AREA SURPLUS (DEFICIT):										
29	Lower Bound of Planning Reserve Requirement (Line 26 * 15%)	5,013	5,079	5,043	5,032	5,018	4,991	4,966	4,932	4,909	4,892
30	Upper Bound of Planning Reserve Requirement (Line 26 * 17%)	5,100	5,167	5,131	5,120	5,105	5,078	5,052	5,018	4,994	4,977
31	Upper Bound 1-in-2 Service Area Surplus (Deficit)	1,114	1,051	1,248	1,307	1,621	1,679	795	1,321	1,347	1,368
32	Lower Bound 1-in-2 Service Area Surplus (Deficit)	1,027	963	1,160	1,219	1,534	1,592	709	1,235	1,262	1,283

PG&E
Physical North of Path 26 (NP26) Capacity Need
Scenario: 33% Environmentally-Constrained

Line		MW									
	SYSTEM AND SERVICE AREA LOAD FORECASTS:	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
1	**System** 1-in-2 Peak Summer Demand	21,988	22,329	22,668	22,924	23,185	23,454	23,750	24,030	24,310	24,626
2	**Total System Resources** (Sum Lines 3, 8, 11 through 16)	**33,132**	**34,866**	**35,789**	**35,277**	**34,681**	**35,062**	**32,916**	**32,957**	**32,998**	**33,039**
	SYSTEM RESOURCES:										
3	Existing Generation (Sum of Lines 4 through 7)	26,623	26,623	26,623	26,623	26,623	26,623	26,623	26,623	26,623	26,623
4	*Existing Renewables (Excludes Hydro)*	1,426	1,426	1,426	1,426	1,426	1,426	1,426	1,426	1,426	1,426
5	*Existing Hydro (Includes RPS-eligible Hydro)*	6,461	6,461	6,461	6,461	6,461	6,461	6,461	6,461	6,461	6,461
6	*Existing CHP*	1,888	1,888	1,888	1,888	1,888	1,888	1,888	1,888	1,888	1,888
7	*Existing OTC*	7,064	7,064	7,064	7,064	7,064	7,064	7,064	7,064	7,064	7,064
8	*Other Generation*	9,784	9,784	9,784	9,784	9,784	9,784	9,784	9,784	9,784	9,784
9	Retirements (Includes Lines 10 & 11)	(497)	(662)	(662)	(1,336)	(1,986)	(1,986)	(4,807)	(4,807)	(4,807)	(4,807)
10	*OTC Retirements*	341	341	341	1,015	1,665	1,665	3,804	3,804	3,804	3,804
11	*Retirements*	156	321	321	321	321	321	1,003	1,003	1,003	1,003
12	Known/High Probability Additions	878	1,733	1,733	1,733	1,733	1,733	1,733	1,733	1,733	1,733
13	Utility Probable Planned Additions	0	784	784	784	784	784	784	784	784	784
14	Other Planned Additions	0	145	973	973	973	973	973	973	973	973
15	RPS Additions (In Service Territory)	20	94	149	269	283	623	1,257	1,257	1,257	1,257
16	Additional CHP	41	82	123	164	204	245	286	327	368	409
17	Net Interchange (Sum of Lines 18 & 19)	6,067	6,067	6,067	6,067	6,067	6,067	6,067	6,067	6,067	6,067
18	*Imports*	6,067	6,067	6,067	6,067	6,067	6,067	6,067	6,067	6,067	6,067
19	*Exports*	0	0	0	0	0	0	0	0	0	0
20	**Service Area Portion of System Resources (Line 2 * 92%)**	**30,481**	**32,077**	**32,926**	**32,455**	**31,907**	**32,257**	**30,283**	**30,321**	**30,358**	**30,396**
	SERVICE AREA SPECIFIC LINE ADJUSTMENTS:										
21	**Service Area** 1-in-2 Peak Summer Demand	20,193	20,510	20,829	21,071	21,318	21,572	21,851	22,117	22,383	22,683
22	Total Demand-Side Reductions	(1,492)	(1,836)	(2,178)	(2,496)	(2,839)	(3,237)	(3,657)	(4,090)	(4,501)	(4,898)
23	*Incremental Uncommitted EE*	98	128	388	620	871	1,180	1,511	1,857	2,184	2,496
24	*Total DR*	1,354	1,627	1,670	1,715	1,767	1,816	1,865	1,911	1,956	2,001
25	*Incremental Demand-Side CHP*	40	80	120	161	201	241	281	321	361	401
26	**Residual Service Area Peak Demand (Line 21 minus Line 22)**	**18,701**	**18,675**	**18,651**	**18,576**	**18,480**	**18,335**	**18,194**	**18,028**	**17,881**	**17,786**
	SERVICE AREA RESERVES:										
27	Amount of Available Resources Exceeding Demand (Line 20 minus Line 26)	11,780	13,402	14,275	13,879	13,427	13,923	12,089	12,293	12,477	12,610
28	Percentage of Available Resources Exceeding Demand (Line 20 / Line 26)	163.0%	171.8%	176.5%	174.7%	172.7%	175.9%	166.4%	168.2%	169.8%	170.9%
	1-in-2 SERVICE AREA SURPLUS (DEFICIT):										
29	Lower Bound of Planning Reserve Requirement (Line 26 * 15%)	21,506	21,476	21,448	21,362	21,251	21,085	20,923	20,732	20,564	20,453
30	Upper Bound of Planning Reserve Requirement (Line 26 * 17%)	21,880	21,849	21,821	21,734	21,621	21,452	21,287	21,092	20,921	20,809
31	Upper Bound 1-in-2 Service Area Surplus (Deficit)	8,975	10,601	11,478	11,093	10,655	11,173	9,360	9,589	9,795	9,943
32	Lower Bound 1-in-2 Service Area Surplus (Deficit)	8,601	10,227	11,105	10,721	10,286	10,806	8,996	9,228	9,437	9,587

Line	SCE Physical South of Path 26 (SP26) Capacity Need Scenario: 33% Environmentally-Constrained										
		MW									
	SYSTEM AND SERVICE AREA LOAD FORECASTS:	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
1	**System** 1-in-2 Peak Summer Demand	23,785	24,142	24,518	24,823	25,149	25,482	25,833	26,169	26,509	26,875
2	**Total System Resources** (Sum Lines 3, 8, 11 through 16)	**30,618**	**31,355**	**32,633**	**32,578**	**33,055**	**32,410**	**31,729**	**30,808**	**29,888**	**27,841**
	SYSTEM RESOURCES:										
3	Existing Generation (Sum of Lines 4 through 7)	21,404	21,404	21,404	21,404	21,404	21,404	21,404	21,404	21,404	21,404
4	*Existing Renewables (Excludes Hydro)*	916	916	916	916	916	916	916	916	916	916
5	*Existing Hydro (Includes RPS-eligible Hydro)*	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470
6	*Existing CHP*	1,489	1,489	1,489	1,489	1,489	1,489	1,489	1,489	1,489	1,489
7	*Existing OTC*	9,250	9,250	9,250	9,250	9,250	9,250	9,250	9,250	9,250	9,250
8	*Other Generation*	8,279	8,279	8,279	8,279	8,279	8,279	8,279	8,279	8,279	8,279
9	Retirements (Includes Lines 10 & 11)	(452)	(452)	(452)	(787)	(2,398)	(3,349)	(4,300)	(5,251)	(6,202)	(8,280)
10	*OTC Retirements*	452	452	452	787	1,122	2,073	3,024	3,975	4,926	7,004
11	*Retirements*	0	0	0	0	1,276	1,276	1,276	1,276	1,276	1,276
12	Known/High Probability Additions	717	917	1,997	1,997	1,997	1,997	1,997	1,997	1,997	1,997
13	Utility Probable Planned Additions	0	500	500	500	1,854	1,854	1,854	1,854	1,854	1,854
14	Other Planned Additions	0	0	0	0	0	0	0	0	0	0
15	RPS Additions (In Service Territory)	0	6	174	423	1,127	1,402	1,641	1,641	1,641	1,641
16	Additional CHP	31	61	92	123	153	184	215	245	276	307
17	Net Interchange (Sum of Lines 18 & 19)	8,918	8,918	8,918	8,918	8,918	8,918	8,918	8,918	8,918	8,918
18	*Imports*	8,918	8,918	8,918	8,918	8,918	8,918	8,918	8,918	8,918	8,918
19	*Exports*	0	0	0	0	0	0	0	0	0	0
20	**Service Area Portion of System Resources (Line 2 * 90%)**	**27,557**	**28,219**	**29,370**	**29,320**	**29,750**	**29,169**	**28,556**	**27,727**	**26,899**	**25,057**
	SERVICE AREA SPECIFIC LINE ADJUSTMENTS:										
21	**Service Area** 1-in-2 Peak Summer Demand	21,305	21,634	21,981	22,262	22,561	22,867	23,189	23,497	23,810	24,146
22	Total Demand-Side Reductions	(1,721)	(2,634)	(3,118)	(3,458)	(3,856)	(4,228)	(4,624)	(5,042)	(5,449)	(5,850)
23	*Incremental Uncommitted EE*	44	60	325	565	834	1,171	1,530	1,912	2,283	2,648
24	*Total DR*	1,641	2,502	2,685	2,749	2,842	2,842	2,842	2,842	2,842	2,842
25	*Incremental Demand-Side CHP*	36	72	108	144	180	216	252	288	324	360
26	**Residual Service Area Peak Demand (Line 21 minus Line 22)**	**19,584**	**19,000**	**18,863**	**18,805**	**18,705**	**18,639**	**18,565**	**18,456**	**18,361**	**18,296**
	SERVICE AREA RESERVES:										
27	Amount of Available Resources Exceeding Demand (Line 20 minus Line 26)	7,973	9,219	10,507	10,516	11,044	10,530	9,991	9,272	8,539	6,761
28	Percentage of Available Resources Exceeding Demand (Line 20 / Line 26)	140.7%	148.5%	155.7%	155.9%	159.0%	156.5%	153.8%	150.2%	146.5%	137.0%
	1-in-2 SERVICE AREA SURPLUS (DEFICIT):										
29	Lower Bound of Planning Reserve Requirement (Line 26 * 15%)	22,521	21,850	21,692	21,625	21,511	21,435	21,350	21,224	21,115	21,041
30	Upper Bound of Planning Reserve Requirement (Line 26 * 17%)	22,913	22,230	22,070	22,001	21,885	21,807	21,721	21,593	21,482	21,407
31	Upper Bound 1-in-2 Service Area Surplus (Deficit)	5,035	6,369	7,677	7,695	8,238	7,735	7,206	6,504	5,785	4,016
32	Lower Bound 1-in-2 Service Area Surplus (Deficit)	4,644	5,989	7,300	7,319	7,864	7,362	6,835	6,134	5,417	3,650

	SDG&E										
	Physical Border Capacity Need										
	Scenario: 33% Environmentally-Constrained										
Line		**MW**									
	SYSTEM AND SERVICE AREA LOAD FORECASTS:	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
1	**System** 1-in-2 Peak Summer Demand	4,578	4,658	4,738	4,797	4,856	4,911	4,973	5,032	5,094	5,157
2	**Total System Resources** (Sum Lines 3, 8, 11 through 16)	**6,127**	**6,130**	**6,291**	**6,317**	**6,454**	**6,457**	**5,500**	**5,662**	**5,665**	**5,668**
	SYSTEM RESOURCES:										
3	Existing Generation (Sum of Lines 4 through 7)	4,410	4,410	4,410	4,410	4,410	4,410	4,410	4,410	4,410	4,410
4	*Existing Renewables (Excludes Hydro)*	21	21	21	21	21	21	21	21	21	21
5	*Existing Hydro (Includes RPS-eligible Hydro)*	4	4	4	4	4	4	4	4	4	4
6	*Existing CHP*	136	136	136	136	136	136	136	136	136	136
7	*Existing OTC*	1,271	1,271	1,271	1,271	1,271	1,271	1,271	1,271	1,271	1,271
8	*Other Generation*	2,978	2,978	2,978	2,978	2,978	2,978	2,978	2,978	2,978	2,978
9	Retirements (Includes Lines 10 & 11)	(311)	(311)	(311)	(311)	(311)	(311)	(1,271)	(1,271)	(1,271)	(1,271)
10	*OTC Retirements*	311	311	311	311	311	311	1,271	1,271	1,271	1,271
11	*Retirements*	0	0	0	0	0	0	0	0	0	0
12	Known/High Probability Additions	55	55	55	55	55	55	55	55	55	55
13	Utility Probable Planned Additions	0	0	159	159	159	159	159	159	159	159
14	Other Planned Additions	0	0	0	0	0	0	0	0	0	0
15	RPS Additions (In Service Territory)	0	0	0	23	157	157	157	317	317	317
16	Additional CHP	3	6	8	11	14	17	20	22	25	28
17	Net Interchange (Sum of Lines 18 & 19)	1,970	1,970	1,970	1,970	1,970	1,970	1,970	1,970	1,970	1,970
18	*Imports*	1,970	1,970	1,970	1,970	1,970	1,970	1,970	1,970	1,970	1,970
19	*Exports*	0	0	0	0	0	0	0	0	0	0
20	**Service Area Portion of System Resources (Line 2)**	**6,127**	**6,130**	**6,291**	**6,317**	**6,454**	**6,457**	**5,500**	**5,662**	**5,665**	**5,668**
	SERVICE AREA SPECIFIC LINE ADJUSTMENTS:										
21	**Service Area** 1-in-2 Peak Summer Demand	4,578	4,658	4,738	4,797	4,856	4,911	4,973	5,032	5,094	5,157
22	Total Demand-Side Reductions	(219)	(242)	(353)	(421)	(492)	(570)	(655)	(743)	(825)	(903)
23	*Incremental Uncommitted EE*	3	4	66	121	179	247	321	398	471	544
24	*Total DR*	210	226	270	277	285	289	293	298	302	302
25	*Incremental Demand-Side CHP*	6	12	17	23	29	35	41	46	52	58
26	**Residual Service Area Peak Demand (Line 21 minus Line 22)**	**4,359**	**4,416**	**4,385**	**4,376**	**4,363**	**4,340**	**4,318**	**4,289**	**4,269**	**4,254**
	SERVICE AREA RESERVES:										
27	Amount of Available Resources Exceeding Demand (Line 20 minus Line 26)	1,768	1,714	1,906	1,941	2,091	2,117	1,182	1,373	1,396	1,414
28	Percentage of Available Resources Exceeding Demand (Line 20 / Line 26)	140.6%	138.8%	143.5%	144.4%	147.9%	148.8%	127.4%	132.0%	132.7%	133.3%
	1-in-2 SERVICE AREA SURPLUS (DEFICIT):										
29	Lower Bound of Planning Reserve Requirement (Line 26 * 15%)	5,013	5,079	5,043	5,032	5,018	4,991	4,966	4,932	4,909	4,892
30	Upper Bound of Planning Reserve Requirement (Line 26 * 17%)	5,100	5,167	5,131	5,120	5,105	5,078	5,052	5,018	4,994	4,977
31	Upper Bound 1-in-2 Service Area Surplus (Deficit)	1,114	1,051	1,248	1,285	1,437	1,466	535	730	756	776
32	Lower Bound 1-in-2 Service Area Surplus (Deficit)	1,027	963	1,160	1,197	1,349	1,379	448	644	671	691

PG&E
Physical North of Path 26 (NP26) Capacity Need
Scenario: 20% Trajectory

Line		MW									
	SYSTEM AND SERVICE AREA LOAD FORECASTS:	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
1	**System** 1-in-2 Peak Summer Demand	21,988	22,329	22,668	22,924	23,185	23,454	23,750	24,030	24,310	24,626
2	**Total System Resources** (Sum Lines 3, 8, 11 through 16)	**33,132**	**34,866**	**35,764**	**35,271**	**34,661**	**35,048**	**32,306**	**32,347**	**32,388**	**32,429**
	SYSTEM RESOURCES:										
3	Existing Generation (Sum of Lines 4 through 7)	26,623	26,623	26,623	26,623	26,623	26,623	26,623	26,623	26,623	26,623
4	*Existing Renewables (Excludes Hydro)*	1,426	1,426	1,426	1,426	1,426	1,426	1,426	1,426	1,426	1,426
5	*Existing Hydro (Includes RPS-eligible Hydro)*	6,461	6,461	6,461	6,461	6,461	6,461	6,461	6,461	6,461	6,461
6	*Existing CHP*	1,888	1,888	1,888	1,888	1,888	1,888	1,888	1,888	1,888	1,888
7	*Existing OTC*	7,064	7,064	7,064	7,064	7,064	7,064	7,064	7,064	7,064	7,064
8	*Other Generation*	9,784	9,784	9,784	9,784	9,784	9,784	9,784	9,784	9,784	9,784
9	Retirements (Includes Lines 10 & 11)	(497)	(662)	(662)	(1,336)	(1,986)	(1,986)	(4,807)	(4,807)	(4,807)	(4,807)
10	*OTC Retirements*	341	341	341	1,015	1,665	1,665	3,804	3,804	3,804	3,804
11	*Retirements*	156	321	321	321	321	321	1,003	1,003	1,003	1,003
12	Known/High Probability Additions	878	1,733	1,733	1,733	1,733	1,733	1,733	1,733	1,733	1,733
13	Utility Probable Planned Additions	0	784	784	784	784	784	784	784	784	784
14	Other Planned Additions	0	145	973	973	973	973	973	973	973	973
15	RPS Additions (In Service Territory)	20	94	123	263	263	609	647	647	647	647
16	Additional CHP	41	82	123	164	204	245	286	327	368	409
17	Net Interchange (Sum of Lines 18 & 19)	6,067	6,067	6,067	6,067	6,067	6,067	6,067	6,067	6,067	6,067
18	*Imports*	6,067	6,067	6,067	6,067	6,067	6,067	6,067	6,067	6,067	6,067
19	*Exports*	0	0	0	0	0	0	0	0	0	0
20	**Service Area Portion of System Resources (Line 2 * 92%)**	**30,481**	**32,077**	**32,903**	**32,450**	**31,888**	**32,244**	**29,722**	**29,759**	**29,797**	**29,835**
	SERVICE AREA SPECIFIC LINE ADJUSTMENTS:										
21	**Service Area** 1-in-2 Peak Summer Demand	20,193	20,510	20,829	21,071	21,318	21,572	21,851	22,117	22,383	22,683
22	Total Demand-Side Reductions	(1,492)	(1,836)	(2,178)	(2,496)	(2,839)	(3,237)	(3,657)	(4,090)	(4,501)	(4,898)
23	*Incremental Uncommitted EE*	98	128	388	620	871	1,180	1,511	1,857	2,184	2,496
24	*Total DR*	1,354	1,627	1,670	1,715	1,767	1,816	1,865	1,911	1,956	2,001
25	*Incremental Demand-Side CHP*	40	80	120	161	201	241	281	321	361	401
26	**Residual Service Area Peak Demand (Line 21 minus Line 22)**	**18,701**	**18,675**	**18,651**	**18,576**	**18,480**	**18,335**	**18,194**	**18,028**	**17,881**	**17,786**
	SERVICE AREA RESERVES:										
27	Amount of Available Resources Exceeding Demand (Line 20 minus Line 26)	11,780	13,402	14,252	13,874	13,409	13,910	11,528	11,732	11,916	12,049
28	Percentage of Available Resources Exceeding Demand (Line 20 / Line 26)	163.0%	171.8%	176.4%	174.7%	172.6%	175.9%	163.4%	165.1%	166.6%	167.7%
	1-in-2 SERVICE AREA SURPLUS (DEFICIT):										
29	Lower Bound of Planning Reserve Requirement (Line 26 * 15%)	21,506	21,476	21,448	21,362	21,251	21,085	20,923	20,732	20,564	20,453
30	Upper Bound of Planning Reserve Requirement (Line 26 * 17%)	21,880	21,849	21,821	21,734	21,621	21,452	21,287	21,092	20,921	20,809
31	Upper Bound 1-in-2 Service Area Surplus (Deficit)	8,975	10,601	11,455	11,088	10,637	11,159	8,798	9,028	9,233	9,381
32	Lower Bound 1-in-2 Service Area Surplus (Deficit)	8,601	10,227	11,082	10,716	10,267	10,793	8,435	8,667	8,876	9,026

SCE
Physical South of Path 26 (SP26) Capacity Need
Scenario: 20% Trajectory

Line		MW									
	SYSTEM AND SERVICE AREA LOAD FORECASTS:	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
1	**System** 1-in-2 Peak Summer Demand	23,785	24,142	24,518	24,823	25,149	25,482	25,833	26,169	26,509	26,875
2	**Total System Resources** (Sum Lines 3, 8, 11 through 16)	**30,618**	**31,355**	**32,633**	**32,578**	**32,920**	**32,276**	**31,553**	**30,632**	**29,712**	**27,665**
	SYSTEM RESOURCES:										
3	Existing Generation (Sum of Lines 4 through 7)	21,404	21,404	21,404	21,404	21,404	21,404	21,404	21,404	21,404	21,404
4	*Existing Renewables (Excludes Hydro)*	916	916	916	916	916	916	916	916	916	916
5	*Existing Hydro (Includes RPS-eligible Hydro)*	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470
6	*Existing CHP*	1,489	1,489	1,489	1,489	1,489	1,489	1,489	1,489	1,489	1,489
7	*Existing OTC*	9,250	9,250	9,250	9,250	9,250	9,250	9,250	9,250	9,250	9,250
8	*Other Generation*	8,279	8,279	8,279	8,279	8,279	8,279	8,279	8,279	8,279	8,279
9	Retirements (Includes Lines 10 & 11)	(452)	(452)	(452)	(787)	(2,398)	(3,349)	(4,300)	(5,251)	(6,202)	(8,280)
10	*OTC Retirements*	452	452	452	787	1,122	2,073	3,024	3,975	4,926	7,004
11	*Retirements*	0	0	0	0	1,276	1,276	1,276	1,276	1,276	1,276
12	Known/High Probability Additions	717	917	1,997	1,997	1,997	1,997	1,997	1,997	1,997	1,997
13	Utility Probable Planned Additions	0	500	500	500	1,854	1,854	1,854	1,854	1,854	1,854
14	Other Planned Additions	0	0	0	0	0	0	0	0	0	0
15	RPS Additions (In Service Territory)	0	6	174	423	992	1,268	1,465	1,465	1,465	1,465
16	Additional CHP	31	61	92	123	153	184	215	245	276	307
17	Net Interchange (Sum of Lines 18 & 19)	8,918	8,918	8,918	8,918	8,918	8,918	8,918	8,918	8,918	8,918
18	*Imports*	8,918	8,918	8,918	8,918	8,918	8,918	8,918	8,918	8,918	8,918
19	*Exports*	0	0	0	0	0	0	0	0	0	0
20	**Service Area Portion of System Resources (Line 2 * 90%)**	**27,557**	**28,219**	**29,370**	**29,320**	**29,628**	**29,048**	**28,397**	**27,569**	**26,741**	**24,898**
	SERVICE AREA SPECIFIC LINE ADJUSTMENTS:										
21	**Service Area** 1-in-2 Peak Summer Demand	21,305	21,634	21,981	22,262	22,561	22,867	23,189	23,497	23,810	24,146
22	Total Demand-Side Reductions	(1,721)	(2,634)	(3,118)	(3,458)	(3,856)	(4,228)	(4,624)	(5,042)	(5,449)	(5,850)
23	*Incremental Uncommitted EE*	44	60	325	565	834	1,171	1,530	1,912	2,283	2,648
24	*Total DR*	1,641	2,502	2,685	2,749	2,842	2,842	2,842	2,842	2,842	2,842
25	*Incremental Demand-Side CHP*	36	72	108	144	180	216	252	288	324	360
26	**Residual Service Area Peak Demand (Line 21 minus Line 22)**	**19,584**	**19,000**	**18,863**	**18,805**	**18,705**	**18,639**	**18,565**	**18,456**	**18,361**	**18,296**
	SERVICE AREA RESERVES:										
27	Amount of Available Resources Exceeding Demand (Line 20 minus Line 26)	7,973	9,219	10,507	10,516	10,923	10,409	9,832	9,113	8,380	6,602
28	Percentage of Available Resources Exceeding Demand (Line 20 / Line 26)	140.7%	148.5%	155.7%	155.9%	158.4%	155.8%	153.0%	149.4%	145.6%	136.1%
	1-in-2 SERVICE AREA SURPLUS (DEFICIT):										
29	Lower Bound of Planning Reserve Requirement (Line 26 * 15%)	22,521	21,850	21,692	21,625	21,511	21,435	21,350	21,224	21,115	21,041
30	Upper Bound of Planning Reserve Requirement (Line 26 * 17%)	22,913	22,230	22,070	22,001	21,885	21,807	21,721	21,593	21,482	21,407
31	Upper Bound 1-in-2 Service Area Surplus (Deficit)	5,035	6,369	7,677	7,695	8,117	7,613	7,047	6,345	5,626	3,858
32	Lower Bound 1-in-2 Service Area Surplus (Deficit)	4,644	5,989	7,300	7,319	7,743	7,241	6,676	5,976	5,258	3,492

	SDG&E										
	Physical Border Capacity Need										
	Scenario: 20% Trajectory										
Line		**MW**									
	SYSTEM AND SERVICE AREA LOAD FORECASTS:	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
1	**System** 1-in-2 Peak Summer Demand	4,578	4,658	4,738	4,797	4,856	4,911	4,973	5,032	5,094	5,157
2	**Total System Resources** (Sum Lines 3, 8, 11 through 16)	**6,127**	**6,130**	**6,291**	**6,332**	**6,439**	**6,446**	**5,489**	**5,491**	**5,494**	**5,497**
	SYSTEM RESOURCES:										
3	Existing Generation (Sum of Lines 4 through 7)	4,410	4,410	4,410	4,410	4,410	4,410	4,410	4,410	4,410	4,410
4	*Existing Renewables (Excludes Hydro)*	21	21	21	21	21	21	21	21	21	21
5	*Existing Hydro (Includes RPS-eligible Hydro)*	4	4	4	4	4	4	4	4	4	4
6	*Existing CHP*	136	136	136	136	136	136	136	136	136	136
7	*Existing OTC*	1,271	1,271	1,271	1,271	1,271	1,271	1,271	1,271	1,271	1,271
8	*Other Generation*	2,978	2,978	2,978	2,978	2,978	2,978	2,978	2,978	2,978	2,978
9	Retirements (Includes Lines 10 & 11)	(311)	(311)	(311)	(311)	(311)	(311)	(1,271)	(1,271)	(1,271)	(1,271)
10	*OTC Retirements*	311	311	311	311	311	311	1,271	1,271	1,271	1,271
11	*Retirements*	0	0	0	0	0	0	0	0	0	0
12	Known/High Probability Additions	55	55	55	55	55	55	55	55	55	55
13	Utility Probable Planned Additions	0	0	159	159	159	159	159	159	159	159
14	Other Planned Additions	0	0	0	0	0	0	0	0	0	0
15	RPS Additions (In Service Territory)	0	0	0	38	142	146	146	146	146	146
16	Additional CHP	3	6	8	11	14	17	20	22	25	28
17	Net Interchange (Sum of Lines 18 & 19)	1,970	1,970	1,970	1,970	1,970	1,970	1,970	1,970	1,970	1,970
18	*Imports*	1,970	1,970	1,970	1,970	1,970	1,970	1,970	1,970	1,970	1,970
19	*Exports*	0	0	0	0	0	0	0	0	0	0
20	**Service Area Portion of System Resources (Line 2)**	**6,127**	**6,130**	**6,291**	**6,332**	**6,439**	**6,446**	**5,489**	**5,491**	**5,494**	**5,497**
	SERVICE AREA SPECIFIC LINE ADJUSTMENTS:										
21	**Service Area** 1-in-2 Peak Summer Demand	4,578	4,658	4,738	4,797	4,856	4,911	4,973	5,032	5,094	5,157
22	Total Demand-Side Reductions	(219)	(242)	(353)	(421)	(492)	(570)	(655)	(743)	(825)	(903)
23	*Incremental Uncommitted EE*	3	4	66	121	179	247	321	398	471	544
24	*Total DR*	210	226	270	277	285	289	293	298	302	302
25	*Incremental Demand-Side CHP*	6	12	17	23	29	35	41	46	52	58
26	**Residual Service Area Peak Demand (Line 21 minus Line 22)**	**4,359**	**4,416**	**4,385**	**4,376**	**4,363**	**4,340**	**4,318**	**4,289**	**4,269**	**4,254**
	SERVICE AREA RESERVES:										
27	Amount of Available Resources Exceeding Demand (Line 20 minus Line 26)	1,768	1,714	1,906	1,956	2,076	2,106	1,171	1,202	1,225	1,243
28	Percentage of Available Resources Exceeding Demand (Line 20 / Line 26)	140.6%	138.8%	143.5%	144.7%	147.6%	148.5%	127.1%	128.0%	128.7%	129.2%
	1-in-2 SERVICE AREA SURPLUS (DEFICIT):										
29	Lower Bound of Planning Reserve Requirement (Line 26 * 15%)	5,013	5,079	5,043	5,032	5,018	4,991	4,966	4,932	4,909	4,892
30	Upper Bound of Planning Reserve Requirement (Line 26 * 17%)	5,100	5,167	5,131	5,120	5,105	5,078	5,052	5,018	4,994	4,977
31	Upper Bound 1-in-2 Service Area Surplus (Deficit)	1,114	1,051	1,248	1,299	1,421	1,455	523	559	585	605
32	Lower Bound 1-in-2 Service Area Surplus (Deficit)	1,027	963	1,160	1,212	1,334	1,368	437	473	500	520

	PG&E										
	Physical North of Path 26 (NP26) Capacity Need										
	Sensitivity: 33% Trajectory (High Load)										
Line		**MW**									
	SYSTEM AND SERVICE AREA LOAD FORECASTS:	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
1	**System** 1-in-2 Peak Summer Demand	24,187	24,562	24,935	25,217	25,504	25,799	26,125	26,433	26,741	27,088
2	**Total System Resources** (Sum Lines 3, 8, 11 through 16)	**33,132**	**34,866**	**35,764**	**35,271**	**34,812**	**35,199**	**32,564**	**32,604**	**32,645**	**32,686**
	SYSTEM RESOURCES:										
3	Existing Generation (Sum of Lines 4 through 7)	26,623	26,623	26,623	26,623	26,623	26,623	26,623	26,623	26,623	26,623
4	*Existing Renewables (Excludes Hydro)*	1,426	1,426	1,426	1,426	1,426	1,426	1,426	1,426	1,426	1,426
5	*Existing Hydro (Includes RPS-eligible Hydro)*	6,461	6,461	6,461	6,461	6,461	6,461	6,461	6,461	6,461	6,461
6	*Existing CHP*	1,888	1,888	1,888	1,888	1,888	1,888	1,888	1,888	1,888	1,888
7	*Existing OTC*	7,064	7,064	7,064	7,064	7,064	7,064	7,064	7,064	7,064	7,064
8	*Other Generation*	9,784	9,784	9,784	9,784	9,784	9,784	9,784	9,784	9,784	9,784
9	Retirements (Includes Lines 10 & 11)	(497)	(662)	(662)	(1,336)	(1,986)	(1,986)	(4,807)	(4,807)	(4,807)	(4,807)
10	*OTC Retirements*	341	341	341	1,015	1,665	1,665	3,804	3,804	3,804	3,804
11	*Retirements*	156	321	321	321	321	321	1,003	1,003	1,003	1,003
12	Known/High Probability Additions	878	1,733	1,733	1,733	1,733	1,733	1,733	1,733	1,733	1,733
13	Utility Probable Planned Additions	0	784	784	784	784	784	784	784	784	784
14	Other Planned Additions	0	145	973	973	973	973	973	973	973	973
15	RPS Additions (In Service Territory)	20	94	123	263	414	760	904	904	904	904
16	Additional CHP	41	82	123	164	204	245	286	327	368	409
17	Net Interchange (Sum of Lines 18 & 19)	6,067	6,067	6,067	6,067	6,067	6,067	6,067	6,067	6,067	6,067
18	*Imports*	6,067	6,067	6,067	6,067	6,067	6,067	6,067	6,067	6,067	6,067
19	*Exports*	0	0	0	0	0	0	0	0	0	0
20	**Service Area Portion of System Resources (Line 2 * 92%)**	**30,481**	**32,077**	**32,903**	**32,450**	**32,027**	**32,383**	**29,959**	**29,996**	**30,034**	**30,071**
	SERVICE AREA SPECIFIC LINE ADJUSTMENTS:										
21	**Service Area** 1-in-2 Peak Summer Demand	22,212	22,561	22,912	23,179	23,450	23,729	24,036	24,329	24,621	24,952
22	Total Demand-Side Reductions	(1,492)	(1,836)	(2,178)	(2,496)	(2,839)	(3,237)	(3,657)	(4,090)	(4,501)	(4,898)
23	*Incremental Uncommitted EE*	98	128	388	620	871	1,180	1,511	1,857	2,184	2,496
24	*Total DR*	1,354	1,627	1,670	1,715	1,767	1,816	1,865	1,911	1,956	2,001
25	*Incremental Demand-Side CHP*	40	80	120	161	201	241	281	321	361	401
26	**Residual Service Area Peak Demand (Line 21 minus Line 22)**	**20,721**	**20,726**	**20,734**	**20,683**	**20,611**	**20,492**	**20,379**	**20,239**	**20,120**	**20,054**
	SERVICE AREA RESERVES:										
27	Amount of Available Resources Exceeding Demand (Line 20 minus Line 26)	9,761	11,351	12,169	11,767	11,416	11,892	9,579	9,757	9,914	10,017
28	Percentage of Available Resources Exceeding Demand (Line 20 / Line 26)	147.1%	154.8%	158.7%	156.9%	155.4%	158.0%	147.0%	148.2%	149.3%	150.0%
	1-in-2 SERVICE AREA SURPLUS (DEFICIT):										
29	Lower Bound of Planning Reserve Requirement (Line 26 * 15%)	23,829	23,835	23,844	23,785	23,703	23,566	23,436	23,275	23,138	23,062
30	Upper Bound of Planning Reserve Requirement (Line 26 * 17%)	24,243	24,249	24,258	24,199	24,115	23,975	23,844	23,680	23,540	23,463
31	Upper Bound 1-in-2 Service Area Surplus (Deficit)	6,653	8,242	9,059	8,664	8,324	8,818	6,522	6,721	6,896	7,009
32	Lower Bound 1-in-2 Service Area Surplus (Deficit)	6,238	7,828	8,645	8,251	7,912	8,408	6,115	6,316	6,494	6,608

	SCE Physical South of Path 26 (SP26) Capacity Need Sensitivity: 33% Trajectory (High Load)										
Line		MW									
	SYSTEM AND SERVICE AREA LOAD FORECASTS:	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
1	**System** 1-in-2 Peak Summer Demand	26,163	26,556	26,970	27,305	27,664	28,031	28,416	28,786	29,160	29,563
2	**Total System Resources** (Sum Lines 3, 8, 11 through 16)	**30,618**	**31,355**	**32,633**	**32,578**	**33,696**	**33,051**	**32,837**	**31,916**	**32,097**	**30,050**
	SYSTEM RESOURCES:										
3	Existing Generation (Sum of Lines 4 through 7)	21,404	21,404	21,404	21,404	21,404	21,404	21,404	21,404	21,404	21,404
4	*Existing Renewables (Excludes Hydro)*	916	916	916	916	916	916	916	916	916	916
5	*Existing Hydro (Includes RPS-eligible Hydro)*	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470
6	*Existing CHP*	1,489	1,489	1,489	1,489	1,489	1,489	1,489	1,489	1,489	1,489
7	*Existing OTC*	9,250	9,250	9,250	9,250	9,250	9,250	9,250	9,250	9,250	9,250
8	*Other Generation*	8,279	8,279	8,279	8,279	8,279	8,279	8,279	8,279	8,279	8,279
9	Retirements (Includes Lines 10 & 11)	(452)	(452)	(452)	(787)	(2,398)	(3,349)	(4,300)	(5,251)	(6,202)	(8,280)
10	*OTC Retirements*	452	452	452	787	1,122	2,073	3,024	3,975	4,926	7,004
11	*Retirements*	0	0	0	0	1,276	1,276	1,276	1,276	1,276	1,276
12	Known/High Probability Additions	717	917	1,997	1,997	1,997	1,997	1,997	1,997	1,997	1,997
13	Utility Probable Planned Additions	0	500	500	500	1,854	1,854	1,854	1,854	1,854	1,854
14	Other Planned Additions	0	0	0	0	0	0	0	0	0	0
15	RPS Additions (In Service Territory)	0	6	174	423	1,768	2,043	2,749	2,749	3,850	3,850
16	Additional CHP	31	61	92	123	153	184	215	245	276	307
17	Net Interchange (Sum of Lines 18 & 19)	8,918	8,918	8,918	8,918	8,918	8,918	8,918	8,918	8,918	8,918
18	*Imports*	8,918	8,918	8,918	8,918	8,918	8,918	8,918	8,918	8,918	8,918
19	*Exports*	0	0	0	0	0	0	0	0	0	0
20	**Service Area Portion of System Resources (Line 2 * 90%)**	**27,557**	**28,219**	**29,370**	**29,320**	**30,327**	**29,746**	**29,554**	**28,725**	**28,887**	**27,045**
	SERVICE AREA SPECIFIC LINE ADJUSTMENTS:										
21	**Service Area** 1-in-2 Peak Summer Demand	23,435	23,798	24,179	24,488	24,817	25,154	25,508	25,847	26,191	26,561
22	Total Demand-Side Reductions	(1,721)	(2,634)	(3,118)	(3,458)	(3,856)	(4,228)	(4,624)	(5,042)	(5,449)	(5,850)
23	*Incremental Uncommitted EE*	44	60	325	565	834	1,171	1,530	1,912	2,283	2,648
24	*Total DR*	1,641	2,502	2,685	2,749	2,842	2,842	2,842	2,842	2,842	2,842
25	*Incremental Demand-Side CHP*	36	72	108	144	180	216	252	288	324	360
26	**Residual Service Area Peak Demand (Line 21 minus Line 22)**	**21,714**	**21,164**	**21,061**	**21,031**	**20,961**	**20,925**	**20,884**	**20,805**	**20,742**	**20,711**
	SERVICE AREA RESERVES:										
27	Amount of Available Resources Exceeding Demand (Line 20 minus Line 26)	5,843	7,056	8,309	8,290	9,365	8,821	8,670	7,919	8,146	6,334
28	Percentage of Available Resources Exceeding Demand (Line 20 / Line 26)	126.9%	133.3%	139.4%	139.4%	144.7%	142.2%	141.5%	138.1%	139.3%	130.6%
	1-in-2 SERVICE AREA SURPLUS (DEFICIT):										
29	Lower Bound of Planning Reserve Requirement (Line 26 * 15%)	24,971	24,338	24,220	24,185	24,106	24,064	24,017	23,926	23,853	23,818
30	Upper Bound of Planning Reserve Requirement (Line 26 * 17%)	25,405	24,761	24,642	24,606	24,525	24,483	24,434	24,342	24,268	24,232
31	Upper Bound 1-in-2 Service Area Surplus (Deficit)	2,585	3,881	5,149	5,135	6,221	5,682	5,537	4,799	5,034	3,227
32	Lower Bound 1-in-2 Service Area Surplus (Deficit)	2,151	3,458	4,728	4,714	5,802	5,263	5,119	4,383	4,619	2,813

Line	SDG&E Physical Border Capacity Need Sensitivity: 33% Trajectory (High Load)										
		MW									
	SYSTEM AND SERVICE AREA LOAD FORECASTS:	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
1	**System** 1-in-2 Peak Summer Demand	5,036	5,124	5,212	5,277	5,341	5,402	5,470	5,535	5,603	5,673
2	**Total System Resources** (Sum Lines 3, 8, 11 through 16)	**6,127**	**6,130**	**6,291**	**6,437**	**6,737**	**6,765**	**5,808**	**5,810**	**6,643**	**6,646**
	SYSTEM RESOURCES:										
3	Existing Generation (Sum of Lines 4 through 7)	4,410	4,410	4,410	4,410	4,410	4,410	4,410	4,410	4,410	4,410
4	*Existing Renewables (Excludes Hydro)*	21	21	21	21	21	21	21	21	21	21
5	*Existing Hydro (Includes RPS-eligible Hydro)*	4	4	4	4	4	4	4	4	4	4
6	*Existing CHP*	136	136	136	136	136	136	136	136	136	136
7	*Existing OTC*	1,271	1,271	1,271	1,271	1,271	1,271	1,271	1,271	1,271	1,271
8	*Other Generation*	2,978	2,978	2,978	2,978	2,978	2,978	2,978	2,978	2,978	2,978
9	Retirements (Includes Lines 10 & 11)	(311)	(311)	(311)	(311)	(311)	(311)	(1,271)	(1,271)	(1,271)	(1,271)
10	*OTC Retirements*	311	311	311	311	311	311	1,271	1,271	1,271	1,271
11	*Retirements*	0	0	0	0	0	0	0	0	0	0
12	Known/High Probability Additions	55	55	55	55	55	55	55	55	55	55
13	Utility Probable Planned Additions	0	0	159	159	159	159	159	159	159	159
14	Other Planned Additions	0	0	0	0	0	0	0	0	0	0
15	RPS Additions (In Service Territory)	0	0	0	143	440	465	465	465	1,295	1,295
16	Additional CHP	3	6	8	11	14	17	20	22	25	28
17	Net Interchange (Sum of Lines 18 & 19)	1,970	1,970	1,970	1,970	1,970	1,970	1,970	1,970	1,970	1,970
18	*Imports*	1,970	1,970	1,970	1,970	1,970	1,970	1,970	1,970	1,970	1,970
19	*Exports*	0	0	0	0	0	0	0	0	0	0
20	**Service Area Portion of System Resources (Line 2)**	**6,127**	**6,130**	**6,291**	**6,437**	**6,737**	**6,765**	**5,808**	**5,810**	**6,643**	**6,646**
	SERVICE AREA SPECIFIC LINE ADJUSTMENTS:										
21	**Service Area** 1-in-2 Peak Summer Demand	5,036	5,124	5,212	5,277	5,341	5,402	5,470	5,535	5,603	5,673
22	Total Demand-Side Reductions	(219)	(242)	(353)	(421)	(492)	(570)	(655)	(743)	(825)	(903)
23	*Incremental Uncommitted EE*	3	4	66	121	179	247	321	398	471	544
24	*Total DR*	210	226	270	277	285	289	293	298	302	302
25	*Incremental Demand-Side CHP*	6	12	17	23	29	35	41	46	52	58
26	**Residual Service Area Peak Demand (Line 21 minus Line 22)**	**4,817**	**4,882**	**4,859**	**4,856**	**4,849**	**4,831**	**4,815**	**4,792**	**4,778**	**4,769**
	SERVICE AREA RESERVES:										
27	Amount of Available Resources Exceeding Demand (Line 20 minus Line 26)	1,310	1,248	1,432	1,581	1,888	1,934	993	1,018	1,865	1,876
28	Percentage of Available Resources Exceeding Demand (Line 20 / Line 26)	127.2%	125.6%	129.5%	132.6%	138.9%	140.0%	120.6%	121.2%	139.0%	139.3%
	1-in-2 SERVICE AREA SURPLUS (DEFICIT):										
29	Lower Bound of Planning Reserve Requirement (Line 26 * 15%)	5,539	5,614	5,588	5,584	5,576	5,556	5,538	5,511	5,495	5,485
30	Upper Bound of Planning Reserve Requirement (Line 26 * 17%)	5,635	5,712	5,685	5,681	5,673	5,653	5,634	5,607	5,590	5,580
31	Upper Bound 1-in-2 Service Area Surplus (Deficit)	588	516	703	853	1,161	1,209	271	299	1,148	1,161
32	Lower Bound 1-in-2 Service Area Surplus (Deficit)	492	418	606	756	1,064	1,112	174	203	1,052	1,066

PG&E
Physical North of Path 26 (NP26) Capacity Need
Sensitivity: 33% Trajectory (Low Load)

Line		MW									
	SYSTEM AND SERVICE AREA LOAD FORECASTS:	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
1	**System** 1-in-2 Peak Summer Demand	19,790	20,096	20,401	20,632	20,867	21,108	21,375	21,627	21,879	22,163
2	**Total System Resources** (Sum Lines 3, 8, 11 through 16)	**33,132**	**34,866**	**35,764**	**35,271**	**34,812**	**35,199**	**32,457**	**32,498**	**32,539**	**32,580**
	SYSTEM RESOURCES:										
3	Existing Generation (Sum of Lines 4 through 7)	26,623	26,623	26,623	26,623	26,623	26,623	26,623	26,623	26,623	26,623
4	*Existing Renewables (Excludes Hydro)*	1,426	1,426	1,426	1,426	1,426	1,426	1,426	1,426	1,426	1,426
5	*Existing Hydro (Includes RPS-eligible Hydro)*	6,461	6,461	6,461	6,461	6,461	6,461	6,461	6,461	6,461	6,461
6	*Existing CHP*	1,888	1,888	1,888	1,888	1,888	1,888	1,888	1,888	1,888	1,888
7	*Existing OTC*	7,064	7,064	7,064	7,064	7,064	7,064	7,064	7,064	7,064	7,064
8	*Other Generation*	9,784	9,784	9,784	9,784	9,784	9,784	9,784	9,784	9,784	9,784
9	Retirements (Includes Lines 10 & 11)	(497)	(662)	(662)	(1,336)	(1,986)	(1,986)	(4,807)	(4,807)	(4,807)	(4,807)
10	*OTC Retirements*	341	341	341	1,015	1,665	1,665	3,804	3,804	3,804	3,804
11	*Retirements*	156	321	321	321	321	321	1,003	1,003	1,003	1,003
12	Known/High Probability Additions	878	1,733	1,733	1,733	1,733	1,733	1,733	1,733	1,733	1,733
13	Utility Probable Planned Additions	0	784	784	784	784	784	784	784	784	784
14	Other Planned Additions	0	145	973	973	973	973	973	973	973	973
15	RPS Additions (In Service Territory)	20	94	123	263	414	760	798	798	798	798
16	Additional CHP	41	82	123	164	204	245	286	327	368	409
17	Net Interchange (Sum of Lines 18 & 19)	6,067	6,067	6,067	6,067	6,067	6,067	6,067	6,067	6,067	6,067
18	*Imports*	6,067	6,067	6,067	6,067	6,067	6,067	6,067	6,067	6,067	6,067
19	*Exports*	0	0	0	0	0	0	0	0	0	0
20	**Service Area Portion of System Resources (Line 2 * 92%)**	**30,481**	**32,077**	**32,903**	**32,450**	**32,027**	**32,383**	**29,861**	**29,898**	**29,936**	**29,974**
	SERVICE AREA SPECIFIC LINE ADJUSTMENTS:										
21	**Service Area** 1-in-2 Peak Summer Demand	18,174	18,459	18,746	18,964	19,186	19,415	19,666	19,906	20,145	20,415
22	Total Demand-Side Reductions	(1,492)	(1,836)	(2,178)	(2,496)	(2,839)	(3,237)	(3,657)	(4,090)	(4,501)	(4,898)
23	*Incremental Uncommitted EE*	98	128	388	620	871	1,180	1,511	1,857	2,184	2,496
24	*Total DR*	1,354	1,627	1,670	1,715	1,767	1,816	1,865	1,911	1,956	2,001
25	*Incremental Demand-Side CHP*	40	80	120	161	201	241	281	321	361	401
26	**Residual Service Area Peak Demand (Line 21 minus Line 22)**	**16,682**	**16,624**	**16,568**	**16,469**	**16,348**	**16,177**	**16,009**	**15,816**	**15,643**	**15,517**
	SERVICE AREA RESERVES:										
27	Amount of Available Resources Exceeding Demand (Line 20 minus Line 26)	13,799	15,453	16,335	15,981	15,680	16,206	13,852	14,083	14,293	14,456
28	Percentage of Available Resources Exceeding Demand (Line 20 / Line 26)	182.7%	193.0%	198.6%	197.0%	195.9%	200.2%	186.5%	189.0%	191.4%	193.2%
	1-in-2 SERVICE AREA SURPLUS (DEFICIT):										
29	Lower Bound of Planning Reserve Requirement (Line 26 * 15%)	19,184	19,117	19,053	18,939	18,800	18,604	18,410	18,188	17,990	17,845
30	Upper Bound of Planning Reserve Requirement (Line 26 * 17%)	19,518	19,450	19,384	19,268	19,127	18,928	18,731	18,505	18,302	18,155
31	Upper Bound 1-in-2 Service Area Surplus (Deficit)	11,297	12,960	13,850	13,511	13,228	13,779	11,450	11,710	11,946	12,129
32	Lower Bound 1-in-2 Service Area Surplus (Deficit)	10,963	12,627	13,519	13,181	12,901	13,456	11,130	11,394	11,634	11,819

	SCE Physical South of Path 26 (SP26) Capacity Need Sensitivity: 33% Trajectory (Low Load)										
Line		MW									
	SYSTEM AND SERVICE AREA LOAD FORECASTS:	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
1	**System** 1-in-2 Peak Summer Demand	21,406	21,728	22,066	22,341	22,634	22,934	23,250	23,552	23,858	24,188
2	**Total System Resources** (Sum Lines 3, 8, 11 through 16)	**30,618**	**31,355**	**32,633**	**32,578**	**33,696**	**33,051**	**32,329**	**31,408**	**30,514**	**28,467**
	SYSTEM RESOURCES:										
3	Existing Generation (Sum of Lines 4 through 7)	21,404	21,404	21,404	21,404	21,404	21,404	21,404	21,404	21,404	21,404
4	*Existing Renewables (Excludes Hydro)*	916	916	916	916	916	916	916	916	916	916
5	*Existing Hydro (Includes RPS-eligible Hydro)*	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470
6	*Existing CHP*	1,489	1,489	1,489	1,489	1,489	1,489	1,489	1,489	1,489	1,489
7	*Existing OTC*	9,250	9,250	9,250	9,250	9,250	9,250	9,250	9,250	9,250	9,250
8	*Other Generation*	8,279	8,279	8,279	8,279	8,279	8,279	8,279	8,279	8,279	8,279
9	Retirements (Includes Lines 10 & 11)	(452)	(452)	(452)	(787)	(2,398)	(3,349)	(4,300)	(5,251)	(6,202)	(8,280)
10	*OTC Retirements*	452	452	452	787	1,122	2,073	3,024	3,975	4,926	7,004
11	*Retirements*	0	0	0	0	1,276	1,276	1,276	1,276	1,276	1,276
12	Known/High Probability Additions	717	917	1,997	1,997	1,997	1,997	1,997	1,997	1,997	1,997
13	Utility Probable Planned Additions	0	500	500	500	1,854	1,854	1,854	1,854	1,854	1,854
14	Other Planned Additions	0	0	0	0	0	0	0	0	0	0
15	RPS Additions (In Service Territory)	0	6	174	423	1,768	2,043	2,241	2,241	2,267	2,267
16	Additional CHP	31	61	92	123	153	184	215	245	276	307
17	Net Interchange (Sum of Lines 18 & 19)	8,918	8,918	8,918	8,918	8,918	8,918	8,918	8,918	8,918	8,918
18	*Imports*	8,918	8,918	8,918	8,918	8,918	8,918	8,918	8,918	8,918	8,918
19	*Exports*	0	0	0	0	0	0	0	0	0	0
20	**Service Area Portion of System Resources (Line 2 * 90%)**	**27,557**	**28,219**	**29,370**	**29,320**	**30,327**	**29,746**	**29,096**	**28,267**	**27,463**	**25,620**
	SERVICE AREA SPECIFIC LINE ADJUSTMENTS:										
21	**Service Area** 1-in-2 Peak Summer Demand	19,174	19,471	19,783	20,036	20,305	20,580	20,870	21,148	21,429	21,731
22	Total Demand-Side Reductions	(1,721)	(2,634)	(3,118)	(3,458)	(3,856)	(4,228)	(4,624)	(5,042)	(5,449)	(5,850)
23	*Incremental Uncommitted EE*	44	60	325	565	834	1,171	1,530	1,912	2,283	2,648
24	*Total DR*	1,641	2,502	2,685	2,749	2,842	2,842	2,842	2,842	2,842	2,842
25	*Incremental Demand-Side CHP*	36	72	108	144	180	216	252	288	324	360
26	**Residual Service Area Peak Demand (Line 21 minus Line 22)**	**17,453**	**16,837**	**16,665**	**16,578**	**16,449**	**16,352**	**16,246**	**16,106**	**15,980**	**15,882**
	SERVICE AREA RESERVES:										
27	Amount of Available Resources Exceeding Demand (Line 20 minus Line 26)	10,103	11,383	12,705	12,742	13,877	13,394	12,849	12,161	11,483	9,739
28	Percentage of Available Resources Exceeding Demand (Line 20 / Line 26)	157.9%	167.6%	176.2%	176.9%	184.4%	181.9%	179.1%	175.5%	171.9%	161.3%
	1-in-2 SERVICE AREA SURPLUS (DEFICIT):										
29	Lower Bound of Planning Reserve Requirement (Line 26 * 15%)	20,071	19,362	19,165	19,065	18,917	18,805	18,683	18,522	18,377	18,264
30	Upper Bound of Planning Reserve Requirement (Line 26 * 17%)	20,420	19,699	19,498	19,397	19,246	19,132	19,008	18,844	18,696	18,582
31	Upper Bound 1-in-2 Service Area Surplus (Deficit)	7,485	8,857	10,205	10,255	11,410	10,941	10,412	9,745	9,086	7,356
32	Lower Bound 1-in-2 Service Area Surplus (Deficit)	7,136	8,520	9,872	9,924	11,081	10,614	10,087	9,423	8,766	7,039

	SDG&E Physical Border Capacity Need Sensitivity: 33% Trajectory (Low Load)										
Line		MW									
	SYSTEM AND SERVICE AREA LOAD FORECASTS:	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
1	**System** 1-in-2 Peak Summer Demand	4,120	4,192	4,264	4,317	4,370	4,420	4,476	4,529	4,585	4,641
2	**Total System Resources** (Sum Lines 3, 8, 11 through 16)	**6,127**	**6,130**	**6,291**	**6,437**	**6,737**	**6,765**	**5,808**	**5,810**	**5,813**	**5,816**
	SYSTEM RESOURCES:										
3	Existing Generation (Sum of Lines 4 through 7)	4,410	4,410	4,410	4,410	4,410	4,410	4,410	4,410	4,410	4,410
4	*Existing Renewables (Excludes Hydro)*	21	21	21	21	21	21	21	21	21	21
5	*Existing Hydro (Includes RPS-eligible Hydro)*	4	4	4	4	4	4	4	4	4	4
6	*Existing CHP*	136	136	136	136	136	136	136	136	136	136
7	*Existing OTC*	1,271	1,271	1,271	1,271	1,271	1,271	1,271	1,271	1,271	1,271
8	*Other Generation*	2,978	2,978	2,978	2,978	2,978	2,978	2,978	2,978	2,978	2,978
9	Retirements (Includes Lines 10 & 11)	(311)	(311)	(311)	(311)	(311)	(311)	(1,271)	(1,271)	(1,271)	(1,271)
10	*OTC Retirements*	311	311	311	311	311	311	1,271	1,271	1,271	1,271
11	*Retirements*	0	0	0	0	0	0	0	0	0	0
12	Known/High Probability Additions	55	55	55	55	55	55	55	55	55	55
13	Utility Probable Planned Additions	0	0	159	159	159	159	159	159	159	159
14	Other Planned Additions	0	0	0	0	0	0	0	0	0	0
15	RPS Additions (In Service Territory)	0	0	0	143	440	465	465	465	465	465
16	Additional CHP	3	6	8	11	14	17	20	22	25	28
17	Net Interchange (Sum of Lines 18 & 19)	1,970	1,970	1,970	1,970	1,970	1,970	1,970	1,970	1,970	1,970
18	*Imports*	1,970	1,970	1,970	1,970	1,970	1,970	1,970	1,970	1,970	1,970
19	*Exports*	0	0	0	0	0	0	0	0	0	0
20	**Service Area Portion of System Resources (Line 2)**	**6,127**	**6,130**	**6,291**	**6,437**	**6,737**	**6,765**	**5,808**	**5,810**	**5,813**	**5,816**
	SERVICE AREA SPECIFIC LINE ADJUSTMENTS:										
21	**Service Area** 1-in-2 Peak Summer Demand	4,120	4,192	4,264	4,317	4,370	4,420	4,476	4,529	4,585	4,641
22	Total Demand-Side Reductions	(219)	(242)	(353)	(421)	(492)	(570)	(655)	(743)	(825)	(903)
23	*Incremental Uncommitted EE*	3	4	66	121	179	247	321	398	471	544
24	*Total DR*	210	226	270	277	285	289	293	298	302	302
25	*Incremental Demand-Side CHP*	6	12	17	23	29	35	41	46	52	58
26	**Residual Service Area Peak Demand (Line 21 minus Line 22)**	**3,901**	**3,950**	**3,912**	**3,896**	**3,878**	**3,849**	**3,821**	**3,786**	**3,759**	**3,738**
	SERVICE AREA RESERVES:										
27	Amount of Available Resources Exceeding Demand (Line 20 minus Line 26)	2,226	2,180	2,379	2,541	2,859	2,916	1,987	2,024	2,054	2,078
28	Percentage of Available Resources Exceeding Demand (Line 20 / Line 26)	157.1%	155.2%	160.8%	165.2%	173.7%	175.7%	152.0%	153.5%	154.6%	155.6%
	1-in-2 SERVICE AREA SURPLUS (DEFICIT):										
29	Lower Bound of Planning Reserve Requirement (Line 26 * 15%)	4,486	4,543	4,498	4,481	4,459	4,427	4,394	4,354	4,323	4,299
30	Upper Bound of Planning Reserve Requirement (Line 26 * 17%)	4,564	4,622	4,577	4,559	4,537	4,504	4,470	4,429	4,398	4,373
31	Upper Bound 1-in-2 Service Area Surplus (Deficit)	1,641	1,587	1,793	1,956	2,278	2,338	1,414	1,456	1,490	1,518
32	Lower Bound 1-in-2 Service Area Surplus (Deficit)	1,563	1,508	1,714	1,878	2,200	2,261	1,338	1,381	1,415	1,443

Appendix A

Standardized Planning Assumptions: Greenhouse Gasses

GHG Metrics
The table below shows the relationship between procurement method, GHG cost and actual GHG emissions embedded by procurement type

	Carbon Price Pass Through for GHG Cost	**Embedded Emissions (to determine total portfolio GHG emissions)**
Self-Owned generation	(Carbon price)*(actual emissions)	Actual emissions of generator
Sales of self-owned generation	(Carbon Price)*(emissions of marginal generator for time/season interval)	LSE average per MWh emissions for given time/season interval
Purchases from Bilateral contracts	(Carbon Price)*(Emissions associated with specified heat rate)	Actual emissions of generator
Market Purchases from other LSEs	(Carbon Price)*(emissions of marginal generator for time/season interval)	LSE average per MWh emissions for given time/season interval
Bilateral Purchases from other LSEs	(Carbon Price)*(emissions of marginal generator for time/season interval)	Emissions of average generation for given time/season interval
Purchases from QFs	(Carbon Price)*(actual emissions)	Actual emissions
Market Purchases from CAISO market	(Carbon Price)*(emissions of marginal generator for time/season interval)	Average emissions of CAISO market pool for each time/season interval

Carbon Price Assumptions

These estimates are provided in the table below. The 2009 MPR results and the low and high carbon price are provided for illustrative purposes. When the IOUs and other parties file their portfolios, pursuant to the schedule, the most recent MPR methodology will be used. The High and Low values are plus and minus 25 percent from the MPR values.[15] The low estimate for 2012 was adjusted upward to align with the floor price applied in ARB's carbon cap and trade regulation.[16]

Year	Market Price Referent Model 2009 (nominal dollars)	Low Carbon Price Estimate	High Carbon Price Estimate
2011	0	0	0
2012	10.44	10.00	13.05
2013	17.83	13.37	22.29
2014	21.08	15.81	26.35
2015	24.35	18.26	30.44
2016	27.91	20.93	34.89
2017	31.49	23.62	39.36
2018	35.37	26.53	44.21
2019	39.29	29.47	49.11
2020	43.52	32.44	54.06

[15] The 25% variance is based off of Staff's analysis of the Economic and Allocation Advisory Committee final report (March 2010) and the Updated Economic Analysis of California's Climate Change Scoping Plan (March 2010).

[16] Air Resources Board, 2010. "Proposed Regulation to Implement the California Cap-and-Trade Program, Staff Report: Initial Statement of Reasons," page II-5. (http://www.arb.ca.gov/regact/2010/capandtrade10/capisor.pdf)

TOU and seasonal marginal emissions
Utilities should use the same time periods provided in the chart below, however, the following estimates are provided only as an example and are not intended to be used by the utilities.

Emissions of Marginal Purchases (Tons per MWh)[17]

	Shoulder (7am-11am)	Peak (11am-5pm)	Shoulder (5pm-10pm)	Nighttime (10pm-7am)
June thru August	.55	.62	.66	.53
Sept. thru Nov & Apr. thru May	.53	.61	.63	.52
Dec. thru Mar.	.59	.62	.63	.63

Allocation of GHG from CHP facilities
Method
In order to calculate electricity sector GHG emission for CHP facilities, it is first necessary to determine the percentage of input fuel that is attributable to electricity generation, versus that which is used for the production of heat. In order to make this calculation, two factors are needed: an average Heat Rate (HR) for CHP facilities and an average heat-to-power ratio (HPR) which is the ratio of process heat (thermal) output to the electrical output of the CHP unit. These factors can be used in the following formula to calculate the percentage of fuel attributable to electricity generated by the CHP system:

(HR – 3,413 * HPR) / HR = % fuel attributable to electricity in a CHP system

Once a percentage of fuel input for electricity generation is calculated, a conversion of fuel to emissions, using an emissions factor for natural gas, results in emissions associated with CHP-generated electricity:

(Fuel input * % fuel attributable to electricity) * NG emissions factor =
GHG emissions from electricity

[17] Derived from McCarthy, et al. 2009. “Interactions Between Electric-Drive Vehicles and the Power Sector in California.”

Discussion
While it is difficult to determine a precise system average HR for CHP expected to come online in the next decade, the California Energy Commission's (CEC's) CHP Market Assessment[18] provides some guidance. This report assesses the technical potential for CHP in the State and compares this capacity with various market scenarios. The sum of these market scenarios, or the "All-In" case in the report, includes a mix of large and small CHP providing on-site and exported electricity. The weighted average HR for CHP systems in the All-In case is 8,893 Btu/kWh without line losses.[19] (For supply-side resources, a line loss factor may be added to the HR to account for less efficient electricity delivered to the grid.)

We believe the weighted average HR provided in the CEC report's All-In case represents an appropriate estimate for new CHP in the next decade. While the overall market penetration of CHP is higher in the All-In case than what is proposed in this proceeding, the characteristics of the market are reflective of we expect to see. That is, we expect a CHP build out roughly evenly split between new CHP above and below 20 MW, with an export market that is dominated by large systems and a carbon payment that will stimulate the CHP market based on the social value of the emissions reduction provided.

We also considered the power-to-heat ratio (PHR) provided in the CEC report. The report provides the power-to-heat ratio for CHP systems by size range:[20]

CHP Technology	<1 MW	1-5 MW	5-20 MW	>20 MW
PHR	0.68	0.80	1.00	1.20

The All-In case assumes 48.7% of new capacity above 20 MW and 51.3% below 20 MW. (CHP Market Assessment, p.91) Taking a weighted average of the PHR provided in the CEC report results in a ratio of 1.01. The inverse of this number is the heat-to-power ratio:

$$HPR = 1/PHR = 1 / 1.01 = 0.99$$

Using an 8,893 HR and 0.99 HPR in the formula provided in the method section above results in 62% of fuel attributable to electricity generation in an average CHP system.

$$(HR – 3{,}413 * HPR) / HR = (8{,}893 – 3{,}413 * 0.99) / 8{,}893 = 62\%$$

[18] Combined Heat and Power Market Assessment, Draft Consultant Report, prepared by ICF International, Inc. for the California Energy Commission. (October 2009) http://www.energy.ca.gov/2009publications/CEC-500-2009-094/CEC-500-2009-094-D.PDF
[19] Ibid, p. 85, table 43.
[20] Ibid, p. 56, table 24.

Appendix B

<u>Standardized Planning Assumptions: System Resources</u>

System Resources

Simplified system resources numbers and resources are located in the Technical Attachment Spreadsheets, under tabs "Existing Generation", "OTC", "Retirements", "Additions", and "Net Interchange".

Existing Resources

The existing resource NQC for each IOU's system planning area was drawn from the following resources: 1) the most current available 2011 NQC [21] as of August 2; and 2) the CAISO master generation list [22] as of July 12. These were combined into an excel spreadsheet, which has been posted by ED staff.[23]

One modification was made to the NQC list, which was for the El Cajon Energy Center. El Cajon was modified from the CAISO NQC list to insert a NQC of 46 MW for the unit.

In order to determine the various NQC's staff has created the following list of selected fields for geographic area. Annual NQC values from Column E and August monthly NQC values from Column M were summed. They were then put into one of three categories:

PG&E

Resources designated as "North" in Column D.

SCE

Resources designated as "South" in Column D. SDG&E's resources were subtracted from the total.

[21] http://www.caiso.com/1796/179688b22c970.html#1b8eaa2643ed0

[22] http://www.caiso.com/14d4/14d4c4ff59780.html

[23] http://www.cpuc.ca.gov/PUC/energy/Procurement/LTPP/ltpp_history.htm

SDG&E

Resources designated as "San Diego" in Column C plus the following three units which connect INSIDE SDG&E territory but OUTSIDE San Diego Local Area. All three connect to the Imperial Valley Substation. These three resources were labeled as "CAISO System" capacity on the final CAISO NQC list but were taken out of SCE service territory and added to SDG&E service territory:

Name of Resource	MW Capacity
TERMOELECTRICA DE MEXICALI 1	595
Ciclo Combinado Mexicali	165
CENTRAL LA ROSITA II COMBINED CYCLE	322

To determine which resources fell into which line for the L&R tables, staff is providing the following matrix. Although some hydro may be RPS-eligible, for existing resources in the system plan, all hydro has been allocated to the "Existing Hydro" line in the L&R tables.

NQC Resource Category	Name in L&R Table
Cogeneration	Existing CHP
Wind	Existing RPS
Solar	Existing RPS
Biomass	Existing RPS
Geothermal	Existing RPS
Peaker	Other Generation
Thermal	Other Generation
Nuclear	Other Generation
Various	Other Generation
Hydro	Existing Hydro

Additional Resources
Plants are characterized as high probability, probable, or other based on the "NewTXandGX" tab of the CAISO OTC scenario analysis tool (dated July 9, 2010).[24] The LADWP and other non-CAISO balancing authority planned additions from the OTC scenario analysis tool are not included in these totals.

There were some additional modifications to the CAISO OTC scenario analysis tool to remove plants that have come online and are in the CAISO NQC list, reclassification of units, and capacity reductions since the development of the CAISO OTC scenario analysis tool. They are listed below:

- Removed Inland Empire Unit 2;
- Removed Orange Grove;
- Reclassified Lodi NCPA from Category 2 to Category 3;
- Reclassified Pittsburg 7 from Category 11 to Category 10;
- Capacity increase of Sentinel from 273 MW to 850 MW[25];
- Capacity reduction of El Segundo Repower from 630 MW to 560 MW[26];
- Added Humboldt Bay Units 1-3 to Category 3 (163 MW in 2010); and
- Capacity reduction of Black Rock Geothermal from 215 MW to 159 MW [27]

Known/High Probability Additions
Known/High Probability Additions are plants under construction (Category 3) in the CAISO OTC scenario analysis tool. This total includes all CAISO balancing authority POU plants.[28]

Utility Probable Planned Additions
Other Utility Probably Planned Additions are resources with Contracts (Category 1) or have approved AFC's (Category 2) according to the CAISO OTC scenario analysis tool.

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[24] http://www.caiso.com/27ce/27ceb7806e50.xlsm
[25] Pursuant to the CEC database: http://www.energy.ca.gov/sitingcases/sentinel/index.html
[26] Pursuant to the CEC database: http://www.energy.ca.gov/sitingcases/elsegundo_amendment/
[27] Pursuant to the CEC database: http://www.energy.ca.gov/sitingcases/saltonsea_amendment/index.html
[28] At the time of analysis, all POU planned additions are currently under construction according to the CEC siting database.

Other Planned Additions

Those resources listed with CPUC approved contracts but do not currently have AFC permits approved according to the CEC "Status of all Projects" list. These resources do not appear in the CAISO's OTC scenario analysis tool, since these resources did not have approved CPUC contracts or approved AFC permits as of the development of the OTC scenario analysis tool.

OTC Retirements

OTC retirements are taken from the State Water Board adopted policy, with the following modifications: Certain OTC plants with permit restrictions or repowering agreements that would become active before the State Water Board adopted policy schedule are placed in earlier years, due to arrangements publically known to the CPUC; OTC in LA Basin remaining as of 2016 and slated to become compliant in 2020 was evenly spread over 2016 – 2019; several plants were assumed to not retire, such as the nuclear units and Moss Landing units 1 and 2. The 15 MW Southbay Gas Turbine is counted under OTC units retiring, although it itself is not an OTC unit.

As to non-OTC aging plants, the scoping memo directs use of the retirements listed in the CAISO's OTC scenario analysis tool, under Category 10.

Net Interchange

The net interchange import values were calculated from the CAISO's *Maximum RA Import Capability for year 2011*, with modifications to name the lines by service area.[29]

[29] http://www.caiso.com/27c6/27c675b81c230.pdf

Forecast Demand

Forecast demand values are taken from the CEC's *Statewide Revised Demand Forecast Forms, Second Edition*.[30] The Technical Attachment Spreadsheet shows the values and lines used in the "Demand Forecast" tab.

System Demand

System demand for each area was taken from Form 1.5b.

Area	Line
NP 26	Total North of Path 26
SP 26	Total SCE TAC Area
SDG&E	SDG&E Service Area

Service Area Demand

Service area demand for each area was taken by summing the following lines from Form 1.5b.

Area	Line
PG&E	Greater Bay Area
PG&E	Non Bay
PG&E	ZP26
SCE	LA Basin
SCE	Big Creek Ventura
SCE	Out of Basin
SDG&E	SDG&E Service Area

Incremental CHP Assumptions

The values presented in the Technical Attachment Spreadsheet are reliant upon several assumptions, as laid out in the Scoping Memo. The calculations are located under the "CHP" tab.

Incremental Energy Efficiency

The incremental EE values are drawn from the CEC's *Incremental Impacts of Energy Efficiency Policy Initiatives Relative to the 2009 Integrated Energy Policy Report Adopted Demand Forecast*, and the *Attachment A: Technical Report*.[31]

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[30] http://www.energy.ca.gov/2009_energypolicy/documents/2009-12-02_business_meeting/forms/Chap1Stateforms-RF2-09.xls

[31] http://www.energy.ca.gov/2010publications/CEC-200-2010-001/index.html

Demand Response

The values presented in the Technical Attachment Spreadsheet are reliant upon several assumptions, as laid out in the Scoping Memo. The calculations are located under the "DR" tab.

Appendix C

Standardized Planning Assumptions: Technical Tables

Appendix C contains the technical tables with more detailed information on the values used to populate the L&R Tables.

Demand Forecast (CED 2010-2020, Form 1.5b)	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
PG&E Service Area - Greater Bay Area	7,873	7,970	8,066	8,131	8,196	8,263	8,339	8,409	8,477	8,558
PG&E Service Area - Non Bay	9,884	10,061	10,239	10,382	10,527	10,677	10,840	10,998	11,156	11,332
PG&E Service Area (ZP26)	2,436	2,480	2,524	2,559	2,595	2,632	2,672	2,711	2,749	2,793
Total PG&E Service Area	20,193	20,510	20,829	21,071	21,318	21,572	21,851	22,117	22,383	22,683
Total North of Path 26	21,988	22,329	22,668	22,924	23,185	23,454	23,750	24,030	24,310	24,626
SCE Service Area - LA Basin	16,703	16,961	17,233	17,454	17,688	17,928	18,180	18,422	18,667	18,930
SCE Service Area - Big Creek Ventura	4,048	4,111	4,176	4,230	4,287	4,345	4,406	4,464	4,524	4,588
SCE Service Area - Out of Basin	554	562	572	579	587	595	603	611	619	628
Total SCE Service Area	21,305	21,634	21,981	22,262	22,561	22,867	23,189	23,497	23,810	24,146
Total SCE TAC Area	23,785	24,142	24,518	24,823	25,149	25,482	25,833	26,169	26,509	26,875
SDG&E Service Area	4,578	4,658	4,738	4,797	4,856	4,911	4,973	5,032	5,094	5,157

Existing Resources NQC

Source: http://www.caiso.com/1796/179688b22c970.html#1b8eaa2643ed0

Source: http://www.caiso.com/14d4/14d4c4ff59780.html

	North	South	San Diego
Geothermal	835	244	0
Wind	180	140	6
Solar	2	382	0
Biomass	409	150	15
Renewable	**1,426**	**916**	**21**
Hydro	**6,461**	**1,470**	**4**
CHP (Cogen)	**1,888**	**1,489**	**136**
Thermal	10,965	12,083	3,541
Peaker	2,370	1,081	705
Nuclear	2,240	2,246	0
Various	6	98	3
#N/A	1,267	2,021	0
Other	**16,848**	**17,529**	**4,249**
Total	**26,623**	**21,404**	**4,410**

OTC Totals and Forecast Retirements						
Source: http://www.caiso.com/27ce/27ceb7806e50.xlsm						
Unit Name	**Owner**	**LCR area or NP26/SP26**	**NQC**	**Technology**	**Retirement date**	**Probability (if different from SWRCB policy)**
POTRERO UNIT 3	Mirant	Bay Area	206	STEAM	12/31/2010	High probability (Transbay cable and agreement between CAISO and SF)
Humboldt	PG&E	NP26	135	Steam	12/31/2010	
CONTRA COSTA UNIT 6	Mirant	Bay Area	337	STEAM	12/31/2014	
CONTRA COSTA UNIT 7	Mirant	Bay Area	337	STEAM	12/31/2014	
MORRO BAY UNIT 3	Dynegy	NP26	325	STEAM	12/31/2015	
MORRO BAY UNIT 4	Dynegy	NP26	325	STEAM	12/31/2015	
PITTSBURG UNIT 5	Mirant	Bay Area	312	STEAM	12/31/2017	
PITTSBURG UNIT 6	Mirant	Bay Area	317	STEAM	12/31/2017	
MOSS LANDING UNIT 6	Dynegy	NP26	754	STEAM	12/31/2017	
MOSS LANDING UNIT 7	Dynegy	NP26	756	STEAM	12/31/2017	
Diablo Canyon Unit 1	PG&E	NP26	1,122	Nuclear	Not retiring	
Diablo Canyon Unit 2	PG&E	NP26	1,118	Nuclear	Not retiring	
MOSS LANDING POWER BLOCK 1	Duke Energy	NP26	510	CCGT	Not retiring	
MOSS LANDING POWER BLOCK 2	Duke Energy	NP26	510	CCGT	Not retiring	
North Total OTC			**7,064**			
HUNTINGTON BEACH GEN STA. UNIT 3	AES	LA Basin	225	STEAM	10/1/2011	High probability (CEC emergency permit expires)
HUNTINGTON BEACH GEN STA. UNIT 4	AES	LA Basin	227	STEAM	10/1/2011	High probability (CEC emergency permit expires)
EL SEGUNDO GEN STA. UNIT 3	NRG	LA Basin	335	STEAM	6/1/2014	High probability (Contract with SCE to retire and repower)
EL SEGUNDO GEN STA. UNIT 4	NRG	LA Basin	335	STEAM	6/1/2015	
MANDALAY GEN STA. UNIT 1	RRI	Big Creek-Ventura	215	STEAM	12/31/2020	
MANDALAY GEN STA. UNIT 2	RRI	Big Creek-Ventura	215	STEAM	12/31/2020	
MANDALAY GEN STA. UNIT 3	RRI	Big Creek-Ventura	130	CT	12/31/2020	
ORMOND BEACH GEN STA. UNIT 1	RRI	Big Creek-Ventura	741	STEAM	12/31/2020	
ORMOND BEACH GEN STA. UNIT 2	RRI	Big Creek-Ventura	775	STEAM	12/31/2020	
Alamitos 1	AES	LA Basin	175	STEAM	12/31/2020	
Alamitos 2	AES	LA Basin	175	STEAM	12/31/2020	
Alamitos 3	AES	LA Basin	332	STEAM	12/31/2020	
Alamitos 4	AES	LA Basin	336	STEAM	12/31/2020	
Alamitos 5	AES	LA Basin	498	STEAM	12/31/2020	
Alamitos 6	AES	LA Basin	495	STEAM	12/31/2020	
HUNTINGTON BEACH GEN STA. UNIT 1	AES	LA Basin	226	STEAM	12/31/2020	
HUNTINGTON BEACH GEN STA. UNIT 2	AES	LA Basin	226	STEAM	12/31/2020	
REDONDO GEN STA. UNIT 5	AES	LA Basin	179	STEAM	12/31/2020	
REDONDO GEN STA. UNIT 6	AES	LA Basin	175	STEAM	12/31/2020	
REDONDO GEN STA. UNIT 7	AES	LA Basin	493	STEAM	12/31/2020	
REDONDO GEN STA. UNIT 8	AES	LA Basin	496	STEAM	12/31/2020	
SAN ONOFRE NUCLEAR UNIT 2	SCE/SDG&E	LA Basin	1,122	Nuclear	Not retiring	
SAN ONOFRE NUCLEAR UNIT 3	SCE/SDG&E	LA Basin	1,124	Nuclear	Not retiring	
South Total OTC			**9,250**			
SOUTHBAY GAS TURBINE 1	Dynegy	San Diego	15	CT	12/31/2011	High probability (Agreement between Chula Vista and CAISO)
SOUTHBAY UNIT 1	Dynegy	San Diego	146	STEAM	12/31/2011	High probability (Agreement between Chula Vista and CAISO)
SOUTHBAY UNIT 2	Dynegy	San Diego	150	STEAM	12/31/2011	High probability (Agreement between Chula Vista and CAISO)
ENCINA GAS TURBINE UNIT 1	NRG	San Diego	14	CT	12/31/2017	
ENCINA UNIT 1	NRG	San Diego	106	STEAM	12/31/2017	
ENCINA UNIT 2	NRG	San Diego	103	STEAM	12/31/2017	
ENCINA UNIT 3	NRG	San Diego	109	STEAM	12/31/2017	
ENCINA UNIT 4	NRG	San Diego	299	STEAM	12/31/2017	
ENCINA UNIT 5	NRG	San Diego	329	STEAM	12/31/2017	
San Diego Total OTC			**1,271**			

OTC Totals

North Total OTC	7,064
South Total OTC	9,250
San Diego Total OTC	1,271

OTC Retirements

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
North	341	341	341	1,015	1,665	1,665	3,804	3,804	3,804	3,804
South	452	452	452	787	1,122	2,073	3,024	3,975	4,926	7,004
South (LA Basin gradual retirement)						951	951	951	951	0
San Diego	311	311	311	311	311	311	1,271	1,271	1,271	1,271

Non-OTC Totals and Forecast Retirements				
Source: http://www.caiso.com/27ce/27ceb7806e50.xlsm				
ResName	**Local Area/SubArea**	**MW LCR**	**Class**	**Proj COD / Retirement Year**
POTRERO UNIT 4	Bay Area	52	10	2010
POTRERO UNIT 5	Bay Area	52	10	2010
POTRERO UNIT 6	Bay Area	52	10	2010
OAKLAND STATION C GT UNIT 1	Bay Area	55	10	2012
OAKLAND STATION C GT UNIT 2	Bay Area	55	10	2012
OAKLAND STATION C GT UNIT 3	Bay Area	55	10	2012
PITTSBURG UNIT 7	Bay Area	682	10	2017
North Total Retirements		**1,003**		
COOLWATER GEN STA. UNIT 1	CAISO System	63	10	2015
COOLWATER GEN STA. UNIT 2	CAISO System	82	10	2015
COOLWATER STATION 3 AGGREGATE	CAISO System	245	10	2015
COOLWATER STATION 4 AGGREGATE	CAISO System	246	10	2015
ETIWANDA GEN STA. UNIT 3	LA Basin	320	10	2015
ETIWANDA GEN STA. UNIT 4	LA Basin	320	10	2015
South Total Retirements		**1,276**		
San Diego Total Retirements		**0**		

Non-OTC Retirements										
	2011	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
North	156	321	321	321	321	321	1,003	1,003	1,003	1,003
South	0	0	0	0	1,276	1,276	1,276	1,276	1,276	1,276
San Diego	0	0	0	0	0	0	0	0	0	0

Forecast Additions
Source: http://www.caiso.com/27ce/27ceb7806e50.xlsm

ResName	Local Area/SubArea	MW LCR	Class	Proj COD / Retirement Year	Zone
CalRENEW-1(A) / Cal RENEW-1 LLC/Cal RENEW-1 LLC	NP26	5	3	2010	NP26
Copper Mountain Solar 1 Pseudo Tie PILOT/El Dorado Energy LLC	NP26	48	3	2010	NP26
Vaca-Dixon Solar Station/	Bay Area	2	3	2010	NP26
Humboldt 1-3	Humboldt	163	3	2010	NP26
Colusa	NP26	660	3	2011	NP26
Avenal Energy Center	NP26	600	3	2012	NP26
Lodi NCPA	NP26	255	3	2012	NP26
North High Probability / Known Additions		**1,733**			
Russell City	Bay Area	600	2	2012	NP26
Mariposa Peaker Project	Bay Area	184	1	2012	NP26
North Utility Probable Additions		**784**			
Tracy	NP26	145	N/A	2012	NP26
Los Esteros	Bay Area	109	N/A	2013	NP26
Marsh Landing	Bay Area	719	N/A	2013	NP26
North Other Planned Additions		**973**			
Blythe Solar I Project/FSE Blythe 1, LLC	SP26	21	3	2010	SP26
Calabasas Gas To Energy Facility / LACSD/County Sanitation District No. 2 of Los Angeles County	LA Basin	14	3	2010	SP26
Chino RT Solar Project/Southern California Edison	LA Basin	2	3	2010	SP26
Chiquita Canyon Landfill / Ameresco Chiquita Energy, LLC/Ameresco Chiquita Energy, LLC	Big Creek-Ventura	9	3	2010	SP26
Inland Empire Unit 2	LA Basin	0	3	2010	SP26
Rialto RT Solar/Southern California Edison	LA Basin	2	3	2010	SP26
Santa Cruz Landfill G-T-E Facility/Santa Cruz Energy LLC	SP26	1	3	2010	SP26
Sierra Solar Generating Station/Sierra SunTower, LLC	SP26	9	3	2010	SP26
Riverside Energy Resource units 3 and 4	LA Basin	96	3	2011	SP26
Victorville Hybrid	SP26	563	3	2011	SP26
Canyon Power Plant	LA Basin	200	3	2012	SP26
El Segundo Repower	LA Basin	560	3	2013	SP26
FPL Blythe II	SP26	520	3	2013	SP26
South High Probability / Known Additions		1,997			
Walnut Creek Energy Center	LA Basin	500	2	2012	SP26
Delano 2	Big Creek-Ventura	49	1	2015	SP26
Ocotillo	SP26	455	1	2015	SP26
Sentinel	SP26	850	1	2015	SP26
South Utility Probable Additions		1,854			
South Other Planned Additions		0			
Celerity I	San Diego	15	3	2010	SP26
Olivenhain-Hodges Pumped Storage - Unit 1/San Diego County Water Authority	San Diego	20	3	2011	SP26
Olivenhain-Hodges Pumped Storage - Unit 2/San Diego County Water Authority	San Diego	20	3	2011	SP26
Orange Grove/Jpower	San Diego	0	3	2011	SP26
San Diego High Probability / Known Additions		55			
Black Rock Geothermal	San Diego	159	1	2013	SP26
San Diego Utility Probable Additions		159			
San Diego Other Planned Additions		0			

High Probability / Known Additions

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
North	878	1,733	1,733	1,733	1,733	1,733	1,733	1,733	1,733	1,733
South	717	917	1,997	1,997	1,997	1,997	1,997	1,997	1,997	1,997
San Diego	55	55	55	55	55	55	55	55	55	55

Utility Probable Additions

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
North	0	784	784	784	784	784	784	784	784	784
South	0	500	500	500	1,854	1,854	1,854	1,854	1,854	1,854
San Diego	0	0	159	159	159	159	159	159	159	159

Other Planned Additions

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
North	0	145	973	973	973	973	973	973	973	973
South	0	0	0	0	0	0	0	0	0	0
San Diego	0	0	0	0	0	0	0	0	0	0

Total Additions

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
North	878	2,662	3,490	3,490	3,490	3,490	3,490	3,490	3,490	3,490
South	717	1,417	2,497	2,497	3,851	3,851	3,851	3,851	3,851	3,851
San Diego	55	55	214	214	214	214	214	214	214	214

Max RA value of Transmission into CAISO

Source: http://www.caiso.com/27c6/27c675b81c230.pdf

BG/MSL Name	Into North or South of CAISO?	Net Import MW	Import ETC Sched MW	Import Unused ETC MW	Maximum Import Capability MW	OTC MW
GONDIPPDC_BG	South	0	0	0	0	4
IPPDCADLN_BG	South	514	0	0	514	647
MCCLMKTPC_MSL	South	0	0	0	0	817
MEADMKTPC_MSL	South	76	0	0	76	551
MEADTMEAD_MSL	South	34	0	0	42	182
MKTPCADLN_MSL	South	251	0	0	251	630
MONAIPPDC_MSL	South	132	0	0	132	236
WSTWGMEAD_MSL	South	131	0	0	131	186
BLYTHE_BG	South	107	0	0	107	210
CASCADE_BG	North	1	0	0	1	80
CFE_BG	South-SD	-55	0	0	90	800
ELDORADO_MSL	South	1158	0	0	1158	1555
IID-SCE_BG	South	315	0	0	502	600
IID-SDGE_BG	South-SD	-159	0	0	0	239
LAUGHLIN_BG	South	-22	0	0	0	0
MCCULLGH_MSL	South	30	0	316	346	2598
MEAD_MSL	South	469	208	505	1000	1460
MERCHANT_BG	South	439	0	0	439	797
NGILABK4_BG	South-SD	-140	0	168	223	366
NOB_BG	South	1469	0	0	1469	1591
PALOVRDE_MSL	South-SD1/2	3139	656	175	3313	3328
PARKER_BG	South	108	63	27	135	220
RNCHLAKE_BG	North	23	23	555	578	1271
SILVERPK_BG	South	0	0	0	0	17
SUMMIT_BG	North	-6	0	0	0	40
SYLMAR-AC_MSL	South	1	0	471	670	1200
VICTVL_MSL	South	0	0	171	289	2400
RDM230_BG	North	0	0	0	0	320
CTW230_BG	North	3	0	0	3	1594
LLNL_BG	North	0	0	0	0	164
PACI_MSL	North	2697	437	43	2739	3127
COTPISO_MSL	North	6	0	0	6	32
TRACY230_BG	North	-207	0	719	719	1366
TRACY500_BG	North	278	37	313	890	4257
NEWMELONP_BG	North	132	132	252	384	384
OAKDALE_BG	North	0	0	174	174	174
STANDIFORD_BG	North	0	0	306	306	306
WESTLYTSLA_BG	North	-100	0	102	102	591
WESTLYLBNS_BG	North	13	0	22	35	600
COTP_MSL	North	117	0	0	117	1531
MARBLE_BG	North	3	3	12	15	15
Total		10956	1559	4330	**16955**	

ADLANTOSP_MSL; ADLANTOVICTVL-SP_MSL; FCORNERS5_MSL; MEADELDORD_BG; TRACYHRDLN_BG; VICTVL_BG; CFEROA_MSL; CFETIJ_MSL; FCORNER3_MSL; and SCISL_BG are either redundant entries or can not be scheduled upon

North	South	San Diego*
6,067	8,918	1,970

Line Loss Factors

Energy Efficiency	
North	9.7%
South	7.6%
San Diego	9.6%

Source: CED 2010-2020, page 50.

Demand Response	
North	11.9%
South	11.2%
San Diego	6.6%

Source: http://www.cpuc.ca.gov/NR/rdonlyres/786A98AC-9F92-4D8D-A071-6A8065944CCE/0/2011IOUDRProgramTotalsFinal728.xls

CHP	
North	7.7%
South	7.7%
San Diego	7.7%

Source: ARB Climate Change Scoping Plan, December 2008, footnote 37

Incremental CHP

Incremental Values (MW) Adjusted

Demand-side savings increased to reflect line losses.

Common Value: Demand-side (MW)

	North	South	San Diego
2011	40	36	6
2012	80	72	12
2013	120	108	17
2014	161	144	23
2015	201	180	29
2016	241	216	35
2017	281	252	41
2018	321	288	46
2019	361	324	52
2020	401	360	58

Common Value: Supply-side (MW)

	North	South	San Diego
2011	41	31	3
2012	82	61	6
2013	123	92	8
2014	164	123	11
2015	204	153	14
2016	245	184	17
2017	286	215	20
2018	327	245	22
2019	368	276	25
2020	409	307	28

2011 Existing CHP NQC (MW)

	Demand-side	% of D-s	Supply-side	% of S-s
North	843	49.01%	1,888	53.74%
San Diego	122	7.09%	136	3.87%
South	755	43.90%	1,489	42.39%
Total	**1,720**	100.00%	**3,513**	100.00%

Other Assumptions:	MW	
ARB target:	4000	
ARB target adjusted:	3742	
% in IOUs territory:	81.3%	3042.246

Existing supply-side CHP capacity is calculated based on the CAISO NQC Local Area Data for Compliance Year 2011 and the CAISO Generation Capability List as of July 12, 2010.
Existing demand-side CHP capacity is based on the CED 2010-2020 Forecast, Form 1.4.

Total (MW)

	Demand-side	Supply-side	
2010	1,720	3,476	
2011	1,796	3,552	
2012	1,872	3,628	
2013	1,948	3,704	
2014	2,024	3,780	
2015	2,100	3,856	
2016	2,176	3,932	
2017	2,252	4,008	
2018	2,328	4,084	
2019	2,405	4,161	
2020	2,481	4,237	
			1,521
Yearly incre	76.05615	76.05615	
	761	761	1,521

Total: Demand-side (MW)

	North	San Diego	South	
2010	843	122	755	
2011	880	127	788	
2012	918	133	822	
2013	955	138	855	
2014	992	144	889	
2015	1,029	149	922	
2016	1,067	154	955	
2017	1,104	160	989	
2018	1,141	165	1,022	
2019	1,178	171	1,055	
2020	1,216	176	1,089	
	49.0%	7.1%	43.9%	2,481
	37.27636	5.39468	33.38511	

Total: Supply-side (MW)

	North	San Diego	South	
2010	1,868	136	1,489	
2011	1,909	139	1,520	
2012	1,950	142	1,550	
2013	1,991	144	1,581	
2014	2,032	147	1,612	
2015	2,072	150	1,642	
2016	2,113	153	1,673	
2017	2,154	156	1,704	
2018	2,195	158	1,734	
2019	2,236	161	1,765	
2020	2,277	164	1,796	
	53.7%	3.9%	42.4%	4,237
	40.88653891	2.801148989	30.668462	

Total: State-wide (MW)

	Demand-side	Supply-side
2010	1,720	3,513
2011	1,814	3,607
2012	1,907	3,700
2013	2,001	3,794
2014	2,094	3,887
2015	2,188	3,981
2016	2,281	4,074
2017	2,375	4,168
2018	2,468	4,261
2019	2,562	4,355
2020	2,656	4,449
	93.55	93.55
	936	936

Common Value Assumptions

Assumptions:

Ratio of demand-side and supply-side capacity remains constant at 2010 ratio.

Incremental additions are evenly split between supply-side and demand-side.

Values are evenly distributed backwards from 2020.

ARB target adjusted reflects adjustments in the 2009 IEPR demand forecasts.

% in IOU territory is based on the NP and SP 15 sales in 2020 from the CED 2010-2020, Form 1.5a

Common Value: Demand-side (MW)

	North	South	San Diego
2011	37	33	5
2012	75	67	11
2013	112	100	16
2014	149	134	22
2015	186	167	27
2016	224	200	32
2017	261	234	38
2018	298	267	43
2019	335	300	49
2020	373	334	54

Incremental: State-wide (MW)

	Demand-side	Supply-side
2010	0	0
2011	94	94
2012	187	187
2013	281	281
2014	374	374
2015	468	468
2016	561	561
2017	655	655
2018	748	748
2019	842	842
2020	936	936

Incremental: State-wide (GWh)

	Demand-side	Supply-side
2010	0	0
2011	756	756
2012	1,511	1,511
2013	2,267	2,267
2014	3,022	3,022
2015	3,778	3,778
2016	4,533	4,533
2017	5,289	5,289
2018	6,045	6,045
2019	6,800	6,800
2020	7,556	7,556

Incremental Uncommitted EE										
	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
PG&E Total	**98**	**128**	**388**	**620**	**871**	**1,180**	**1,511**	**1,857**	**2,184**	**2,496**
PG&E	89	117	354	565	794	1076	1377	1693	1991	2275
IOU Programs			116	229	340	443	548	651	752	853
Goals AB1109			25	24	16	35	71	107	122	119
Goals Standards			16	34	63	125	188	261	336	412
BBEES (Low)			56	114	191	272	356	449	547	648
Decay Replacement	89	117	141	164	184	201	214	225	234	243
SCE Total	**44**	**60**	**325**	**565**	**834**	**1,171**	**1,530**	**1,912**	**2,283**	**2,648**
SCE	41	56	302	525	775	1088	1422	1777	2122	2461
IOU Programs			131	258	382	497	614	727	839	951
Goals AB1109			19	17	10	25	53	83	95	93
Goals Standards			18	37	69	147	226	315	406	500
BBEES (Low)			67	137	231	329	432	547	667	792
Decay Replacement	41	56	67	76	83	90	97	105	115	125
SDG&E Total	**3**	**4**	**66**	**121**	**179**	**247**	**321**	**398**	**471**	**544**
SDG&E	3	4	60	110	163	225	293	363	430	496
IOU Programs			37	73	108	140	174	206	238	270
Goals AB1109			5	5	3	7	13	20	23	23
Goals Standards			3	6	11	22	34	48	61	75
BBEES (Low)			9	19	33	47	62	78	96	114
Decay Replacement	3	4	6	7	8	9	10	11	12	14

* Totals are grossed up to include line loss.

All values were taken from the CEC's Incremental Impacts of Energy Efficiency Policy Initiatives Relative to the 2009 Integrated Energy Policy Report Adopted Demand Forecast, and the Attachment A: Technical Report
http://www.energy.ca.gov/2010publications/CEC-200-2010-001/index.html

Decay Replacement is from the CEC's report, Table 12, at page 50.
All other values are from the Attachment A, at the following Tables and Pages:
PG&E: BBEES, Table 7-4, at page 139; all other values from Table 7-8, at page 142.
SCE: BBEES, Table 8-4, at page 150; all other values from Table 8-8, at page 153.
SDG&E: BBEES, Table 9-4, at page 161; all other values from Table 9-8, at page 164.
Decay Replacement is from the CEC's report, Table 12, at page 50.

Forecasted Demand Response Programs

		2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
PG&E	*Total DR**	1,354	1,627	1,670	1,715	1,767	1,816	1,865	1,911	1,956	2,001
	Total DR	1,210	1,454	1,492	1,533	1,579	1,623	1,667	1,708	1,748	1,788
	Non-Emergency Demand Response (DR)	543	741	723	728	736	744	752	759	765	773
	Emergency DR	205	219	230	241	252	263	274	285	297	308
	Total AMI Enabled DR	210	231	259	284	311	336	361	384	406	427
	Non-Event Based DR (PLS/TOU)	252	263	280	280	280	280	280	280	280	280
SCE	*Total DR**	1,641	2,502	2,685	2,749	2,842	2,842	2,842	2,842	2,842	2,842
	Total DR	1,476	2,250	2,415	2,472	2,556	2,556	2,556	2,556	2,556	2,556
	Non-Emergency Demand Response (DR)	213	385	591	782	773	764	754	744	734	724
	Emergency DR	1,251	1,097	929	752	761	771	781	790	800	811
	Total AMI Enabled DR	0	755	883	925	1,009	1,009	1,009	1,009	1,009	1,009
	Non-Event Based DR (RTP)	13	13	13	13	13	13	13	13	13	13
SDG&E	*Total DR**	210	226	270	277	285	289	293	298	302	302
	Total DR	197	212	253	260	267	271	275	280	283	283
	Non-Emergency Demand Response (DR)	165	185	230	241	248	252	255	260	263	263
	Emergency DR	32	27	23	19	19	19	20	20	20	20
	*Total AMI Enabled DR***	0	0	0	0	0	0	0	0	0	0
	Non-Event Based DR	0	0	0	0	0	0	0	0	0	0

* Totals are grossed up to include line loss.

** SDG&E included AMI enabled DR in the 2010 Load Impacts.

AMI decisions are as follows: D.09-03-026 (PG&E), D.08-09-039 (SCE), and D.0704-043 (SDG&E)
PG&E Values:
PG&E's updated 2010-2010 ex-ante forecast, PG&E's LI forecast which included: residential and non-residential TOU, non-residential default PDP, residential voluntary PDP.
PG&E's emergency DR included BIP only assuming the Smart AC will have a "price trigger" (Application pending)
PG&E's AMI enabled DR is PTR and PCT
However, since PG&E did not provide any ex-ante forecast for some AMI-related DR programs, ED Staff developed the AMI-related MW from the AMI upgrade decision (D.09-03-026) and PG&E's workpapers.
SCE Values:
SCE's April 22, 2010 Ex-ante Portfolio Forecast, SCE's LI which included: non-residential default CPP
SCE emergency DR had the LI set at the cap, assuming AC cycling will have a "price trigger", and are based on the percentage from the Phase 3 settlement, with a peak load forecast consistent with the 2010 LTPP
SCE's AMI enabled DR includes CPP, PTR, and PCT
However, since SCE did not provide any ex-ante forecast for AMI-related DR programs, ED Staff developed the AMI-related MW from the SCE's AMI testimony & SCE AMI testimony (SCE-4 Errata) and the settlement adopted in D.08-09-039.
SDG&E Values:
SDG&E's April 2010 ex-ante portfolio forecast.
Emergency DR is set at the cap, assuming AC cycling will have a "price trigger", and are based on the percentage from the Phase 3 settlement.
In its supplemental comments, SDG&E indicated that the forecast for PTR reflects a degree of uncertainty since it is a new program.
However, SDG&E's forecast is in line with the estimated MWs in its AMI settlement.

Load for RPS Calculation
Values are in GWh

"BASE CASE" LOAD	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Total Statewide Retail Deliveries	276,509	269,250	269,705	272,572	276,407	280,650	283,767	286,908	290,084	293,410	296,617	299,869	303,253
Pumping loads	11,715	13,331	13,324	13,339	13,358	13,394	13,417	13,440	13,462	13,490	13,511	13,533	13,556
Sales from LSEs serving <200 GWh/yr*	2,008	1,969	1,981	2,004	2,031	2,063	2,089	2,115	2,143	2,172	2,201	2,229	2,260
EE Decay replacement	169	313	488	693	913	1,093	1,254	1,391	1,504	1,598	1,684	1,769	1,861
EE Uncommitted - IOU	0	0	0	0	0	1,613	2,823	3,983	5,490	7,294	9,101	10,607	11,867
EE Uncommitted - non-IOU, RPS obligated	0	0	0	0	0	391	684	965	1,330	1,767	2,204	2,569	2,874
EE Uncommitted - non-IOU, non-RPS obligated**	0	0	0	0	0	12	22	31	43	57	71	83	93
Incremental DG	0	0	0	0	0	0	0	0	0	0	0	0	0
CHP	0	0	0	756	1,511	2,267	3,022	3,778	4,533	5,289	6,045	6,800	7,556
TOTAL RPS Eligible Retail Sales	**262,617**	**253,636**	**253,912**	**255,780**	**258,594**	**259,830**	**260,478**	**261,236**	**261,622**	**261,800**	**261,870**	**262,362**	**263,280**
33% RPS Requirement												Expected	**86,882**

"LOW" LOAD	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
"Base Case Load" RPS Eligible Retail Sales	262,617	253,636	253,912	255,780	258,594	259,830	260,478	261,236	261,622	261,800	261,870	262,362	263,280
10% reduction	-26,262	-25,364	-25,391	-25,578	-25,859	-25,983	-26,048	-26,124	-26,162	-26,180	-26,187	-26,236	-26,328
TOTAL RPS Eligible Retail Sales	**236,356**	**228,273**	**228,521**	**230,202**	**232,735**	**233,847**	**234,430**	**235,112**	**235,460**	**235,620**	**235,683**	**236,125**	**236,952**
33% RPS Requirement													**78,194**

"HIGH" LOAD	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
"Base Case Load" RPS Eligible Retail Sales	262,617	253,636	253,912	255,780	258,594	259,830	260,478	261,236	261,622	261,800	261,870	262,362	263,280
10% increase	26,262	25,364	25,391	25,578	25,859	25,983	26,048	26,124	26,162	26,180	26,187	26,236	26,328
TOTAL RPS Eligible Retail Sales	**288,879**	**279,000**	**279,304**	**281,358**	**284,454**	**285,813**	**286,526**	**287,359**	**287,784**	**287,980**	**288,057**	**288,598**	**289,608**
33% RPS Requirement													**95,570**

All EE values were taken from the CEC's Incremental Impacts of Energy Efficiency Policy Initiatives Relative to the 2009 Integrated Energy Policy Report Adopted Demand Forecast, and the Attachment A: Technical Report, available here:
http://www.energy.ca.gov/2010publications/CEC-200-2010-001/index.html

Decay Replacement is from the CEC's report, Table 12, at page 50.
All other values are totalled from Attachment A to the CEC's Report, at the following Tables and Pages:
BBEES (Low Goals Case): Table 4-15, at page 62.
IOU Programs, AB 1009, Title 24 & Fed Standards (Mid Goals Case): Table 4-15, at page 62.

For Incremental CHP, see the Statewide tables under the "CHP" tab.

Non-IOU savings - the total of "non-IOU, RPS obligated" and "non-IOU, non-RPS obligated" - equals 25% of IOU savings, since the three large IOUs are roughly 75% of statewide electricity consumption (CEC report, at page 4.)

* LSEs with annual retail sales of less than 200 GWh/yr are assumed to be exempt from the RPS, consistent with the Air Resource Board's proposed regulations for a 33% Renewable Electricity Standard.

** These values represent the portion of the total non-IOU EE Uncommitted savings that are assumed to be achieved, based on their proportional shares of non-IOU load, by LSEs with annual retail sales less than 200 GWh/yr. Because these entities' retail sales have already been subtracted from the RPS obligation, their assumed energy efficiency reductions are not subtracted.

RPS NQC

Values are in MW

		2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
33% Trajectory, Base Case Load	North	20	94	123	263	414	760	904	904	904	904
	South		6	174	423	1,768	2,043	2,749	2,749	3,819	3,819
	San Diego				143	440	465	465	465	508	508
	Connection to POU Systems					44	44	366	675	675	675
33% Time-Constrained, Base Case Load	North	20	108	202	294	390	719	719	719	719	719
	South		6	174	451	1,843	2,118	2,315	2,315	2,315	2,315
	San Diego				14	74	74	74	74	74	74
	Connection to POU Systems					44	44	44	44	44	44
33% Cost-Constrained, Base Case Load	North	20	94	123	278	359	704	853	853	853	853
	South		6	174	427	1,148	1,423	1,620	1,620	1,620	1,620
	San Diego				45	342	370	418	909	909	909
	Connection to POU Systems					44	44	44	44	44	44
33% Environ.-Constrained, Base Case Load	North	20	94	149	269	283	623	1,257	1,257	1,257	1,257
	South		6	174	423	1,127	1,402	1,641	1,641	1,641	1,641
	San Diego				23	157	157	157	317	317	317
	Connection to POU Systems					44	44	53	53	53	53
20% Trajectory, Base Case Load	North	20	94	123	263	263	609	647	647	647	647
	South		6	174	423	992	1,268	1,465	1,465	1,465	1,465
	San Diego				38	142	146	146	146	146	146
	Connection to POU Systems					44	44	53	110	110	110
33% Trajectory, High Load Sensitivity	North	20	94	123	263	414	760	904	904	904	904
	South		6	174	423	1,768	2,043	2,749	2,749	3,850	3,850
	San Diego				143	440	465	465	465	1,295	1,295
	Connection to POU Systems					44	44	366	675	675	675
33% Trajectory, Low Load Sensitivity	North	20	94	123	263	414	760	798	798	798	798
	South		6	174	423	1,768	2,043	2,241	2,241	2,267	2,267
	San Diego				143	440	465	465	465	465	465
	Connection to POU Systems					44	44	338	647	647	647

(END OF ATTACHMENT 1)

ATTACHMENT 2

Standardized Planning Assumptions (Part 2 – Renewables) for System Resource Plans

Summary of Updates

This brief document summarizes the most significant changes in the attached Standardized Planning Assumptions (Part 2 – Renewables), as compared to the draft Long-Term Renewable Resource Planning Standards released on June 22, 2010.

For ease of comparison, throughout the attached Planning Assumptions, all changes to the *inputs* or *methodology* presented in the June 22 draft Planning Standards are also highlighted in red, with the titles to tables highlighted in red if there are changes to any of that table's content. The one exception is that, given the substantial changes to Appendix E, that Appendix has been replaced in its entirety. Language changes in the report that simply clarify or provide more detail about the methodology that was presented in the June draft is not highlighted.

Significant changes and updates include:

Resource and Cost Assumptions

- Small solar PV availability is updated as described in Table 6, fixing discrepancies between potential identified by E3/B&V and the amounts included in the June 18th Calculator.
- Biomass potential in the Northwest and California has been reduced, as discussed in Section II.5.1.
- Tables B2 and B3 are updated as described in Appendix B, to reflect updated assumptions about resource RPS eligibility, and to correct for discrepancies between the Energy Division database and modeled commercial resources.
- NOx permit costs are now considered for biomass resources in sensitive Air Quality Basins; this applies only to the Fairmont and Palm Springs zones.
- The displayed costs in the Pro Forma tab are updated to consistently calculate California (rather than U.S. averages), and the error in the June 18th Calculator with double application of regional multipliers has been resolved, resulting in changes to the costs shown in Table 1. Also, Table 1 now reflects only California-average costs, rather than the WECC-wide averages shown previously. This also resulted in changes to the capacity values shown in Table 3, as the Gas CT cost used to calculate the capacity value was subject to the same double application of regional multipliers.
- The transmission cost assumption was reduced from $68/kW-yr. to $54/kW-yr. The average annual cost of new transmission lines in California is used as a proxy for network upgrades that may be required for NonCREZ resources.

Energy and Capacity Valuation

- NQC values for in-state resources are updated, as reflected in Table 3:
    - Biogas, small solar PV, and small hydro no longer receive a capacity credit. These resources are assumed to connect via the Small Generator Interconnection Process or Wholesale Distribution Access Tariffs available to generators < 20

MW, and those study processes do not currently include the deliverability study that is necessary for capacity to be counted towards California's Resource Adequacy program.

- Biomass reduced from 100% to 68%
- Small hydro reduced from 65% to 60%
- Wind NQC increased from 11% to 16%
- Geothermal reduced from 100% to 72%

- Energy Value calculation for small hydro resources is updated, as reflected in Table 2.
- Costs and losses associated with delivering Idaho REC resources to the local market are updated, resulting in changed energy values in Table 3.

Timing Assumptions

- Generation timing assumptions in Table 5 and Appendix F1 are updated; Table 5 now includes detail about the timing of different development steps that was previously only contained in Appendix F1, identifies timing assumptions unique to biogas facilities, clarifies that the 33% RPS Calculator only considers a resource for inclusion in a scenario as of its first full year of commercial operation, and reflects adjustments to general project development timing made in response to party comment. With few exceptions, the updated assumptions reflect longer development timeframes.
- Transmission timing assumptions in Table 7 and Appendix F2 have been lengthened slightly to reflect party comment.
- A lag of 18 months is assumed between the completion of any transmission line and the availability in the Calculator of all the generation in that line's zone, as discussed in Section II.7.2, below.

Ranking and Scenario Creation Methodology

- The environmental scoring methodology is updated significantly, in response to party comment, as detailed in Appendix E.
- The Net Short Calculation has been updated to reflect the demand levels adopted in the Scoping Memo and presented in the Standardized Planning Assumptions (Part 1).
- Three new scenarios have been added, pursuant to the direction in the Scoping Memo: a 20% by 2020 Trajectory Scenario, and high and low load sensitivities around the 33% Trajectory Scenario.
- The weighting of scores used to create the Time-Constrained Scenario has been adjusted slightly as shown in Table 9 and described in that section.
- Model has been adjusted to ensure that *local, non-California* RPS builds are always based on cost, not the criteria that a user has selected to sort resources for delivery *to California.*

Updates to 33% RPS Calculator Functionality

- The updated calculator will be available on the 2010 LTPP History webpage: http://www.cpuc.ca.gov/PUC/energy/Procurement/LTPP/ltpp_history.htm.
- The Solar Pro Forma Tool is now integrated into the 33% RPS Calculator. Previously, solar costs had to be brought in from an external pro forma model to ensure adequate debt-service coverage ratios.
- The user can now select thin-film or crystalline tracking as the default technology for large-scale solar PV resources. In the June 18th version of the model, all large-scale solar PV resources were assumed to use crystalline tracking technology. While that remains the default, the user now has the option to select thin-film as the default large-scale solar PV technology.
- The user can now run sensitivities assuming that Wyoming and Montana resources are delivered by DC lines; default assumption continues to be AC lines

Other

- The Results section is updated to reflect the new scenarios resulting from the revised inputs and methodology, and to allow for easier comparison across scenarios.
- The Out-of-State REC Supply Table in Appendix B6 has been added, as it was inadvertently omitted from the June 22 draft.
- The formatting problems with Appendix D that had made it difficult to read and understand the source of the information in that Appendix.
- Language throughout is updated to reflect the change from a draft staff proposal to a final adopted document.

Table of Contents

Standardized Planning Assumptions (Part 2 – Renewables) for System Resource Plans

I Introduction

I.1 2010 Long-Term Procurement Plan Proceeding

The Commission opened the 2010 Long-Term Procurement Plan (LTPP) proceeding with an Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans (OIR) on May 6, 2010. In that OIR, the Commission stated its intent "to continue our efforts to ensure a reliable and cost-effective electricity supply in California through integration and refinement of a comprehensive set of procurement policies, practices and procedures underlying long-term procurement plans. This is the forum in which we shall consider the Commission's electric resource procurement policies and programs and how to implement them."[1]

The 2010 LTPP is expected to consider new generation needs within the 2010-2020 planning term. The OIR laid out three tracks for the proceeding:

> "(1) **Track I** will identify California Public Utilities Commission (CPUC)-jurisdictional needs for new resources to meet system or local resource adequacy and to consider authorization of IOU procurement to meet that need, including issues related to long-term renewables planning and need for replacement generation infrastructure to eliminate reliance on power plants using once-through- cooling (OTC).
>
> "(2) **Track II** will address the development and approval of individual IOU "bundled" procurement plans consistent with §454.5.
>
> "(3) **Track III** will consider rule and policy changes related to the procurement process which were not resolved in R.08-02-007…"[2]

As noted in the OIR, the need to integrate renewables is anticipated to be one of the "primary drivers for any need for new resources identified in this proceeding."[3] These standardized planning assumptions present the set of inputs, assumptions, methodologies, and resulting scenarios that will guide long-term renewables planning within the 2010 LTPP.

I.2 Background

Since Decision (D.) 05-07-039, the Commission has stated its intent to integrate long-term planning for renewables into the LTPP proceeding. D.05-07-039 states: "We will address the long-term plans filed in this proceeding in a subsequent decision. After that decision, we intend to return long-term RPS planning to the long term procurement planning component of R.04-04-003 or its successor, as contemplated by [Pub. Util. Code] § 399.14(a)."[4] In the Scoping

[1] Rulemaking (R.) 10-05-006, at p. 2.
[2] *Id.*, at p. 9.
[3] *Id.*, at p. 12.
[4] D.05-07-039, at p. 29.

Memo for the 2006 LTPP, the Commission stated that "The 2006 LTPPs will identify the key planning decisions that the utilities need to make in the next few years in order to ensure the Commission's energy policy objectives are maintained and pursued in the future, including moving on a path to achieve the EAP [Energy Action Plan] II goal of 33% renewables by 2020".[5] The utilities were specifically directed to include in their plans "information about the extent to which the IOUs [Investor Owned Utilities] will exceed the existing legislative mandate of 20% renewables by 2010 and work towards the EAP policy goal of 33% by 2020."[6]

In response to the 2006 Long-Term Procurement Plans filed by the IOUs, and recognizing the growing support for increasing the existing 20% by 2010 Renewables Portfolio Standard (RPS) to a standard of 33% by 2020, the Commission directed "parties to work with ED staff to refine a methodology for resource planning and analysis that will allow [the IOUs] to adequately address the issue of a 33% renewables target by 2020 in subsequent LTPPs ....We expect these sections to be much more robust in subsequent LTPPs and expect that parties will work to make RETI [Renewable Energy Transmission Initiative] useful in this regard."[7] In response to this direction, Energy Division staff worked with parties to the 2008 LTPP proceeding, R.08-02-007, and other stakeholders to assess implementation of a 33% RPS, considering various resource portfolios with which the state might achieve such a target, as well as the associated timing, costs, and risks.

In June 2009, Energy Division staff released its *33% RPS Implementation Analysis Preliminary Results*[8] report. A December 9, 2009 ACR in the 2008 LTPP confirmed that the study had responded to the Commission's direction to develop a methodology for considering a 33% renewables target within long-term procurement planning; stated that it exemplified the sort of system-wide "Renewables and Transmission Study" that parties had generally supported in the 2008 LTPP proceeding; and anticipated that staff would "refine the 33% RPS Implementation Analysis assumptions and methodology in an updated study, as a direct input to the 2010 system planning proceeding."[9] On December 9-10, 2009, Energy Division staff held a workshop to review party comments on the *33% RPS Implementation Analysis Preliminary Results* report and to consider the refinements that should be incorporated into an updated analysis for the 2010 LTPP.

I.3 Preliminary Process and Relationship to other Considerations in LTPP

On May 28, 2010, a Ruling in R.10-05-006 transmitted two Energy Division staff proposals related to the Track I system plans – *Standardized Load and Resources Tables for System Resource Plans*, and *Planning Standards for System Resource Plans* (similar documents for the Track II bundled plans were also released). The scenarios presented in this report are discussed in the May 28 Planning Standards proposal:

[5] September 25, 2006 ACR/Scoping Memo, at p. 18
[6] *Id*., at p. 20
[7] D. 07-12-052, at p. 256.
[8] Available here: http://www.cpuc.ca.gov/NR/rdonlyres/1865C207-FEB5-43CF-99EB-A212B78467F6/0/33PercentRPSImplementationAnalysisInterimReport.pdf
[9] Assigned Commissioner's Ruling in R.08-02-007, December 3, 2009, p. 3

> "The Energy Division shall propose a minimum set of renewable generation scenarios in its draft report due in June 2010. In addition to comments on staff's proposed renewable scenarios, the IOUs or any other party may propose other scenarios the Commission should consider to achieve the goals of this proceeding. The Assigned Commissioner will determine a reasonable minimum set of resource planning scenarios in the Scoping Memo, based on initial proposals and parties' comments. The required scenarios shall be consistent with the guiding principles set forth in Section II."[10]

This attachment presents seven "RPS scenarios", containing specific portfolios of generation and transmission resources with which the state might achieve a 33% RPS in 2020, as well as sensitivities around the Trajectory Scenario for high and low load levels, and a 20% by 2020 scenario. These RPS scenarios, however, are only one set of many inputs and assumptions discussed in the Standardized Planning Assumptions as critical to the LTPP's determination of need for new system resources.

Some of the "non-RPS" inputs to the LTPP, such as assumptions about the retirement of once-through-cooled plants, have little or no impact on the makeup of the RPS scenarios. Others, however, including forecasts of load and of "load modifiers" such as customer-side distributed generation (DG) and combined heat and power (CHP), affect the amount of renewable generation assumed necessary under a 33% RPS, by affecting retail sales. The May 28, 2010 Planning Standards document proposed and solicited party comment on these inputs, and a separate, more detailed report specifically on energy efficiency assumptions was released on June 22, 2010 as "Resource Planning Assumptions – Part 3" and discussed at a workshop on June 25.

The scenarios selected for further analysis have been updated to be consistent with the demand-side assumptions presented in the Standardized Planning Assumptions (Part I), as discussed in the "Resource Gap Calculation" section below.

II Methodology

II.1 Terminology – Scenarios, Sensitivities, Cases, Portfolios

These planning assumptions rely on the terminology for scenarios, cases, etc. presented in the Standardized Planning Assumptions Part I – with the important exception noted in the next section. Specifically, for the terms relevant to this report:

> ***Scenario*** - A possible future state of the world encompassing assumptions about policy requirements, market realities and resource development choices. *Required scenarios* are those specified in the Scoping Memo. *Supplemental scenarios* are any additional scenarios provided by parties, and evaluated in addition to those required in the Scoping Memo.
>
> ***Portfolio*** - A set of electric resources, both supply-side and demand-side, that provides electric service to all system ratepayers, under a given scenario. *Utility-Preferred*

[10] *Administrative Law Judge's Initial Ruling on Procurement Planning Standards and Setting Schedule for Comments and Workshops*, May 28, 2010, Attachment 2, at p. 6.

Portfolio is a resource portfolio identified by the IOU as a preferred resource portfolio and submitted to the Commission for consideration and possible adoption.

Resource Plan – A filing before the Commission containing information and analysis on all portfolios developed and evaluated, including complete documentation of each portfolio's performance under required evaluation criteria.

Case – A set of input assumptions and parameters (e.g., gas price, or electricity demand) under a given scenario that drives the selection of a given portfolio of resources.

Common Values – A set of input assumptions and parameters that represent the expected or most likely values for each scenario. All required scenarios shall have the same common value assumptions, whereas supplemental scenarios may consider alternative assumptions.

Sensitivity Analysis - A test to measure the change in output variable (e.g., cost, resource need) due to a change in input assumptions and parameters. Sensitivity analysis is conducted by changing one or more input assumptions from the common value to an alternative value.

II.2 Statewide Approach

The one exception to these planning assumptions' consistent use of these terms is that the "portfolios" presented here contain resources providing electric service to all ratepayers statewide, rather than to just the "system" ratepayers of one or all of the three large IOUs.

The need for a statewide approach to the development of the 33% RPS scenarios is due to the nature of renewable resources. The highest-quality renewable resources are clustered in distinct geographic areas, and they are often transmission-constrained. In order to assure that multiple utilities – whether investor-owned or publicly-owned – do not count on the same transmission-constrained resource to meet their long-term RPS targets, a statewide approach is warranted. Such an approach can also serve to identify priority resource areas to which utilities might consider developing transmission lines that would benefit ratepayers both inside and outside the system operated by the California Independent System Operator (ISO).

In order to be useful for the IOUs' system plans, the statewide scenarios presented in this report have also been disaggregated, with resources "allocated" to each IOU for system planning purposes, based on physical location. These allocations are presented in the Loads and Resources (L&R) Tables attached to the Scoping Memo.

II.3 33% Resource Gap Calculation

These planning assumptions estimate the level of statewide renewable generation in every year between 2010 and 2020, the end of the 2020 LTPP planning horizon, under seven different scenarios: four 33% by 2020 scenarios, two load sensitivities around the 33% Trajectory Scenario, and one 20% by 2020 scenario. In order to calculate the need, or "RPS resource gap" in each year, assumptions must first be made about three inputs: existing/baseline generation, load, and load-modifying demand-side resources.

II.3.1 Baseline generation

Energy Division's consultant, Energy and Environmental Economics, Inc. (E3) relied on the California Energy Commission's 2008 Net System Power Report[11] for California utilities' claims of renewable energy deliveries in 2008. Because the 2009 Net System Power Report for 2009 is not yet available, E3 added to the 2008 list those renewable resources that came online in 2009 according the CPUC's records, yielding a figure that represent the total existing renewable generation contracted to or located in California as of 2009.

In order to project the RPS need in 2020, E3 also had to make assumptions about the RPS generation facilities that would either retire or roll off their contracts over the next several years. A number of the projects now under contract to California utilities have short-term contracts that expire before 2020. In the case that these are in-state resources, E3 has assumed that the contracts would be renewed such that those resources would continue to contribute to the target through 2020; for out-of-state resources, E3 has assumed that no re-contracting occurs and that the local jurisdiction repossesses the RECs associated with these resources before 2020. E3 has assumed no renewable generation facility retirements over the course of the study period.

II.3.2 Load forecast

These standardized planning assumptions rely on the forecast developed by the California Energy Commission as part of the 2009 Integrated Energy Policy Report process[12] for estimates of statewide retail energy demand 2010-2020. See Appendix A for more detail.

II.3.3 Load-modifying demand-side assumptions

These standardized planning assumptions use a common set of demand-side assumptions to create four 33% by 2020 scenarios (described in more detail in Section II.4.4, below), and one 20% by 2020 scenario. These demand-side values assume statewide achievement of:

1.) The mid-case incremental energy efficiency forecasts[13] presented by the Energy Commission in its *Incremental Impacts of Energy Policy Initiatives Relative to the* 2009 Integrated Energy Policy Report *Adopted Demand Forecast.*[14] The Energy Commission's estimates for IOU savings have been scaled up in order to estimate statewide – not only IOU – savings, by applying an assumed IOU:non-IOU ratio of 75:25. This scaling was performed only on the savings estimated from "2020 Incremental Uncommitted Impacts", and not on the "IOU Program Decay Replacement" savings.

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[11] Nyberg, Michael, 2009. *2008 Net System Power Report*. California Energy Commission. CEC-200-2009-010.

[12] Kavalec, Chris and Tom Gorin, 2009. *California Energy Demand 2010-2020, Adopted Forecast*. California Energy Commission. CEC-200-2009-012-CMF.

[13] See discussion in the Scoping Memo on Energy Efficiency and decrements to Big Bold Energy Efficiency Strategies, for more detail.

[14] Electricity and Natural Gas Committee. *Incremental Impacts of Energy Policy Initiatives Relative to the* 2009 Integrated Energy Policy Report *Adopted Demand Forecast*. CEC-200-2009-001-CTF.

2.) The customer-side DG assumptions embedded in the 2009 IEPR forecast. Because the load forecast already assumes a large amount of customer-side DG, no additional installments of customer-side DG are assumed within the planning horizon.

3.) Increases in CHP in IOU service territories at the midpoint between no incremental CHP and the IOUs' portion of the nearly 4,000 MW of incremental state-wide CHP that ARB targets in its AB 32 Scoping Plan. Additional assumptions include: existing CHP capacity is maintained through 2020; incremental CHP growth is split evenly between on-site use and exports to the grid; the ratio of capacity between the IOUs' territories remains constant at the 2010 percentages for supply-side and demand-side CHP; and the 2020 values are evenly distributed back to 2010.

These standardized planning assumptions also test the sensitivity of one of the four 33% RPS scenarios – the Trajectory Scenario – to changes in load levels, presenting a Trajectory Scenario – Low Load and a Trajectory Scenario – High Load. The "Low Load" sensitivity assumes total RPS eligible retail sales of 10% *below* the standard demand assumption, and the "High Load" sensitivity assumes total eligible RPS sales of 10% *above* the standard demand assumption.

More detail on the assumptions and their values are provided in the Scoping Memo, in Attachment 1 and its appendices, and in Appendix A to this report.

II.4 Portfolio Development Approach and Required Scenarios

II.4.1 Guiding Principles for RPS Scenario Development

At the December 10-11, 2009 workshop, staff proposed that the following principles should guide development of new 33% RPS scenarios. These principles are reflected in the adopted methodology and scenarios:

Guiding Principles for development of Inputs, Assumptions and Methodologies:

1.) Assumptions should reflect the behavior of market participants, to the extent possible

2.) Methodology should be consistent with previous regulatory decisions, to the extent applicable

3.) Any proposal should explain the policy basis for the proposal

4.) Any proposal must include supporting documentation

Guiding Principles for development of RPS Scenarios:

5.) RPS scenarios should be reasonably feasible and reflect plausible procurement strategies with associated (conceptual) transmission.

6.) RPS scenarios should represent substantially unique procurement strategies resulting in material changes to corresponding (fossil) procurement needs and/or required (conceptual) transmission.

7.) The number of RPS scenarios should be limited to 3-5

Although not explicitly listed in the guiding principles, transparency was also a primary goal for staff, and the attempt to bring transparency to the planning process drove key decisions related to methodology, as described below.

II.4.2 Inclusion of a "Discounted Core" of Contracted Projects

One weakness of the June 2009 *33% RPS Implementation Analysis* was that, for all scenarios except the "33% Reference Case", insufficient consideration was given to the thousands of MW of projects with which California's utilities have signed contracts since the beginning of the RPS program, but which are not yet delivering energy. In effect, the "High Wind", "High DG" and "High Out-of-State" cases in that analysis were built on the assumption that utilities could either step out of many of the contracts they had signed to pursue a different procurement strategy, or that those resources would fail to develop in accordance with the contract specifications. While it is not realistic to assume that all of the projects contracted to utilities will deliver as contracted, the IOU contracts nevertheless represent the best information available about the state's potential renewable resource portfolios over the next 10 years.

The adopted methodology addresses this issue via the identification of a "discounted core" of resources intended to represent the most viable of the projects with which IOUs have signed contracts. These projects are held constant across all scenarios, assuming that these projects are reliable under several different futures. The exception, however, is that a project that meets the criteria described below for inclusion in the discounted core is not "forced" into a scenario if that project would prompt the need in the model for new transmission. New transmission is only added to accommodate *discounted core* projects – and thus included in all of the scenarios – if discounted core projects would provide at least 67% of the energy that could be accommodated over the added transmission line. If the discounted core projects in a zone don't meet that threshold, then they enter the larger pool of "commercial interest" projects and compete for inclusion in each scenario as per the methodology described in Section II.8. Users can adjust and test the sensitivity of results to this assumption by changing cell D16 on the Control Tab sheet of the 33% RPS Calculator.

The intent of this approach is to ensure, given the model's limited choice of sizes for new transmission lines, that discounted core resources do not "force" the inclusion in every scenario of major new transmission lines that would serve only a small amount of RPS generation that met the policy goal of that scenario. Historical experience suggests that major transmission projects must provide access to a significant amount of renewable generation in order to be successfully permitted and financed.

The adopted methodology uses entirely public information as criteria for choosing the discounted core. Although the Commission has access to confidential information about project development and viability, use of such information – or of subjective judgments about project viability that could harm an individual project's ability to secure financing – in order to determine inclusion in the discounted core would preclude the public release of the specific portfolios of resources in each scenario. Given the widespread interest in long-term planning for renewables and the desire that the scenarios be fully vetted by parties, the benefits of transparency in this case outweighed the potentially small gains in accuracy that might be gained by using confidential information.

To be included in the discounted core, the project must be a new, repowered, or restarted RPS-eligible generation project with:

1.) a **signed power purchase agreement** (PPA) either under review or already approved by the Commission as of June 1, 2010; and
2.) its **major permit** (Application for Certification if under the jurisdiction of the Energy Commission; Conditional Use Permit in most other cases) filed with and deemed data adequate by the appropriate agency, as of March 1, 2010.

Staff also considered the use of other public, objective information about developers' project development and ownership experience, and past demonstration of a technology at the scale proposed. Although these criteria are not adopted, the functionality to test the use of these criteria on the makeup of the discounted core remains in the tool developed by E3, for parties to consider.

The discounted core also includes the full MW potential that would be developed under the wholesale solar PV programs proposed and approved by the Commission for Southern California Edison (SCE) and Pacific Gas and Electric (PG&E), and the program proposed and under review by the Commission for San Diego Gas & Electric (SDG&E).[15] If successful, these programs would lead to the development of 1,052 MW of rooftop and ground-mounted PV programs under 20 MW, over the next 5 years. Although the programs are relatively un-tested, it is reasonable to assume the goals will be met, given the large solar PV potential identified for this analysis, and the increasing number of bids in RPS solicitations from projects less than 20 MW, and the high level of commercial interest in the utility programs.

II.4.3 Zone-based Approach

The approach to portfolio development used in these standardized planning assumptions is an updated version of that used in the 2009 33% Implementation Analysis. The approach draws heavily on the resource identification, cost assessment, environmental ratings and Competitive Renewable Energy Zone (CREZ) identification done by the Renewable Energy Transmission Initiative (RETI).[16] Using an updated version of the 33% RPS Calculator developed for last year's analysis, E3 builds 33% RPS portfolios in three main steps:

Step 1: Identify resources geographically as located in one of 41 CREZs; as a "non-CREZ" resource that will deliver energy to California; or as an out-of-state

[15] On September 2, 2010, the Commission issued Decision (D.)10-09-016, approving SDG&E's proposed Solar Energy Project. Rather than the 52 MW total proposed in SDG&E's application, the Decision authorized a program total of 100 MW of primarily 1-2 MW projects. The assumptions for this analysis were already finalized by the time of the Decision's release, however, with 52 MW in the discounted core, rather than 100. Given the relatively small impact that a change from 52 to 100 MW in the discounted core would have on the overall results, the analysis was not updated.

[16] Information about RETI is available on the RETI website, http://www.energy.ca.gov/reti/.

"REC" resource assumed to deliver energy into the local out-of-state market (detail in Section II.6);

Step 2: Rank resources based on cost, timing, environmental concern, and commercial interest (detail in Section II.8);

Step 3: For each CREZ, select resources into bundles according to transmission constraints:

Increment 1: Generation that can fit on the existing transmission system;
Increment 2: Generation that can be accommodated by minor upgrades;
Increments 3-6: Generation that can be accommodated by the addition of new generic transmission lines of various sizes;

Step 4: Select from among non-CREZ resources, CREZ "bundles", and RECs enough resources to meet the 33% target (Section II.6)

One major change to last year's approach is in the treatment of transmission, as described in Step 2. This approach is explained in more detail in Section II.6.3, below.

II.4.4 Proposed Scenario Definitions

A key finding of last year's *Implementation Analysis* was that the scenarios developed for that study – High Wind, High DG, High Out-of-State Delivered and a Reference Case weighted towards contracts signed and under negotiation –varied in their achievement of policy goals often attributed to the RPS program.[17] From a high-level, for example, the High DG scenario may perform better on market transformation, while the High Wind case performs better on cost, but no one scenario performed well across all policy objectives.

For this updated analysis, the 33% scenarios are in fact defined by the policy objectives against which they are expected to perform best:

1.) Cost-constrained Scenario;

2.) Time-constrained Scenario;

3.) Environmentally-constrained Scenario; and

4.) a Trajectory Scenario weighted heavily towards commercial contracts, thus representing the IOUs' current contracting/procurement trajectory

In order to develop these scenarios, staff and its consultants developed metrics for zones and distributed projects related to that project or zone's estimated cost, estimated online date, estimated high-level environmental concern, and commercial interest/contracting status. The development of each of these metrics is discussed in more detail in the following sections.

[17] California Public Utilities Commission, *33% RPS Implementation Analysis: Preliminary Results*, June 2009, at p. 10.

II.5 Resource Potential, Cost, and Performance

II.5.1 Overview of Resource Potential

The RPS model includes estimates of resource potential for renewables throughout the WECC based on four sources:

1.) **Commercial Projects Database:** The Commercial Projects Database includes data on potential projects currently under some phase of development by California utilities and draws from two sources: the CPUC Energy Division (ED) Database for IOU solicitations and resource plans for POUs in California. The ED Database includes all of the renewable resources with pending or approved contracts as well as projects that have been shortlisted by the IOUs. Details on the projects with pending or approved contracts are available to the public through the CPUC and are included explicitly in the RPS model. A subset of these projects is distinguished as the "Discounted Core," as described above.

The database also includes IOU shortlisted projects, which are confidential and cannot be included in the public model individually; therefore, the RPS model includes aggregate info on these contracts when there are at least 3 projects of the same technology type in a single CREZ. This process is necessary in order to preserve the confidentiality of projects that have not yet begun the permitting process. The RPS model has also incorporated information on planned Publicly-Owned Utility (POU) procurement based on data gathered from the Energy Commission. This data is similar in format and treatment in the model to the non-Discounted Core ED Database projects. Most of the projects included in this set of data are small and are unlikely to require major transmission upgrades, but several POUs have expressed interest in the development of resources in CREZ that might require new transmission.

2.) **RETI Phase 2B Database**: This database includes assessments of renewable resources in California within CREZ as well as estimates of out-of-state potential developed as part of the Western Renewable Energy Zone (WREZ) Transmission Model. The resource potential quantified in the WREZ model is based on an assessment of high-quality remote resources that could be developed with new transmission and is not a comprehensive assessment of out-of-state potential. In addition to resource potential, RETI provides cost and performance metrics for each of the sites considered in its analysis.

E3 made adjustments to the resource availability where appropriate. Specifically, while RETI and other sources report substantial potential for biomass generation, many questions remain about the extent to which this potential can ultimately be realized. Air quality concerns, fuel transport costs, and competing uses for the feedstock are just some of the hurdles that may prevent large-scale development of biomass generation in the near term. As a result of these hurdles, and party comments received in response to the 2009 *Implementation Analysis*, E3 reduced the RETI biomass potential estimates for California from 1,421 MW to 474 MW, and for the Northwest from 883 MW to 514 MW.

3.) **E3 Greenhouse Gas (GHG) Calculator:** E3 has used data that it developed on renewable resource potential throughout the Western Electricity Coordinating Council (WECC) as part of the GHG Calculator, to supplement the RETI Phase 2B data on out-of-state resources. The resource potential estimates in the GHG Calculator were developed using a wide range of sources including National Renewable Energy Laboratory, the US Energy Information Administration, the Alberta Electric System Operator and the British Columbia Hydro and Power Authority. E3 data were used to develop "local" renewable resource builds for each zone (resources were selected assuming that the most cost-effective resources in each zone were selected to meet local RPS targets), and to develop resource bundles available for export to California from Colorado, Montana, and the Canadian provinces of British Columbia and Alberta.

4.) **E3/Black & Veatch Estimates of Statewide DG Potential:** As part of the 2010 LTPP, E3 and another CPUC consultant, Black & Veatch, have worked together to assess the resource potential, performance, and cost of distributed solar photovoltaic (PV) resources in the state of California. These latest estimates are included as candidate resources to meet California's RPS target.

The solar resources were divided into two bins. The first bin (500 MW each from PG&E and SCE, 52 MW from SDG&E – see footnote 15) reflects the IOUs' recently approved plans for procurement of wholesale distributed solar procurement efforts. All of these resources are considered a part of the Discounted Core, i.e. they are included in all of the required RPS scenarios. The second bin represents the remaining DG potential statewide, and is treated as a generic (i.e. non-Commercial) project.

Resources in the model are divided into two categories: those available for delivery to California, which include all in-state resources and out-of-state resources that would require new transmission; and those only available as unbundled Renewable Energy Credit (REC) purchases, which include all out-of-state resources that could be developed without major new transmission investments. The model thus incorporates the functionality to build up a renewable portfolio with a combination of delivered resources and REC-only transactions.

II.5.2 Resource Cost and Performance

The RPS model assumes that new renewable resources are developed under PPAs between an independent power producer (IPP) and a credit-worthy utility. The utility's cost of developing a resource is the PPA price, which is a function of three types of assumptions: resource costs, resource performance, and financing characteristics. Using a detailed pro-forma model, the RPS model calculates a levelized cost of energy (LCOE) for each resource, which is used as the PPA price in the model.

For each resource type, cost assumptions are derived based on an average of the site-specific costs included in the RETI Phase 2B Database, supplemented with data from the E3 Capital Cost Tool for resource types not included in RETI. These costs, which include capital costs, fixed and variable operations and maintenance (O&M), and fuel, serve as a generic set of assumptions for the costs of renewable resources in California. Site-specific information is preserved for the RETI and WREZ resources, while average costs are applied to the in-state resources from the ED and POU databases. For out-of-state resources, the model includes regional cost multipliers that are used to adjust resource costs appropriately based on local costs of labor, construction, and materials.

A similar methodology is applied to determine the capacity factor for each resource: site-specific information is used where available (RETI and WREZ resources), while a generic average of the RETI projects is used for projects that do not have specific performance characteristics (ED and POU databases). The capacity factors for wind resources from the GHG Calculator are based on the resource class, which is used to make adjustments from the generic capacity factor for those resources.

Table 1.

Technology	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Variable O&M ($/MWh)	Heat Rate (Btu/kWh)	Capacity Factor	LCOE ($/MWh)
Biogas - Landfill	$ 2,750	$ 130	$ -	12,070	80%	$ 96
Biogas - Other	$ 5,500	$ 165	$ -	13,200	80%	$ 121
Biomass	$ 4,529	$ 93	$ 13	14,749	85%	$ 128
Geothermal	$ 5,155	$ -	$ 35	-	83%	$ 115
Hydro - Small	$ 3,960	$ 30	$ -	-	35%	$ 196
Solar Thermal	$ 5,300	$ 66	$ -	-	27%	$ 202
Wind	$ 2,399	$ 60	$ -	-	32%	$ 99

Based on these cost and performance assumptions, the RPS model calculates a levelized cost of electricity using a pro-forma tool included with the model. In addition to cost and performance, the levelized cost depends upon the tax credits available to and financing assumptions used for a specific resource, both of which vary by resource type. In order to capture real-world financing activity in new renewable development, E3 has adjusted the fractions of debt and equity in each project so that the debt-service coverage ratio of the project is at least 1.4. Subject to this constraint, the levelized cost of energy is calculated for each renewable technology considered in the model and is used as the representative generic PPA price for that technology.

II.6 Transmission and Geographic Classification

II.6.1 Overview

As described above, the RPS model selects from among hundreds of candidate resources to meet the 33% target. Resources are first identified geographically as being located either in one of the 41 CREZs, as a “non-CREZ” resource that will deliver energy to California, or as an out-of-state “REC” resource that is assumed to deliver energy into the local out-of-state market.

II.6.2 Geographic Classification

Resources are classified into three geographic categories:

1.) CREZ resources;

2.) non-CREZ resources; and

3.) out-of-state RECs.

Non-CREZ resources are resources that are not in an identified CREZ, but are located in California or directly across the border and assumed to deliver energy directly to California. These resources generally require transmission upgrades. Where there is specific information regarding the transmission upgrade costs, this information is included in the total delivered cost. Non-CREZ resources for which no specific information is available are assigned a "neutral" transmission upgrade cost calculated as an average of the upgrade costs for CREZ resources.

REC resources are resources that are located distant from California and would be scheduled over the western transmission grid. These resources may or may not schedule their energy to California. For pricing purposes, the resources are assumed to sell energy and capacity services into the wholesale energy market closest to the project location (e.g., the Mid-Columbia or Palo Verde markets). RECs are priced at the "Net Cost" or "Green Premium" discussed below in Section II.8.1: the resource's LCOE plus transmission and integration services minus the revenues earned through sale of energy and capacity services into the local market. E3 has assumed that the costs of integration will be captured in any REC contract and uses a flat adder of $7.50 per MWh[18] for intermittent resources. The following tables show the energy and capacity revenues for each REC resource type in each state in the WECC. These values include the cost of firm, point-to-point service from the resource location to the nearest market hub. More detail about REC resource assumptions is available in Appendix B.

Table 2.

REC Resource Energy Value by State and Resource Type ($/MWh)							
	Biogas	Biomass	Geothermal	Hydro - Small	Large Scale Solar PV	Solar Thermal	Wind
Alberta	$ 59	$ 59	$ 59	$ 53	n/a	n/a	$ 60
Arizona	$ 55	$ 55	$ 55	$ 56	$ 60	$ 62	$ 52
British Columbia	$ 47	$ 47	$ 47	$ 42	n/a	n/a	$ 49
Colorado	$ 51	$ 51	$ 51	$ 52	$ 57	$ 58	$ 49
Idaho	$ 47	$ 47	$ 47	$ 39	n/a	n/a	$ 45
Montana	$ 49	$ 49	$ 49	$ 44	n/a	n/a	$ 50
New Mexico	$ 50	$ 50	$ 50	$ 51	$ 55	$ 56	$ 48
Nevada	$ 53	$ 53	$ 53	$ 44	$ 56	$ 56	$ 52
Oregon	$ 55	$ 55	$ 55	$ 50	n/a	n/a	$ 55
Utah	$ 47	$ 47	$ 47	$ 39	$ 49	$ 49	$ 45
Washington	$ 55	$ 55	$ 55	$ 50	n/a	n/a	$ 55
Wyoming	$ 47	$ 47	$ 47	$ 42	n/a	n/a	$ 48

[18] This value was developed during E3's Greenhouse Gas modeling for the Commission in Rulemaking (R).06-04-009. It is used here in the absence of more rigorous analysis of California-specific integration costs.

Table 3.

REC Resource Capacity Value by State and Resource Type ($/MWh)							
	Biogas	Biomass	Geothermal	Hydro - Small	Large Scale Solar PV	Solar Thermal	Wind
Alberta	$ 21	$ 20	$ 20	$ 31	n/a	n/a	$ -
Arizona	$ 20	$ 19	$ 19	$ 29	$ 39	$ 30	$ -
British Columbia	$ 21	$ 20	$ 20	$ 31	n/a	n/a	$ -
Colorado	$ 25	$ 23	$ 24	$ 37	$ 49	$ 38	$ -
Idaho	$ 19	$ 18	$ 19	$ 29	n/a	n/a	$ -
Montana	$ 24	$ 23	$ 24	$ 36	n/a	n/a	$ -
New Mexico	$ 24	$ 22	$ 23	$ 35	$ 46	$ 36	$ -
Nevada	$ 28	$ 27	$ 27	$ 42	$ 55	$ 43	$ -
Oregon	$ 21	$ 20	$ 20	$ 31	n/a	n/a	$ -
Utah	$ 19	$ 18	$ 19	$ 29	$ 38	$ 30	$ -
Washington	$ 21	$ 20	$ 20	$ 31	n/a	n/a	$ -
Wyoming	$ 19	$ 18	$ 18	$ 28	n/a	n/a	$ -

We understand that REC-only transactions are not currently compliant with RPS rules. Utilities' RPS transactions must be bundled (energy plus RECs) and if the facility is not interconnected within California, then the energy must be delivered to California pursuant to the provisions in the CEC's RPS Eligibility Guidebook.[19] However, since the current Guidebook allows the energy from the RPS-eligible facility to be remarketed in an out-of-state market before it is delivered to California, the assumptions used in this analysis are not inconsistent with current RPS rules. These assumptions may not reflect what would be allowed under future RPS policies and law, as the Commission is currently considering petitions for modification of a stayed Decision that would authorize REC-only transactions, define bundled versus REC-only transactions, and set limits on the amount and the cost of REC-only transactions that could be used for RPS compliance. In addition, the delivery requirements at the Energy Commission are subject to change and the California Legislature is considering eligibility and delivery rules for RPS resources in a 33% RPS bill. The Commission may revisit the assumptions adopted here if the Commission adopts a Decision on tradable RECs.

CREZ resources were identified principally through the RETI process; however, the commercial projects represented in the ED database have also been assigned to CREZs or identified as a non-CREZ resource by the contracting IOU and CPUC staff, based on stated project location. Resources that are located in CREZs are first assessed based on transmission availability.

The model uses the following CREZs:

[19] http://www.energy.ca.gov/2007publications/CEC-300-2007-006/CEC-300-2007-006-ED3-CMF.PDF

Table 4.

Resource Zone Name	Description or Source
Alberta	GHG Calculator Zone
Arizona	RETI Competitive Renewable Energy Zone (CREZ)*
Baja	RETI CREZ
Barstow	RETI CREZ
British Columbia	RETI CREZ*
Carrizo North	RETI CREZ
Carrizo South	RETI CREZ
Colorado	GHG Calculator Zone
Cuyama	RETI CREZ
Fairmont	RETI CREZ
Imperial East	RETI CREZ
Imperial North	RETI CREZ
Imperial South	RETI CREZ
Inyokern	RETI CREZ
Iron Mountain	RETI CREZ
Kramer	RETI CREZ
Lassen North	RETI CREZ
Lassen South	RETI CREZ
Montana	GHG Calculator Zone
Mountain Pass	RETI CREZ
Nevada C	RETI CREZ*
Nevada N	RETI CREZ*
New Mexico	RETI CREZ*
NonCREZ	Resources of all types in the CPUC ED Database or POU Database that are assumed to come online without substantial transmission upgrades, though generic transmission costs are assigned as discussed in Section D.3
Northwest	RETI CREZ*
Owens Valley	RETI CREZ
Palm Springs	RETI CREZ
Pisgah	RETI CREZ
Riverside East	RETI CREZ
Round Mountain	RETI CREZ
San Bernardino - Baker	RETI CREZ
San Bernardino - Lucerne	RETI CREZ
San Diego North Central	RETI CREZ
San Diego South	RETI CREZ
Santa Barbara	RETI CREZ
Solano	RETI CREZ
Tehachapi	RETI CREZ
Twentynine Palms	RETI CREZ
Utah-Southern Idaho	RETI CREZ*
Victorville	RETI CREZ
Westlands	RETI CREZ
Wyoming	RETI CREZ*

* - RETI did not look at Small Hydro or Biogas options in the Out-of-State zones, so these zones are supplemented with E3 GHG Calculator data for those resource types.

II.6.3 Transmission sizing for CREZ resources

Resources from any one CREZ compete to fill transmission bundles from that zone, in the following increments:

Increment 1: Generation that can fit on the existing transmission system;

Increment 2: Generation that can be accommodated by minor upgrades;

Increments 3-4: Generation that can be accommodated by the addition of new generic transmission lines of various sizes[20];

Estimates of capacity on existing transmission system, and with minor upgrades

The previous 33% RPS Implementation Analysis assumed that the existing transmission system could not accommodate any new generation, and that new major new transmission lines would be needed to access any CREZs. While staff and parties agreed that this was a weakness, staff did not have the expertise to make any other informed assumption.

For purpose of this new analysis, the ISO has provided high-level estimates, based on the results of interconnection studies, of the amount of new renewable generation from certain CREZ that could be accommodated on the existing transmission system, as well as the amount of incremental generation that could be accommodated by new, relatively minor and inexpensive upgrades.

The ISO numbers are high-level estimates, they are not available for CREZ in which there are not a number of interconnection requests, and they are not in any way a guarantee. Nonetheless, this addition is a significant improvement – the estimates are based on the ISO's recent experience with interconnection studies for the extraordinarily large amount of generation now moving through the ISO's interconnection process, and they may allow for a more realistic assessment of the cost as well as the timing of generation from several CREZ.

The model selects resources delivered over existing transmission and minor upgrades in different fashions. Resources delivered over existing transmission are selected on a resource-by-resource basis, reflecting the fact that the cost of delivering these resources to load is not a function of the other resources selected to fill the remaining existing transmission. In contrast, minor upgrades are selected as bundles. This ensures that the costs of the minor upgrade are properly allocated across the resources on that minor upgrade, and that the minor upgrade as a whole is competitive (by whatever ranking metric the user chooses).

The assessment from the ISO is available in Appendix D.

[20] For our analysis, the maximum total capacity added by new transmission from any CREZ to or within California is 3,000 MW. The Excel 2007 Version of the RPS Calculator allows the user to allow up to four lines (maximum of 12,000 MW).

Addition of new generic transmission lines

The size and cost of new generic transmission lines depends on the CREZ. Transmission lines from CREZs are sized on a case-by-case basis based on the total potential for resources within the zone and the distance between the CREZ and load centers. Generally, high voltage (500kV) lines are used to link zones that have large resource potential or that are very far from California loads (e.g. out-of-state lines), while lower voltage lines are assumed for smaller CREZs close to loads. The cost of each line is a function primarily of its length and capacity; the main components are the cost of the line itself, new substation costs, and right-of-way costs. E3 uses generic estimates of each of these types of cost to assign a total capital cost to each potential transmission line considered in the model.

II.6.4 Consideration of RETI Conceptual Transmission Plan

Another source of information that has become available since the release of the June 2009 *Implementation Analysis* is the RETI Phase 2A Conceptual Statewide Plan,[21] finalized in September 2009 with the active participation and support of dozens of stakeholders, including the Commission. The Phase 2A plan represents an important contribution to statewide planning, particularly in its introduction of an objective methodology for considering the value of particular groups of transmission lines for accessing renewable energy, and a process and methodology for considering environmental concerns early in the process of transmission planning.

Energy Division's consultant, Zaininger Engineering Company, Inc. (ZECO), estimated the amount of new capacity that could be accommodated by the transmission segments identified by RETI. This assessment is included in Appendix D to this report. To date, the RETI assessment has not been directly incorporated into the 33% modeling effort. Because the RETI line segments are tied to more than one CREZ, and vice versa – each CREZ is potentially dependent on several line segments – direct consideration of these lines in the 33% model is challenging. However, direct incorporation of the RETI information and attention to specific line segments would allow for more detail on the cost, timing, and environmental aspects of this assessment.

II.7 Zone Timing Assessment

The 2009 *Implementation Analysis* presented a first-of-its-kind attempt to estimate whether the state could actually develop the generation and transmission infrastructure estimated as necessary under the 33% Reference Case, under 3 different "states of the world". The analysis found that it would be very difficult to build 24,000 MW of new generation and 11 major new transmission lines by 2020, given existing permitting and planning processes, risks around deployment of new technology, concerns about environmental impacts, and other factors. That report stated that this finding might be justification for considering procurement strategies that offered less timing risk, due to a decreased dependence on new transmission or other factors.

[21] http://www.energy.ca.gov/2009publications/RETI-1000-2009-001/RETI-1000-2009-001-F-REV2.PDF

Because the ARB has identified a 33% renewable energy target as a key strategy for reducing GHG emissions, timing is a critical consideration. For this updated analysis, generation and transmission development timing is an explicit input into scenario development, and the "Time-Constrained Scenario" is weighted towards those resources estimated to be available earliest.

II.7.1 Timeline Tool

The Commission's consultant, Black & Veatch, developed an Excel-based timeline tool to automate the timing considerations and methodology developed by Aspen Environmental Group (Aspen) and CPUC staff for the *Implementation Analysis*.

The assumptions populating the tool – estimates about the time required to develop various types of generation and transmission resources – have changed very little since last year's analysis, given their basis in historical experience and general party support for last year's assumptions. Based on party comments on the June 22 draft planning standards, we have not updated these assumptions to reflect recent efforts by the Energy Commission, the Bureau of Land Management, and others to streamline generation permitting, and by the ISO to reform its annual Transmission Planning Process to more explicitly account for transmission needed for renewables. Because many of these new efforts are in their early stages, it is difficult as of this writing to estimate their effect.

The timeline tool has not yet been released to parties, as it is still being updated to reflect the new scenarios. Staff anticipates release of the tool later in 2010, so that parties can use it to test assumptions and assist in the potential construction of alternative scenarios.

II.7.2 Incorporating "Timing" into Scenario Development

The process for incorporating timing into scenario development involved three steps: estimating the availability of individual *generation* projects, combining those generation timelines with transmission timing to create *zone* timelines, and creating timelines for entire *scenarios*, once the zones for each scenario had been chosen.

<u>Generation Timing</u>

Each candidate generation project or resource, whether a non-CREZ or CREZ resource, was assigned an online date, based on expected commercial online date (COD) per a contract, or an estimate based on project size and type, assuming that development started on 7/1/2010, and that *transmission was available*. Those assumptions are detailed in Table 5 below, and details about permitting jurisdiction assumptions are in Appendix F1:

Table 5. Generation Development Timing Assumptions

Project Type		Project Development (months)	Permitting (months)	Construction (months)	**Total** (months) *excluding transmission*	**Estimated Online Date** (first **full** year of commercial operation)
Biogas	< 50 MW > 50 MW	12 12	12 24	10 12	34 48	2014 2015
Biomass	< 50 MW > 50 MW	12 18	14 24	24 26	50 68	2015 2017
Geothermal	< 50 MW > 50 MW	12 18	14 24	20 28	46 70	2015 2017
Small Hydro		12	14	20	46	2015
Solar Thermal	< 50 MW > 50 MW	12 18	14 24	24 32	50 74	2015 2017
Solar PV	20 - 50 MW > 50 MW	12 18	10 18	12 18	34 54	2014 2015
Wind	< 50 MW > 50 MW	12 18	10 18	12 18	34 54	2014 2015
ED Database projects 1. Filed/approved by CPUC (public) 2. Under negotiation (confidential)						1. Per public contract information 2. Per generic estimates above
*Timelines assume that the contracting process proceeds in parallel to project development.						

Projects from the ED Database that are still under development, but for which the public expected commercial online dates have already passed, were all assigned an online date of 6/1/2013. This rough date, which is earlier than the dates assigned to most generic projects above, is meant to reflect the uncertainty associated with projects that have already missed expected deadlines, but also the assumption that such projects have already undertaken significant development activities.[22]

The 0.5-20 MW solar PV resources identified by E3 and B&V were assigned a different development schedule than other PV resources. Because this market segment is relatively new and very few of these wholesale distributed generation (WDG) projects have been developed, it is difficult to estimate how many MW could be available in each year before 2020. However, for purposes of this analysis, staff assume that the utility PV programs approved by the Commission for Southern California Edison (SCE) and Pacific Gas and Electric (PG&E), and San Diego Gas & Electric (SDG&E), each meet their program targets of 500, 500, and 52 MW, respectively, within 5 years (see footnote 15). For the other generic resources identified by E3 and B&V, staff assumed that the full potential identified by E3 and B&V could be available by 2020. For the 0.5-20 MW

[22] The timing assessment is another area in which, when dealing with ED Database projects, staff faced a tradeoff between the use of transparent, public information and confidential information or subjective assessments that might present more realistic estimates of individual projects' online dates. Section II.4.2 discusses this tradeoff. The adopted methodology relies on objective, public information.

"easier to interconnect" projects, staff assumed a smooth build-out 2014-2020 that would allow the realization of the full identified potential by 2020. For the remote, "harder to interconnect" projects that might require more upgrades to the transmission or distribution system, staff assumed a build-out that begins in 2015 and then accelerates until that potential is fully built-out in 2020. The resulting timing assumptions are detailed in Table 6 below:

Table 6. Assumed Availability of Wholesale Distributed Generation, by Year

Year	0.5-2 MW Roof available/year		0.5-2 MW Ground		2-5 MW Ground		5-20 MW Ground		20 MW Remote		CUMULATIVE TOTAL		
	IOU Programs* (MW)	Generic** (MW)	IOU Prog. (MW)	Generic (MW)	IOU Prog. (MW)	Generic (MW)	IOU Prog. (MW)	Generic MW)	IOU Prog. (MW)	Generic (MW)	**IOU Prog. (MW)**	**Generic (MW)**	**TOTAL (MW)**
2011	86		5				68				**159**	**0**	**159**
2012	86						96				**340**	**0**	**340**
2013	86						128				**554**	**0**	**554**
2014	86	377	2	6		28	222	141			**863**	**552**	**1,415**
2015	86	377		6		28	103	141		500	**1,052**	**1,604**	**2,656**
2016		497		6		28		242		750	**1,052**	**3,127**	**4,057**
2017		497		6		28		242		1,000	**1,052**	**4,900**	**5,952**
2018		497		6		28		242		1,500	**1,052**	**7,173**	**8,225**
2019		497		6		28		242		2,000	**1,052**	**9,946**	**10,998**
2020		497		6		28		242		3,417	**1,052**	**14,136**	**15,188**
TOTAL	**430**	**3,241**	**7**	**43**	**0**	**194**	**615**	**1,492**	**0**	**9,167**			

* IOU program assumptions, based on program specifics approved or under review by the Commission (see footnote 15)

SCE: 10% is 10 MW ground; 90% is 1-2 MW rooftop

PG&E: 5% is .5-2 MW rooftop; 95% is 1-20 MW ground

SDG&E: all 1-2 MW roof

The timing above allocates the potential remaining evenly over the five years from 2011 – 2015 after netting out projects identified in the ED Database

** Generic numbers assume that all of the MW potential identified by E3 and B&V is available by 2020, less the MW already counted under IOU programs or in the ED database (2 projects subtracted from the 0.5-2 MW Ground category; 23 projects subtracted from the 5-20 MW Ground category)

Numbers may not sum correctly due to rounding.

Transmission and Zone Timing

Following the generation timing assessment, each CREZ "transmission bundle"– incremental MW accommodated by the existing system; MW accommodated by minor upgrades; and MW accommodated by major new transmission lines – was assigned an online date, based on the expected development horizon of the required transmission.

The timeline tool allows users to assign to each CREZ transmission increment one of 9 different transmission schedules, and to choose a development start date:

Table 7. Transmission Development Timing Assumptions, by Schedule Type

Transmission Schedule Type	**Transmission Planning by CAISO/ POU/ WECC** (months)	**Project Description Prep by Utility** (months)	**CEQA/ NEPA Review by CPUC/POU / Feds** (months)	**Final Review and Approval by CPUC/ POU/Feds** (months)	**Final Design and Construction by Utilities** (months)	**Total** (months)
Existing / Distributed	0	0	0	0	0	**0**
Typical	18	12	24	6	24	**84**
Typical - Short	12	12	12	3	18	**57**
Typical - Long	24	18	24	6	30	**102**
Long-Distance	24	18	24	6	30	**102**
Tehachapi	0	0	0	6	48	**54**
Sunrise	0	0	0	0	24	**24**
Devers - CO River	0	0	0	0	30	**30**

CREZs and transmission increments were assigned schedules and start dates as detailed in Table 8 below, with few exceptions as justified by public details about specific projects such as the Tehachapi Renewable Transmission Project. A detailed list of the schedule type and development start date assigned to each CREZ and its transmission increments is provided in Appendix F2.

Table 8. Transmission Schedule Type Assignments for Transmission Increments

CREZ and Transmission Increment	**Transmission Schedule Type**	**Development Start Date**
Non-CREZ	Existing/Distributed	6/1/2010
CREZ – accommodated by existing system	Existing/Distributed	"
CREZ – accommodated by minor upgrades	Typical-Short	"
CREZ – 230 kV line, in-state	Typical-Short	"
CREZ – 500 kV line, in-state	Typical or Typical-Long, depending on location	6/1/2010 for up to 4500 MW of capacity; every 2 years thereafter
Out-of-state Resource	Long-Distance	"

The output of the timeline tool for each transmission increment within each CREZ – a single date for each – becomes an input to the 33% Calculator. In the calculator, then, CREZ projects and non-CREZ projects can be compared to each other according to their expected online dates, allowing the creation of a "Time-Constrained Scenario" that chooses resources based on their expected availability by year.

Lag of Eighteen Months assumed between Transmission Completion and Generation Availability

In the June 22, 2010 draft planning standards, staff proposed that generation be assumed to develop concurrent with required transmission, such that an entire zone of generation would be available to the market upon completion of an enabling transmission line. This differed from the 2009 *Implementation Analysis*, but was proposed as perhaps justified, given the long time horizon associated with much of the candidate transmission development and increased state efforts to signal the market as to the location of priority resource areas.

No parties offered support for this new assumption, and several parties commented that it was likely too optimistic. Thus, these standardized planning assumptions adopt the addition of an 18-month lag between transmission and the availability of all (if any, given the modeling approach that adds zones in "chunks") of the dependent generation in that zone. This assumption remains overly simplistic, as some generation will likely be available immediately after transmission completion, and some not available for potentially several years. It is sufficient for modeling purposes, however. It is a significantly shorter lag than the 30-month delay found in the 2009 *Implementation Analysis*, but reflects current activity in the market, where many renewable energy developers are investing millions of dollars prior to final assurance from transmission permitting agencies.

II.8 Resource Ranking and Selection Methodology

II.8.1 Resource Scoring Metrics

The model's resource ranking algorithm uses four scoring metrics to compare resources, including cost, environmental, commercial, and timing scores. Each score represents a characteristic of a candidate resource that may be used to better understand that project's likelihood of development. These four scores serve as the basis for the ranking process used to select resources and build scenarios.

Cost Score

The cost score is based on the Modified RETI Economic Ranking cost, which captures the "Green Premium" associated with a specific renewable resource: the net cost to California ratepayers of procuring an additional MWh of that resource. This ranking cost is based on the levelized cost of energy; transmission, interconnection, and integration costs; and the market value of energy and capacity associated with that resource:

+ Levelized Cost of Energy (PPA Price)
+ Interconnection Cost
+ Integration Cost
+ Transmission Cost
- T&D Avoided Costs
- Energy Value
- Capacity Value

= Modified Economic Ranking Cost

Each component of the Modified Economic Ranking Cost captures a part of the cost (or benefit) to California ratepayers to develop a specific resource:

1.) **Levelized Cost of Energy** is the sum of all direct costs (capital, fixed and variable O&M, fuel, and NOx permits for biomass resources) required to construct and operate a plant of the specified type. All costs are amortized over the plant's lifetime, resulting in an average cost of generating electricity from that particular plant.

2.) **Interconnection Costs** are any costs associated with interconnecting into the grid; these costs were obtained directly from RETI where available. For resources from the E3 GHG Calculator, these costs are based on the assumed length of the interconnection.

3.) **Integration Costs** apply only to intermittent resources (wind and solar) and capture the increased costs of dispatching conventional generators and procuring sufficient ancillary services in order to integrate these renewable resources into the grid. E3 assumed a flat integration cost adder of $7.50/MWh (see footnote 18), which is adopted here.

4.) **Transmission Costs** capture the cost of any transmission developments required to deliver energy from the point of generation to load. For resources delivered over existing transmission, this cost is zero; if resources are developed along with a transmission upgrade or a new line, the cost of that new line is allocated to each unit of generation to reflect cost of developing transmission along with the resources. The cost of each potential transmission line is calculated using E3's Transmission Cost Calculator, which includes costs of the line itself ($/mile), the right-of-way cost ($/mile), and substation costs.

5.) **T&D Avoided Costs** apply to a small set of resources, most often distributed renewables. The development of distributed renewable resources can result in the deferral of transmission and distribution network upgrades, which results in a net benefit to ratepayers.

6.) **Energy Value** is the average value in wholesale markets that a specific resource would receive for its generation over the course of the year. This adjustment captures the varying value of generation at different points of the day; resources that produce a large fraction of energy during peak periods (e.g. solar) have a higher energy value than resources that produce energy during off-peak periods (e.g. wind). Energy value is calculated for each resource based on the resource's production profile and wholesale market prices in California over the course of the year. The energy values assigned to categories of resources, expressed in heat rates, can be found in rows 174 to 244 of the "ProForma" tab of the 33% RPS Calculator.

7.) **Capacity Value** is the value to ratepayers of avoided investments in conventional capacity resources in order to maintain resource adequacy. Each renewable resource provides a certain amount of capacity in peak periods (dependent on the type of generation); this capacity results in avoided construction of new conventional units to meet peak loads. The capacity value of a resource is a function of its availability during peak load hours and the carrying cost of a combustion turbine, which E3 uses as a proxy for the cost of capacity. The capacity values assigned to categories of resources can be found in rows 102 to

172 of the "ProForma" tab of the 33% RPS Calculator. The capacity values assigned to CA resources are intended to be as consistent as possible with California's adopted Net Qualifying Capacity methodology,

The ranking cost for each resource is translated to a cost score by assigning a score of 0 to a resource with a $0 (or less) green premium, and a score of 100 to the LCOE of the most expensive solar PV resource (representing a backstop technology). The cost score for each resource is a linear interpolation between these two endpoints.

Environmental Score

As with the Implementation Analysis, this update attempts to take into account environmental concerns with an infrastructure development as potentially massive as that required to achieve a 33% RPS. Ongoing efforts, including the Desert Renewable Energy Conservation Plan (DRECP) and the Bureau of Land Management's Solar Programmatic Environmental Impact Statement (PEIS) are examining these factors in a scientific and rigorous way, and will provide direction to developers in coming months and years. In the absence of results from those efforts, however, Aspen and staff have updated the 2009 methodology as described in detail in Appendix E, relying in part on information gleaned from the environmental review of several renewable generation facilities now requesting certification by the Energy Commission.

The adopted methodology continues to rely heavily on RETI's environmental ratings. Among the most significant changes, however, is that environmental scores are now specific to each pairing of location and resource type, so that a project-specific score can be created. This was necessary given the project-specific ranking methodology used in the analysis, and also reflects the fact that environmental concerns and potential impacts on factors such as sensitive species will vary with both the choice of technology and the site of development. While not in any way intended or adequate to reflect project-specific environmental assessments, this methodology attempts to capture some of the risk and uncertainty that environmental concerns introduce into the project development process.

Commercial Score

The commercial score is used to distinguish those projects currently under contract, negotiation or development by IOUs and POUs, from the generic resources included in the model: the former is assigned a commercial score of 0 (a "better" score, for purposes of ranking), while the latter is assigned a commercial score of 100. This scoring distinction is included to allow for scenario analysis of compliance portfolios that rely to differing extents upon the resources already in the permitting process.

Timing Score (Online Date)

As described in Section II.7, timing scores were developed by the Commission to distinguish between projects that can be brought online within a relatively short timeframe from those that are unlikely to be developed soon due to expected delays or extensions in the generation and transmission development process. Distributed resources and resources that can be delivered over existing transmission perform better on the timing assessment, relative to resources requiring major new transmission lines.

II.8.2 Resource Ranking and Selection Methodology

Resource ranking and selection is carried out differently for each scenario. The model first calculates the cost, commercial, environmental and timing scores as discussed above based on user-defined inputs. It then calculates a weighted-average project score for each resource based on user-defined weights that sum to 100%. For example, if the user selects 25% for each of the four metrics, the model will score resources evenly across the four metrics. If the user selects 85% for cost and 5% for commercial, environmental and timing, the model will select a resource mix based heavily on the cost metric. The following table lists the weights used for each required Scenario:

Table 9. Score Weights, by Scenario

Scenario	Cost Weight	Commercial Weight	Environmental Weight	Timing Weight
Trajectory	20%	60%	20%	0%
Cost-Constrained	100%	0%	0%	0%
Environmentally-Constrained	0%	0%	100%	0%
Time-Constrained	0%	0%	5%	95%

The Trajectory Scenario gives some weight to cost and environmental concern to account for the impact these factors may have on the viability of those commercial projects that are very early in the development process and may not yet even have contracts. The Time-Constrained Scenario includes environmental score essentially as a tie-breaker, given the limited differentiation that exists among the timing scores, which depend only upon first full expected year of operation. The environmental criterion was chosen as the tiebreaker given the impact that environmental concerns could have on a project's permitting and construction timelines.

As discussed above, CREZ resources are ranked and selected first to make use of any existing available transmission capacity from a zone. Remaining resources in the zone are selected in increments to fill transmission bundles.

In the ranking, projects from the Discounted Core are always ranked higher than all other commercial and theoretical projects. Once capacity has been allocated (either on existing or new transmission) to all of the Discounted Core projects in a zone, capacity is allocated to commercial and generic projects. On existing transmission and minor upgrades, the remaining commercial projects compete with theoretical projects based on their score; on potential new lines, the remaining commercial projects are ranked above all the theoretical projects. Thus, commercial projects (particularly Discounted Core projects that didn't meet the threshold for forcing in new transmission, as described in Section II.4.2) are much more likely to be assigned to lower-cost transmission bundles than are generic projects.

After all of the commercial projects have been included, generic projects are selected to fill any remaining capacity created by the assumed transmission upgrades. Aggregate scores for each of the 4 metrics are then calculated for each CREZ bundle, and the bundles then compete against non-CREZ resources and RECs for inclusion in each 33% scenario.

III Results

This section presents the portfolio of resources selected for each of 7 scenarios, along with the scenario ranking metrics resulting from the modeling process described above. The tables summarize the resources selected in various ways, and allow for easy comparison across scenarios.

The results show that each scenario scores best on the criterion that defines the policy goal for that scenario, e.g., the cost-constrained case has the lowest cost, the environmentally-constrained case the lowest environmental impact, the time-constrained case has the lowest time score, and the trajectory case has the most commercial interest. Accordingly, there is significant variety across the scenarios as to the types of resources selected by the model to meet the policy goal of each scenario.

Table 10. Comparison of Scenario Scores

Scenario	Scenario Score, by Ranking Metric			
	Cost	Environmental Concern	Commercial Interest	Timing
33% Trajectory	20.3	29.2	6.3	50.7
33% Environmentally-Constrained	28.6	14.3	47.9	53.0
33% Cost-Constrained	15.4	20.9	37.8	47.5
33% Time-Constrained	19.0	23.2	36.9	42.3
33% Trajectory - Low Load	17.9	25.9	0.5	45.8
33% Trajectory - High Load	19.5	27.6	17.0	55.6
20% Trajectory	18.3	24.6	0.8	42.3

Table 11. Scenario Composition, by Generation Project Status

Scenario	Scenario Composition by Generation Project Status (MW)				Scenario Composition by Generation Project Status (GWh/yr)			
	Discounted Core	Commercial Non-Core	Generic	Total	Discounted Core	Commercial Non-Core	Generic	Total
33% Trajectory	9,013	9,192	1,061	19,266	23,376	27,484	3,409	54,269
33% Environmentally-Constrained	8,109	1,991	10,429	20,530	21,121	7,143	26,005	54,269
33% Cost-Constrained	8,378	3,864	5,251	17,493	21,892	11,880	20,497	54,269
33% Time-Constrained	7,951	4,747	7,104	19,802	20,669	13,548	20,052	54,269
33% Trajectory - Low Load	8,384	7,523	102	16,009	21,905	23,426	249	45,581
33% Trajectory - High Load	9,025	9,695	2,044	20,763	23,405	28,868	10,684	62,957
20% Trajectory	8,061	2,127	100	10,287	20,981	7,991	244	29,216

Table 12. Scenario Composition, by Transmission Delivery Type

Scenario	Scenario Composition by Transmission Delivery Type (MW)					Scenario Composition by Transmission Delivery Type (GWh/yr)				
	Accomodated on Existing System	Minor Upgrades	New Lines	Out-of-State Undelivered RECs	Total	Accomodated on Existing System	Minor Upgrades	New Lines	Out-of-State Undelivered RECs	Total
33% Trajectory	8,517	2,362	3,295	5,093	19,266	22,398	8,722	8,777	14,372	54,269
33% Environmentally-Constrained	15,327	2,384	-	2,818	20,530	37,606	6,852	-	9,811	54,269
33% Cost-Constrained	8,034	2,661	-	6,798	17,493	23,424	10,682	-	20,163	54,269
33% Time-Constrained	10,291	937	-	8,574	19,802	27,547	2,095	-	24,627	54,269
33% Trajectory - Low Load	8,517	2,362	38	5,093	16,009	22,398	8,722	88	14,372	45,581
33% Trajectory - High Load	8,517	2,362	4,791	5,093	20,763	22,398	8,722	17,465	14,372	62,957
20% Trajectory	6,446	1,444	-	2,398	10,287	17,937	4,043	-	7,236	29,216

Tables 13 and 14. Scenario Composition, by Technology and Location

	Scenario Composition by Technology and Location (MW)													
	33% Trajectory		33% Environmentally-Constrained		33% Cost-Constrained		33% Time-Constrained		33% Trajectory - Low Load		33% Trajectory - High Load		20% Trajectory	
	In-State	Out-of-State	In-State	Out-of-State	In-State	Out-of-State	In-State	Out-of-State	In-State	Out-of-State	In-State	Out-of-State	In-State	Out-of-State
Biogas	178	-	178	66	168	73	172	73	178	-	178	-	178	-
Biomass	126	34	404	156	291	129	212	103	126	34	126	34	126	34
Geothermal	667	154	240	270	797	202	-	158	617	154	1,591	154	113	154
Hydro	-	16	-	132	-	14	-	223	-	16	-	16	-	16
Large Scale Solar PV	3,527	340	2,315	340	1,549	340	2,543	340	3,147	340	3,684	340	1,509	340
Small Solar PV	1,052	-	9,077	-	1,052	-	2,322	-	1,052	-	1,052	-	1,052	-
Solar Thermal	3,589	400	1,072	400	1,279	400	1,084	400	1,790	400	3,589	400	1,034	400
Wind	5,034	4,149	4,426	1,454	5,559	5,639	4,895	7,276	4,006	4,149	5,450	4,149	3,877	1,454
Total	***14,173***	***5,093***	***17,711***	***2,818***	***10,696***	***6,798***	***11,228***	***8,574***	***10,916***	***5,093***	***15,670***	***5,093***	***7,889***	***2,398***

	Scenario Composition by Technology and Location (GWh/yr)													
	33% Trajectory		33% Environmentally-Constrained		33% Cost-Constrained		33% Time-Constrained		33% Trajectory - Low Load		33% Trajectory - High Load		20% Trajectory	
	In-State	Out-of-State	In-State	Out-of-State	In-State	Out-of-State	In-State	Out-of-State	In-State	Out-of-State	In-State	Out-of-State	In-State	Out-of-State
Biogas	1,248	-	1,248	489	1,178	546	1,206	546	1,248	-	1,248	-	1,248	-
Biomass	938	250	3,007	1,152	2,167	961	1,577	757	938	250	938	250	938	250
Geothermal	4,843	1,116	1,837	1,945	6,066	1,463	-	1,135	4,458	1,116	11,951	1,116	819	1,116
Hydro	-	48	-	404	-	65	-	737	-	48	-	48	-	48
Large Scale Solar PV	7,808	864	5,179	864	3,485	864	5,719	864	6,839	864	8,210	864	3,382	864
Small Solar PV	2,105	-	18,050	-	2,105	-	4,565	-	2,105	-	2,105	-	2,105	-
Solar Thermal	8,512	935	2,627	935	3,112	935	2,656	935	4,306	935	8,512	935	2,540	935
Wind	14,442	11,159	12,509	4,023	15,993	15,330	13,919	19,653	11,313	11,159	15,619	11,159	10,947	4,023
Total	***39,896***	***14,372***	***44,458***	***9,811***	***34,106***	***20,163***	***29,642***	***24,627***	***31,208***	***14,372***	***48,585***	***14,372***	***21,980***	***7,236***

Table 15. Scenario Composition, by Resource Location

	Resources Selected by Scenario (MW)							Resources Selected by Scenario (GWh/yr)						
	33% Trajectory	33% Environ-mentally-Constrained	33% Cost-Constrained	33% Time-Constrained	33% Trajectory - Low Load	33% Trajectory - High Load	20% Trajectory	33% Trajectory	33% Environ-mentally-Constrained	33% Cost-Constrained	33% Time-Constrained	33% Trajectory - Low Load	33% Trajectory - High Load	20% Trajectory
Tehachapi	4,445	3,491	3,491	4,150	4,445	4,445	2,976	11,465	10,019	10,019	11,437	11,465	11,465	8,413
Imperial	1,202	347	1,125	-	1,125	2,625	207	6,193	2,092	6,740	-	5,733	14,677	1,053
Northwest	2,359	838	2,359	2,359	2,359	2,359	630	6,044	2,676	6,510	6,308	6,044	6,044	1,619
Pisgah	1,775	275	275	275	313	1,775	275	4,169	643	643	643	731	4,169	643
NonCREZ	1,074	599	1,211	1,080	1,074	1,074	471	3,944	3,489	5,316	4,342	3,944	3,944	2,536
Solano	1,129	300	300		300	1,129	300	3,473	860	992	-	860	3,473	860
Riverside East	1,042	1,042	1,042	1,500	1,042	1,042	1,042	2,433	2,433	2,433	3,542	2,433	2,433	2,433
Alberta	886	450	450	886	886	886	450	2,422	1,230	1,230	2,422	2,422	2,422	1,230
Mountain Pass	888	-	-	-	-	888	-	2,178	-	-	-	-	2,178	-
Carrizo South	900	900	900	900	900	900	900	1,960	1,959	1,960	1,959	1,960	1,960	1,960
Utah-Southern Idaho	258	258	258	258	258	258	244	1,379	1,446	1,417	1,060	1,379	1,379	1,345
San Diego South	400	400	699	400	400	400	400	1,227	1,227	2,096	1,227	1,227	1,227	1,227
Colorado	420	-	600	1,371	420	420		1,169	-	1,679	3,767	1,169	1,169	
Nevada C	450	549	500	549	450	450	450	1,062	1,745	1,403	1,745	1,062	1,062	1,062
Distributed Solar - PG&E	500	1,757	500	790	500	500	500	1,015	3,313	1,015	1,546	1,015	1,015	1,015
Montana	300	300	300	300	300	300	300	994	994	994	994	994	994	994
Distributed Solar - SCE	500	2,345	500	895	500	500	500	991	4,658	991	1,771	991	991	991
Arizona	290	290	872	1,390	290	290	290	737	737	2,171	3,448	737	737	737
Wyoming	96	4	461	461	96	96		317	27	1,460	1,465	317	317	
New Mexico	32	78	947	947	32	32	32	238	573	2,927	3,034	238	238	238
Round Mountain	78	100	100	100	78	78	78	221	383	374	383	221	221	221
Palm Springs	77	178	178	178	77	77	77	217	532	532	532	217	217	217
San Bernardino - Lucerne	49	140	261	261	49	49	49	168	845	753	868	168	168	168
Kramer	62	62	62	62	62	62	62	145	145	145	145	145	145	145
Distributed Solar - SDGE	52	397	52	127	52	52	52	99	798	99	249	99	99	99
British Columbia	2	52	50	52	2	2	2	12	384	372	384	12	12	12
Remote DG (Brownfield) - SDGE	-	78	-	4	-	-	-	-	171	-	9	-	-	-
Remote DG (Brownfield) - PG&E	-	1,842	-	100	-	-	-	-	3,740	-	204	-	-	-
Remote DG (Brownfield) - SCE	-	564	-	31	-	-	-	-	1,258	-	69	-	-	-
Distributed Solar - Other	-	1,522	-	344	-	-	-	-	2,890	-	650	-	-	-
Westlands	-	800	-	-	-	-	-	-	1,781	-	-	-	-	-
Remote DG (Brownfield) - Other	-	571	-	31	-	-	-	-	1,222	-	67	-	-	-
Fairmont	-	-	-	-	-	74	-	-	-	-	-	-	204	-
Total In-State	14,173	17,711	10,696	11,228	10,916	15,670	7,889	39,896	44,458	34,106	29,642	31,208	48,585	21,980
Total Out-of-State	5,093	2,818	6,798	8,574	5,093	5,093	2,398	14,372	9,811	20,163	24,627	14,372	14,372	7,236
Total	***19,266***	***20,530***	***17,493***	***19,802***	***16,009***	***20,763***	***10,287***	***54,269***	***54,269***	***54,269***	***54,269***	***45,581***	***62,957***	***29,216***

IV Next Steps ***(removed)***

Appendix A

Load Forecast and Demand-Side Assumptions

A1: 2009 Integrated Energy Policy Report Demand Forecast

A2: Assumptions about Load-Modifying Demand-Side Resources

A1: 2009 Integrated Energy Policy Report Demand Forecast

The demand forecast used for this analysis can be found in Table 1.1c of the Energy Commission's California energy Demand 2010-2020, available here: http://www.energy.ca.gov/2009publications/CEC-200-2009-012/CEC-200-2009-012-CMF.PDF. To calculate RSP-obligated sales, E3 used "Total Statewide Retail Deliveries excluding pumping load", minus forecasted sales from small load-serving entities. Any load-serving entity with 2020 retail sales less than 200 GWh/yr qualifies as a small LSE and is exempt from compliance with the RES; the LSEs that E3 included in that category are shown below:

Load Serving Entity	2020 Retail Sales (GWh)
City of Shasta Lake	193
City of Banning	184
Bear Valley Electric Service	176
Plumas-Sierra Rural Electric Cooperation	172
Truckee-Donner Public Utility District	163
Lassen Municipal Utility District	153
City of Lompoc	151
Boulder City/Parker Davis	137
City of Ukiah	133
Trinity Public Utility District	99
Surprise Valley Electrification Corporation	92
City of Healdsburg	76
City of Rancho Cucamonga	67
Moreno Valley Utilities	65
Anza Electric Cooperative, Inc.	62
City of Needles	58
Port of Oakland	54
City of Cerritos	48
City of Gridley	42
Victorville Municipal	32
Calaveras Public Power Agency	30
Tuolumne County Public Power Agency	29
City of Biggs	20
Port of Stockton	14
Valley Electric Association, Inc.	7
Mountain Utilities	4
Total	**2,260**

A2: Assumptions about Load-Modifying Demand-Side Resources

The assumptions described in Section II.3.3 result in the following reductions to the demand forecast referenced above, to create the load forecast used for the four "standard" 33% by 2020 RPS Scenarios and the one 20% by 2020 Scenario.

Load Decrement (GWh)	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
EE Decay replacement	169	313	488	693	913	1,093	1,254	1,391	1,504	1,598	1,684	1,769	1,861
EE Uncommitted - IOU	0	0	0	0	0	1,613	2,823	3,983	5,490	7,294	9,101	10,607	11,867
EE Uncommitted - Non-IOU	0	0	0	0	0	403	706	996	1,373	1,824	2,275	2,652	2,967
Incremental DG	0	0	0	0	0	0	0	0	0	0	0	0	0
CHP	0	0	0	756	1,511	2,267	3,022	3,778	4,533	5,289	6,045	6,800	7,556
Total	**169**	**313**	**488**	**1,449**	**2,424**	**5,376**	**7,805**	**10,148**	**12,900**	**16,005**	**19,105**	**21,828**	**24,251**

As described in Section II.3.3, for the low and high load sensitivities performed around the 33% Trajectory Scenario, total RPS-eligible demand was assumed to be 10% lower and 10% higher, respectively, than the standard demand level that results from the retail sales and load decrements referenced above.

Appendix B

RPS Generation Resource Assumptions

B1: RPS Baseline: Existing Generation and Retirement Assumptions

B2: Planned Procurement by Publicly-Owned Utilities

B3: Energy Division Database

B4: Statewide Solar PV Resource Assessment

B5: Renewable Energy Transmission Initiative Phase 2B List of Resources

B6: Out-of-State Renewable Energy Credit Supply Estimates

B1: RPS Baseline – Existing Generation and Retirement Assumptions

	Energy (GWh)	Source
Total In-State Renewable Generation, 2008	28,804	*2008 Net System Power Report* (p.5)
Utilities Claims for Out-of-State Renewable Generation, 2008 (Northwest)	1,728	*2008 Net System Power Report* (p.A-2)
Utilities Claims for Out-of-State Renewable Generation, 2008 (Southwest)	740	*2008 Net System Power Report* (p.A-2)
Total Existing Renewable Generation, 2008	***31,272***	
New In-State Resources Online in 2009	992	ED Database
New Out-of-State Resources Online in 2009 with Long-Term Contracts	350	ED Database
Total Existing Renewable Generation, 2009	***32,613***	

B2: POU Data

Data on planned procurement of renewables has been gathered for a number of the larger POUs in California. This data was obtained from the California Energy Commission and gives POU renewable resource plans for 2010 and 2018; the data has been adjusted in order to incorporate it in to the RPS model, which uses 2008 and 2020 as its starting and ending points. The table below shows an overview of the distribution of POU planned procurement incremental to 2008 levels by resource type. There are 140 MW of small hydro included in the POUs's plans that are excluded from this table and the model, due to uncertainty about the current RPS eligibility of those resources, given their location in British Columbia.

	In-State		Out-of-State	
	MW	GWh	MW	GWh
Biogas	145	1,013	-	-
Biomass	-	-	2	12
Geothermal	550	3,884	42	299
Hydro - Small	-	-	16	48
Solar Thermal	358	836	-	-
Solar PV	-	-	-	-
Wind	504	1,455	648	1,871
Total	***1,557***	***7,188***	***708***	***2,230***

B3: Energy Division Database

The Energy Division (ED) Database tracks the IOU solicitations for renewables and includes both CREZ and non-CREZ resources. The database includes both public projects that are in advanced stages of permitting and confidential shortlisted projects. A public list of the RPS contracts approved and under review by the Commission is available here: http://www.cpuc.ca.gov/PUC/energy/Renewables. The tables below show an overview of the distribution of the resources included in the RPS model from the ED Database.

CREZ	MW	GWh
Alberta	1,018	2,782
Arizona	290	737
British Columbia	114	290
Carrizo South	849	1,830
Colorado	420	1,169
Distributed Solar - PG&E	244	503
Distributed Solar - SCE	140	323
Fairmont	296	752
Imperial	1,213	4,019
Inyokern	242	566
Kramer	250	584
Montana	300	994
Mountain Pass	710	1,720
Nevada C	450	1,062
New Mexico	32	238
NonCREZ	573	2,166
Northwest	3,162	8,089
Palm Springs	182	514
Pisgah	1,700	3,974
Riverside East	1,042	2,433
Round Mountain	78	221
San Bernardino - Lucerne	49	168
San Diego South	415	1,269
Santa Barbara	83	233
Solano	240	690
Tehachapi	4,173	10,697
Utah-Southern Idaho	90	229
Total	**18,354**	**48,251**

	Signed - Approved		Signed - Pending Approval		In Negotiations		*Total Projects Included in RPS Calculator*	
	MW	GWh	MW	GWh	MW	GWh	*MW*	*GWh*
Biogas	21	144	13	91	-	-	**34**	**235**
Biomass	81	603	90	673	-	-	**171**	**1,276**
Geothermal	139	1,005	40	289	-	-	**179**	**1,294**
Hydro	-	-	-	-	-	-	**-**	**-**
Large Scale Solar PV	1,138	2,574	1,421	3,477	1,596	3,350	**4,155**	**9,400**
Small Solar PV	7	14	268	587	109	225	**384**	**826**
Solar Thermal	1,615	3,775	2,434	5,812	-	-	**4,049**	**9,587**
Wind	2,950	8,313	2,521	6,650	3,910	10,668	**9,382**	**25,632**
Total	**5,951**	**16,428**	**6,788**	**17,580**	**5,615**	**14,243**	***18,354***	***48,251***

B4: Statewide Solar PV Resource Assessment

The assessment of the solar PV resource potential was adjusted from the original 33% RPS Implementation Analysis approach. PV potential estimates were identified as 'Easy-to-connect' and 'Harder-to-connect' and were further broken down into 4 size categories (0.5 – 2 MW rooftop, 0.5 – 2 MW ground-mounted, 2 – 5 MW ground mounted, and 5 – 20 MW ground mounted) and 4 locations across California (Desert, Central Valley, North Coast, South Coast). The proprietary utility substation data and the large rooftop potential data from satellite imagery were screened for 'easy' interconnection, participation, and penetration. Existing PV programs including the California Solar Initiative (CSI), Self-Generation Incentive Program (SGIP) and other utility PV programs were accounted for. The table below shows the results of the solar PV resource assessment:

Easy to Interconnect						Harder to Interconnect	
Ground Mounted (5-20MW)	Ground Mounted (2-5MW)	Ground Mounted (0.5-2MW)	Large Rooftop	Small Rooftop	Easy to Interconnect Total	RETI projects (>30%)	TOTAL
2,107	200	43	3,671	977	6,999	9,167	16,165

The solar PV assessment performed by E3 and Black & Veatch is available here, in PowerPoint form: http://www.cpuc.ca.gov/NR/rdonlyres/A0CBE958-E2C4-4AC7-9D56-3AB4D14D723D/0/BVE3PVAssessment.ppt.

B5: RETI Phase 2B list of resources

The list of RETI resources, costs, and other detail is available on the RETI website, http://www.energy.ca.gov/reti/documents/phase2B/CREZ_name_and_number.xls.

B6: Out-of-State REC Supply

The RPS model assumes that a subset of the out-of-state candidate resources is available to California for use as REC-only transactions. The potential out-of-state supply of RECs is constrained by several criteria. It is unlikely that any resource that would require significant new transmission would be developed for RECs alone. For this reason, the highest quality wind resources in each zone—which are generally also the most remote—are excluded from the potential supply of RECs. These remote, high-quality wind resources are available for development for delivery to California if a new transmission line from that zone to California is selected in the ranking process.

The supply of potential REC resources—especially wind—is further limited by the physical operating constraints of the grid. There is a limit to the amount of wind that an area can easily integrate before it begins to have major effects on market operations and integration costs increase substantially. As that limit is approached, it would become increasingly difficult to find a buyer for the energy produced, and the economics of a REC deal based on the "green premium" that is calculated in the model (described in Sections II.6.2 and II.8.1) would no longer apply. E3 has roughly estimated this limit in each out-of-state resource zone by analyzing 2020 production simulations to determine the point at which REC resources would begin to displace baseload generators instead of intermediate gas generators; this gives a good approximation of the point at which market operations would shift dramatically. The capacity of REC resources that can be developed for REC-only deals for California is then capped in each zone at the greater of (1) half of the zone's REC limit reduced by existing installed renewable capacity and (2) existing ED database contracts; these limits are shown in the table below. With these two constraints on supply, the final set of resources that is available as RECs for California is scored using the same methodology as candidate delivered resources. The REC resources then compete against transmission bundles and non-CREZ resources for selection in California's renewable portfolio.[23]

	ED Database RECs	Estimated Near-Term Physical Limits on RPS Supply (MW)	Existing and Near-Term RPS Resources (MW)	RECs assumed available to CA (MW)	Modeled Cap on RECs available to CA (MW)
AB	886	2,211	595	808	886
AZ	740	3,968	90	1,939	1,939
BC	2	1,700	0	850	850
CFE	0	0	0	0	0
CO	420	3,665	922	1,371	1,371
MT	300	738	189	275	300
NM	32	2,135	240	947	947
NV	0	0	50	0	0
NW	2,359	6,461	1,948	2,257	2,359
UT	258	229	135	47	258
WY	96	1,231	308	461	461
Total	**5,093**	**22,337**	**4,477**	**8,955**	**9,372**

[23] See the discussion in Section II.6.2 on the relationship of these assumptions to current policy.

Appendix C

RPS Generation Cost Assumptions

C1: Project Characteristics and Cost Calculator spreadsheet
C2: E3 Capital Cost Tool
C3: PV Cost Calculator

For each renewable resource type included in the RPS model, E3 has developed cost and performance assumptions using data from several sources. E3's general approach in modeling is to use any site-specific public cost and performance information where it is available and to apply generic estimates to resources without site-specific data. The table below shows the source of the generic assumptions for each resource in the model.

Resource Type	Description or Source
Biogas	E3 Capital Cost Tool
Biomass	RETI Project Characteristics and Cost Calculator
Geothermal	RETI Project Characteristics and Cost Calculator
Hydro	E3 Capital Cost Tool
Large Scale Solar PV - Thin Film	PV Cost Calculator
Large Scale Solar PV - Tracking	PV Cost Calculator
Small Scale Solar PV	PV Cost Calculator
Solar Thermal	RETI Project Characteristics and Cost Calculator
Wind	RETI Project Characteristics and Cost Calculator

C1: Project Characteristics and Cost Calculator spreadsheet

RETI maintains the Project Characteristics and Cost Calculator spreadsheet[24], a detailed database with site-specific data on resource potential, cost, and performance in California and similar data for the out-of-state zones in the WECC based on data developed as part of the WREZ transmission modeling efforts. E3 has incorporated each of these individual resources, along with site-specific information on costs (capital, fixed and variable O&M, gen-tie, fuel) and performance (heat rate, capacity factor, on-peak availability) into the RPS model. In addition, E3 uses the Project Characteristics and Cost Calculator to develop generic assumptions for the renewable technologies included in the RPS model that do not have site-specific information from RETI. E3's generic cost and performance assumptions, below, are based on averages of the data in the RETI spreadsheet (table is identical to the updated Table 1, earlier in the report).

Technology	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Variable O&M ($/MWh)	Heat Rate (Btu/kWh)	Capacity Factor	LCOE ($/MWh)
Biogas - Landfill	$ 2,750	$ 130	$ -	12,070	80%	$ 96
Biogas - Other	$ 5,500	$ 165	$ -	13,200	80%	$ 121
Biomass	$ 4,529	$ 93	$ 13	14,749	85%	$ 128
Geothermal	$ 5,155	$ -	$ 35	-	83%	$ 115
Hydro - Small	$ 3,960	$ 30	$ -	-	35%	$ 196
Solar Thermal	$ 5,300	$ 66	$ -	-	27%	$ 202
Wind	$ 2,399	$ 60	$ -	-	32%	$ 99

[24] The RETI Project Characteristics and Cost Calculator can be found here: http://www.energy.ca.gov/reti/documents/phase2B/CREZ_name_and_number.xls

C2: E3 Capital Cost Tool

The E3 Capital Cost Tool was developed in collaboration with WECC's Transmission Expansion Planning Policy Committee (TEPPC) in order to facilitate further analysis of TEPPC's studies of WECC-wide transmission development. The tool contains generic assumptions for a wide range of resources; E3 consulted a large number of sources in the development of these estimates. The tool is used to inform the RPS model's assumptions for resources that are not included in the scope of the RETI analysis; for these resource types, cost and performance information was taken directly from the E3 Capital Cost Tool. The RPS Model also uses the regional multipliers developed in the tool in order to translate generic costs for the WECC into region-specific costs, which vary based on local costs of labor, materials, and construction.

The E3 Capital Cost Tool is available for public download via TEPPC: http://www.wecc.biz/committees/BOD/TEPPC/Shared%20Documents/E3%20Capital%20Cost%20Tool/E3_TEPPC_ProForma_2010-01-17.xls.

C3: PV Cost Calculator

The PV cost calculator tool was developed to accurately calculate the levelized cost of solar PV projects, given user-defined inputs. The financial modeling behind the tool includes features to balance complexity with applicability for a broad range of projects. The PV cost and performance assumptions were developed as a joint effort by E3 and Black and Veatch.

The adopted assumptions and key results of the cost calculator are detailed here: http://www.cpuc.ca.gov/NR/rdonlyres/A0CBE958-E2C4-4AC7-9D56-3AB4D14D723D/0/BVE3PVAssessment.ppt.

The cost calculator is available here: http://www.cpuc.ca.gov/NR/rdonlyres/A52A5A3E-F737-49E1-A4D5-E81ED68F3E41/0/FinalPVProForma.xls.

Appendix D

Transmission Assumptions

D1: California ISO assessment of capacity on existing transmission system, and with minor upgrades

D2: ZECO assessment of capacity over segments of RETI Phase 2A conceptual plan

D3: E3 additions of generic 500kV transmission lines and project-specific cost assumptions

D4: Avoided T&D costs for PV

D1: California ISO assessment of capacity on existing transmission system, and with minor upgrades

In May 2010, the CAISO provided the CPUC with assumptions about the existing capacity on the transmission system that could be used to deliver renewable resources from the various CREZs. The data provided included estimates of the existing capacity without any incremental upgrades and identified those areas in which relatively minor transmission upgrades could provide spare capacity on the system. For those projects, CAISO provided a rough estimate of the total cost of the upgrade. The table provided by the CAISO, which includes the assumptions underlying the numbers, is below.

A rough estimate of available transmission by CREZ, assuming that transmission that has been approved by the ISO Board and the CPUC (if required) is built. So, the full Tehachapi Renewable Transmision Project, Sunrise, and Devers-Midpoint (we'll assume that it meets the ISO's LGIA test) are all assumed built, as well as perhaps some smaller upgrades, to the extent that they've met the approval threshold.

CREZ #	CREZ Name	MW of existing transmission capability with no upgrades	MW of existing transmission capability with minor upgrades not approved by ISO	Description of minor transmission upgrades	Cost of minor upgrade ($)	Comments
14	Carrizo North					No interconnection requests in this area
18	Carrizo South	300	900	reconductoring from Carrizo interconnection Points to Midway and possibly from Morro Bay to Templeton	$100 M	
17	Cuyama					No interconnection requests in this area
2	Lassen North					No interconnection requests in this area
1	Lassen South					No interconnection requests in this area
3	Round Mountain	100	100			
8	Solano	0	300	various reconductorings South of Contra Costa	$100 M	
	Westlands	0	800	reconductor Borden-Gregg 230 kV line	$50 M	
45	Barstow					No interconnection requests in this area
47	Fairmont					No interconnection requests in this area
29	Imperial East					No interconnection requests in this area
31	Imperial North					No interconnection requests in this area
51	Inyokern	0	62	Inyo 115 kV phase shifter replacement and revised existing SPS in North of Lugo	$20 M	
50	Kramer					

37	Iron Mountain					No interconnection requests in this area
25	Owens Valley					No interconnection requests in this area
30	Imperial South	0	1125	install third Imperial Valley 500/230kV bank	$50 M	
34	Needles					No interconnection requests in this area
27	San Diego South	400	761	connect Boulevard substation to new 500/230 kV substation between Imperial Valley and Miguel substations	$60 M	
40	Mountain Pass	0	0			
43	Pisgah	0	275	SPS	$40 M	
44	San Bernardino - Lucerne	261	261			
41	San Bernardino - Baker					No interconnection requests in this area
52	Tehachapi	4500	5825	2nd and 3rd AA banks at Whirlwind	$100 M	
26	San Diego North Central					No interconnection requests in this area
32	Palm Springs	1000	1000			
16	Santa Barbara					No interconnection requests in this area
36	Riverside East	1500	1500			West of Dever reconductoring is needed to go beyond these levels
38	Twentynine Palms					No interconnection requests in this area
46	Victorville					No interconnection requests in this area

Column Heading	**Explanation of information in this column**
MW of existing transmission capability with no upgrades	ISO engineers reviewed previously completed interconnection studies and applied judgement to determine these MW amounts. Total MWs of interconnection requests as well as intermediate amounts of interconnection requests and necessary transmission upgrades associated with these amounts were reviewed to make this determination. If no delivery transmission upgrades were necessary for a particular amount of interconnection requests then this amount was entered into this cell. Generation already in-service was not included in the amount. There may be higher queued non-renewable generation included in this amount.
MW of existing transmission capability with minor upgrades not approved by ISO	These numbers were developed following the same process as above, but if only minor transmission upgrades were necessary for a particular amount of interconnection requests then these upgrades were assumed to be built and the corresponding amount of generation was entered into this cell.
Description of minor transmission upgrades	A description of the minor upgrades assumed to be built, if any, is included here. These minor upgrades have not been approved by the ISO.
Cost of minor upgrade ($)	A very rough cost estimate of the minor upgrades assumed to be built, if any, is included here. These minor upgrades have not been approved by the ISO.

D2: ZECO assessment of capacity over segments of RETI Phase 2A conceptual plan

General Assumptions

The potential MW capacity of each CREZ is listed in Table 2-2 on Page 2-36 of the RETI 2A report. Looking at Table 2-2, the potential 2A CREZ MW capacity totals more than 77,000 MW. Note, only a fraction of this CREZ capacity will be required to deliver the renewable energy requirement for 2020.

Transmission expansion requirements to deliver the CREZ energy to the California utility customers in the RETI 2A report are broken into three groups - several local transmission collector line segment groups to reliably inject the power from the associated local CREZs into the transmission foundation group, transmission foundation group line segment additions to reliably deliver the renewable power between northern and southern California load centers, and delivery group line segment additions to deliver the power within the northern and southern California load centers. Table 3-5 in the RETI 2A report presents the transmission collector line segment groups developed as part of the RETI 2A study and associated CREZ accessed by the transmission collector groups. Line segments developed for each transmission collector group as well as the foundation and delivery groups are listed on Page F-55 in Appendix F, the line segments are described in Appendix G, the line segment costs and mileage are listed in Appendix H, new substations and network upgrades are listed in Appendix I and CREZ injection points and new substations used for the RETI 2A study are listed in Appendix J.

Transmission cost assumptions used in the RETI 2A study for the line segment costs in Appendix H were obtained from Jan Strack of San Diego Gas & Electric Co. Some of these assumptions listed in Table 1 have been used to develop the incremental transmission line segment cost estimates in this work. All new 230 kV line segments are assumed to be double circuit construction as in the RETI 2A study. Line termination costs are assumed to be an adder of 25% to the line segment cost as assumed in the RETI 2A study.

Table 1 - Transmission cost assumptions from RETI 2A Study

Line Segment Description	Line Cost $1000/mi
Cost of 230 kV double circuit towers with one circuit	2000
Cost of second 230 kV circuit on double circuit 230 kV towers	500
Cost of 230 kV double circuit towers with two circuits	2500
Cost of 500 kV single circuit construction	2600
Cost of 500 kV double circuit towers with one circuit	4500
Cost of second 500 kV circuit on double circuit 500 kV towers	500
Cost of 500 kV double circuit towers with two circuits	5000
Adder for "Line Termination" costs	25%

The MW capacity of the transmission line segments employed in the RETI 2A study was not included in the RETI 2A report. The typical range of existing 230 kV transmission line ratings is from 200 - 800 MW[25]. For this high level estimate, existing 230 kV lines will be assumed to have a 500 MW rating per circuit. New and uprated 230 kV lines will be assumed to have a higher line rating of 1000 MW per circuit, which is compatible with the capacity assigned for a potential new 230 kV line included for the Carrizo area upgrades described in Appendix G of the RETI 2A report. The typical range of existing 500 kV transmission line ratings in the above referenced EPRI synthetic utility system report is from 1200 - 2500 MW. Both new and existing 500 kV line capacity is assumed to be 2000 MW per circuit, which is compatible with the ratings of existing 500 kV lines.

The philosophy of this high level, first cut allowable local CREZ estimate is to consider the above assumed transmission ratings for the new transmission collector line segment additions for each line segment along with the assumed ratings of other existing local transmission facilities in the vicinity, when estimating how much power can reliably be injected into the foundation transmission facilities. The simplified transmission reliability considerations are that there must be enough transmission capacity remaining to transmit the power from the local CREZ to the foundation transmission lines with any one of the new or existing single circuit lines out of service. For double circuit lines on the same structures, there must be enough transmission capacity remaining to transmit the power from the local CREZ to the foundation lines with both circuits out of service. Foundation and delivery line segments are assumed to be adequate to deliver the power from the transmission lines to the California load centers in this task. These transmission reliability assumptions used for this simplified high level estimate of allowable local CREZ are compatible with the category B single contingency (N-1) criteria and category C credible double contingency (N-2) criteria presented in the NERC/WECC Planning Standards26 commonly used in WECC detailed bulk power system planning assessments.

The following caveats should be considered when interpreting the accuracy level of the results of this work. The high level estimates of allowable CREZ are based on inspection of the RETI 2A report and maps showing collector line segments added for each of the collector groups along with other existing local transmission corridors. This high level inspection also included review of associated existing transmission facilities shown on a pre 9/11 WSCC one line diagram27 to identify characteristics of existing transmission facilities in the transmission corridors. No power flow, transient or post transient analyses commonly employed in transmission planning assessments have been performed for this high level estimates.

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[25] Table 4-19, page 4-44, *Synthetic Electric utility Systems for Evaluating Advanced Technologies*, EPRI EM-285, Final Report, February 1977.
[26] Table 1, page 24, *Western Electricity Coordinating Council NERC/WECC Planning Standards*, Revised April 10, 2003.
[27] *Western Systems Coordinating Council Map of Principal Transmission Lines*, January 1, 2000.

Carrizo

Table 2 presents the resulting high level estimates of allowable local CREZ MW capacity for the Carrizo Collector Group first assuming the line segments developed in the RETI 2A report, then adding additional transmission facilities to estimate the next incremental increase in allowable local CREZ MW. Reconductoring the Midway - Carrizo 230 kV lines will provide the first 1100 MW as described in Appendix G of the RETI 2A report. Reconductoring the Morro Bay - Gates 230 kV lines will provide the next 1000 MW resulting in a total local allowable local CREZ of about 2100 MW, as also described in Appendix G of the RETI 2A report. Mileage and cost assumptions for these line segment upgrades from the RETI 2A report are also included.

Adding a new 230 kV line from Carrizo to Gates is expected to increase the allowable local CREZ MW capacity another 1000 MW, resulting in a total local allowable local CREZ of about 3100 MW. This line segment addition is also described in Appendix G of the RETI 2A report. Note adding this new approximately 70 mi. line segment to allow the next 1000 MW of local CREZ is expected to cost significantly more than the reconductoring of the existing line segments.

Individual CREZ and transmission considerations

Reconductoring the Midway - Carrizo 230 kV lines is expected to provide adequate transmission capacity for a total of 1100 MW local CREZ installed at Carrizo South and Cuyama . Adding a new 230 kV line from Carrizo to Gates is expected to increase the allowable local CREZ MW capacity another 1000 MW to 2100 MW.

Reconductoring the Morro Bay - Gates 230 kV lines is expected to provide adequate transmission capacity for 1000 MW local CREZ installed at Carrizo North.

Table 2 – Carrizo Collector Group

CREZ Accessed: Carrizo North, Carrizo South, Cuyama

Line Segment	Mileage	Cost $Millions	Allowable CREZ MW
MIDW_CARZ_1	46	31.05	1100
GATE_MBAY_1	70	47.25	1000
Totals RETI 2A	116	78.30	2100
Incremental mi Cost and CREZ	70	175.00	1000
New Totals	186	253.30	3100

North

Table 3 presents the resulting high level estimates of allowable local CREZ MW capacity for the North Collector Group first assuming the line segments developed in the RETI 2A report, then adding additional transmission facilities to estimate the next incremental increase in allowable local CREZ MW. Building a 500 kV line from Collinsville – Tracy, a +/- 500 kV HVDC line from NE Oregon – Collinsville, and a Selkirk, BC - NE Oregon double circuit 500 kV line kV line will provide a total local allowable local CREZ of about 3000 MW. This assumes that there are adequate transmission facilities in the Northern portion of WECC to supply the 3000 MW for a credible N-2 outage in the DC or double circuit portion of the RETI 2A line segments. Mileage and cost assumptions for these line segments show that delivering these CREZ more than 1200 mi. will be costly. If there is serious consideration about delivering a significant amount of these Northern CREZ to California, a detailed transmission study will be required to determine how much the other existing northern WECC transmission facilities can transmit for a credible N-2 outage of these proposed RETI line segments.

Building a second set of line segments, another 500 kV line from Collinsville – Tracy, another +/- 500 kV HVDC line from NE Oregon – Collinsville, and a second Selkirk, BC - NE Oregon double circuit 500 kV line kV line will increase total local allowable local CREZ to about 6000 MW, assuming existing northern WECC transmission facilities can supply 3000 MW for a credible N-2 outage. If northern WECC transmission facilities cannot supply 3000 MW for a credible N-2 outage of the RETI 2A lines, the second set of transmission line segments will firm up the Northern collector lines and allow about 3000 MW of local CREZ during a credible N-2 event on one of the sets of line segments.

Individual CREZ and transmission considerations

Building a 500 kV line from Collinsville – Tracy, a +/- 500 kV HVDC line from NE Oregon – Collinsville, and a Selkirk, BC - NE Oregon double circuit 500 kV line kV line is expected to provide for a total allowable local CREZ of about 3000 MW for CREZ installed in British Columbia and Oregon assuming there are adequate transmission facilities in Northwest WECC. If all the 3000 MW of CREZ are located in Oregon, the Selkirk, BC - NE Oregon double circuit 500 kV line kV line is not required.

The +/- 500 kV HVDC line from NE Oregon – Collinsville is shown going right by the Round Mountain A and B CREZ. Thus, the Round Mountain A and B CREZ are included in both the North and Northeast transmission collector groups. However, my cursory investigation indicates that the Round Mountain A and B CREZ should not be included in the North collector group, because of expected high costs to connect the CREZ in the middle of the DC line.

Instead the Round Mountain A and B CREZ can be connected to the Northeast transmission collector group or be connected to existing transmission facilities without adding any of the North collector group transmission lines. There are two existing 500 kV lines and the Round Mountain substation in the vicinity of the Round Mountain CREZ which could be used to interconnect these CREZ. For example, the Round Mountain A and B CREZ could be connected to the Round Mountain substation. See the Northeast collector group discussion for potential mileage and cost estimates for the Round Mountain trunk-lines.

These assumptions would be similar to connect to the ZETA1 subatation, which is about a mile away from the Round Mountain substation .

Table 3 – North Collector Group

CREZ Accessed: British Columbia, Oregon, Round Mountain

Line Segment	Mileage	Cost $Millions	Allowable CREZ MW
COLL_TRCY2_1	40	130.00	
NEO_COLL_1	640	2080.00	
SELK_NEO_1	270	843.75	
SELK_NEO_2	270	843.75	
Totals RETI 2A	1220	3897.50	3000
Incremental mi Cost and CREZ	1220	3897.50	3000
New Totals	2440	7795.00	6000

Northeast

Table 4 presents the resulting high level estimates of allowable local CREZ MW capacity for the Northeast Collector Group first assuming the line segments developed in the RETI 2A report, then adding additional transmission facilities to estimate the next incremental increase in allowable local CREZ MW. The RETI 2A line segments consist of a single circuit 500 kV line from Olinda - Dillard Rd, a single circuit 500 kV line from Zeta1 – Olinda, a short 500 kV connection from Zeta1 - Round Mountain. Adding these 500 kV lines is expected to result in a total local allowable local CREZ of about 2000 MW. These lines are part of the TANC project, which is no longer actively being pursued I believe.

Adding a second set of these line segments, another single circuit 500 kV line from Olinda - Dillard Rd, another single circuit 500 kV line from Zeta1 – Olinda, and another short 500 kV connection from Zeta1 - Round Mountain Sub is expected to increase the allowable local CREZ MW capacity another 2000 MW, resulting in a total local allowable local CREZ of about 4000 MW.

Individual CREZ and transmission considerations

The key issue for this transmission collector group is how to transmit the power from the local CREZ to the ZETA1 substation.

Round Mountain A CREZ could be connected to the ZETA1 substation with a single circuit 230 kV approximately 50 mi. long trunk-line costing about $125 million.

Round Mountain B CREZ could be connected to the ZETA1 substation with a single circuit 230 kV approximately 10 mi. long trunk-line costing about $25 million.

On Page G-75 of the RETI 2A report, Lassen North and South CREZ are shown connected to the ZETA1 substation with two 80-100 mi. 500 kV collector lines costing up to about $650 million to maintain N-1 reliability. This transmission would also apply to other CREZ in northern Nevada.

Table 4 – Northeast Collector Group

CREZ Accessed: Round Mountain A&B, Lassen N&S, N Nevada

Line Segment	Mileage	Cost $Millions	Allowable CREZ MW
OLND_DILL_1	183	594.75	
ZETA1_OLND_1	42	136.50	
ZETA1_RDMT_1	1	3.25	
Totals RETI 2A	226	734.50	2000
Incremental mi Cost and CREZ	226	734.50	2000
New Totals	452	1469.00	4000

Inyo

Table 5 presents the resulting high level estimates of allowable local CREZ MW capacity for the Inyo Collector Group first assuming the line segments developed in the RETI 2A report, then adding additional transmission facilities to estimate the next incremental increase in allowable local CREZ MW. The RETI 2A line segments consist of a building a 230 kV line using 500 kV construction from Control - Lone Pine, building a 230 kV line using 500 kV construction from Inyokern – Kramer, and building a 230 kV line using 500 kV construction from Lone Pine - Inyokern. Adding these 230 kV lines is expected to result in a total local allowable local CREZ of about 500 MW, assuming that the parallel existing 230 kV is limiting with an outage of these new lines.

Adding a second set of single circuit 500 kV line segments from Control - Lone Pine, Inyokern - Kramer, Lone Pine - Inyokern, and operating both sets of lines at 500 kV is expected to increase the allowable local CREZ MW capacity to 2000 MW, an incremental increase of 1500 MW.

Individual CREZ and transmission considerations

The transmission collector line segments proceed in series southward from Control to Lone Pine to Inyokern to Kramer. Although the new 230 kV line segments will have a rating of about 1000 MW when operated at 230 kV, total local CREZ is limited to 500 MW due to the line capacity of an existing parallel 230 kV line. Since the collector line segments are constructed using 500 kV construction, the plan should be to construct additional 500 kV transmission collector segments to access more than 500 MW of local CREZ. If a second set of 500 kV line segments are built and the two sets of line segments are operated at 500 kV in parallel, the above local CREZ totals will increase to about 2000 MW.

Kramer is near the foundation transmission system and Kramer CREZ can be accessed through the foundation system as well as the Inyo collector group. Several thousand MW of Kramer CREZ can be connected directly to the foundation transmission system without connecting to the transmission collector system.

Accessing Inyokern CREZ requires building the Inyokern – Kramer line segment. Assuming only the Inyokern – Kramer line segment is built as described in the RETI 2A report, the collector system can reliably inject a total of about 500 MW of Inyokern CREZ and any Kramer CREZ connected to the Inyo collector group into the foundation system. If a second set of 500 kV line segments are built from Inyokern – Kramer and the two sets of line segments are operated at 500 kV in parallel, the total local CREZ at Inyokern will increase to about 2000 MW, or 1500 MW, with an additional 500 MW total CREZ at Owens Valley and Central Nevada.

Accessing the Owens Valley CREZ requires building the Inyokern – Kramer line segment and the Lone Pine – Inyokern line segment. Assuming the Inyokern – Kramer line segment and the Lone Pine – Inyokern line segment are built, the collector system can reliably inject a total of about 500 MW of Owens Valley CREZ, Inyokern CREZ and any Kramer CREZ connected to the Inyo collector group into the foundation system. If a second set of 500 kV line segments are built from Lone Pine - Inyokern – Kramer and the two sets of line segments are operated at 500 kV in parallel, the total local CREZ at Inyokern and

Owens Valley will increase to about 2000 MW, or 1500 MW, with an additional 500 MW total CREZ in Central Nevada.

Accessing the Central Nevada CREZ requires building the Inyokern – Kramer line segment, the Lone Pine – Inyokern line segment, and the Control – Lone Pine line segment. Assuming the Inyokern – Kramer line segment, the Lone Pine – Inyokern line segment, and the Control – Lone Pine line segment are built, the collector system can reliably inject a total of about 500 MW of Central Nevada CREZ, Owens Valley CREZ, Inyokern CREZ and any Kramer CREZ connected to the Inyo collector group into the foundation system. If a second set of 500 kV line segments are built from Control - Lone Pine - Inyokern – Kramer and the two sets of line segments are operated at 500 kV in parallel, the total local CREZ at Inyokern, Owens Valley and Central Nevada will increase to about 2000 MW.

Note this transmission expansion from Control – Lone Pine – Inyokern – Kramer could temporarily transmit approximately 1000 MW of CREZ while operating at 230 kV. However, it would not maintain N-1 transmission system reliability.

Table 5 – Inyo Collector Group

CREZ Accessed: Central Nevada, Inyokern, Owens Valley, Kramer

Line Segment	Mileage	Cost $Millions	Allowable CREZ MW
CONT_LPIN_1	45	202.50	
INYK_KRAM_1	66	214.50	
LPIN_INYK_1	53	238.50	
Totals RETI 2A	164	655.50	500
Incremental mi Cost and CREZ	164	533.00	1500
New Totals	328	1188.50	2000

MtPass

Table 6 presents the resulting high level estimates of allowable local CREZ MW capacity for the MtPass Collector Group first assuming the line segments developed in the RETI 2A report, then adding additional transmission facilities to estimate the next incremental increase in allowable local CREZ MW. The RETI 2A line segments consist of a building a 500 kV line from Baker - Barstow, building a 500 kV line from Barstow - Lugo, building a 500 kV line from Mountain Pass – Baker and building a 500 kV line from Mountain Pass - Eldorado. Adding these 500 kV lines is expected to result in a total local allowable local CREZ of about 2000 MW.

Adding a second set of single circuit 500 kV line segments from Baker - Barstow, Barstow - Lugo, Baker - Mountain Pass and Mountain Pass – Eldorado is expected to increase the allowable local CREZ MW capacity another 2000 MW, resulting in a total local allowable local CREZ of about 4000 MW.

Individual CREZ and transmission considerations

The 500 kV line segments result in a 500 kV path from Eldorado – Mt. Pass – Baker – Barstow – Lugo. Eldorado is a large substation with two existing 500 kV lines heading to the LA area and two other 500 kV lines heading elsewhere in WECC. Lugo is part of the foundation group. With any collector line segment out of service it is expected that 2000 MW can be delivered into the foundation system either through Lugo or via the 500 kV lines out of Eldorado.

The Victorville CREZ is located near the foundation transmission system and is its power expected to be injected directly into the foundation network rather than through the collector lines.

Mt. Pass, Baker and Barstow CREZ are expected to be accessed by the Mt. Pass collector group transmission lines. This high level assessment indicates that a total of about 2000 MW at these three CREZ locations can be reliably injected into the foundation lines. If a second set of collector lines is installed, the total allowable CREZ can be increased to about 4000 MW.

Considering the CREZ individually, Mt. Pass is about 150 mi. from Lugo. 2000 MW of Mt. Pass CREZ could be probably be reliably injected into Eldorado substation with two 32 mi. 500 kV line segments costing about $248 Million, and delivered to the foundation system via the existing 500 kV transmission system.

Barstow is about 50 mi. from Lugo. 2000 MW of Barstow CREZ could be reliably delivered to Lugo with two 51 mi. 500 kV line segments from Lugo – Barstow costing about $574 million.

Baker is about 100 mi. from Lugo. 2000 MW of Barstow plus Baker CREZ could be reliably delivered to Lugo with two 51 mi. 500 kV line segments from Lugo – Barstow and two 50 mi. 500 kV line segments from Barstow – Baker costing about $962 million. Note this alternative is more expensive than building the transmission line segments from Lugo – Barstow – Baker – Mt. pass – Eldorado in shown in Table 6.

Table 6 – MtPass Collector Group

CREZ Accessed: Mountain Pass, Baker, Barstow, Victorville

Line Segment	Mileage	Cost $Millions	Allowable CREZ MW
BAKR1_BARS1_1	50	193.75	
BARS1_LUGO_1	51	286.88	
MTPS1_BAKR1_1	50	193.75	
MTPS1_ELDO_1	32	124.00	
Totals RETI 2A	183	798.38	2000
Incremental mi Cost and CREZ	183	594.75	2000
New Totals	366	1393.13	4000

BarrenRidge

Table 7 presents the resulting high level estimates of allowable local CREZ MW capacity for the BarrenRidge Collector Group first assuming the line segments developed in the RETI 2A report, then adding additional transmission facilities to estimate the next incremental increase in allowable local CREZ MW. The RETI 2A line segments consist of upgrading the existing Owens Gorge - Rindaldi 230 kV line from Barren Ridge switching station to Haskel Canyon switching station, building double circuit 230 kV line #2 from Barren Ridge switching station to Haskel Canyon switching station, adding 230 kV #2 line from Castaic power plant - Haskel Canyon on open side of towers, and upgrading the existing Owens Gorge - Rindaldi 230 kV line from Haskel Canyon switching station to Rinaldi. Upgrading and adding these 230 kV lines is expected to result in a total local allowable local CREZ of about 2000 MW.

Adding additional single circuit 230 kV lines from Barren Ridge switching station to Haskel Canyon switching station, from Castaic power plant - Haskel Canyon, and from Haskel Canyon to Rindaldi is expected to increase the allowable local CREZ MW capacity another 1000 MW, resulting in a total local allowable local CREZ of about 3000 MW.

Individual CREZ and transmission considerations

First further review of the RETI 2A report, Page G-61 indicates that the allowable CREZ in Table 7 should be increased from 2000 MW to 2200 MW.

This transmission collector group provides a path to deliver approximately 2200 MW of Tehachapi and Kramer CREZ to the LADWP system as described in the RETI 2A report. The additional transmission expansion is expected to increase the allowable CREZ another 1000 MW to 3200 MW.

Table 7 – BarrenRidge Collector Group

CREZ Accessed: Kramer, Tehachapi

Line Segment	Mileage	Cost $Millions	Allowable CREZ MW
BRNR_HASC_1	60	40.50	
BRNR_HASC_2	60	150.00	
CAST_HASC_2	12	7.50	
HASC_RNLD_1	15	10.13	
Totals RETI 2A	147	208.13	2200
Incremental mi Cost and CREZ	87	217.50	1000
New Totals	234	425.63	3200

IronMt

Table 8 presents the resulting high level estimates of allowable local CREZ MW capacity for the IronMt Collector Group first assuming the line segments developed in the RETI 2A report, then adding additional transmission facilities to estimate the next incremental increase in allowable local CREZ MW. The RETI 2A line segments consist of rebuilding double circuit 500 kV line circuits #1 and #2 from Iron Mountain - Junction over existing 230 kV to assess Iron Mountain CREZ, rebuilding a 500 kV line from Junction - Camino over existing 230 kV to access Needles CREZ, and building a double circuit 500 kV line circuit #1 and #2 from Jontry Junction – Pisgah. Unfortunately uprating and adding all these 500 kV lines is expected to only result in a total allowable local CREZ of about 500 MW at Iron Mountain and possibly 1000 MW at Needles, while meeting transmission reliability criteria discussed above. Problems associated with reliably delivering larger amounts of power from potential Iron Mountain CREZ are discussed in the RETI 2A report on page 3-71. Note, there is enough capacity in the double circuit 500 kV line to deliver about 4000 MW of CREZ into the foundation transmission system with both circuits in service, without meeting the credible N-2 outage criteria.

If the current problems can be resolved, Adding another double circuit 500 kV line from Iron Mountain – Jontry Junction - Pisgah, could deliver up to 4000 MW from Iron Mountain or 1000 MW at Needles with 3000 MW at Iron Mountain, while maintaining a credible N-2 reliability criteria.

Individual CREZ and transmission considerations

The individual CREZ and transmission considerations associated with Iron Mountain and Needles CREZ are discussed above.

Table 8 – IronMt Collector Group

CREZ Accessed: Iron Mountain, Pisgah, Needles

Line Segment	Mileage	Cost $Millions	Allowable CREZ MW
IRMT_SCEJ_1	39	134.06	
IRMT_SCEJ_2	39	134.06	
SCEJ_CAMI_1	10	38.75	
SCEJ_PISG_1	84	262.50	
SCEJ_PISG_2	84	262.50	
Totals RETI 2A	256	831.88	500
Incremental mi Cost and CREZ	123	768.75	3500
New Totals	379	1600.63	4000

Riverside

Table 9 presents the resulting high level estimates of allowable local CREZ MW capacity for the Riverside Collector Group first assuming the line segments developed in the RETI 2A report, then adding additional transmission facilities to estimate the next incremental increase in allowable local CREZ MW. The RETI 2A line segments consist of building two 500 kV lines from Desert Center - Devers, and building a 500 kV line from Midpoint – Desert Center. Adding these 500 kV lines is expected to result in a total local allowable local CREZ of about 4000 MW.

Adding another single circuit 500 kV line from Midpoint – Desert Center, and from Desert Center - Devers is expected to increase the allowable local CREZ MW capacity another 2000 MW, resulting in a total local allowable local CREZ of about 6000 MW, with up to 4000 MW of the CREZ connected at Midpoint.

Individual CREZ and transmission considerations

The above allowable CREZ limits apply to Riverside East CREZ.

The Palm Springs CREZ appears to be located near Devers substation, and the CREZ power should be able to be injected directly into the foundation transmission system using a 10 mi. 230 kV trunk-line costing about $25 million.

Table 9 – Riverside Collector Group

CREZ Accessed: Riverside East, Palm Springs

Line Segment	Mileage	Cost $Millions	Allowable CREZ MW
DESC_DEVR_1	40	125.00	
DESC_DEVR_2	40	125.00	
MIDP_DESC_1	70	227.50	
Totals RETI 2A	150	477.50	4000
Incremental mi Cost and CREZ	110	357.50	2000
New Totals	260	835.00	6000

LEAPS

Table 10 presents the resulting high level estimates of allowable local CREZ MW capacity for the LEAPS Collector Group first assuming the line segments developed in the RETI 2A report, then adding additional transmission facilities to estimate the next incremental increase in allowable local CREZ MW. The RETI 2A line segments consist of reconductoring the double circuit Talega - Escondido 230 kV #1 line from Escondido - Camp Pendleton, adding a second #2 circuit to the towers, reconductoring the double circuit Talega - Escondido 230 kV #1 line from Talega - Camp Pendleton, and adding a second #2 circuit to the towers, and building a 500 kV Talega to Escondido to the Valley - Serrano line. Reconductoring the 230 kV lines and adding the 500 kV line is expected to result in a total local allowable local CREZ of about 2000 MW.

Adding another single circuit 500 kV line from Talega to Escondido to the Valley - Serrano line is expected to increase the allowable local CREZ MW capacity another 2000 MW, resulting in a total local allowable local CREZ of about 4000 MW.

Individual CREZ and transmission considerations

Table B-1 in the RETI 2A report indicates that the total local developable North Central San Diego CREZ is 281 MW. The above cursory examination of the transmission segments proposed in the RETI 2A report indicates that the proposed collector segments provide for about 2000 MW of allowable local CREZ. In my opinion the existing 230 kV transmission may be adequate to inject a large portion of the developable North Central San Diego CREZ power directly into the San Diego transmission system.

Table 10 – LEAPS Collector Group

CREZ Accessed: San Diego North Central

Line Segment	Mileage	Cost $Millions	Allowable CREZ MW
CMPL_ECND_1	37	24.98	
CMPL_ECND_2	37	23.13	
CMPL_TALG_1	10	6.75	
CMPL_TALG_2	10	6.25	
LELK_CMPL_1	31	100.75	
Totals RETI 2A	125	161.85	2000
Incremental mi Cost and CREZ	31	100.75	2000
New Totals	156	262.60	4000

Tehachapi

Table 11 presents the resulting high level estimates of allowable local CREZ MW capacity for the Tehachapi Collector Group first assuming the line segments developed in the RETI 2A report, then adding additional transmission facilities to estimate the next incremental increase in allowable local CREZ MW. The RETI 2A line segments consist of upgrading the existing line #1 from Antelope - Vincent from 220 kV to 500 kV, upgrading the existing line #2 from Antelope - Vincent from 220 kV to 500 kV on separate right of way, upgrading existing 220 kV line from Chino – Mira Loma to double circuit 220 kV lines #1 and #2, adding 220 kV circuit to the open side of existing 500 kV creating Chino - Mira Loma 220 kV line #3 (using 500 kV construction), adding 220 kV Gould – Eagle Rock 220 kV line using existing towers, rebuilding a portion of the Eagle Rock - Pardee 220 kV line creating the Mesa - Vincent #2 220 kV line, building the Rio Hondo - Vincent #2 220 kV line, changing the Windhub - Antelope line operating voltage from 220 kV to 500 kV, building the Whirlwind - Windhub 500 kV line, and building the Whirlwind - Antelope 500 kV line. Upgrading the above 220 kV lines and adding the 500 kV lines creates a lot of transmission capacity. The total local allowable CREZ capacity is difficult to estimate without performing load flow analysis. However, all these upgrades and additions are expected to result in a total local allowable local CREZ of at least 4000 MW.

Adding another single circuit 500 kV line, say from Windhub – Whirlwind - Vincent is expected to increase the allowable local CREZ MW capacity another 2000 MW, resulting in a total local allowable local CREZ of about 6000 MW.

Individual CREZ and transmission considerations

Table B-1 in the RETI 2A report indicates that the total local developable Tehachapi CREZ is more than 10,000 MW and Fairmont CREZ is more than 3500 MW. It appears that the following list of Tehachapi collector group transmission line segments in Table 11 were developed based on a relatively extensive transmission assessment by the RETI group. If more than 6000 MW local CREZ is planned, I suggest we contact the appropriate transmission planners to develop a more accurate estimate of the allowable local CREZ associated with the transmission facilities added in the RETI report.

Table 11 – Tehachapi Collector Group

CREZ Accessed: Tehachapi, Fairmont

Line Segment	Mileage	Cost $Millions	Allowable CREZ MW
ANTE_VINC_1	21	16.28	
ANTE_VINC_2	18	68.20	
CHNO_MIRA_1	7	24.06	
CHNO_MIRA_2	7	15.31	
CHNO_MIRA_3	7	15.31	
GULD_EGLR_1	9	3.53	
MESA_VINC_2	36	126.00	
RIOH_VINC_2	32	124.39	
WHUB_ANTE_1	26	16.64	
WHUB_WRLW_1	17	54.60	
WRLW_ANTE_1	16	50.70	
WRLW_VINC_1	33	10.79	
Totals RETI 2A	228	525.81	4000
Incremental mi Cost and CREZ	50	162.50	2000
New Totals	278	688.31	6000

Imperial

Table 12 presents the resulting high level estimates of allowable local CREZ MW capacity for the Imperial Collector Group first assuming the line segments developed in the RETI 2A report, then adding additional transmission facilities to estimate the next incremental increase in allowable local CREZ MW. The RETI 2A line segments consist of rebuilding the existing 161 kV Line to double circuit 230 kV line #1 from Avenue 58 - Coachella Valley, rebuilding the existing 161 kV line to double circuit 230 kV line #1 from Avenue 58 – Bannister, adding a second circuit to double circuit 230 kV line creating Bannister - Coachella Valley line #1, building the 500 kV Bannister - Devers #1 line, adding the second circuit to double circuit 230 kV creating the Bannister - El Centro line #1, building 230 kV Bannister - Geo #1 line, building 230 kV Bannister - Geo #2 line, building 230 kV Coachella Valley - Devers II line #1, building 230 kV Coachella Valley - Devers II line #2 , upgrading 230 kV Coachella Valley - Mirage line #1, upgrading 230 kV Coachella Valley - Mirage line #2, adding a short 500 kV line connection between Devers – Devers II, rebuilding existing 161 kV to double circuit 230 kV line #1 from Dixieland – Bannister, rebuilding existing 161 kV to double circuit 230 kV line #1 from El Centro – Highline, adding second circuit to double circuit 230 kV creating El Centro - Highline line #2, building El Centro - Imperial ValleyII 230 kV line #2, building the 500 kV Bannister - Imperial Valley line#1, replacing the existing 500/230 kV 600 MVA Imperial Valley transformer with a new 1120 MVA transformer, adding a third 500/230 kV 1120 MVA Imperial Valley transformer, building Midway - Geo double circuit 230 kV lines #1 and #2, upgrading existing Mirage - Devers 230 kV line #1, and upgrading existing Mirage - Devers 230 kV line #2. I believe the transmission capability of all these upgrades and additions has been studied pretty thoroughly, as can be seen in the RETI 2A report. As stated in Appendix G, page G-57 of the RETI 2A report, 3200 MW of local CREZ capacity can be delivered at to LADWP and SCE at Devers/Mirage and 1800 MW of local CREZ can be delivered to SDGE at Imperial Valley, resulting in a total allowable local CREZ of 5000 MW.

Adding another single circuit 500 kV line 500 kV line from Imperial Valley - Bannister – Devers is expected to increase the allowable local CREZ MW capacity delivered to LADWP and SCE at Devers/Mirage another 2000 MW, to about 5200 MW, and increasing the total allowable local CREZ to 7000 MW.

Individual CREZ and transmission considerations

This collector group has been thoroughly studied in determining the allowable local CREZ. If more than 7000 MW local CREZ is planned, I suggest we contact the appropriate transmission planners to discuss additional transmission facilities to add.

Table 12 – Imperial Collector Group

CREZ Accessed: Imperial North A&B, Imperial South, Imperial East, Baha

Line Segment	Mileage	Cost $Millions	Allowable CREZ MW
AV58_CHCV_1	18	32.81	
BANN_AV58_1	61	107.41	
BANN_CHCV_1	56	140.22	
BANN_DEVR_1	91	296.40	
BANN_ELCN_1	28	51.56	
BANN_GEO_1	16	25.00	
BANN_GEO_2	16	25.00	
CHCV_DVR2_1	35	54.69	
CHCV_DVR2_2	35	54.69	
CHCV_MIRG_1	20	13.50	
CHCV_MIRG_2	20	13.50	
DEVR_DVR2_1	0	0.98	
DIXL_BANN_1	43	51.56	
ELCN_HILN_1	19	35.63	
ELCN_HILN_2	19	35.63	
ELCN_IMPV2_2	18	33.75	
IMPV_BANN_1	51	165.75	
IMPV_XFMR_2	0	51.25	
IMPV_XFMR_3	0	51.25	
MIDW_GEO_1	16	25.00	
MIDW_GEO_2	16	25.00	
MIRG_DEVR_1	15	10.13	
MIRG_DEVR_2	15	10.13	
Totals RETI 2A	608	1310.81	5000
Incremental mi Cost and CREZ	142	462.15	2000
New Totals	750	1772.96	7000

D3: E3 additions of generic 500kV transmission lines and project-specific cost assumptions

E3's analysis includes a look at the relative values of fixed capacity transmission lines from the various zones. The size of the transmission lines from each zone are chosen to reflect the total resource availability in that zone, up to a maximum of 3,000 MW consisting of two single-circuit 500 kV lines or one dual-circuit 500 kV line. The lines are assumed to originate at the center of the resource clusters in each zone[28] and terminate at the closer of the Tesla (near Tracy, CA) or Victorville substations, whichever. These two substations were chosen because they represent transmission hubs in close proximity to major California load centers.

With the exception of the line from British Columbia, which E3 models as a hybrid alternating current (AC) and direct current (DC) line, E3 assumes all lines to be AC lines. The cost of these lines is estimated using a generic line costing model that accounts for both equipment (substations, towers, conductors, etc.) and right-of-way acquisition.[29] The following table details the cost and size of the transmission line that E3 assumes from each zone, as well as the losses associated with those lines.

[28] For example, the Wyoming line originates in eastern rather than central Wyoming due to the fact that most wind resources are located in the eastern part of the state.
[29] This transmission costing model was the same as that used for the GHG Calculator. It can be found at http://www.ethree.com/GHG/Transmission_Line_Cost_2007-11-16.xls

CREZ Name	Assumed Line Capacity	Transmission Line Distance (Miles)	Transmission Configuration	Segment Capital Cost (2008$ millions)	Segment Losses	Levelized Cost (2008$ Millions)
Alberta	3,000	1498	500 kV Double Circuit AC Line	$7,998	17.20%	$1,160
Arizona	1,500	403	500 kV Single Circuit AC Line	$2,044	4.63%	$296
Baja	1,500	211	500 kV Single Circuit AC Line	$1,425	2.42%	$207
Barstow	1,500	48	500 kV Single Circuit AC Line	$889	1.11%	$129
British Columbia	3,000	1045	500 kV Double Circuit AC Line and 3,000 MW DC Line	$5,100	13.39%	$740
Carrizo North	1,500	87	500 kV Single Circuit AC Line	$1,127	2.00%	$163
Carrizo South	1,500	119	500 kV Single Circuit AC Line	$1,478	2.72%	$214
Colorado	3,000	936	500 kV Double Circuit AC Line	$5,250	10.75%	$761
Cuyama	500	124	500 kV Single Circuit AC Line	$1,094	0.54%	$159
Distributed Solar - PG&E	All Distributed Solar Resources are assumed to utilize existing transmission					
Distributed Solar - SCE						
Distributed Solar - SDGE						
Distributed Solar - Other						
Fairmont	1,500	7	500 kV Single Circuit AC Line	$549	0.15%	$80
Imperial	1,500	93	500 kV Single Circuit AC Line	$1,252	2.13%	$182
Inyokern	1,500	59	500 kV Single Circuit AC Line	$948	1.35%	$138
Iron Mountain	1,500	85	500 kV Single Circuit AC Line	$1,120	1.96%	$162
Kramer	1,500	41	500 kV Single Circuit AC Line	$823	0.94%	$119
Lassen North	1,500	133	500 kV Single Circuit AC Line	$1,642	3.06%	$238
Lassen South	1,500	172	500 kV Single Circuit AC Line	$1,940	3.95%	$281
Montana	3,000	1105	500 kV Double Circuit AC Line	$6,090	12.69%	$883
Mountain Pass	1,500	97	500 kV Single Circuit AC Line	$1,287	2.23%	$187
Nevada C	1,500	215	500 kV Single Circuit AC Line	$1,345	2.46%	$195
Nevada N	500	476	230 kV Single Circuit AC Line	$1,232	0.86%	$179
New Mexico	3,000	790	500 kV Double Circuit AC Line	$4,522	9.08%	$656
NonCREZ	All NonCREZ Resources are assigned a transmission cost of $54/kW-yr.					
Northwest	1,500	611	500 kV Single Circuit AC Line	$3,270	8.48%	$474
Owens Valley	1,500	94	500 kV Single Circuit AC Line	$1,211	2.16%	$176
Palm Springs	1,000	36	500 kV Single Circuit AC Line	$668	0.32%	$97
Pisgah	1,500	56	500 kV Single Circuit AC Line	$908	1.28%	$132
Remote DG (Brownfield) - PG&E	All Remote DG Resources are assumed to utilize existing transmission					
Remote DG (Brownfield) - SCE						
Remote DG (Brownfield) - SDGE						
Remote DG (Brownfield) - Other						
Remote DG (Greenfield) - PG&E						
Remote DG (Greenfield) - SCE						
Remote DG (Greenfield) - SDGE						
Remote DG (Greenfield) - Other						
Riverside East	1,500	85	500 kV Single Circuit AC Line	$1,143	1.94%	$166
Round Mountain	500	96	500 kV Single Circuit AC Line	$879	0.42%	$128
San Bernardino - Baker	1,500	63	500 kV Single Circuit AC Line	$1,002	1.44%	$145
San Bernardino - Lucerne	1,500	32	500 kV Single Circuit AC Line	$732	0.74%	$106
San Diego North Central	500	23	500 kV Single Circuit AC Line	$585	0.10%	$85
San Diego South	1,000	102	230 kV Double Circuit AC Line	$1,118	0.89%	$162
Santa Barbara	500	140	230 kV Single Circuit AC Line	$1,153	0.61%	$167
Solano	1,000	10	230 kV Double Circuit AC Line	$538	0.09%	$78
Tehachapi	3,000	40	500 kV Double Circuit AC Line	$1,252	0.92%	$182
Twentynine Palms	1,000	56	230 kV Double Circuit AC Line	$766	0.49%	$111
Utah-Southern Idaho	1,500	676	500 kV Single Circuit AC Line	$2,925	7.76%	$424
Victorville	1,500	21	500 kV Single Circuit AC Line	$674	0.49%	$98
Westlands	1,500	75	500 kV Single Circuit AC Line	$1,058	1.71%	$153
Wyoming	3,000	1030	500 kV Double Circuit AC Line	$5,796	11.83%	$840

D4: Distribution System Benefits/Upgrade Penalties for Wholesale Distributed Solar Resources

E3 has modeled four different types of wholesale distributed solar PV generation for this effort. These different types of solar resource are either given a credit for the benefits that they provide to the distribution system (small installations serving load downstream of the substation) or assessed a penalty for system upgrades that they might trigger (larger installations that violate Rule 21[30]).

The size of the benefit for the smaller installations was determined by where they interconnect to the system. Remote DG installations that are not compliant with Rule 21 are assessed a generic $68/kW-yr system upgrade penalty. The following table shows the different benefits/penalties by interconnection point and the types of distributed resources to which they correspond.

Interconnection Point	Upgrade Penalty (Distribution System Benefit), $/kW-yr.	Applicable Solar PV Technologies
Meter	($45)	Large Rooftop (0-2 MW)
Feeder	($45)	Small Ground (0-2 MW)
Dist. Bank	($45)	
Transmission Substation	($10)	Mid Ground (2-5 MW), Large Ground (5-20 MW)
Remote DG	$68	Large Ground (5-20 MW), Not Rule 21 Compliant

[30] Rule 21 governs the amount of downstream distributed generation that can be connected to a given substation. More information on Rule 21 can be found at the California Energy Commission website: http://www.energy.ca.gov/distgen/interconnection/california_requirements.html.

Appendix E

Environmental Scoring

Note: Due to the number of changes to the environmental scoring methodology since the June 22 draft, the Appendix has been replaced in its entirety, and individual changes are not highlighted.

Environmental Scoring for 33% RPS Scenarios

This white paper describes work conducted by Aspen Environmental Group (Aspen) in consultation with Energy and Environmental Economics, Inc. (E3) to support the ongoing effort by CPUC to identify various 33% RPS Scenarios. Aspen's tasks were to help CPUC update the methodology for environmental ranking of renewable resources and to assign scores to generation resources so environmentally-ranked scenarios (portfolios) could be developed. A preliminary methodology was identified in our June 9, 2010 paper (as Staff's proposal for Resource Planning Assumptions, in Appendix E of Attachment 1 of the June 22, 2010 filing [R. 10-05-006, Long Term Renewable Resource Planning Standards]). This white paper substantially updates the approach to improve transparency and reflect public comments.

Aspen is under contract to provide RPS Technical Support to the California Institute for Energy and Environment (CIEE) through direction from the CPUC Energy Division. The CPUC 33% RPS Implementation Analysis team will use the scores to create environmentally-constrained scenarios of new renewable generating resources to fill the RPS need and for use in the Long-Term Procurement Planning (LTPP) process.

Revisions from Proposal Released June 22, 2010

This white paper reflects the following revisions from Aspen's previous scoring methodology:

- Remove the "weighting" approach of how each environmental criterion may or may not be relevant to the successful development of a given renewable technology. The new methodology avoids using a relative weight of the environmental criteria for the potential level of concern by technology. In eliminating weighing of the environmental criteria for each renewable technology, the present methodology instead relies on published data from the RETI process to first quantify the environmental concerns over each geographic area then factor the "area needs" (or footprint per energy output) of each technology. The "area needs" are weighted by the percentage of land found not to be 'mechanically disturbed' in that zone. Weighting by the percentage of Undisturbed Land in a given zone results in favorable scores (lower "area needs") for resource development that may occur where there is abundant Mechanically Disturbed Land. This penalizes a resource for its area needs if in a zone with a high fraction of Undisturbed Land. The product of the environmental ranking and the area need (multiplied by the Undisturbed Land fraction) equals the score.
- Restore the RETI EWG criteria for "Sensitive Areas in CREZs" and "Sensitive Areas in CREZ Buffer Areas" that were initially not used in the scores to improve consistency with RETI efforts. These criteria originally from the RETI EWG are now included in the present scoring, although Aspen's experience indicates that these criteria are not highly relevant to specific projects. Projects can be directed by agencies to avoid sensitive areas, and the presence of an adjacent sensitive area does not necessarily increase environmental concern.
- Remove "high desert ecosystems" and "regional air quality" as environmental indicators because no consensus could be found in the public comments on how to treat these issues methodologically. The "high desert ecosystems" indicator of our original scoring methodology reflected Aspen's experience that valuable biological resources correlate especially well with portions of the desert at higher elevations. Aspen recommended this indicator as a proxy for information not yet reflected in statewide databases and to reflect our review of various proposals for renewable projects located in

the California Mojave and Sonoran Deserts. "Regional air quality" conditions were originally considered as a partial proxy for environmental justice and public health concerns because most of California's population resides in polluted air basins. Public comments suggested more work would be needed before including these two indicators in scoring.

- Include an environmental score for minor transmission upgrades and new transmission from a given zone. Transmission scores were based on the length of the line, and weighted according to whether they were minor upgrades (x2) or new transmission corridors (x4).

1. Introduction

1.1 Purpose

Aspen Environmental Group shows a way of scoring individual renewable energy projects based on the relative environmental ranking of its location [using the Renewable Energy Transmission Initiative (RETI) Competitive Renewable Energy Zone (CREZ)] and the technology of the resource. Aspen also provides comparable scores for projects that are out-of-state or do not fall within a CREZ.

The CPUC Energy Division is forecasting scenarios of new renewable generation development to comply with the mandate for 33% renewable electricity by 2020. In separate work for the LTPP, a range of development scenarios for 2020, including those that are environmentally-constrained, will be made up of specific selected projects. This white paper describes how each project can be given an environmental score. Each environmental score is a composite of the environmental ranking of the applicable CREZ, which characterizes location, and the relative area needs of each technology per unit of energy production.

1.2 Reliance on Renewable Energy Transmission Initiative

RETI EWG Environmental Criteria. The Renewable Energy Transmission Initiative includes an Environmental Working Group (EWG) that developed eight environmental criteria for measuring the level of environmental concern associated with developing renewable generation in various Competitive Renewable Energy Zones (CREZs). The eight criteria originally defined as part of RETI Phase 1B are documented in the RETI Phase 1B report of January 2009.

Identification of Resources. New generating resources to fill the RPS need come from the RETI Phase 2B Supporting Documents and the confidential CPUC Energy Division database. Given the variety of resources and the different levels of available information on possible projects, this white paper identifies a way of discerning which projects would have the least environmental concern based solely on the ranking of each project's CREZ and the technology proposed.

- **Projects Identified by RETI:** Scores are assigned to projects identified by RETI Phase 2B Supporting Documents (1,222 projects),[31] which do not include distributed solar photovoltaic (PV) projects.

[31] The RETI Phase 2B Supporting documents include the list of 1,222 projects with the following description (available at: http://www.energy.ca.gov/reti/documents/index.html, accessed June 2, 2010): "Hypothetical proxy projects have been located based on relative resource potential and other constraints in a general area; pre-

- **Photovoltaic Distributed Generation (DG):** Separate scores were derived for rural small-scale PV systems considering that only a portion of the environmental score would be relevant when compared to utility-scale projects. Urban DG PV projects are given low scores to ensure priority in selecting these resources.

Revisiting RETI Environmental Criteria. This white paper shows how our environmental scoring departs from CREZ Environmental Ranking of the RETI process in several ways. Our work:

1) revises the two RETI environmental criteria regarding development footprint and land degradation;

2) identifies the fraction of mechanically disturbed farmland as an environmental indicator within each CREZ;

3) includes new publicly-available data for degraded land;

4) divides each environmental indicator by the area of the CREZ (acres or ac), rather than the anticipated energy produced by each CREZ (gigawatt-hours or GWh);

5) applies data from the RETI process on the "area needs" of each technology and weights it by the fraction of undisturbed land with the zone to arrive at a the level of environmental concern for each renewable technology; and

6) results in scores for each technology in each CREZ, rather than area rankings, in a range of 0 to over 100, with 0 representing the projects with the lowest level of environmental concern and scores over 100 indicating the highest level of environmental concern.

The formulas developed and documented in the RETI Phase 1B report determined the relative levels of concern for the environmental criteria as follows:

$$\frac{\textit{Environmental Indicator for CREZ}}{\textit{Annual Energy Produced by CREZ}}$$

This white paper uses a two-step set of formulas instead of the RETI formula. Environmental scoring in this white paper uses the RETI data on environmental indicators divided by the CREZ area, rather than energy output. This "normalizes" the relative level of environmental concern so that it does not depend on the renewable technology mix or presumed energy output of the CREZ. Our formula first uses the environmental concern per unit of area to derive a ranking, then applies a separate factor depending on the "undisturbed area needs" of the major renewable technologies per unit of energy production, as follows:

$$\left[\frac{\textit{Environmental Indicator for CREZ}}{\textit{Total CREZ Area}}\right] \times$$

identified projects have been located based on known commercial interest in a general area. Locations of actual projects may vary significantly from locations shown in the [RETI] GIS files."

$$\left[\frac{\text{Footprint Area of Technology in CREZ} \times \left(\frac{\text{CREZ Area} - \text{Mechanically Disturbed Area}}{\text{CREZ Area}}\right)}{\text{Annual Energy Produced by Technolgy in CREZ}}\right]$$

This results in a table of environmental scores that are factors of the environmental ranking of the applicable zone and the relative area needs of each technology. The results of scoring resources in California are then extrapolated to score renewable projects outside of California, where data on project location and environmental attributes are scarce. Projects are drawn from the RETI list and projects within the Energy Division database.

The remainder of this paper explains the goals and methodology used to arrive at the environmental scores in more detail and the scoring results.

2. Goals in Deriving an Environmental Score

Aspen's primary goal is to score resources on a clear range for side-by-side comparison. A total of seven environmental criteria (or environmental concerns) were considered for each location and each major renewable technology, using a mix of existing RETI data and additional publicly-available data. For each geographic location, each criterion was given a score of between 0 and 10, 0 representing the least environmental concern and 10 the greatest. The seven environmental criteria were then totaled and multiplied by the undisturbed area needs for each renewable technology based on the premise that greater area needs are directly related to greater environmental concerns, and that development in an area with less Mechanically Disturbed land is associated with greater environmental concern. Projects in geographic areas with the greatest combined potential environmental concern across the seven criteria and the greatest undisturbed area needs result in total environmental scores over 100, where scores closer to 0 indicate the least environmental concern.

Another goal was to arrange the scoring system so projects from the RETI and CPUC Energy Division (ED) project databases could be treated with the same methodology. The location of each project determines whether it is within or near a ranked CREZ. If it is within or near a ranked CREZ, the project is given a score appropriate for that technology in that CREZ. When a project falls far beyond a CREZ boundary or out-of-state, then it is treated as a Non-CREZ or out-of-state resource, as needed. The environmental score is only a function of the project's location relative to a CREZ and the project's technology.

3. Environmental Criteria

This section details the eight environmental criteria representing the level of environmental concern for each renewable resource. The environmental criteria originate from RETI EWG scores and are modified by Aspen to normalize the environmental concerns by CREZ area, rather than energy output.

3.1 RETI EWG Environmental Assessment of CREZs

The RETI EWG determined how environmental considerations should be factored into CREZ development and ranking. The EWG's work was finalized in the January 2009 Phase 1B report as a 46-page appendix addressing "Environmental Assessment of CREZs."

The RETI EWG assessment illustrated the relative merits of each zone. The RETI EWG scores are not intended for use in evaluating individual projects, and the EWG makes no recommendations for the level of environmental concern for resources outside of defined CREZs (Non-CREZ), outside a scored sub-CREZ (portions of CREZs with differing economic profiles), or areas outside of California (out-of-state). RETI EWG Phase 2B results included updates limited to environmental ranking of certain CREZs, rather than all CREZs, and Phase 2B also provided one alternate set of CREZ rankings to address a lack of consensus on how the footprint of wind projects should be defined (May, 2010). RETI identified alternative CREZ rankings under the assumption that typical wind projects have a disturbed footprint of 3.5% of the lease area.

The RETI EWG scores apply uniformly across each CREZ and do not discern which types of projects within a ranked CREZ might have a lower or higher level of environmental concern. The occurrence of an environmental concern within each CREZ is normalized by RETI by assuming a given annual energy output of each CREZ. This means that the RETI scores originally introduced in Phase 1B embody certain fixed assumptions of the technology mix. Because our environmental scoring aims to show the environmental concern for various types of renewable projects in each CREZ, with a variable mix of renewable technologies, our approach normalizes the environmental concerns across the total land in the CREZ rather than assuming the CREZ energy production.

Table 1. RETI Phase 2B Annual Energy Mix

CREZ Name	Biomass/ Biogas (GWh/yr)	Wind (GWh/yr)	Solar (GWh/yr)	Geothermal (GWh/yr)	Total Annual Energy (GWh/yr)	CREZ Area (acres)
Barstow	---	2,363	3,000	---	5,362	98,687
Carrizo North	---	---	3,053	---	3,053	45,868
Carrizo South	---	---	5,823	---	5,823	47,181
Cuyama	---	---	801	---	801	6,150
Fairmont	976	1,992	4,032	---	7,000	95,391
Imperial East	---	200	3,216	---	3,416	66,724
Imperial North-A	---	---		10,095	10,095	52,073
Imperial North-B	212	---	3,753	---	3,965	67,901
Imperial South	253	113	7,405	426	8,197	77,172
Inyokern	---	678	4,911	---	5,589	71,605
Iron Mountain	---	143	10,145	---	10,288	96,149
Kramer	---	448	14,176	160	14,784	127,328
Lassen North	---	3,595	---	---	3,595	185,291
Lassen South	---	1,051	---	---	1,051	32,393
Mountain Pass	---	445	1,667	---	2,111	78,790
Owens Valley	---	---	10,651	---	10,651	67,370
Palm Springs	---	1,047	---	---	1,047	17,170
Pisgah	---	---	4,706	---	4,706	12,360
Riverside East	---	---	22,525	---	22,525	181,834

Table 1. RETI Phase 2B Annual Energy Mix

CREZ Name	Biomass/ Biogas (GWh/yr)	Wind (GWh/yr)	Solar (GWh/yr)	Geothermal (GWh/yr)	Total Annual Energy (GWh/yr)	CREZ Area (acres)
Round Mountain-A	---	---	---	2,557	2,557	9,363
Round Mountain-B	---	339	---	---	339	19,236
San Bernardino - Baker	---	---	7,064	---	7,064	67,694
San Bernardino - Lucerne	644	1,586	3,427	---	5,656	167,805
San Diego North Central	---	502	---	---	502	37,608
San Diego South	---	1,829	---	---	1,829	31,844
Santa Barbara	---	1,121	---	---	1,121	37,461
Solano	---	2,721	---	---	2,721	34,744
Tehachapi	262	9,075	16,095	---	25,432	317,323
Twentynine Palms	---	---	3,959	---	3,959	36,172
Victorville	---	1,161	2,737	---	3,899	88,896
Westlands	---	---	8,317	---	8,317	35,413

Source: RETI Phase 2B, May 2010 and supporting spreadsheets (Black & Veatch).

3.2 Environmental Criteria Retained

The ranking criteria originally developed as part of RETI EWG Phase 1B address important environmental concerns, some of which were used directly in our environmental scoring. The following criteria were carried forward as part of our environmental scoring, modified to remove the CREZ energy production assumptions and to reflect a 0 to 10 scale instead of 0 to 5 as used by RETI:

- **Transmission Footprint:** This criterion includes the amount of land needed for new transmission rights-of-way (ROW) as a useful measure of the expected impact on the environment.
- **Sensitive Areas in CREZs:** Each CREZ may include sensitive areas in which development is restricted or prohibited (mapped by RETI as Category 1 or Category 2 areas), such as: National Wildlife Refuges, Areas of Critical Environmental Concern (ACEC), and proposed and potential conservation reserves.
- **Sensitive Areas in CREZ Buffer Areas:** The RETI EWG agreed that lands within 2 miles of a CREZ boundary may be affected by development in the CREZ. This criterion therefore is scored on the amount of sensitive lands within 2 miles of a CREZ boundary.
- **Significant Species:** State and federal policies identify species of wildlife that are of significant concern. This criterion gives preference to CREZs in which fewer significant species are known to occur. Sensitive species data collected during recent environmental reviews for major California renewable projects is not yet entered into the California Natural Diversity Database. Because this data has yet to be published in the database, it was not included in our environmental scores, which are based on database searches originally conducted by the RETI EWG. This criterion in particular should continue to be updated based on new information that is continuously uploaded in the California Natural Diversity Database.

- **Wildlife Corridors:** Biologists have recognized the importance of the integrity of wildlife corridors that enable animals to move as needed from one habitat to another. Although corridors are not well understood and existing data is preliminary, the EWG included corridor data to give preference to those CREZs that minimize conflicts with wildlife corridors. As with the significant species data, this criterion does not reflect the most recent data on wildlife corridors found during environmental review of major renewable projects in the California Mojave and Sonoran Deserts and potentially elsewhere, like the Carrizo Plain. This criterion should also continue to be updated based on ongoing environmental studies.
- **Important Bird Areas:** Potential impacts of energy development on avian species are of significant environmental concern. Areas designated as Important Bird Areas (IBA) by the National Audubon Society are areas designated as vital to bird species, including common and game species as well as rare species.

The January 2009 RETI Phase 1B report includes more information on the economic and environmental rankings of the CREZs and the data sources for quantifying these environmental concerns in each CREZ.

Additional environmental concerns, including aesthetics (visual impact), Native American concerns (cultural resources), and some land use conflicts (regarding forest use), are neither represented in the existing RETI data nor the criteria in this white paper. Identifying potential conflicts with agricultural use is beyond the scope of this analysis, as is a consideration of air quality or environmental justice. However, these concerns could be addressed by the environmental scores in future updates of this work as criteria and data become available.

Disclaimers within the RETI Phase 1B report remain applicable to this environmental scoring methodology. Namely, that the: "*. . . ranking process is not intended in any way to prejudge or substitute for a thorough environmental review of proposed projects as required by the California Environmental Quality Act (CEQA) or the National Environmental Policy Act (NEPA)*."

3.3 Environmental Criteria Updated or Added

Our environmental scoring takes into account two additional and updated environmental factors, building on the criteria of the RETI EWG rankings. In addition to the six RETI EWG criteria that were incorporated (see Section 3.2), we revised the criterion for development opportunities on degraded lands, including brown-field and other EPA-tracked sites.

EPA Tracked Degraded Lands

We sought to capture the results of work completed in February 2010 by U.S. EPA and the National Renewable Energy Laboratory (NREL) regarding renewable energy development opportunities on "degraded" lands. The U.S. EPA and NREL published a tool that tracks certain EPA and state-tracked degraded sites and maps these based on their appropriateness for renewable development.[32] We identified the acreage of tracked degraded land considered appropriate for renewable development inside of each CREZ and within 10 miles of each CREZ boundary. A 10-mile buffer from each CREZ edge

[32] See http://www.epa.gov/renewableenergyland/ for further tools compiled by the EPA for siting renewable energy on potentially contaminated land and mine sites.

was used because the boundaries of the opportunity sites are not mapped in the U.S.EPA and NREL data and because many large-scale renewable energy proposals currently under review in California specify a distance of 10 miles or less from transmission as one of the project objectives.

We calculated the area of degraded land inside or within 10 miles of each CREZ and divided that by the total CREZ area. For degraded lands known to be currently in use, such as is the case for active military lands, ten percent of these degraded lands were included for the calculation. CREZs with excess or the most degraded land available received the lowest (best) scores, and CREZs with little or no degraded land available were assigned higher (worse) scores.

Table 2 shows the data for each of the RETI CREZs supporting the eight environmental criteria.

Table 2. Data Used for Environmental Criteria

CREZ Name	Mechanically Disturbed (ac)	ROW Transmission Footprint (ac)	CREZ Yellow & Black Area (ac)	Buffer Yellow & Black Area (ac)	Important Bird Area (ac)	Significant Species (# species)	Wildlife Corridors (meters)	EPA Tracked Degraded (ac)
Barstow	582	42,538	55,489	127,499	3,795	73	16,704	215
Carrizo North	10,587	35,633	3,784	17,540	0	111	3,693	54
Carrizo South	0	28,003	0	4,788	6,695	109	7,886	0
Cuyama	0	3,923	94	6,005	0	65	0	0
Fairmont	8,630	46,827	0	29,894	8,936	130	10,463	480
Imperial East	0	26,758	11,496	59,721	720	116	4,662	156
Imperial North-A	23,281	50,526	16,673	57,133	31,489	114	7,803	0
Imperial North-B	15,985	44,203	15,012	72,973	25,523	126	4,245	796
Imperial South	23,047	48,826	13,055	64,123	30,770	111	13,007	170
Inyokern	996	29,972	34,441	88,859	0	82	5,320	21
Iron Mountain	0	54,315	5,079	31,729	0	52	0	5
Kramer	0	68,610	61,291	186,399	7,964	65	16,202	30,302
Lassen North	0	84,206	2,222	37,419	0	110	7,928	2
Lassen South	0	12,411	5,027	87,065	10,159	112	18,917	3,792
Mountain Pass	0	23,479	23,150	118,089	5,420	108	0	371
Owens Valley	0	35,452	69	14,764	3,335	92	51,665	65
Palm Springs	1,210	9,801	11,182	42,434	2,422	133	28	148
Pisgah	0	875	153	14,202	0	50	0	5
Riverside East	6,770	46,792	22,265	137,212	0	107	0	426
Round Mountain-A	0	9,363	7,684	43,929	0	74	0	1
Round Mountain-B	96	9,078	754	9,942	0	82	4,371	0
San Bernardino - Baker	0	27,808	15,855	107,660	31	56	16,802	17
San Bernardino - Lucerne	1,096	95,717	25,083	122,518	252	201	15,984	650
San Diego North Central	1,490	19,129	10,498	54,304	9,058	169	3,105	40
San Diego South	67	7,255	3,757	38,021	96	129	8,349	9
Santa Barbara	738	7,129	5,121	24,074	0	119	7,965	9,947
Solano	0	6,654	137	3,783	30,012	120	6,280	5,502
Tehachapi	13,520	103,466	35,819	35,819	18,948	143	44,810	690
Twentynine Palms	0	16,519	39	13,729	0	66	5,692	113
Victorville	254	29,341	28,756	67,335	463	66	2,560	1,120
Westlands	34,784	4,791	0	0	0	77	7,987	3,637

Sources: RETI Phase 2B, May 2010 and supporting spreadsheets (Black & Veatch), except for "Mechanically Disturbed" and "EPA Tracked Degraded," as described in text.

3.4 Relative Ranking Results

Table 3 shows how each of the environmental criteria occur over the total CREZ area using the formula established in this white paper. This shows the environmental concern per unit of total CREZ area.

Table 3. Environmental Concern per CREZ acre

CREZ Name	ROW Transmission (ac/CREZ ac)	Yellow & Black Area (ac/CREZ ac)	Buffer Yellow & Black Area (ac/CREZ ac)	Important Bird Area (ac/CREZ ac)	Signif. Species (# species/CREZ ac)	Wildlife Corridors (meters/CREZ ac)	EPA Tracked Degraded (ac/CREZ ac)
Barstow	0.43	0.56	1.29	0.0007	0.17	0.038	1.00
Carrizo North	0.78	0.08	0.38	0.0024	0.08	0.000	1.00
Carrizo South	0.59	0.00	0.10	0.0023	0.17	0.142	1.00
Cuyama	0.64	0.02	0.98	0.0106	0.00	0.000	1.00
Fairmont	0.49	0.00	0.31	0.0014	0.11	0.094	0.99
Imperial East	0.40	0.17	0.90	0.0017	0.07	0.011	1.00
Imperial North-A	0.97	0.32	1.10	0.0022	0.15	0.605	1.00
Imperial North-B	0.65	0.22	1.07	0.0019	0.06	0.376	0.99
Imperial South	0.63	0.17	0.83	0.0014	0.17	0.399	1.00
Inyokern	0.42	0.48	1.24	0.0011	0.07	0.000	1.00
Iron Mountain	0.56	0.05	0.33	0.0005	0.00	0.000	1.00
Kramer	0.54	0.48	1.46	0.0005	0.13	0.063	0.76
Lassen North	0.45	0.01	0.20	0.0006	0.04	0.000	1.00
Lassen South	0.38	0.16	2.69	0.0035	0.58	0.314	0.88
Mountain Pass	0.30	0.29	1.50	0.0014	0.00	0.069	1.00
Owens Valley	0.53	0.00	0.22	0.0014	0.77	0.050	1.00
Palm Springs	0.57	0.65	2.47	0.0077	0.00	0.141	0.99
Pisgah	0.07	0.01	1.15	0.0040	0.00	0.000	1.00
Riverside East	0.26	0.12	0.75	0.0006	0.00	0.000	1.00
Round Mountain-A	1.00	0.82	4.69	0.0079	0.00	0.000	1.00
Round Mountain-B	0.47	0.04	0.52	0.0043	0.23	0.000	1.00
San Bernardino - Baker	0.41	0.23	1.59	0.0008	0.25	0.000	1.00
San Bernardino - Lucerne	0.57	0.15	0.73	0.0012	0.10	0.002	1.00
San Diego North Central	0.51	0.28	1.44	0.0045	0.08	0.241	1.00
San Diego South	0.23	0.12	1.19	0.0041	0.26	0.003	1.00
Santa Barbara	0.19	0.14	0.64	0.0032	0.21	0.000	0.73
Solano	0.19	0.00	0.11	0.0035	0.18	0.864	0.84
Tehachapi	0.33	0.11	0.11	0.0005	0.14	0.060	1.00
Twentynine Palms	0.46	0.00	0.38	0.0018	0.16	0.000	1.00
Victorville	0.33	0.32	0.76	0.0007	0.03	0.005	0.99

Table 3. Environmental Concern per CREZ acre

CREZ Name	ROW Transmission (ac/CREZ ac)	Yellow & Black Area (ac/CREZ ac)	Buffer Yellow & Black Area (ac/CREZ ac)	Important Bird Area (ac/CREZ ac)	Signif. Species (# species/CREZ ac)	Wildlife Corridors (meters/CREZ ac)	EPA Tracked Degraded (ac/CREZ ac)
Westlands	0.14	0.00	0.00	0.0022	0.23	0.000	0.90

Table 4 shows the relative ranking according to the seven criteria used in this white paper. These ranking results differ substantially from those of the RETI process due this paper's use of the RETI data on environmental indicators divided by the CREZ area, rather than the presumed energy output of the CREZ (as explained in Section 1.2).

Table 4. Environmental Criteria and Ranking Results

CREZ Name	ROW Transmission	Yellow & Black Area	Buffer Yellow & Black Area	Important Bird Area	Signif. Species	Wildlife Corridors	EPA Tracked Degraded	Total Rankings (per CREZ ac)
Barstow	4.3	6.9	2.8	0.7	2.2	0.4	10.0	27.2
Carrizo North	7.8	1.0	0.8	2.3	1.0	0.0	10.0	22.9
Carrizo South	5.9	0.0	0.2	2.2	2.2	1.6	10.0	22.2
Cuyama	6.4	0.2	2.1	10.0	0.0	0.0	10.0	28.6
Fairmont	4.9	0.0	0.7	1.3	1.4	1.1	9.9	19.3
Imperial East	4.0	2.1	1.9	1.6	0.9	0.1	10.0	20.7
Imperial North-A	9.7	3.9	2.3	2.1	2.0	7.0	10.0	37.0
Imperial North-B	6.5	2.7	2.3	1.8	0.8	4.4	9.9	28.3
Imperial South	6.3	2.1	1.8	1.4	2.2	4.6	10.0	28.3
Inyokern	4.2	5.9	2.6	1.1	1.0	0.0	10.0	24.7
Iron Mountain	5.6	0.6	0.7	0.5	0.0	0.0	10.0	17.5
Kramer	5.4	5.9	3.1	0.5	1.7	0.7	7.6	24.9
Lassen North	4.5	0.1	0.4	0.6	0.6	0.0	10.0	16.2
Lassen South	3.8	1.9	5.7	3.3	7.6	3.6	8.8	34.8
Mountain Pass	3.0	3.6	3.2	1.3	0.0	0.8	10.0	21.8
Owens Valley	5.3	0.0	0.5	1.3	10.0	0.6	10.0	27.6
Palm Springs	5.7	7.9	5.3	7.3	0.0	1.6	9.9	37.8
Pisgah	0.7	0.2	2.4	3.8	0.0	0.0	10.0	17.1
Riverside East	2.6	1.5	1.6	0.6	0.0	0.0	10.0	16.2
Round Mountain-A	10.0	10.0	10.0	7.5	0.0	0.0	10.0	47.5
Round Mountain-B	4.7	0.5	1.1	4.0	3.0	0.0	10.0	23.3
San Bernardino - Baker	4.1	2.9	3.4	0.8	3.2	0.0	10.0	24.4
San Bernardino - Lucerne	5.7	1.8	1.6	1.1	1.2	0.0	10.0	21.4
San Diego North Central	5.1	3.4	3.1	4.3	1.1	2.8	10.0	29.7
San Diego South	2.3	1.4	2.5	3.8	3.4	0.0	10.0	23.5
Santa Barbara	1.9	1.7	1.4	3.0	2.8	0.0	7.3	18.1
Solano	1.9	0.0	0.2	3.3	2.4	10.0	8.4	26.2
Tehachapi	3.3	1.4	0.2	0.4	1.8	0.7	10.0	17.8
Twentynine Palms	4.6	0.0	0.8	1.7	2.1	0.0	10.0	19.1
Victorville	3.3	3.9	1.6	0.7	0.4	0.1	9.9	19.9
Westlands	1.4	0.0	0.0	2.1	2.9	0.0	9.0	15.3

3.5 Scoring Out of State Resources

Out of state resources that are adjacent to the California border and have similar environmental characteristics as their neighboring CREZs were given a score that reflects the average score of the neighboring California CREZs. This groups the out of state resources with those that would have similar ecology as neighboring California.

For instance, the Baja California CREZ falls within the La Rumorosa mountain chain which is an extension of the Peninsular Ranges of eastern San Diego. As such it has a similar habitat and similar special status species as one would find in eastern San Diego. Efforts such as the *Las Californias Binational Conservation Initiative* recognize the shared landscape between these two border regions and the many shared resources. Likewise, the CREZs located in the Sonoran Desert of eastern Imperial County share numerous ecological characteristics with the adjacent Sonoran Desert in western Arizona. For these reasons, the Baja California, Arizona, and Nevada zones were given the average of the neighboring California CREZ scores.

Oregon and other out of state renewable resources were given a median environmental score reflecting the median of all CREZs. This was done in an attempt to retain a relatively neutral ranking for renewable resources outside California.

4. Applying the Environmental Criteria to Technologies

This section outlines our approach for considering how the environmental criteria apply to each major given renewable technology. Because the environmental ranking of each CREZ is given here per acre of the total area of the zone, the area needed by each renewable technology must be considered before completing the score. Technologies with greater land use and "undisturbed area needs" per unit of energy production result in higher (worse) scores, where lower scores indicate less environmental concern.

4.1 Indentifying Area Needs by Technology

The RETI process provides the availability of energy production for biomass/biogas, wind, solar, and geothermal technologies for each CREZ as well as the expected energy development footprints for each of these resources except biomass/biogas. Footprints vary by geographic region, energy output, and the relative area needs of each technology.

Table 5 shows the development footprints expected by RETI within each CREZ and the area needs, which are simply the footprint divided by energy output expected by RETI for each technology and CREZ (in Table 1).

Table 5. RETI Phase 2B Development Footprints and Area Needs by Technology

CREZ Name	Total Annual Energy (GWh/yr)	Wind (ac)	Solar (ac)	Geothermal (ac)	Wind (ac per GWh/year)	Solar (ac per GWh/year)	Geothermal (ac per GWh/year)	Undisturbed Land (ac/CREZ ac)
Barstow	5,362	49,930	8,960	0	21.13	2.99	---	0.99
Carrizo North	3,053	0	10,240	0	---	3.35	---	0.77
Carrizo South	5,823	0	19,200	0	---	3.30	---	1.00
Cuyama	801	0	2,560	0	---	3.19	---	1.00
Fairmont	7,000	32,365	12,800	0	16.25	3.17	---	0.91
Imperial East	3,416	11,852	9,600	0	59.26	2.98	---	1.00
Imperial North-A	10,095	0	0	1,370	---	---	0.14	0.55
Imperial North-B	3,965	0	11,520	0	---	3.07	---	0.76
Imperial South	8,197	2,710	22,848	64	23.90	3.09	0.15	0.70
Inyokern	5,589	22,936	13,728	0	33.85	2.80	---	0.99
Iron Mountain	10,288	6,089	35,840	0	42.47	3.53	---	1.00
Kramer	14,784	16,545	39,584	24	36.95	2.79	0.15	1.00
Lassen North	3,595	100,968	0	0	28.09	---	---	1.00
Lassen South	1,051	19,954	0	0	18.99	---	---	1.00
Mountain Pass	2,111	44,295	4,992	0	99.64	2.99	---	1.00
Owens Valley	10,651	0	32,000	0	---	3.00	---	1.00
Palm Springs	1,047	7,376	0	0	7.05	---	---	0.93
Pisgah	4,706	0	11,520	0	---	2.45	---	1.00
Riverside East	22,525	0	67,520	0	---	3.00	---	0.96
Round Mountain-A	2,557	0	0	384	---	---	0.15	1.00
Round Mountain-B	339	10,125	0	0	29.87	---	---	1.00
San Bernardino - Baker	7,064	0	23,488	0	---	3.33	---	1.00
San Bernardino - Lucerne	5,656	47,313	14,976	0	29.84	4.37	---	0.99
San Diego North Central	502	18,631	0	0	37.13	---	---	0.96
San Diego South	1,829	24,607	0	0	13.45	---	---	1.00
Santa Barbara	1,121	30,285	0	0	27.01	---	---	0.98
Solano	2,721	27,990	0	0	10.29	---	---	1.00
Tehachapi	25,432	168,513	46,048	0	18.57	2.86	---	0.96
Twentynine Palms	3,959	0	11,552	0	---	2.92	---	1.00
Victorville	3,899	51,463	7,680	0	44.31	2.81	---	1.00
Westlands	8,317	0	32,000	0	---	3.85	---	0.02
Median Footprint per Output	---	---	---	---	28.09	3.00	0.15	
Lowest Footprint per Output	---	---	---	---	7.05	2.45	0.14	

Source: RETI Phase 2B, May 2010 and supporting spreadsheets (Black & Veatch); wind area is shown without adjusting by 0.035. Development footprint divided by energy output (Table 1) equals the area need (ac per GWh/yr).

4.2 Discussion of Area Needs by Technology

Biomass and Biogas. The primary environmental concern for most biomass and biogas generation is air quality, because biomass and biogas projects do not require large land resources as compared to other renewable technologies. However, biomass and biogas projects can serve a role in air quality management if the fuel would otherwise be burned in an uncontrolled manner. The RETI Phase 1B report noted: "*Environmental concerns associated with biomass projects are primarily associated with production, collection and transportation of fuels for which no acceptable data exist. Biomass CREZs are therefore not included in the EWG ranking process.*" For the present environmental scores, a single factor of 0.15 acres per GWh/yr is assumed (equal to geothermal median area need that is from RETI Phase 1B), although this is only an approximation for ranking purposes because the area needs for biomass and biogas vary widely depending on the fuel type and the distance fuel must travel to the biomass or biogas power plant.

Geothermal. Geothermal generation has the lowest footprint per output and results in relatively low area needs due to the high capacity factor. Environmental concerns can be avoided by strategic placement of geothermal project elements like wells and piping. RETI Phase 1B specifies one acre per megawatt of capacity (or a median of 0.15 acres per GWh/yr).

Solar Photovoltaic (PV) and Solar Thermal. RETI data merges the energy development footprint for these two technologies. As a result, the methodology in this white paper does not distinguish the differences or comparative advantages of these two technologies for environmental scoring. Relatively high levels of environmental concern occur for utility-scale solar PV development, especially due to large project footprints and likely impacts to significant species and habitat corridors. Solar PV projects are generally more configurable than solar thermal projects, meaning that significant species and habitat corridors may be less of a concern for PV than they are for solar thermal. However, utility-scale solar thermal projects generally have an advantage with higher energy conversion efficiency of the solar resource, which compensates for the comparative inflexibility in siting that this technology seems to have.

Wind. Wind generation has the highest footprint per output in terms of project lease area. RETI data presents the development footprint for wind in terms of both expected lease area for project development (shown here in Table 5) and the development footprint or fraction of ground disturbance caused by turbines and roads (given as 3.5% of the lease area, presented in RETI Phase 1B and Phase 2B). Adjusted for expected ground disturbance, wind has a median area need of about 28 acres per GWh/yr times 3.5%, or 1 acre per GWh/yr. The primary environmental concern for developing wind resources is typically avian mortality.

Photovoltaic Distributed Generation (DG). Rural solar photovoltaic (PV) that would occur at the scale of distributed generation (DG) (on the order of 20 MW or less) has similar environmental concerns as utility-scale solar PV. Because there is a greater flexibility and ability to avoid major wildlife corridors when locating a rural DG PV project compared to a larger utility scale project, the environmental criterion for wildlife corridors is not included in this score.

Urban PV Distributed Generation. Urban solar PV developed on a DG scale would be likely to avoid most of the environmental concerns discussed in this report. Rooftop PV could essentially avoid all of the environmental concerns identified here. To reflect this and to ensure priority in selecting these resources, where available, urban PV DG are assigned scores matching the lowest score of any resource in the CREZ.

4.3 Weighting "Area Needs" by Percentage of Undisturbed Land

In order to reflect the differences in Undisturbed vs. Mechanically Disturbed land between zone, the area needs above were weighted by the percentage of Undisturbed Land in each zone (shown in the rightmost column of Table 5, above). This weighting results in favorable scores (lower "area needs") for resource development that may occur where Mechanically Disturbed Land is abundant. Resources would be penalized for higher area needs if in a zone with a high fraction of undisturbed land.

5. Transmission Scores

Each RETI CREZ was assigned a transmission score for both minor upgrades (where available) and new transmission from that CREZ to a load center. Scores were assigned based on the distance from the CREZ to a major delivery point in California, and weighted by the type of transmission. The scores and weightings used are shown in the table below. Minor upgrades were given a much smaller weight than new transmission because, although associated in the scoring methodology with the mileage between the relevant CREZ and the major load center, the minor upgrades were in some cases only additions to a substation that would not result in any expansion of the substation footprint. The nature of the minor upgrades is detailed in the CAISO's assessment, in Appendix D1, above.

Table 6. Transmission Line Scoring

Length of Line	Minor Upgrades	New Transmission
<25 miles	1.0	4.0
25 – 50 miles	2.0	8.0
50 – 100 miles	3.0	12.0
100 - 200 miles	4.0	16.0
>200 miles	5.0	20.0

6. Results

6.1 Environmental Rankings and Scores

Each RETI CREZ was analyzed according to the seven environmental criteria (Section 3). The results for each area were then multiplied by the undisturbed area needs of each technology (Section 4) to arrive at an individual score for each technology in each CREZ, as shown in Table 7.

Table 7. Environmental Scores by Technology and CREZ

CREZ Name	Biomass / Biogas	Geothermal	Large Scale Solar PV and Solar Thermal	Wind	Minor Upgrades	New Transmission
Barstow	3.5	3.5	80.9	19.9	4.0	8.0
Carrizo North	2.3	2.3	59.1	17.3	6.0	12.0
Carrizo South	2.8	2.8	73.1	21.8	8.0	16.0
Cuyama	3.7	3.7	91.5	28.2	8.0	16.0
Fairmont	2.2	2.2	55.8	9.1	2.0	4.0
Imperial East	2.6	2.6	61.7	42.9	6.0	12.0
Imperial North-A	2.6	1.5	61.4	20.1	6.0	12.0
Imperial North-B	2.8	2.8	66.4	21.3	6.0	12.0
Imperial South	2.5	2.1	61.3	11.6	6.0	12.0
Inyokern	3.1	3.1	68.2	28.5	6.0	12.0
Iron Mountain	2.2	2.2	61.8	26.0	6.0	12.0
Kramer	3.2	3.7	69.4	32.2	4.0	8.0
Lassen North	2.1	2.1	48.8	16.0	8.0	16.0
Lassen South	4.4	4.4	104.5	23.1	8.0	16.0
Mountain Pass	2.8	2.8	65.3	76.0	6.0	12.0
Owens Valley	3.5	3.5	82.9	27.1	6.0	12.0
Palm Springs	4.5	4.5	105.6	8.1	4.0	8.0
Pisgah	2.2	2.2	41.9	16.8	6.0	12.0
Riverside East	2.0	2.0	46.8	15.3	6.0	12.0
Round Mountain-A	6.1	7.1	142.6	46.7	6.0	12.0
Round Mountain-B	3.0	3.0	69.6	24.1	6.0	12.0
San Bernardino - Baker	3.1	3.1	81.0	24.0	6.0	12.0
San Bernardino - Lucerne	2.7	2.7	93.1	22.1	4.0	8.0
San Diego North Central	3.6	3.6	85.6	35.6	2.0	4.0
San Diego South	3.0	3.0	70.6	11.0	8.0	16.0
Santa Barbara	2.3	2.3	53.2	16.4	8.0	16.0
Solano	3.4	3.4	78.8	9.4	2.0	4.0
Tehachapi	2.2	2.2	48.8	10.6	4.0	8.0
Twentynine Palms	2.4	2.4	55.8	18.8	6.0	12.0
Victorville	2.5	2.5	55.6	30.6	2.0	4.0
Westlands	0.0	0.0	1.0	0.3	6.0	12.0
Arizona	4.0	4.1	66.4	21.3	10.0	20.0
Nevada	3.1	3.1	72.9	38.4	10.0	20.0
Northwest	2.8	2.8	66.4	21.3	10.0	20.0
Baja	3.3	3.3	78.1	23.3	10.0	20.0
Out-of-State (Other)	2.8	2.8	66.4	21.3	10.0	20.0

Table 7. Environmental Scores by Technology and CREZ

CREZ Name	Biomass / Biogas	Geothermal	Large Scale Solar PV and Solar Thermal	Wind	Minor Upgrades	New Transmission
NonCREZ	2.8	2.8	66.4	21.3		

The area need (acres per GWh/yr, Table 5) multiplied by the percentage of Undisturbed land (Table 5) multiplied by the ranking results (Table 4) equals the environmental score.

6.2 Environmental Scores for Small Scale PV

Small scale PV was separated into three categories for environmental scoring: Distributed Solar, Remote DG (Brownfield), and Remote DG (Greenfield). Distributed Solar was assumed to be easy to connect and sited on rooftops or mechanically disturbed land, and was assigned an environmental score of 0. Remote DG (Brownfield) was assumed to be hard to connect (requiring gen-tie construction) and sited on mechanically disturbed land. It was assigned an environmental score of 4.0 to reflect an average 45-mile gen-tie rated as a minor upgrade. Remote DG (Greenfield) was assumed to be hard to connect (requiring gen-tie construction) and sited on undisturbed land with the average solar acres/GWh score across all zones (3.1). This resulted in an environmental score of 76.8 with a transmission adder of 4.0 (for a 45-mile gen-tie) for a total of 80.8.

Solar Resource	Environmental Score
Distributed Solar	0.0
Remote DG (Brownfield)	4.0
Remote DG (Greenfield)	80.8

6.3 Environmental Supply Curve

The “environmental supply curve” shows the cumulative annual energy in gigawatt-hours per year (GWh/yr) that could be provided by renewable projects in relation to the environmental scores.

The environmental scores from this white paper (Table 6) can be assigned to each of the projects in the RPS calculator that is not reserved for local use, representing ~900,000 GWh/yr potential generation, and the results are shown in Figure 1.

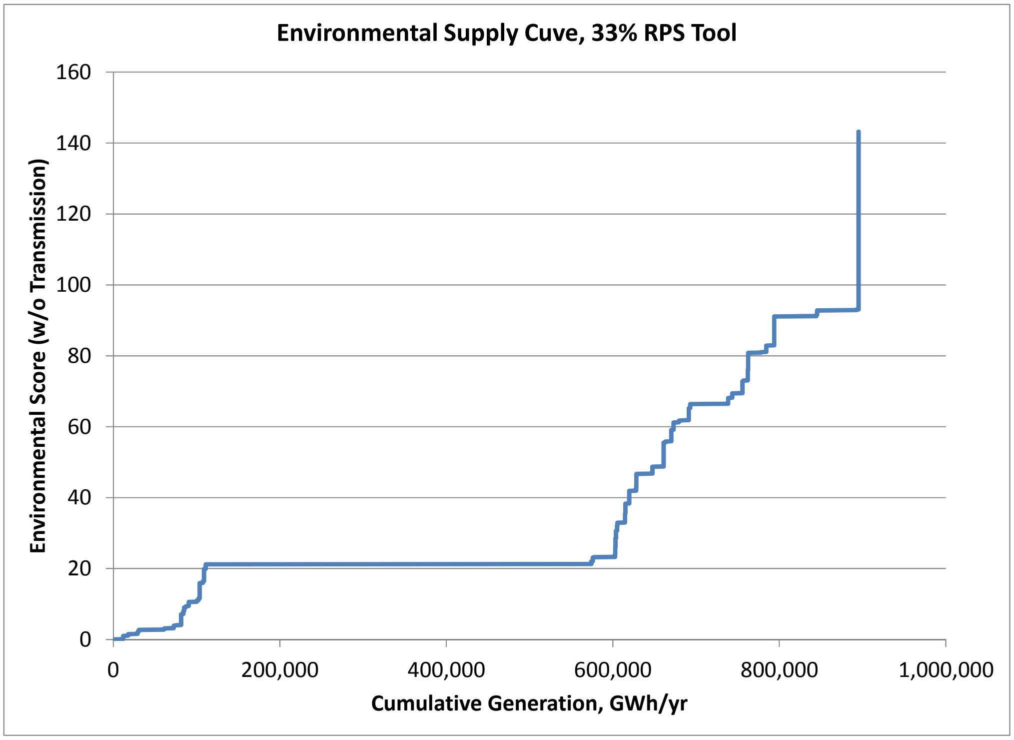

Figure 1. Environmental Scoring Results for 33% RPS Tool Projects

References

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Appendix F

Timing Assessment

F1: Generation timing assumptions

F2: Transmission timing assumptions

F1: Generation Timing Assumptions

The table below summarizes the timing assumptions used to develop the summary development timelines presented in Section II.7 of this report.

Technology	Size	Permitting Jurisdiction	Development Duration (months)			
			Preparation	Permitting / Environmental Review	Construction	Total
Biogas						
	<50 MW	City/County/Federal	12	12	10	**34**
	≥ 50 MW	State/Federal	12	24	12	**48**
Biomass						
	<50 MW	City/County/Federal	12	14	24	**50**
	≥ 50 MW	State/Federal	18	24	26	**68**
Geothermal						
	<50 MW	City/County/Federal	12	14	20	**46**
	≥ 50 MW	State/Federal	18	24	28	**70**
Small Hydro						
		City/County/Federal	12	14	20	**46**
Solar Thermal						
	<50 MW	City/County/Federal	12	14	24	**50**
	≥ 50 MW	State/Federal	18	24	32	**74**
Solar PV - ground mounted, ≥ 20 MW						
	20-50 MW	City/County/Federal	12	10	12	**34**
	≥ 50 MW	City/County/Federal	18	18	18	**54**
Wind						
	<50 MW	City/County/Federal	12	10	12	**34**
	≥ 50 MW	City/County/Federal	18	18	18	**54**

F2: Transmission Timing Assumptions

As described in Section II.7, each transmission "bundle" from each CREZ was assigned to one of the following transmission schedules:

Transmission Schedule Type	Transmission Planning by CAISO/ POU/ WECC (months)	Project Description Prep by Utility	CEQA/ NEPA Review by CPUC/POU / Feds	Final Review and Approval by CPUC/ POU/Feds	Final Design and Construction by Utilities	Total
Existing / Distributed	0	0	0	0	0	**0**
Typical	18	12	24	6	24	**84**
Typical - Short	12	12	12	3	18	**57**
Typical - Long	24	18	24	6	30	**102**
Long-Distance	24	18	24	6	30	**102**
Tehachapi	0	0	0	6	48	**54**
Sunrise	0	0	0	0	24	**24**
Devers - CO River	0	0	0	0	30	**30**

In general, zones were assigned to schedules as follows:

CREZ and Transmission Increment	Transmission Schedule Type	Development Start Date
Non-CREZ	Existing/Distributed	6/1/2010
CREZ – accommodated by existing system	Existing/Distributed	“
CREZ – accommodated by minor upgrades	Typical-Short	“
CREZ – 230 kV line, in-state	Typical-Short	“
CREZ – 500 kV line, in-state	Typical or Typical-Long, depending on location	6/1/2010 for up to 4500 MW of capacity; every 2 years thereafter
Out-of-state Resource	Long-Distance	“

The table below lists CREZ transmission bundles more specifically, by the size of the incremental bundle, the assumed transmission schedule, and the assumed development start time.

For the modeling effort, E3 assumed that each zone was available at the beginning of the year following whatever date resulted from the combination of the assigned start date and transmission schedule.

Transmission Zone	Line Capacity (MW)	Schedule Type	Start Date
Existing		Existing	1-Jun-2010
Alberta		Long-Distance	1-Jun-2010
Arizona-Southern Nevada			
Arizona-Southern Nevada - 1	1500	Long-Distance	1-Jun-2010
Arizona-Southern Nevada - 2	1500	Long-Distance	1-Jun-2010
Arizona-Southern Nevada - 3	1500	Long-Distance	1-Jun-2010
Arizona-Southern Nevada - 4	1500	Long-Distance	1-Jun-2010
Baja			
Baja - 1	1500	Typical - Short	1-Jun-2009
Baja - 2	1500	Typical - Short	1-Jun-2010
Baja - 3	1500	Typical - Short	1-Jun-2010
Baja - 4	1500	Typical - Short	1-Jun-2010
Barstow			
Barstow - 1	1500	Typical	1-Jun-2010
Barstow - 2	1500	Typical	1-Jun-2010
British Columbia			
British Columbia - 1	3000	Long-Distance	1-Jun-2009
British Columbia - 2	3000	Long-Distance	1-Jun-2012
British Columbia - 3	3000	Long-Distance	1-Jun-2014
British Columbia - 4	3000	Long-Distance	1-Jun-2016
Carrizo North			
Carrizo North - 1	1500	Typical	1-Jun-2010
Carrizo South			
Carrizo South - existing/approved	300	Existing	1-Jun-2010
Carrizo South - minor new	600	Typical - Short	1-Jun-2009
Carrizo South - 1	1500	Typical	1-Jun-2010

Colorado			
Colorado - 1	3000	Long-Distance	1-Jun-2010
Colorado - 2	3000	Long-Distance	1-Jun-2012
Colorado - 3	3000	Long-Distance	1-Jun-2014
Colorado - 4	3000	Long-Distance	1-Jun-2016
Cuyama			
Cuyama - 1	500	Typical - Short	1-Jun-2010
Distributed Biogas		Distributed	1-Jun-2010
Distributed Biomass		Distributed	1-Jun-2010
Distributed CPUC Database		Distributed	1-Jun-2010
Distributed Geothermal		Distributed	1-Jun-2010
Distributed Solar		Distributed	1-Jun-2010
Distributed Wind		Distributed	1-Jun-2010
Fairmont			
Fairmont - 1	1500	Typical	1-Jun-2010
Fairmont - 2	1500	Typical	1-Jun-2010
Imperial East			
Imperial East - 1	1500	Typical	1-Jun-2010
Imperial North			
Imperial North - 1	1500	Typical	1-Jun-2010
Imperial North - 2	1500	Typical	1-Jun-2010
Imperial South			
Imperial South - minor new	1125	Sunrise	1-Jun-2010
Imperial South - 1	1500	Typical	1-Jun-2010
Imperial South - 2	1500	Typical	1-Jun-2010
Inyokern			
Inyokern - 1	1500	Typical - Long	1-Jun-2010
Inyokern - 2	1500	Typical - Long	1-Jun-2010
Iron Mountain			
Iron Mountain - 1	1500	Typical - Long	1-Jun-2010
Iron Mountain - 2	1500	Typical - Long	1-Jun-2010
Iron Mountain - 3	1500	Typical - Long	1-Jun-2010
Kramer			
Kramer - minor new	62	Existing	1-Jun-2010
Kramer - 1	1500	Typical - Long	1-Jun-2010
Kramer - 2	1500	Typical - Long	1-Jun-2010
Kramer - 3	1500	Typical - Long	1-Jun-2010
Kramer - 4	1500	Typical - Long	1-Jun-2012
Lassen North			
Lassen North - 1	1500	Typical - Long	1-Jun-2010
Lassen South			
Lassen South - 1	1500	Typical - Long	1-Jun-2010
Montana			
Montana - 1	3000	Long-Distance	1-Jun-2010
Montana - 2	3000	Long-Distance	1-Jun-2012
Montana - 3	3000	Long-Distance	1-Jun-2014
Montana - 4	3000	Long-Distance	1-Jun-2016
Mountain Pass			
Mountain Pass - 1	1500	Typical - Short	1-Jun-2010
Nevada N			
Nevada N - 1	500	Typical - Long	1-Jun-2010
Nevada N - 2	500	Typical - Long	1-Jun-2010
Nevada N - 3	500	Typical - Long	1-Jun-2010

Nevada N - 4	500	Typical - Long	1-Jun-2010
Nevada C			
Nevada C - 1	1500	Typical - Long	1-Jun-2010
Nevada C - 2	1500	Typical - Long	1-Jun-2010
Nevada C - 3	1500	Typical - Long	1-Jun-2010
Nevada C - 4	1500	Typical - Long	1-Jun-2012
New Mexico			
New Mexico - 1	3000	Long-Distance	1-Jun-2010
New Mexico - 2	3000	Long-Distance	1-Jun-2012
New Mexico - 3	3000	Long-Distance	1-Jun-2014
New Mexico - 4	3000	Long-Distance	1-Jun-2016
NonCREZ		Distributed	1-Jun-2010
Northwest			
Northwest - 1	1500	Long-Distance	1-Jun-2010
Northwest - 2	1500	Long-Distance	1-Jun-2010
Northwest - 3	1500	Long-Distance	1-Jun-2010
Northwest - 4	1500	Long-Distance	1-Jun-2012
Owens Valley			
Owens Valley - 1	1500	Typical - Long	1-Jun-2010
Owens Valley - 2	1500	Typical - Long	1-Jun-2010
Owens Valley - 3	1500	Typical - Long	1-Jun-2010
Palm Springs			
Palm Springs - existing/approved	1000	Existing	1-Jun-2010
Pisgah			
Pisgah - minor new	275	Typical - Short	1-Jun-2010
Pisgah - 1	1500	Typical	1-Jun-2010
Pisgah - 2	1500	Typical	1-Jun-2010
Pisgah - 3	1500	Typical	1-Jun-2010
Remote DG		Distributed	1-Jun-2010
Reno Area/Dixie Valley			
Reno Area/Dixie Valley - 1		Typical - Long	1-Jun-2010
Reno Area/Dixie Valley - 2		Typical - Long	1-Jun-2010
Reno Area/Dixie Valley - 3		Typical - Long	1-Jun-2010
Reno Area/Dixie Valley - 4		Typical - Long	1-Jun-2010
Riverside East			
Riverside East - existing/approved	1500	Devers - Colorado River	1-Jun-2010
Riverside East - 1	3000	Typical	1-Jun-2010
Riverside East - 2	3000	Typical	1-Jun-2012
Riverside East - 3	3000	Typical	1-Jun-2014
Round Mountain			
Round Mountain - existing/approved	100	Existing	1-Jun-2010
Round Mountain - 1	500	Typical - Short	1-Jun-2010
San Bernardino - Baker			
San Bernardino - Baker - 1	1500	Typical	1-Jun-2010
San Bernardino - Baker - 2	1500	Typical	1-Jun-2010
San Bernardino - Lucerne			
San Bernardino - Lucerne - existing/approved	261	Existing	1-Jun-2010
San Bernardino - Lucerne - 1	1500	Typical	1-Jun-2010
San Diego North Central			
San Diego North Central - 1	500	Typical - Short	1-Jun-2010
San Diego South			
San Diego South - existing/approved	400	Existing	1-Jun-2010
San Diego South - minor new	361	Typical - Short	1-Jun-2010

Santa Barbara			
Santa Barbara - 1	500	Typical - Short	1-Jun-2010
Solano			
Solano - minor new	300	Typical - Short	1-Jun-2010
Solano - 1	1000	Typical - Short	1-Jun-2010
Tehachapi			
Tehachapi - existing/approved	4500	Tehachapi	1-Jun-2010
Tehachapi - existing/approved	3400	Tehachapi 4-11	1-Jun-2010
Tehachapi - minor new	1325	Typical - Short	1-Jun-2010
Tehachapi - 1	3000	Typical	1-Jun-2012
Tehachapi - 2	3000	Typical	1-Jun-2014
Twentynine Palms			
Twentynine Palms - 1	1000	Typical	1-Jun-2010
Twentynine Palms - 2	1000	Typical	1-Jun-2010
Utah-Southern Idaho			
Utah-Southern Idaho - 1	1500	Long-Distance	1-Jun-2010
Utah-Southern Idaho - 2	1500	Long-Distance	1-Jun-2010
Utah-Southern Idaho - 3	1500	Long-Distance	1-Jun-2010
Utah-Southern Idaho - 4	1500	Long-Distance	1-Jun-2012
Victorville			
Victorville - 1	1500	Typical	1-Jun-2010
Westlands			
Westlands - minor new	800	Typical - Short	1-Jun-2010
Westlands - 1	1500	Typical	1-Jun-2010
Westlands - 2	1500	Typical	1-Jun-2010
Wyoming			
Wyoming - 1	3000	Long-Distance	1-Jun-2010
Wyoming - 2	3000	Long-Distance	1-Jun-2012
Wyoming - 3	3000	Long-Distance	1-Jun-2014
Wyoming - 4	3000	Long-Distance	1-Jun-2016

(END OF ATTACHMENT 2)

Attachment 3

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

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Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans.	)))	Rulemaking 10-05-006

MOTION FOR EXPEDITED SUSPENSION OF TRACK 1 SCHEDULE, AND FOR APPROVAL OF SETTLEMENT AGREEMENT BETWEEN AND AMONG PACIFIC GAS AND ELECTRIC COMPANY, SOUTHERN CALIFORNIA EDISON COMPANY, SAN DIEGO GAS & ELECTRIC COMPANY, THE DIVISION OF RATEPAYER ADVOCATES, THE UTILITY REFORM NETWORK, GREEN POWER INSTITUTE, CALIFORNIA LARGE ENERGY CONSUMERS ASSOCIATION, THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR, THE CALIFORNIA WIND ENERGY ASSOCIATION, THE CALIFORNIA COGENERATION COUNCIL, THE SIERRA CLUB, COMMUNITIES FOR A BETTER ENVIRONMENT, PACIFIC ENVIRONMENT, COGENERATION ASSOCIATION OF CALIFORNIA, ENERGY PRODUCERS AND USERS COALITION, CALPINE CORPORATION, JACK ELLIS, GENON CALIFORNIA NORTH LLC, THE CENTER FOR ENERGY EFFICIENCY AND RENEWABLE TECHNOLOGIES, THE NATURAL RESOURCE DEFENSE COUNCIL, NRG ENERGY, INC., THE VOTE SOLAR INITIATIVE, AND THE WESTERN POWER TRADING FORUM

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Dated: August 3, 2011

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans.	)))	Rulemaking 10-05-006

MOTION FOR EXPEDITED SUSPENSION OF TRACK 1 SCHEDULE, AND FOR APPROVAL OF SETTLEMENT AGREEMENT BETWEEN AND AMONG PACIFIC GAS AND ELECTRIC COMPANY, SOUTHERN CALIFORNIA EDISON COMPANY, SAN DIEGO GAS & ELECTRIC COMPANY, THE DIVISION OF RATEPAYER ADVOCATES, THE UTILITY REFORM NETWORK, GREEN POWER INSTITUTE, CALIFORNIA LARGE ENERGY CONSUMERS ASSOCIATION, THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR, THE CALIFORNIA WIND ENERGY ASSOCIATION, THE CALIFORNIA COGENERATION COUNCIL, THE SIERRA CLUB, COMMUNITIES FOR A BETTER ENVIRONMENT, PACIFIC ENVIRONMENT, COGENERATION ASSOCIATION OF CALIFORNIA, ENERGY PRODUCERS AND USERS COALITION, CALPINE CORPORATION, JACK ELLIS, GENON CALIFORNIA NORTH LLC, THE CENTER FOR ENERGY EFFICIENCY AND RENEWABLE TECHNOLOGIES, THE NATURAL RESOURCE DEFENSE COUNCIL, NRG ENERGY, INC., THE VOTE SOLAR INITIATIVE, AND THE WESTERN POWER TRADING FORUM

I. INTRODUCTION AND SUMMARY OF RELIEF SOUGHT

Pursuant to Rule 12.1 of the California Public Utilities Commission's (Commission) Rules of Practice and Procedure, Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), San Diego Gas & Electric Company (SDG&E), the Division of Ratepayer Advocates (DRA), The Utility Reform Network (TURN), Green Power Institute, California Large Energy Consumers Association (CLECA), the California Independent System Operator (CAISO), the California Wind Energy Association (CalWEA), the California Cogeneration Council (CCC), the Sierra Club, Communities for a Better Environment (CBA), Pacific Environment, Cogeneration Association of California (CAC), Energy Producers and Users Coalition (EPUC), Calpine Corporation (Calpine), Jack Ellis, GenOn California North LLC (GenOn), the Center for Energy Efficiency and Renewable Technologies (CEERT), the Natural Resource Defense Council (NRDC), NRG Energy, Inc. (NRG), the Vote Solar Initiative (VoteSolar), and the Western Power Trading Forum (WPTF) (collectively referred to as the "Settling Parties" or individually as a " Settling Party"), submit for the Commission's review and approval the attached Settlement Agreement proposing a resolution to Track 1 of this proceeding that is mutually acceptable to the Settling Parties.[1] The proposed Settlement Agreement is in the public interest and represents a fair and equitable resolution of the issues in Track 1 (with the exception of (1) SDG&E's pending request for a need determination for new resources to meet Local Capacity Requirements (LCR) and (2) the possibility of need to procure currently uncontracted existing resources), and the Settling Parties' request that the Commission approve the Settlement Agreement without modification. The Settling Parties also request that, except as it relates to the two Track 1 issues not resolved by the Settlement Agreement, the Track 1 schedule be suspended pending Commission consideration of the Settlement Agreement. The Settling Parties do not propose any modification of the Track III schedule.

The Settling Parties request that their proposal to suspend the Track 1 schedule be addressed on an expedited basis, as without a suspension parties would be obligated to submit their litigation, pre-settlement testimony on August 4, 2011.

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[1] Each of the Settling Parties has authorized PG&E to file this motion on its behalf.

II. PROCEDURAL BACKGROUND

The Commission has determined that the purpose of Track I is to identify Commission-jurisdictional needs for new resources to meet system or local resource adequacy and to consider authorization of Investor-Owned Utility (IOU) procurement to meet that need, including issues related to long-term renewables planning and need for replacement generation infrastructure to eliminate reliance on power plants using once through cooling (OTC). (R.10-05-006, p. 9.) In carrying out this investigation, the Commission anticipated that in addition to maintaining an adequate reserve margin, system requirements to: 1) integrate renewables, 2) support OTC policy implementation, 3) maintain local reliability, and 4) meet greenhouse gas (GHG) goals will be primary drivers for any need for new resources identified in this proceeding. (*Id*., p. 12.)

Through a series of rulings (*see, e.g.*, February 10, 2011, Administrative Law Judge's Ruling Modifying System Track 1 Schedule and Setting Prehearing Conference), the Assigned Commissioner and Assigned Administrative Law Judges (ALJs) have refined the analysis required to be carried out by the IOUs, in conjunction with the California Independent System Operator (CAISO). In response, the IOUs and the CAISO developed and analyzed system resource plans using four scenarios described in rulings and in the December 3, 2010 Scoping Ruling to fulfill the standardized planning assumptions established by the Commission (four CPUC-Required Scenarios). In addition, the IOUs developed three scenarios and a further sensitivity analysis (IOU Common Scenarios). The CAISO also analyzed two others scenarios, one of which was identified in the December 3, 2010 Scoping Memo. Also in response to the requirements set forth in the series of ruling, the IOUs and the CAISO, in conjunction with Energy and Environmental Economics, Inc., (E3), a consultant to the IOUs, calculated the "performance evaluation metrics" associated all of these scenarios.

III. SUMMARY OF THE SETTLEMENT AGREEMENT

The Settlement Agreement addresses the fundamental issue in Track 1 of the LTPP proceeding: should the Commission determine that, due to system needs, the investor-owned utilities should be directed to obtain additional generation resources?

Summary of the non-procedural provisions of the attached Settlement Agreement:

- The Settling Parties agree not to dispute that the IOUs and the CAISO have complied with Commission directions in Track 1 with respect to issues resolved by the Settlement Agreement.
- As set forth in substantially more detail in the Settlement Agreement, the Settling Parties recommend that the Commission, in conjunction with the CAISO's ongoing work on this subject, should further expeditiously examine the system resource need and the integration of intermittent renewable resources into the CAISO grid, either in the next LTPP cycle or in an extension of the current LTPP cycle. There is general agreement that further analysis is needed before any renewable integration resource need determination is made. The Settling Parties recommend that a final Commission assessment of need or a decision should be issued no later than December 31, 2012.
- The Commission does not need to authorize procurement authority relating to LCR for SCE's and PG&E's service areas at this time.
- The Settlement Agreement does not address SDG&E's request for local LCR procurement authority, and each Settling Party remains free to advocate its individual litigation position on this issue.

- The Settlement Agreement does not address the possibility of need to procure currently uncontracted existing resources, and each Settling Party remains free to advocate it individual litigation position on this issue.
- Those Settling Parties who are also parties to the qualifying facility/combined heat and power settlement, adopted by the Commission in D.10-12-035, agree that nothing in the Settlement Agreement qualifies, defers, or relaxes any obligation of any party under that settlement.

IV. THE SETTLEMENT AGREEMENT IS REASONABLE AND IN THE PUBLIC INTEREST.

The Commission will approve a settlement if it finds the settlement "reasonable in light of the whole record, consistent with law, and in the public interest."[2] Here, the proposed settlement readily meets all of these criteria.

First, the Settlement Agreement is reasonable in light of the whole record. With respect to renewables integration, the IOUs have established that the analysis of the issue that has been presented in this proceeding "should be viewed as an initial effort to understand the complex problems of accommodating the significant increase in renewable energy expected over the next decade. There are a number of key areas where further analysis is necessary. . . ." (Joint IOU Supporting Testimony, pp. 1-3.) Thus, this aspect of the Settlement Agreement is reasonable in light of the whole record.

With respect to local capacity reliability requirements, PG&E's and SCE's testimony established that the Commission does not need to authorize procurement authority relating to

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[2] Rule 12.1(d); *see also* D.09-10-017.

local capacity requirements for PG&E's or SCE's service area at this time. This Settlement Agreement does not address SDG&E's request for LCR procurement authority in Track I of this LTPP. Each of the Settling Parties remains free to advocate its individual litigation position on the issue of SDG&E's LCR need. Thus, this aspect of the Settlement Agreement is reasonable in light of the whole record, as well.[3]

Second, the Settlement Agreement is fully consistent with the law and existing Commission precedent. Based on the record in this proceeding, Commission adoption of the Settlement Agreement recommendations is consistent with legislative mandates to meet 33 percent of California's electric load in 2020. Further, Commission adoption of the Settlement Agreement is consistent with the Commission's general mandate to act to ensure safe, reliable electric service in California.

Finally, approval of the Settlement Agreement is in the public interest. As the Commission has stated, to determine whether a settlement is in the public interest:

> [W]e consider individual elements of the settlement in order to determine whether the settlement generally balances the various interests at stake as well as to assure that each element is consistent with our policy objectives and the law.[4]

Here, the Settlement Agreement resolves many of the system need determinations that are to be addressed in this track of this proceeding at this time. It does so in a manner consistent with the recommendations in the record, and so generally balances the various interests at stake in the proceeding.

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[3] Additionally, the Settlement Agreement does not address the possibility of need to procure currently uncontracted existing resources. Each of the Settling Parties remains free to advocate its individual litigation position on this issue. Nor does the Settlement Agreement address either Track III issues or schedule.

[4] D.96-01-011; 64 CPUC2d 241, 267, citing D.94-04-088.

Based on the record, the adoption of the elements of the Settlement Agreement is consistent with the Commission's policy objectives and the law. Specifically, the Settlement Agreement is consistent with the Commission's policy objectives and the law with respect to the use of renewable resources to meet 33 percent of the electric load in California in 2020, and with respect to ensuring that Californians are provided with safe, reliable electric service

In short, the Settlement Agreement is entirely in the public interest.

V. THE SETTLING PARTIES HAVE COMPLIED WITH THE REQUIREMENTS OF RULE 12.1(b)

Commission Rule 12.1(b) requires parties to provide a notice of a settlement conference at least seven days before a settlement is signed. On July 22, 2011, the IOUs properly notified all of the parties on the service list of a settlement conference and subsequently convened the settlement conference on July 29, 2011, to describe and discuss the terms of the proposed settlement. Representatives of the Settling Parties participated in the settlement conference. The Settlement Agreement was finalized and executed on August 3, 2011.

VI. THE TRACK 1 PROCEDURAL SCHEDULE IN THE PROCEEDING SHOULD BE MODIFIED, ON AN EXPEDITED BASIS, TO ALLOW THE COMMISSION TO CONSIDER THIS TRACK 1 SETTLEMENT

An assigned Administrative Law Judge's ruling dated June 13, 2011, established the current schedule in this proceeding. Under that schedule, parties other than the IOUs and the CAISO are to serve Track 1 testimony on August 4, 2011. The Settling Parties request that the schedule for testimony, hearings, and briefing of the issues addressed in this Settlement Agreement (all Track I issues other than (1) SDG&E's pending request for a need determination for new resources to meet local capacity requirements and (2) the possibility of need to procure currently uncontracted existing resources) should be suspended pending Commission consideration of the Settlement Agreement.

In light of the number of active parties supporting the Settlement Agreement, which resolves a significant number of Track 1 issues as among the Settling Parties,[5] the record will be simplified and the need for hearings substantially reduced if the Settlement Agreement is adopted. In order to avoid the time and effort of going through the submission of testimony and the conducting of hearings on all Track 1 issues on a pre-settlement basis, as would be necessary if the Track 1 schedule is not suspended, the better approach is to suspend these hearings, with respect to issues addressed in the Settlement Agreement, pending consideration of the Settlement Agreement. Therefore, the Settling Parties' request that the Track 1 schedule, with respect to all Track 1 issues other than (1) SDG&E's pending request for a need determination for new resources to meet LCR, and (2) the possibility of need to procure currently uncontracted existing resources, be suspended pending consideration of whether the Settlement Agreement should be granted.

The Settling Parties request that this aspect of the motion be acted upon on an expedited basis. Unless there is a suspension of the schedule, Settling Parties would be obligated to submit their litigation, pre-settlement testimony on August 4, 2011.

VII. CONCLUSION

For all the foregoing reasons, the Settling Parties request the Commission approve the Settlement Agreement without change, that the Settling Parties' request to suspend the Track 1 schedule pending consideration of the Settlement Agreement be acted upon on an expedited basis, and that the Track 1 schedule, with the exception of the two Track 1 issues not resolved by

[5] Settling Parties may submit testimony on August 4 on the two Track 1 issues the Settlement Agreement expressly states it does not address.

the Settlement Agreement among the Settling Parties, be suspended pending consideration of the Settlement Agreement.

Respectfully submitted,

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/s/

By: Mark R. Huffman

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NATURAL RESOURCE DEFENSE COUNCIL,
NRG ENERGY, INC., AND
VOTE SOLAR INITIATIVE
WESTERN POWER TRADING FORUM

August 3, 2011

ATTACHMENT

SETTLEMENT AGREEMENT

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans.	Rulemaking 10-05-006

SETTLEMENT AGREEMENT BETWEEN AND AMONG PACIFIC GAS AND ELECTRIC COMPANY (U-39 E), SOUTHERN CALIFORNIA EDISON COMPANY (U-338-E), SAN DIEGO GAS & ELECTRIC COMPANY (U-902-E), THE DIVISION OF RATEPAYER ADVOCATES, THE UTILITY REFORM NETWORK, GREEN POWER INSTITUTE, CALIFORNIA LARGE ENERGY CONSUMERS ASSOCIATION, THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR, THE CALIFORNIA WIND ENERGY ASSOCIATION, THE CALIFORNIA COGENERATION COUNCIL, THE SIERRA CLUB, COMMUNITIES FOR A BETTER ENVIRONMENT, PACIFIC ENVIRONMENT, COGENERATION ASSOCIATION OF CALIFORNIA, ENERGY PRODUCERS AND USERS COALITION, CALPINE CORPORATION, JACK ELLIS, GENON CALIFORNIA NORTH LLC, THE CENTER FOR ENERGY EFFICIENCY AND RENEWABLE TECHNOLOGIES, THE NATURAL RESOURCE DEFENSE COUNCIL, NRG ENERGY, INC., THE VOTE SOLAR INITIATIVE, AND THE WESTERN POWER TRADING FORUM

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans.	Rulemaking 10-05-006

SETTLEMENT AGREEMENT BETWEEN AND AMONG PACIFIC GAS AND ELECTRIC COMPANY (U-39 E), SOUTHERN CALIFORNIA EDISON COMPANY (U-338-E), SAN DIEGO GAS & ELECTRIC COMPANY (U-902-E), THE DIVISION OF RATEPAYER ADVOCATES, THE UTILITY REFORM NETWORK, GREEN POWER INSTITUTE, CALIFORNIA LARGE ENERGY CONSUMERS ASSOCIATION, THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR, THE CALIFORNIA WIND ENERGY ASSOCIATION, THE CALIFORNIA COGENERATION COUNCIL, THE SIERRA CLUB, COMMUNITIES FOR A BETTER ENVIRONMENT, PACIFIC ENVIRONMENT, COGENERATION ASSOCIATION OF CALIFORNIA, ENERGY PRODUCERS AND USERS COALITION, CALPINE CORPORATION, JACK ELLIS, GENON CALIFORNIA NORTH LLC, THE CENTER FOR ENERGY EFFICIENCY AND RENEWABLE TECHNOLOGIES, THE NATURAL RESOURCE DEFENSE COUNCIL, NRG ENERGY, INC., THE VOTE SOLAR INITIATIVE, AND THE WESTERN POWER TRADING FORUM

I. INTRODUCTION

In accordance with Rule 12.1 of the California Public Utilities Commission's (Commission) Rules of Practice and Procedure, Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), San Diego Gas & Electric Company (SDG&E), the Division of Ratepayer Advocates (DRA), The Utility Reform Network (TURN), Green Power Institute, California Large Energy Consumers Association (CLECA), the California Independent System Operator (CAISO), the California Wind Energy Association (CalWEA), the California

Cogeneration Council (CCC), the Sierra Club, Communities for a Better Environment (CBA), Pacific Environment, Cogeneration Association of California (CAC), Energy Producers and Users Coalition (EPUC), Calpine Corporation (Calpine), Jack Ellis, GenOn California North LLC (GenOn), the Center for Energy Efficiency and Renewable Technologies (CEERT), the Natural Resource Defense Council (NRDC), NRG Energy, Inc. (NRG), the Vote Solar Initiative (VoteSolar), and the Western Power Trading Forum (WPTF) (collectively referred to as the "Settling Parties" or individually as a " Settling Party"), hereby enter into this Settlement Agreement proposing a resolution to Track 1 of this proceeding that is mutually acceptable to the Settling Parties.

The Settling Parties believe that this Settlement Agreement is in the public interest and represents a fair and equitable resolution of the issues in Track 1 of this proceeding that is mutually acceptable to the Settling Parties of all Track 1 issues of this proceeding, with the exception of (1) SDG&E's pending request for a need determination for new resources to meet Local Capacity Requirements (LCR) and (2) the possibility of need to procure currently uncontracted existing resources. Therefore, the Settling Parties request that the Commission approve the Settlement Agreement without modification.

II. RECITALS

The Commission has determined that the purpose of Track I is to identify Commission-jurisdictional needs for new resources to meet system or local resource adequacy and to consider authorization of Investor-Owned Utility (IOU) procurement to meet that need, including issues related to long-term renewables planning and need for replacement generation infrastructure to eliminate reliance on power plants using once through cooling (OTC). (R.10-05-006, p. 9.) In carrying out this investigation, the Commission anticipated that in addition to maintaining an adequate reserve margin, system requirements to: 1) integrate renewables, 2) support OTC policy implementation, 3) maintain local reliability, and 4) meet greenhouse gas (GHG) goals will be primary drivers for any need for new resources identified in this proceeding. (*Id.*, p. 12.)

Through a series of rulings (*see, e.g.*, February 10, 2011, Administrative Law Judge's Ruling Modifying System Track 1 Schedule and Setting Prehearing Conference), the Assigned Commissioner and Assigned Administrative Law Judges (ALJs) have refined the analysis required to be carried out by the IOUs, in conjunction with the California Independent System Operator (CAISO). In response, the IOUs and the CAISO developed and analyzed system resource plans using four scenarios described in rulings and in the December 3, 2010 Scoping Ruling to fulfill the standardized planning assumptions established by the Commission (four CPUC-Required Scenarios). In addition, the IOUs developed three scenarios and a further sensitivity analysis (IOU Common Scenarios). The CAISO also analyzed two other scenarios, one of which was identified in the December 3, 2010 Scoping Memo. Also in response to the requirements set forth in the series of rulings, the IOUs and the CAISO, in conjunction with Energy and Environmental Economics, Inc., (E3), a consultant to the IOUs, calculated the "performance evaluation metrics" associated with all of these scenarios.

III. SETTLEMENT AGREEMENT

A. Compliance With Commission Directives

As a compromise among their respective litigation positions, and subject to the recitals and reservations set forth in this Settlement Agreement, the Settling Parties agree not to dispute that the IOUs and the CAISO have complied with the directions contained in a series of rulings in this proceeding, with respect to the issues resolved in this Settlement Agreement. However, Settling Parties have differing views on the underlying input assumptions used in the analyses that inform the resolution of issues included in this Settlement Agreement, and this Settlement Agreement does not imply Settling Parties' support for those input assumptions.

B. System Need

As a compromise among their respective litigation positions, and subject to the recitals and reservations set forth in this Settlement Agreement, the Settling Parties agree that:

- With respect to system resource need and the integration of intermittent renewable resources into the CAISO grid, the Settling Parties encourage the Commission, in conjunction with the CAISO's ongoing work on this subject, to further examine this issue expeditiously in the next Long-Term Procurement Plan (LTPP) cycle or in an extension of the current LTPP cycle.

- All references to a potential "need to add capacity for renewable integration purposes" shall be interpreted within the context of the CAISO process which considers alternatives as further described in Section III.C below to determine the type of resources (including existing units) available to meet any defined needs. There is no presumption that any Phase 1 "need" requires the addition of new gas-fired generation resources above and beyond those needed to meet the current planning reserve margin.

- As requested by the Commission, the CAISO developed a methodology for assessing renewable integration resource needs (the "CAISO methodology"), and applied this methodology with the assistance of the IOUs to assess the need for flexible capacity for the four CPUC-Required Scenarios and one other CPUC scenario analyzed by the CAISO. The results show no need to add capacity for renewable integration purposes above the capacity available in the four scenarios for the planning period addressed in this LTPP cycle (2012-2020). The additional scenario studied by the CAISO did show need.

- The IOUs applied the same CAISO methodology for the IOU Common Scenarios using different assumptions from those used in the CPUC-Required Scenarios.

The results of the IOUs' modeling show need for additional capacity for renewable integration purposes under certain circumstances.

- The resource planning analyses presented in this proceeding do not conclusively demonstrate whether or not there is need to add capacity for renewable integration purposes through the year 2020, the period to be addressed during the current LTPP cycle. The Settling Parties have differing views on the input assumptions used in, and conclusions to be drawn from the modeling. There is general agreement that further analysis is needed before any renewable integration resource need determination is made. For example, in the CAISO 2011/2012 transmission planning process, the CAISO intends to complete its analysis of local area needs driven by the OTC schedule for resource retirements or repowerings, and this work will be completed by the end of 2011. Once these study results become available, the CAISO will incorporate them into the renewable integration model using the methodology developed in this proceeding, and will complete this analysis by the end of the first quarter, 2012. Accordingly, the Commission should, in collaboration with the CAISO, continue the work undertaken thus far in this proceeding to refine and understand the future need for new renewable integration resources, either as an extension of the current LTPP cycle or as part of the next LTPP, which should be initiated expeditiously in the first quarter, 2012 and contain the procedural milestones set forth in agreement. Specifically, the Settling Parties agree that the CAISO should present the results of its additional OTC and renewable integration studies reflecting the recommendations described in Section below by no later than March 31, 2012. During the second quarter, 2012, the Settling Parties recommend that the Commission provide a process for parties to conduct discovery, serve testimony and participate in an evidentiary hearing on the CAISO's renewable integration model and study results. Settling Parties further recommend that a final Commission assessment of need or a decision should be issued no later than December 31, 2012.

- Either as an extension of the current LTPP cycle, or as part of the next LTPP cycle and consistent with the procedural milestones in the previous paragraph, the Commission should continue the process undertaken in this proceeding that allows public review and comment on CAISO and IOU models; scenarios and and inputs used to analyze renewable integration needs. In addition, the process should allow all parties the opportunity to submit recommendations or proposals regarding assumptions, scenarios, modeling and inputs for inclusion in the record of the proceeding, including recommendation by the CAISO and other parties as to plausible scenarios that may be used for the CAISO's operational needs and market design enhancements.

C. Recommendations on Issues that Should Be Addressed in an Extension of the Current LTPP Cycle or the Next LTPP Cycle

As a compromise among their respective litigation positions, and subject to the recitals and reservations set forth in this Settlement Agreement, the Settling Parties recommend, either as an extension of the current LTPP cycle, or as part of the next LTPP cycle: (i) the continued review and adjustment of the methodology and assumptions used in the renewable integration analysis; and (ii) the analysis of the potential of integrating renewables with a variety of resources as intended in CAISO's proposed Phase 2 analysis. The purpose of the Phase 2 analysis is to determine the amount and operational characteristics of resources, whether supply or demand side resources, that could address the operational needs of renewable integration, including not only conventional generation but also resources such as demand response, renewable resource dispatchability, energy storage, electric vehicle charging, smart grid, and greater reliance on renewables resources that require fewer integration services, either individually or combined with a suite of other renewable resources.

D. Local Area (LCR) Need

As a compromise among their respective litigation positions, and subject to the recitals and reservations set forth in this Settlement Agreement, the Settling Parties agree that:

- It is important to incorporate the LCR work that the CAISO intends to complete as described above in Section B, System Need, and to reflect the results of that work in subsequent need assessments to be accomplished during the remainder of 2011 and the first half of 2012, either as an extension of the current LTPP cycle or as part of the next LTPP cycle.
- SCE's analysis of its LCR need is inconclusive, and that PG&E and SCE have not requested procurement authorization for new LCR resources in Track I of this LTPP.
- This Settlement Agreement does not address SDG&E's request for LCR procurement authority in Track I of this LTPP. Each of the Settling Parties remains free to advocate its individual litigation position on the issue of SDG&E's LCR need.
- The Commission does not need to authorize procurement authority relating to local capacity requirements for SCE's and PG&E's service areas at this time.

E. Existing Generation

As a compromise among their respective litigation positions, and subject to the recitals and reservations set forth in this Settlement Agreement, the Settling Parties agree that:

- This Settlement Agreement does not address the possibility of need to procure currently uncontracted existing resources. Each of the Settling Parties remains free to advocate its individual litigation position on this issue.

F. QF/CHP Settlement

Those Settling Parties who are also parties to the Qualifying Facility (QF)/Combined Heat and Power (CHP) settlement, adopted by the Commission in D.10-12-035 and subsequent orders, agree that nothing in the Settlement Agreement qualifies, defers or relaxes any obligation of any party under the QF/CHP settlement.

G. Exclusion of Track III Issues

As a compromise among their respective litigation positions and subject to the recitals and reservations set forth in this Settlement Agreement, the Settling Parties agree that:

- This Settlement Agreement does not address Track III issues or schedule.

H. Conclusion of Track 1 Of This Proceeding

As a compromise among their respective litigation positions, and subject to the recitals and reservations set forth in this Settlement Agreement, the Settling Parties agree that:

- The schedule for testimony, hearings, and briefing of the issues addressed in this Settlement Agreement (all Track I issues other than (1) SDG&E's pending request for a need determination for new resources to meet Local Capacity Requirements (LCR) and (2) the possibility of need to procure currently uncontracted existing resources) should be suspended pending Commission consideration of the Settlement Agreement. Intervening parties who sign the Settlement Agreement but have not served testimony will be permitted to submit data responses provided by the IOUs and the CAISO as part of the formal record of this proceeding. If the schedule is not suspended, however, Settling Parties may serve testimony on the date it is due (currently August 4, 2011). It will not violate this Settlement Agreement if, in that testimony, Settling Parties present arguments and positions that differ from the recommendations in this Settlement Agreement. The Settling Parties reserve the right to submit or present reply testimony, limited to rebuttal to any testimony submitted on August 4, 2011.

I. Commission Approval

This Settlement Agreement shall become effective on the date of a final Commission decision approving the terms of this Settlement Agreement without modifications unacceptable to any Settling Party.

J. General Terms and Conditions

1. The Settlement Agreement is intended to be a resolution among the Settling Parties of some of the issues in Track I of the LTPP proceeding.

2. The Settling Parties agree to support the Settlement Agreement and perform diligently, and in good faith, all actions required or implied hereunder to obtain Commission approval of the Settlement Agreement, including without limitation, the preparation of written pleadings. No Settling Party will contest in this proceeding, or in any other forum or in any manner before this Commission, this Settlement Agreement.

3. The Settling Parties agree by executing and submitting this Settlement Agreement that the relief requested herein is just, fair and reasonable, and in the public interest.

4. The Settlement Agreement is not intended by the Settling Parties to be precedent regarding any principle or issue. The Settling Parties have assented to the terms of this Settlement Agreement only for the purpose of arriving at the compromise embodied in this Settlement. Each Settling Party expressly reserves its right to advocate, in current and future proceedings, positions, principles, assumptions, and arguments which may be different than

those underlying this Settlement Agreement, and each Settling Party declares that this Settlement Agreement should not be considered as precedent for or against it.

5. This Settlement Agreement embodies compromises of the Settling Parties' positions. No individual term of this Settlement Agreement is assented to by any Settling Party, except in consideration of the other Settling Parties' assent to all other terms. Thus the Settlement Agreement is indivisible and each part is interdependent on each and all other parts. Any Settling Party may withdraw from this Settlement Agreement if the Commission modifies, deletes from, or adds to the disposition of the matters stipulated herein. The Settling Parties agree, however, to negotiate in good faith with regard to any Commission-ordered changes in order to restore the balance of benefits and burdens, and to exercise the right to withdraw only if such negotiations are unsuccessful.

6. The terms and conditions of the Settlement Agreement may only be modified in writing subscribed to by the Settling Parties and approved by a Commission order.

The Settling Parties have caused this Settlement Agreement to be executed by their authorized representatives. By signing this Settlement Agreement, the representatives of the Settling Parties warrant that they have the requisite authority to bind their respective principals.

DATED: August 3, 2011

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Signature pages to follow.

PACIFIC GAS AND ELECTRIC COMPANY

BY: ___________/S/___________________
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ITS: ATTORNEY

SOUTHERN CALIFORNIA EDISON COMPANY

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THE CALIFORNIA LARGE ENERGY CONSUMERS ASSOCIATION

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BY: ___________/S/________________
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ITS: _ATTORNEY

Attachment F

Capacity Procurement Mechanism Designation of Sutter Energy Center and Request for Waiver

Summary of Stakeholder Comments

The California ISO posted a report on the basis and need to designate the Sutter Energy Center (Sutter) as capacity at risk of retirement pursuant to the provisions of the ISO tariff regarding the capacity procurement mechanism (CPM) on December 6, 2011. The ISO hosted a stakeholder conference call on December 9, 2011 to review the report. Many stakeholders have expressed concern with or opposed the ISO's proposals to designate the Sutter Energy Center as capacity at risk of retirement and to request a tariff waiver to prevent the retirement through the use of the capacity procurement mechanism based on the ISO's finding of need in the 2017/2018 timeframe.[1] The ISO has categorized stakeholder concerns with the proposal as follows:

- The ISO's determination of need and supporting study assumptions;
- Whether the ISO's proposed waiver filing will undermine state regulatory proceedings and the development of a capacity backstop procurement mechanism;
- The adequacy of the ISO's stakeholder process;
- Transparency regarding the procurement costs to prevent the retirement of the Sutter Energy Center;
- Cost allocation associated with procuring the Sutter Energy Center;
- Whether Calpine Corporation (Calpine), the owner of the Sutter Energy Center, can demonstrate that its asset is financially distressed;
- Whether the facility can satisfy the needs identified in the ISO's study;
- Whether the ISO has adequately assessed alternatives to the use of a capacity procurement mechanism; and
- Whether the ISO has assessed the risk that other generators will request similar relief.

[1] The following stakeholders filed comments on the report: California Municipal Utilities Association (CMUA); the California Large Energy Consumers Association (CLECA); the Division of Ratepayer Advocates (DRA); California Department of Water Resources State Water Project (CDWR); the Alliance for Retail Energy Markets Direct Access Customer Coalition, the Energy Users Forum and Shell Energy North America (AReM *et al*.); Dynegy; Six Cities; San Diego Gas & Electric Company (SDG&E); California State Senator Doug LaMalfa, California State Assembly Member Jim Nielson, Sutter County Supervisor James Gallagher, and Yuba City Mayor John Miller (Senator LaMalfa *et al*.); Silicon Valley Power; Western Power Trading Forum; Independent Energy Producers; Pacific Gas and Electric Company; Northern California Power Agency; Southern California Edison Company; California Wind Energy Association (CalWEA); and NRG Energy.

The ISO also received supportive comments from Senator LaMafla *et al*. to designate Sutter as capacity at risk of retirement and seek a waiver of existing tariff provisions to permit the ISO to prevent the retirement in 2012 through the use of its capacity procurement mechanism. Stakeholder positions and the ISO's responses are summarized in the following table.

Stakeholder Position	ISO Response
The ISO has not demonstrated the need for the Sutter Energy Center and the ISO's analytical study is not sufficiently robust. • The ISO relies only on one possible scenario several years in the future, not supported by CPUC staff, not fully vetted and agreed upon by stakeholders, and not supported in the state's integrated energy policy report. • Considerable uncertainty exists regarding the timing of need for flexible capacity, how impacted once-through cooling units will achieve compliance with State Water Resources Control Board regulations, and the degree to which future flexible capacity needs will be met with resources also needed for local capacity requirements. • The ISO's 2018 analysis is just an interpolation, not a full-blown analysis, as was the ISO's 2020 analysis. • Studies are in the midst of being revised and it is inappropriate to use the studies while they are being revised. • The ISO fails to state how much of the plant's over 500 MW capacity can actually provide flexible products such as Regulation and Flexible Ramping. • The ISO should undertake a sensitivity analysis that will give greater understanding of the timing of the need for capacity and may allow for other options.	**Response:** The ISO conducted an analysis to assess the need for the Sutter Energy Center generally in accordance with Section 7.3.5.2 of the ISO Business Practice Manual for Reliability Requirements, which states that the ISO will use a diverse set of tools and follow a multi-step process whereby the generating facility is studied for its impact on local and system reliability and operational flexibility, given the best available information regarding future grid conditions and the assumed availability of resource adequacy resources procured for the current Resource Adequacy Compliance Year (including other known generator retirements) and any new generation that will achieve commercial operation to meet future needs. Under the Business Practice Manual, once a CPM request is made, the ISO must complete its assessment of whether the retirement of the generating unit would affect the reliability of the transmission system within 30 days. The ISO has relied on planning assumptions

Stakeholder Position	ISO Response
	within the scope of the CPUC long-term procurement plan proceeding (CPUC Rulemaking 10-05-006). The ISO applied these planning assumptions to a study scenario established in that proceeding that reflects future uncertainties in forecast demand. Specifically, under the 33% RPS trajectory scenario with high load (operations planning scenario), there will be a “gap” or shortage in the capacity needed to meet system-wide needs in California by the end of this planning horizon in 2020. Although certain assumptions underlying the scenario used by the ISO are different from the assumptions for the other scenarios within the scope of the CPUC’s procurement plan proceeding, the ISO has concluded that, consistent with good utility practice, it must consider this scenario of future needs to maintain capacity currently on the system to enable successful operations during this planning horizon. The purpose of the ISO's study was to determine if and when the ISO may need the operating capability of the Sutter Energy Center. The 2018 study was not just an interpolation. While the ISO interpolated some of the study assumptions, the study results rely on a production simulation model run for July of

Stakeholder Position	ISO Response
	2018. The proposed measure to secure the Sutter Energy Center in 2012 recognizes the fact that additional studies will be conducted in the future to allow the ISO and stakeholders to continuously consider alternatives in future years. Because Calpine has stated that it intends to retire the Sutter Energy Center as soon as May 2012 and because Calpine has asserted that the unit, once retired, may not return to service, failing to act now will eliminate the possibility of maintaining the capabilities of the Sutter Energy Center. The ISO intends to designate the entire capacity of the Sutter Energy Center as capacity at risk of retirement under the capacity procurement mechanism. If the power plant retires, the ISO will not be able to preserve the specific operating capabilities of the power plant that the ISO projects the system will need. The ISO cannot be placed in a position where it needs a resource to maintain reliability in 2018, but that resource is not available at such time because it was allowed to retire in 2012. The ISO understands that it is at times placed in the precarious position to have to balance the state mandated resource adequacy requirements with maintaining its own responsibilities to operate the system reliably.

Stakeholder Position	ISO Response
	The CPM risk of retirement category was adopted precisely to allow the ISO to cure for those instances in which the ISO has projected that the state level resource adequacy programs to do not match up with its need to maintain system reliability so that the ISO not be left in the untenable position of having to compromise its reliability responsibilities. The ISO's study includes reasonable assumptions developed in the CPUC long-term procurement plan proceeding about both unit retirements and the addition of planned resources. Other than currently planned resources, there is no certainty that additional system or local resources will be built by 2018 in response to the State of California's once-through cooling policy. In other words, based on the best information available to the ISO at this time and appropriate studies, Sutter needs to be available to maintain reliability in 2018, and there is no clear demonstration that there will be alternative resources available by that date that obviate the need for Sutter. It cannot be stressed enough that the ISO is simply proposing to procure Sutter for 2012 based on the needs identified in current studies. The ISO is not seeking to procure the resource for 2013-2017. This means that in future years, under a

Stakeholder Position	ISO Response
	new tariff mechanism that the ISO will be proposing this year, the ISO will be able to evaluate in future years – based on updated data and studies – whether Sutter remains needed for reliability purposes and whether there are viable alternatives in lieu of Sutter to fill that need.
The ISO's proposal undermines state regulatory authority and further development of a backstop procurement process. • Waiver proposal undermines future discussion about ISO backstop procurement authority as well as long-term procurement rules developed by local regulatory authorities (CPUC and municipals). The proposal is inconsistent with California's rejection of a centralized capacity market. • FERC indicated that the eligibility of these units for CPM designations should not "duplicate or interfere with the CPUC or other local regulatory agencies' jurisdiction," consistent with FERC's view that this type of CPM designation would only apply to the procurement of "needed capacity, as a last resort, in the event that state or local procurement plans do not meet ISO's operational and reliability needs." The ISO's proposal to provide a risk-of-retirement CPM designation represents a material deviation from the "narrowly tailored" provisions approved by FERC. • Proposal is premature since the ISO has not yet initiated the stakeholder process it is considering to evaluate a longer-term procurement mechanism and is in the middle of conducting a renewable integration study. • Proposal could lead to material distortions in the resource adequacy markets.	**Response:** The ISO's waiver request will not undermine CPUC or municipal long-term procurement efforts. The waiver request is tailored to provide the ISO authority to procure the Sutter Energy Center capacity for no more than six months of 2012, should the resource not be procured through any of the CPUC and municipal programs. Once the ISO's waiver request is approved, the ISO also intends to allow parties an additional 30 days to procure capacity from the Sutter Energy Center. The ISO will not seek broad authority to procure the Sutter Energy Center under all circumstances or in any year beyond 2012. The ISO has determined that the resource is needed for reliability due to its operational characteristics at a time beyond the next resource adequacy compliance year. The ISO, therefore, requests waiver only of tariff provisions relating to the time period to

Stakeholder Position	ISO Response
The price paid to Calpine under a CPM designation may possibly set a precedent for the longer-term capacity procurement mechanism that the ISO proposes to develop. For these reasons, should the ISO proceed with its proposal, any payments to Calpine should reflect the lowest possible cost-based alternative specific to this situation.	determine the need for the resource in order to address the risk that the resource will retire in 2012. The ISO does not request a waiver of other backstop elements that apply to the current risk of retirement category already approved by FERC to ensure that the procurement of Sutter Energy Center remains consistent with those approved provisions. In particular, the ISO is not proposing to change the requirement recognized by FERC in its order approving the CPM mechanism, that all other avenues for procuring the resource be exhausted before the ISO procures the resource. The waiver, if granted, does not change the nature of the ISO's backstop procurement to address the risk of retirement under the capacity procurement mechanism. The sole purpose of this waiver request is to permit the ISO's analysis of reliability needs to look forward a period of five years rather than the two-year period currently contemplated by Section 43.2.6 of the tariff. The ISO is not seeking waiver of the tariff price authorized by FERC under the capacity procurement mechanism. The payment for such capacity procurement is intended to keep the resource viable for the remainder of the current compliance year. While the ISO is requesting a

Stakeholder Position	ISO Response
	waiver because the resource is needed for reliability reasons due to operational requirements in years beyond the next compliance year (2013), the procurement authorization requested under the waiver would not extend beyond the current year. There is no material difference in the costs to secure the resource for the remainder of the 2012 compliance year, regardless of whether the resource is needed in the next compliance year or in future compliance years. Indeed, an argument can be made that it would be unduly discriminatory for the ISO to designate two resources for the exact same time period, *i.e.,* during the current RA compliance year, but pay each a different price because one is needed in 2013 and the other is needed in 2018. The procurement for both occurs in 2012, not 2013 or 2018. At present, there does not appear to be a basis to pay each a different price. The ISO may determine alternative arrangements under its upcoming stakeholder process that may yield reason for differential pricing, such as a mothballing option that does not include a must-offer requirement for the resource, which would warrant disparate treatment. However, in this case the resource would be subject to the same full operational

Stakeholder Position	ISO Response
	requirements under the must-offer requirement pursuant to the current CPM program. The ISO is commencing a new stakeholder process to address the design of a backstop procurement mechanism to address similar long-term capacity need issues in the future. There will be an opportunity in that process to discuss whether the ISO should price procurement arrangements based on longer-term system or local needs differently from the current risk of retirement category.
The ISO should develop market-based solutions and extend the stakeholder process to provide sufficient time for vetting of such complicated issues related to long-term procurement. • The Sutter Energy Center situation should be seen as direct evidence of our collective failure to have addressed capacity compensation in the past, including the recent redesign of the ICPM/CPM mechanism. Urge the ISO and the CPUC to jointly resolve the fundamentals to which this issue points. • California must establish market mechanisms for ensuring that it has the resources the ISO needs to maintain reliability, and should not rely on ad hoc, out-of-market procurements. Must be focused on creating market mechanisms rather than simply addressing the subtleties of its backstop procurement. • It is problematic for the ISO to propose to provide this type of financial support to a single market participant without establishing a comprehensive approach to fixing the underlying revenue issues.	**Response:** The ISO recognizes stakeholder concerns with the need to develop a market mechanism to secure existing generating capacity in order to support the integration of variable energy resources and/or to serve load. These concerns, however, do not obviate the need for the instant waiver request in order to address the risk that the Sutter Energy Center will retire in 2012. Based on current facts and circumstances, the ISO cannot take the risk that Sutter will not be available in 2018 when needed.

Stakeholder Position	ISO Response
• Expedited six-month stakeholder process is not sufficient to develop either new risk-of-retirement provisions or a comprehensive new capacity market structure. • View the ISO's proposed CPM designation for the Sutter Energy Center as a temporary backstop mechanism until such time as the CPUC resolves this procurement gap or, alternatively, until the ISO creates a tariff mechanism to accomplish such outcomes through the marketplace. Resources needed for their capacity and/or operational characteristics over the next 1-10 years ought to be procured by the appropriate LSEs benefiting from their operational characteristics; they ought to be procured in light of other reliability and public policy needs within a 10-year planning horizon; and, the ISO should exercise its authority to procure such resources solely as a backstop mechanism.	
The ISO has not held an adequate stakeholder process. • Stakeholder process is extraordinarily short to discuss financial and policy impacts. Lack of sufficient analysis of Calpine's financial hardship and no venue for questioning the information exists. • Difficult to evaluate whether ISO's proposed reliability solution (CPM designation for Sutter) is the most efficient or most cost-effective solution to maintain reliability in 2017. • While a more transparent, market-based procurement process to address the ISO's determination of need for 2017 would have been preferable, Dynegy does not oppose the ISO's waiver request to implement the Sutter CPM backstop designation.	**Response:** The ISO has completed a stakeholder process as specified in its tariff to designate a resource as at risk of retirement under its capacity procurement mechanism. In order to prevent the retirement of the Sutter Energy Center, the ISO requests an order providing a tariff waiver by March 29, 2012. The ISO estimates that it will need this authority to provide the Sutter Energy Center with a sufficient payment under the capacity procurement mechanism to remain operational in 2012. The ISO has provided stakeholders with information on all the studies it relied on for its conclusions and has identified publicly available information in the CPUC long-term procurement plan proceeding that constituted key inputs for the ISO's studies. In response to

Stakeholder Position	ISO Response
	a subpoena, the ISO has also provided the CPUC with confidential information submitted by Calpine.
The ISO has not provided transparency regarding the total procurement costs; stakeholders should have the opportunity to review the analysis of financial hardship conducted by the ISO's Department of Market Monitoring (DMM). • If waiver is granted, should capacity procurement mechanism pricing or cost allocation apply or should the ISO request alternative relief for those issues as well? • There is no economic analysis of the cost of paying a CPM price to this plant for 2012 or possibly subsequent years, if it is not needed until 2017/2018. • DRA estimates that ratepayers will pay a minimum of $157.5 million over a five-year CPM contract beginning in 2012. • The ISO is contemplating an $18,000,000 to $23,000,000 procurement under the tariff waiver for the eight (8) months of 2012 during which Sutter is expected to receive its CPM payments. The ISO only spent a combined $2.7 million under the full range of its backstop capacity procurement authority for 2009 and 2010, according to information provided by the ISO during the FERC CPM Technical Conference conducted in April 2011.	**Response:** Stakeholders have estimated that the cost of procuring the Sutter Energy Center will reflect procurement of the resource for the full 12 months of 2012. As is the case under the current tariff requirements, however, the ISO intends only to provide a sufficient payment to the resource to keep it operational in 2012. If the ISO receives a waiver, it ISO intends to procure Sutter for a maximum of six months in 2012. The ISO anticipates that other procurement processes will occur for subsequent years with sufficient payments to keep the resource economically viable. Stakeholders also appear to believe that the ISO intends to procure the resource for the long-term. Rather, pursuant to its waiver request, the ISO will procure the resource only for specific months in the current calendar year.

Stakeholder Position	ISO Response
• The ISO has not stated how much it will cost to keep the unit on-line. Based on the current price of $55/kW-year set forth in the ISO tariff, total compensation per year could amount to over $27 million, which is significant. • If the ISO proceeds with its proposed waiver, it should also seek a waiver of the price contained in the CPM tariff as part of its intended filing with the FERC so that it can set a more appropriate price to pay the Sutter plant. • Would like to see clear evidence that the amount of compensation provided to the Sutter Energy Center is equal to the minimum requirement necessary to keep the unit on-line. • CPM is the wrong solution to this issue, and in turn the price paid would be too high. CPM was designed as an "RA contract replacement," and as such, the ISO purchases daily must-offer participation from CPM units. But here, the ISO has no such "must-offer" need for 2012. • CPM compensation is predicated upon a capacity payment for a resource needed to maintain reliability in the coming year only. Inappropriate to suggest that the same payment structure put in place for backstop procurement needed in the current year should be applied for backstop procurement five years hence. • The DMM is to review requests made under this category independently. The ISO should make that information public.	The ISO is not seeking wavier of the application of the tariff price authorized by FERC, because FERC's approval of that tariff price means the price is just and reasonable for all existing categories under the ISO's capacity procurement mechanism. If granted, the wavier will not change the purpose of the payment: to keep the resource operational until the end of the current RA compliance year. Any evaluation undertaken by DMM of Calpine's request for designation of the Sutter Energy Center as risk of retirement under the capacity procurement mechanism is taken as part of DMM's normal responsibilities. The ISO cannot unilaterally require DMM to make its evaluation available to the public.
The ISO needs to address cost allocation issues associated with its proposal. • Costs of special operating characteristics needed for renewable resources should be allocated to those resources and not socialized to loads. The ISO should also seek cost allocation based on cost causation.	**Response:** The ISO assessment of need for the Sutter Energy Center reflects system-wide load following requirements. As a result, the ISO will allocate the costs of procuring the Sutter Energy Center in 2012 to all load within the ISO balancing authority area consistent with the FERC-approved cost allocation rules for

Stakeholder Position	ISO Response
	CPM risk-of-retirement designations. While the need for operational flexibility is impacted by the increased presence of variable energy resources (such as renewable energy resources), there is no evidence that the needed operational flexibility identified in the ISO studies is in fact due to the existence of variable energy resources. Rather, the ISO studies show that the reliability requirements arise largely due to the State of California's once-through cooling policy that may result in the retirement of significant capacity.
The ISO has not demonstrated that Calpine's Sutter facility is suffering financial hardship. • There is no certainty that Calpine will shutter the plant without a CPM designation. Additional scrutiny is necessary. Stakeholders deserve the opportunity to query the basis for Calpine's claim that it is in financial difficulty and that a retirement decision has been made. • Calpine's claims are particularly suspect in light of the December 14, 2011 approval by the California Energy Commission of a petition to amend the Sutter Energy Project and a transfer of ownership for the Sutter Project pipeline, to allow the construction of a new pipeline to serve the plant.	**Response:** The ISO's tariff provisions addressing the capacity procurement mechanism do not provide the ISO with authority to audit Calpine's assertions regarding the financial hardship facing the Sutter Energy Center. FERC rejected a proposal for the ISO to conduct financial assessments of resources requesting risk of retirement CPM designations, stating that, "Based on the fact that a market participant is prohibited from submitting false or misleading information to CAISO, the affidavit should be sufficient to establish that a resource cannot continue to operate economically. If the Department of Market Monitoring has reason to suspect that a resource submitted false, inaccurate, or otherwise misleading information

Stakeholder Position	ISO Response
	in its affidavit, the CAISO tariff requires such a suspected violation to be referred to the Commission for appropriate sanction." 134 FERC ¶ 61,211 at P 132. The ISO recognizes that DMM is examining Calpine's financial assertions and that FERC may also examine these assertions to assess whether granting the waiver in this case is appropriate.
The Sutter facility is not capable of meeting identified needs. • The Sutter facility is not highly flexible, which appears to be the need the ISO is attempting to satisfy through a proposed waiver filing. • If, as claimed in the ISO report, Sutter has an almost 70% capacity factor, there is no assessment of whether a plant that is running so much can provide flexibility when needed, other than in the downward direction. On the face of it, constructing a new pipeline to serve a plant purportedly on the verge of closure would appear to be a questionable business decision. • The Sutter Energy Center is outside the ISO balancing authority area and a risk-of-retirement CPM designation for a unit outside the ISO balancing authority area sets a particularly bad precedent for ISO ratepayers, especially given the quantity of generation presently existing and currently slated to come online inside the ISO balancing authority area. • The results of the ISO's analysis on page 8, indicates "Flexibility" representing	**Response:** Based on Sutter Energy's Center's minimum ramp rate over a significant portion of its available capacity and its relatively short start-up time, the ISO believes the resource possesses flexible operating characteristics that will help serve load in the 2018 timeframe. The Sutter Energy Center can contribute to load following capacity needs by having unloaded capacity available or, if loaded, allowing other unloaded resources to provide load following flexibility. The Sutter Energy Center participates in the ISO's market under a pseudo-tie arrangement, which effectively puts the Sutter Energy Center inside the ISO's balancing authority area. In its studies, the ISO refers to generic capacity to mean blocks of generic combustion turbines

Stakeholder Position	ISO Response
Load Following, Upward A/S and Load Following shortages. The ISO should clearly define what the terms "generic" and "non-generic" capacity mean and establish such capacity need as "upfront standard" for each type by years in the 10-year planning horizon under the CPUC's long-term procurement plan proceeding process.	(LMS 100) <u>LMS 100 characteristics</u> Pmin = 40 MW, Pmax = 100 MW Ramp rate = 12 MW/min Load following capacity = 60 MW (20 mins.) Regulation capacity = 37 MW (10 mins.); both equivalent to maximum operational range The ISO refers to "non-generic" capacity to mean an actual specific resource and its associated characteristics. The important point is that the specific operating characteristics of Calpine's Sutter Energy Center exist on the system today and can support the load following needs identified in the ISO's study. Sutter lies at the top of the stack of the existing fleet in terms of flexibility and the ISO sees no rational reason why it would let this resource shut down knowing that it will be needed for its flexibility in the future.
The ISO has not adequately considered alternatives to the use of a capacity procurement mechanism. • Waiver proposal does not discuss commercial options available to Calpine but which Calpine rejected.	**Response:** The authority of the ISO to consider alternatives under its current capacity procurement mechanism tariff authority is limited. In developing its proposal to seek a waiver, however, the ISO did consider alternatives. Based on information and belief,

Stakeholder Position	ISO Response
• There is no assessment of the reality of the risk that, if the plant is mothballed, it will need new environmental permits that may not be available. • A mothballing option should provide least-cost, cost-based payments to allow the Sutter plant to be mothballed in a manner to meet any EPA requirements to retain its air quality permits, but would not require Sutter to provide capacity or a daily "must-offer" to the ISO. • The ISO should have evaluated whether Sutter had received offers to provide resource-adequacy services to a load-serving entity for the upcoming compliance year and, if so, whether Sutter had placed itself, by its own decisions, in an untenably uneconomic situation. • Is RMR a cheaper option?	these alternatives appear to be either not applicable to the current situation or less effective than the proposal to designate the Sutter Energy Center as capacity at risk of retirement for a portion of the 2012 calendar year. First, the ISO has no tariff authority to direct the resource owner to mothball the Sutter Energy Center and return it to service, nor does the tariff address any compensation to be provided to a resource that is mothballed. Second, Calpine has informed the ISO that air permitting concerns associated with new source review create additional uncertainty regarding whether Sutter Energy Center could return to operational status. Finally, the ISO does not believe an RMR option will cost less than the use of the capacity procurement mechanism. The ISO is proposing only to compensate Calpine for its going-forward costs. The ISO, moreover, has greater operational flexibility to use CPM resources than it does RMR resources, and CPM capacity provides greater overall system benefits than does RMR capacity. Also, RMR is primarily designed to meet locational needs. That is not the case here.
The ISO has not assessed whether other similarly situated generators will request similar relief.	**Response:** The bulk of procurement for 2012 has already occurred. Parties cannot expect

Stakeholder Position	ISO Response
• There is no assessment of the risk that other generating plants will pursue the same route as Calpine for the Sutter plant and that the costs of giving them CPM status may also be imposed on consumers. • The ISO should provide information on whether there is a significant level of additional uncommitted resources that might seek the same designation. • The ISO may be unable to deny similar requests; the impact of significant amounts of procurement in this manner will serve to compromise bilateral transactions and severely impede capacity market price formation.	the same treatment for any un-procured capacity unless a resource like Sutter demonstrates that it is at risk for retirement and unless the ISO determines that the resource is needed due to its operational or locational characteristics. While stakeholders assert that the ISO's waiver request may result in an incentive for other generators to seek similar treatment, the ISO believes this outcome is highly unlikely in 2012. The ISO has conducted a review of natural gas resources within the ISO's balancing authority area that have flexible, dispatchable capacity and that have other characteristics comparable to the Sutter Energy Center. The vast majority of these resources have resource adequacy contracts for 2012. Among the few that do not, Sutter Energy Center is the largest. Based on this review, the ISO does not expect other resources within its balancing authority area to assert that they are at risk of retirement in 2012 and require a designation under the ISO's capacity procurement mechanism. At this time, the ISO has not received any additional requests to designate capacity at risk of retirement in 2012 under the capacity procurement mechanism.

Attachment G

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

California Independent System Operator Corporation	))	Docket No. ER12-____-000

PROTECTIVE ORDER

(Issued _______, 2012)

1. This Protective Order shall govern the use of all Protected Materials produced by, or on behalf of, any Participant. Notwithstanding any order terminating this proceeding, this Protective Order shall remain in effect until specifically modified or terminated by the Federal Energy Regulatory Commission (Commission) or the Presiding Administrative Law Judge (Presiding Judge) (which includes the Chief Administrative Law Judge), if one should be appointed.

2. This Protective Order applies to the following two categories of materials: (A) A Participant may designate as protected those materials which customarily are treated by that Participant as sensitive or proprietary, which are not available to the public, and which, if disclosed freely, would subject that Participant or its customers to risk of competitive disadvantage or other business injury; (B) A Participant shall designate as protected those materials which contain critical energy infrastructure information, as de fined in 18 CFR§ 388.1 13(c)(1) (Critical Energy Infrastructure Information); and (C) A Participant shall designate as protected those documents or other materials that are confidential under the Tariff of the California Independent System Operator Corporation (ISO).

3. Definitions -- For purposes of this Order:

(a) The term "Competitive Duties" shall mean: (i) the marketing or sale of electric power at wholesale; (ii) the purchase or sale of electric power at wholesale; (iii) the direct supervision of any employee with such responsibilities; or (iv) the provision of consulting services in connection with the purchase, sale, or other marketing of electricity in the ISO's markets or the State of California.

(b) The term "Competitive Duty Personnel" shall mean any individual engaged in Competitive Duties. Counsel, or outside consultants who do not provide consulting services in connection with the purchase, sale, or other marketing of electricity in the ISO's markets or the State of California are not Competitive Duty Personnel.

(c) The term "Participant" shall mean a Participant as defined in 18 C.F.R. § 385.102(b).

(d) (1) The term “Protected Materials” shall mean (A) materials (including depositions) provided by a Participant and designated by such Participant as protected; (B) any information contained in or obtained from such designated materials; (C) any other materials which are made subject to this Protective Order by the Commission, by the Presiding Judge (if one should be appointed), by any court or other body having appropriate authority, or by agreement of the Participants; (D) notes of Protected Materials; and (E) copies of Protected Materials. The Participant producing the Protected Materials shall physically mark them on each page as “PROTECTED MATERIALS” or with words of similar import as long as the term "Protected Materials" is included in that designation to indicate that they are Protected Materials. Alternatively, a Participant making available via secure website, CD, or DVD electronic files containing Protected Materials may indicate on the secure website, CD, or DVD that the documents contained therein include “PROTECTED MATERIALS” rather than physically marking each document. If the Protected Materials contain Critical Energy Infrastructure Information, the Participant producing such information shall additionally mark on each page containing such information the words “CONTAINS CRITICAL ENERGY INFRASTRUCTURE INFORMATION - DO NOT RELEASE.” Alternatively, a Participant making available via secure website, CD, or DVD electronic files containing Protected Materials including Critical Energy Infrastructure Information may indicate on the secure website, CD, or DVD that the documents therein “CONTAIN CRITICAL ENERGY INFRASTRUCTURE INFORMATION - DO NOT RELEASE.” If the Protected Materials contain information not available to Competitive Duty Personnel pursuant to Paragraph 8(c), the Participant producing such information shall additionally mark on each page containing such information the words “PROTECTED MATERIALS NOT AVAILABLE TO COMPETITIVE DUTY PERSONNEL.” Alternatively, a Participant making available via secure website, CD, or DVD electronic files containing Protected Materials including information not available to Competitive Duty Personnel may indicate on the secure website, CD, or DVD that the documents contained therein include “PROTECTED MATERIALS NOT AVAILABLE TO COMPETITIVE DUTY PERSONNEL.”

(2) The term “Notes of Protected Materials” shall mean memoranda, handwritten notes, or any other form of information (including electronic form) which copies or discloses materials described in Paragraph 3(b)(1). Notes of Protected Materials are subject to the same restrictions provided in this Protective Order for Protected Materials except as specifically provided in this Order.

(3) Protected Materials shall not include (A) any information or document that has been filed with and accepted into the public files of the Commission, or contained in the public files of any other federal or state agency, or any federal or state court, unless the information or document has been determined to be protected by such agency or court, or (B) information that is public knowledge, or which becomes public knowledge, other than through disclosure in violation of this Protective Order, or (C) any information or document labeled as “Non-Internet Public” by a Participant, in accordance with Paragraph 30 of *Critical Energy Infrastructure Information*, FERC Order No. 630, FERC

Stats. & Regs. ¶ 31,140 (2003). Protected Materials do include any information or document contained in the files of the Commission that has been designated as Critical Energy Infrastructure Information.

(e) The term "Non-Disclosure Certificate" shall mean the certificate annexed hereto by which Participants who have been granted access to Protected Materials shall certify their understanding that such access to Protected Materials is provided pursuant to the terms and restrictions of this Protective Order, and that such Participants have read the Protective Order and agree to be bound by it. All Non-Disclosure Certificates shall be served on all parties on the official service list maintained by the Secretary in this proceeding.

(f) The term "Reviewing Representative" shall mean a person who has signed a Non-Disclosure Certificate and who is:

(1) Commission Trial Staff designated as such in this proceeding;

(2) an attorney who has made an appearance in this proceeding for a Participant;

(3) attorneys, paralegals, and other employees associated for purposes of this case with an attorney described in Subparagraph (2);

(4) an expert or an employee of an expert retained by a Participant for the purpose of advising, preparing for, or testifying in this proceeding;

(5) a person designated as a Reviewing Representative by order of the Commission or the Presiding Judge (if one should be appointed); or

(6) employees or other representatives of Participants appearing in this proceeding with significant responsibility for this docket;

provided, however, that, notwithstanding Sections 3(f)(1) through 3(f)(6), Competitive Duty Personnel may act as a Reviewing Representative only as provided in Section 8(d).

4. Protected Materials shall be made available under the terms of this Protective Order only to Participants and only through their Reviewing Representatives as provided in Paragraphs 7-9.

5. Protected Materials shall remain available to Participants until the later of the date that an order terminating this proceeding becomes no longer subject to judicial review, or the date that any other Commission proceeding relating to the Protected Materials is concluded and no longer subject to judicial review. If requested to do so in writing after that date, the Participants shall, within fifteen (15) days of such request, return the Protected Materials (excluding Notes of Protected Materials) to the Participant that produced them, or shall destroy the materials, except that copies of filings, official transcripts, and exhibits in this proceeding that contain Protected Materials, and Notes of

Protected Material may be retained, if they are maintained in accordance with Paragraph 6, below. Within such time period each Participant, if requested to do so, shall also submit to the producing Participant an affidavit stating that, to the best of its knowledge, all Protected Materials and all Notes of Protected Materials have been returned or have been destroyed or will be maintained in accordance with Paragraph 6. To the extent Protected Materials are not returned or destroyed, they shall remain subject to the Protective Order. Protected Materials marked as "NOT AVAILABLE TO COMPETITIVE DUTY PERSONNEL" shall be returned to the Participant that produced them or destroyed by the Participant that received such Protected Materials within fifteen (15) days of the later of the date that an order terminating this proceeding becomes no longer subject to judicial review, or the date that any other Commission proceeding relating to the Protected Material is concluded and no longer subject to judicial review.

6. All Protected Materials shall be maintained by the Participant in a secure place. Access to those materials shall be limited to those Reviewing Representatives specifically authorized pursuant to Paragraphs 8-9. The Secretary shall place any Protected Materials filed with the Commission in a non-public file. By placing such documents in a nonpublic file, the Commission is not making a determination of any claim of privilege. The Commission retains the right to make determinations regarding any claim of privilege and the discretion to release information necessary to carry out its jurisdictional responsibilities. For documents submitted to Commission Trial Staff ("Staff"), Staff shall follow the notification procedures of 18 C.F.R. § 388.112 before making public any Protected Materials.

7. Protected Materials shall be treated as confidential by each Participant and by the Reviewing Representative in accordance with the Non-Disclosure Certificate executed pursuant to Paragraph 9. Protected Materials shall not be used except as necessary for the conduct of this proceeding, nor shall they be disclosed in any manner to any person except a Reviewing Representative who is engaged in the conduct of this proceeding and who needs to know the information in order to carry out that person's responsibilities in this proceeding. Reviewing Representatives may make copies of Protected Materials, but such copies become Protected Materials. Reviewing Representatives may make notes of Protected Materials, which shall be treated as Notes of Protected Materials if they disclose the contents of Protected Materials.

8. (a) If a Reviewing Representative's scope of employment includes the marketing of energy, the direct supervision of any employee or employees whose duties include the marketing of energy, the provision of consulting services to any person whose duties include the marketing of energy, or the direct supervision of any employee or employees whose duties include the marketing of energy, such Reviewing Representative may not use information contained in any Protected Materials obtained through this proceeding to give any Participant or any competitor of any Participant a commercial advantage.

(b) In the event that a Participant wishes to designate as a Reviewing Representative a person not described in Paragraph 3(f) above, the Participant shall seek agreement from the Participant providing the Protected Materials. If an agreement is reached that person shall be a Reviewing Representative pursuant to Paragraph 3(f) above with respect to those materials. If no agreement is reached, the Participant may submit the disputed designation to the Commission or the Presiding Judge (if one should be appointed) for resolution.

(c) When Protected Materials have been marked "NOT AVAILABLE TO COMPETITIVE DUTY PERSONNEL," those materials and information derived therefrom may not be reviewed by, or disclosed to, Competitive Duty Personnel. If any person who has been a Reviewing Representative subsequently is assigned to perform any Competitive Duties, or if the designation of previously available Protected Materials is changed to "NOT AVAILABLE TO COMPETITIVE DUTY PERSONNEL," that person shall thereafter have no access to materials marked "NOT AVAILABLE TO COMPETITIVE DUTY PERSONNEL," shall either destroy such materials or return such materials to the Participant that produced them, and shall continue to comply with the requirements set forth in the Non-Disclosure Certificate executed by such person and this Protective Order with respect to any Protected Materials to which such person previously had access.

(d) Notwithstanding the foregoing, persons who otherwise would be disqualified as Competitive Duty Personnel may serve as Reviewing Representatives, subject to the following conditions: (i) the Participant who employs or has retained that person must certify in writing to the Commission and each affected producing Participant that its ability effectively to participate in this proceeding would be substantially and unduly prejudiced if it were unable to rely upon the assistance of the particular Reviewing Representative; (ii) the party claiming such prejudice must identify by name and job title the particular Reviewing Representative required, and must acknowledge in writing to the affected producing Participant that access to the Protected Materials that are designated "NOT AVAILABLE TO COMPETITIVE DUTY PERSONNEL" shall be restricted only to the purpose of participation in this proceeding, absent the written consent of the affected producing Participant; and (iii) the Participant who employs or has retained that person must acknowledge that any other use of the materials shall constitute a violation of a lawful order issued by the Commission; and the person designated as one of the Competitive Duty Personnel must provide a Non-Disclosure Certificate, in the form specified in the Attachment to this Protective Order, acknowledging his or her familiarity with the contents of this Order and the particular restrictions contained in this paragraph. If a producing Participant objects to the designation as Reviewing Representative of a person with Competitive Duties pursuant to the exception in this Section 8(d) and the Participants are unable to resolve their differences after a good faith effort to do so, the Participant seeking the Reviewing Representative designation shall submit such request to the Commission or the Presiding Judge (if one should be appointed) for resolution.

(e) If a Participant believes that Protected Materials previously distributed to Reviewing Representatives contain market sensitive information, public disclosure of which would competitively harm that Participant, and should be treated as if they had been labeled "NOT AVAILABLE TO COMPETITIVE DUTY PERSONNEL," that Participant will be responsible for redistributing or re-labeling the materials.

(f) Once materials are clearly and correctly labeled, compliance will be the responsibility of the Reviewing Party.

9. (a) A Reviewing Representative shall not be permitted to inspect, participate in discussions regarding, or otherwise be permitted access to Protected Materials pursuant to this Protective Order unless that Reviewing Representative has first executed a Non-Disclosure Certificate; provided that if an attorney qualified as a Reviewing Representative has executed such a certificate, the paralegals, secretarial personnel, and clerical personnel under the attorneys instruction, supervision, or control need not do so. A copy of each Non-Disclosure Certificate shall be provided to counsel for the Participant asserting confidentiality prior to disclosure of any Protected Material to that Reviewing Representative.

(b) Attorneys qualified as Reviewing Representatives are responsible for ensuring that persons under their supervision or control comply with this Protective Order.

10. Any Reviewing Representative may disclose Protected Materials to any other receiving Reviewing Representative both have executed a Non-Disclosure Certificate and provided those certificates to counsel for the disclosing Participant. In the event that any Reviewing Representative to whom the Protected Materials are disclosed ceases to be engaged in these proceedings, or is employed or retained for a position whose occupant is not qualified to be a Reviewing Representative under Paragraph 3(f), access to Protected Materials by that person shall be terminated. Even if no longer engaged in this proceeding, every person who has executed a Non-Disclosure Certificate shall continue to be bound by the provisions of this Protective Order and the certification.

11. Subject to Paragraph 18, the Commission or the Presiding Judge (if one should be appointed) shall resolve any disputes arising under this Protective Order. Prior to presenting any dispute under this Protective Order to the Commission or the Presiding Judge, the parties to the dispute shall use their best efforts to resolve it. Any Participant that contests the designation of materials as protected shall notify the party that provided the Protected Materials by specifying in writing the materials the designation of which is contested. This Protective Order shall automatically cease to apply to such materials five (5) business days after the notification is made unless the designator, within said five-day period, files a motion with the Commission or the Presiding Judge, with supporting affidavits, demonstrating that the materials should continue to be protected. In any challenge to the designation of materials as protected, the burden of proof shall be on the Participant seeking protection. If the Commission or the Presiding Judge finds that the materials at issue are not entitled to protection, the procedures of Paragraph 18 shall apply. The procedures described above shall not apply to Protected Materials designated by a Participant as Critical Energy Infrastructure Information. Materials so designated shall remain protected and subject to the provisions of this Protective Order, unless a Participant requests and obtains a determination from the Commission's Critical Energy Infrastructure Information Coordinator that such materials need not remain protected.

12. All copies of all documents reflecting Protected Materials, including the portion of the hearing testimony, exhibits, transcripts, briefs and other documents which refer to Protected Materials, shall be filed and served in sealed envelopes or other appropriate containers (including properly designated electronic means) endorsed to the effect that they are sealed pursuant to this Protective Order. Such documents shall be marked "PROTECTED MATERIALS" and shall be filed under seal and served under seal upon the Commission or the Presiding Judge (if one should be appointed), and all Reviewing Representatives who are on the service list. Such documents containing Critical Energy Infrastructure Information shall be additionally marked "CONTAINS CRITICAL ENERGY INFRASTRUCTURE INFORMATION - DO NOT RELEASE." Such documents containing materials not available to Competitive Duty Personnel shall be additionally marked "CONTAINS MATERIAL NOT AVAILABLE TO COMPETITIVE DUTY PERSONNEL." For anything filed under seal, redacted versions or, where an entire document is protected, a letter indicating such, will also be filed with the Commission and served on all parties on the service list or the Presiding Judge if one is appointed. Counsel for the producing Participant shall provide to all Participants who request the same, a list of Reviewing Representatives who are entitled to receive such material. Counsel shall take all reasonable precautions necessary to assure that Protected Materials are not distributed to unauthorized persons.

13. If any Participant desires to include, utilize, or refer to any Protected Materials or information derived there from in testimony or exhibits during a hearing in this proceeding in such a manner that might require disclosure of such material to persons other than Reviewing Representatives, such participant shall first notify both counsel for the disclosing participant and the Commission or the Presiding Judge (if one should be appointed) of such desire, identifying with particularity each of the Protected Materials. Thereafter, use of such Protected Material will be governed by procedures determined by the Commission or the Presiding Judge.

14. Nothing in this Protective Order shall be construed as precluding any Participant from objecting to the use of Protected Materials on any legal grounds.

15. Nothing in this Protective Order shall preclude any Participant from requesting the Commission, the Presiding Judge (if one should be appointed), or any other body having appropriate authority, to find that this Protective Order should not apply to all or any materials previously designated as Protected Materials pursuant to this Protective Order. The Commission or the Presiding Judge may alter or amend this Protective Order as circumstances warrant at any time during the course of this proceeding.

16. Each party governed by this Protective Order has the right to seek changes in it as appropriate from the Commission or the Presiding Judge (if one should be appointed).

17. All Protected Materials filed with the Commission, the Presiding Judge (if one should be appointed), or any other judicial or administrative body, in support of, or as a part of, a motion, other pleading, brief, or other document, shall be filed and served in sealed envelopes or other appropriate containers (including properly designated

electronic means) bearing prominent markings indicating that the contents include Protected Materials subject to this Protective Order. Such documents containing Critical Energy Infrastructure Information shall be additionally marked “CONTAINS CRITICAL ENERGY INFRASTRUCTURE INFORMATION - DO NOT RELEASE.” Such documents containing materials not available to Competitive Duty Personnel shall be additionally marked “CONTAINS MATERIAL NOT AVAILABLE TO COMPETITIVE DUTY PERSONNEL.”

18. If the Commission or the Presiding Judge (if one should be appointed) finds at any time in the course of this proceeding that all or part of the Protected Materials need not be protected, those materials shall, nevertheless, be subject to the protection afforded by this Protective Order for three (3) business days from the date of issuance of the Commission’s or the Presiding Judge’s determination, and if the Participant seeking protection files an interlocutory appeal or requests that the issue be certified to the Commission with regard to the Presiding Judge’s determination, for an additional seven (7) business days. None of the Participants waives its rights to seek additional administrative or judicial remedies after the Commission’s or the Presiding Judge’s decision respecting Protected Materials or Reviewing Representatives, or the Commission’s denial of any appeal thereof. The provisions of 18 C.F.R. §§ 388.112 and 388.113 shall apply to any requests under the Freedom of Information Act. (5 U.S.C. § 552) for Protected Materials in the files of the Commission.

19. Nothing in this Protective Order shall be deemed to preclude any Participant from independently seeking through discovery in any other administrative or judicial proceeding information or materials produced in this proceeding under this Protective Order.

20. None of the Participants waives the right to pursue any other legal or equitable remedies that may be available in the event of actual or anticipated disclosure of Protected Materials.

21. The contents of Protected Materials or any other form of information that copies or discloses Protected Materials shall not be disclosed to anyone other than in accordance with this Protective Order and shall be used only in connection with this proceeding. Any violation of this Protective Order and of any Non-Disclosure Certificate executed hereunder shall constitute a violation of an order of the Commission.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

California Independent System Operator Corporation	))	Docket No. ER12-____-000

NON-DISCLOSURE CERTIFICATE
CONCERNING PROTECTED MATERIAL

(Issued _______, 2012)

I hereby certify my understanding that access to Protected Materials is provided to me pursuant to the terms and restrictions of the Protective Order in this proceeding, that I have been given a copy of and have read the Protective Order, and that I agree to be bound by it. I understand that the contents of the Protected Materials, any notes or other memoranda, or any other form of information that copies or discloses Protected Materials shall not be disclosed to anyone other than in accordance with that Protective Order. I acknowledge that a violation of this certificate constitutes a violation of an order of the Federal Energy Regulatory Commission.

By: ______________________________

Printed Name: _____________________

Title: ____________________________

Representing: ______________________

Date: _____________________________