

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

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**BEFORE THE PUBLIC UTILITIES COMMISSION OF THE**

3

**STATE OF CALIFORNIA**

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

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**I. BACKGROUND**

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

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**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.

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**Q. Please describe your educational and professional background.**

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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

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

10

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

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

18

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

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

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

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

15  
16 **Q. How has the ISO participated in this proceeding?**

17 **A.** The preliminary 33% integration study work was performed in coordination and  
18 support of this Long Term Procurement Plans (LTPP) proceeding using assumptions  
19 from the prior LTPP assumptions (Docket No. R. 08-02-007 and predecessor  
20 dockets). In the context of this case, in 2010 the 33% study work was primarily  
21 used to familiarize parties and gain agreement regarding the renewable integration  
22 study methodology. During the third and fourth quarters of 2010, the ISO  
23 conducted Step 1 modeling and Step 2 production simulation using 2009 vintage  
24 scenarios developed by the CPUC's Energy Division (ED) staff. The ISO described  
25 its 33% integration model at a workshop on August 24, 2010; the Step 1 modeling at  
26 a workshop on October 22, 2010; and the Step 2 results at a workshop on November  
27 30, 2010. In addition, the ISO reviewed the Lawrence Berkeley National Lab's

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

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

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

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

14  
15 **Q. Do the 33% integration study methodology and the renewable portfolio**  
16 **scenarios that the ISO studied and that you describe in your testimony provide**  
17 **sufficient information to make procurement and infrastructure decisions?**

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

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1 future renewable scenarios that the ISO intends to run and will make available in the  
2 next LTPP proceeding.

3  
4 In future studies, assumption areas needing further validation are the levels of  
5 energy efficiency and demand response captured in some of the renewable portfolio  
6 scenarios because such levels may take many years to achieve. Forecast error  
7 improvements should also be considered in future study work.

8  
9 Because of the uncertainty around many of the study assumptions, the ISO believes  
10 that infrastructure decisions regarding the resources needed to support renewable  
11 integration is best determined on an incremental basis over the course of several  
12 years. For now it is important that the programs needed to achieve the levels of  
13 energy efficiency and demand response load reduction assumptions must be put in  
14 place as soon as possible. As the OTC study results become available, decisions  
15 about repowering or new generation siting must be considered. At the same time,  
16 the ISO will be developing market rules and integration policies that will align the  
17 operational and environmental objectives.

18

19 **Q. Please describe how your testimony is organized.**

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

30

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

3

4 **Q. You stated that the ISO ran the 33% integration model using 2009 vintage**  
5 **renewable scenarios, and these results were presented during workshops in**  
6 **2010. What was the ISO’s role with respect to the updated renewable scenarios**  
7 **described in the December 3, 2010 Scoping Ruling?**

8 **A.** The ISO 33% integration study was updated to reflect the latest scenario  
9 assumptions developed by the ED staff and described in the December 3, 2010  
10 scoping ruling<sup>3</sup>. Seven scenarios were specified:

11

- 12 1. 33% Trajectory Base Load
- 13 2. 33% Environmentally Constrained
- 14 3. 33% Cost Constrained
- 15 4. 33% Time Constrained
- 16 5. 20% Trajectory
- 17 6. 33% Trajectory High Load
- 18 7. 33% Trajectory Low Load

19

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

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<http://www.cpuc.ca.gov/PUC/energy/Procurement/LTPP/LTPP2010/2010+LTPP+Tools+and+Spreadsheets.htm>

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1           29, 2011 and discussed at the workshop held on May 10, 2011. In addition to the  
2           five CPUC scenarios, the ISO also studied an “All Gas” scenario in support of  
3           development of metrics by the IOUs, and conducted a sensitivity analysis assuming  
4           all three Helms pumps are available year round. I discuss in this testimony the  
5           results of those studies.

6

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

9           **A.** The four priority scenarios described in the scoping memo and modeled by the ISO  
10          all have the same load assumption based on the 2009 California Energy  
11          Commission (CEC) load forecast. The priority scenarios differ with respect to the  
12          assumptions about the type and location of renewables needed to achieve 33% RPS.  
13          Of these scenarios, the Environmentally Constrained scenario relies more heavily on  
14          distributed solar (about 9000 MW), which includes small to medium sized solar  
15          photovoltaic (PV) plants selling their entire output to utilities. The Cost  
16          Constrained and Time Constrained scenarios have higher levels of out of state  
17          renewables. The fifth CPUC scenario studied, the 33% Trajectory High Load  
18          scenario, has a 10% higher load assumption than the four priority scenarios to  
19          reflect any combination of future uncertainties (*e.g.*, increased load growth and  
20          programmatic performance). The Trajectory High Load scenario also had  
21          1,497MW of additional renewable resource versus the Trajectory Base Load  
22          scenario. Slide 5 in Exhibit 1 contains a list of the load and renewable assumptions  
23          for the five CPUC scenarios that the ISO ran. The All Gas scenario uses similar  
24          base load assumptions but does not include new renewable resources. The All Gas  
25          scenario does include existing renewables and 1750 MW of expected customer PV.

26

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

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

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

4

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

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

13

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

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

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

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

4  
5 **Q. Did the ISO make additional input assumptions and clarifications?**

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

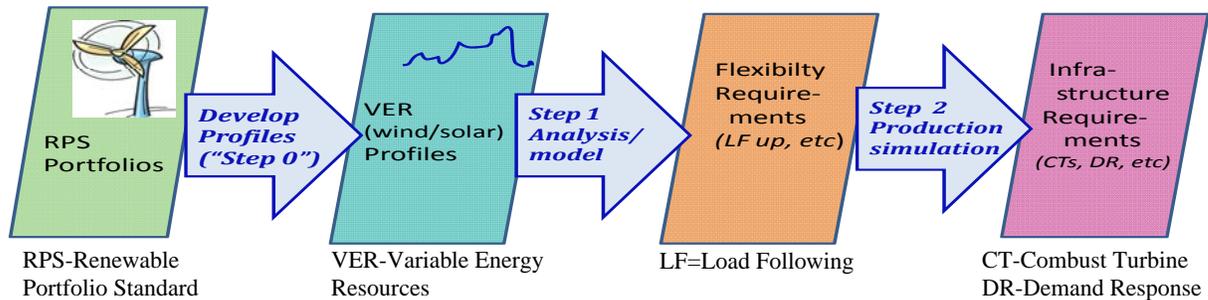
10  
11 **III. STUDY METHODOLOGY**

12  
13 **Q. Can you provide an overview of the 33% integration model, and the study  
14 methodology steps followed by the ISO, to develop the results summarized in  
15 Exhibit 1?**

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

1

Figure 1: Renewable Integration Study Process



2

3

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

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

12

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

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

19

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

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

4 **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 <sup>4</sup> (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.

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<sup>4</sup> 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.

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**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.

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

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

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

13  
14 **Q. What steps did the ISO take to develop profiles for new wind resources?**

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

17  
18 First, a representative number of plants and their geographical locations were  
19 developed, whose total capacities (MW) matched the MW in each Competitive  
20 Renewable Energy Zone (CREZ), based on the resources included in each of the  
21 scenarios developed by the CPUC. To identify the number of units and locations  
22 for the projected additions the CPUC used data from the IOU procurement  
23 processes as a starting point and generic plant information from the Renewable  
24 Energy Transmission Initiative (RETI) process and other sources. The number of  
25 plants that were ultimately used to represent the wind generation were chosen so  
26 that no one plant represented more than about 5% of the total wind generation.

27

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<sup>5</sup> 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.

<sup>6</sup> NREL production data is based upon a wind farm using Vestas V-90 3 MW generators.

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

9

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

17

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

20

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

26

27          Finally, using this 1 minute statistical model, variability was then added to each 1  
28          minute splined set of data using a process that adds variability randomly as a  
29          function of the wind farm size. The final data set of 1 minute wind farm data for  
30          each plant, which includes 1 minute variability, was then used for the Step 1

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1           statistical model to determine operational regulation and load following  
2           requirements. The hourly wind generation profiles were developed by averaging the  
3           60 - 1 minute production data over each hour of the year.

4

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

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

9

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

18

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

25

26

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

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Table 2: Plant Area by Technology

<b>Plant Technology</b>	<b>Area Required in Square Miles for 10 MW Facility</b>
Solar Thermal	0.0855 Square Miles <sup>8</sup>
Solar PV without Tracking	0.093 Square Miles
Solar PV with Tracking	0.093 Square Miles

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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<sup>9</sup> 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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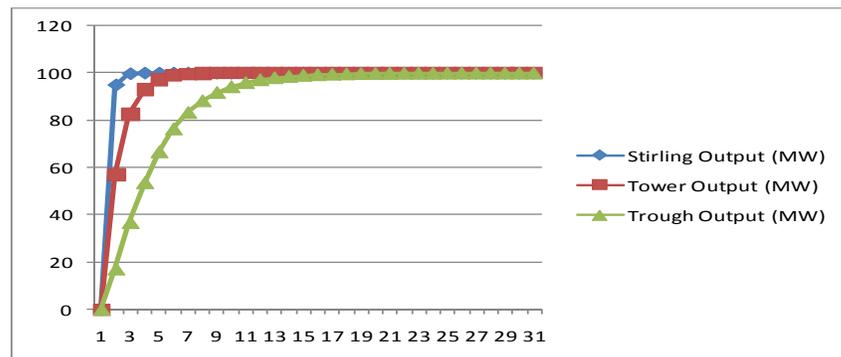
<sup>8</sup> Average of solar thermal tower and trough technology.

<sup>9</sup> The Solar Anywhere satellite solar irradiance data can be found at:  
<https://www.solaranywhere.com/Public/About.aspx>

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

3  
4 Seventh, variability was introduced into the smoothed 1 minute plant production  
5 data using a process that inserted the variability captured from historical 1 minute  
6 irradiance data from measurements collected by NREL's Measurement and  
7 Instrumentation Data Center (MIDC)<sup>10</sup> at the SMUD Anatolia site in Rancho  
8 Cordova, CA, Loyola Marymount University in Los Angeles, and the SolarCAT  
9 station in Phoenix, AZ. At this stage in the process, the 1 minute data captures the  
10 variability of a plant that occupies the full plant footprint. This step is discussed in  
11 more detail below.

12  
13 Eighth, to reflect the fact that certain technologies have inherent time delays in their  
14 response to changes in irradiance, the data described in step 7 was processed in an  
15 inertial delay algorithm to arrive at the final 1 minute production data. This step was  
16 applied only to solar thermal plants as it is believed that solar PV plants have  
17 negligible time delay in their response to changes in irradiance. For the three types  
18 of solar thermal technologies (trough, tower and Stirling) three different  
19 characteristics were used as shown in Figure 22.



21  
22 Figure 2: Response to Step Increase in Irradiance by Solar Thermal  
23 Technology v, Time in Minutes  
24

<sup>10</sup> [www.nrel.gov/midc](http://www.nrel.gov/midc)

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1

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

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

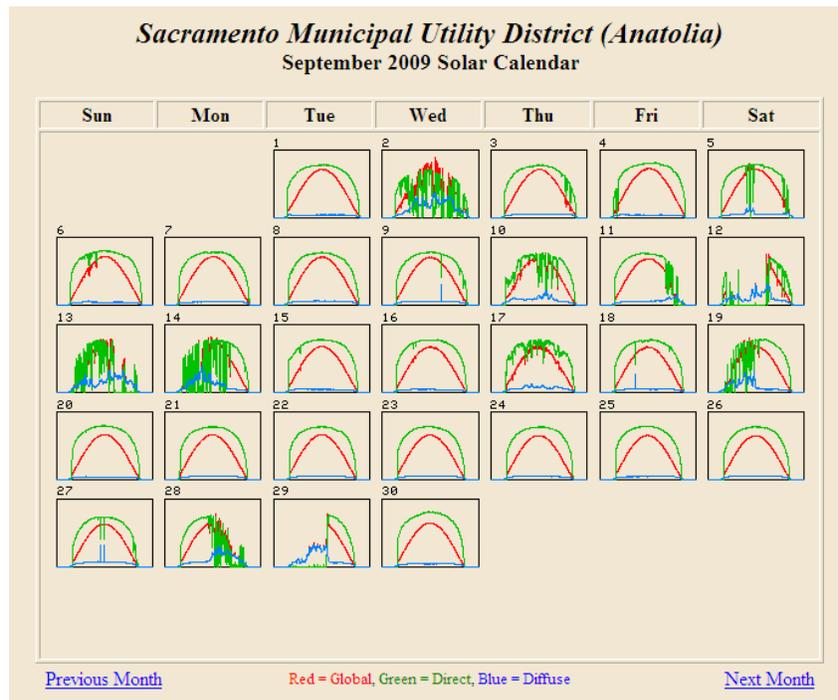
6 First, a Data Library was developed of 1 minute variability from historical 1 minute  
7 irradiance data collected by Sacramento Municipal Utility District (SMUD) in  
8 Sacramento, Loyola Marymount University in Los Angeles, and the SolarCAT in  
9 Phoenix, AZ. A summary plot of the raw historical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

11

12 Second, this 1 minute data was converted to a normalized derate value by dividing  
13 the 1 minute actual irradiance data by the irradiance measurement that would have  
14 existed had there been no clouds in that minute (clear sky). The resulting data was  
15 a set of 1 minute historical per unit irradiance derate values that ranged from 0 to  
16 1.0, with 0 representing full reduction from a clear sky level to a zero irradiance  
17 level and 1.0 representing no reduction from a clear sky level. Six different sets of  
18 this 1 minute derate data were developed for solar thermal and solar PV for the  
19 various sizes of plants (number of 1 kilometer squares in the plants footprint). A  
20 moving average was applied to each of the libraries, based on the number of 1km  
21 irradiance grids, to represent the 1 minute variability over the full footprint of the  
22 plant. Thus six libraries are developed for use in the subsequent steps.

23

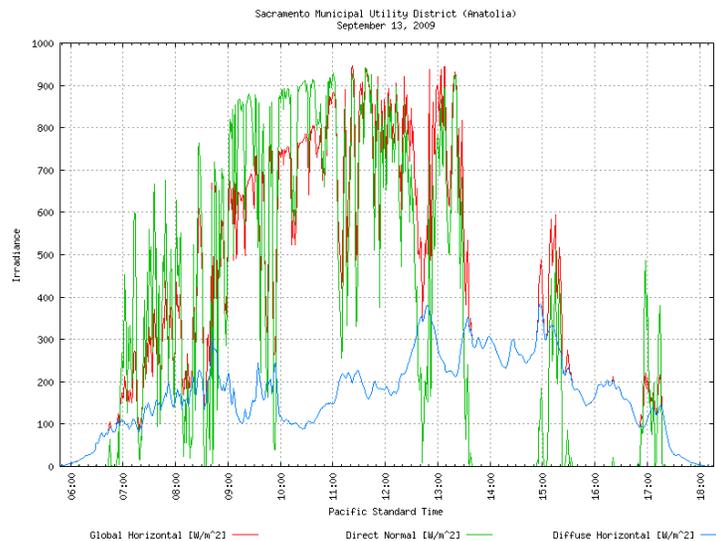
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Figure 3: SMUD 1 Minute Irradiance Data for September 2009

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



9  
10  
11

Figure 4: 1 Minute Irradiance for September 13, 2009

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

10  
11 Next, average production derate values were calculated on an hourly basis from the  
12 1 minute derate values. Then for each hour of the year that had a derate value lower  
13 than 0.95, the 1 minute production derate values were replaced by an hour of  
14 irradiance derate values from the library developed that had the same hourly derate  
15 value. Which of the six libraries was used for this substitution depended on the  
16 plant size (number of 1 Kilometer squares in the plant footprint). This step added  
17 variability based upon historical data to the 1 minute production derate values while  
18 maintaining the average derate over the hour at the same level as in the production  
19 data.

20

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

22 Yes, we performed the following checks:

23

- 24
- 25 • To ensure that there were no significant step changes caused by the derate data  
26 substitution, the start minute and end minute derate values were tested to make  
27 sure they were within 1% of the minute before and the minute after the starting  
28 and ending minutes, respectively.
  - 29 • To ensure that historical data was as representative as possible, substitution data  
30 was required to come from hours in the library that were within +/- 2 hours. For  
31 example, afternoon variability would not be applied to morning hours.
  - 32
  - 33 • To increase the number of library “hours” available for substitution, sets of 60 1  
34 minute values (library hours) were created by shifting the start of the 60 minute

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1           period by 1 minute. For example, data from 2 hours could be used to construct  
2           60 library hours.

- 3
- 4           • To ensure that a bias was not introduced in the substitution process, a random  
5           selection process was used to find the derate data that met the end effects  
6           tolerances. This hourly process proceeded through the entire year to develop a  
7           full year of 1 minute production derate values.

8

9

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

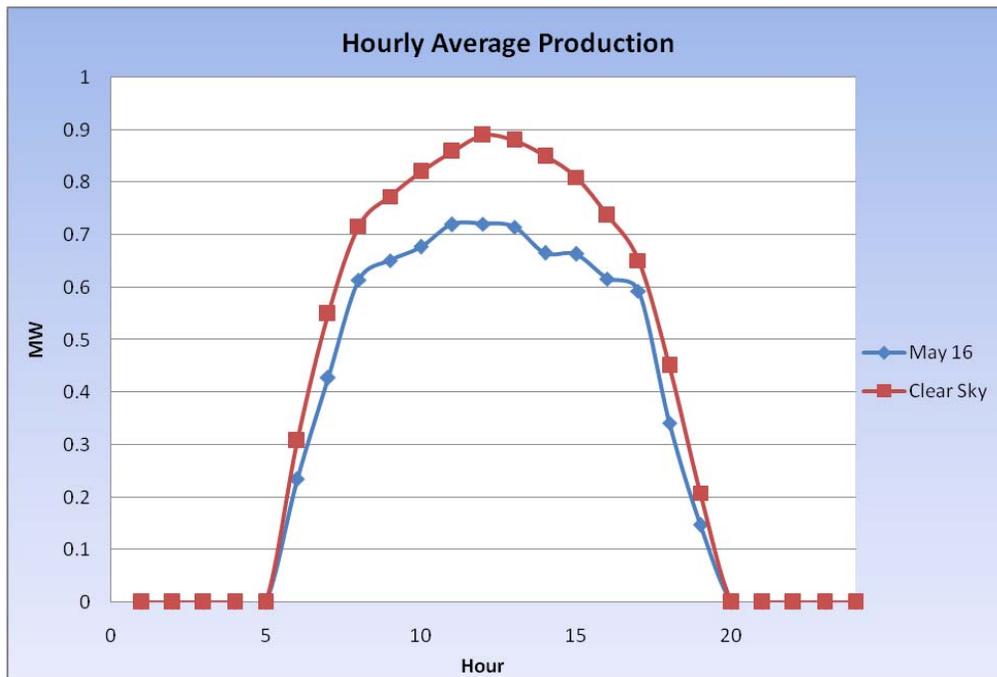
11   A.    The final step converted the derate values into 1 minute production values by  
12       multiplying the derate values by the 1 minute production expected from a plant  
13       under clear sky conditions.

14

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

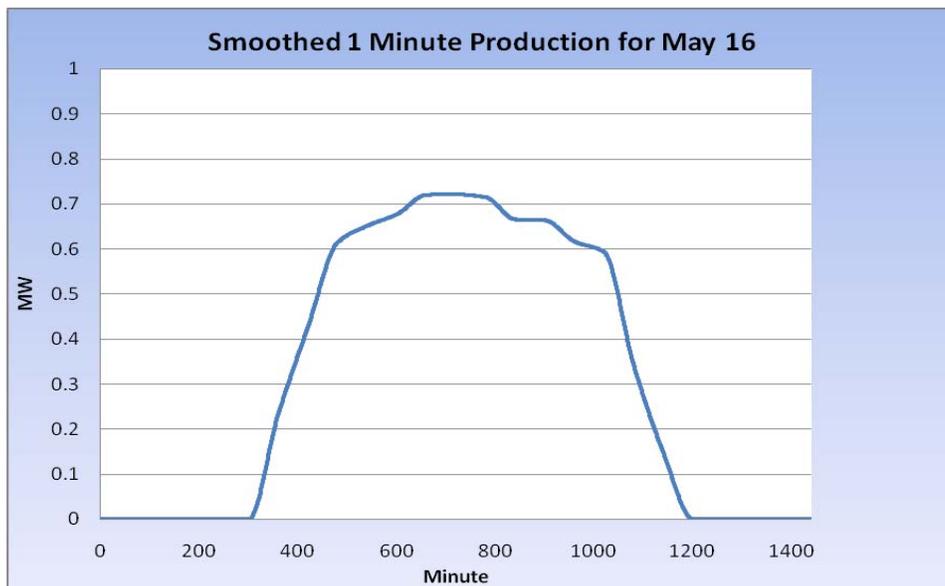
16   A.    Yes. The results of this process are shown graphically in the figures below. Figure  
17       5 shows the hourly production data output of the SAM for May 16, 2020. Figure 6  
18       shows the smoothed 1 minute production data and Figure 7 shows the production  
19       data after historical variability has been added.

20  
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1 1 Minute Smoothed Production Data for a Tracking PV in the Mountain Pass/Tehachapi  
2 for May 16, 2020

Figure 5: Hourly Production Data Output from SAM Model

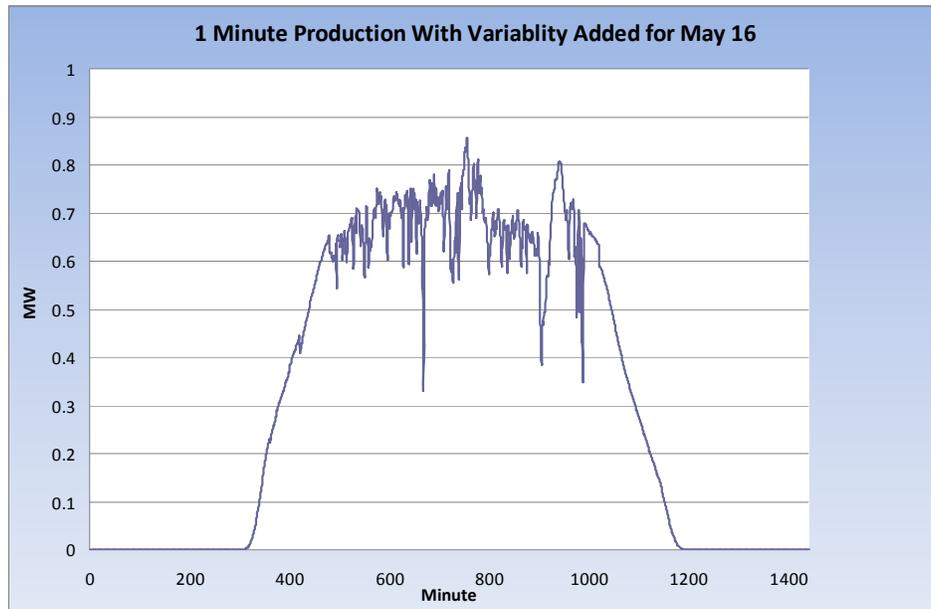


3 1 Minute Smoothed Production Data for a Tracking PV in the Mountain Pass/Tehachapi  
4 for May 16, 2020

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

5

1



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

2

3

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

4

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

5

**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.

13

14

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

15

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

16

17

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

5  
6 The numbers in the column labeled “Number of Sites” is not the actual number of  
7 sites, which are in the thousands, but the number of projects selected from RPS  
8 Calculator, each of which would be distributed over many sites. The first five  
9 columns of the Table contain clarifying information provided to Nexant by ED staff  
10 as the profiles were being developed. The last two columns, “grids” and “MWs/  
11 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
<b>Total</b>		367	9077.2	<b>Total</b>	20	

14  
15  
16 For each square grid, we assumed that the plants are uniformly distributed over the  
17 grid. For the categories (rows) with relatively small amounts of generation, we  
18 decided that accuracy would not suffer if they were combined with other categories  
19 that had similar technologies and capacity factors. For example, under Central  
20 Valley there is 133 MW of Mid Ground and 26 MW of Small Ground. We

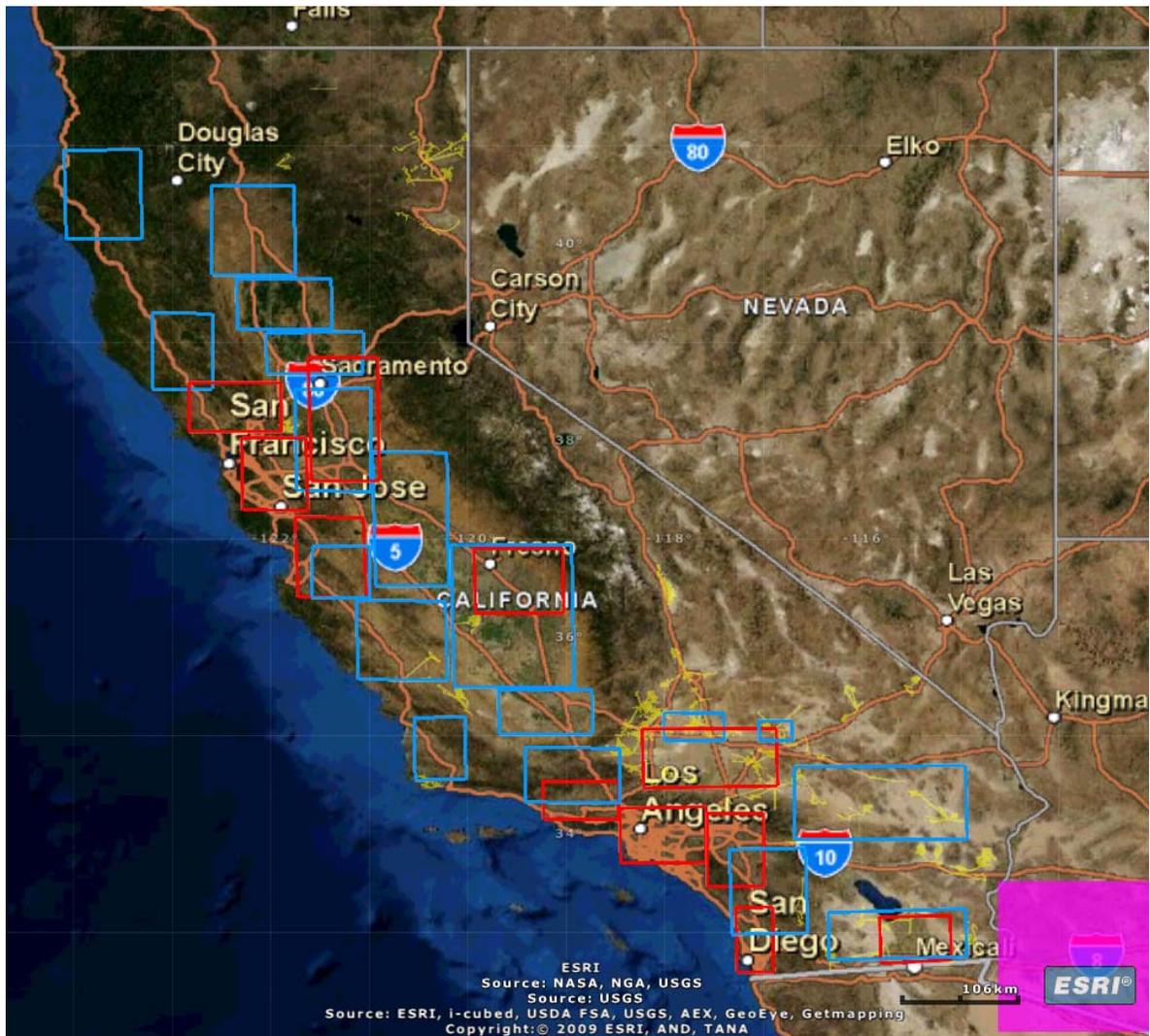
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1           determined that for modeling purposes these projects should be added to others in  
2           the same region with the same or similar characteristics.

3  
4   **Q.    How were the grids distributed geographically?**

5  
6           Figure 8 shows the grids that are used for the 9000 MWs of solar PV.

7  
8                           Figure 8: Distributed Solar Geographic Areas



10  
11  
12  
13           In this geographic representation, blue squares are for large ground projects and  
14           red squares are for large roof projects.

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

3  
4 We selected 25 1 km by 1 km satellite irradiance data that was evenly distributed  
5 over the grid. For some grids this might be one every 5 km and others might be one  
6 every 20 km. That data was averaged on an hourly basis for each rectangle.

7  
8 Next, we processed the averaged irradiance data in the SAM to develop hourly  
9 production for the MWs represented by the group. Using a cubic spline curve fit  
10 function on the hourly production, we then developed 1 minute profiles for each  
11 geographic area, which has no 1 minute variability.

12  
13 We added 1 minute variability to the 1 minute production data using algorithms  
14 similar to those described above used for developing large solar plant profiles and,  
15 as the final step, we developed clear sky production for each geographic area in the  
16 same manner as with the large solar – by selecting the maximum production in each  
17 hour for each month.

18  
19 **Q. What was the process used for developing small customer-side PV?**

20  
21 **A.** The process for small PV on the customer side of the meter was similar to the  
22 process used for small supply PV plants. Five grids were used, as presented on  
23 Figure 9. Table 4 provides the location, size and capacity factor planning  
24 assumptions for these customer side solar resources.

25

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1

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%

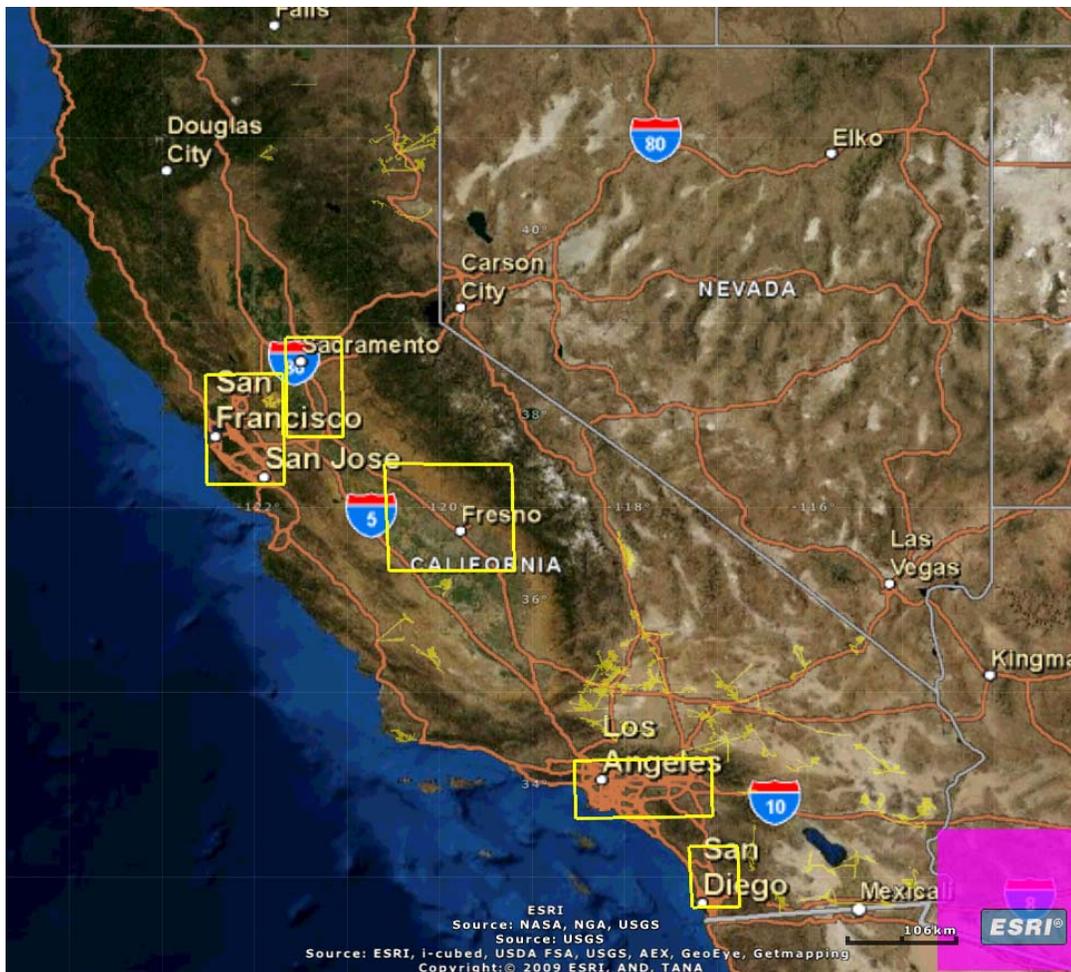
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Figure 9: Customer Side PV Geographic Areas



6

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

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

8

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

12

13 **B. STEP 1- MODELING LOAD FOLLOWING AND REGULATION**  
14 **REQUIREMENTS**

15

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

18 **A.** The Step 1 load following and regulation requirements were developed from the  
19 load, wind and solar 1 minute profiles developed in Step 0 along with distributions  
20 of load, wind and solar forecast errors. This step in the study uses a stochastic  
21 process developed by the ISO and PNNL that employs Monte Carlo simulation, a  
22 sampling over multiple trials or iterations used to estimate the statistical  
23 characteristics of a mathematical system. The simulation is designed to model  
24 aspects of the daily sequence of ISO operations and markets in detail, from hour-  
25 ahead to real-time dispatch. The objective is to measure changes in operations at the  
26 aggregate power system level, rather than at any particular location in the system.  
27 The model provides realistic representations of the interaction of load, wind, and  
28 solar forecast errors and variability in those time frames and evaluates their possible  
29 impact on operational requirements through a very large number of iterations. A  
30 summary of the regulation and load following requirements produced by Step 1

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1 analysis is provided on Slides 3 and 4 of Exhibit 1. The detailed Step 1 hourly  
2 results for the following scenarios are available at:  
3

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

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**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.

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

3    **A.**    Yes.  These differences are depicted on Slide 59 of Exhibit 1.  For the load  
4    forecasts, we observed a significant reduction in hour ahead load forecast error.  
5    This reduction is because our forecast is now based on forecasts that are produced  
6    75 minutes prior to actual operating hour.  The load forecast errors in the vintage  
7    scenarios were based on load forecast that was produced 2 hours prior the operating  
8    hour.  In addition, the ISO has made improvements to its load forecasting tools.

9

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

13

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

19

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

23

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

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

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1 **Q. How were the load forecast errors determined?**

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

10

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

12 **A.** The hour-ahead and 5-minute load forecast errors determined are presented on Slide  
13 59 of Exhibit 1.

14

15 **Q. How were the wind forecast errors determined?**

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

17

18 **Q. What is T-1 persistence analysis?**

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

24

25 **Q. Why was a 1 hour comparison used?**

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

29

30

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

3 **A.** The hour-ahead wind forecast errors we determined are presented on Slide 61 of  
4 Exhibit 1.  
5

6 **Q. How were the solar forecast errors determined?**

7 **A.** The solar forecast errors were determined based on a T-1 persistence analysis of the  
8 clearness index for hours 12 through 16, separately for different solar technologies-  
9 PV, solar thermal, distributed solar and customer side PV- using the profiles  
10 developed in Step 0, and broken down into 4 different clearness index categories.  
11

11

12

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

15 **A.** The solar forecast error analysis was separated due to different solar technology  
16 production patterns and variability as a function of solar irradiance. As a result,  
17 separating the forecast error analysis by solar technology and clearness index  
18 allows the ISO to better reflect the impacts of the relative quantity of different solar  
19 technology.  
20

20

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

22 **A.** The forecast error analysis was limited to hours 12-16 to avoid introducing errors  
23 that result from sunrise and sunset which would distort T-1 persistence error  
24 analysis. Hours 12-16 are hours where the clear sky solar irradiance is relatively  
25 stable from one hour to the next and better reflects forecast conditions.  
26

26

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

29 **A.** No. In the analysis of solar forecast errors conducted so far, the ISO recognized  
30 that there is further research needed to refine the impact on forecasting modeling of  
31 plant-scale effects, operational properties and performance characteristics and

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1 capabilities of different solar technologies, including startup-up in the morning and  
2 shutdown-down during the evening hours.

3

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

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

8

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

11 **A.** The hour-ahead solar forecast errors determined are presented on Slide 65 of Exhibit  
12 1.

13

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

16 **A.** A detailed description of the statistical analysis methodology is found in the  
17 technical appendix to the ISO's 20% RPS integration study that I discussed earlier  
18 in my testimony. The basic method is as follows: First, the load and renewable  
19 production data is aggregated from the 1-minute data set to create averaged hour-  
20 ahead and 5-minute dispatch schedules for each hour of the year. Second, the  
21 probability distributions of forecast errors, and other statistical properties, such as  
22 autocorrelation, for load, and wind and solar production in the hour-ahead and 5-  
23 minute-ahead timeframes are constructed. Both wind and solar forecast errors are  
24 used in the hour-ahead random draws. However, in the 5-minute time frame, the  
25 ISO uses a wind persistence forecast, which is the basis for the simulation. Hence,  
26 in the 5-minute sampling, the wind variability is preserved but the forecast error is  
27 static for the period of the persistence model. For the solar resources, the 5-minute  
28 forecast errors are modeled explicitly because of the more extreme morning and

1 evening ramp periods for solar in which persistence would not be an appropriate  
2 assumption.

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

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

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

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

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

---

<sup>11</sup> 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.

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1 simulation and its formulation can be found in Section D of the Integration of  
2 Renewable Resources: Technical Appendix for California ISO Renewable  
3 Integration Studies<sup>12</sup>  
4

5 **Q. What model was used in the production simulation?**

6 **A.** The Step 2 underlying model is a Plexos Solutions representation of the WECC  
7 Transmission Expansion Planning Policy Committee (TEPPC) model version PC0  
8 dated March 21, 2011.  
9

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

11 **A.** Yes, the California portion of the model had to be reconciled and modified to  
12 comply with the assumptions for the renewable scenarios described in the December  
13 3, 2010 scoping memo.  
14

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

17 **A.** The load pattern in California was modified to reflect assumptions in the scoping  
18 memo including accounting for energy efficiency and demand response. Supply  
19 resources and patterns were modified to reflect the renewable resource build out as  
20 well as planned retirement additions specified in scoping memo including expected  
21 retirements of once through cooled (OTC) resources. The maximum import  
22 capability into California was modified to reflect expected condition. The natural  
23 gas prices in California were modified to reflect Market Price Referent (MPR)  
24 method specified in the CPUC scoping memo. The natural gas prices used in  
25 California can be found on slide 42 of Exhibit 1. CO2 price assumptions were used.  
26 The details of these changes can be found at slides 32-43 of Exhibit 1.  
27

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<sup>12</sup> <http://www.caiso.com/282d/282d85c9391b0.pdf>

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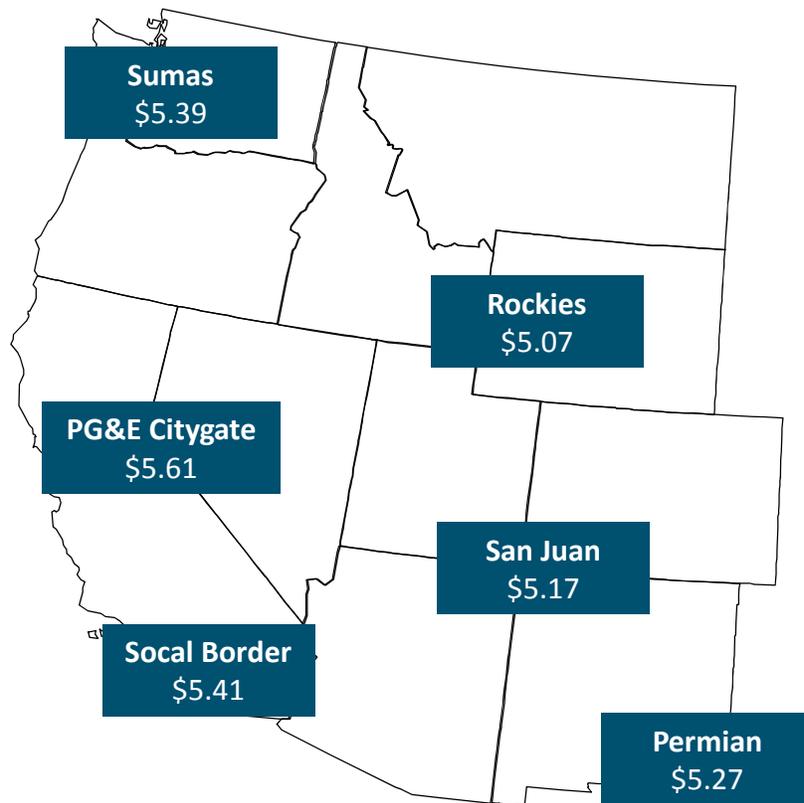
1 **Q. Were there any other modification made to the model that were not specified in**  
2 **the CPUC LTPP scoping memo?**

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

12  
13 **Q. Do you have any more detail regarding how the gas prices outside of California**  
14 **were developed?**

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

1 **Figure 10: 2020 Average Wholesale Natural Gas Prices for Major Western**  
2 **Pricing Points (2010 Dollars per MMBtu, based on a Henry Hub price of**  
3 **\$5.61/MMBtu)**



4  
5  
6 E3 then applied the natural gas delivery charges from the TEPPC PC0 case, with  
7 two modifications to better reflect actual market conditions: (1) eliminated the  
8 TEPPC delivery charge for natural gas in British Columbia, and (2) established  
9 SoCal Border instead of Permian as the reference pricing point for Arizona. The  
10 table below shows the delivery charges applied in 2020.

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

<b>Generator Location</b>	<b>Natural Gas Hub</b>	<b>Natural Gas Delivery Point</b>	<b>Delivery Charge (2010 \$/MMBtu)</b>
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	-

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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.

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

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

2

3

4

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6

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

8

**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.

12

13

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

15

**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.

19

20

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

21

**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

22

23

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1 run is referred to as the “need” run. For this “need” run, monthly maximum  
2 requirements for regulation and load following were used for each hour to ensure  
3 that the fleet had sufficient capability to meet a wide range of expected conditions  
4 for each month. After the “need” run was completed, a second production  
5 simulation run was performed to determine production costs, annual fuel burn,  
6 emissions and capacity factors. This second run is referred to as a “cost” run. For  
7 the “cost” run, the hourly regulation and load following requirements were used to  
8 better reflect the expected knowledge of requirements based on operational  
9 conditions.

10

11 **Q. What was the ISO’s involvement in Step 3?**

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

20

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

23 **A.** Yes. For the peak demand calculation, Nexant consulted with ED staff and  
24 developed load profiles, based on the Statewide Net Peak Demand (70,964 MW)  
25 from Form 1.4<sup>13</sup> of the CEC’s 2009 IEPR. Exhibit 3 attached to my testimony sets  
26 forth the load profile energy and demand assumptions and adjustments made to the  
27 Form 1.4 peak quantities:

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<sup>13</sup> Form 1.4, Second Edition, [http://www.energy.ca.gov/2009publications/CEC-200-2009-012/adopted\\_forecast\\_forms/Chap1Stateforms-Adopted-09.xls](http://www.energy.ca.gov/2009publications/CEC-200-2009-012/adopted_forecast_forms/Chap1Stateforms-Adopted-09.xls)  
Statewide Revised Demand Forecast Forms

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- 1,131 MW of upward adjustment were made to account for behind the meter PV that was modeled as supply.

3

4

- 7005MW of downward adjustment was made to account for incremental energy efficiency.

5

6

- 1008MW of downward adjustment were made to account for behind the meter CHP.

7

8

- 327MW of downward adjustment was made to account for demand side programs.

9

10

11 **Q. How was the load distributed in the model?**

12 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.

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

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

10  
11 **Q. How was the Helms Pumps storage facility modeled?**

12 **A.** The model contains the following assumptions about the Helms pumps:  
13  
14 • There are three pumps that can operate simultaneously from January to May and  
15 from October to December. There will be only one pump available for the rest  
16 of year 2020.  
17  
18 • PG&E provided the following pump and usage targets. The storage should reach  
reservoir maximum volume at the end of May.

<b>Pump/Usage</b>												
<b>Target</b>	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			

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

<b>Reservoir Storage</b>												
	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

20  
21  

---

<sup>14</sup> Form 1.5b, Second Edition, [http://www.energy.ca.gov/2009publications/CEC-200-2009-012/adopted\\_forecast\\_forms/Chap1Stateforms-Adopted-09.xls](http://www.energy.ca.gov/2009publications/CEC-200-2009-012/adopted_forecast_forms/Chap1Stateforms-Adopted-09.xls)

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1

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

3 A. Based on ISO transmission planning studies and planned transmission upgrades for  
4 2020, the ISO determined that the Helms pumping window would be restricted to  
5 one pump due to the load level in the Fresno area.

6

7 **IV. STUDY RESULTS**

8

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

11 A. No upward incremental shortfalls were identified for the four priority scenarios,  
12 and, thus, no incremental needs of resources beyond capacity already planned were  
13 identified in any of these scenarios. However, the results show 506MW and  
14 539MW shortfalls in downward load-following capacity in the Trajectory and  
15 Environmentally Constrained scenarios, respectively. No downward load-  
16 following shortfalls were observed in the Cost and Time Constrained scenarios. No  
17 regulation shortfalls were observed in any of the four priority scenarios. Slides 10  
18 and 11 of Exhibit 1 provide additional details about these observations.

19

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

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

25

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

28 A. Yes. We observed 1400MW capacity need in the All Gas scenario and 4600MW  
29 capacity need in the High Load Trajectory scenario to resolve shortfalls in upward  
30 ancillary service and load following. No downward load following shortfall was

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1 observed in the All Gas. Downward load following shortfalls up to 856MW were  
2 observed in the Trajectory High Load scenario. Slides 10 and 11 of Exhibit 1  
3 contain additional details about these observations.

4

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

7 **A.** In the All Gas scenario, all new renewable resources were removed (except for  
8 1750MW of customer side solar) while no additional resources were added from the  
9 base scenario. Due to the removal of such capacity, the flexible fleet capacity is  
10 being used to meet the load and does not remain available to meet the load  
11 following and regulation upward requirements. What this indicates is that qualified  
12 capacity in excess of the planning reserve margin in the four priority scenarios  
13 provides sufficient unloaded flexible capacity to meet the load following and  
14 regulation needs while the renewable resource capacity is meeting the load. In the  
15 All Gas scenario the planning reserve margin is significantly reduced while still  
16 maintaining the required planning reserve margin. In the Trajectory High Load  
17 scenario, the load was increased by 10% over Trajectory Base Load scenario. At  
18 these high load levels the flexible fleet capacity needs to produce energy to meet the  
19 load during higher load periods. As a result, remaining flexible capacity is  
20 insufficient to simultaneously meet the load following requirements.

21

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

24 **A.** No. The four priority scenarios reflect scenarios with resource capacity in excess  
25 of the required planning reserve margin (PRM) of 15%-17%. Table 7 and Figure  
26 11, below, show the planning reserve margin of the different scenarios as calculated  
27 by E3. As a result, the excess capacity above PRM provides sufficient flexible  
28 capacity to meet the simultaneous energy, operating reserve, regulation and load  
29 following requirements of these four scenarios. However, we cannot conclude from  
30 these results whether sufficient flexible capability would exist to meet the

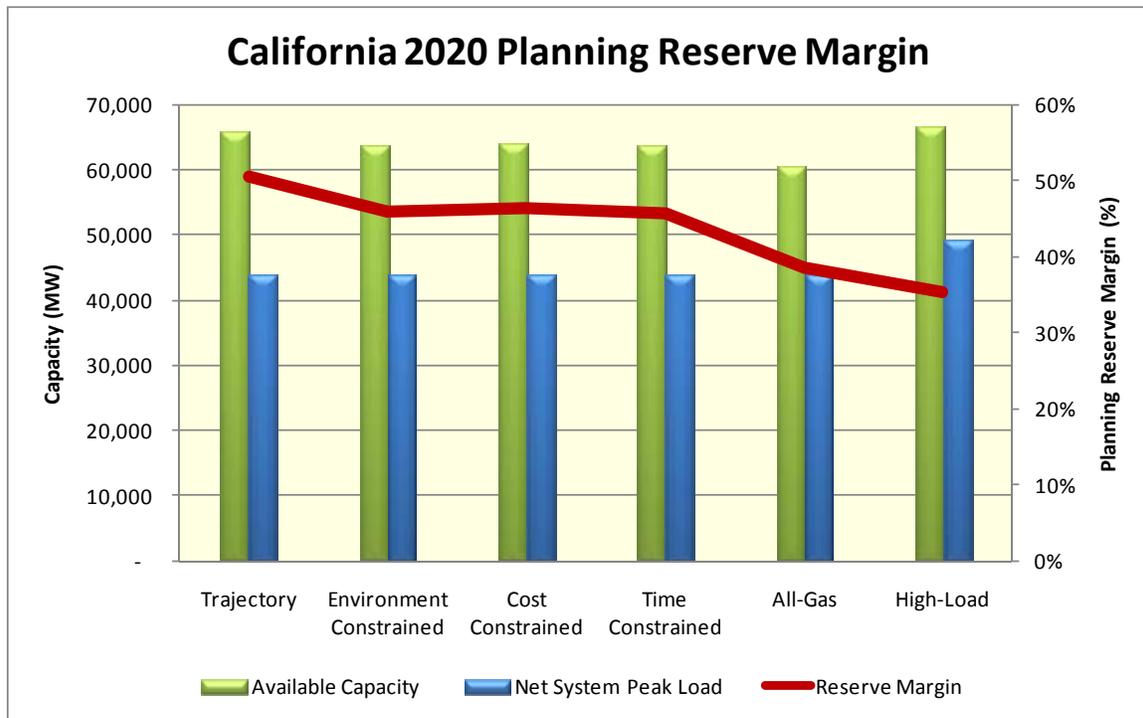
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1 simultaneous energy, operating reserve, regulation and load following requirements  
 2 if the available generation capacity was not in excess of the 15-17% PRM. For  
 3 example, if the utilities contract for less import qualifying capacity, just meeting  
 4 their PRM of 117%, the ISO may need to dispatch the capacity that is currently  
 5 unloaded and providing flexibility services in these cases, and therefore may be  
 6 short the needed flexible capacity. The four priority scenarios were not analyzed  
 7 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**



11  
12  
13

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

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

10

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

12 **A.** The total production cost of the four priority scenarios are all within 0.3% of each  
13 other, with WECC wide production costs ranging from \$18.85 billion for  
14 Environmentally Constrained scenario to \$18.89 billion for the Cost Constrained  
15 scenario. The production costs to meet WECC load in the All Gas scenario were \$  
16 20.79 billion. The production costs to meet WECC load in the Trajectory High  
17 Load scenario were \$19.63 billion. This information can be found on Slide 14 of  
18 Exhibit 1.

19

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

22 **A.** The total production costs to meet the California load of the four priority scenarios  
23 were within 4% of each other. The Time Constrained scenario had the highest  
24 costs to meet California load (\$7.45 billion), while the Environmentally Constrained  
25 scenario had the lowest cost to meet California load (\$7.17 billion). The production  
26 costs to meet California load in the All Gas scenario were \$8.37 billion. The  
27 production costs to meet California load in the Trajectory High Load scenario were  
28 \$8.07 billion. This information can be found on Slide 18 of Exhibit 1.

29

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

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

8

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

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

16

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

18 **A.** The total WECC emissions for the four priority scenarios ranged from 364,684  
19 million metric tons at a cost of \$13.238 billion in the Time Constrained scenario to  
20 366,059 million metric tons at a cost of \$13.287 billion in the Environmentally  
21 Constrained scenario. The total WECC emission in the All Gas scenario was  
22 398,089 million metric tons at a cost of \$14.450 billion. The total WECC emission  
23 in the Trajectory High Load scenario was 377,070 at a cost of \$13.687 billion. This  
24 information can be found on Slides 21 and 22 of Exhibit 1.

25

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

28 **A.** The Environmentally Constrained scenario reflects the lowest emissions of 76,101  
29 million metric tons while the Time Constrained scenario had the highest among the  
30 four priority scenarios of 80,987 million metric tons. The Trajectory High Load

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1 scenario had 85,822 million metric tons attributable to meet California load. The  
2 all gas scenario has a 92,299 million metric tons meet California load. This  
3 information can be found on Slide 24 of Exhibit 1.  
4

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

6 A. The maximum imports between the four priority scenarios had similar maximum  
7 California net import of approximately 12,000MW. The Cost and Time  
8 Constrained scenarios had the highest average net imports due the higher imports  
9 renewable capacity. Slide 17 of Exhibit 1 provides a comparison of California  
10 average net import for the different scenarios.  
11

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

14 A. A higher average number of annual starts on California gas turbines of  
15 approximately 80-100 starts/year are observed versus 40-55 starts/year observed for  
16 the WECC. A lower average number of starts on California combined cycle  
17 resources of 40 starts/year versus 70-80 starts/year observed for the WECC. The  
18 capacity factor of WECC coal resources is approximately 60% in the scenarios. The  
19 capacity factor for combined cycle resources in California and WECC are both in  
20 the range of 40%. The capacity factor for gas turbines in California are  
21 approximately 6.4% versus 8% for WECC. Slides 25 and 26 of Exhibit 1 provide a  
22 comparison of start-up and capacity factors for California and WECC for the  
23 different scenarios.  
24

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

27 A. Yes. As I discussed earlier in my testimony, the ISO performed a sensitivity run on  
28 the Trajectory Base Load scenario assuming Helms could pump with 3 pumps year  
29 round. The total annual production costs to meet California load was reduced by  
30 \$2.3 million when Helms was not restricted. However, additional scenarios and

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1 benefit considerations are needed to fully evaluate the incremental benefit of having  
2 greater access to Helms pumping capabilities.

3

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

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

8

9 **V. NEXT STEPS**

10

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

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

27

28 **Q. Does this conclude your testimony?**

29 A. Yes, it does.

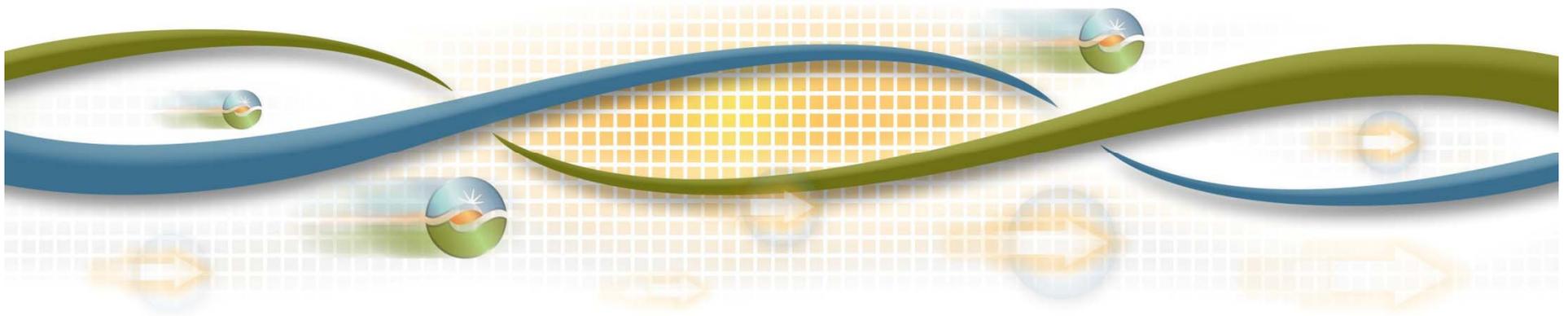
## Exhibit 1



California ISO  
Shaping a Renewed Future

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

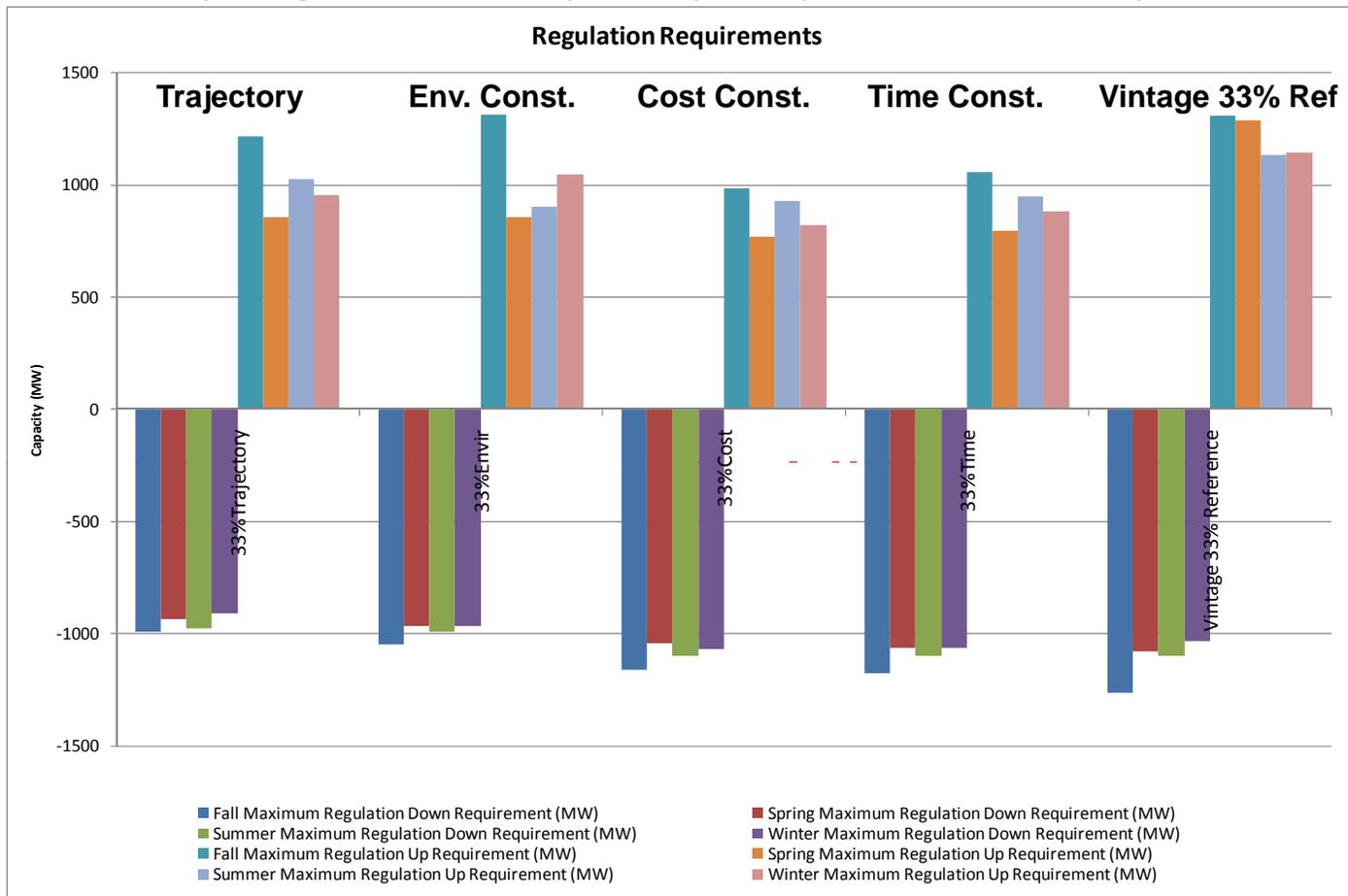
July 1, 2011



## 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 calculate 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

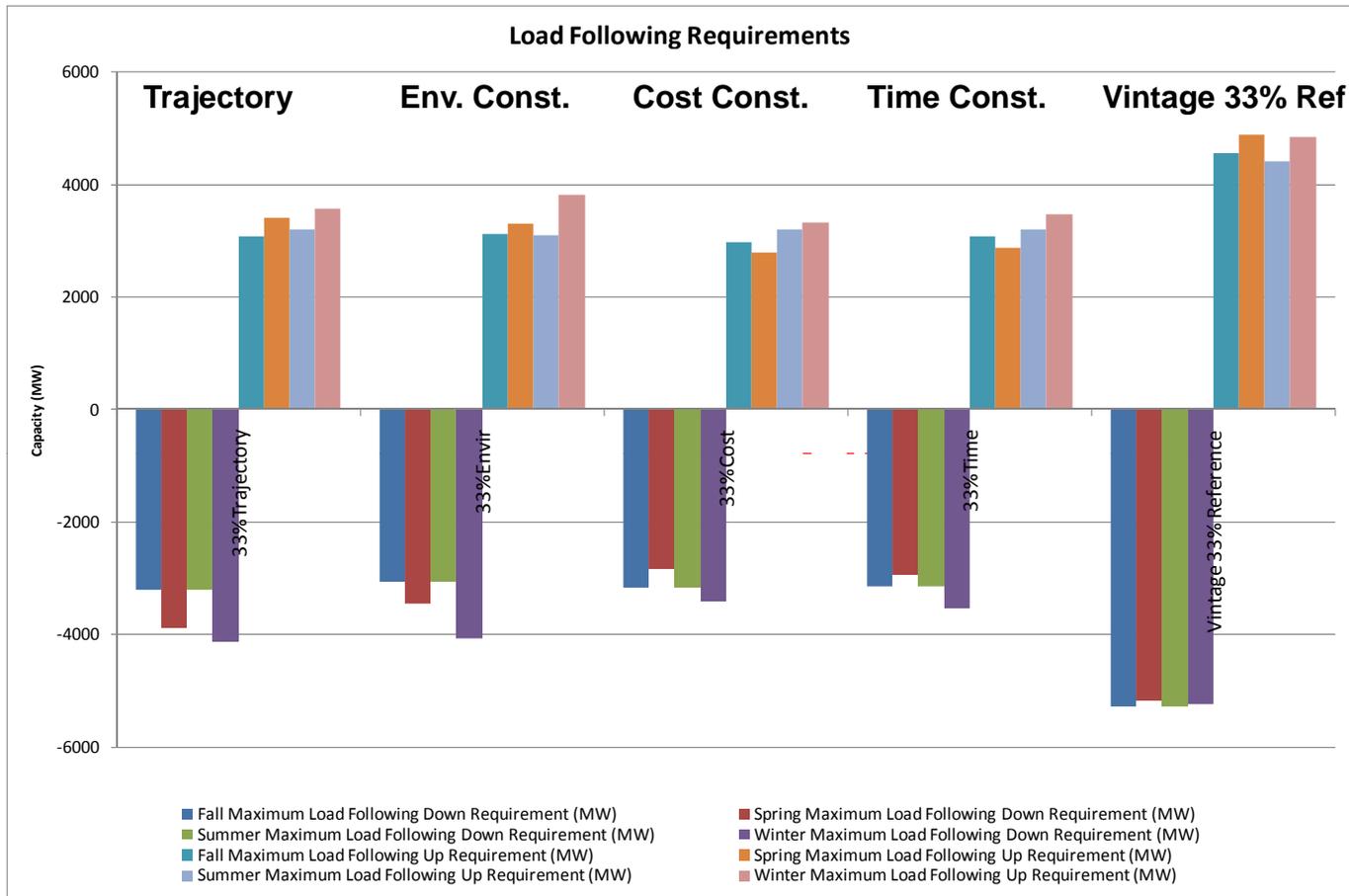
# Step 1: Hourly regulation capacity requirements, by scenario



**Notes:**

- For purposes of comparison, the figures show the single highest hourly seasonal requirement from Step 1 for each season (using the 95<sup>th</sup> 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 95<sup>th</sup> 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

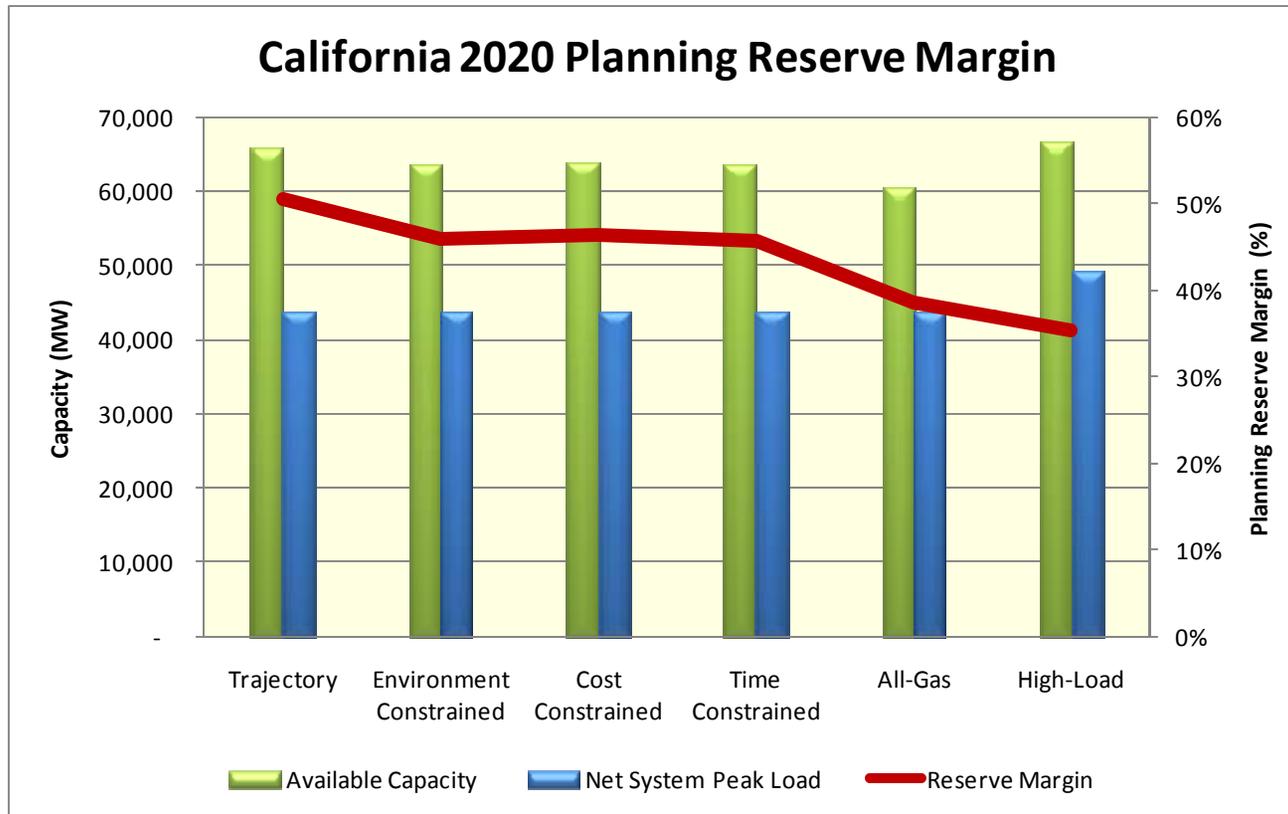
# Renewable portfolios for 2020: 2010 LTPP Scenarios

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

# Renewable portfolios for 2020: 2010 LTPP Scenarios

Capacity (MW)	33% Trajectory		33% Env Constrained		33% Cost Constrained		33% Time		33% Trajectory 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

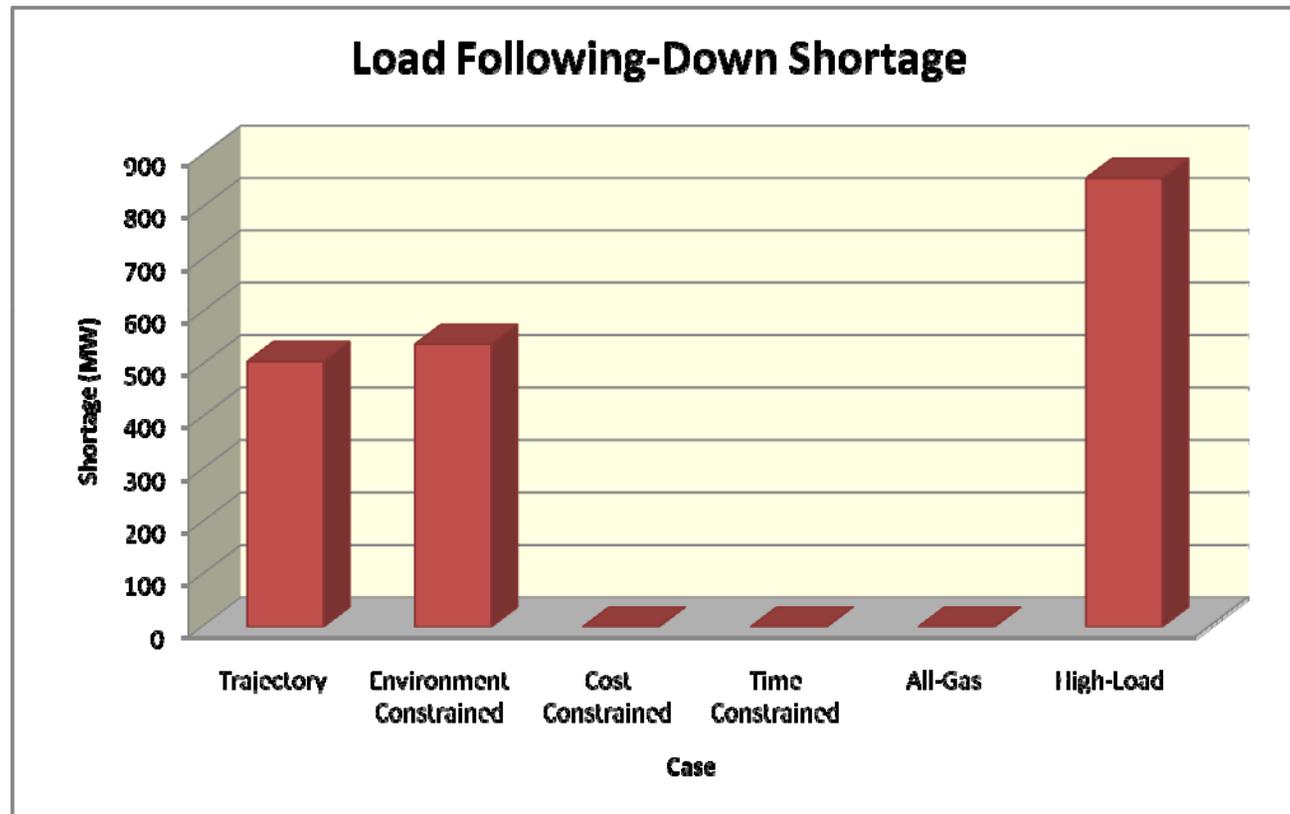
## Production simulation results in this section reflect certain assumptions

- 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.

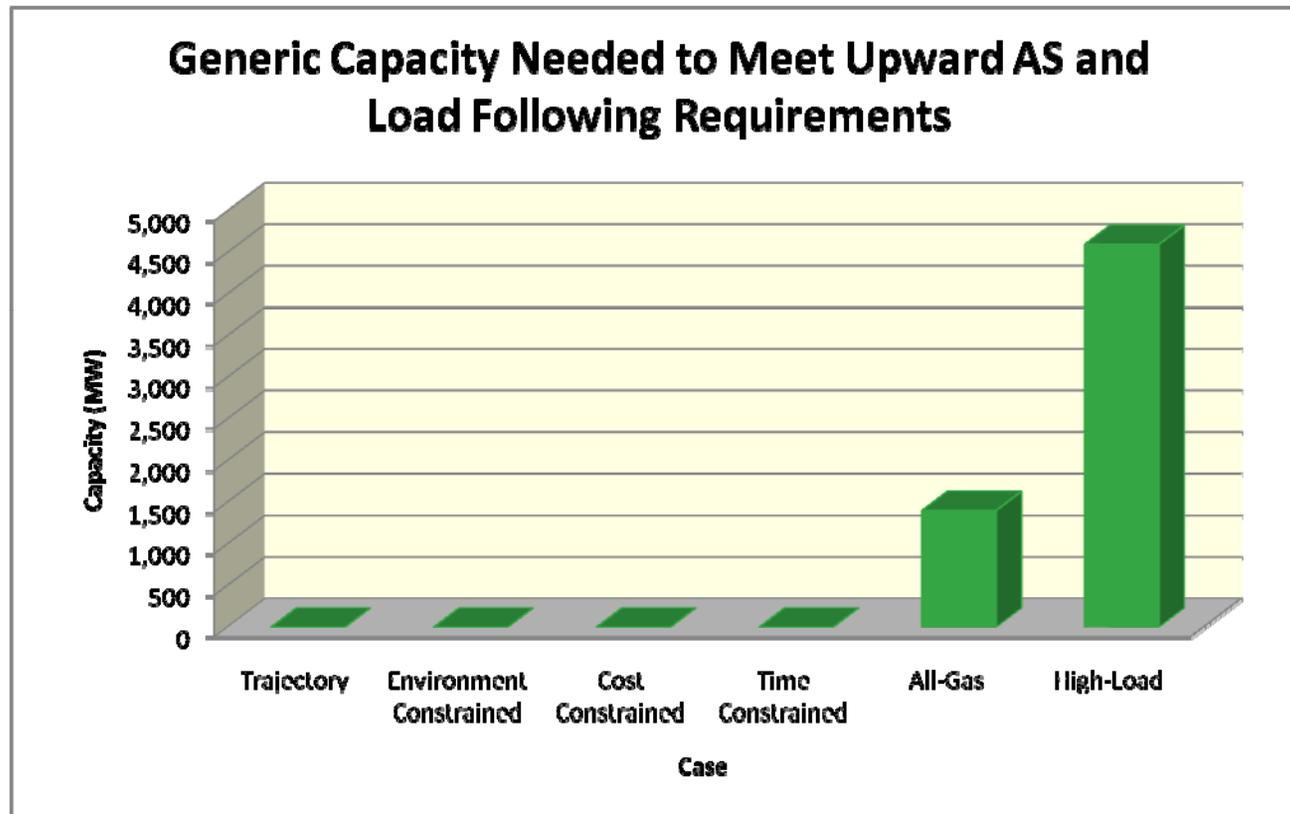
- LTPP analysis did not require adding any generic units to meet PRM because CPUC scoping memo assumptions create a 2020 base dataset that has a significant amount of capacity above PRM
- Next slide shows operational requirement shortages (constraint violations)
- Results for production costs, fuel use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

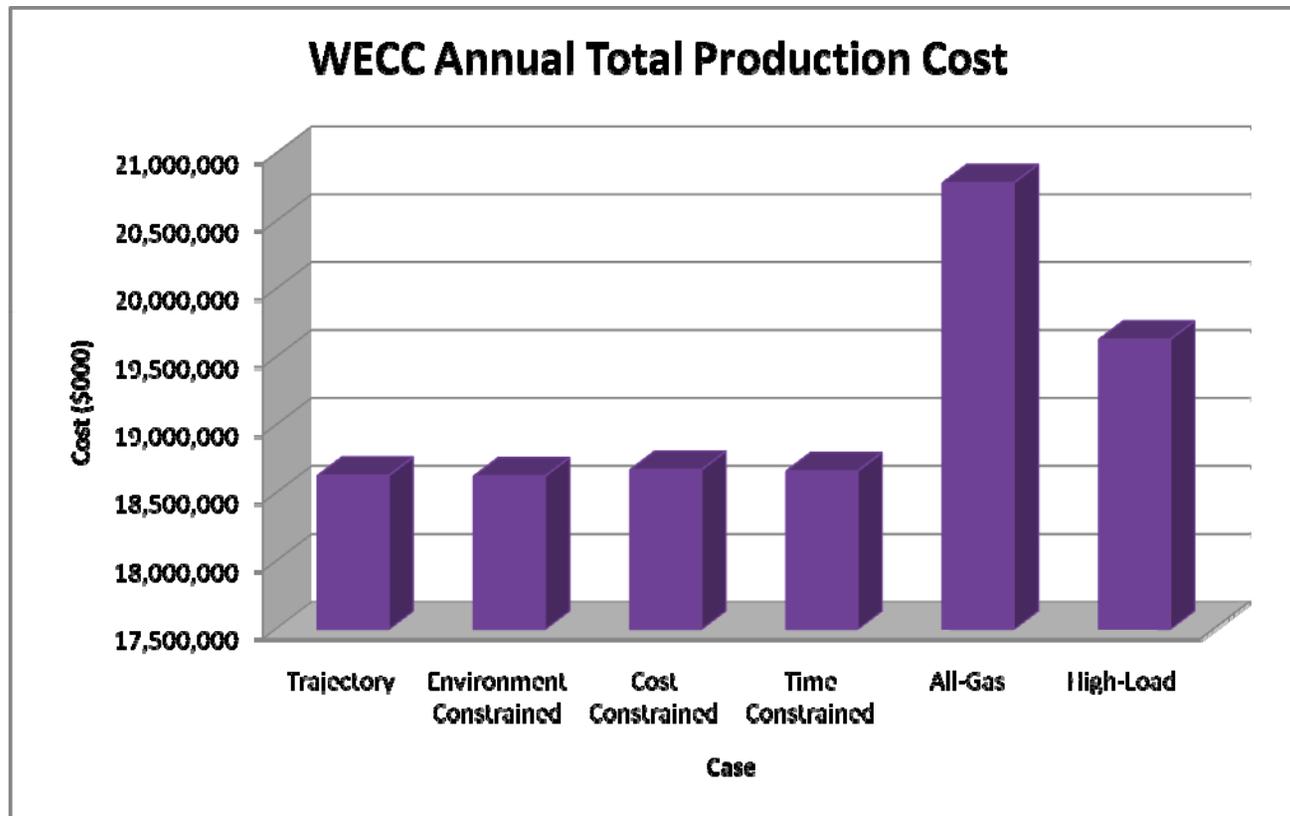
## Discussion of results on additional resources

- 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

$$\left( \begin{array}{l} \text{CA IMPORTS} \\ \bullet \text{ Dedicated Resources} \\ \quad - \text{ Renewables} \\ \quad \bullet \text{ Firmed} \\ \quad \bullet \text{ Non-Firmed} \\ \quad - \text{ Conventional Resources} \\ \quad \bullet \text{ } i.e., \text{ Hoover, Palo Verde} \\ \bullet \text{ Undesignated (or non-dedicated) Resources} \\ \quad - \text{ Marginal resources in various regions} \end{array} \right) + \left( \begin{array}{l} \text{CA EXPORTS} \\ \bullet \text{ Undesignated (or non-dedicated) Resources} \\ \quad - \text{ Marginal resources within CA regions} \end{array} \right)$$

## 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)

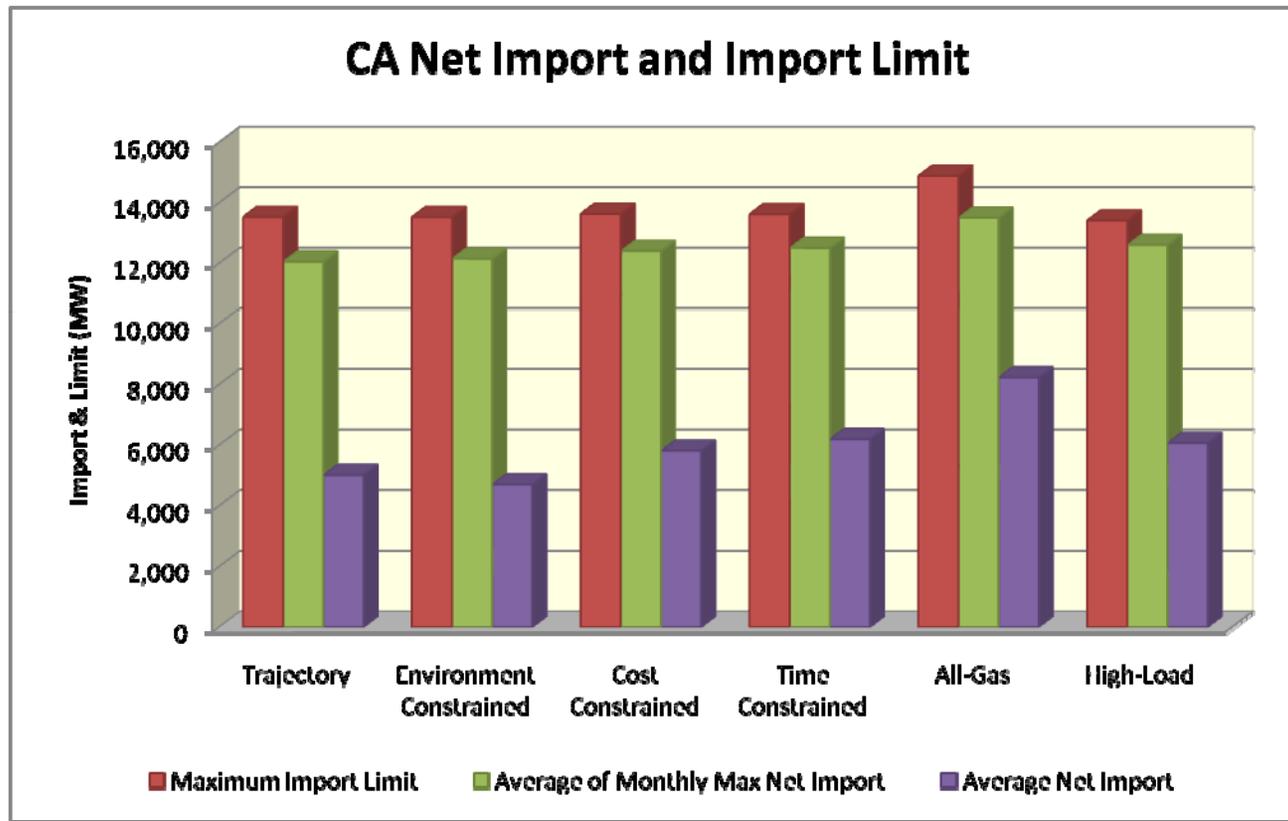
- Undesignated (or non-dedicated) Export Costs

### = Total Production Cost of meeting CA load

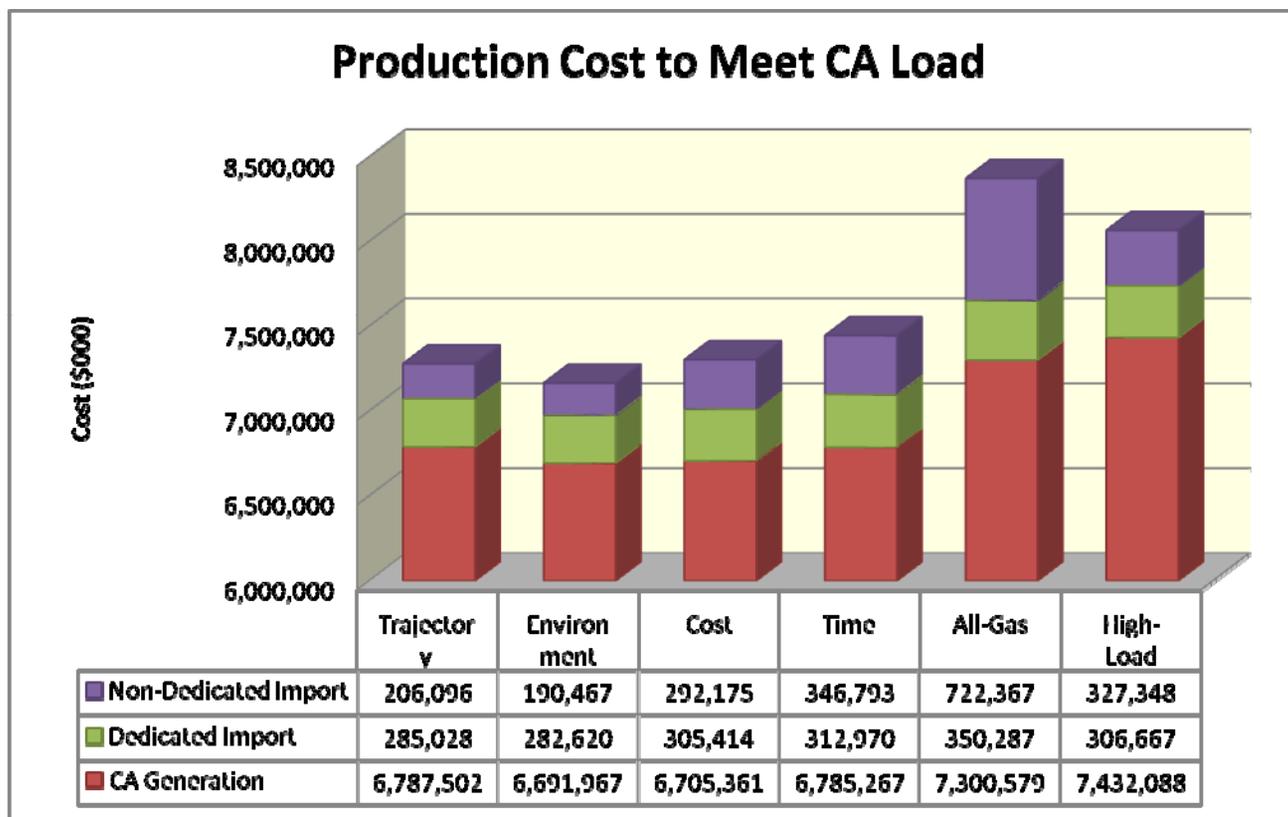
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Note: Dedicated vs. Non-dedicated may also be known as specified or non-specified

# California annual net import results by case

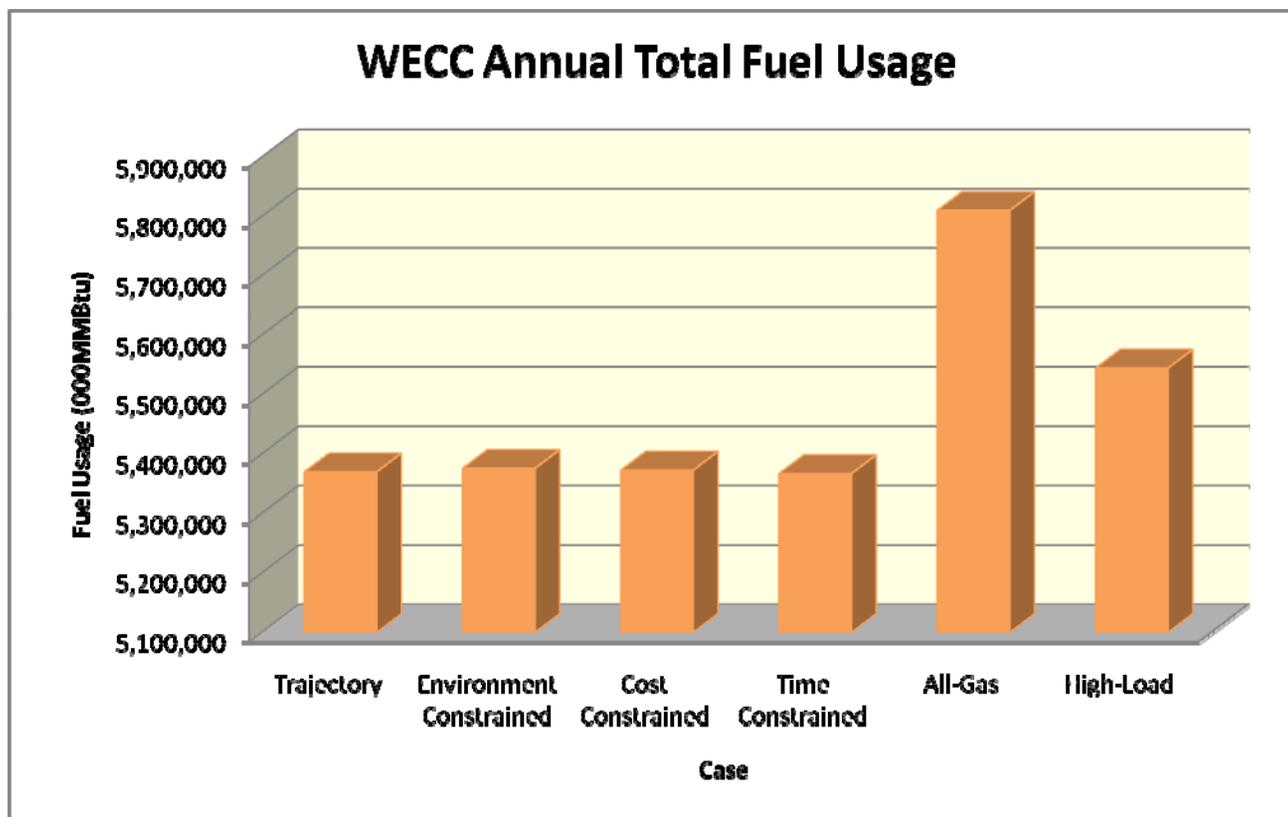


# Annual production costs associated with California load (accounting for import/exports), by case



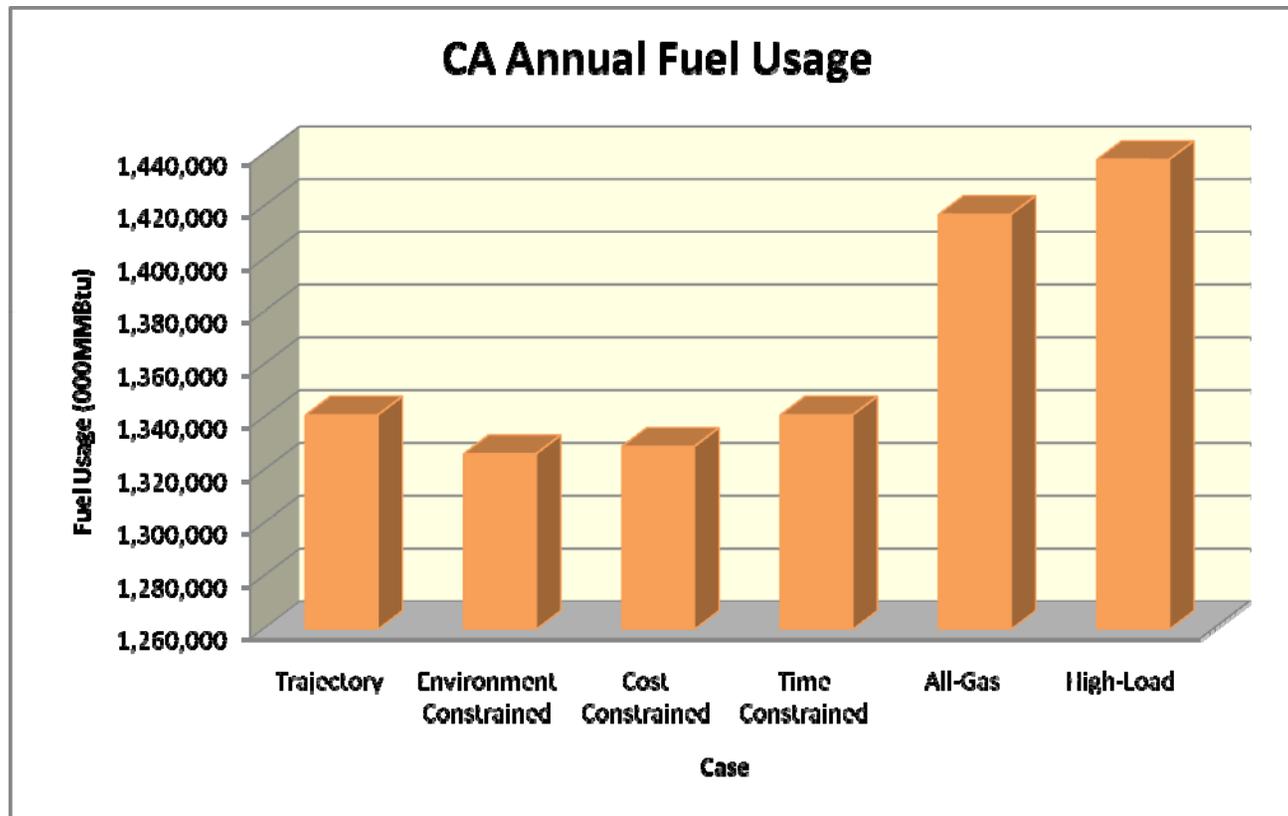
Note: Production cost associated with non-dedicated import is calculated based on the average cost (\$/MWh) of each of the regions the energy is imported from; for dedicated import it is based on the actual production cost of each of the dedicated resource and its energy flows into CA

# WECC (including California) annual fuel usage (MMBtu), by case



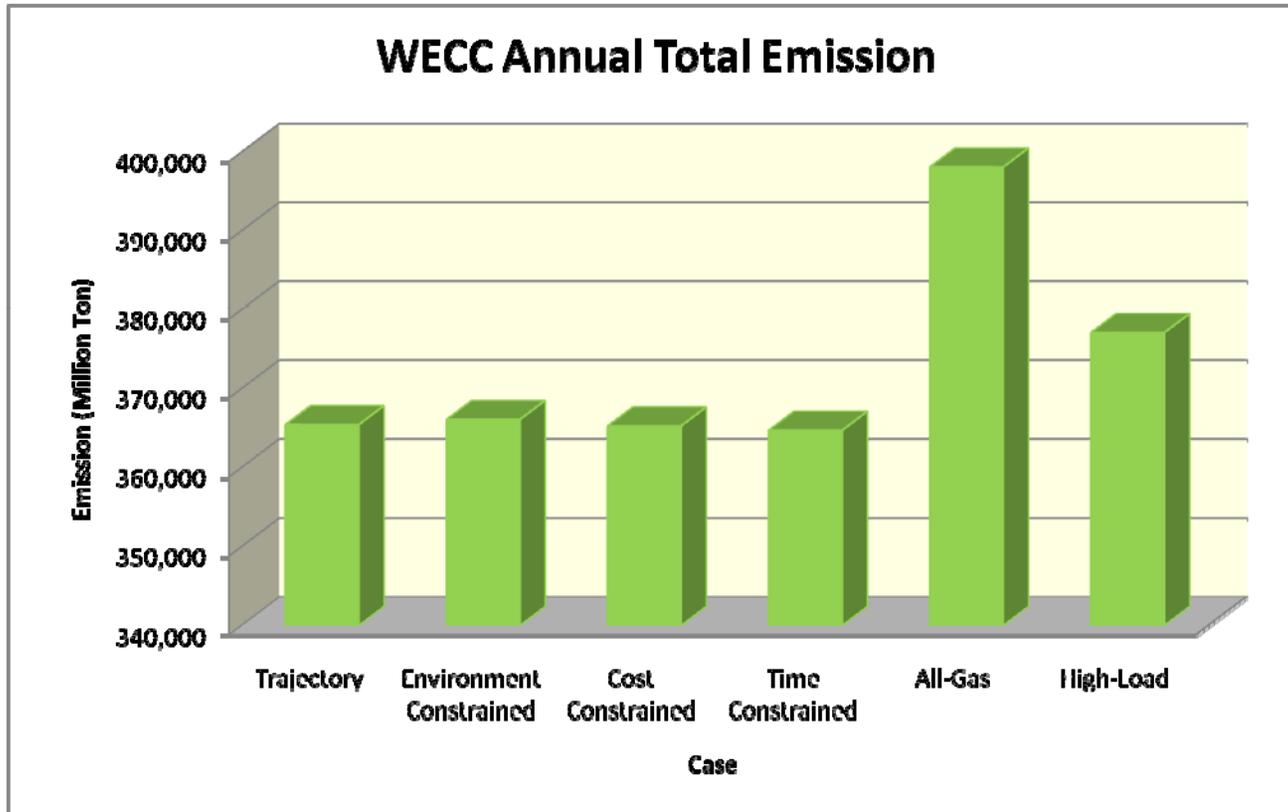
MMBtu = million BTU for conventional/fossil resources

# California annual in-state generation fuel usage by case

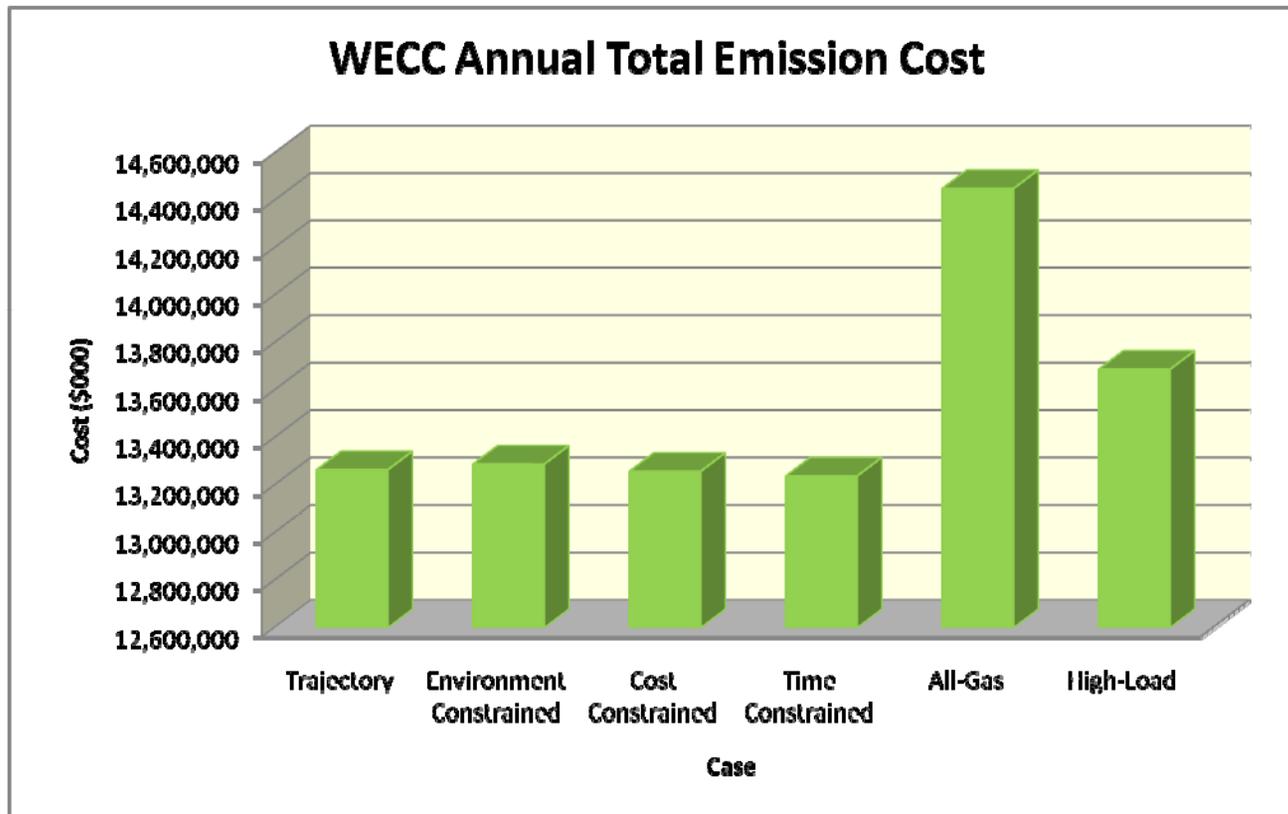


MMBtu = million BTU for conventional/fossil resources

# WECC (including California) annual emissions by case



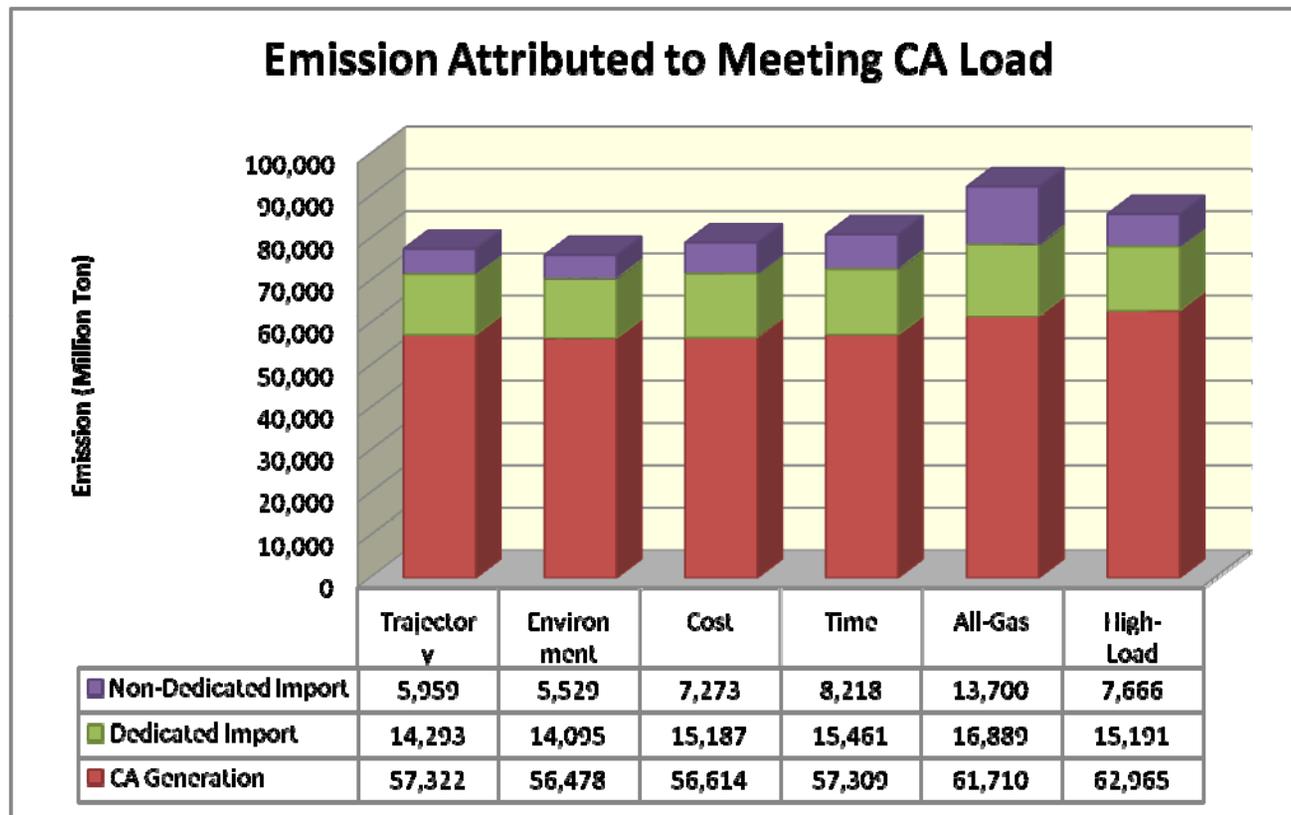
# WECC (including California) annual emission costs by case



## Calculation of emissions associated with California

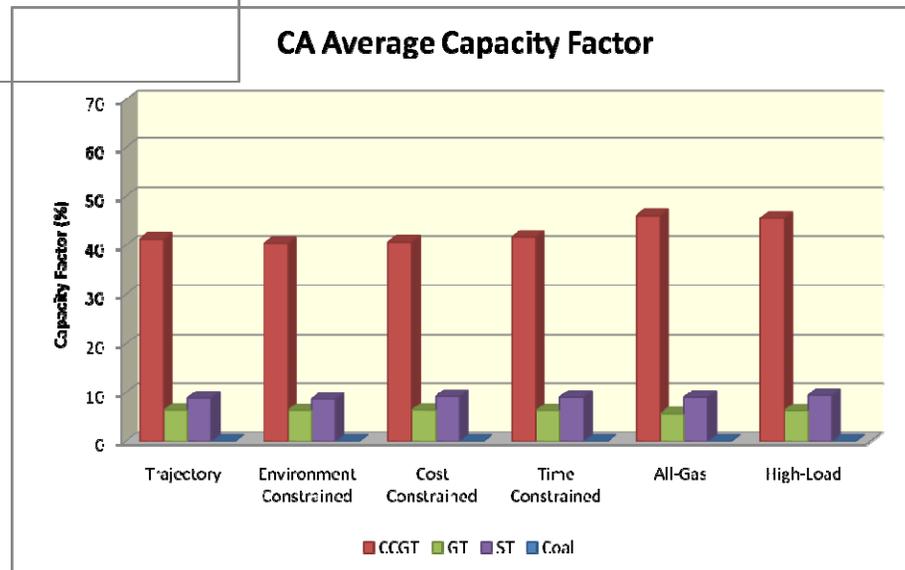
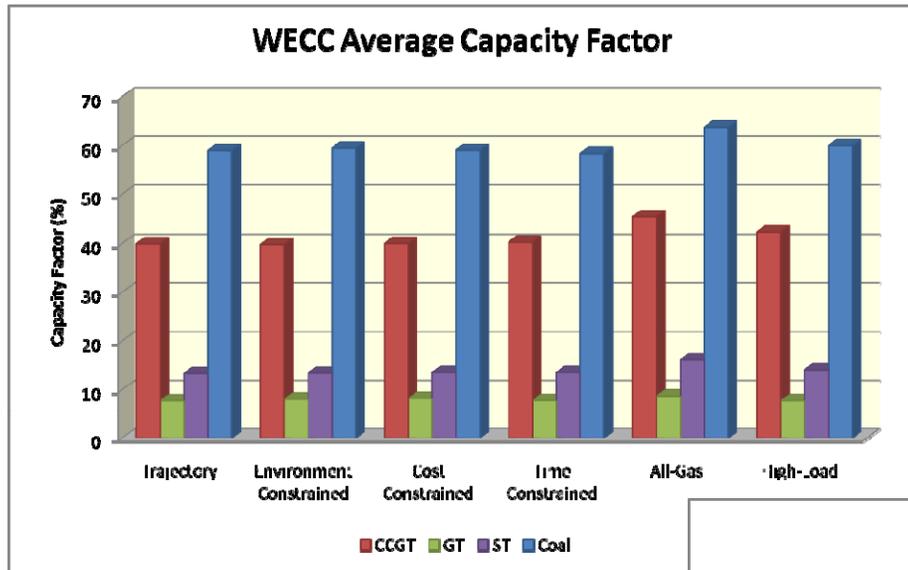
- Production simulation modeling output includes GHG emissions (tons) per generator to capture WECC-wide emissions reductions, but:
  - The model solves production simulation for the WECC without considering contractual resources specifically dedicated to meet California load
  - Not all out of state (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

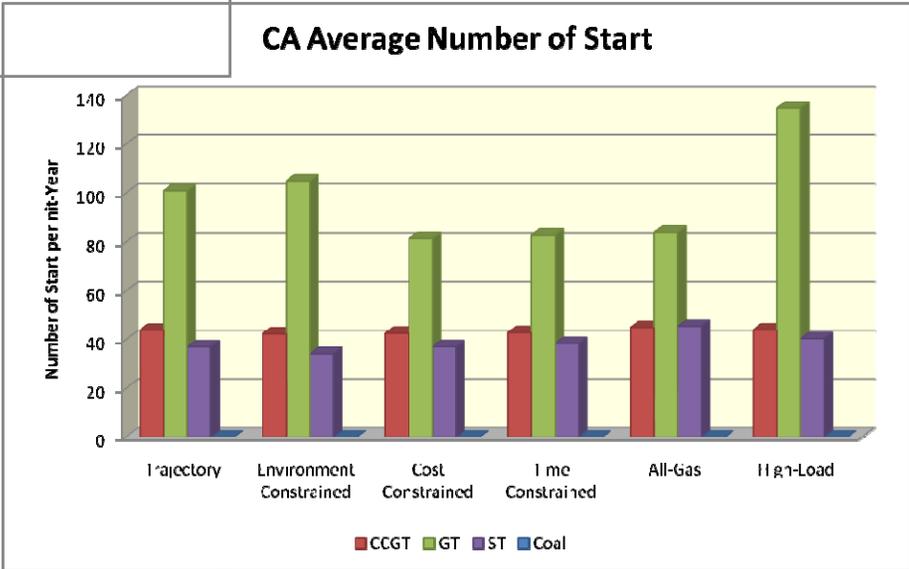
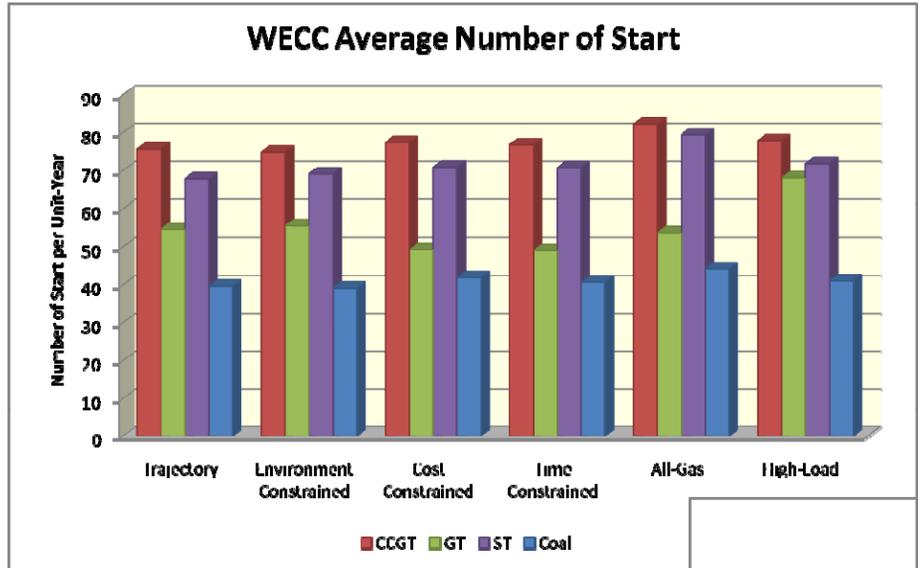


Note: Emissions associated with non-dedicated import is calculated based on the average emission rate (ton/GWh) of each of the regions the energy is imported from; for dedicated import it is based on the actual emission of each of the dedicated resource and its energy flows into CA

# WECC and California annual average capacity factors by case

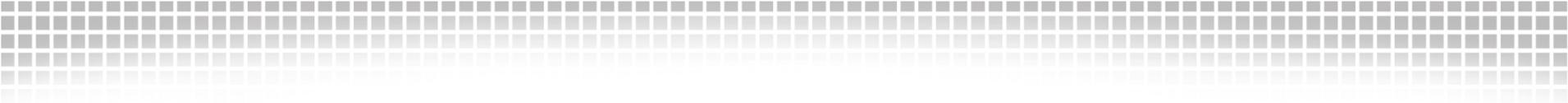


# WECC and California annual average number of startup by case



## Comparison of WECC (including CA) and CA results

Case	Trajectory	Environment	Cost	Time	All-Gas	High-Load
<b>Annual Average Capacity Factor (%)</b>						
<b>WECC</b>						
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
<b>CA</b>						
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
<b>Number of Start per Unit per Year</b>						
<b>WECC</b>						
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
<b>CA</b>						
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



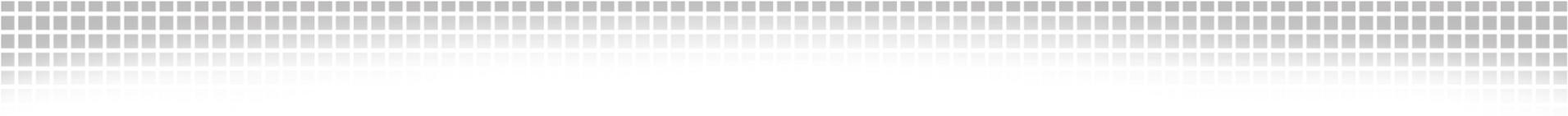
# APPENDIX: PRODUCTION SIMULATION MODEL CHANGES

## 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 29<sup>th</sup> 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<sub>2</sub> price assumption
- Non-specified assumptions updated by the ISO
  - Allocation of reserve requirements between ISO and munis
  - Generator operating characteristics and profiles
  - Operational inertia 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<sup>nd</sup>, 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
<i>Load</i>										
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
<i>Resources</i>										
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
<i>Summary</i>										
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	<b>16,395</b>	<b>19,480</b>	<b>22,010</b>	<b>21,748</b>	<b>22,924</b>	<b>22,936</b>	<b>19,376</b>	<b>18,827</b>	<b>19,340</b>	<b>17,513</b>

## 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
<i>Load</i>										
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
<i>Resources</i>										
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
<i>Summary</i>										
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
<i>Difference in Surplus between CPUC and CAISO</i>	<b>2,755</b>	<b>2,755</b>	<b>2,914</b>	<b>2,914</b>	<b>3,369</b>	<b>3,369</b>	<b>3,369</b>	<b>3,369</b>	<b>3,369</b>	<b>3,369</b>

## 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

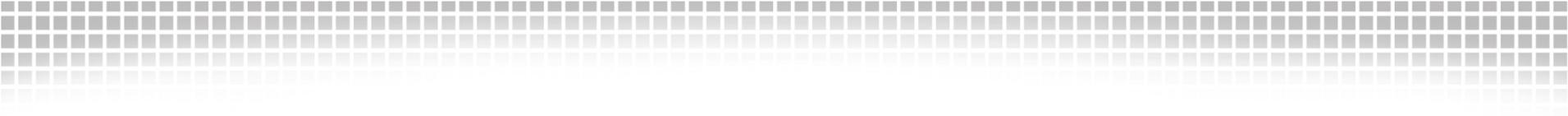
# CA Gas Forecast

- 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<sub>2</sub> Price

- A \$36.30/short ton of CO<sub>2</sub> (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

<b>Transmission Limits (MW)</b>	Summer Pk	Summer Off Pk	Winter Pk	Winter Off Pk
<b>Trajectory Case</b>				
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
<b>Environmental Case</b>				
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
<b>Cost Case</b>				
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
<b>Time Case</b>				
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
<b>All-Gas</b>				
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
<b>High-Load</b>				
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 PCO Case

- PCO, 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 PCO
  - Excluded the resources assumed to contribute to California's RPS portfolio that are located outside of California

# Exclusion of RPS Resources from PCO

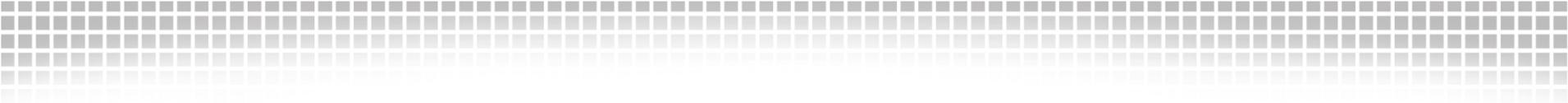
- TEPPC’s PCO case includes enough renewables to meet RPS goals in California and the rest of the WECC
  - The portfolio for California is very similar to the Trajectory Case specified for the LTPP, which includes out-of-state renewables
- To develop consistent scenarios for LTPP, the RPS builds for CA in PCO must be adjusted according to the following framework:

	<b>WECC-Wide RPS Resources in PCO</b>
–	PCO RPS Resources in CA
–	PCO OOS RPS Resources Attributed to CA
+	CPUC RPS Portfolio (Traj/Env/Cost/Time)
=	<b>RPS-Compliant LTPP Scenario</b>

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
<b>Total</b>		<b>5,544</b>	<b>16,760</b>

# Coal retirements by 2020

- PCO 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					Vintage 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	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	545.18	216.05	0.61	0.86	Spring	831.11	126
Summer	636.03	288.03	0.7	0.92	Summer	1150.61	126
Fall	539.69	277.38	0.65	0.9	Fall	835.11	126
Winter	681.86	230.96	0.54	0.85	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%

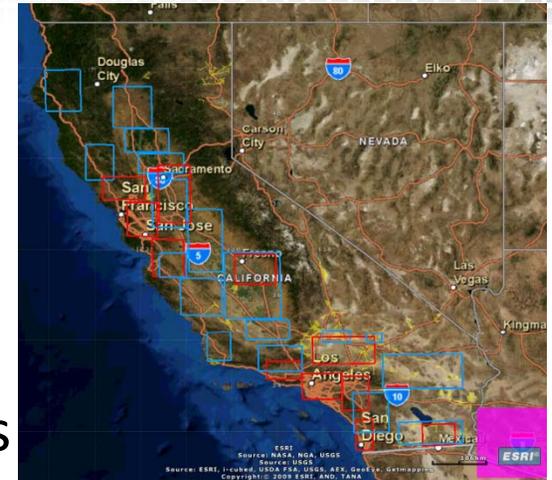
## Refinements to solar profiles

- Profiles for 2010 scenarios are developed based on satellite irradiation data<sup>1</sup> 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

<sup>1</sup>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



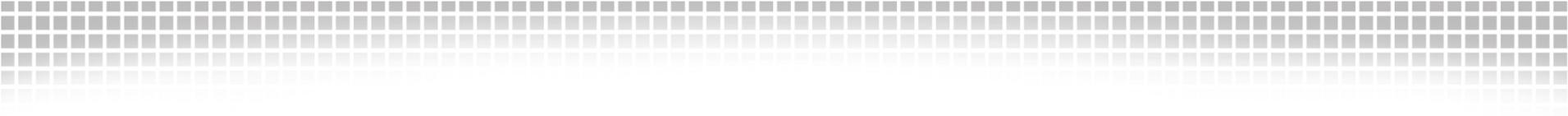
## Refinements to solar forecast errors

- 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	$0 \leq CI < 0.2$	$0.2 \leq CI < 0.5$	$0.5 \leq CI < 0.8$	$0.8 \leq CI \leq 1$
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



# 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-minute 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-minute 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-minute upward ramp capability
  - The sum of regulation-down and 50% of load following down provisions is less than or equal to 10-minute 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

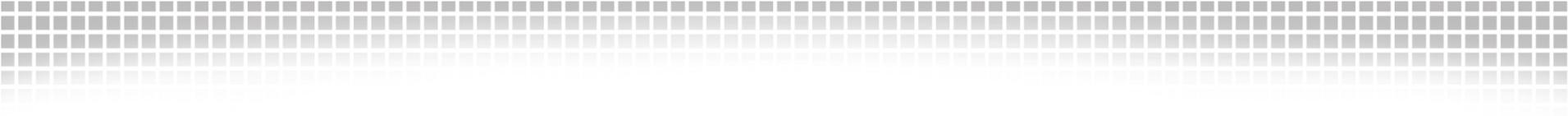
- Model has mixed integer optimization in CA only
  - Mixed integer optimization applies to all CA generators and generators as dedicated import to CA only
  - These generators are subject to unit commitment decision in the optimization
  - Other generators outside CA are not subject to unit commitment decision
  - These generators are available for dispatch at any time (when they are not in outage)

## 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
  - Tier 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

