ATTACHMENT A

PACIFIC GAS AND ELECTRIC COMPANY
Oakley Generation Station
Application 12-03-026
Data Response

PG&E Data Request No.:	DRA_003-05		
PG&E File Name:	OakleyGeneratingStation_DR_DRA_003-Q5		
Request Date:	June 8, 2012	Requester DR No.:	003
Date Sent:	June 21, 2012	Requesting Party:	DRA
PG&E Witness:	Antonio Alvarez	Requester:	Yuliya Shmidt

QUESTION 5

Please list state the source data, for each of the following values identified in PG&E's Prepared Testimony:

a. 4,600 MW need for renewable integration (p.5-2)

b. 800 MW for downward balancing flexibility (p.5-2)

c. 2,535 MW deficiency in flexible capacity requirements (p.5-2)

d. 3,750 MW of additional capacity needs (p.5-2)

e. Shortfalls in excess of 500 MWs (p.5-4)

f. Shortfall of several thousand megawatts of ramping capacity (p.5-4)

g. 3,570 MW for meeting system-wide capacity needs (p.30, Attachment 1 to Chapter 5)

For each distinct source data, provide copies of any documents that constitute or explain the source data's modeling results, modeling assumptions, workpapers, and/or assumptions used for load and resources (including demand-side resources). If PG&E contends that it is not in possession of such documents, state whether PG&E has access to these documents.

ANSWER 5

The following table lists the source data for the values identified by this question, and indicates the documents that constitute or explain modeling results, modeling assumptions, workpapers and/or assumptions for loads and resources.

Values identified by this question	Documents that constitute or explain identified value	Does PG&E have these

		documents?
a. 4,600 MW need for renewable integration (p.5-2)	Source data, and documents that constitute or explain the source data's modeling results, modeling assumptions, workpapers, and/or assumptions used for load and resources (including demand-side resources) can be found in: CAISO's renewable integration studies filed in the 2010 LTPP on July 1, 2011, and the CPUC's adopted standard planning assumptions provided by rulings to parties in the 2010 LTPP proceeding. These documents are publicly available.	Yes
b. 800 MW for downward balancing flexibility (p.5-2)	See documents listed for part a of this question. The 800 MW figure corresponds to the 856 MW of downward load following shortfall that the CAISO found in its renewable integration studies filed in the 2010 LTPP proceeding on July 1, 2011. (See page 44 of, and slide 10 of Exhibit 1 to, CAISO's 2010 LTPP testimony for the actual values.)	Yes
c. 2,535 MW deficiency in flexible capacity requirements (p.5-2)	Source data, and documents that constitute or explain the source data's modeling results, modeling assumptions, workpapers, and/or assumptions used for load and resources (including demand-side resources) can be found in: CAISO's Sutter Waiver Request at FERC dated January 25, 2012, CAISO's renewable integration studies filed in the 2010 LTPP proceeding on July 1, 2011, and the CPUC's adopted standard planning assumptions provided by rulings to parties in the 2010 LTPP proceeding. These documents are publicly available.	Yes
d. 3,750 MW of additional capacity needs (p.5-2)	The 3,750 MW figure in PG&E's testimony is a typo, and should have been 3,570 MW. The source data for the 3,570 MW value is the same as for the value in Part c of this question.	Yes

e. Shortfalls in excess of 500 MWs (p.5-4)	See documents listed for part a of this question.	Yes
f. Shortfall of several thousand megawatts of ramping capacity (p.5-4)	See documents listed for part a of this question.	Yes
g. 3,570 MW for meeting system-wide capacity needs (p.30, Attachment 1 to Chapter 5)	See documents listed for part c of this question.	Yes

ATTACHMENT B

PACIFIC GAS AND ELECTRIC COMPANY
Oakley Generation Station
Application 12-03-026
Data Response

PG&E Data Request No.:	DRA_005-01		
PG&E File Name:	OakleyGeneratingStation_DR_DRA_005-Q01		
Request Date:	July 3, 2012	Requester DR No.:	005
Date Sent:	July 13, 2012	Requesting Party:	Division of Ratepayer Advocates
PG&E Witness:	Antonio Alvarez	Requester:	Yuliya Shmidt

QUESTION 1

For each of the following CAISO statements, comments, straw proposals, and memoranda referenced in Chapter 5 to PG&E's testimony please answer the questions shown in (i) to (iv) below. Please provide an actual response, do not simply refer to PG&E's responses to other data requests.

(a) Pages 5-1, line 29 to 5-2 line 1 and footnote 1 (generalized statement);

(b) Page 5-2, lines 5-10 (CAISO comments on the 2010 LTPP Settlement Agreement and Opening Brief on Track I issues in 2010 LTPP);

(c) Pages 5-2 line 17 to 5-3 line 2, page 5-3 lines 12-14 and the Attachment 1 to Chapter 5 (CAISO Sutter Waiver filing and Rothleder Declaration);

(d) Pages 5-3 line 22 to 5-4 line 15 and footnotes 8-9 (CAISO Flexible Capacity Procurement straw proposal);

(e) Page 5-4 lines 16-26 and footnote 10 (Report of CAISO CEO Steve Berberich);

(f) Page 5-14 lines 24-25 (Statement that the AISO has now made a demonstration of significant negative reliability risks from integrating a 33% renewable Portfolio Standard);

(g) Page 5-16, lines 15-16 (existing and new resources are needed);

QUESTIONS FOR EACH REFERENCE:

1. Is the underlying modeling (defined as the methodology and input assumptions) that supports this reference the same modeling used in the analysis filed by the CAISO in the 2010 LTPP proceeding on July 1, 2011?

2. Does this reference rely on the same assumptions that were used in the CAISO's High Load Trajectory Scenario results?

3. If your answer to (i) or (ii) is anything but an unqualified 'Yes', state the source of the underlying modeling (defined as the methodology and input assumptions), state the results of such modeling, provide the date on which such modeling was completed, provide a copy of the results, and explain how the assumptions for this analysis differ from the assumptions used in the High Load Trajectory Scenario.

4. Is the Oakley facility included (i.e., assumed to be operational) in the assumptions for the underlying analysis?

ANSWER 1

PG&E objects to DRA's instruction to provide an "actual response" and not to refer to other data responses. To date, PG&E has received hundreds of data requests in this proceeding when considering the numerous subparts included in many data requests. Many of these data requests are similar or identical, and a number of parties, including DRA, have requested copies of all data requests. Responding to numerous duplicative and/or redundant data requests is unduly burdensome given the volume of data requests and schedule in this proceeding. While PG&E responds to DRA's requests below, it objects to the instruction not to refer to other data requests.

i) Is the underlying modeling (defined as the methodology and input assumptions) that supports this reference the same modeling used in the analysis filed by the CAISO in the 2010 LTPP proceeding on July 1, 2011?

a) Not entirely. The CAISO performed an additional analysis for the Sutter Waiver Request to estimate need for 2018 using the same methodology which it had used in the renewable integration studies summarized in CAISO's July 1, 2011 to estimate resource need in 2020. Also, the CAISO has performed additional analyses to estimate flexibility requirements for the resource adequacy proceeding, and continued to refine its methodology and perform additional sensitivities with the advisory group and in the 2012 LTPP proceeding.

b) Not necessarily. The CAISO's comments also rely on scenarios presented by the Joint IOU 2010 LTPP Testimony.

c) See response to part b of this question.

d) No.

e) Not entirely. The CAISO performed an additional analysis for the Sutter Waiver Request to estimate need for 2018 using the same methodology which it had used in the renewable integration studies summarized in CAISO's July 1, 2011 to estimate resource need in 2020.

f) See response to part a) of this question.

g) See response to part a) of this question.

ii) Does this reference rely on the same assumptions that were used in the CAISO's High Load Trajectory Scenario results?

a) Not entirely. As mentioned in response to part i), the CAISO has performed additional work since completing its evaluation of the 2020 resource need under the High Load Trajectory Scenario which it filed on July 1, 2011 in the 2010 LTPP proceeding.

b) Not exclusively. The CAISO's comments also reference scenarios presented by the Joint IOU 2010 LTPP Testimony.

c) See response to part b of this question.

d) No.

e) Not entirely. As noted before, the CAISO performed an additional analysis for the Sutter Waiver Request to estimate need for 2018 using the same methodology which it had used in the renewable integration studies summarized in the CAISO's July 1, 2011 LTPP testimony to estimate resource need in 2020.

f) See response to part a) of this question.

g) See response to part a) of this question.

iii) If your answer to (i) or (ii) is anything but an unqualified 'Yes', state the source of the underlying modeling (defined as the methodology and input assumptions), state the results of such modeling, provide the date on which such modeling was completed, provide a copy of the results, and explain how the assumptions for this analysis differ from the assumptions used in the High Load Trajectory Scenario.

a) The following provides the requested information:

- For the Sutter Waiver Request: The CAISO analysis was filed at the Federal Energy Regulatory Commission (FERC) on January 25, 2012, and completed prior to that date. The declaration of Mark Rothleder presenting the analysis and results for CAISO's Sutter Waiver Request was provided in PG&E's May 21, 2012 testimony. The results of the analysis are summarized in Table 1 of such a filing. Table 1 compares the differences in loads and resources used for the Sutter Waiver Request.

- For the CAISO analyses to estimate flexibility requirements presented in the resource adequacy proceeding: The CAISO analysis was filed with the CPUC on March 2, 2012, and completed prior to that date. An electronic to the filing is provided below. The filing summarizes the results from prior 2010 LTPP and Sutter Waiver Request filings and provides estimates flexibility requirements (not resource need) for 2013 using past experience in 2006, 2010 and 2011.

  http://www.caiso.com/Documents/2012-03-02_R11-10-023_Subm_Supp_Info_Prop.pdf

- For the CAISO's working group efforts: The work is still on-going. The latest summary of these efforts' analysis and results was presented by CAISO at a CPUC workshop on June 4, 2012, and completed prior to that date. An electronic link to the presentation is provided below. The presentation provides the results and differences with the CAISO's 2010 LTPP filing analysis.

  http://www.cpuc.ca.gov/NR/rdonlyres/32D2572E-7B0B-4DAD-8D99-AB13CBA1470F/0/201206OpFlexMeetingpresentationPDF.pdf

b) See response to part a) of this question for information about the FERC Sutter Waiver Request. See CAISO's July 1, 2011 filing for information about the CAISO's 2010 LTPP renewable integration analysis and results.

c) See response to part b) of this question.

d) See response to part a) of this question for information about the CAISO's Flexible Capacity Procurement straw proposal.

e) See response to part b) of this question.

f) See response to part a) of this question.

g) See response to part a) of this question.

iv) Is the Oakley facility included (i.e., assumed to be operational) in the assumptions for the underlying analysis?

a) No, the Oakley Project was not included, but the CAISO analysis included two additional combined cycle units of about the same size of the Oakley Project, which have subsequently been determined to likely be unavailable.

b) As explained in part a), CAISO's analysis did not include the Oakley Project; the Joint IOU analysis did include the Oakley Project.

c) See response to part b) of this question.

d) No.

e) See response to part a) of this question.

f) See response to part b) of this question.

g) See response to part a) of this question.

ATTACHMENT C

[CONFIDENTIAL]

PG&E Data Request No.:	DRA_005-10		
PG&E File Name:	OakleyGeneratingStation_DR_DRA_005-Q10		
Request Date:	July 3, 2012	Requester DR No.:	005
Date Sent:	July 18, 2012	Requesting Party:	Division of Ratepayer Advocates
PG&E Witness:	Marino Monardi	Requester:	Yuliya Shmidt

QUESTION 10

With reference to the Shared Value Agreement in Exhibit R to the Amended PSA, please answer the following questions and provide references to the supporting or relevant sections of the Shared Value Agreement.

a. What is the earliest date that the Oakley facility could begin to produce power pursuant to the Shared Value Agreement, assuming that CPUC Approval is received on or before December 10, 2012? What is the latest date that the facility could run assuming the online date in your response?

b. Does PG&E intend to seek recovery of any costs incurred under the Shared Value Agreement to the Amended PSA through ERRA or any other means? If yes, state the estimated costs or range of costs that PG&E expects to incur and indicate the method by which PG&E seeks to recover such costs. Include in your answer the costs per MWh for energy and/or ancillary services, fixed costs, or other additional costs that PG&E is obligated to pay pursuant to the Shared Value Agreement. Specify the capacity value for any Resource Adequacy purchased through the Shared Value Agreement.

c. What is the maximum cumulative number of start-ups and operating hours that could be incurred under the Shared Value agreement?

d. Who will pay for the Oakley facility's Operations and Maintenance costs incurred under the Shared Value Agreement?

e. Would operations under the Shared Value Agreement impact the cost of any Long Term Service Agreements for Oakley? If so, how?

f. Does PG&E propose to reduce the initial capital costs of the project to reflect depreciation caused by operations under the Shared Value Agreement? If so, how?

g. Describe any additional costs, and provide supporting documentation, that PG&E will be responsible for during the period of sales covered by the Shared Value Agreement. For example, if PG&E is required to provide staff, gas deliveries or other services under the Shared Value Agreement, state the amounts PG&E expects will be due.

h. Will PG&E self-schedule the project into the CAISO markets for operations subject to the Shared Value agreement? If not, how will the Oakley facility be scheduled and/or dispatched under the agreement?

ANSWER 10

This response contains Confidential Protected Material, protected under D.06-06-066 Appendix 1 and General Order 66-C, as set forth in the accompanying declaration/matrix.

a. PG&E objects because the question is vague and does not define "CPUC Approval." For the purposes of this answer, PG&E assumes the question is referring to a Commission vote on a Final Decision granting approval of the Amended and Restated Purchase and Sale Agreement ("Amended PSA") and the associated cost recovery for the Oakley Project. If a Final Decision is voted on by December 12, 2012, this does not constitute final, non-appealable CPUC Approval. The earliest that final, non-appealable CPUC Approval could occur is 30 days after the Commission vote, i.e. January 2013. If the Decision is challenged, this gap would be longer.

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

b. Yes, all benefits and costs associated with the SVA will accrue to PG&E's customers. [redacted]

c. During the Delivery Term, the facility would be required to operate within the emissions limits specified in its CEC License and ATC permits. Also, see Exhibit E of the Amended PSA.

d. [redacted]

e. PG&E has not executed the Long Term Service Agreement (LTSA) for the Oakley Project. However, PG&E does not expect operations under the SVA to affect the costs of the LTSA.

f. No. Also, see PG&E's response to part b of this question listed above.

g. See PG&E's response to part b of this question listed above, Section 4 of the SVA, and Exhibit S of the Amended PSA.

h. No, PG&E will likely not self-schedule the project into the CAISO Markets during the Delivery Term. PG&E will act as the Scheduling Coordinator during the Delivery Term and will bid the facility into the CAISO Markets pursuant to its standard Least Cost Dispatch procedures based upon the facility's incremental costs. The incremental costs will be based upon the current cost of natural gas, the facility's heat rate, and the Variable O&M Payments. The Oakley Project will only be dispatched if it is awarded a schedule by the CAISO. In other words, the Oakley Project will only be dispatched if the bid price of its awarded schedule is equal to or less than the CAISO Market clearing price.

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ATTACHMENT D

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

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

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

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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

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

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

I. BACKGROUND

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

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

Q. Please describe your educational and professional background.

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

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

Q. What is the purpose of your testimony?

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

Q. Why does the ISO conduct renewable integration studies?

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

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

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

Q. How has the ISO participated in this proceeding?

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

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

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

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

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

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

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

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

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

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

Q. Please describe how your testimony is organized.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

III. STUDY METHODOLOGY

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

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

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

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

IV. STUDY RESULTS

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

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

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

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

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

A. Yes. We observed 1400MW of upward load following need in the All Gas scenario. 4600MW of incremental upward load following need was observed in the High Load Trajectory scenario to resolve the load following upward shortfalls. No

downward load following shortfalls or needs were observed in the All Gas or Trajectory High Load scenarios. No regulation shortfalls were observed in the All Gas and Trajectory High Load scenarios. Slides 10 and 11 of Exhibit 1 contain additional details about these observations.

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

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

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

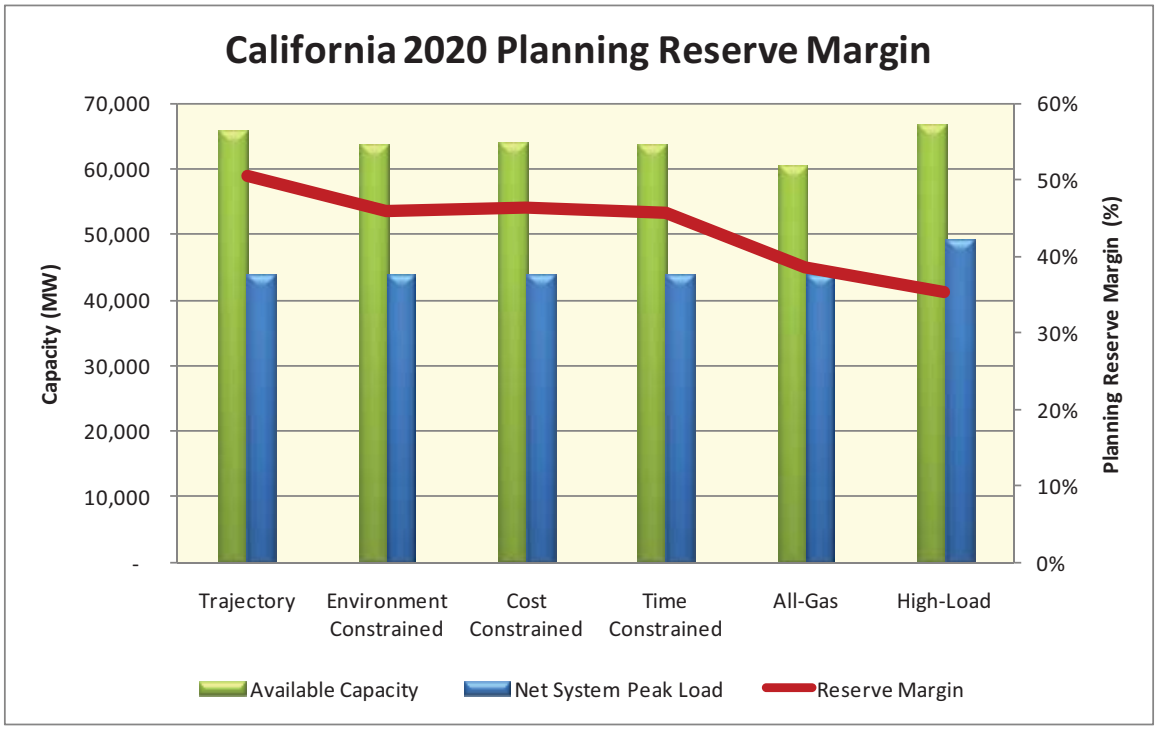
A. No. The four priority scenarios reflect scenarios with resource capacity in excess of the required planning reserve margin (PRM) of 15%-17%. Table 7 and Figure 11, below, show the planning reserve margin of the different scenarios as calculated by E3. As a result, the excess capacity above PRM provides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

these results whether sufficient flexible capability would exist to meet the simultaneous energy, operating reserve, regulation and load following requirements if the available generation capacity was not in excess of the 15-17% PRM. For example, if the utilities contract for less import qualifying capacity, just meeting their PRM of 117%, the ISO may need to dispatch the capacity that is currently unloaded and providing flexibility services in these cases, and therefore may be short the needed flexible capacity. The four priority scenarios were not analyzed assuming the PRM would just be met but not exceeded.

Table 7: Planning Reserve Margin Calculated by E3

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

Figure 11: Planning Reserve Margin



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

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

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

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

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

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

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

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

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

V. NEXT STEPS

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

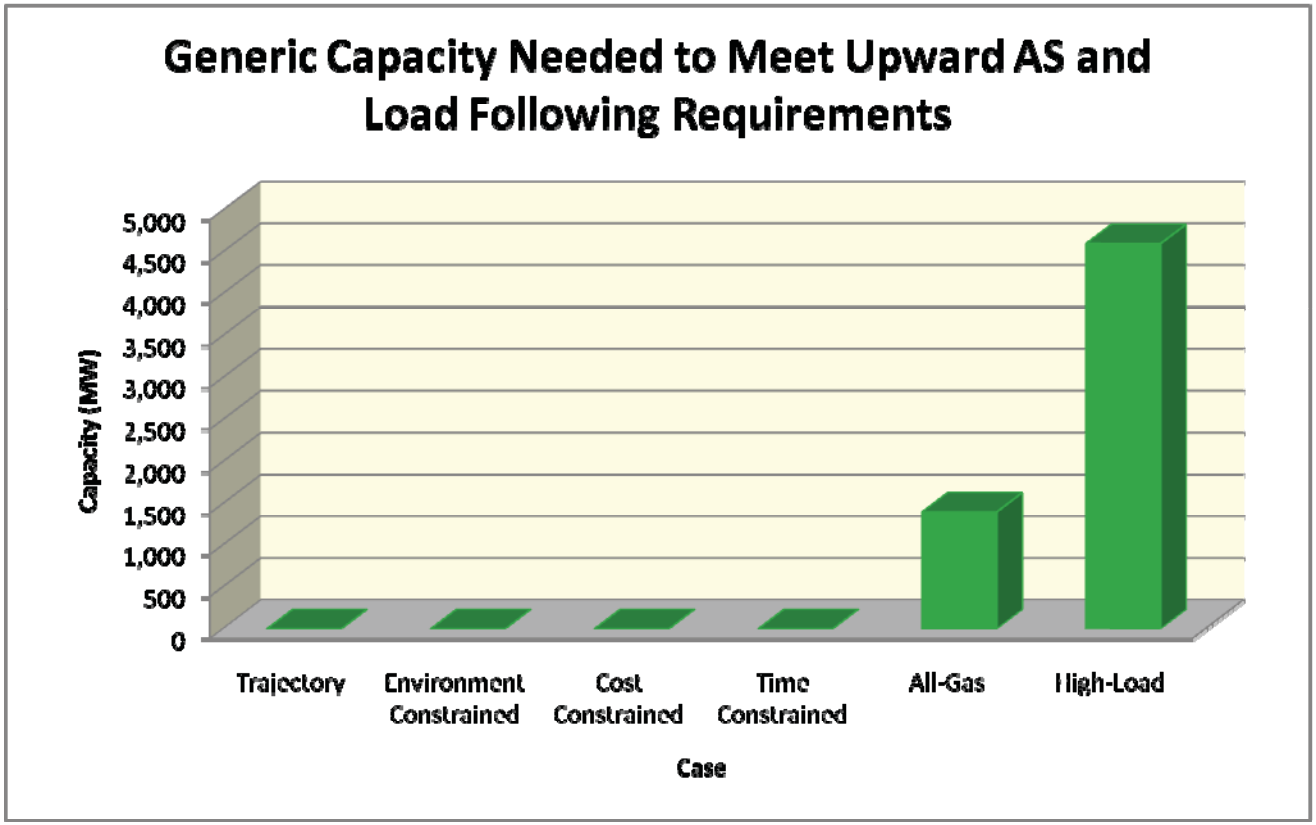
A. Yes. The ISO recognizes that these 33% integration studies are based on a set of planning assumptions that will continue to evolve. The ISO intends to run additional scenarios and sensitivities that are relevant to the ISO's operational responsibilities. For example, as I discussed above, the ISO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

Q. Does this conclude your testimony?

A. Yes, it does.

Exhibit 1

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

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ATTACHMENT E

PACIFIC GAS AND ELECTRIC COMPANY
Oakley Generating Station
Application 12-03-026
Data Response

PG&E Data Request No.:	TURN_001-01		
PG&E File Name:	OakleyGeneratingStation_DR_TURN_001-Q1		
Request Date:	April 27, 2012	Requester DR No.:	001
Date Sent:	May 11, 2012	Requesting Party:	The Utility Reform Network
PG&E Witness:	Antonio Alvarez	Requester:	Bob Finkelstein

QUESTION 1

Does PG&E contend that the California Public Utilities Commission has performed or approved a resource planning analysis that conclusively demonstrates a need to add any capacity in PG&E's service territory for renewable integration purposes through the year 2020? If the response to this question is anything other than an unqualified negative, please explain the response in full, including but not limited to identifying the decision or other document setting forth the resource planning analysis and each specific page that PG&E contends sets forth the performance or approval of an analysis regarding the need to add capacity for renewable integration purposes.

ANSWER 1

PG&E objects to the phrase "conclusively demonstrate" as vague and ambiguous. By its very nature, a planning analysis, which is intended to look at future events and outcomes, includes numerous inputs and assumptions which may affect the determination or outcome of the analysis. No planning analysis, which models future outcomes, can "conclusively demonstrate" that all of the inputs and assumptions, which reflect future events and circumstances, will absolutely and conclusively occur. Indeed, that is why the Commission uses various scenarios and planning assumptions in its resource planning process. *See e.g. Assigned Commissioner and Administrative Law Judge's Joint Scoping Memo and Rule,* issued December 3, 2010 in R.10-05-006 at p. 7. Thus, PG&E understands the term "conclusively demonstrates" to mean demonstrates or shows.

Subject to PG&E's objection, No. In a settlement submitted on August 3, 2011, twenty-six parties agreed that there was not a conclusive demonstration in the 2010 Long-Term Procurement Plan ("LTPP") concerning "whether or not there [was] need to add new capacity for renewable integration purposes through the year 2020, the period addressed in the current LTPP cycle." *See* Settlement Agreement at p. 5. The parties to the Settlement Agreement noted that the CAISO had ongoing work to address this issue. *Id*. at p. 4. The Settlement Agreement was approved by the Commission in D.12-04-046. The Commission recently initiated the 2012 LTPP proceeding but has not

yet, in the context of that proceeding, addressed capacity needs in California. However, the CAISO has continued its work on renewable integration needs.

Since completing the 2010 LTPP studies in July 2011, the CAISO has repeatedly raised the need for additional operating flexibility to maintain reliability with the higher levels of wind and solar generation to meet California's 33 percent renewables goal.[1]

In its September 2011 comments in the 2010 LTPP proceeding on the Settlement Agreement, the CAISO stated that its studies indicated a potential renewable integration capacity need of 4,600 MW.[2]

On January 25, 2012, the CAISO submitted a waiver request to the Federal Energy Regulatory Commission ("FERC") for the Sutter plant. The CAISO supported the need for Sutter explaining that the plant could provide energy, operating reserves such as spinning and non-spinning reserves, as well as flexibility services such as regulation and load following up and down.[3] Compared to other existing combined cycle units like the Sutter plant, the Oakley Project offers greater operating flexibility to the CAISO because of its Rapid Response technology and controls improvements associated with the new turbine design. The Oakley Project also has a lower heat rate than other combined cycle units, and therefore it is more efficient and produces less greenhouse emissions. The CAISO also explained in the Sutter Waiver Request that currently proposed generation projects face substantial development risks and may never be constructed.[4] Thus, the fact that projects are proposed or have CAISO interconnection queue positions does not guarantee that they will actually be built. Finally, the CAISO's Sutter Waiver Request also referenced the Oakley Project and indicated that, even with the Oakley Project, there would be shortfalls in flexible generating capacity needed by 2018.[5] Based on the CAISO's analysis, if the Oakley Project does not proceed, the flexible capacity shortfalls will only be greater in 2018.

Aside from the planning studies, Commission staff and the CAISO have proposed revisions to the 2013 year-ahead Resource Adequacy ("RA") compliance showings by Load Serving Entities to ensure there is sufficient flexible capacity for the CAISO to operate reliably.[6] Beyond 2013, integrating generation from renewable resources will require increasing amounts of flexible capacity which the current RA program is not designed to provide for the CAISO to operate reliably. The Commission Staff's

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1 August 18, 2011 Briefing on Renewable Integration to CAISO Board of Governors by Keith Casey, Vice President, Market and Infrastructure Development.

2 *Opening Brief of the California Independent System Operator on Track I Issues*, filed September 16, 2011 in R.10-05-006.

3 Sutter Waiver Request at p. 28.

4 *Id*. at pp. 29-30.

5 *Id*. at p. 31.

6 See Energy Division's (ED) report on the January 26-27, 2012 Resource Adequacy Workshop (Workshop Report), p. 5-18. The EDs report can be found at: http://docs.cpuc.ca.gov/efile/RULINGS/162601.pdf.

Workshop Report explains that the current RA framework is based on peak load and a series of maximum amounts of resources allowed in four resource categories or buckets. This RA framework "was created in 2005 for then existing energy contracts, which have changed considerably over time. With the increase of renewable generation, these buckets might not be accurate indicators of actual contribution to grid reliability. The current methodology does not account for the dispatchability of resources…Recent studies have indicated that reliability risk will soon be detached from peak load conditions and might occur more during off-peak months and during periods of ramping, such as when the wind ramps down in the morning at the same time as the load ramps up. For this reason, ED proposes to start defining the resource buckets as inclusive of dispatchability, instead of defining them solely based on hours of operation over peak."[7]

In a Straw Proposal issued on March 7, 2012, regarding the procurement of flexible capacity, the CAISO concluded that "[w]hile the energy production of [existing] conventional resources is being displaced by intermittent resources, the ISO will need even more flexible capacity that many conventional resources provide in order to maintain grid reliability under the 33 percent RPS. Consequently, the need to ensure that a sufficient fleet of flexible resources is maintained will only increase."[8]

More recently, in his report to the CAISO Board, CAISO Chief Executive Officer Steve Berberich highlighted the critical need for new and flexible generation capacity:

> While California has adequate capacity at this time, in the next five years there is a potential for a shortfall of flexible resources that can help maintain reliability by quickly ramping up or down to compensate fluctuations in wind and solar power. The amount of shortfall is highly affected by the potential retirements of coastal gas-fired plants required to comply with a new once through cooling regulation. Under most likely scenarios, the system is still likely to be short several thousand megawatts of ramping capacity.[9]

The Oakley Project has the operating characteristics to satisfy the operating requirements of incremental flexible capacity needed by the CAISO.

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7 *Id.*, at p. 5.

8 See http://www.caiso.com/Documents/StrawProposal-FlexibleCapacityProcurement.pdf ("CAISO Flexible Capacity Proposal") at p. 8.

9 See http://www.caiso.com/Documents/CEOReport-MemoMar2012.pdf ("CEO Report") at p. 2 (emphasis added).

ATTACHMENT F

Rulemaking: 10-05-006
(U 39 E)
Exhibit No.: IOU-1
Date: July 1, 2011
Witness: Various

SOUTHERN CALIFORNIA EDISON COMPANY, PACIFIC GAS AND ELECTRIC COMPANY, SAN DIEGO GAS & ELECTRIC COMPANY

SYSTEM RESOURCE PLAN

ORDER INSTITUTING RULEMAKING TO INTEGRATE AND REFINE PROCUREMENT POLICIES AND CONSIDER LONG-TERM PROCUREMENT PLANS

JOINT IOU SUPPORTING TESTIMONY

TABLE 5-6
JOINT ANALYSIS
SOUTHERN CALIFORNIA EDISON'S ONCE-THROUGH COOLING RETIREMENT SCHEDULE

Line No.	Plant	Capacity (MW)	CPUC-Required Scenarios Retirement Year	IOU Common Scenarios 1 and 2 Retirement Year	IOU Common Scenario 3 Retirement Year
1	Alamitos	2,010	2020	2020(a)	2021
2	El Segundo 3	335	2015	2015(b)	2015(b)
3	El Segundo 4	335	2014	2014(b)	2014(b)
4	Huntington Beach 1	226	2020	2020(a)	2021
5	Huntington Beach 2	226	2020	2020(a)	2021
6	Huntington Beach 3	225	2012	2012(b)	2012(b)
7	Huntington Beach 4	227	2012	2012(b)	2012(b)
8	Mandalay	430	2020	2020(a)	2021
9	Ormond Beach	1,516	2020	2020(a)	2021
10	Redondo Beach	1,343	2020	2020(a)	2021
11	SONGS	2,246	Not Retiring	Not Retiring	Not Retiring

(a) Retirement date for modeling purposes only to study the year 2020.

(b) SCE has different retirement projections but used the CPUC's assumptions to minimize differences between the CPUC-Required and IOU Common Scenarios.

TABLE 5-7
JOINT ANALYSIS
SOUTHERN CALIFORNIA EDISON'S LOCAL CAPACITY RELIABILITY ADDITION SCHEDULE

Line No.	Plant	Capacity (MW)	Scenarios 1 and 2 Addition Year	Scenario 3 Addition Year
1	LCR Replacement CTs	1,000	2020(a)	N/A
2	LCR Replacement CCGTs	1,000	2020(a)	N/A

(a) Addition date for modeling purposes only to study the year 2020.

SCE's assumptions regarding the fossil-based units subject to OTC regulations for the two IOU Common Scenarios differ from the assumptions in the CPUC-Required Scenarios since SCE is only considering resource build-outs that address LCR needs. The CPUC-Required Scenarios are short of the necessary LCR resources in the Los Angeles Basin and possibly the Big Creek/Ventura Basin since the fossil-based units subject to OTC

regulations have been retired without replacing any of the lost capacity. With the retirement of all fossil-based units subject to OTC regulations in its territory, SCE expects there to be a need of approximately 2,000 MW of additional resources in 2020.[13]

SCE also made some different assumptions from the CPUC-Required Scenarios regarding the retirement or addition of non-OTC resources in its service territory. SCE assumed that Etiwanda 3 and 4 (640 MW total capacity) would not retire by the end of 2020 since these units are not fossil-based units subject to OTC regulations and the owner of the units has not made any public announcements about retiring the units. For planned additions, SCE assumed that the Victorville 2 Hybrid Power Project (563 MW total capacity) and FPL Blythe II (520 MW total capacity) would not be constructed prior to the end of 2020. Neither of these projects has signed a PPA with an IOU or other Load Serving Entity. On the other hand, SCE included MCGPKGEN (SCE's Oxnard peaker, LM6000) as it has approval from the Commission to construct the unit.

2. Pacific Gas and Electric Company's Service Area

For the IOU Common Scenarios, PG&E's assumptions for the units subject to OTC regulation in northern California are shown in Table 5-8 below.

[13] Additional detail on SCE's LCR needs is contained in SCE's individual testimony, Exhibit SCE-1.

TABLE 5-8
JOINT ANALYSIS
ONCE-THROUGH COOLING RETIREMENTS ASSUMED IN NORTHERN CALIFORNIA (a)

Line No.	Unit Name	CPUC-Required Scenarios Retirement Year	IOU Common Scenarios Retirement Year	Size (MW)
1	Contra Costa 6	2014	2014	337
2	Contra Costa 7	2014	2014	337
3	Potrero Unit 3	2010	2010	206
4	Pittsburg 5	2017	2017	312
5	Pittsburg 6	2017	2017	317
6	Humboldt Bay CT	2010	2010	15
7	Humboldt Bay CT	2010	2010	15
8	Humboldt Bay 1	2010	2010	52
9	Humboldt Bay 2	2010	2010	53
10	Morro Bay 3	2015	2015	325
11	Morro Bay 4	2015	2015	325
12	Moss Landing 6	2017	2017	754
13	Moss Landing 7	2017	2017	756
14	Diablo Canyon Unit 1	Not Retiring	Not Retiring	1,122
15	Diablo Canyon Unit 2	Not Retiring	Not Retiring	1,118
16	Moss Landing Power Block 1	Not Retiring	Not Retiring	510
17	Moss Landing Power Block 2	Not Retiring	Not Retiring	510

(a) PG&E has different retirement projections for some of these units but used the CPUC's assumptions to minimize differences between the CPUC-Required and IOU Common Scenarios.

PG&E's assumptions for the retirement of units not subject to OTC regulation in northern California are shown in Table 5-9 below. For the IOU Common Scenarios, the difference in the assumptions compared with the CPUC-Required Scenarios is that the three Oakland units were removed from the retirement list as they are needed for Bay Area reliability reasons.

TABLE 5-9
JOINT ANALYSIS
NON ONCE-THROUGH COOLING RETIREMENTS ASSUMED
IN NORTHERN CALIFORNIA(a)

Line No.	Unit Name	CPUC-Required Scenarios Retirement Year	IOU Common Scenarios Retirement Year	Size (MW)
1	Potrero 4	2010	2010	52
2	Potrero 5	2010	2010	52
3	Potrero 6	2010	2010	52
4	Pittsburg 7	2017	2017	682
5	Oakland 1	2012	Not Retiring	55
6	Oakland 2	2012	Not Retiring	55
7	Oakland 3	2012	Not Retiring	55

(a) PG&E has different retirement projections for some of these units but used the CPUC's assumptions to minimize differences between the CPUC-Required and IOU Common Scenarios.

PG&E's assumptions for planned additions in northern California are shown in Table 5-10 below. For the IOU Common Scenarios, the addition of Marsh Landing was changed to 2014 compared to the CPUC-Required Scenarios to align with the retirement of the Contra Costa 6 and 7 units. To be included as a planned addition in the IOU Common Scenarios, units had to pass one of two criteria: identified as having an executed PPA contract or as having passed a minimum of 10% of construction completion. With these criteria for the IOU Common Scenarios, the Oakley unit was included with an on-line year of 2016 and the Avenal unit was not included.

TABLE 5-10
JOINT ANALYSIS
RESOURCE ADDITIONS IN NORTHERN CALIFORNIA(a)

Line No.	Unit Name	CPUC-Required Scenarios On-Line Year	IOU Common Scenarios on-Line Year	Size (MW)
1	Humboldt	2010	2010	163
2	Colusa	2011	2011	660
3	Lodi	2012	2012	255
4	Russell City	2012	2012	600
5	Mariposa	2012	2012	184
6	Tracy (incremental addition)	2012	2012	145
7	Los Esteros (incremental addition)	2013	2013	109
8	Marsh Landing	2013	2014	719
9	Oakley	Not Included	2016	623
10	Avenal	2012	Not Included	600

(a) PG&E has different retirement projections for some of these units but used the CPUC's assumptions to minimize differences between the CPUC-Required and IOU Common Scenarios.

3. San Diego Gas & Electric Company's Service Area

SDG&E included the same retirements of fossil-based units subject to OTC regulations that were included in the CPUC-Required Scenarios. However, the IOU Common Scenarios also include the retirement of 188 MW of older peakers. All these are units that were built in the 1970s and have very limited operating hours. These units are expected to be retired at the end of 2013 when their current land leases expire. SDG&E also added 300 MW of generic units to its service area. It was necessary to add these units to meet the CAISO local grid reliability criteria.[14]

[14] Additional detail on SDG&E's LCR needs is contained in SDG&E's individual testimony, Exhibit SDG&E-1.

TABLE 5-11
JOINT ANALYSIS
SAN DIEGO GAS AND ELECTRIC COMPANY'S RETIREMENTS

Line No.	Unit Name	CPUC-Required Scenarios Retirement Year	IOU Common Scenarios Retirement Year	Size (MW)
1	South Bay 1 - 2 & GT	2011	2010	311
2	Encina 1-5 & GT	2017	2017	960
3	El Cajon GT	Not Retiring	2013	16
4	Kearny GT2 Aggregate	Not Retiring	2013	59
5	Kearny GT3 Aggregate	Not Retiring	2013	61
6	Kearny GT1	Not Retiring	2013	16
7	Miramar 1	Not Retiring	2013	18
8	Miramar 2	Not Retiring	2013	18

TABLE 5-12
JOINT ANALYSIS
SAN DIEGO GAS AND ELECTRIC COMPANY'S ADDITIONS

Line No.	Unit Name	CPUC-Required Scenarios On line Year	IOU Common Scenarios On line Year	Size (MW)
1	LCR Replacement CTs	N/A	2017	300

G. California Import and Southern California Import Transmission Limits

The California Import and Southern California Import Transmission ("SCIT") Limits developed by CAISO for the Trajectory Scenario were used for IOU Common Scenarios 1 and 2 since the thermal resource portfolio in each of these IOU Common Scenarios is similar to that in the Trajectory Scenario. However, for IOU Common Scenario 3, the IOUs developed different limits based on the CAISO's approach for developing these limits to account for differences in the thermal and renewables portfolios. This scenario was treated differently because inclusion of the SCE-area fossil-based units subject to OTC regulations retiring at the end of 2020 results in a thermal resource portfolio that is significantly different from that assumed for the CPUC-Required Scenarios. A comparison of the California Import and SCIT Limits used in the IOU Common Scenarios and CPUC-Required Scenarios is shown Table 5-13.

ATTACHMENT G

PACIFIC GAS AND ELECTRIC COMPANY
Oakley Generation Station
Application 12-03-026
Data Response

PG&E Data Request No.:	DRA_002-04		
PG&E File Name:	OakleyGeneratingStation_DR_DRA_002-Q4		
Request Date:	June 5, 2012	Requester DR No.:	002
Date Sent:	June 12, 2012	Requesting Party:	DRA
PG&E Witness:	Jon Maring / Marino Monardi	Requester:	Yuliya Shmidt

QUESTION 4

Does PG&E contend that approval of the Oakley facility will directly cause or enable the retirement of "existing, inefficient once-through cooling facilities"? (p.1-1) If yes, identify each such facility and state:

a. The name of the facility

b. The capacity in megawatts and annual output in megawatt-hours of the facility

c. The location of the facility and identify any CAISO local capacity requirements area or sub-area in which the facility is located.

d. The deadline for the facility to meet the State Water Resources Control Board's once-through cooling mitigation policy, and state whether the facility is planned to retire or has submitted any alternative mitigation compliance plan to allow the facility to continue operations or to re-power the facility.

e. The heat rate in British Thermal Units of that facility

ANSWER 4

PG&E stated in its Application and Initial Testimony that the Oakley Project will ***facilitate*** the retirement of once-through cooling (OTC) facilities. The OTC facilities are all older and much less efficient resources. Evidence of their relative inefficiency can be seen in the table below which indicates the heat rates for natural gas-fired once-through-cooling units that are within CAISO territory and were operational in June 2012.[1]

[1] The source of heat rate data is the 2011 California Energy Commission QFER report: http://energyalmanac.ca.gov/electricity/web_qfer/Heat_Rates.php

OTC Facility	2011 Heat Rate (Btu/kWh)
Alamitos	12,333
Contra Costa	11,916
El Segundo	14,676
Encina	13,639
Huntington Beach	10,976
Mandalay	13,010
Morro Bay	10,952
Moss Landing	7,685
Ormond Beach	12,450
Pittsburg	12,599
Redondo Beach	12,099

It is important to note that an owner of a generation resource is the ultimate decision-maker who can commit to retire it's plant. PG&E does not own any gas-fired OTC facilities, and therefore PG&E cannot directly commit to retire any of these OTC units that are owned by third parties.

All investor-owned utilities (IOUs) in California are required to follow the standards of least cost dispatch (LCD) outlined in CPUC Standard of Conduct 4, adopted in Decision 02-10-062 and elaborated in Decisions 02-12-069, 02-12-074, 03-06-076, and 05-01-054. These decisions mandate that IOUs dispatch their portfolios of existing resources, allocated DWR contracts and market purchases to meet their electric load obligations in a least-cost manner. To implement these LCD requirements, PG&E schedules and bids resources in order to achieve the result that resources are dispatched when their variable costs are below market prices. With fossil-fired resources, variable costs are largely dependent upon the price of natural gas. Therefore, resources with very high heat rates will have higher variable costs. Resources with higher heat rates and therefore higher variable costs are dispatched less frequently than resources with lower heat rates and lower variable costs.

As noted in the table above, all of these OTC facilities have much higher heat rates than the Oakley Project. As more resources are added to the system with lower variable costs (e.g., the Oakley Project), the older, less-efficient OTC facilities will be dispatched less. As those OTC facilities are dispatched less, revenues will decline, which facilitates their retirement for economic reasons, possibly prior to their SWRCB OTC compliance deadline. In addition to the relative efficiency and expected lower operating costs associated with the Oakley Project, the project will provided needed operational flexibility to the CAISO grid and thereby further reduce the need for reliance on OTC units. Furthermore, PG&E's determination is supported by the CEC's Final Staff Assessment in March 2011 which notes: "new resources would out-compete aging

plants and would likely displace the energy provided by OTC facilities and accelerate [their] retirements."[2]

In response to parts (b) to (d) above, information about specific OTC units, the date that these units are required to comply with State Water Resources Control Board ("SWRCB") regulations, and current proposals for these facilities is available at:

http://www.waterboards.ca.gov/water_issues/programs/ocean/cwa316/powerplants/

The location of the affected OTC facilities is available in a map on the CEC's website at:

http://www.waterboards.ca.gov/water_issues/programs/ocean/cwa316/powerplants/docs/map.pdf

[2] California Energy Commission Final Staff Assessment, March 2011, Application for Certification of Oakley Generating Station (Docket 09-AFC-4), pp. 4.1-88

ATTACHMENT H

PACIFIC GAS AND ELECTRIC COMPANY
Oakley Generating Station
Application 12-03-026
Data Response

PG&E Data Request No.:	IEP_001-08		
PG&E File Name:	OakleyGeneratingStation_DR_IEP_001-Q08		
Request Date:	June 6, 2012	Requester DR No.:	001
Date Sent:	June 13, 2012	Requesting Party:	Independent Energy Producers Association
PG&E Witness:	Antonio Alvarez	Requester:	Brian Cragg

QUESTION 8

To PG&E's witnesses' knowledge, has the CAISO specified that the identified need for flexible capacity must be met by resources located in PG&E's service territory? If so, please provide copies of all documents related to the CAISO's position.

ANSWER 8

No, the CAISO has not specified that the identified need for flexible capacity must be met by resources located in PG&E's service territory. The CAISO's studies identified in PG&E's response to question "3.c" of this data request have determined system-wide need.

ATTACHMENT I

FER/sbf 3/12/2012

FILED
03-12-12
11:24 AM

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of San Diego Gas & Electric Company (U 902 E) for Authority to Enter into Purchase Power Tolling Agreements with Escondido Energy Center, Pio Pico Energy Center and Quail Brush Power.	Application 11-05-023 (Filed May 19, 2011)

ASSIGNED COMMISSIONER'S AMENDED SCOPING MEMO AND RULING

This ruling amends the July 29, 2011, Scoping Memo and Ruling of the Assigned Commissioner to add the issue of San Diego Gas & Electric Company's (SDG&E) local capacity requirement (LCR) to the scope of the proceeding, to set a revised schedule to accommodate this amendment, and to change the designated presiding officer. The California Independent System Operator (CAISO) shall serve prepared testimony on its local capacity study methodology and SDG&E's local capacity requirement on March 9, 2012. An informational workshop shall be held on March 21, 2012, for the CAISO to answer parties' questions regarding its prepared testimony. SDG&E's prepared supplemental testimony on the issue of its LCR shall be served on April 4, 2012; intervenors' prepared supplemental testimony shall be served on April 24, 2012; SDG&E's prepared supplemental rebuttal testimony shall be served on May 9, 2012; and evidentiary hearing will be held on May 29 through 31, 2012; as set forth more fully in this amended scoping memo and ruling.

Background

Rulemaking (R.) 10-05-006 on the utilities' long-term procurement plans encompassed, among other things, the determination of SDG&E's LCR. In that proceeding, SDG&E advocates the need for, and requests authority to procure, 415 megawatts (MW) for its service area. This application for authority to enter into three power purchase agreements totaling 450 MWs is premised, in large part, on SDG&E's asserted need for 415 MW as advocated in R.10-05-006. Before the Commission had an opportunity to determine SDG&E's LCR in R.10-05-006, the CAISO issued a report on "2011/2012 Transmission Planning Process Stakeholder Meeting Policy-Driven & Economic Study Preliminary Results." By Joint Assigned Commissioners' Ruling, President Peevey, who is the commissioner assigned to R.10-05-006, and Commissioner Ferron, who is the commissioner assigned to this application, directed that this report be considered in the determination of SDG&E's LCR and, for speed and efficiency, delegated the issue to this application for determination.

The Administrative Law Judge (ALJ) conducted a prehearing conference on January 31, 2012, to consider the schedule and process for taking the CAISO's report into consideration in this proceeding and for giving the parties an opportunity to address it. During the course of the prehearing conference, the parties clarified that the CAISO's December 8, 2011, "2011/2012 Transmission Planning Process Stakeholder Meeting Policy-Driven & Economic Study Preliminary Results" report would be followed by the CAISO's draft 2011-2012 transmission plan, and that the draft 2011-2012 transmission plan would ultimately be submitted to the CAISO Board of Governors for approval.

By motion dated February 24, 2012, the CAISO moved to become a party to this proceeding. The CAISO stated that it has now released its draft 2011-2012

transmission plan, and requested leave to serve prepared testimony by March 9, 2012, on its local capacity study methodology and SDG&E's local capacity requirement. In order to expedite the discovery process, the CAISO offered to participate in a workshop to explain its study methodology and answer questions. By informal ruling dated March 1, 2012, and affirmed here, ALJ granted the CAISO's motion for party status,[1] set March 9, 2012, as the time for CAISO to serve its prepared testimony, and set an informational workshop to be held on March 21, 2012. I affirm the ALJ's rulings.

Amended Scope of Issues

The scope of issues to be determined in this proceeding, as identified in the July 29, 2011, scoping memo, is amended to add the following issue:

> 1A. Local Capacity Requirement: How much new generation, if any, does SDG&E require to meet its Local Capacity Requirement for the planning horizon 2011 to 2020 considering, but not limited to, the CAISO's 2011-2012 transmission plan?

Amended Schedule

The following amended schedule is adopted here and may be modified by the ALJ as required to promote the efficient and fair resolution of the application.

Informational Workshop

The Energy Division will facilitate an informational workshop on Wednesday, March 21, 2012, at 9:00 a.m., in the Courtyard Room, State Office Building, 505 Van Ness Avenue, San Francisco. The purpose of this workshop is to assist the parties' understanding of the CAISO's local capacity study

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[1] By informal ruling that same date, the ALJ also granted the Natural Resources Defense Council's motion for party status. That ruling is also affirmed here.

methodology and its March 9, 2012, prepared testimony on SDG&E's LCR. It is expected that the parties will use the workshop in order to focus their subsequent discovery efforts. The informational workshop will not be reported, and statements made at the workshop will be considered hearsay and generally will not be admissible into evidence. Parties may seek confirmation and clarification of the CAISO's workshop statements through responses to data requests, which are generally admissible evidence.

The tentative workshop agenda is as follows:

9:00-9:05	Introduction
9:05-10:00	CAISO presentation
10:00-12:00	Methodology assumptions
12:00-1:00	Break
1:00-2:30	Results: sensitivity to other facility locations/loading order/etc.
2:30-2:45	Break
2:45-4:30	Comparison to previous LCR studies
4:30	Conclude

If parties have other or additional recommended general areas of inquiry to be addressed, they shall provide them, by email copied to the Official Service List, to Lily Chow (cho@cpuc.ca.gov) by no later than March 16, 2012.

Schedule for Prepared Testimony and Evidentiary Hearing

Parties shall serve any prepared testimony on Issue 1A, and any supplemental testimony on Issue 1 (need) as may be prompted by the new testimony on Issue 1A, pursuant to the schedule set forth below. Parties shall serve any prepared supplemental testimony on the official service list pursuant to Rule 1.9 and Rule 1.10, and shall serve two hard copies of it on the assigned ALJ.

If parties wish to offer portions of the evidentiary record in R.10-06-005 into evidence in this proceeding, they shall do so as attachments to prepared testimony or as cross-examination exhibits. Such attachments and cross-examination exhibits shall be limited to portions of the documents or transcripts that are relevant and material to this proceeding, pursuant to Rule 13.7(c).

The following schedule for serving prepared testimony and resolving the proceeding is adopted here and may be modified by the ALJ as required to promote the efficient and fair resolution of the application:

CAISO prepared testimony on SDG&E's LCR served	March 9, 2012
SDG&E prepared supplemental testimony served	April 4, 2012
Intervenor prepared supplemental testimony served	April 25, 2012
SDG&E prepared supplemental rebuttal testimony served	May 9, 2012
Cross-examination estimates served (by email)	May 22, 2012
Evidentiary hearings (on all issues)	May 29-31, 2012 at 9:00 a.m. Commission Courtroom State Office Building 505 Van Ness Avenue San Francisco, California
Concurrent opening briefs filed	June 21, 2012
Concurrent reply briefs filed (proceeding submitted)	July 5, 2012
Proposed decision	[no later than 90 days after submission]
Commission decision	[no sooner than 30 days after the proposed decision]

Requests for final oral argument pursuant to Rule 13.13(b) shall be made in concurrent opening briefs.

The proceeding should be resolved within 18 months of this scoping memo as provided by Pub. Util. Code § 1701.5.

Presiding Officer

The July 29, 2011, scoping memo designated ALJ Burton W. Mattson as the presiding officer. By notice dated September 6, 2011, this application was reassigned from ALJ Burton W. Mattson to ALJ Hallie Yacknin. Accordingly, the July 29, 2011, scoping memo is amended to designate ALJ Hallie Yacknin as the presiding officer to the proceeding.

IT IS RULED that:

1. The scope of this proceeding is amended as described above.
2. The schedule of this proceeding is amended as set forth above.
3. The July 29, 2011, scoping memo is amended to designate Administrative Law Judge Hallie Yacknin as the presiding officer.
4. The Administrative Law Judge's rulings granting party status to the California Independent System Operator and the Natural Resources Defense Council are affirmed.

Dated March 12, 2012, at San Francisco, California.

/s/ MARK J. FERRON
Mark J. Ferron
Assigned Commissioner

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ATTACHMENT J

MF1/DMG/sbf 5/17/2012

FILED
05-17-12
02:19 PM

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans.	Rulemaking 12-03-014 (Filed March 22, 2012)

SCOPING MEMO AND RULING OF ASSIGNED COMMISSIONER AND ADMINISTRATIVE LAW JUDGE

This ruling determines this proceeding's scope, schedule, and need for hearing in accordance with Rule 7.3(a) of the Commission's Rules of Practice and Procedure (Rules).[1]

Background

The March 22, 2012 Order Instituting Rulemaking (OIR) in this proceeding summarized the procedural and substantive background of this proceeding. Overall, the purpose of this rulemaking is to ensure a reliable and cost-effective electricity supply in California through integration and refinement of a comprehensive set of procurement policies, practices and procedures underlying long-term procurement plans.[2]

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[1] Rule 7.3(a) requires the assigned Commissioner to determine the scope and schedule of a proceeding.

[2] A core tenet is the concept of "least cost/best fit" portfolios as discussed in Decision (D.) 06-06-064.

This proceeding is the successor proceeding to rulemakings dating back to 2001 to ensure that California's major investor-owned utilities (IOUs) can maintain electric supply procurement responsibilities on behalf of their customers. The most recent predecessor to this proceeding was Rulemaking (R.) 10-05-006. As stated in this rulemaking in Ordering Paragraph 3, the record developed in R.10-05-006 is "fully available for consideration in this proceeding" and is therefore incorporated into the record of this proceeding.

In R.12-03-014, the Commission provided a preliminary scoping memo to be considered in this proceeding. On April 6, 2012, parties filed comments on their proposals for the scope and schedule for this proceeding. On April 18, 2012, a prehearing conference (PHC) was held to take appearances, and to consider the scope and schedule of this proceeding. In this scoping memo, we refine the preliminary scoping memo from R.12-03-014 pursuant to Rule 7.3(a).

Scope of the Proceeding

There will be three major tracks in this proceeding:

1. Local Reliability
2. System Needs
3. Procurement Rules and Bundled Procurement

We establish here a detailed scope and schedule for 2012 for the Local Reliability track and the System Needs track. We discuss in less detail the scope and schedule for the System Needs track in 2013 and the Procurement Rules and Bundled Procurement track. We intend to issue one or more further amended Scoping Memos or other Rulings at a later point in this proceeding to provide further detail on the scope and schedule for the remainder of this proceeding after 2012.

Track 1 -- Local Reliability Track

In recent years the California Independent System Operator (ISO) has performed an annual Local Capacity Requirements (LCR) study, which is filed in the Commission's Resource Adequacy (RA) proceeding (currently R.11-10-023). This study is used to adopt local RA procurement requirements for the next year (for example, requirements for 2013 will be adopted in R.11-10-023, the 2012 RA proceeding). The Commission should issue a decision on this matter by the end of June each year so that load-serving entities (LSEs) can have sufficient time to obtain the resources to meet their local RA procurement requirements for the next year.

In past RA decisions, the Commission has focused on LCR for local reliability for one forward year. In R.11-10-023, this would provide for meeting local reliability for 2013. In R.11-10-023, the Commission is currently considering proposals by the ISO, the Energy Division and other parties to provide specific guidance for flexible contracting for local reliability.[3] Proposals include specific methods for including flexible capacity attributes for local reliability contracts, such as voltage support, regulation and other attributes of electricity which contribute to local reliability. A decision on these proposals is expected in June 2012.

In the Local Reliability track of this proceeding, we will consider authorizing procurement of new infrastructure for local reliability purposes. This proceeding will be informed by any Commission decisions in R.11-10-023. The end result of this proceeding should be that the IOUs and/or other LSEs will

[3] Currently, IOUs have authority to enter into contracts for capacity, with Commission approval.

be authorized or required to contract for local reliability needs over the next several years, to the extent that the Commission finds there is such a need.

In a settlement agreement approved by the Commission in D.12-04-046 in R.10-05-006, parties to the agreement found that in the first quarter of 2012 the ISO would present a study of integration of renewable power plants into local transmission-constrained areas, along with a study of the effect of potential once-through cooling (OTC) plant retirements. A number of OTC plants may retire in the next several years in the local transmission-constrained areas of the Los Angeles Basin, Big Creek/Ventura and San Diego because of state water control board regulations.[4] The ISO study referenced in the settlement agreement in D.12-04-046 was to be presented to the Commission in testimony, followed potentially by hearings. The settling parties recommended that the Commission issue a decision by the end of 2012 on the need for resources sufficient to integrate the number of renewable resources coming online to meet a 33% renewable portfolio standard by 2020 and the retirement of OTC plants.

At the PHC, the ISO stated that it has completed a study of local capacity requirements through 2016 in its Transmission Planning Process. The ISO has also completed a study of local capacity needs related to expected or potential retirements of OTC plants through 2021. These studies are consistent with the studies anticipated in the settlement agreement adopted in D.12-04-046. In its comments on the scope of this proceeding and at the PHC, the ISO maintained that it cannot evaluate any additional renewable portfolio scenarios beyond those

[4] Issues related to infrastructure needs for the San Diego local area are being considered in Application 11-05-023 and will not be in the scope of this proceeding, except to the extent that any decisions in that proceeding inform the record.

already in the record of R.10-05-006 in time for a decision by the Commission by the end of 2012. Beyond any guidance which the Commission may provide in R.11-10-023, Track 1 of this proceeding will focus on the studies to be served in testimony by the ISO. However, parties will have the opportunity to present evidence that the ISO's studies should be modified, or that the Commission should consider additional factors beyond the ISO's studies, for the purposes of determining local reliability needs.

Issues in the scope of this phase of the proceeding are:

1. Whether additional capacity is required to meet local reliability needs in the Los Angeles Basin and Big Creek/Ventura area between 2014 and 2021, and, if so, how much;
2. Whether flexible capacity attributes should be incorporated into a decision regarding additional capacity required to meet local reliability needs between 2014 and 2021 and, if so, how;
3. How any relevant decisions in the Commission's RA docket R.11-10-023 regarding flexible capacity should be incorporated into a decision on procurement of additional local capacity;
4. What assumptions concerning retirements of OTC plants should be made for the purpose of detemining future local reliability needs;
5. Whether the ISO's local capacity requirements and OTC studies should be adopted by the Commission as the basis for procurement of additional local capacity, and, if not, what should form the basis of a Commission decision;
6. How resources aside from conventional generation, such as uncommitted energy efficiency, demand response, energy storage and distributed generation resources should be considered in determining future local reliability needs;

7. Whether any additional local reliability procurement obligations should be met solely by IOUs or by all LSEs;
8. How the costs of any additional local reliability needs should be allocated among LSEs in light of the Commission's adopted cost allocation mechanism (CAM) per Senate Bill (SB) 695,[5] SB 790[6], D.11-05-005 and any relevant previous decisions;[7]
9. Whether the CAM should be modified at this time;
10. Whether LSEs should be able to opt-out of the CAM, and, if so, what the requirements should be to allow such opt-out;
11. What rules should govern procurement of additional local reliability needs not already covered by the Commission's RA rules.

Both the settlement agreement adopted in D.12-04-046 and a number of parties in their comments maintain that is it important for the Commission to finalize a decision allowing or requiring procurement of new resources in local areas to meet future capacity requirements (possibly including flexible attributes) by or near the end of 2012. A decision in this timeframe would allow any new capacity to be built in a timely manner to meet future local capacity area needs, including integrating system variability. For example, GenOn asserts that it can take seven to nine years to develop and construct a new generation project in

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[5] SB 695 (Stats. 2009, Ch. 337) required the Commission to impose non-bypassable charges associated with certain ISO procurement on direct access and community choice aggregator customers.

[6] Stats. 2011, ch. 599. This statute regards the relationship between IOUs and Community Choice Aggregators.

[7] Any CAM-related issued considered in R.12-02-009 related to implementation of SB 790 are not in the scope of this proceeding.

California. A Commission decision at or near the end of 2012 will allow the process to begin in 2013. We hereby set a schedule to allow for a decision at or near the end of 2012 by the Commission.

Consistent with the attached schedule, the ISO has committed to serve testimony including its local reliability studies by May 23, 2012. At the PHC, the ISO committed to providing parties access to these studies ahead of the filing date.[8] We emphasize the need for transparency and timeliness on the part of all parties in order to attain the schedule advocated by many parties and adopted here. Parties will have the opportunity to provide testimony and replies consistent with the scope of this proceeding on local capacity requirements and the ISO studies. We anticipate that hearings will be necessary and accordingly provide for this in the schedule.

Schedule for Track 1—Local Reliability

Workshop	Held on May 3, 2012
ISO testimony with studies served	May 23, 2012
Testimony by all other parties served	June 25, 2012
Further Workshop(s)	As needed
Second Prehearing Conference	July 9, 2012
Reply Testimony (including ISO) served	July 23, 2012
Evidentiary Hearings	August 7-10 and 13-17, 2012

[8] As part of this process, a Commission workshop on these ISO studies was held on May 3, 2012.

Briefs/Reply Briefs filed	To be determined at close of hearings
Proposed Decision issued	November or December 2012

Track 2 -- System Reliability Track

A major purpose of this proceeding is to maintain and ensure reliability in CPUC-jurisdictional areas in California over a long-term planning horizon. This requires anticipation of changes in both supply and demand. To accomplish this, it is important to consider the potential retirement of existing plants, the likelihood of relicensing of nuclear power plants, changes in mandates for renewable power, development of energy storage facilities, increased energy efficiency and demand response resources, and the developing of distributed generation resources.

D.12-04-046 adopted a settlement among a number of parties in R.10-05-006, the precursor to this proceeding. In that settlement, parties agreed that no decision should be made in that docket about whether new resources would be needed to ensure system reliability through 2020.

In Track 2 of this proceeding we will consider the following issues related to system needs in order to determine if new infrastructure is needed:

1. What assumptions should be made about the availability of various supply resources and levels of electricity demand over the next 20 years. This may entail use of assumptions from other proceedings involving supply resources and electricity demand, including proceedings concerning energy efficiency, demand response, distributed generation, energy storage, the renewable portfolio standard, and greenhouse gas issues;
2. What assumptions from other organizations and agencies such as the ISO and the California Energy Commission should be incorporated into long-term electricity system needs forecasts in this proceeding;

3. How the development of renewable resources consistent with a 33% renewable portfolio standard will affect reliability;
4. Whether increased variability amongst load and generation may require changes in procurement of resources to meet reliability needs;
5. What rules should govern procurement of additional system reliability needs not already covered by the Commission's RA rules;
6. Determination of specific scenarios to be developed to analyze long-term system reliability needs; these scenarios will form the basis for the Commission's submittal to the ISO for its 2013-2014 Transmission Planning Process;
7. How the potential for shutdown of nuclear power plants in California would impact long-term system reliability needs;
8. What specific Commission authorization of IOUs and/or LSEs is required for them to procure to meet long-term system reliability needs;
9. What cost-effective resource strategies should be implemented to achieve greenhouse gas (GHG) goals;
10. How to inform other infrastructure planning processes, including the ISO Transmission Planning Process and other regional planning processes; and
11. Issues deferred to this proceeding from D.12-04-046.

We anticipate that this track will require at least two Commission decisions. First, we will develop standard planning assumptions leading to specific supply and demand scenarios for the next 20 years. This process will commence with a proposal by the Energy Division, with subsequent workshops. Out of necessity, the data for the first 10 years is likely to be much more detailed and robust than data for the second 10 years.

Second, we will consider issues related to system variability, such as renewable integration, into the state's energy future. We anticipate that the ISO, in conjunction with Energy Division staff, will hold workshops during 2012 to explain the methodologies associated with understanding and quantifying system variability. In 2013, we anticipate that updated studies will be performed using new scenarios from the 2012 Long Term Procurement Plans (LTPP), and that methodologies may be changed based on party input and comments. To the extent that new resources are authorized in Track 1 to meet local capacity needs, we expect that any modeling would incorporate this information.

Schedule for Track 2—System Needs

Energy Division Standardized Planning Assumptions Proposal	Distributed May 10, 2012
Workshops on Energy Division Standardized Planning Assumption Proposal	May 17, 2012 and potentially others to be scheduled by Energy Division
Comments on Proposal filed	May 31, 2012
Reply Comments on Proposal filed	June 11, 2012
ACR on Planning Assumptions issued	June 21, 2012
Energy Division Draft Scenarios	August 1, 2012
Workshops	To be scheduled by Energy Division
Comments to Energy Division on Draft Scenarios (not filed)	September 1, 2012
Proposed Scenarios issued by Ruling	September 14, 2012
Comments on Proposed Scenarios filed	October 1, 2012
Proposed Decision on Scenarios issued	November 2012
Schedule to incorporate ISO updated Renewable Integration Report and determine system needs	To be determined in a future Ruling

Track 3 -- Procurement Rules and Bundled Procurement Plans

The LTPP proceedings generally operate on a two-year cycle with the IOUs responsible for submitting procurement plans that project their need, and their action plan for meeting that need, over a ten-year horizon. Pursuant to Assembly Bill (AB) 57,[9] codified as Section 454.5, by approving procurement plans, the Commission establishes "up-front standards" for the IOUs' procurement activities and cost recovery. This obviates the need for after-the-fact reasonableness review by the Commission of the resulting utility procurement decisions that are consistent with the approved plans.

Based on the record in R.10-05-006, we find it reasonable to continue to direct the IOUs' filing of bundled LTPPs to be based on a limited set of planning standards using the best information available at that time. Our intent is to ensure that the IOUs' plans can be more easily compared to each other and to maintain consistency, where appropriate, with Commission policy in other procurement-related proceedings.

There will be two portions of Track 3. First we will consider what changes should be made to current procurement rules, as well as what new procurement rules should be adopted. Second, and after a decision on procurement rules, we will require the IOU to file bundled procurement plans. In this Scoping Memo we preliminarily lay out the issues and schedule for this track of the proceeding. In a future amended Scoping Memo or Ruling, we intend to provide more detail and an updated schedule in this proceeding we expect to consider the following issues related to procurement rules:

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[9] AB 57 (Stats. 2002, ch. 850, Sec 3, Effective September 24, 2002), added Pub. Util. Code § 454.5., enabling utilities to resume procurement of electric resources.

1. Flexible resources procurement and contract policies;
2. Preserving competition in the resource adequacy market;
3. Ensuring utilities reduce their need to procure GHG compliance instruments by pursuing cost-effective GHG emissions reductions on a portfolio-wide basis;
4. Addressing any unresolved issues or issues that need to be revisited from the 2010 LTPP related to GHG compliance product procurement authority;
5. Establishing a fair standard under which to compare Utility-Owned Generation renewable applications to other recent renewable proposals and contracts;
6. Making enhancements to the Energy Resource Recovery Account compliance filing requirements;
7. OTC power procurement policies;
8. Nuclear fuel procurement policies;
9. Policies related to ISO new markets and market products, including flexi-ramp products and intra-hour products;
10. Refinements to the Procurement Review Group;
11. Refinements to the independent evaluator process;
12. Multi-year forward procurement requirements;
13. Long-term contract solicitation rules;
14. Changes to the Commission's adopted CAM per SB 695,[10] SB 790, D.11-05-005 and any relevant previous decisions (beyond any changes considered in Track 1);[11]

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[10] SB 695 required the Commission to impose non-bypassable charges associated with certain ISO procurement on direct access and community choice aggregator customers.

[11] Any CAM-related issued considered in R.12-02-009 related to implementation of SB 790 are not in the scope of this proceeding.

15. GHG procurement policies necessary to facilitate the implementation of the California Air Resources Board's cap-and-trade program.

In Track 3 of this proceeding we expect to consider the following issues related to bundled procurement plans:

1. Maximum and minimum limits on IOU forward purchasing of energy, capacity, fuel and hedges;
2. Specification of the products that the IOUs can purchase;
3. Specification of rules that, if followed, would exempt the IOUs from reasonableness review;
4. An integrated plan to comply with state policies, including the loading order.

Schedule for Track 3—Bundled Procurement

Parties file proposed Rules	October 15, 2012
Reply comments to proposed rules	November 5, 2012
Proposed Decision on rules	January 2013
IOUs file Bundled Procurement Plans	March 2013 (tentative)
Remainder of schedule	To be determined in future Ruling

As noted above, this schedule is preliminary and subject to modification by a future Ruling or amended Scoping Memo. Depending on procedural needs, there may be workshops, hearings, briefs and/or other procedural activity in this track.

Need for Evidentiary Hearings

The OIR stated that the issues evidentiary hearings are anticipated in this proceeding. This Ruling confirms the preliminary determination in the OIR that factual issues in Tracks 1, 2 and 3 will require evidentiary hearings.

Procedural Schedule

The schedule delineated herein is adopted, subject to modification by the assigned Commissioner or Administrative Law Judge (ALJ).

We anticipate Tracks 1, 2 and 3 will be resolved as set forth herein and completed by January 2014. In any event, we anticipate that this proceeding will be resolved with 24 months of the date of the issuance of this Scoping Memo pursuant to Public Utilities Code Sections 1701.5.

Alternative Dispute Resolution

The Commission strongly encourages all parties to every proceeding to consider whether a means other than litigation can more efficiently and effectively resolve the matter. As set forth in the schedule herein, workshops are scheduled to narrow issues in dispute and to work toward consensus. Issues which are not resolved in the workshop process may be able to be resolved or narrowed through an alternative dispute resolution process.

The Administrative Law Judge Division has ALJs trained in all Alternative Dispute Resolution techniques, as well as extensive subject matter experience, available to assist parties in resolving disputes. Requests for appointment of an ALJ to assist with Alternative Dispute Resolution should be made to ALJ Jean Vieth (xjv@cpuc.ca.gov).

Intervenor Compensation

The PHC in this matter was held on April 18, 2012. Pursuant to Pub. Util. Code § 1804(a)(1), a customer who intends to seek an award of compensation

should file and serve a notice of intent to claim compensation no later than May 18, 2012. Parties who were previously found eligible to request compensation in R.10-05-006 shall remain eligible in this proceeding and do not need to file a notice of intent within 30 days, provided there are no material changes in their by-laws or financial status. All others must comply with the statute. When filing requests for compensation, parties should cite to this ruling and any earlier rulings granting them eligibility in prior LTPP rulemakings.

Final Oral Argument

In Track 1, any party wishing to request Final Oral Argument before the full Commission per Rule 13.13 shall do so no later than the date of Opening Briefs in that track. In Tracks 2 and 3, any party wishing to request Final Oral Argument before the full Commission per Rule 13.13 shall do so no later than the date of reply comments or Opening Briefs (whichever comes later), or a date established by a subsequent Ruling in this proceeding.

Categorization

This Scoping Memo confirms the preliminary determination in R.12-03-014 that this proceeding is "ratesetting," as defined by Rule 1.3(e).

Presiding Officer

The assigned ALJ is David M. Gamson, who will act as the presiding officer in this proceeding.

Ex Parte Communications

In accordance with Rule 8.2, *ex parte* communications in this ratesetting

proceeding are allowed, subject to the reporting requirements in Rule 8.3 and the restrictions in Rule 8.2.

IT IS RULED that:

1. Evidentiary hearings are needed for Tracks 1, 2 and 3 of this proceeding.
2. The scope of this proceeding is as stated herein.
3. The schedule for the Track 1 of this proceeding is as stated herein. The Schedules for Tracks 2 and 3 are preliminary set forth herein, and will be set forth in more detail in a future Ruling.
4. Administrative Law Judge David M. Gamson shall be the presiding officer in this proceeding.
5. The preliminary determination in Rulemaking 12-03-014 that this proceeding is categorized as ratesetting is confirmed.

Dated May 17, 2012, at San Francisco, California.

/s/ MICHEL PETER FLORIO	/s/ DAVID M. GAMSON
Michel Peter Florio	David M. Gamson
Assigned Commissioner	Administrative Law Judge

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ATTACHMENT K

Application No.: _____

Exhibit No.: _____

Witness: Robert Sparks

Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans.	Rulemaking 12-03-014

TESTIMONY OF ROBERT SPARKS
ON BEHALF OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

Table 1: Summary of OTC (2021) study results

Local Area	Local Area Requirements (MW)				Replacement OTC Generation Need (MW)			
	Trajectory	Environmentally Constrained	ISO Base Case	Time Constrained	Trajectory	Environmentally Constrained	ISO Base Case	Time Constrained
LA Basin (this area includes sub-area below)	10,743	11,246	11,010	12,165	2,370 – 3,741	1,870 – 2,884	2,424 – 3,834	2,460 – 3,896
Western LA Basin (sub-Area of the larger LA Basin)	7,797	7,564	7,517	7,397				
Big Creek/Ventura (BC/V) Area	2,371	2,604	2,438	2,653	(Need is for Moorpark only, a sub-area of the Big Creek/Ventura Local area)			
					430	430	430	430

Table 1 shows the total local area capacity needs for the LA Basin and Big Creek/Ventura local capacity resource areas under each of the four RPS portfolio scenarios. Table 1 also identifies ranges of the amount of generation at existing OTC sites or electrically equivalent sites in the local area (replacement OTC generation) that would be needed under each of the RPS portfolio scenarios. The replacement OTC generation needs in the LA Basin are all within the Western LA Basin, which is a sub-area of the larger LA Basin. In addition, there is also an identified replacement OTC generation need in the Ellis sub-area, which is within the Western LA Basin.

Q. Please explain why there is a range of repowered former OTC needs for each RPS scenario for the Western LA Basin sub-area.

A. The lower end of the repowered former OTC range value corresponds to the amount of generation that would be needed if it were located at existing OTC sites that are the most effective at mitigating the identified transmission constraint. The higher end of the OTC range value corresponds to the amount of generation inside the sub-area that would be needed if it were located at existing OTC sites that are the least effective at mitigating the identified transmission constraint.

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ATTACHMENT L

[CONFIDENTIAL]

PACIFIC GAS AND ELECTRIC COMPANY
Oakley Generating Station
Application 12-03-026
Data Response

PG&E Data Request No.:	TURN_003-17		
PG&E File Name:	OakleyGeneratingStation_DR_TURN_003-Q17		
Request Date:	June 6, 2012	Requester DR No.:	003
Date Sent:	June 22, 2012	Requesting Party:	The Utility Reform Network
PG&E Witness:	Marino Monardi / Antonio Alvarez	Requester:	Robert Finkelstein

QUESTION 17

Answer the following questions regarding the "three large, gas-fired projects in the CAISO territory" cited at the sentence spanning pp. 5-11 and 5-12 of PG&E's May 21 Prepared Testimony in Application 12-03-026:

a. Identify the three projects, each project's owner, and, to the extent of PG&E's knowledge, the current permitting and development status of each project.

b. Explain why only the three projects "could possibly be considered as viable alternatives to the Oakley Project", as stated at p. 5-12, lines 1-2.

c. Identify each other project that PG&E assessed and determined could not be considered a viable alternative, and explain the basis for that determination.

ANSWER 17

This response and associated attachment contain Confidential Protected Material, protected under D.06-06-066 Appendix 1 and General Order 66-C, as set forth in the accompanying declaration/matrix.

a. [redacted]

[redacted]

[1] Ongoing legal challenges to the Avenal Project's PSD Permit are provided in a Petition for Post-Certification Amendment filed in March 2012 and available here: http://www.energy.ca.gov/sitingcases/avenal/compliance/2012-03-05_petition_to_amend.pdf

[redacted]

[redacted]

[redacted]

[redacted]

b. [redacted]

[redacted]

c. Please see the attachment entitled: OakleyGeneratingStation_DR_TURN_003-Q17-Atch01-CONF. This attachment contains confidentially protected information.

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ATTACHMENT M

PACIFIC GAS AND ELECTRIC COMPANY
Oakley Generating Station
Application 12-03-026
Data Response

PG&E Data Request No.:	IEP_001-10		
PG&E File Name:	OakleyGeneratingStation_DR_IEP_001-Q10		
Request Date:	June 6, 2012	Requester DR No.:	001
Date Sent:	June 20, 2012	Requesting Party:	Independent Energy Producers Association
PG&E Witness:	Marino Monardi	Requester:	Brian Cragg

QUESTION 10

Please identify the projects referred to on pages 5-11 through 5-12 of PG&E's Prepared Testimony that could be considered as "viable alternatives to the Oakley Project."

ANSWER 10

PG&E objects to this request to the extent that IEP is a market participant and has not signed a Non-Disclosure Agreement with PG&E. In developing this portion of PG&E's testimony, it relied on a combination of public data as well as market knowledge, much of it confidential, derived from PG&E's active participation in the energy procurement market. Public data sources include the California Independent System Operator ("CAISO") queue, California Energy Commission ("CEC") project status list and other CEC permitting documents, the trade press, and public documents disclosed by the California Public Utilities Commission ("CPUC"), Federal Energy Regulatory Commission ("FERC"), CAISO, other investor-owned utilities ("IOUs"), and municipalities.

Given PG&E's understanding of the development process and other market knowledge, only three projects were determined "viable alternatives to the Oakley Project." To be an alternative to the Oakley Project, the project must have the potential to come online prior to 2018. Therefore, among other requirements, the project must have an active position in the CAISO queue, complete or advanced permitting approval from the CEC, and not already under contract to a Load-serving entity. PG&E's evaluation found three projects that met the criteria. However, all three of these projects face remaining development challenges which may prevent the facility from coming online by 2018.

ATTACHMENT N

[CONFIDENTIAL]

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CONFIDENTIAL PAGES REMOVED

FROM

PUBLIC VERSION OF TESTIMONY

ATTACHMENT O

R.12-03-012: 2012 LTPP Operating Flexibility Analysis

Nathaniel Skinner

Senior Analyst, Generation & Transmission Planning

California Public Utilities Commission

June 4, 2012

Remote Access

- Webex

  https://van.webex.com/van/j.php?ED=183770997&UID=491292852&PW=NM2FmOGYxNTUx&RT=MiM0
  Meeting Number: 743 103 614
  Meeting Password: energy

- Phone

  Call in #:
  866-687-1675
  *Note: *6 to mute/unmute*

  Passcode:
  3481442

Agenda

Time	Item
10:00 - 10:10	Introduction, Schedule Overview
10:10 – 10:20	Expectations, LTPP / RA Interaction
10:20 - 12:00	Status of studies: Past efforts (2010 LTPP) models and methods
12:00 – 1:00	Lunch
1:00 – 2:30	Status of studies: Current/future efforts (2012 LTPP) models and methods
2:30 – 2:45	Break
2:45 – 3:15	Modeling resources: Inside & outside of the CAISO system
3:15 – 3:45	Overview of additional assumptions/metrics needed for studying operational flexibility
3:45 – 4:00	Wrap-up/Next steps

Meeting Purpose

- Familiarize parties with the studies conducted in the 2010 LTPP
- Begin informing parties about current and future studies
- Begin assessing what additional assumptions and metrics beyond those identified in the planning standards are needed for modeling

Meeting Purpose (cont)

- What do we want to call these studies?
  - Issues are broader than renewable integration (includes load variability)
  - Broader than variability studies (includes forecast uncertainty)

Study Schedule

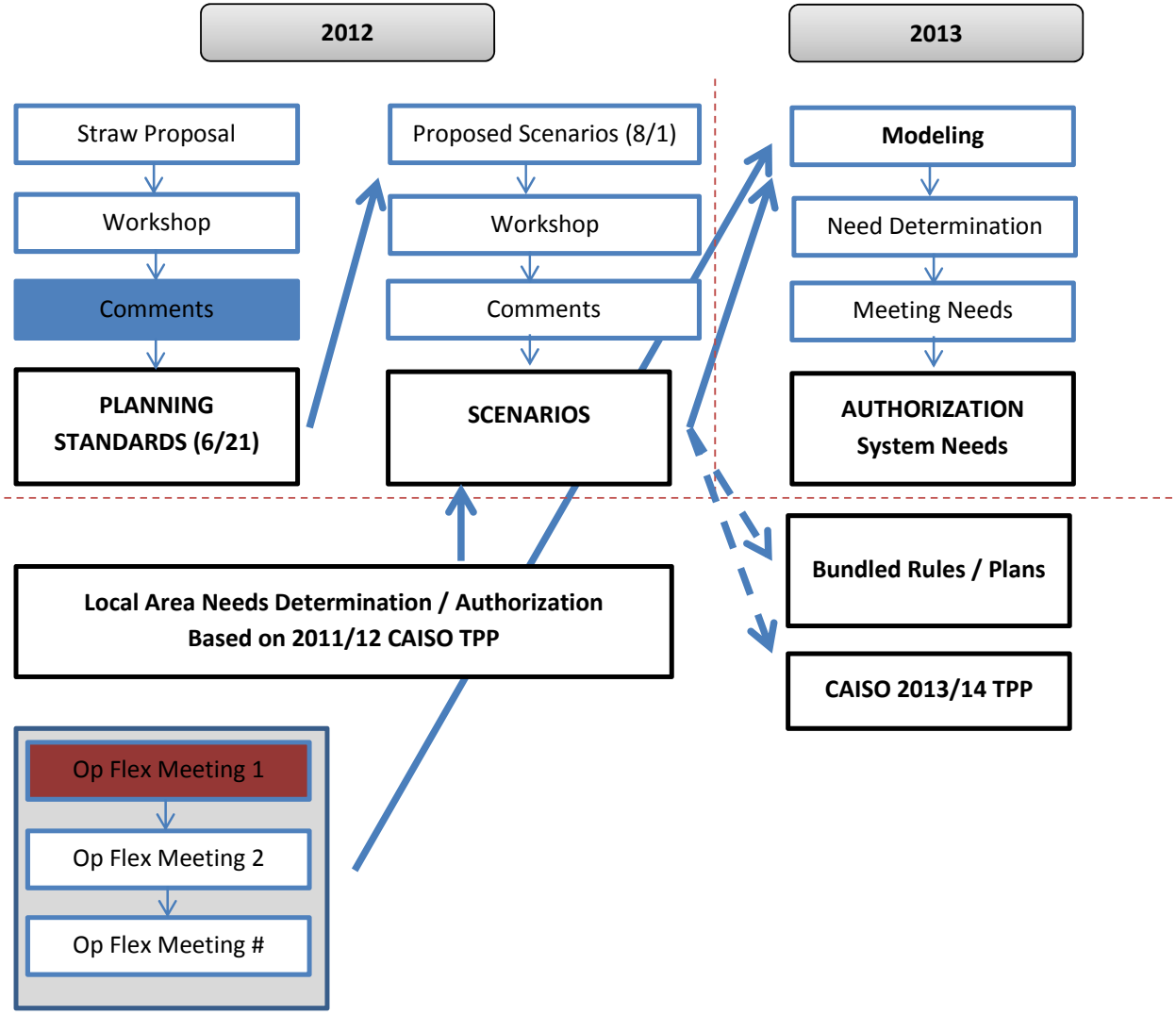
- 6/4: Meeting #1
- Mid/late August: Meeting #2
- Mid September: Meeting #3
- Additional schedule TBD

- Schedule for incorporating information into the record will be established in a future ruling

Other Anticipated Schedule

- Track I (Local Area Reliability)
  - 5/23: CAISO testimony on LCR
  - 6/25: Other parties' testimony on LCR
  - 7/9: Second Prehearing Conference
  - 7/23: Reply testimony (all parties)
  - 8/7-10 & 8/13-17: **Evidentiary Hearings**
    - If needed
    - Some subset of days may be selected
  - Nov-Dec: Proposed Decision issued

Roadmap


2012
2013
Straw Proposal
Workshop
Comments
PLANNING STANDARDS (6/21)
Proposed Scenarios (8/1)
Workshop
Comments
SCENARIOS
Modeling
Need Determination
Meeting Needs
AUTHORIZATION System Needs
Bundled Rules / Plans
CAISO 2013/14 TPP
Local Area Needs Determination / Authorization Based on 2011/12 CAISO TPP
Op Flex Meeting 1
Op Flex Meeting 2
Op Flex Meeting #

Expectations

- Highly technical studies, parties will need to allocate their resources as they best see fit
- Collaborative process to advance studies
- Any recommended methods or data source changes need to be documented, justified, and cited for consideration

LTPP/RA Interaction

- Work is undergoing to assess interaction between RA (procurement) and LTPP (planning & resource development)
- Need for clear definitions and procedural location to meet both proceedings' needs

Past Efforts

California ISO
Shaping a Renewed Future

Operating Flexibility Analysis for R.12-03-014

Mark Rothleder, Executive Director, Market Analysis and Development

Shucheng Liu, Principal Market Developer

Clyde Loutan, Senior Advisor

Arne Olson , E3

CPUC, Workshop June 4, 2012

Description of Past Method and Model

Study process quantifies operational requirements and evaluates fleets ability to meet operating requirements.

Renewable Portfolios

Develop Profiles

Variable Resource

Wind / Solar and Load

Profiles

Statistical Analysis/ model

Flexibility Requirements

(Regulation, Balancing)

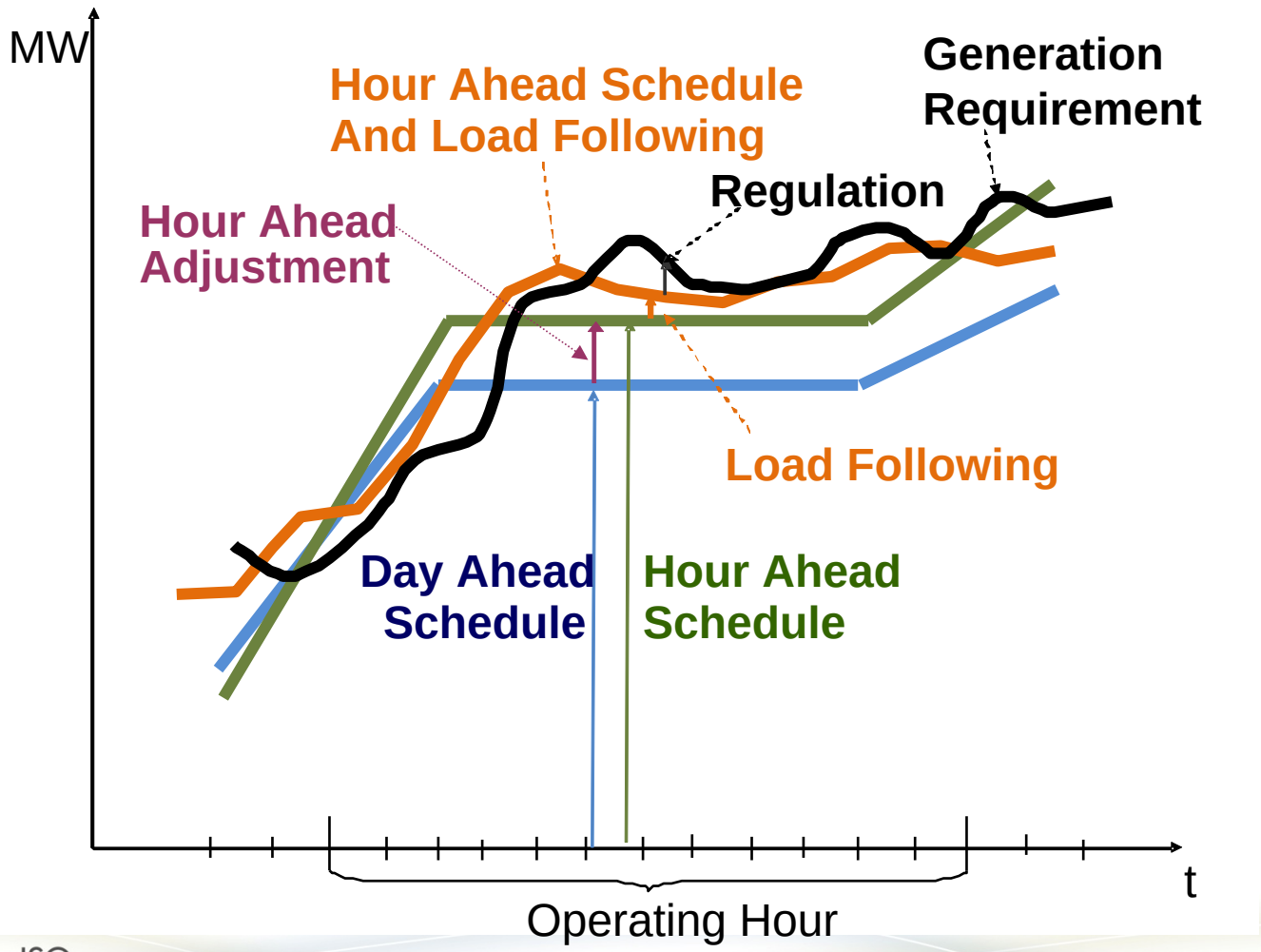
Production simulation

Shortages

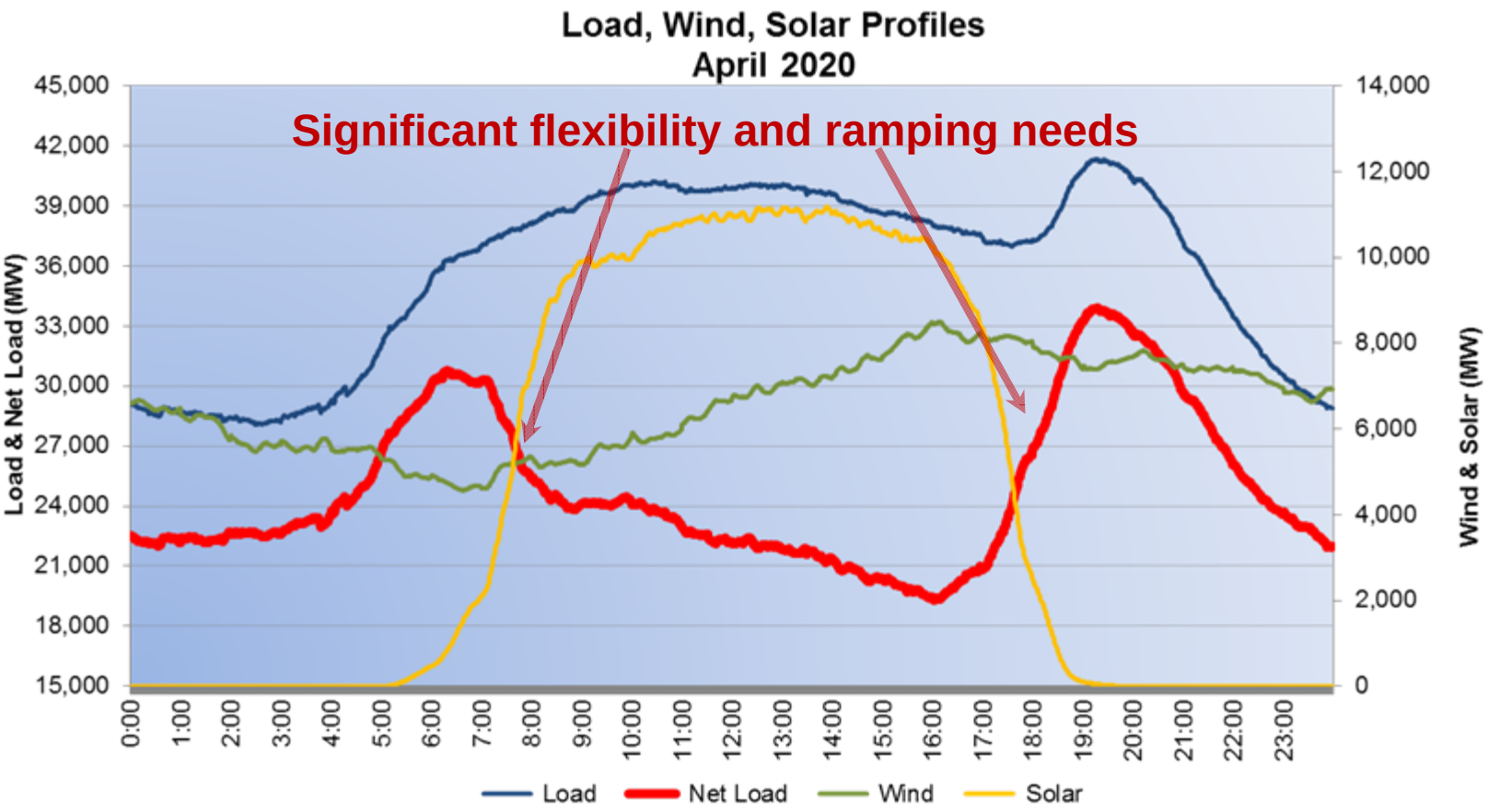
Infrastructure Needs

Costs, Emissions
Import/Export
Capacity Factor

To be prepared for increased supply variability … fleet flexibility requirements must be understood



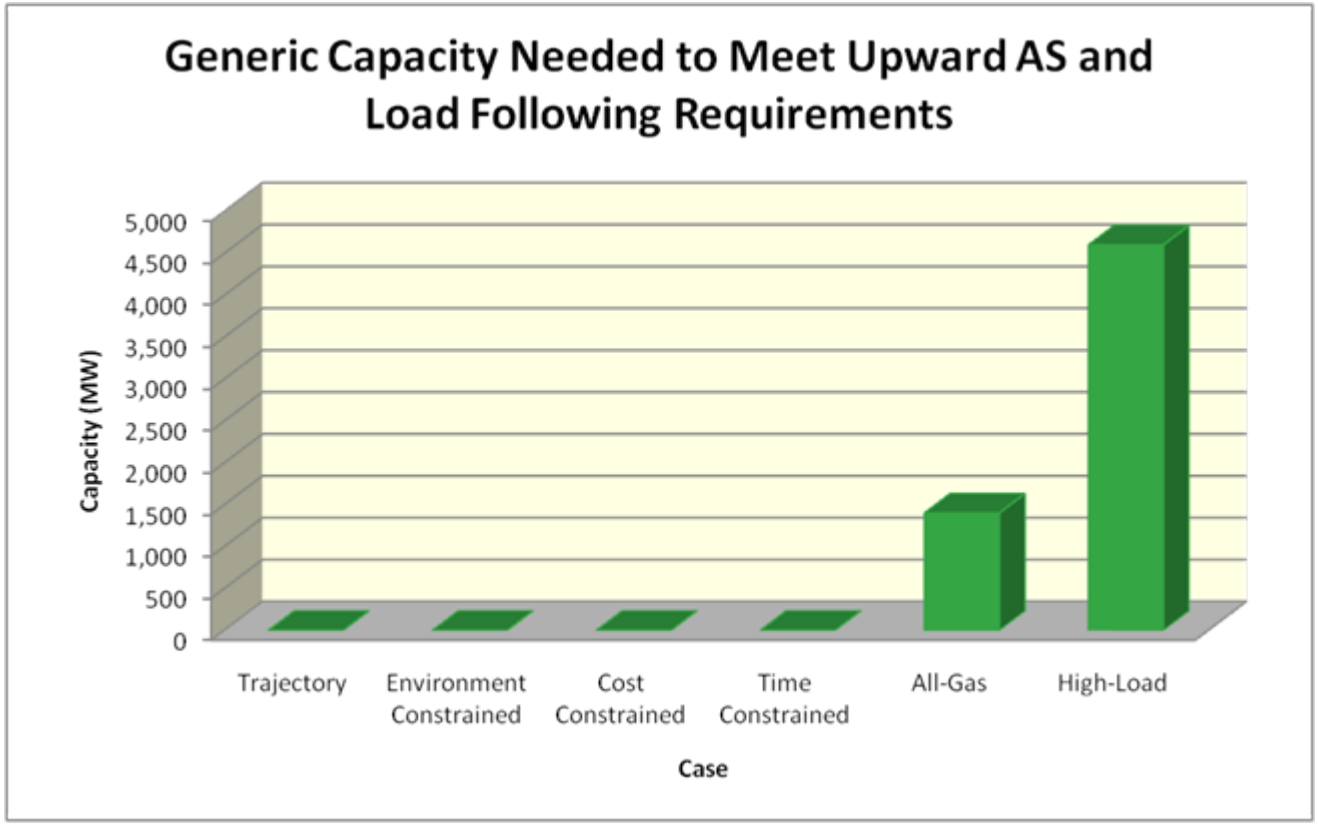
Conventional resources will be dispatched to the net load demand curve



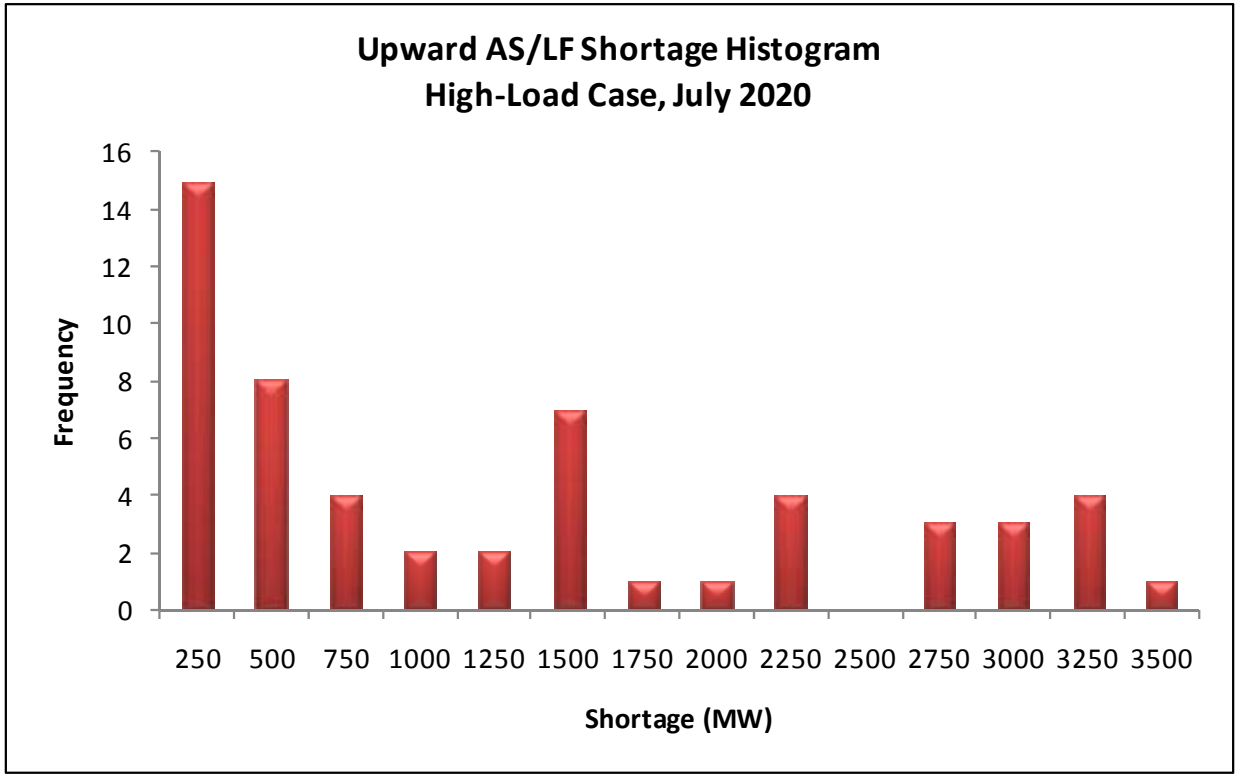
33% scenarios in 2020 cover range renewable and load conditions.

Case	Case Title	Description
1	33% Trajectory	Based on contracted activity
2	Environmental Constrained	High distributed solar
3	Cost Constrained	Low cost (wind, out of state)
4	Time Constrained	Fast development (out-of-state)
5	20% Trajectory	For comparison
6	33% Trajectory High Load	Higher load growth and/or energy program under-performance
7	33% Trajectory Low Load	Lower load growth and/or energy program over-performance

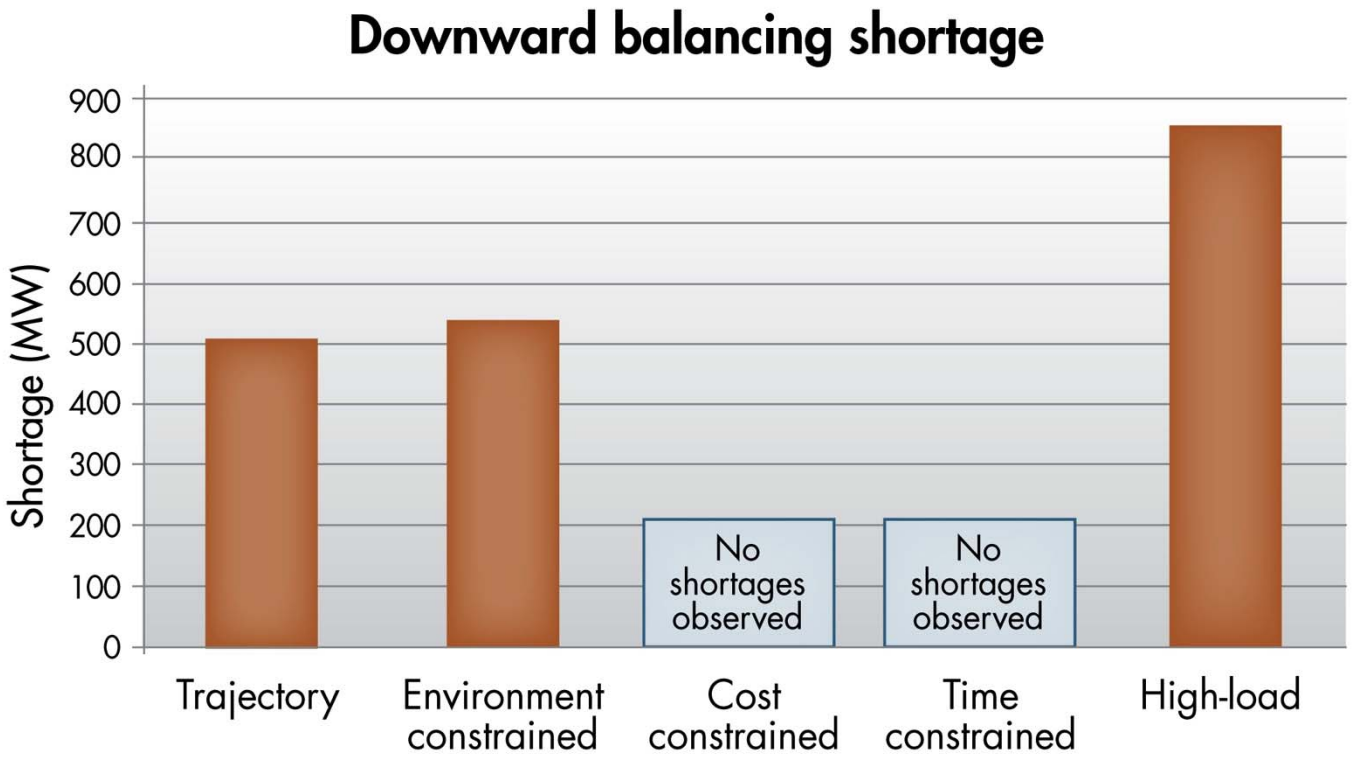
Generic resources are added to meet upward ancillary services and load following requirements in the two cases.



There is a total of 55 hours of shortage observed in July 2020 High-Load Case

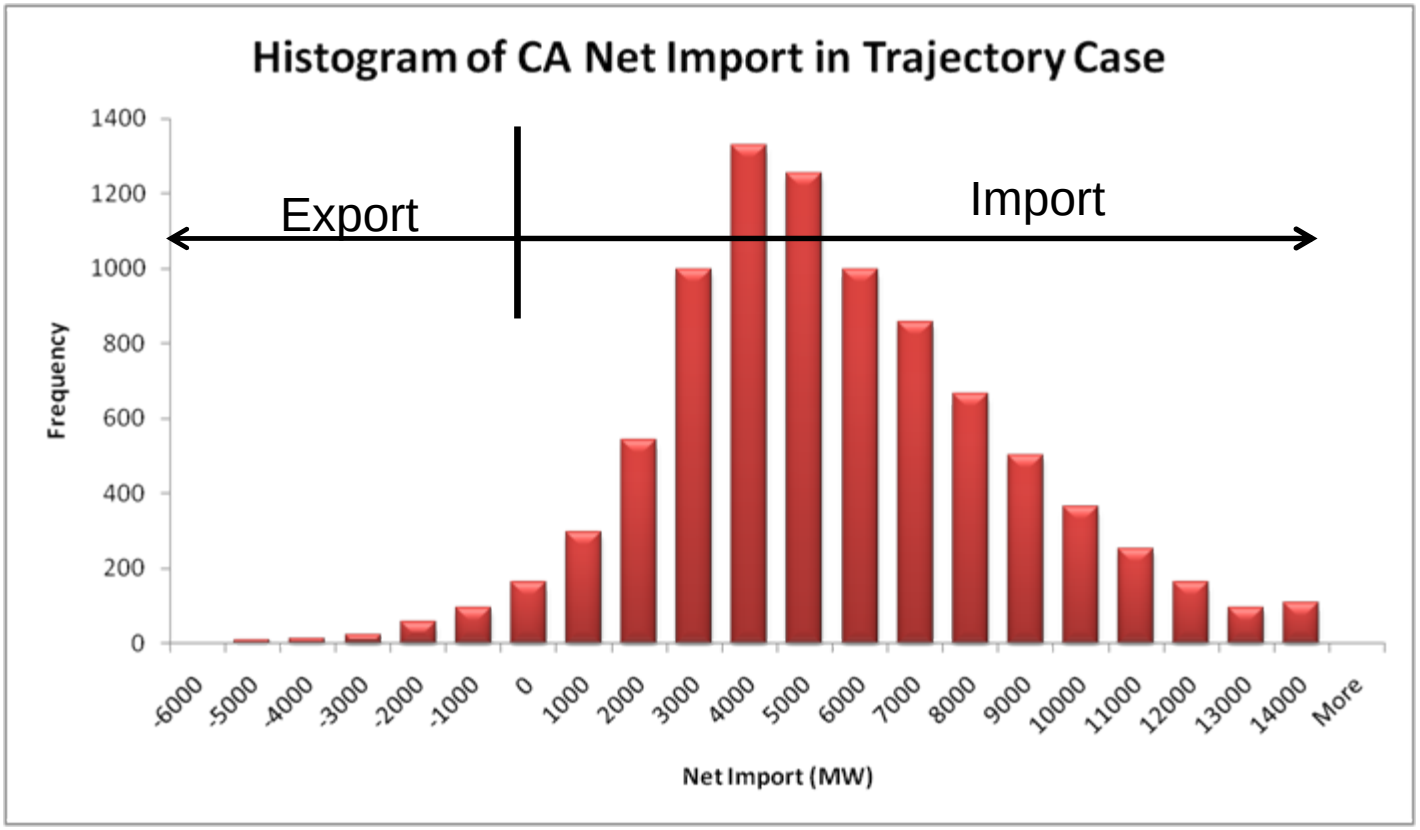


Out of approximately 3,500 MW downward balancing requirements, some hours of potential shortages were observed.

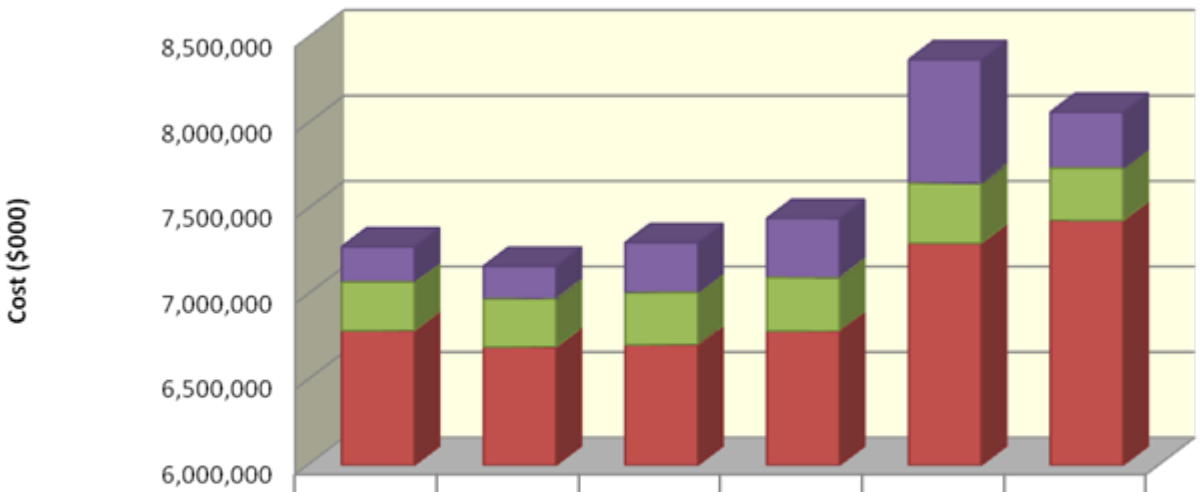


Note: Downward balancing may be more effectively and efficiently managed using curtailment or storage rather than less economic dispatch of flexible resources to higher level to maintain downward flexibility

Large quantity of net export observed in the cases need to be reviewed.



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



	Trajectory	Environment	Cost	Time	All-Gas	High-Load
Non-Dedicated Import	206,096	190,467	292,175	346,793	722,367	327,348
Dedicated Import	285,028	282,620	305,414	312,970	350,287	306,667
CA Generation	6,787,502	6,691,967	6,705,361	6,785,267	7,300,579	7,432,088

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

Additional sensitivity and analysis performed since July 2011

1. PRM Analysis Deep Dive analysis of PRM
2. Step 1 Sensitivity
3. 5 minute simulation
4. Regional modeling and coordination
5. Incorporate Local Capacity Requirements
6. Frequency Response
7. 2018 risk of retirement

California ISO
Shaping a Renewed Future

CAISO Deep Dive Analysis

Shucheng Liu

Next Steps: Test operational robustness of underlying assumptions

- Assess alternatives for meeting residual needs
- Test underlying assumptions regarding
- Perform additional analysis testing robustness of assumptions
  - Demand Response
  - Energy Efficiency
  - Load forecast
  - Outage / Maintenance rates
  - Import / Export limitations
  - Renewable online schedule

Next Steps: Develop method for studying alternative to meeting needs

- Purpose:
  - Determine if shortages can be resolved using energy or ramping capability.
    - Additional energy may free up flexible resource capability
    - If insufficient ramping, then ramping may be needed
  - After consideration of local resources, if residual shortage needs are identified test different solutions for meeting residual needs:

Ramping Solutions	Energy Solutions
Peaker	Peaker
CCGT (40%-60% of Capability)	CCGT
Storage	Additional demand response
Dispatchable dynamic import	Energy Efficiency
Hydro (not run of river, not in spill)	Imports
Other ramping technologies	Other ramping solutions

  - Assess feasibility of alternative solutions
  - Leverage EPRI/NREL work to the extent possible

Incorporate Local Capacity Requirement

Approximately 1,200MW of residual need observed after incorporating LCR resources.

- Total 3,173 MW Local Capacity Requirement (LCR) resources
- A combination of CCGT and GT
  - 1,800 MW GT in SCE region
  - 1,000 MW CCGT in SCE regulation
  - 373 MW CCGT in SDG&E region
- Four hours in July 2020 with shortage observed
- A maximum 1,051 MW 20-minute ramping capacity shortage
- Equivalent to about 1,200 MW residual need for capacity

High-Load Trajectory case LCR resources monthly average capacity factors in production cost-run.

	1	2	3	4	5	6	7	8	9	10	11	12
CCGT - CA Average	42.2%	37.9%	34.6%	29.1%	30.3%	37.4%	61.9%	62.8%	52.9%	46.1%	40.4%	43.4%
GT – CA Average	6.5%	7.1%	5.3%	5.4%	5.4%	5.4%	9.8%	7.9%	4.3%	4.4%	5.4%	5.9%
SCE LCR CCGT	78.8%	79.2%	79.4%	78.4%	78.1%	77.6%	83.0%	83.7%	81.2%	80.6%	79.7%	79.6%
SCE LCR LMS100	10.2%	13.5%	12.0%	10.4%	10.6%	16.2%	21.3%	19.8%	8.2%	10.3%	8.4%	10.5%
SDGE LCR CCGT	79.1%	79.6%	78.5%	79.8%	78.4%	78.8%	83.2%	84.3%	80.8%	80.4%	79.6%	79.9%

Note: Emissions limitations not modeled.

- SCE LCR CCGT – 2 x 500 MW CCGT units, each unit has Pmin = 200 MW, ramp rate = 7.5 MW per minute
- SCE LCR LMS100 – 18 x 100 MW GT units, each unit has Pmin = 50 MW, ramp rate = 12 MW per minute
- SDGE LCR CCGT – 1 x 373 MW CCGT unit with Pmin = 200 MW, ramp rate = 7.5 MW per minute

Process Update

Where We Have Been

- CAISO has been using PLEXOS to estimate need for new resources to integrate renewables
  - Develop detailed data inputs for hourly production simulation
    - Loads, renewable profiles, etc.
    - Regulation and Load Following Requirements (Step 1)
    - Import capabilities
  - Run PLEXOS to simulate hourly production
  - Log “violation” when resource stack is insufficient to meet load, reserve, regulation and LFU requirements
  - Add resources until no more violations

Where We Are Now

- CAISO is now proposing to supplement our modeling with a different type of analysis to address those factors unrelated to integration need, as a new step in the process
  - Reliability modeling that calculates Loss of Load Probability (LOLP) and Loss of Load Expectation (LOLE)
  - PG&E and E3 have been developing models to conduct this analysis
  - CAISO has also developed a stochastic analysis approach that to test simultaneous ramping capability
  - CAISO has not yet decided which model to use in this case

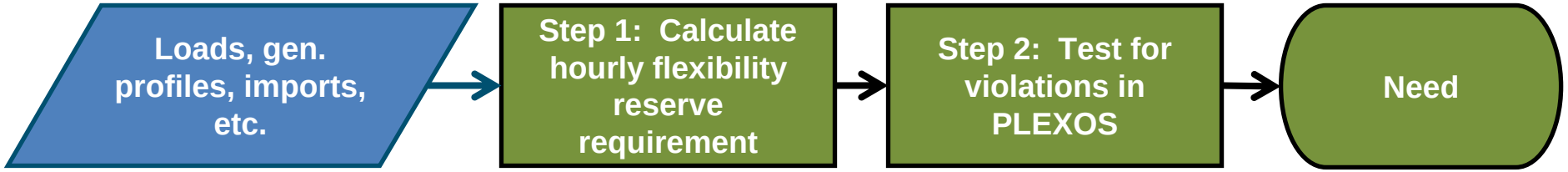
Two Types of Renewable Integration Need

1. <u>Capacity Need:</u>
   - Resources needed to serve load reliably using traditional reliability metrics such as Planning Reserve Margin (PRM) and Loss of Load Expectation (LOLE)

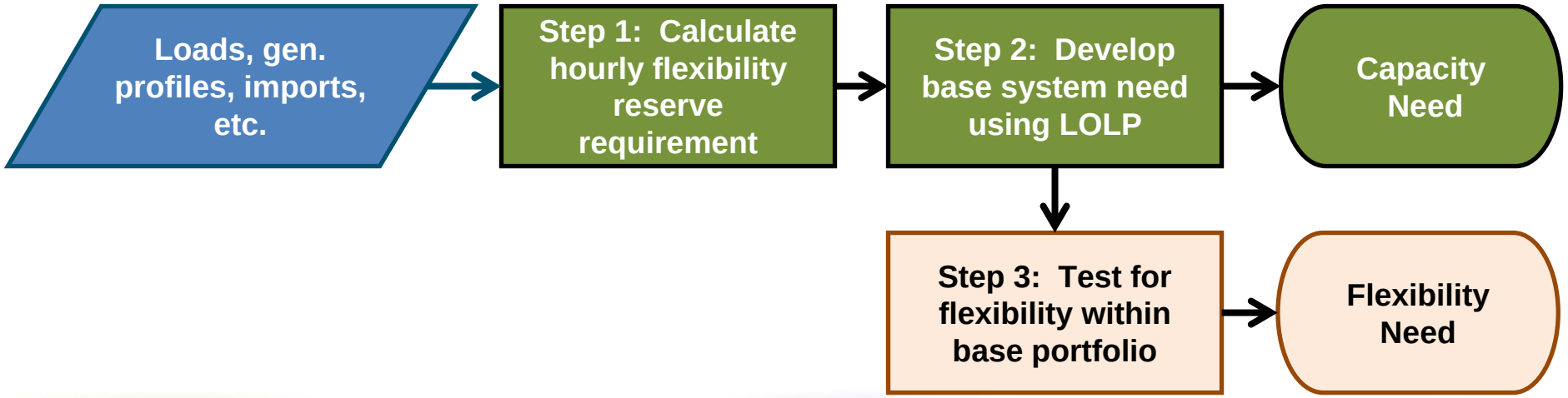
2. <u>Flexibility need:</u>
   - Resources needed to meet 10-minute, 20-minute and hourly ramp requirements

CAISO Proposed New Approach

Previous Methodology



Current Proposal



Step 1 of Proposed New Approach

- Calculate Regulation and Load Following Requirements associated with variability and uncertainty of load, wind and solar for each resource portfolio
- Unchanged from previous approach

Step 2 of Proposed New Approach

- Conduct LOLP modeling to determine need for new capacity to meet a reliability standard of 1-day-in-10-years
  - Calibrate model to reflect 17% PRM under All-Gas Case
  - For each portfolio, calculate change to PRM needed to achieve same reliability as All-Gas Case
    - Expected renewable production will be different from NQC
    - Incremental increase in Reg. and LFU requirements due to renewable penetration
  - Add resources as needed to meet the updated PRM to reflect changes from All-Gas case

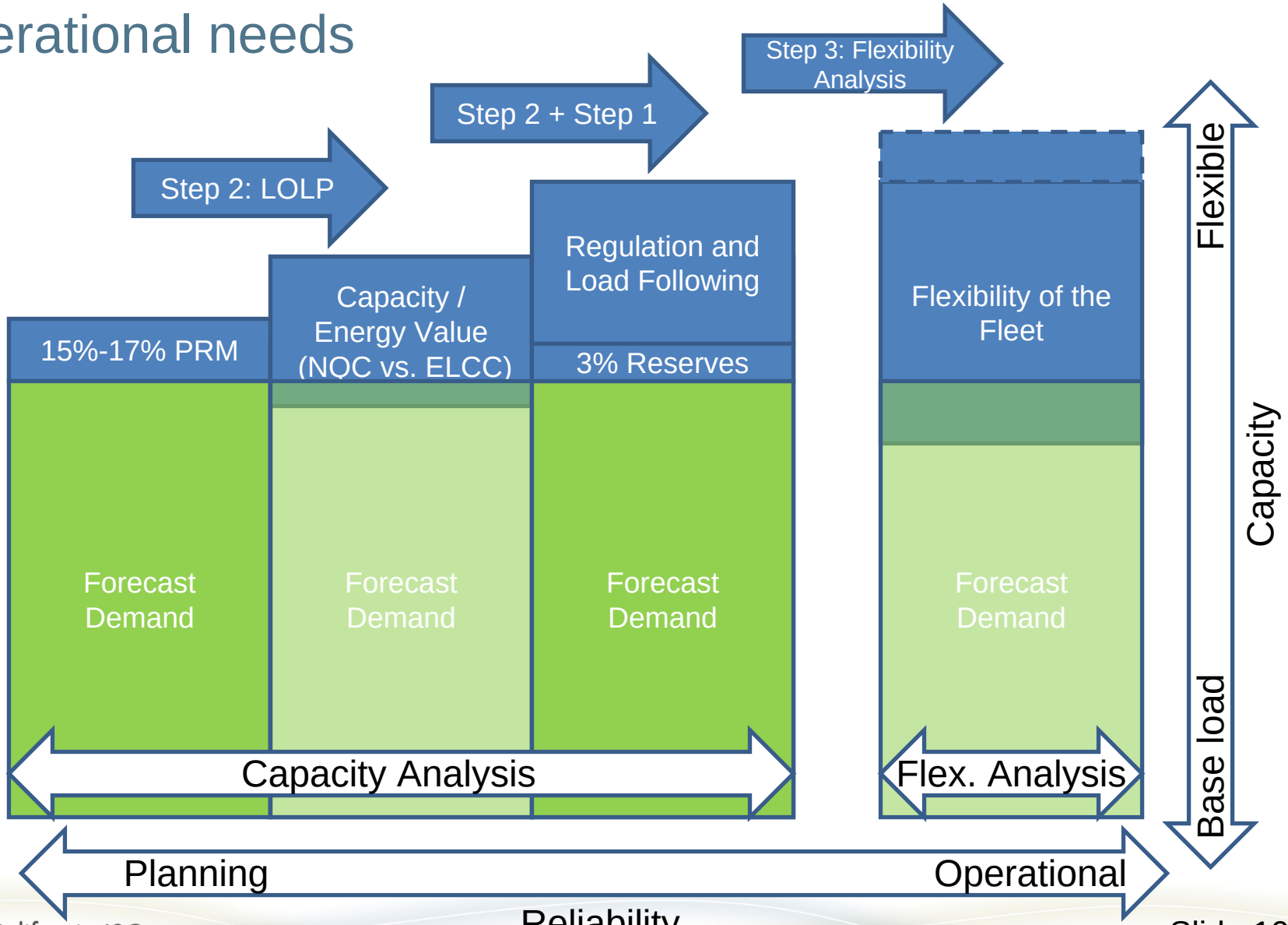
Step 3 of Proposed New Approach

- Test for flexibility within portfolio that comes from Step 2
  - Includes any resources added to meet reliability standard
- Need for ramping capability is not the same thing as need for new resources
  - Conversion of existing resources to something more flexible could solve a ramping problem without changing the PRM
- Stochastic component estimates the probability of having a ramping capacity shortage based on distribution of hourly ramps
  - Within-hour ramps also assessed through incorporation of Step 1 results
- PLEXOS runs to test operability of portfolio that comes from Step 3

Stochastic Simulation

- Purpose
  - To incorporate uncertainties in key input assumptions in determining need for capacity
- Scope
  - May apply to all cases
  - May be used together with Plexos simulation
- Study Approach
  - Probabilistic simulation
  - Loss of Load Probability (LOLP)
  - Assess probability of flexibility shortage

Flexibility needs analysis bridges planning and operational needs



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Shaping a Renewed Future

Overview of Stochastic Methodology – E3

Arne Olson
Andrew DeBenedictis
Ryan Jones

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ATTACHMENT P

PACIFIC GAS AND ELECTRIC COMPANY
Oakley Generating Station
Application 12-03-026
Data Response

PG&E Data Request No.:	IEP_001-13		
PG&E File Name:	OakleyGeneratingStation_DR_IEP_001-Q13		
Request Date:	June 6, 2012	Requester DR No.:	001
Date Sent:	June 20, 2012	Requesting Party:	Independent Energy Producers Association
PG&E Witness:	Marino Monardi / Jon Maring	Requester:	Brian Cragg

QUESTION 13

On page 2-2 of PG&E's Prepared Testimony, the witness describes the "Rapid Response" technology to be used in the Oakley plant:

a. To PG&E's witness's knowledge, does the Oakley Project have an exclusive license for the use of the "Rapid Response" technology in California?

ANSWER 13

a. No.

PACIFIC GAS AND ELECTRIC COMPANY
Oakley Generating Station
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PG&E Data Request No.:	IEP_001-13		
PG&E File Name:	OakleyGeneratingStation_DR_IEP_001-Q13		
Request Date:	June 6, 2012	Requester DR No.:	001
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PG&E Witness:	Marino Monardi / Jon Maring	Requester:	Brian Cragg

QUESTION 13

On page 2-2 of PG&E's Prepared Testimony, the witness describes the "Rapid Response" technology to be used in the Oakley plant:

b. Is PG&E aware of any other technologies that allow combined cycle units to operate in a manner similar to GE's "Rapid Response" technology? If so, please describe those technologies. Please also explain the advantages and disadvantages of the "Rapid Response" technology relative to any competing technologies.

ANSWER 13

b. PG&E is aware that some of the major combustion turbine manufacturers provide products that are similar to GE's Rapid Response technology, including Siemens, and Mitsubishi. PG&E is not aware of the details of each manufacturers' designs and is only aware of what can be found through public information.

PACIFIC GAS AND ELECTRIC COMPANY
Oakley Generating Station
Application 12-03-026
Data Response

PG&E Data Request No.:	IEP_001-13		
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Request Date:	June 6, 2012	Requester DR No.:	001
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PG&E Witness:	Marino Monardi / Jon Maring	Requester:	Brian Cragg

QUESTION 13

On page 2-2 of PG&E's Prepared Testimony, the witness describes the "Rapid Response" technology to be used in the Oakley plant:

c. Is PG&E aware of any power plants currently under development or construction that will use the competing technologies described in PG&E's response to the preceding Request? If so, please identify all such projects.

ANSWER 13

c. PG&E understands that this request concerns power plants located in California. Subject to that understanding, PG&E is aware of two projects under construction in California using the Siemens Flex Plant design: the Lodi Energy Center and the El Segundo Power Redevelopment Project. In addition, the following three projects are under development in California and intend to use Siemens rapid response technology: the Blythe Energy Project Phase II, the Carlsbad Energy Center Project, and the Willow Pass Generating Station. These projects were identified based upon a review of publicly available permitting information from the California Energy Commission ("CEC"). Further information regarding these projects can be found on the CEC website.

   PG&E's answer to this question relied upon a review of public information from active projects on the CEC website. PG&E is aware of one additional project under development in California not listed above that has an active California Independent System Operator ("CAISO") queue position, intends to use a competing flexible technology but has not started the permitting process. However, PG&E's knowledge of this project stems from confidential market information submitted in the 2008 Long-Term Request for Offers ("LTRFO") Solicitation. IEP has not signed a Non-Disclosure Agreement with PG&E.

Therefore, PG&E cannot disclose in a non-confidential data response the name of this additional project.

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ATTACHMENT Q

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CONTROL ENGINEERING
To defend your production from outside attackers you must implement security at the device level.
Download Control Engineering's eGuide:
Practical Defense:
Protecting your Production from Cyber Crime
UE UNITED ELECTRIC CONTROLS

High-Efficiency Gas Turbines Add New Flexibility

Siemens' H-Class Gas Turbine, The Largest Machine Of Its Type In Production, Recently Broke The 60% Net Thermal Efficiency Barrier In Combined-Cycle (CC) Operation. Other Gas Turbine Makers With Efficient Machines Also Are Exploiting Design And Control Advances In CC Power Plant Applications—And In Evolving Hybrid CC Plants That Incorporate Renewable Energy.

Frank J. Bartos, PE

07/25/2011

First it was high power output and unprecedented thermal efficiency of new industrial gas turbines that drew the attention of prospective customers. Now the latest generation of these machines demonstrates remarkable operating flexibility under varying loads—in combined-cycle gas turbine (CCGT) power plants—thereby widening their application. Besides the gas turbine, a modern CCGT power plant comprises a steam turbine, generator, heat recovery steam generator, myriad subsystems, and control systems to coordinate them. Precise control of the gas turbine is key to optimal plant operation.

Combined-cycle power plants are well suited for fast-response reserve power to balance large grid load fluctuations due to the rising share of electricity generated from renewable power sources. Short-time weather changes affecting wind power and diurnal interruption of solar power cause load fluctuations that make it difficult to keep the grid in balance. CCGT plants are here to help.

Breaking the 60% thermal efficiency barrier has been the goal of gas turbine manufacturers for some time. Major suppliers, such as Alstom, GE, Mitsubishi Heavy Industries, and Siemens, offer turbines "designed for 60+% efficiency in CC operation." However, as far as it's known, Siemens' H-class SGT5-8000H machine was the first to set an independently verified record of 60.75% net thermal efficiency with 578 megawatt (MW) output at an actual CC power plant in May 2011 (see Ref. 1, online). The turbine went into commercial operation as part of the 8000H CC plant in late July 2011.

Efficiency milestone announcements by others included "gross efficiency," expected numbers, or similar qualifiers. Unofficially, other turbine makers are at or above the 60% efficiency mark, which is good for customers and the industry.

Operational flexibility

While even tenths of a percent efficiency improvement translate into energy cost savings at some plant operating mode, ability to operate flexibly at different loads—not necessarily peak efficiency—also becomes important.

Siemens has consistently demonstrated the 8000H gas turbine's flexibility for efficient use throughout base, intermediate, and peak-load ranges. Stable operation down to 100 MW has been shown in combined-cycle mode, which is under 20% of rated output—along with load ramp rates of up to 35 MW/min, explained Lothar Balling, head of Siemens Energy's GT Power Plant Solutions.

"The requirement to balance grid power fluctuations cannot be met by existing energy storage facilities and only to a very limited extent by today's nuclear or coal-fired power plants," Balling said. "However, CCGT plants with rapid cycling capability can meet the challenge."

Dr. Michael Suess, CEO of Siemens Energy Sector, added that, "Fast start-up and ramp-down times given for the 8000H turbine are verified and consistent." He noted a further option available with this new breed of gas turbines. Adding a second gas turbine to the unit allows future plants to reach 1,100-1,200 MW output. "This way, a CCGT plant can match the output of large-scale power plants using other energy sources," Suess stated.

As for the 60-Hz version H-class turbine, Siemens is confident about meeting the same efficiency numbers as the 50-Hz design. Scaled from the 50-Hz version and benefiting from experience gained during that lengthy development and validation, only limited work remains to prove out the 60-Hz model, according to Willibald Fischer, Siemens Energy's program director for 8000H turbines. Orders for eight 60-Hz machines are on hand (Ref. 2, online), with some units being assembled for delivery in 2012.

Alstom Power likewise emphasizes operational flexibility of its CC power plant technology, recognizing that customers more often need to operate their gas turbines at part load. "Power markets are changing with the introduction of intermittent renewable power technologies like wind and solar," said Mark Coxon, senior VP of Alstom's Gas business. "Combined-cycle power plants are expected to operate over a wide range of operating regimes from base-load to daily start-and-stop, and quickly bring the missing (intermittent) power to the grid."

Announced in early June 2011, Alstom's "next generation" KA26 combined-cycle power plant integrates flexibility, using the extensively upgraded GT26 (50 Hz) gas turbine. New KA26 is "designed to enable 61+% efficiency in CC operation" and provide more than 500 MW output, according to Alstom.

"High part-load efficiency, not just base-load efficiency, becomes increasingly important as well as ramp-up speed of the power output," continued Coxon. Part-load efficiency can often be even more important. He explained that efficiency of enhanced KA26 stays virtually constant down to 80% of full load, and it can operate down to 20% CC load.

This "parked mode" around 100 MW output provides a fast response standby to anticipate load ramp-up. "New KA26 can ramp up from low load to deliver more than 350 MW in less than 15 minutes. It can be started up in less than 30 minutes without a 'lifetime penalty' or the need for additional equipment," Coxon added.

GT26 gas turbine incorporates two technologies—sequential combustion, a design feature invented by Alstom, and multiple variable compressor guide vanes—to optimize the difficult combination of high efficiency plus low plant turn-down with low emissions. In addition,

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GT26 has two online switchable control modes with maintenance implications. Performance optimized mode uses higher turbine firing and exhaust temperatures to maximize power output, while lifetime optimized mode lowers firing/exhaust temperatures, allowing up to 30% longer turbine inspection intervals, according to Alstom. Only a small performance reduction is said to result with the latter mode.

Going for 1,700 C

Meanwhile in February 2011, Mitsubishi Heavy Industries Ltd. (MHI) started test operation of a J-series (M501J) gas turbine at the company's CC power plant for verification testing. Said to offer "the world's largest power generation capacity," the 60-Hz turbine has power output of 460 MW in combined-cycle operation. Under commercialization for more than two years, J-series gas turbine achieved gross thermal efficiency exceeding 60% and 1,600 C inlet temperature in test operations, according to MHI.

That temperature is 100 degrees higher than the company's previous G-series turbine, a workhorse machine with more than 700,000 cumulative operating hours. Looking ahead, industrial gas turbines with still higher inlet temperatures are under development at Mitsubishi. MHI is part of an ongoing Japanese national project with the objective to develop "core technologies" needed for a new turbine class capable of 1,700 C inlet temperature. New technologies derived from the project are being adopted in J-series machines, according to the company.

The objective of going to higher turbine inlet temperatures is clear. It allows thermal efficiency improvement, but it also subjects turbine components to higher thermal stresses and complicates material choices and overall design. Consequently, other major turbine makers design for lower inlet temperatures, generally under 1,500 C. First shipments of MHI's J-series turbine are expected in 2011 to a Japanese power company. Development of a 50-Hz gas turbine (M701J) is also underway, with first shipments slated for 2014, says the company.

Still higher efficiency?

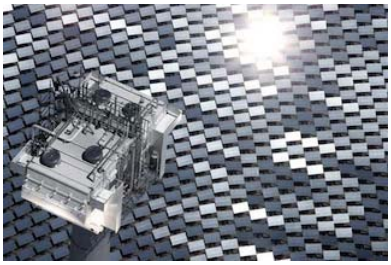
Gas turbine manufacturers will undoubtedly continue the quest for higher thermal efficiency, but it's a case of "low-hanging fruit already picked." Further gains will likely be smaller and require difficult material and design choices.

Siemens Energy's Fischer said, "We're getting close to efficiency ceilings, but some possibilities remain." Without revealing to competitors what steps might be taken, Fischer mentioned that more than 61.5% net efficiency is likely for Siemens turbines in the 2015 time frame.

As for the 1,700 C inlet temperature turbine project at Mitsubishi Heavy Industries, a 62% to 65% efficiency range in CC operation is an estimate. Larger gains can come from hybrid CC power plants (see below) because they change the efficiency equation. GE Energy's 50-Hz 9FB, another upgraded gas turbine with long service history, is featured in the trademarked FlexEfficiency 50 combined-cycle power plant recently announced by the company. GE puts the CCGT plant's "expected base-load efficiency at greater than 61%" and rated output at 510 MW. Part-load efficiency values are also said to be favorable, for example, 60% efficiency at 40% of rated load. Reportedly, FlexEfficiency can reach rated output in 1 hr from cold start (28 min from hot start) and will provide 50 MW/min ramp rate.

Current focus on gas turbines at GE Energy is on F-class machines, according to a company spokesman. Earlier, GE developed H-class turbines now running at CC power plants in the U.K., Japan, and the U.S. (see Ref. 3, online).

Gas + wind + solar synergy



Much has been said about applying CCGT power plants to balance and control electricity flow on the grid, filling in for intermittent power generated from renewable energy sources, such as wind and solar. However, CC can more than balance grid loads. Modern CCGT technology can provide the basis of various hybrid power plant designs that integrate renewable power, thereby further raising thermal efficiency of the overall plant.

Such a development was announced by GE in early June 2011 when its FlexEfficiency CCGT technology was selected by Turkish project developer MetCap Energy Investments for an integrated renewables combined-cycle (IRCC) power plant with wind and solar power to be built in Turkey. FlexEfficiency 50 will be used to integrate all elements of a CC plant plus 22 MW of GE Energy wind turbines and 50 MW of eSolar concentrated solar thermal tower technology.

Located in Karaman, Turkey, the IRCC plant, which GE claims to be the world's first, will be rated at 530 MW output and achieve 69% efficiency at site conditions, according to GE. Latest version of the 9FB turbine is at the core of the plant's CC section. A GE Mark VIe plant control system will integrate and control all the diverse plant elements. Commercial operation of the IRCC power plant is scheduled for 2015.

eSolar, an advanced concentrated solar thermal tower technology provider, will supply that part of the IRCC plant. GE will incorporate eSolar technology and software into its IRCC and stand-alone solar thermal power plants, under an investment and licensing agreement.

In simplest terms, eSolar's technology uses small, flat mirrors, sensors, and motion controls to accurately track the sun, concentrating solar heat to a tower-mounted receiver where water is turned into steam. In the IRCC plant, solar-generated steam feeds the steam turbine of the CC plant to generate extra power without using more natural gas.

Hybrid CCGT technology will require thorough site-specific evaluation for suitability and economic sense. However, further development of efficient gas turbines can stimulate growth of CC power plants, whether conventional or an evolving hybrid variety.

Frank J. Bartos, PE, is a Control Engineering *contributing content specialist. Reach him at braunbart(at)sbcglobal.net.*

www.alstom.com/power/fossil

www.esolar.com

www.ge.com/energy

www.mhi.co.jp/en

www.energy.siemens.com

Related Reading...

Ref. 1 - Siemens gas turbine breaks 60% efficiency barrier

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Ref. 3 – "Advancing technology: High-efficiency gas turbines"

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- Posted by Chris Vavra, *Control Engineering*, www.controleng.com

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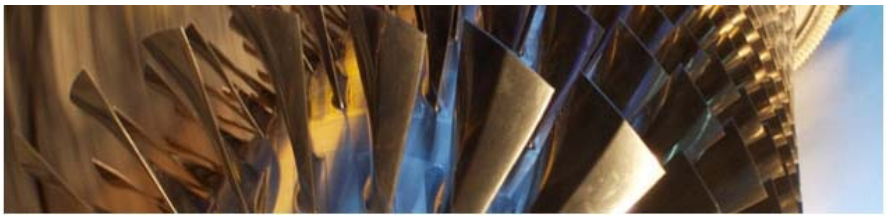
GT24 and GT26 gas turbines



Tackle unprecedented changes in the energy market with clean, high performance gas turbines from Alstom

Built to reduce cost and boost efficiency, the GT24 and GT26 gas turbines are excellent choices for 60 Hz and 50 Hz requirements.

Why choose Alstom's GT24 and GT26 gas turbines?

- clean, efficient, reliable and flexible power generation for your industry

The GT24 and GT26 gas turbines utilise the unique sequential combustion. Here's how they can help you:

- **Low costs** of electricity due to **high efficiency** close to 60% in combined-cycle operation
- **Superior plant operational flexibility**
- **Optimised to handle the wide range of fuel gas compositions**
- **Low emissions** over a wide load range
- **Long inspection intervals online selection between performance and lifetime optimised mode of operation to address changing market conditions**

Home / Power / Fossil / Gas power / Gas turbines / GT24 and GT26 gas turbines

ALSTOM

KA26 combined cycle power plant

Achieve highly competitive performance at both full -load and part-load operation with our gas powered KA26 combined cycle power plant

This advanced class gas power plant achieves high-base efficiency and flexibility for the 50 Hz market.

Why choose Alstom's KA26 combined cycle power plant?

- **outstanding performance**
- **genuine operational and fuel flexibility**
- **low emissions**, meeting the world's most stringent environmental rules and regulations

Benefit from the KA26's market-leading technology and utility:

Performance

- Improve plant net efficiency with **more than 59% capability**
- **Get high performance** that extends over a wide ambient range
- **Get outstanding operating efficiency** at **both part-load and low-load** operation modes
- **Power augmentation capability** (inlet cooling) with:
  o Choice of evaporative cooling, fogging and high fogging options
  o Significant power increase for a very low investment and maintenance cost

Operating flexibility

- Turndown to **40% combined cycle load and below**
- Combined cycle **start-up time in less than 30 minutes** from hot conditions
- **Lower minimum technical level of power plant load** for increased flexibility (within NOx emission limit)
- **Flexible maintenance concept: online selection between performance and lifetime optimised mode to address changing market conditions**

Low load operational capability (LLOC) down to 20% CCPP load

- **Reduce fuel consumption** during "parking" at low-load operation points during off-peak periods
- **Provide ancillary services when required** – the plant remains online and can be ramped up to full-load: **+340 MW in only 15 minutes**
- Avoid the risk of start failures

Fuel flexibility

- Easily **handle a wide range of natural gas compositions**, with increased content of hydrocarbons (C2+) and inert gases
- **No need for hardware exchange or fuel preheating** to handle varying gas qualities thanks to our superior Wobbe Index flexibility

Low emissions

- **Very low environmental impact** thanks to our unique, dry low NOx Environmental Burner (EV Burner)
- No de-rating
- **Low NOx emissions** at full and part load
- **Save money** – no catalyst needed with associated continuous operation and maintenance costs for the ammonia system
- **Improve efficiency** with no ammonia slippage to the environment from the catalyst

Success stories

From Spain, to Germany and Australia, our KA26 CCPP has achieved outstanding technical performance, functionality and reliability. **See related documents below**.

Home / Power / Fossil / Gas power / Gas power plants / Combined cycle power plants / KA26 combined cycle power plant

ATTACHMENT R

PACIFIC GAS AND ELECTRIC COMPANY
Oakley Generation Station
Application 12-03-026
Data Response

PG&E Data Request No.:	DRA_003-09		
PG&E File Name:	OakleyGeneratingStation_DR_DRA_003-Q9		
Request Date:	June 8, 2012	Requester DR No.:	003
Date Sent:	June 22, 2012	Requesting Party:	DRA
PG&E Witness:	Joe O'Flanagan / Marino Monardi / Jon Maring	Requester:	Yuliya Shmidt

QUESTION 9

a. Identify all changes to estimated capital costs and/or operations and maintenance costs between the original and amended PSA. For any cost changes, explain the basis for any increase, if any, and provide documents that support or refute the need to make such cost adjustments.

b. For PG&E's estimates based on the amended PSA:

   1. Provide an updated breakdown and explanation of all O&M expenses and capital costs, including any contingency and incentive payments.

      I. Explain why the Fixed O&M figures (WP 6-2) are different from the O&M Expense (WP 6-3).

      II. Explain all components of "Cap Adds RRQ" (WP 6-2) and why PG&E requests that for 2020-2023.

      III. Explain all components of "Manufacturing Deduction" (WP 6-3).

   2. Provide a comparison and breakdown of all O&M expenses, capital costs, and labor costs for PG&E's similar combined-cycle facilities.

   3. What is the cost for the two General Electric (GE) 7FA.05 gas turbines?

   4. Provide recent (within the last 4 years) market cost and trends for new combined-cycle facilities.

ANSWER 9

a. PG&E does not propose any changes to its capital or operations and maintenance estimates between the original and amended PSA.

b.

1. PG&E's 2016 O&M estimate and its initial capital cost estimate are included in Confidential Attachment 1 to Chapter 6 of its Initial Testimony. A more detailed breakdown of O&M expenses and initial capital cost estimate can be found in PG&E's response to the Energy Division's first data request, question 2, in the Chapter 8 Workpapers and Chapter 7 Workpapers, respectively.

   The O&M expense figures on line 2 of WP 6-3 are equal to line 8 of WP 6-2. Line 8 of WP 6-2 is the sum of Lines 2 (Fixed O&M) and Lines 3 through 5, which are Cap Add RRQ, Insurance, Uncollectibles and Franchise Requirements, respectively.

   The Cap Adds RRQ on line 4 of WP 6-2 includes capital additions that are expected to be required in years 2020-2023. This represents the revenue requirement of the amounts shown on line 43, page 8-1of the original Chapter 8 Workpapers.

   The "Manufacturing Deduction" is a tax deduction under Section 199 of the Internal Revenue Code. The deduction is computed as 9% of the federal taxable income that is derived from goods manufactured and produced in the United States including electric generation. The Manufacturers Deduction serves to reduce the federal income tax component of the initial revenue requirement.

2. Although PG&E's current combined-cycle facilities, Gateway and Colusa, have some similarities to the Oakley Project, they do not have the same capabilities of Oakley. The following table shows the Commission-adopted amounts for the initial capital costs and the first year O&M expense for Gateway and Colusa Generating Stations.

Millions of Dollars

Facility	Initial Capital Cost	First Year O&M
Gateway	$370	14.6
Colusa	$673	19.3

3. PG&E does not have this information. CCGS is responsible for the development and construction for the Oakley Project pursuant to the original and amended PSA. Therefore, procurement of the two GE 7FA.05 gas turbines is the responsibility of CCGS, not PG&E. The purchase price in the

Amended and Restated PSA is for the entire Oakley Project with no breakout prices for equipment. PG&E is not aware of the price of individual equipment or components.

4. PG&E does not have information regarding market trends for the costs of new combined cycle facilities. As noted above, CCGS is responsible for the development and construction of the Oakley Project, not PG&E. While Gateway and Colusa were brought online within the last four years, neither facility provides a good basis for market costs and trends. All the major equipment on Gateway was purchased around 2001 and in storage until PG&E purchased the plant from Mirant. Colusa was ultimately built by PG&E under a different contractual structure and arrangement, where PG&E assumed much more development and construction risk. As a result, this price is not a good comparison to the Oakley Project.

PACIFIC GAS AND ELECTRIC COMPANY
Oakley Generation Station
Application 12-03-026
Data Response

PG&E Data Request No.:	DRA_003-09		
PG&E File Name:	OakleyGeneratingStation_DR_DRA_003-Q9		
Request Date:	June 8, 2012	Requester DR No.:	003
Date Sent:	June 22, 2012	Requesting Party:	DRA
PG&E Witness:	Joe O'Flanagan / Marino Monardi / Jon Maring	Requester:	Yuliya Shmidt

QUESTION 9

a. Identify all changes to estimated capital costs and/or operations and maintenance costs between the original and amended PSA. For any cost changes, explain the basis for any increase, if any, and provide documents that support or refute the need to make such cost adjustments.

   3. What is the cost for the two General Electric (GE) 7FA.05 gas turbines?

ANSWER 9

   3. PG&E does not have this information. CCGS is responsible for the development and construction for the Oakley Project pursuant to the original and amended PSA. Therefore, procurement of the two GE 7FA.05 gas turbines is the responsibility of CCGS, not PG&E. The purchase price in the Amended and Restated PSA is for the entire Oakley Project with no breakout prices for equipment. PG&E is not aware of the price of individual equipment or components.

PACIFIC GAS AND ELECTRIC COMPANY
Oakley Generation Station
Application 12-03-026
Data Response

PG&E Data Request No.:	DRA_003-09		
PG&E File Name:	OakleyGeneratingStation_DR_DRA_003-Q9		
Request Date:	June 8, 2012	Requester DR No.:	003
Date Sent:	June 22, 2012	Requesting Party:	DRA
PG&E Witness:	Joe O'Flanagan / Marino Monardi / Jon Maring	Requester:	Yuliya Shmidt

QUESTION 9

b. For PG&E's estimates based on the amended PSA:

4. Provide recent (within the last 4 years) market cost and trends for new combined-cycle facilities.

ANSWER 9

b.

4. PG&E does not have information regarding market trends for the costs of new combined cycle facilities. As noted above, CCGS is responsible for the development and construction of the Oakley Project, not PG&E. While Gateway and Colusa were brought online within the last four years, neither facility provides a good basis for market costs and trends. All the major equipment on Gateway was purchased around 2001 and in storage until PG&E purchased the plant from Mirant. Colusa was ultimately built by PG&E under a different contractual structure and arrangement, where PG&E assumed much more development and construction risk. As a result, this price is not a good comparison to the Oakley Project.

ATTACHMENT S

PACIFIC GAS AND ELECTRIC COMPANY
Oakley Generation Station
Application 12-03-026
Data Response

PG&E Data Request No.:	DRA_004-05		
PG&E File Name:	OakleyGeneratingStation_DR_DRA_004-Q05		
Request Date:	June 28, 2012	Requester DR No.:	004
Date Sent:	July 6, 2012	Requesting Party:	Division of Ratepayer Advocates
PG&E Witness:	Jon Maring	Requester:	Yuliya Shmidt

QUESTION 5

Has PG&E monitored trends in the cost or technological capabilities of new, flexible combined cycle generation to provide operational flexibility since evaluating the results from the 2008 LTRFO?

a. If yes, explain what price trends PG&E has observed and state what technological advancements have been developed and/or implemented in new generation facilities since 2008 for flexible, combined cycle facilities that are not utilized in the Oakley Project.

b. If no, please explain why PG&E has not monitored cost and/or technological developments for new flexible, combined cycle facilities since the conclusion of its last LTRFO in 2008.

ANSWER 5

See responses to IEP Set 1, Question 13 and DRA Set 3, Question 9.

Because PG&E's primary business does not involve constructing conventional generation power plants, PG&E does not actively solicit price quotes to construct these types of facilities or monitor cost and/or technology developments. Individual PG&E employees may, as a result of their responsibilities, be aware of cost and technology developments for conventional generation facilities. PG&E may also consult industry materials or experts as needed to obtain this type of information. Moreover, as stated in prior data responses and Initial Testimony, the Amended and Restated PSA allows PG&E to acquire the facility at a fixed price. Fixed price offers are very different from general price trends that others may speculate upon. Furthermore, the Amended and Restated PSA was structured so that the Seller (CCGS) takes on most of the development and construction risks (e.g., inflation, financing and construction risks). For a more detailed explanation of this allocation of risk, see response to DRA Set 3, Question 1.

ATTACHMENT T

PACIFIC GAS AND ELECTRIC COMPANY
Oakley Generation Station
Application 12-03-026
Data Response

PG&E Data Request No.:	DRA_003-07		
PG&E File Name:	OakleyGeneratingStation_DR_DRA_003-Q7		
Request Date:	June 8, 2012	Requester DR No.:	003
Date Sent:	June 22, 2012	Requesting Party:	DRA
PG&E Witness:	Joe O'Flanagan	Requester:	Yuliya Shmidt

QUESTION 7

PG&E recognizes that the Settlement adopted in D.10-07-045 is not binding on the settling parties for the purposes of this application, but proposes that the Commission adopt in this proceeding a cost recovery and ratemaking mechanism that is identical to the cost recovery and ratemaking mechanism for the Oakley Project included in the Settlement (p.6-1). Please explain why PG&E considers this to be the most reasonable ratemaking and cost recovery treatment. Identify any other Utility Owned Generation projects approved by the Commission since 2000 and for each such project state whether it used identical ratemaking and cost recovery mechanisms as PG&E proposes for the Oakley project.

ANSWER 7

The ratemaking and cost recovery mechanism included in the Partial Settlement Agreement, which was originally proposed in Application ("A.") 09-09-021, and is being proposed by PG&E in this proceeding for the Oakley Project is reasonable because in its proposal, PG&E has agreed to: (1) reduce its initial capital cost estimate by $24.5 million; (2) cap the O&M costs and capital addition costs to the estimated costs used in the 2008 Long-Term Request for Offers ("LTRFO") evaluation process for a period of eight years; and (3) provide detailed plant availability and heat rate information to TURN, DRA and the Commission for not only the facilities at issue in this proceeding, but other PG&E owned facilities. With regard to the initial capital cost estimates, PG&E's proposal also includes a cost recovery band for costs above the initial estimates, which is a ratemaking mechanism previously approved by the Commission for utility-owned facilities. The ratemaking proposal for the Amended PSA and the Oakley Project is consistent with previous Commission decisions regarding utility-owned generating projects, which have approved initial capital costs and, in some instances, the use of a cost recovery band and cost sharing for costs above the initial capital cost estimates.

With regard to other ratemaking and cost recovery mechanisms approved for PG&E's other post-2000 utility-owned generation ("UOG") facilities, the Commission has approved the following:

- Gateway Generating Station (formerly Contra Costa 8) approved in D.06-06-035
- Colusa Generating Station and Humboldt Generating Station approved in D.06-11-048
- PG&E's Fuel Cell projects approved in D.10-04-028
- PG&E's Photovoltaic program approved in D.10-04-062

Each of these decisions describes in detail the unique and project specific ratemaking and cost recovery mechanism for these UOG facilities.

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ATTACHMENT U

[CONFIDENTIAL]

Introduction and Background

On April 1, 2008, Pacific Gas & Electric (PG&E) issued its 2008 All Source/Long-Term Request for Offers (LTRFO) for capacity and energy to satisfy the utility's projected incremental resource needs with new capacity that had to be on-line no later than 2015. The LTRFO sought approximately 800-1,200 MW of new generation to be located in (or with long-term firm delivery into) NP-15, PG&E's Northern California electricity market area.[1] Bidders could respond with offers for either or both of two types of contemplated transactions – a power purchase agreement (PPA) or a purchase and sale agreement (PSA). The PPA offers would entail the development of facilities where the developers would continue to own and operate the facilities and sell power to PG&E over the term of the contract. The PSA offers would entail the development and sale of a facility to PG&E upon the facility's commercial operation date; thus, PG&E would be the long-term owner of the power plant.

The California Public Utilities Commission (CPUC) has issued several decisions in the last several years that now require California's investor-owned utilities to retain an Independent Evaluator (IE) in All Source/long-term resource solicitations.[2] In September 2007, in compliance with these CPUC decisions, PG&E retained Sedway Consulting, Inc. (Sedway Consulting) as an IE to monitor PG&E's 2008 LTRFO solicitation, provide an independent evaluation of PG&E's process and the offers it may receive, and help the CPUC and PG&E's Procurement Review Group (PRG) and Cost Allocation Mechanism (CAM) participants by providing them with information and assessments to ensure that the solicitation was conducted fairly and that the best combination of offered products were acquired. This IE report provides an assessment of PG&E's LTRFO solicitation from the initial phase of the solicitation (i.e., development of the LTRFO documents) through the selection of final contracts.

The remainder of this report follows the template that was issued by the CPUC as part of R.06-02-013 (Attachment A: CPUC Independent Evaluator Template [Long Form]) to organize and structure IE reports regarding solicitations for long-term power supplies undertaken by California utilities. That template includes eight question/topic areas that are depicted in boxes in this report and Confidential Appendix B.

[1] Exceptions were made for Qualifying Facilities (QFs), which could be located in either NP-15 or the ZP-26 Central California market area.

[2] D.04-12-048 (Findings of Fact 94-95, Ordering Paragraph 28) and D.06-05-039 (Finding of Fact 20, Conclusion of Law 3, Ordering Paragraph 8).

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PACIFIC GAS AND ELECTRIC COMPANY

CONFIDENTIAL APPENDIX 1.2

2008 LTRFO SHORTLIST DATED OCTOBER 20, 2008

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Confidential Appendix 1.4
2008 All Source RFO Market Valuation
Evaluation Protocol

Introduction

This evaluation protocol specifies how the Market Valuation criterion will be evaluated. Market Valuation means how an Offer's cost compares to an Offer's benefits, from a market perspective within the context of California's Energy Action Plan II Loading Order ("EAP Loading Order"). An Offer's cost is reflected in the Offer's pricing. An Offer's benefits are the market value of the energy, capacity, and ancillary services offered. These costs and benefits may include: fixed and variable costs; transaction costs, such as market bid-ask spreads; location-specific value, as represented by locational price differentiation; and operating flexibility, as represented by option value. The risks and uncertainties associated with an Offer's costs and benefits will be considered as part of Market Valuation.

An important component of market valuation benefit is operating flexibility. PG&E uses option valuation models to quantify how operating flexibility contributes to market valuation. Included in Market Valuation are the costs attributed to greenhouse gas ("GHG") emissions associated with the Offer.

For purposes of this RFO, also included in Market Valuation are the impacts an Offer is anticipated to have on the electric transmission system. In evaluating an Offer, PG&E will consider the network upgrade costs as described in Section IX.D – System Impacts. PG&E will also consider congestion risk.

All anticipated significant relevant costs and benefits associated with either a Power Purchase Agreement (PPA) Offer or Offer Variation or a Purchase and Sale Agreement (PSA) Offer or Offer Variation are quantified, and the net present value of benefits minus costs is expressed in present value dollars per levelized kW of capacity per year

Details

It is anticipated that most of the Offers will be for gas-fired dispatchable generating units. Paragraphs 1 through 4 below apply to gas-fired dispatchable generating units. Paragraph 5 below applies to non-gas-fired dispatchable Offers. Paragraph 6 below applies to non-dispatchable Offers.

1. **Energy Benefits and Variable Costs:**
   a. *Asset Model:* Energy Gross Margin is energy benefits minus variable costs. For gas-fired dispatchable generating units, the present value of expected Energy Gross Margin is calculated using an option model. Essentially, ownership or rights to call on a gas-fired dispatchable generating unit convey a strip of call options on the spark spread. The precise value of the strip of spark spread call options depends on the detailed configuration of the

ATTACHMENT V

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BEFORE THE
PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company (U 39-E) for Approval of 2008 Long-Term Request for Offer Results and for Adoption of Cost Recovery and Ratemaking Mechanisms.	Application 09-09-021 (Filed September 30, 2009)

PACIFIC GAS AND ELECTRIC COMPANY'S (U 39-E) PETITION FOR MODIFICATION OF DECISION 10-07-045

(PUBLIC VERSION OF DECLARATION OF MARINO MONARDI IN SUPPORT OF PACIFIC GAS AND ELECTRIC COMPANY'S PETITION FOR MODIFICATION OF DECISION 10-07-045 ATTACHED)

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PACIFIC GAS AND ELECTRIC COMPANY

Date: August 23, 2010

BEFORE THE
PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company (U 39-E) for Approval of 2008 Long-Term Request for Offer Results and for Adoption of Cost Recovery and Ratemaking Mechanisms.	Application 09-09-021 (Filed September 30, 2009)

PACIFIC GAS AND ELECTRIC COMPANY'S (U 39-E)
PETITION FOR MODIFICATION OF DECISION 10-07-045

(PUBLIC VERSION OF DECLARATION OF MARINO MONARDI IN SUPPORT OF PACIFIC GAS AND ELECTRIC COMPANY'S PETITION FOR MODIFICATION OF DECISION 10-07-045 ATTACHED)

Pacific Gas and Electric Company ("PG&E") files this petition for modification of Decision ("D.") 10-07-045 (the "LTRFO Decision") as a result of changed circumstances that support modifying the decision to provide for the approval of the Oakley Generating Station ("Oakley Project"). As the Commission is aware, the Oakley Project was one of the winning proposals in PG&E's 2008 Long-Term Request For Offers ("LTRFO") and can provide a unique combination of attributes to serve the energy needs of Northern California. In particular, the Oakley Project represents the latest evolution of cost-effective resources specifically designed to facilitate the integration of renewable resources. The Oakley Project has an extremely low heat rate and excellent operating flexibility. Given California's aggressive Renewable Portfolio Standard ("RPS"), the Oakley Project is exactly the kind of resource needed in PG&E's service area to integrate renewables, while also will providing one of the best heat rates and lowest emissions in California.

During the Commissioners' comments on the LTRFO Decision, several Commissioners expressed support for the Oakley Project and indicated that, if the date for the Oakley Project had

been later, the project may have been approved. PG&E and Contra Costa Generating Station, LLC ("Contra Costa LLC"), the developer of the Oakley Project, took these comments to heart and re-negotiated the Oakley Purchase and Sale Agreement ("PSA") to extend the guaranteed commercial availability date from June 1, 2014 to June 1, 2016. Given this change in circumstances, and the substantial benefits of the Oakley Project for California ratepayers, PG&E requests that the Commission modify the LTRFO Decision.

I. FACTUAL BACKGROUND AND CHANGED CIRCUMSTANCES

The Oakley Project and Mirant Marsh Landing Project were two of the three winning proposals in PG&E's 2008 LTRFO.[1] These projects were discussed at length at the Commission's July 29th meeting, at which the LTRFO Decision was adopted. During their oral comments, several Commissioners recognized the high value of the Oakley Project. For example, Commission President Peevey referred to the Oakley Project as "exceptional" and possessing "attributes that would provide benefits for California ratepayers." Commissioner Ryan noted that "[t]he Oakley Project would deploy state-of-the-art technologies and could provide needed operational flexibility that's exactly what we need for renewable integration." Despite the recognized benefits of the Oakley Project, the Commission ultimately decided not to approve the Oakley PSA.

However, during the Commissioners' discussion of the 2008 LTRFO application, several Commissioners indicated they could potentially support the Oakley Project if the contract was modified to allow for an availability date later than June 1, 2014. Commission President Peevey remarked that the Oakley Project may have been approved with a later availability date and Commissioner Bohn remarked "[w]hat I would have liked to have seen, for example, is to have

[1] The third winning offer was the Mariposa Generation Station, which was approved by the Commission in D.09-10-017.

the opportunity to consider approving the Oakley Project, with its newer technology and superior flexibility but with a later date for construction and operation so as to better match the needs of PG&E and its ratepayers with the estimated turn in the economy and increase in demand." Commissioner Bohn re-iterated this point in his written concurrence to the LTRFO Decision.

PG&E and Contra Costa LLC responded the Commissioners' comments and immediately began to negotiate a modification to the PSA to extend the guaranteed commercial availability date from June 1, 2014 to June 1, 2016. As a result of these discussions, PG&E and Contra Costa LLC have agreed to an amendment to the PSA ("Amendment"), which is attached as Exhibit A to the confidential version of the *Declaration of Marino Monardi in Support of PG&E's Petition to Modify*. The Amendment changes the guaranteed commercial availability date for the Oakley Project from June 1, 2014 to June 1, 2016. This allows for the development of this beneficial project and ensures that it will not "fall off the face of California," consistent with the Commissioners' comments at the July 29th Commission meeting.[2]

Under Commission Rule 16.4(b), a Commission decision can be modified when there are changed facts or circumstances. Here, the modification of the Oakley Project guaranteed commercial availability date in the Amendment constitutes a significant change in circumstances.

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[2] The Amendment includes on additional contractual change resulting from the extension of the guaranteed commercial availability. The additional change is described in paragraph 4 of the confidential version of the Monardi Declaration.

II. REQUEST FOR MODIFICATION

PG&E requests that, given the extension of the PSA guaranteed commercial availability date, the Commission approve the Oakley Project PSA and the Amendment. Pursuant to Commission Rule 16.4(b), Appendix A to this motion includes specific wording to carry out the requested modifications to the decision.

Respectfully submitted,

CHARLES R. MIDDLEKAUFF
MARY A. GANDESBERY

By: _____/s/_____
CHARLES R. MIDDLEKAUFF

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Attorneys for
PACIFIC GAS AND ELECTRIC COMPANY

Dated: August 23, 2010

ATTACHMENT W

PACIFIC GAS AND ELECTRIC COMPANY
Oakley Generation Station
Application 12-03-026
Data Response

PG&E Data Request No.:	DRA_002-06		
PG&E File Name:	OakleyGeneratingStation_DR_DRA_002-Q6		
Request Date:	June 5, 2012	Requester DR No.:	002
Date Sent:	June 12, 2012	Requesting Party:	DRA
PG&E Witness:	Jon Maring / Marino Monardi	Requester:	Yuliya Shmidt

QUESTION 6

Explain the basis for PG&E's estimated interconnection facilities costs shown in the confidential material on page 3-9, including providing a breakdown of the costs in spreadsheet form and provide all source documents. State and explain the reason for the differences between the estimates used for the Oakley project in the 2008 LTRFO economic evaluations and the final transmission costs (p. 3-9).

ANSWER 6

The attachments to this response contain Confidential Protected Material, protected under D.06-06-066 Appendix 1 and General Order 66-C, as set forth in the accompanying declaration/matrix.

The source of PG&E's estimated interconnection facilities and transmission network upgrade costs shown in the confidential attachment entitled: OakleyGeneratingStation_DR_DRA_002-Q06-Atch01, on page 3-9 is the Large Generator Interconnection Agreement for the Oakley Project. The Oakley Project was studied within the CAISO's Transition Cluster. Both the Phase I and Phase II CAISO Interconnection studies have been completed, and an LGIA was executed in February 2012. There are generally two categories of up-front costs identified in LGIAs that a new generation resource must fund to deliver power to the CAISO grid: interconnection facilities costs and network upgrade costs. These costs are determined during the CAISO interconnection study process and final costs are memorialized in each generator's LGIA.

Interconnection facilities costs capture any sole use facilities that must be modified, added or upgraded in order to physically and electrically interconnect the Generating Facility to the Participating Transmission Owner's ("TO") system.[1] Final Interconnection

[1] See Oakley LGIA, section 1 for more specific definitions of Interconnection Facilities and Participating TO's Interconnection Facilities.

Facilities costs for the Oakley Project are identified in Appendix A to the Oakley LGIA (page 75).

Network upgrade costs (Reliability and Delivery) capture and additions, modifications and upgrades to the Participating TO's system beyond the point of interconnection that are needed to relieve constraints on the CAISO Controlled Grid and to remedy short circuit or stability problems.[2] Final Network Upgrade costs for the Oakley Project are identified in Appendix G to the Oakley LGIA (page 88-89).

At the time the 2008 LTRFO offers were evaluated, the CAISO had not completed a Phase I or Phase II cluster studies for the Oakley Project. PG&E used the 2008 Transmission Ranking Cost Report to evaluate offers submitted in that solicitation.[3] The evaluation can be seen in the attached workpapers entitled: OakleyGeneratingStation_DR_DRA_002-Q06-Atch02.

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[2] See Oakley LGIA, section 1 for more specific definitions of Network Upgrades, Participating TO's Delivery Network Upgrades and Participating TO's Reliability Network Upgrades.

[3] See the 2008 Transmission Ranking Cost Report Of Pacific Gas and Electric Company here: http://www.pge.com/includes/docs/pdfs/b2b/energysupply/wholesaleelectricsuppliersolicitation/renewableportfoliostdsori-ii_other-doc_pge_20070907-01.pdf

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ATTACHMENT X

PACIFIC GAS AND ELECTRIC COMPANY
Oakley Generating Station
Application 12-03-026
Data Response

PG&E Data Request No.:	CEB_001-08		
PG&E File Name:	OakleyGeneratingStation_DR_CEB_001-Q08		
Request Date:	May 17, 2012	Requester DR No.:	001
Date Sent:	May 25, 2012	Requesting Party:	Communities for a Better Environment
PG&E Witness:	Jon Maring	Requester:	Shana Lazerow

QUESTION 8

The Application states that "[i]n order to accomplish [the completion of construction milestones within the envisioned timeframe], commitments for major equipment and materials must be made by the Oakley Project to mitigate potential inflation risk. CCGS has indicated that they will be unable to do so until a final and non-appealable Commission approval is granted."[1] Please identify each piece of major equipment and materials CCGS is unable to acquire, and explain all efforts PG&E and CCGS have made to acquire those materials. Please provide all correspondence and documents supporting the contention that materials and equipment are unavailable until Commission approval of the PSA.

ANSWER 8

PG&E objects to this request as overbroad and burdensome to the extent that it seeks "all correspondence and documents" regarding the timing and purchase of major equipment and materials for the Oakley Project. Subject to this objection, PG&E understands that Contra Costa Generating Station LLC ("CCGS") has indicated that it will be unable to make commitments for major equipment and materials until after the Commission has issued a decision regarding PG&E's application for approval of the Amended PSA. The major equipment includes the HRSGs, main power transformers, air cooled condenser, and the boiler feed pumps. Although PG&E is not directly involved, it is PG&E's understanding that limited procurement activities have taken place on this equipment.

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1 A.12-03-026 at 21-22 (emphasis added).

ATTACHMENT Y

PACIFIC GAS AND ELECTRIC COMPANY
Oakley Generation Station
Application 12-03-026
Data Response

PG&E Data Request No.:	DRA_002-01		
PG&E File Name:	OakleyGeneratingStation_DR_DRA_002-Q1		
Request Date:	June 5, 2012	Requester DR No.:	002
Date Sent:	June 12, 2012	Requesting Party:	DRA
PG&E Witness:	Jon Maring	Requester:	Yuliya Shmidt

QUESTION 1

Are the General Electric (GE) 7FA.05 gas turbines that will be used at the Oakley facility at use in any other facility? If yes, identify the each facility, the owner or operator, and the year when such facility became operational. (p.1-1, p.4-1)

ANSWER 1

To PG&E's knowledge the GE 7FA.05 combustion turbines are not in use at any facility at this time.

ATTACHMENT Z

This response contain Confidential Protected Material, protected under D.06-06-066 Appendix 1 and PUC Section 583

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 9

RATEMAKING PROPOSAL, REVENUE REQUIREMENT AND COST RECOVERY

Revision Due to Delay in Closing

In developing its initial capital cost estimate, PG&E assumed a closing date of June 1, 2014. Any delay in the closing date may result in an increase in PG&E's costs for inflation, project oversight, and additional capitalized overheads. In the event of a delay in closing, PG&E may request an increase in the capital cost for these increased costs. Under most circumstances, a delay in closing will result in liquidated damages being paid by the seller. Any liquidated damages received by PG&E will be credited against the actual project costs.

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ATTACHMENT AA

PACIFIC GAS AND ELECTRIC COMPANY
Oakley Generation Station
Application 12-03-026
Data Response

PG&E Data Request No.:	DRA_004-11		
PG&E File Name:	OakleyGeneratingStation_DR_DRA_004-Q11		
Request Date:	June 28, 2012	Requester DR No.:	004
Date Sent:	July 3, 2012	Requesting Party:	Division of Ratepayer Advocates
PG&E Witness:	Joe O'Flanagan	Requester:	Yuliya Shmidt

QUESTION 11

Table 6-1 of PG&E's Testimony only shows the proposed revenue requirement for the first eight years of the Oakley Project's operation; please provide the total cost for the service life of the facility. Please include a breakdown of the costs by major line item.

ANSWER 11

See Attachment DRA004 Q11 for a 30 year forecast of the revenue requirement for the Oakley Project.

Oakley Generating Station
30 Year Revenue Requirement Forecast
(thousands of dollars)

Line No.	Description	1 2016	2 2017	3 2018	4 2019	5 2020	6 2021	7 2022	8 2023	9 2024	10 2025
1	Operating Revenue:	222,281	206,641	202,013	194,900	188,269	181,872	175,701	169,739	164,054	158,410
	Operating Expenses:										
2	Fuel	0	0	0	0	0	0	0	0	0	0
3	Fixed O&M	20,852	20,852	20,852	20,852	20,852	20,852	20,852	20,852	20,852	20,852
4	Cap Adds RRQ	0	0	0	0	14	28	42	55	55	55
5	Insurance	1,087	1,087	1,087	1,087	1,087	1,087	1,087	1,087	1,087	1,087
6	Uncollectibles	574	533	521	503	486	469	453	438	423	409
7	Franchise Requirements	1,678	1,560	1,525	1,472	1,422	1,373	1,327	1,282	1,239	1,196
8	Subtotal Expenses	24,191	24,033	23,986	23,914	23,861	23,810	23,761	23,714	23,657	23,599
	Taxes:										
9	Property	13,295	12,845	12,394	11,943	11,493	11,042	10,591	10,140	9,690	9,239
10	State Corporation Franchise	9,958	5,396	5,544	5,335	5,163	5,007	4,867	4,741	4,639	4,540
11	Federal Income	36,896	30,607	31,023	29,151	27,536	25,980	24,488	23,053	21,809	20,590
12	Subtotal Taxes	60,150	48,848	48,961	46,429	44,192	42,029	39,946	37,935	36,138	34,369
13	Depreciation	38,124	38,124	38,124	38,124	38,124	38,124	38,124	38,124	38,124	38,124
14	Decommissioning Expense	785	785	785	785	785	785	785	785	785	785
15	Total Operating Expenses	123,250	111,789	111,856	109,252	106,962	104,748	102,616	100,559	98,703	96,878
16	Net for Return	99,030	94,852	90,158	85,648	81,307	77,123	73,085	69,180	65,351	61,532
17	Weighted Average Rate Base	1,126,032	1,078,518	1,025,148	973,863	924,509	876,937	831,016	786,621	743,078	699,656
18	**Rate of Return:**	8.79%	8.79%	8.79%	8.79%	8.79%	8.79%	8.79%	8.79%	8.79%	8.79%

Oakley Generating Station
30 Year Revenue Requirement Forecast
(thousands of dollars)

Line No.	Description	11 2026	12 2027	13 2028	14 2029	15 2030	16 2031	17 2032	18 2033	19 2034	20 2035
1	Operating Revenue:	157,711	152,745	147,802	142,879	137,978	133,185	128,330	123,499	118,693	113,912
	Operating Expenses:										
2	Fuel	0	0	0	0	0	0	0	0	0	0
3	Fixed O&M	12,610	13,039	13,484	13,945	14,422	15,000	15,513	16,045	16,596	17,167
4	Cap Adds RRQ	13,118	13,354	13,594	13,838	14,087	14,341	14,599	14,862	15,130	15,402
5	Insurance	1,087	1,087	1,087	1,087	1,087	1,087	1,087	1,087	1,087	1,087
6	Uncollectibles	407	394	381	369	356	344	331	319	306	294
7	Franchise Requirements	1,191	1,153	1,116	1,079	1,042	1,006	969	932	896	860
8	Subtotal Expenses	28,412	29,027	29,662	30,317	30,994	31,777	32,499	33,245	34,015	34,810
	Taxes:										
9	Property	8,788	8,338	7,887	7,436	6,986	6,535	6,084	5,634	5,183	4,732
10	State Corporation Franchise	4,446	4,347	4,249	4,150	4,052	3,954	3,855	3,757	3,658	3,560
11	Federal Income	19,389	18,169	16,951	15,733	14,516	13,298	12,081	10,863	9,646	8,429
12	Subtotal Taxes	32,624	30,854	29,087	27,320	25,553	23,787	22,020	20,254	18,487	16,721
13	Depreciation	38,124	38,124	38,124	38,124	38,124	38,124	38,124	38,124	38,124	38,124
14	Decommissioning Expense	785	785	785	785	785	785	785	785	785	785
15	Total Operating Expenses	99,945	98,790	97,658	96,547	95,456	94,473	93,429	92,408	91,411	90,440
16	Net for Return	57,766	53,955	50,143	46,332	42,521	38,712	34,901	31,091	27,282	23,472
17	Weighted Average Rate Base	656,836	613,497	570,160	526,826	483,494	440,176	396,850	353,527	310,207	266,890
18	**Rate of Return:**	8.79%	8.79%	8.79%	8.79%	8.79%	8.79%	8.79%	8.79%	8.79%	8.79%

Oakley Generating Station
30 Year Revenue Requirement Forecast
(thousands of dollars)

Line No.	Description	21 2036	22 2037	23 2038	24 2039	25 2040	26 2041	27 2042	28 2043	29 2044	30 2045
1	Operating Revenue:	108,276	103,968	101,594	99,163	96,766	94,295	91,959	89,655	87,385	84,939
	Operating Expenses:										
2	Fuel	0	0	0	0	0	0	0	0	0	0
3	Fixed O&M	17,665	18,275	18,908	19,563	20,242	20,843	21,569	22,322	23,102	23,911
4	Cap Adds RRQ	15,680	15,962	16,250	16,543	16,842	17,146	17,455	17,770	18,091	18,418
5	Insurance	1,087	1,087	1,087	1,087	1,087	1,087	1,087	1,087	1,087	1,087
6	Uncollectibles	279	268	262	256	250	243	237	231	226	219
7	Franchise Requirements	818	785	767	749	731	712	694	677	660	641
8	Subtotal Expenses	35,528	36,378	37,274	38,198	39,151	40,030	41,043	42,087	43,165	44,276
	Taxes:										
9	Property	4,282	3,831	3,380	2,929	2,479	2,028	1,577	1,127	676	225
10	State Corporation Franchise	3,382	3,288	3,349	3,403	3,458	3,512	3,567	3,621	3,676	3,588
11	Federal Income	6,121	4,141	3,498	2,779	2,064	1,348	634	(81)	(796)	(1,578)
12	Subtotal Taxes	13,784	11,259	10,227	9,112	8,001	6,889	5,778	4,667	3,556	2,236
13	Depreciation	38,124	38,124	38,124	38,124	38,124	38,124	38,124	38,124	38,124	38,124
14	Decommissioning Expense	785	785	785	785	785	785	785	785	785	785
15	Total Operating Expenses	88,222	86,546	86,410	86,219	86,060	85,828	85,730	85,663	85,631	85,421
16	Net for Return	20,054	17,422	15,183	12,944	10,706	8,467	6,229	3,992	1,754	(482)
17	Weighted Average Rate Base	228,026	198,102	172,642	147,186	121,734	96,272	70,827	45,386	19,950	(5,483)
18	**Rate of Return:**	8.79%	8.79%	8.79%	8.79%	8.79%	8.79%	8.79%	8.79%	8.79%	8.79%

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ATTACHMENT BB

PACIFIC GAS AND ELECTRIC COMPANY
Oakley Generation Station
Application 12-03-026
Data Response

PG&E Data Request No.:	DRA_002-Q13		
PG&E File Name:	OakleyGeneratingStation_DR_DRA_002-Q13		
Request Date:	June 5, 2012	Requester DR No.:	002
Date Sent:	June 13, 2012	Requesting Party:	DRA
PG&E Witness:	Marino Monardi	Requester:	Yuliya Shmidt

QUESTION 13

Is it possible, under the Amended PSA, that the Oakley facility will achieve commercial operations and sell power in the CAISO market (e.g., as a merchant generator) prior to PG&E's purchasing of the facility? If so, please explain the circumstances under which this might occur and the estimated total hours of operations, number of starts/stops, and identify the entity or corporation that will be responsible for operating and maintaining the plant prior to its sale to PG&E.

ANSWER 13

No, under the Amended and Restated PSA, CCGS cannot sell power into the CAISO market as a merchant generator upon reaching commercial operation.