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DOCKET
07-AFC-6
DATE DEC 08 2011
RECD. DEC 08 2011

STATE OF CALIFORNIA
State Energy Resources
Conservation and Development Commission

In the Matter of:	)	DOCKET NO: 07-AFC-6
CARLSBAD ENERGY CENTER PROJECT	)	CENTER FOR BIOLOGICAL DIVERSITY'S NOTICE OF DOCUMENTS THAT MAY BE USED DURING CROSS EXAMINATION

The Center for Biological Diversity ("Center") hereby gives notice that during the December 12th, 2011 evidentiary hearing that the Center may introduce the following documents or excerpts thereof into the evidentiary record during cross-examination:

Attachment A:	CPUC Final Report on the Audit of the Encina Power Plant, December 10, 2010.
Attachment B:	CAISO 2009 RMR/Black Start/Dual Fuel Contract Status
Attachment C:	CAISO 2008 RMR/Black Start/Dual Fuel Contract Status
Attachment D:	CAISO Letter to Mr. Randy Hickok re: RMR status terminated, October 15, 2010
Attachment E:	SCE Submission of Contracts for Procurement of Renewable Energy Resulting from Renewables Standard Contracts Program, January 31, 2011
Attachment F:	CAISO Summary of Preliminary Results of 33% Renewable Integration Study – 2010 CPUC LTPP Docket No. R.10-05-006, May 20, 2011.
Attachment G:	February 8, 2011 Renewable Energy World article "Solar PV Becoming Cheaper than Gas in California.

In addition, the Center may introduce "Renewable Power in California: Status and Issues" California Energy Commission, Pub # CEC-150-2011-002-LCF, posted December 6, 2011 found at http://www.energy.ca.gov/2011_energypolicy/documents/index.html. Due to its availability on the web and size, the Center is not attaching it.[1]

The Center provides this notice out of abundance of caution, because the Committee cautioned that "the presentation of previously undisclosed evidence during the hearings is disruptive to the process and will be avoided wherever feasible." (Committee Order) Since

[1] The Center previously served Attachments A – G on June 8, 2011 as part of Center for Biological Diversity's Response in Support of City of Carlsbad's Motion to Take Official Notice and the Center's Motion to Take Official Notice And Re-Open The Evidentiary Record.

these documents may be used in cross-examination, the Center serves this notice by the reply testimony deadline. The Center is not sponsoring any reply testimony.

DATED: December 8, 2011

_____

William B. Rostov
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APPLICATION FOR CERTIFICATION FOR THE *CARLSBAD ENERGY CENTER PROJECT*

Docket No. 07-AFC-6
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(Revised 11/29/2011)

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DECLARATION OF SERVICE

I, John W. Wall, declare that on, December 8, 2011, I served and filed copies of the attached CENTER FOR BIOLOGICAL DIVERSITY'S NOTICE OF DOCUMENTS THAT MAY BE USED DURING CROSS EXAMINATION dated December 8, 2011. The original document, filed with the Docket Unit or the Chief Counsel, as required by the applicable regulation, is accompanied by a copy of the most recent Proof of Service list, located on the web page for this project at: **[www.energy.ca.gov/sitingcases/carlsbad/ index.html]**.

The document has been sent to the other parties in this proceeding (as shown on the Proof of Service list) and to the Commission's Docket Unit or Chief Counsel, as appropriate, in the following manner:

(***Check all that Apply***)

For service to all other parties:

_X_ Served electronically to all e-mail addresses on the Proof of Service list;

____ Served by delivering on this date, either personally, or for mailing with the U.S. Postal Service with first-class postage thereon fully prepaid, to the name and address of the person served, for mailing that same day in the ordinary course of business; that the envelope was sealed and placed for collection and mailing on that date to those addresses marked "hard copy required."

AND

For filing with the Docket Unit at the Energy Commission:

_X_ by sending an original paper copy and one electronic copy, mailed with the U.S. Postal Service with first class postage thereon fully prepaid and e-mailed respectively, to the address below (preferred method); ***OR***

____ by depositing an original and 12 paper copies in the mail with the U.S. Postal Service with first class postage thereon fully prepaid, as follows:

CALIFORNIA ENERGY COMMISSION – DOCKET UNIT
Attn: Docket No. 07-AFC-6
1516 Ninth Street, MS-4
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docket@energy.state.ca.us

OR, if filing a Petition for Reconsideration of Decision or Order pursuant to Title 20, § 1720:

____ Served by delivering on this date one electronic copy by e-mail, and an original paper copy to the Chief Counsel at the following address, either personally, or for mailing with the U.S. Postal Service with first class postage thereon fully prepaid:

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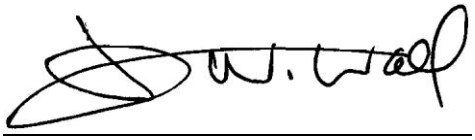
I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct, that I am employed in the county where this mailing occurred, and that I am over the age of 18 years and not a party to the proceeding.



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ATTACHMENT A

DOCKET NO: 07-AFC-6

CENTER FOR BIOLOGICAL DIVERSITY'S NOTICE OF DOCUMENTS THAT MAY BE USED DURING CROSS EXAMINATION

FINAL REPORT ON THE AUDIT OF THE ENCINA POWER PLANT

CONDUCTED UNDER GENERAL ORDER 167
TO DETERMINE COMPLIANCE WITH
OPERATION, MAINTENANCE, AND LOGBOOK STANDARDS

ELECTRIC GENERATION PERFORMANCE BRANCH
CONSUMER PROTECTION AND SAFETY DIVISION
CALIFORNIA PUBLIC UTILITIES COMMISSION
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December 10, 2010

Richard W. Clark, Director
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438181

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EXECUTIVE SUMMARY

This is the Final Report on the August 2008 audit of the Encina Power Plant ("Encina" or "the plant") prepared by the Commission's Consumer Protection and Safety Division (CPSD). CPSD audited the plant for compliance with the California Public Utilities Commission's ("CPUC's" or "Commission's") General Order 167, which includes Operation, Maintenance, and Logbook Standards for power plants.

In June 2008, CPSD notified Encina of the audit and requested pertinent documents. CPSD visited the plant site in August 2008 in order to observe plant operations, inspect equipment, review documents, and interview plant staff. From these activities, CPSD evaluated whether the plant needed improvements in operation or maintenance policies and whether the plant's programs and procedures met various Operation, Maintenance, and Logbook Standards.

CPSD found 16 violations[1] of Operation and Maintenance Standards. In September 2009, CPSD sent Encina a Preliminary Audit Report which discussed all 16 violations and requested the plant to submit a Corrective Action Plan (CAP). In October 2009, the plant submitted a CAP to address CPSD's concerns on the violations. In March 2010, CPSD held a teleconference with Encina to discuss the plant's CAP and requested the plant to submit more supporting documents. In April 2010, the plant submitted supplemental data to address CPSD's outstanding concerns on the violations. CPSD held a meet-and-confer meeting with Encina on June 22, 2010 to resolve five remaining violations. CPSD now issues this Final Audit Report.

[1] The term "violation" as used in CPSD's Final Audit Report refers to conditions or events where auditors determined that the facility failed to meet G.O. 167 standards. Identification of conditions or events as "violations" in this Final Audit Report does not constitute a formal determination of a G.O. 167 violation by the CPUC. A definitive finding of a G.O. 167 violation requires a formal Commission enforcement proceeding.

INTRODUCTION

In August 2008, a team from the Consumer Protection and Safety Division (CPSD) of the California Public Utilities Commission ("CPUC" or "Commission") audited the Encina Power Plant ("Encina" or "the plant") to determine whether the plant was in compliance with General Order (GO) 167, which includes Operation, Maintenance, and Logbook Standards for power plants.

The team first notified Encina of the audit on June 24, 2008 and requested pertinent documents. The team consisted of Ben Brinkman, Alan Shinkman, and Rick Tse. During the site visit from August 18 to 22, 2008, the team observed plant operations, inspected equipment, reviewed documents, and interviewed plant staff. The team found 16 violations of Operation and Maintenance Standards.

In September 2009, CPSD sent Encina a Preliminary Audit Report which identified the 16 violations and asked the plant to submit a Corrective Action Plan (CAP). In October 2009, the plant submitted a CAP to address CPSD's concerns on the violations. In March 2010, CPSD held a teleconference with Encina to discuss the plant's CAP and asked the plant to submit more supporting documents. In April 2010, the plant submitted additional documents to address CPSD's outstanding concerns. CPSD subsequently held a meet-and-confer meeting with Encina on June 22, 2010 to resolve five remaining violations. The violations and their final outcome and follow-up are detailed in Section 2 and summarized below:[2]

Finding 2.1 Encina failed to inspect and monitor flow-assisted corrosion in high-energy pipes and components. Over time, corrosion wears down pipe walls, particularly at elbows, bends and flow restrictions. If high-energy pipes rupture, they will release high pressure steam and potentially damage equipment, and injure or kill workers. In response, the plant stated that it has conducted periodic spot inspections on both Units 4 and 5 to monitor flow-assisted corrosion. Spot inspections, however, do not qualify as full inspections. The plant cannot fully address the risks of corrosion without a full inspection. Although the plant has conducted more spot inspections in April 2010, the plant should do a full inspection as soon as possible and to develop a formal inspection program. The plant stated that it has allocated more funds toward FAC inspection in next year's budget. The plant will also develop a Piping Assessment Program pursuant to NRG's corporate directive. The program will identify and establish inspection method, location, and frequency. CPSD will inspect Encina and request additional data to determine if the program addresses the risks of high-energy pipe corrosion.

[2] Unless specified otherwise, CPSD auditors made these findings based on plant conditions at the time of the site visit, and information obtained pursuant to data requests. Actual plant conditions may have changed since the time of the site visit.

Finding 2.2 Encina delayed repairs on Unit 4's high pressure steam turbine, through which high pressure and temperature steam flows. This steam inflicts serious wear and tear on components along its path, particularly on stator vanes and rotating blades. Over time, its components corrode, erode, and undergo metal fatigue and creep. If turbine blades crack, fail, and fly through the turbine, they can cause serious damage and shut down the plant for many months. In response, the plant explained that it deferred the repairs because the recommendation to do so was based on old operating characteristics. Since the recommendation, the number of operating hours and starts has decreased significantly. The steam turbine also runs mostly at low loads and subject to lower pressure and temperature steam. The plant, therefore, extended the repair interval. Nonetheless in February 2010, the plant overhauled Unit 4's HP steam turbine. No further corrective action is required.

Finding 2.3 The plant failed to evaluate or establish a schedule to complete safety improvements that would reduce the plant's exposure to fires. A fire can injure or kill workers and damage equipment that may shut down the plant for many months. In response, the plant completed several safety recommendations to reduce fire risks. The plant also declined several other recommendations, but provided reasonable justification for its decision. See Finding 2.3 in Section 2 for details.

Finding 2.4 The plant's Emergency Response Plan (ERP) lacks information on how to respond to earthquakes and wildfires, lacks information on what steps the plant should take after an emergency, and failed to assign certain emergency duties in case of a fire. Emergencies occur without warning. Without proper planning and procedures, the plant cannot effectively respond to emergencies. In response, the plant updated is ERP accordingly. No further corrective action is required.

Finding 2.5 Encina lacks a procedure for processing work orders in its new work management database. Encina still uses the procedure prepared for a database it no longer uses. An updated procedure would explain how the plant initiates, tracks, plans, and schedules work orders, and draw a clear line of responsibility for staff. In response, the plant explained it was transitioning to a new work management database during the audit. And that the new and old databases share similar workflow process. The lack of a procedure for the new database would not have impeded work order planning. The plant explained that it has since completed the transition and fully trained its staff on the new system; therefore CPSD requires no further corrective action.

Finding 2.6 The plant failed to follow its root-cause procedure when it investigated a November 2006 outage when an expansion joint failed. A root-cause analysis (RCA) is a systematic way to identify the ultimate causes of failures to prevent recurrence. Failure to conduct systematic investigations can lead to misdiagnosis and improper correction. In response, the plant explained that the RCA for the November 2006 incident was done per the old procedure. Since July 7, 2008, the

plant has adopted a newer and more detailed procedure that governs how staff conducts RCA. In April 2010, the plant submitted a RCA investigation which conformed to the new procedure. No further corrective action is required.

Finding 2.7 The lead operator could not explain the function of a digital display, or why the display was tagged out. The lead operator takes charge in the control room and therefore should know the function and status of controls at all times. This lack of awareness compromises operational reliability and workers' safety. In response, the plant explained that the lead operator at the time did not understand the auditor's question. The auditor's intent, however, was to test how well a lead operator knows his or her controls. Nonetheless, in October 2009, the plant had retrained its operators on this system, which is used to control Unit 4's SCR. No further corrective action is required.

Finding 2.8 The plant has two conflicting black-start test procedures. The plant uses the procedures to test whether the gas turbine can black-start the steam units. The conflicts may confuse staff and cause test errors or inconsistent test results. In response, the plant explained that one of the procedures is a corporate-wide procedure and the other is a plant-specific standard operating procedure. The two procedures work in conjunction with each other. However, the fact that two procedures exist for the same thing may confuse staff. CPSD asked and the plant added a note to cross-reference the two procedures. No further corrective action is required.

Finding 2.9 The plant delayed repairs on its circulating water tunnel. The deteriorating tunnel poses safety risks for workers, and could shut the plant down. Falling concrete can injure or kill workers who go inside to clean and inspect the tunnel. While walking atop the tunnel, operators on routine inspections can trip and fall over deteriorating concrete and uneven walk surfaces. In response, the plant provided pull-test records on Unit 4's tunnel that were conducted in 2006. The records indicated that the tunnel is structurally sound and in good condition. The plant also provided documents to show that it cleaned and inspected all four tunnels in 2009. In regards to surface de-lamination atop the tunnel, the plant made multiple repairs, and erected orange cones and barrier tapes as mitigating measures, where necessary. The plant also agreed to add inspection requirements to its tunnel cleaning procedures and checklists. No further corrective action is required.

Finding 2.10 The plant delayed repairs on a recirculation fan bearing. The defective bearing registered higher than normal operating temperature and could fail. If the bearing fails, it will take the recirculation fan out-of-service and limit the unit's power output. In response, the plant explained that the outboard seal on the re-circ fan failed and not the bearing. On October 29, 2008, the plant repaired the outboard fan seal via Work Order #08-282124. No further corrective action is required.

Finding 2.11 The plant delayed repairs on asbestos-laden insulation. Inhaled asbestos can cause cancer. Also, damaged insulation exposes hot pipes, which can burn

workers. In response, the plant analyzed the insulation to confirm it did not contain asbestos. To mitigate burn risk hazards, the plant repaired the broken insulation. No further corrective action is required.

Finding 2.12 The plant delayed high-priority repairs to an oil leak onto hot piping, moisture removal equipment for instrument air, and a defective flood-chamber valve. In response, the plant explained that those repairs are not high-priority repairs because the deficiencies posed no imminent safety hazards. However, operators apparently designated the work orders a priority five, the highest priority in the work order system. At CPSD's request, the plant retrained its staff on work order priority in June 2010. All personnel who enters, prioritizes, and approves work orders attended the training. No further corrective action is required.

Finding 2.13 The plant lacks a knowledge retention program. If senior staff retire in the near future, they will take away with them detailed and valuable knowledge about operation and maintenance. Without a program to retain and transfer institutional knowledge to other staff, upcoming retirements may affect the plant's operation. In response, the plant stated that in 2007 it filled six "transition positions", which are positions filled early on to replace outgoing employees. At the meet-and-confer meeting, the plant explained that knowledge retention is only critical for positions in operations and instrumentation and control. In that regards, the plant has an extensive training and certification program for those positions, which includes mentoring, skill assessment, written and hands-on tests. In addition, experienced operators are often involved in many levels of work processes, such as creating checklists and work procedures to capture institutional knowledge. CPSD requires no further corrective action.

Finding 2.14 The plant failed to post evacuation maps and signs throughout the facility. Contractors or new employees who are unfamiliar with the plant's layout may become disoriented in emergencies and face unnecessary risks; such confusion may slow the plant's response to the emergency. In response, the plant posted evacuation maps and added more exit signage. The plant marked exit pathways with luminescent tape. The plant also placed warning signs at doors and stairways that are ***not*** exit paths. No further corrective action is required.

Finding 2.15 The plant failed to maintain an attendance list at one of the assembly areas. In an evacuation, the safety manager uses the attendance list at the assembly area to take roll call. Without an attendance list, the safety manager cannot accurately account for onsite staff. This may slow the plant's response to an emergency. In response, the plant updated all attendance lists at each of the assembly areas in July 2009. CPSD asked and the plant created a recurring work order to update the attendance list on a regular basis. No further corrective action is required.

Finding 2.16 The plant failed to label critical system components to identify what equipment belongs to which unit; doing so may help operators orient and familiarize themselves with the equipment which they operate, and prevent operational

errors. In response, the plant started labeling critical system components. The plant has already labeled about 84% of all valves in all units. The plant has also labeled about 80% of its feedwater system components, which include feedwater heaters. CPSD asks that by April 13, 2011, the plant reports on the progress of its labeling effort.

POWER PLANT DESCRIPTION

Encina Power Plant is located next to the Coastal Highway in Carlsbad, California, about 32 miles North of San Diego. San Diego Gas and Electric (SDG&E) built the plant in the 1950s and operated it until 1999. In May 1999, after California restructured the electric industry, SDG&E sold the plant to Cabrillo Power, a joint venture between Dynegy and NRG. In March 2006, NRG acquired Dynegy's interests in Cabrillo Power and now wholly owns and operates Cabrillo Power.

Photo 1. Encina Power Plant as seen from Carlsbad Boulevard.

The 965-megawatt plant has six generation units; all but Unit 6 are conventional steam units. Units 1, 2, and 3, built in the 1950s, generate 106, 104, and 110 megawatts, respectively. Units 4 and 5, built in the 1970s, generate 300 and 330 megawatts, respectively. The plant also has a 15-megawatt gas turbine. All six units can burn either natural gas or fuel oil, though they typically use the former due to air quality regulations. The plant's 138-kV and 230-kV switchyards deliver the plant's power to the grid.

Table 1. Encina Power Plant has five steam units and one gas turbine unit.

	Year Built	Capacity (megawatts)[3]	Primary Fuel	Backup Fuel
Unit 1	1954	106	Natural Gas	Number 6 Fuel Oil
Unit 2	1956	104	Natural Gas	Number 6 Fuel Oil
Unit 3	1958	110	Natural Gas	Number 6 Fuel Oil
Unit 4	1973	300	Natural Gas	Number 6 Fuel Oil
Unit 5	1978	330	Natural Gas	Number 6 Fuel Oil
Gas Turbine	1968	15	Natural Gas	Diesel Fuel

Unlike most power plants, Encina houses its steam units inside a building. The building protects the units from corrosive sea air and hides the plant's industrial-scale equipment, which some find unaesthetic. Flue gas from all five units exhausts through one smoke stack. The units also share one water intake, which channels seawater from the Agua Hedionda Lagoon to the condensers for cooling. Every two years, the plant dredges the Lagoon to prevent sediment from restricting water flow into the intake structure.

The gas turbine unit is located outside the power plant building. It is of an aero-derivative design; in other words, it closely resembles jet engines used on aircrafts. Although the gas turbine is cheaper to construct than the steam units, it is less fuel efficient and was designed to

[3] CAISO SLIC Database pMAX values

generate power during "peak" days when electricity demand is high. The gas turbine has black-start capability, that is, it can help the grid recover from major blackouts because it can start up without external power.

Encina recently upgraded the plant to reduce nitrogen oxides (NOx) emissions, which contribute to smog and accelerate global warming. In July 2003, the plant replaced the steam units' burners with "low-NOx" burners, which operate below the temperature at which NOx forms. The plant also installed a Selective Catalytic Reduction (SCR) system on each of the steam units. These systems inject ammonia into the flue gas and pass the mixture over a catalyst to reduce NOx. With these upgrades, Encina meets current State of California air standards.

In November 2008, the plant changed Unit 4's control system from analog to digital.[4] The plant did the same on Unit 5 in May 2009. Digital controls allow operators to gather operating data more easily, are easier to operate, and less likely to fail. With access to data, operators can generate trends and statistics and run the unit more efficiently and reliably. The plant has no plans to upgrade controls on Units 1, 2 or 3 because the plant wants to retire these units in the near future.

In September 2007, NRG applied for a license with the California Energy Commission (CEC) to build two new combined-cycle units in the area currently occupied by the plant's fuel tanks.[5] The new units will add 540-megawatts to the plant's capacity. The increased capacity will allow the plant to retire Units 1, 2, and 3, but the company plans to operate Units 4 and 5 through at least 2017. The license application is still under CEC review. However, with the State's new once-through cooling (OTC) regulation, it is uncertain whether NRG will move forward with its plan to construct the new combined-cycle units.

Encina no longer has an RMR[6] contract. The manager of the state's electric grid, the California Independent System Operator (CAISO), ended the plant's RMR contract in December 2007. However, because the plant can burn dual fuel and black-start on its own, the CAISO awarded the plant a contract to provide those services. Once a year, the CAISO requires the plant to test and re-certify those capabilities in order to maintain its contract. However as of January 2009, CAISO terminated its dual fuel contract with Encina.

[4] Analog systems use hydraulic or compressed air controls. Digital systems are electronic.
[5] Docket Number 07-AFC-06 (Application for Certification)
[6] RMR stands for Reliability-Must-Run. Where demand within a local area exceeds the transmission capacity into that area, the CAISO signs RMR contracts with one or more generators in the area to assure that power is available at reasonable prices.

POWER PLANT PERFORMANCE

CPSD used data collected by NERC GADS[7] and analyzed four performance factors to study Encina's operating performance in the last five years:

(1) Net Capacity Factor (NCF),
(2) Equivalent Availability Factor (EAF),
(3) Start Reliability (SR), and
(4) Forced Outage Factor (FOF).

Together, the factors give an insight as to how well the plant has performed in recent years.

NCF measures how close a plant operates to its full capacity. For example, a 50% NCF means a plant generates just half of what it can produce. Table 2 shows Encina's NCF in the last 14 years.

Table 2. Encina's NCF in the last 14 years.

Years	NCF (%)
1995	23
1996	26
1997	28
1998	35
1999	No Data Available
2000	No Data Available
2001	47
2002	No Data Available
2003	No Data Available
2004	37
2005	22
2006	15
2007	8
2008	12

In 2007, Encina generated just 8% of the electricity it can produce. That number is about the same as what other California steam plants had produced in that same year. However, it is dwarfed compared to other North America steam plants, which produced 60% of their total megawatt capacity in 2007. Encina's NCF in 2007 reinforces the fact that California's aging steam plants are becoming less efficient and competitive, and therefore are less likely called upon to run. These steam plants now generally run only during the summer months when demand for electricity is high. During off-peak seasons, these plants idle while hydro and the more efficient combined-cycle plants supply the needed electricity.

[7] NERC is a self-regulatory agency which develops and enforces standards to ensure that the North America power system remains reliable. The agency also maintains the GADS database which it developed in 1982. The GADS database stores operating data that participating power plants submit voluntarily. However, the CPUC's GO 167 makes GADS participation mandatory for California power plants.

Although Encina now runs less, the plant is still able to upkeep with maintenance and operators' skill to keep the plant available. EAF measures a plant's availability to produce power. For example, if a plant breaks down frequently, which makes it unavailable to produce power, then the plant will have a low EAF. Table 3 shows Encina's EAF in the last 14 years.

Table 3. Encina's EAF in the last 14 years.

Years	EAF (%)
1995	96
1996	91
1997	93
1998	84
1999	No Data Available
2000	No Data Available
2001	86
2002	No Data Available
2003	No Data Available
2004	87
2005	88
2006	90
2007	89
2008	91

Encina's average EAF remained much about the same before and after deregulation. A high EAF is always desirable, especially for plants that hardly run. In such a case, a high EAF means that even when the plant has been offline for awhile, it can still startup and produce power if it needs to.

Encina's ability to startup reliably also attributes to the plant's high EAFs. SR calculates the ratio of actual starts to attempted starts. It measures how often a plant actually started when it was attempted to start. This index suggests how well a plant is maintained, i.e. a well-maintained plant starts reliably. It also indicates how well operators are trained. Table 4 shows Encina's SR in the last 5 years.

Table 4. Encina's SR in the last 5 years.

Years	SR (%)
2004	100
2005	100
2006	100
2007	100
2008	98

Finally, FOF measures how often a plant is in forced outages. Obviously, a low FOF is desirable. Table 5 shows Encina's FOF in the last 5 years.

Table 5. Encina's FOF in the last 5 years.

Years	FOF (%)
2004	2
2005	3
2006	1
2007	2
2008	1

Encina underwent forced outages infrequently; predictably because it had such high EAFs. In 2008, the plant spent just 1% of the time in forced outages; that's only 87.6 hours out of 8,760 hours in a year. That number is slightly better than other California steam plants, which were out 1.5% in 2008, and much better than other North America steam plants, which were out 5% in the same year. This suggests that Encina does well in terms of maintenance to avoid forced outages.

SECTION 1 – SAFETY HAZARDS REQUIRING IMMEDIATE CORRECTION

Staff found no safety hazards that require immediate correction.

SECTION 2 – VIOLATIONS REQUIRING CORRECTION

FINDING 2.1 – THE PLANT FAILED TO REGULARLY INSPECT AND MONITOR FLOW-ASSISTED CORROSION IN HIGH-ENERGY PIPES AND COMPONENTS.

The plant failed to regularly inspect for, monitor, trend, and correct flow-assisted corrosion in high-energy pipes and components, violating operation standards.[8] Flow-assisted corrosion is erosion-corrosion[9] caused by a fast moving fluid at high temperature or by a two phase flow (fluid and steam). Over time, it wears down pipe walls, particularly at elbows, bends and flow restrictions. If the plant fails to monitor and correct the corrosion, pipes can rupture and release high pressure steam, which can damage equipment, and injure or kill workers nearby. Plants must therefore monitor and correct corrosion over time.

The plant has never fully inspected Units 1, 2, and 3 for flow-assisted corrosion, and last inspected Units 4 and 5 in 1997 and 1998 respectively. While those inspections found acceptable remaining wall thicknesses[10], substantial additional corrosion may have occurred because both units have subsequently operated many hours.

Outcome and Follow-up

In response, the plant reiterated that it fully inspected Units 4 and 5 for flow-accelerated corrosion in 1997, and 1998 respectively. CPSD acknowledged the adequacy of those inspections, but those inspections were conducted more than 10 years ago. Substantial corrosion may have occurred because both units have subsequently operated many hours.

The plant stated that since the 1997 and 1998 inspections, it has conducted spot inspections. For example, in December 2001, the plant reexamined the boiler feed pump (BFP) discharge pipe wall, an area where the 1998 inspection revealed possible FAC indications. The 2001 inspection did not detect any wall loss at that location. And then in May 2009, subsequent to the CPUC audit, the plant again reexamined the same location for FAC. Again, the inspection detected no change in wall thickness.

While spot inspections are better than no inspection, CPSD feels that the plant is overdue for a full inspection, particularly on Units 4 and 5, which run more frequently than Units 1, 2, and 3. Flow-assisted corrosion is a complex phenomenon and is affected by multitude of variables. Pipe configuration, design, metallurgy, water chemistry, and operating characteristics are just a few. Consequently, just because the plant reexamined the most prone location and found no corrosion does not mean that there are no corrosion elsewhere in the system. Because of the range of variables involved, one cannot fully address the risks of FAC without a full inspection.

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[8] Operation Standard 27: Flow Assisted Corrosion; Guidelines A, B, C & D

[9] Erosion-corrosion occurs when a metal surface erodes and corrodes at the same time. First, a pipe surface's protective oxide layer (called "magnetite") breaks down. This allows the pipe surface to corrode. As it corrodes, a fast-moving fluid carries away rusts and erodes the pipe. This exposes the pipe surface and allows it to corrode further. And the self-sustaining process continues.

[10] Per ASME Power Piping Code B31.1

Spot inspections do not qualify as full inspections. As such, CPSD expects the plant to do a full inspection as soon as possible and to develop a FAC inspection program going forward.

To the plant's credit, the plant has already taken the initial steps toward creating a FAC inspection program. For example, in November 2008, plant engineers attended an Aptech seminar to learn to develop and implement a FAC monitoring program. The plant will also develop a Piping Assessment Program to comply with a NRG corporate directive. Plant engineers also attended demonstration of advanced FAC inspection equipment, which enable offline inspection without insulation removal. The plant is also evaluating the need to contract outside experts to identify and select pipe locations for FAC inspection. And finally in the interim, the plant plans to do more spot inspections during overhauls in 2010 and 2011 for Units 4 and 5, respectively.

At the meet-and-confer meeting, the plant provided a report of a FAC inspection conducted in April 2010.[11] A company called Q. PRO Technical Services conducted a Pulse Eddy Current (PEC) inspection. PEC is an inspection technology that can inspect insulated carbon steel piping for internal and external corrosion and erosion through the insulation without disturbing the insulation or coating. Q. PRO inspected some piping and pumps for each of the 5 units and presented the data it collected to the plant. However, the report contains no conclusions or recommendations from the inspection. CPSD asks that the plant's engineering staff evaluate the results of the PEC examination and to determine whether corrosion or erosion has occurred which warrant repairs.

CPSD will continue to monitor the plant's progress to meet NRG's corporate directive, which requires the plant to develop a Piping Assessment Program. The program will identify and establish inspection method, location, and frequency. CPSD will inspect Encina and request additional data to determine if the program addresses the risks of high-energy pipe corrosion.

FINDING 2.2 – THE PLANT DELAYED REPAIRS ON UNIT 4'S HIGH PRESSURE STEAM TURBINE.

The plant delayed repairs on Unit 4's high pressure steam turbine, which violates maintenance standards.[12] The steam turbine is a critical piece of equipment. High-pressure and temperature steam flows through the turbine. This causes wear and tear on components along the steam path, particularly on stator vanes and rotating blades. Over time, the metal parts corrode, erode, and undergo metal fatigue and creep. If turbine blades crack and fail, they can fly through the turbine, destroy other blades and puncture the turbine casing. Such incidents can injure or kill workers, and can shut down the plant for many months.

The plant last inspected Unit 4's high pressure steam turbine in 1999.[13] At the time, the 10th stage rotating blades showed initial signs of creep[14]. The contractor who inspected the turbine

[11] PEC Examination for FAC at the NRG Cabrillo Power Plant, Carlsbad, CA dated April 24, 2010
[12] Maintenance Standard 7: Balance of Maintenance Approach; Guidelines A & L
Maintenance Standard 9: Conduct of Maintenance; Guideline H
[13] APTECH report dated June 2008

recommended that the plant replace the blades when the machine reaches 40,000 Equivalent Operating Hours (EOH).[15] At the time of the audit, the machine had already reached 59,000 EOH, but the machine continues to run on its old blades.

Outcome and Follow-up

In response, the plant explained that the contractor's recommendation to replace the 10th stage rotating blades was based on old operating characteristics. The steam turbine now runs mostly at low loads and subject to lower pressure and temperature steam. Furthermore, the unit now runs less. In 1999, the unit operated over 7,300 hours per year with 27 startups. Between 2006 and 2008, the unit operated less than 5,300 hours per year with just 17 startups. The contractor's recommendation to replace the blades at 40,000 EOH did not take into account these new operating characteristics, which resulted in a longer service life. In light of this, the plant extended the replacement interval from 40,000 to 60,000 EOH. Nonetheless in February 2010, the plant overhauled Unit 4's HP steam turbine and replaced all 10th stage rotating blades. No further corrective action is required.

FINDING 2.3 – THE PLANT FAILED TO EVALUATE OR ESTABLISH A SCHEDULE TO COMPLETE SAFETY IMPROVEMENTS TO REDUCE FIRE RISKS.

The plant failed to evaluate or establish a schedule to complete safety improvements to reduce fire risks, violating operation and maintenance standards.[16] The safety improvements reduce the plant's exposure to fires. A fire can injure or kill workers and destroy plant equipment that may shut down the plant for many months. In particular, fires fueled by high-pressure oil sprays can quickly become conflagrations that threaten the entire plant.

In June 2008, Encina's insurer assessed the plant for fire risks. The insurer recommended that the plant:

1) Install fire sprinklers over the turbine bearings. If bearing seals fail, lube oil under high pressure can spray over a wide area. Hot bearing surfaces can ignite the lube oil.
2) Install sprinklers over the lube oil tank. If the tank or its piping ruptures, a large quantity of lube oil can release. If ignited, the lube oil will result in a pool fire. Such a fire can damage the turbine and generator directly above.
3) Develop a procedure to safely shut down the lube oil system when it catches on fire. An oil fire will burn as long as the oil continues to flow. Cutting off the oil too early will damage the turbine, and shutting it off too late will fuel the fire. A safe shutdown procedure will ensure that oil flow will stop as soon as practical.

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[14] Creep occurs when a metal slowly deforms when exposed to prolong periods of stress and heat.
[15] Equivalent operating hours differ from actual operating hours because it takes into account how many start/stop cycle a unit goes through, the amount of time a unit spends over-firing, and other factors which shorten a unit's service life.
[16] Operation & Maintenance Standard 1: Safety; Guideline C3.

4) Install sprinklers over the hydraulic fluid and hydrogen seal oil system. Flange gaskets and fittings may leak and spray a mist of hydraulic and seal oil. Hot surfaces can ignite the oil and result in a spray-fire.
5) Install fire sprinklers over the auxiliary transformers. Transformers use oil to insulate its interior. If the oil loses its insulating property, arcing may occur inside the transformer, sparking an explosion.
6) Install fire sprinklers in the Administration Building. Sprinklers can control a fire before the fire department arrives, greatly reducing total damage.
7) Install a seismic gas shutoff valve for the Storage and Administration Building. The seismic shutoff valve will automatically shut off the gas supply in earthquakes, which are common in Southern California. A strong earthquake can rupture gas lines and release flammable gas that could ignite inside buildings.
8) Perform a periodic leak test of its boiler gas safety shutoff valves.
9) Test the heat sensors and smoke detectors.

At the time of the audit, the plant has not yet evaluated, nor established a schedule to complete these recommendations. While CPSD does not specifically require plants to follow contractor recommendations, it does expect plants to evaluate those recommendations and to provide justifications when the plant declines them.

Outcome and Follow-up

In response, the plant directly complied with the requirements of Items 3, 8, and 9 listed above, and provided explanations and documentation to address the other items in the list. First, in response to Items 3, 8, and 9 above, the plant developed lube-oil shut-off procedures (Item 3), installed a gas seismic shutoff valve[17], and provided documentation showing regular contractor inspections of smoke detectors and gas safety shutoff valves (Items 8 and 9).

Second, in response to the portion of Item 4 relating to electro-hydraulic oil, the plant explained that it uses fire resistant and self extinguishing Fyrquel® Electro-Hydraulic oil[18].

Third, in response to Item 6, lack of automatic sprinklers in the administration building, the plant stated that although its original intention was to install these sprinklers, the administration building is very small, and with multiple exits, making these sprinklers unnecessary. The plant also believes installing water sprinklers in the building could damage critical computer systems, and plans to install an Argonite extinguisher system in the administration building's server rooms later this year. CPSD asks that by April 13, 2011, the plant reports on the installation of this system.

In response to the remaining items, which recommend automatic sprinklers for the turbine bearings (Item 1), lube oil tanks (Item 2), hydrogen seal oil system (Item 4), and auxiliary transformers (Item 5), the plant stated that it relies on portable CO_2 fire extinguishers, staff monitoring for potential fire hazards, and the local fire department, which is only three minutes

[17] Work Order 09-21031, Purchase Requisition MX140118, PO # 66405, and Vendor Invoice #161709.
[18] Fyrquel® Electro-Hydraulic Control Fluids are phosphate ester based fire-resistant fluids formulated with trixylenyl and or butylated phenyl phosphates. The fluids are in the class of "non aqueous hydraulic fluids" sometimes referred to as "synthetic fire resistant fluids".

away. At the meet-and-confer meeting, CPSD verified multiple fire extinguisher systems near the steam turbines (See Photos 2 and 3).

Photo 2. Fire extinguishers are readily available on the turbine deck.

Photo 3. Fire blankets are available near the control room.

Additionally, the plant originally claimed that the use of automatic sprinklers for this equipment was not recommended industry standard, and could cause worse equipment damage. CPSD researched NFPA Codes[19] and FM Global data sheets and found that this claim is not fully supported by current industry practice. In fact, several jurisdictional plants, particularly newer combine-cycle plants, utilize this fire protection technology. CPSD discussed this with the plant

[19] National Fire Protection Association (NFPA) 850. Recommended Practice for Fire Protection for Electric Generating Plants and High Voltage Direct Current Converter Stations.

in a teleconference, and asked the plant to provide further data and justification for its claims, along with a cost-benefit analysis.

The plant provided a cost-benefit analysis, based on EPRI report NP-4144, which indicated only minor financial risk and little cost benefit to a fully engineered automated fire system. The plant found that only 10% of NRG plants nationwide utilize such systems. Additionally, the plant correctly maintains that FM Global, an insurer known for strict standards, still chose to insure the plant.

CPSD notes that Encina completed several other risk mitigation measures that FM Global recommended, which includes:

- Sealing the cable penetrations in Unit 3-4 Control Room,
- Installing locks on sprinkler position control valves,
- Improving the existing sprinkler control valve inspection procedure,
- Developing a Fire Protection System valve list with system designators keyed to the plant fire system site map, and
- Providing exposure protection for control room windows.

FINDING 2.4 – THE PLANT'S EMERGENCY RESPONSE PLAN NEEDS IMPROVEMENT.

The plant's Emergency Response Plan (ERP) violates operation standards[20] because it fails to specify: 1) the steps the plant should take after an emergency, 2) how to respond to earthquakes and wildfires, and 3) who should assume certain emergency duties in case of a fire. Emergencies occur without warning and without proper planning and procedure, the plant cannot effectively respond to emergencies. As a result, emergencies may unnecessarily delay the plant's return-to-service.

First, the ERP lacks response information for earthquake or wildfires, events which have recently occurred in Southern California. The plant's insurer recommends that the plant include specific earthquake response measures in its ERP.

Second, the plant's ERP failed to include information on what steps the plant should take following an emergency, such as which authorities to notify. Although the plant includes some of this information in its Injury and Illness Prevention Plan, the information is lacking in its ERP. Information on how to report safety incidents to the CPUC does not appear in either plan.

Finally, the plant's ERP failed to assign certain emergency duties in the event of a fire. The plant's insurer recommends that the ERP assign someone to monitor fire pumps and sprinkler valves during a fire.

[20] Operation Standard 20: Preparedness for On-Site and Off-Site Emergencies; Guidelines A-E

Outcome and Follow-up
In response, the plant updated its ERP to include: 1) a new procedure for wildfires, 2) instructions for reporting safety incidents to CPSD, and 3) descriptions of staff responsibilities during an emergency. At CPSD's request, the plant also corrected an inaccurate telephone number and added the CPUC safety reporting website information to its ERP.

In addition, the plant updated its Standard Operating Procedures[21] which describe staff duties during an earthquake. These duties include monitoring lagoon level and boiler drafts. The instructions emphasize safety, and require staff to evacuate and congregate in the Emergency Assembly Area until it is safe to return. No further corrective action is required.

FINDING 2.5 – THE PLANT LACKS A PROCEDURE FOR ITS COMPUTERIZED WORK MANAGEMENT DATABASE.

The plant lacks a procedure for processing work orders (WO) entered into Maximo (a software program), violating maintenance standards.[22] A procedure would explain how the plant initiates, tracks, plans, and schedules WOs, which draw a clear line of responsibility for staff. The plant replaced MainSaver with Maximo in May 2008, but did not update the relevant procedure. Without such a procedure, staff may process WOs inconsistently and fail to make timely repairs.

Outcome and Follow-up
In response, the plant explained that it was transitioning from one WO database to another during the audit. At the time, the plant did not have a WO procedure for the new system. Auditors felt that a new procedure should have been in place to avoid workflow confusion. The plant contests that the two systems are very similar and that both systems share a similar process to initiate, plan, schedule, and track WOs. Therefore, the lack of a new procedure would not have caused workflow confusion. Auditors did not investigate in-depth enough to decide whether differences between the two systems may have impeded WO planning. However, since Encina completed the transition and fully trained its staff on the new system, CPSD requires no further corrective action.

FINDING 2.6 – THE PLANT FAILED TO FOLLOW ITS ROOT-CAUSE PROCEDURE WHEN IT INVESTIGATED A NOVEMBER 2006 INCIDENT.

The plant failed to follow its root-cause procedure[23] when it investigated a November 2006 outage when an expansion joint failed, violating operation standards.[24] A root-cause investigation is a systematic way to identify the ultimate causes of failures to prevent recurrence. Failing to follow the procedure to investigate systematically may lead to misdiagnosis and improper correction.

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[21] Operator Instruction Manual, Instruction 820.10.1.5, dated September 29, 2009.
[22] Maintenance Standard 8: Maintenance Procedures and Documentation; Guideline H
[23] Directive No. – OPO – 207 dated July 7, 2008
[24] Operation Standard 4: Problem Resolution and Continuing Improvement; Guideline B

An auditor reviewed three root-cause analyses that the plant conducted in recent years. The auditor also reviewed the plant's procedure for root-cause investigations. The auditor noticed that at least one analysis did not conform to the procedure. In November 2006, a failed expansion joint took Unit 4 out-of-service. The plant investigated and attributed the failure to improper operating procedures. While the plant has identified the root cause and has since revised that procedure to prevent recurrence, the plant failed to follow its root-cause procedure when it conducted the analysis. According to the root-cause procedure, each person who is involved in an incident must fill out an interview form. The plant uses the form to collect factual information so that the plant can investigate a failure thoroughly. The analysis for the expansion joint incident lacks those interview forms.

Outcome and Follow-up

In response, the plant explained that the root-cause analysis for the November 2006 incident was conducted per the old procedure. Since July 7, 2008, the plant has adopted a newer and more detailed procedure that governs how staff conducts RCA. The old procedure was more general and did not prescribe the forms that were required under the new procedure.

In December 2008, since the plant adopted the new procedure, twenty plant staff attended a problem-solving class to learn how to properly investigate and conduct RCA. The plant also designated its Technical Service Group to oversee all root-cause investigations. In January 2009, the plant fully implemented the newly RCA process. NRG is also currently developing a company-wide RCA database to keep record of RCA investigations which would enable staff to offload lessons learned from incidents across NRG's fleet of power plants.

CPSD asked that the plant provide a copy of RCA done per the new procedure, if any. In April 2010, the plant submitted a RCA investigation conducted under the new procedure. The investigation used the Kepner-Tregoe RCA technique to investigate a discharge pipe failure on Unit 5's electro-hydraulic pump. The failure, which took place in January 2009, was the second failure in recent history. The RCA identified the root cause to be improper weld preparation during the initial repair. The RCA conformed to the plant's new procedure. No further corrective action is required.

FINDING 2.7 – THE LEAD OPERATOR COULD NOT EXPLAIN A DIGITAL DISPLAY'S FUNCTION AND COULD NOT EXPLAIN WHY THE DISPLAY WAS TAGGED OUT.

The lead operator could not explain the function of a digital display, or why the display was tagged out, which violates operation standards.[25] The lead operator takes charge in the control room and therefore should know the function and status of controls at all times. This lack of awareness compromises operational reliability and workers' safety.

An auditor toured the control room and saw a deficiency tag on a digital display. He then asked the lead operator at the time to explain the display's function and the reason for the tag. The lead operator was unable to explain the display's function or why it was tagged.

[25] Operation Standard 8: Plant Status and Configuration; Guideline A1

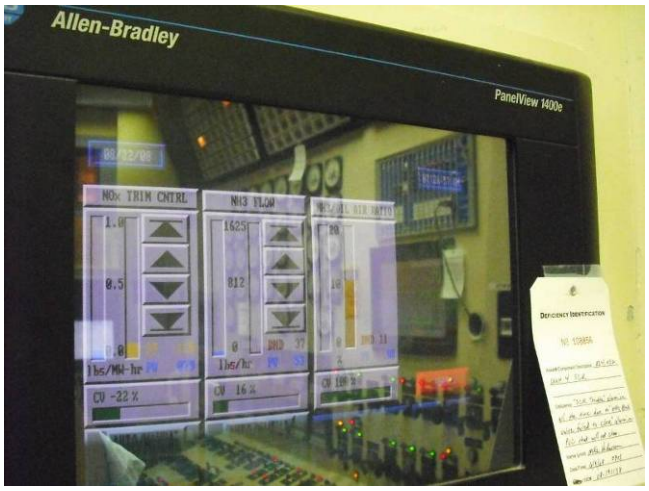

Photo 4. Deficiency tag on a digital display in the control room.

Outcome and Follow-up
In response, the plant explained that the digital display is used to control Unit 4's SCR system.[26] The plant tagged the display because the display annunciated a false alarm. The plant explained that the lead operator at the time did not understand the auditor's question or the implication of the auditor's question. However, the auditor's question was simple and direct, and the implication is to test how well a lead operator knows his or her controls.

In light of this finding, the plant has traced the deficiency to a faulty solenoid valve. The plant has since replaced the valve, cleared all alarms, and restored the system to service. In October 2009, the plant had also retrained its operators on this system. No further corrective action is required.

FINDING 2.8 – THE PLANT HAS TWO BLACK-START TEST PROCEDURES THAT CONFLICT WITH EACH OTHER.

The plant has two black-start test procedures that conflict with each other, violating operation standards.[27] The plant has a two-page, informal, procedure and as well as a more detailed and formalized procedure that was a part of the plant's operator manual.[28] The plant uses the procedure to test whether the gas turbine can black-start the steam units. The conflict may confuse staff and cause test errors or inconsistent test results.

Outcome and Follow-up
In response, the plant explained that the two black-start procedures work in conjunction with each other. The two-page informal procedure is a corporate-wide black-start procedure for all NRG facilities. The detailed procedure is a plant-specific standard operating procedure. The

[26] The SCR system injects ammonia into the flue gas stream. The mixture passes through and reacts with catalysts to reduce Nitrogen Oxide. The plant relies on this system to comply with air emission limits.
[27] Operation Standard 12: Operations Conduct; Guidelines A-E
[28] NRG Cabrillo Power Operations Inc, Operator Instruction Manual, Gas Turbine – Test of Black Start Capabilities

plant reviewed the two procedures and confirmed that following each procedure correctly will not yield test errors or inconsistent test results. However, the fact that two procedures exist for the same thing may confuse staff. CPSD asked and the plant added a note on its standard operating procedure to refer to the corporate-wide procedure. No further corrective action is required.

FINDING 2.9 – THE PLANT DELAYED REPAIRS ON ITS CIRCULATING WATER TUNNEL.

The plant delayed repairs on its circulating water tunnel, violating maintenance standards.[29] The circulating water tunnel channels seawater from the lagoon to each unit's condenser for cooling. The deteriorating tunnel poses safety risks for workers and threatens the plant's reliability.

The deteriorating tunnel poses safety risks for workers. On several occasions, concrete actually fell from the tunnel's ceiling. Falling concrete can injure or kill workers who go inside to clean and inspect the tunnel. Operators who walk atop the tunnel to routinely inspect the units can trip and fall over deteriorating concrete and uneven walk surfaces.

In addition, because the deteriorating tunnel might collapse, the repair delays threaten the plant's reliability. Even a partial collapse would restrict water flow to the condensers. This would reduce a condenser's cooling capacity and limit a unit's power output.

As a precaution, the plant erected a warning sign at the tunnel's entry. The plant also said it will hire a contractor to use a special epoxy to repair the tunnel. At the time of the audit, the plant has not yet repaired the deteriorating tunnel.

Photo 5. Sinking concrete atop the circulating water tunnel.

Outcome and Follow-up

In response, the plant acknowledged that the circulating water (CW) tunnel is a critical plant asset, of which if not properly maintained, may threaten the plant's reliability. In 2006, the plant evaluated bio-fouling coatings on the tunnel. At the time, the plant pull tested random areas of

[29] Maintenance Standard 7: Balance of Maintenance Approach; Guidelines A & L
Maintenance Standard 9: Conduct of Maintenance; Guideline H

Unit 4's tunnel per ASTM D4541 standards[30]. The test results indicated that the tunnel is structurally sound and in good condition. The plant also stated that it regularly cleans and maintains its tunnel. The plant provided documents that showed it cleaned all four tunnels in 2009.[31]

However, the plant did not provide "pull-test" records for other tunnels. The plant must maintain the integrity of its circulating water tunnels. If it chooses not to conduct more extensive testing, at a minimum it must conduct regular and frequent visual inspections, and insure that the tunnels experience no instances of falling concrete or debris. The plant also admits that the CW deck does have areas of de-lamination, which the plant had repaired before, but which delaminated again. The plant further states that:

> "The concrete in the picture is not in danger of breaking or falling into the circulating water tunnel, but it can present a tripping hazard to employees; the bright orange cones and barrier tape are mitigating actions. Any areas on the CW deck providing critical access have been promptly repaired; areas that are not providing critical access are isolated and marked, and will be repaired in normal course."

The plant made multiple repairs (See Photo 6), and allocated funds in the budget for future repairs. The plant also agreed to add inspection requirements to its tunnel cleaning procedures and checklists. No further corrective action is required.

Photo 6. The plant repaired areas of surface delamination.

[30] ASTM (American Society for Testing and Materials) D4541 - 09 Standard Test Method for Pull-Off Strength of Coatings Using Portable Adhesion Testers. According to their website, "ASTM International is one of the largest voluntary standards development organizations in the world-a trusted source for technical standards for materials, products, systems, and services."

[31] The work order (WO) numbers for the tunnel cleanings are as follows: Units 1-3 WO#09-5790, Unit 4 WO#09-38067 and Unit 5 WO#09-71843

FINDING 2.10 – THE PLANT DELAYED REPAIRS ON A RECIRCULATION FAN BEARING.

The plant delayed repairs on a recirculation fan bearing, violating maintenance standards.[32] The recirculation fan recycles flue gas into the furnace for re-burn. The defective bearing has registered higher than normal operating temperature. At the time of the audit, the plant used an air blower to blow ambient air to the bearing to keep it from overheating. The bearing can fail if operators continue to operate it above its normal temperature. If the bearing fails, it will take the recirculation fan out-of-service and limit the unit's power output.

Photo 7. The plant blows air to the bearing to keep it from overheating.

Outcome and Follow-up

In response, the plant clarified that the outboard seal on the re-circ fan failed and not the bearing. The defective seal allowed hot flue gas to leak out. The plant, therefore, placed an air blower to disperse the heat to mitigate burn risks hazards. Subsequently on October 29, 2008, the plant repaired the outboard fan seal via Work Order #08-282124. No further corrective action is required.

FINDING 2.11 – THE PLANT DELAYED REPAIRS ON ASBESTOS-LADEN INSULATION.

The plant delayed repairs on asbestos-laden insulation, which violates operation and maintenance standards.[33] Asbestos is resistant to heat and is often used in pipe insulation. Asbestos insulation was exposed at a valve on Unit 4. Workers who inhale asbestos face an increased risk of cancer. Also, broken insulation poses burn-risk hazards to operators who walk the area routinely to inspect the unit.

[32] Maintenance Standard 7: Balance of Maintenance Approach; Guidelines A & L
Maintenance Standard 9: Conduct of Maintenance; Guideline H

[33] Operation & Maintenance Standard 1: Safety; Guidelines A2 & C3

Photo 8. Asbestos insulation exposed at a valve on Unit 4.

Outcome and Follow-up

In response, the plant hired an insulation contractor to analyze the insulation for asbestos. The result was negative and the plant provided a copy of the analysis. To mitigate burn risk hazards, the plant repaired the broken insulation. No further corrective action is required.

(Before)

(After)

FINDING 2.12 – THE PLANT DELAYED HIGH-PRIORITY CORRECTIVE REPAIRS.

The plant delayed high-priority corrective repairs, violating operation and maintenance standards.[34] Corrective repairs are repairs ordered after something has already failed. Delaying corrective repairs, especially those of high-priority, can inflict more damage and result in longer

[34] Operation & Maintenance Standard 1: Safety; Guidelines A1 & C3
Maintenance Standard 7: Balance of Maintenance Approach; Guidelines A & L

outages. At the time of the audit, the plant had 266 pending corrective repairs.[35] Three of them were of highest priority and were three months overdue at the time:

(1) Work Order # CB1C119045 reported an oil leak from a boiler-feed-pump throttle valve. Although the work order stated that "*oil was dripping onto hot piping causing an extremely high risk of fire*", the leakage posed no immediate fire hazard because the oil leak is slow (about one drop per second) and that the plant has temporarily installed metal sheeting which redirects the oil away from hot surfaces. Nevertheless, the plant has delayed this repair and the plant must repair the leak before it gets worse.

Photo 9. The plant temporarily installed metal sheeting which redirects oil drips away from hot surfaces.

(2) Work Order # CB1C119011 reported a broken Hankison RefrigiFilter. This equipment removes moisture from the air that the plant uses to control pneumatic instruments. Moist air can cause instruments to malfunction and affect the plant's operation.
(3) Work Order # CB1C117554 reported a defective flood-chamber valve. The defective valve has caused large water puddle to form on the ground near Site Column 20A. Water puddle is a breeding ground for algae and poses slip-and-fall hazards for workers who walk the area to routinely inspect equipment.

[35] Corrective Maintenance (CM) Work Order Backlog Report dated 8/15/08

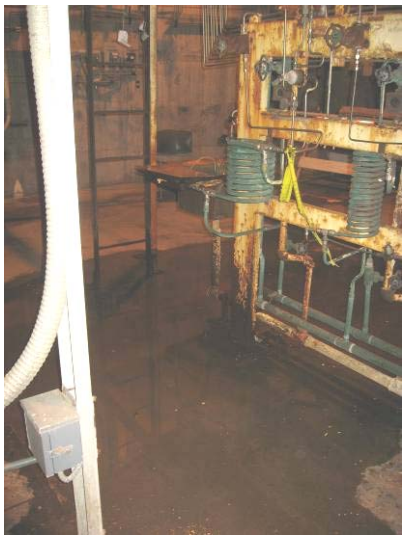

Photo 10 and 11. A defective chamber valve causes large water puddle to form on the ground near Site Column 20A.

Outcome and Follow-up

In response, the plant explained that the three work orders cited were not fix-it-now (FIN) repairs because the deficiencies posed no imminent safety hazards. To the contrary, operators entered the work orders and designated them a priority five, the highest priority in the work order system. If the repairs were not urgent, as the plant explained, then the plant needs to retrain its operators to distinguish FIN repairs from non-urgent repairs so that they will correctly prioritize work orders in the system. Proper work order priorities enable the plant to allocate resources in the most effective manner.

At CPSD's request, the plant retrained its staff on work order priority. The plant conducted training in June 2010. All personnel who enters, prioritizes, and approves work orders attended the training. The plant provided a presentation and an attendance report for the training. CPSD requires no further corrective action.

FINDING 2.13 – THE PLANT LACKS A KNOWLEDGE RETENTION PROGRAM.

The plant lacks a knowledge retention program, which violates operation and maintenance standards.[36] Such a program would collect what is sometimes called “Tribal knowledge”, undocumented processes, procedures, and expertise that an organization develops over time. Many of Encina’s senior staff worked for SDG&E and will retire in the near future. Unless Encina develops a program to retain and transfer tribal knowledge to other staff, upcoming retirements may affect the plant’s operation.

[36] Operation Standard 3: Operations Management and Leadership; Guideline C1
Operation Standard 4: Problem Resolution and Continuing Improvement; Guideline C
Maintenance Standard 3: Maintenance Management and Leadership; Guideline C1

Outcome and Follow-up
In response, the plant submitted a spreadsheet that projects Encina's staffing needs through 2011. The spreadsheet shows that in 2007 the plant filled six "transition positions".[37] Transition positions are positions filled early on so new employees can transition into their new roles as they replace outgoing employees. While the plant anticipates retirements and actively fills transition positions, auditors found no evidence that the plant has a knowledge retention program or strategy, such as mentorship, knowledge transfer training, or exit interviews. CPSD believes the plant benefits if it develops a program to retain critical and undocumented knowledge before an exodus of veteran employees.

At the meet-and-confer meeting, the plant explained that knowledge retention is only critical for positions in operations and instrumentation and control. In that regards, the plant has an extensive training and certification program for those positions. Operators are classified into one of four different skill levels (OMT-1 to OMT-4). At each level, an operator attends training classes, mentors with an experienced operator, takes written and hands-on performance tests. Upon successful completion, the O&M Manager has to approve before an operator progresses to the next skill level. At the top level, OMT-4 operators are often involved in many levels of work processes, such as creating checklists and work procedures to capture institutional knowledge. The plant briefed auditors on its operator training and certification process and provided a current training status of its operators. CPSD requires no further corrective action.

FINDING 2.14 – THE PLANT FAILED TO POST EVACUATION MAPS AND SIGNS THROUGHOUT THE FACILITY.

The plant failed to post adequate maps and signs, a violation of operation standards.[38] Although the plant maintains a thorough evacuation procedure and identifies its assembly areas clearly, the plant failed to post maps of evacuation routes and assembly areas. Contractors or new employees who are unfamiliar with the plant's layout may become disoriented in emergencies and face unnecessary safety risks. Assembling such workers may slow the plant's response to the emergency.

Outcome and Follow-up
In response, the plant posted evacuation maps and added additional exit signage. Additionally, the plant marked exit pathways with luminescent tape (See Photo 12). The plant also placed warning signs at doors and stairways that are ***not*** exit paths. The plant notes that it already discusses emergency exit procedures with contractors during its pre-outage safety orientation. No further corrective action is required.

[37] Four auxiliary operators and two shift supervisors
[38] Operation Standard 20: Preparedness for On-Site and Off-Site Emergencies

Photo 12. The plant marked this exit stairwell with luminescent tape.

FINDING 2.15 – THE PLANT FAILED TO MAINTAIN AN ATTENDANCE LIST AT ONE OF THE ASSEMBLY AREAS.

The plant failed to maintain an attendance list at one of the assembly areas, a violation of operation standards.[39] In an evacuation, plant staff gathers at one of three assembly areas. The safety manager uses the attendance list at the assembly area to take roll call. Without an attendance list, the safety manager cannot accurately account for onsite staff. This slows the plant's response to the emergency.

Outcome and Follow-up

In response, the plant stated that on September 25, 2008 it held an evacuation drill, at which time it verified that each assembly areas had attendance sheets in place. In addition, the plant grouped these attendance sheets based on job classification in order to facilitate checking attendance during an evacuation. The plant explained that the security guard keeps a real-time list of all staff and visitors on site. During an evacuation, the safety manager at each assembly areas takes roll call on an attendance sheet, and then brings these sheets to the guard's station to reconcile with the real-time list. In July 2009, the plant updated all attendance lists at each of the assembly areas. CPSD asked and the plant created a recurring work order to update the attendance list on a regular basis. No further corrective action is required.

[39] Operation Standard 20: Preparedness for On-Site and Off-Site Emergencies

FINDING 2.16 – THE PLANT FAILED TO LABEL CRITICAL SYSTEM COMPONENTS.

The plant failed to label critical system components, a violation of operation standards.[40] In particular, the plant did not label feed-water heaters for Units 1 and 2 that are near each other. Without clear signage, operators can mistake one unit's heater for another's, leading to maintenance or operational errors, reducing the plant's reliability and safety.

Outcome and Follow-up

In response, the plant stated that it has started labeling critical system components. The plant has already labeled about 72% of all valves in all units. The plant's goal is label all critical control, isolation, and pressure relief valves. The plant has also labeled about 50% of its feedwater system components, which include feedwater heaters.

At the meet-and-confer meeting, the plant stated that it has labeled about 84% of all valves in all units. For its feedwater system, labeling is about 80% complete. The plant has committed to complete all labeling by December 2010. CPSD asks that by April 13, 2011, the plant reports on the progress of its labeling effort.

Photo 13. A metal valve tag on an attemperator.

[40] Operation Standard 5: Operations Personnel Knowledge and Skills; Guideline D

Photo 14. The plant labeled Unit 1's feedwater heater.

Photo 15. The plant labeled Unit 2's induced draft fan motor.

Photo 16. Unit 1's condensate storage tank to be labeled.

SECTION 3 – OBSERVATIONS

OBSERVATION 3.1 – THE PLANT FOLLOWS A STRICT PROCESS TO SELECT AND QUALIFY CONTRACTORS.

The plant maintains a list of qualified suppliers and contractors. The plant contracts only with firms on this list. The plant adds new suppliers to the list only after a strict qualification process.

The plant uses a web-based program called "Ariba" to pre-qualify suppliers. Potential suppliers answer an extensive list of questions, concerning the company's experience, qualification and employees' certification. The plant also looks at the company's Experience Modification Rating (EMR) to determine the company's safety history. EMR measures how many claims a company has filed for workers' compensation, and compares that number to those of similar companies. A lower EMR means a company has had fewer accidents.

Once a potential supplier completes the questionnaire, the plant's safety manager must review and approve it before the plant can award the supplier a contract. An auditor reviewed the completed questionnaire of Total Western, a company contracted to provide repair service to Encina. The questionnaire conformed to the plant's qualification process.

OBSERVATION 3.2 – THE PLANT REQUIRES CONTRACTORS TO COMPLETE A CONTRACTOR SAFETY NOTICE BEFORE THEY CAN START WORK.

Before contractors can start work, the plant requires them to fill out a 31-page contractor safety notice. The plant issues contractors this notice at the pre-job briefing, held before the contractor commences work on the first day. The contractor must read the notice and initial each section to acknowledge that he or she understands it. At this time, the plant also discusses with the contractor any specific safety issues that relates to the job at hand. The contractor receives a copy of the notice while the plant keeps the original on-file. An auditor reviewed the contractor safety notices of three companies and found them consistent with the process.[41]

OBSERVATION 3.3 – THE PLANT USES CHECKLISTS FOR ROUTINE INSPECTION.

The plant uses checklists for routine inspection. An auditor walked-down Unit 4 alongside an operator. While the operator did not carry a checklist with him, he did have a note pad to write down any deficiencies he observed. After the walk-down, the operator returned to the control room where he filled out a checklist and filed it away in the shift supervisor's office. The auditor reviewed several completed checklists, which conformed to the routine inspection.[42] However

[41] Contractor safety notice for Preferred Piping, dated 12/19/07, to repair #3 basement air compressor
Contractor safety notice for Laser Electric, dated 12/18/07, to maintain office's air conditioning unit
Contractor safety notice for Vortex, dated 12/17/07, to inspect crane at circulating water deck

[42] NRG Cabrillo Basement Log Sheet Units 1, 2, and 3

during the walk-down, the auditor saw several equipment defects. See Findings 2.9, 2.10, and 2.11.

OBSERVATION 3.4 – THE PLANT MAINTAINS A LOGBOOK COMPLIANCE DOCUMENT ONSITE.

General Order 167 Section 5.6 requires plants to maintain onsite a logbook compliance document. This document explains how and where plants record their logbook data. An auditor reviewed Encina's operators' log manual, which met the requirement of GO 167. The auditor also reviewed a copy of an actual log which conformed to the plant's log manual.[43]

OBSERVATION 3.5 – THE PLANT IMPLEMENTS A LOCK-OUT TAG-OUT PROGRAM.

The plant uses a lock-out tag-out program and follows a strict clearance procedure. If a piece of equipment needs repair, the plant not only tags and de-energizes it, but it also locks it such that the equipment stays electrically isolated. This prevents someone from accidentally turning the equipment on while a worker repairs it. Under this program, only the technician in charge of the repair can take the equipment out-of-service, and only the person who placed the lock can remove it. If the person who placed the lock is absent, only the shift supervisor can override his or her authority and remove the lock. The plant has a shack where it keeps all the locks and binders that track all active clearances. The plant also trains its staff on the clearance procedure regularly.

NRG Cabrillo Sub-basement Log Sheet Units 4 and 5
NRG Cabrillo Unit 1, 2, and 3 Boiler Casing Leak Inspection Log
NRG Cabrillo Unit 4 and 5 Boiler Casing Leak Inspection Log

[43] Unit 5's control operator's log dated 8/4/08

Photo 17 and 18. On the turbine deck, the plant has a shack where it keeps its locks and binders that track all active clearances.

OBSERVATION 3.6 – THE PLANT CONDUCTS EVACUATION DRILLS REGULARLY.

The plant conducts evacuation drills regularly. The plant conducts two evacuation drills annually. The plant seeks continuous improvements by evaluating every drill. An auditor reviewed drill evaluations and verified that the plant conducted at least two drills in each of the last two years. The evaluations stated that all staff was accounted for in each of the drills and did not note any deficiencies.

OBSERVATION 3.7 – THE PLANT KEEPS ITS FACILITY ORDERLY AND CLEAN.

The plant keeps its facility orderly and clean. The plant is clean, particularly inside the power plant building. The plant stores unused equipment properly; secured and away from walk-aisles. During the plant tour, an auditor saw the shift supervisor repeatedly picking up and properly disposing trash and debris.

Photo 19. The plant keeps the turbine deck clean and orderly.

OBSERVATION 3.8 – THE PLANT MAINTAINS ITS CATHODIC PROTECTION SYSTEM.

The plant inspects and maintains its cathodic protection system regularly. A cathodic protection system prevents underground pipes from corrosion, particularly cooling water pipes. It works by applying an electric current to an anode on the pipe. This forces the anode to corrode rather than the pipe. As such, the anode is called a "sacrificial" anode. Once the anode corrodes completely, the plant must replace it with a new anode in order to continue to protect the pipe. If the plant does not upkeep its cathodic protection equipment, underground pipes will corrode rapidly and will eventually fail.

An auditor reviewed the cathodic protection report for 2003, and for 2005 through 2008.[44] In each of these years, the plant hired a specialist (Norton Corrosion) to inspect its cathodic protection systems on all five units. The specialist inspected the rectifiers, anodes and reference cells[45] on the traveling screens, condenser waterboxes, and cooling water pipes.[46]

The plant repaired all defects found by the inspections. For example, the 2003 inspection report lists several defective anodes and reference cells.[47] The 2005 report indicates that the plant had replaced these items. The most recent report, completed in June 2008, lists several defective parts. The plant has created work orders to repair them.[48]

[44] Norton Corrosion Limited – Cathodic Protection Annual Survey for 2003, 2005, 2006, 2007, and 2008
[45] A rectifier converts AC voltage to DC voltage for the impressed current. Reference cells provide a known voltage level and are used in testing.
[46] Traveling screens filter the intake cooling water for the condensers. The condenser waterbox is where the cooling water enters the condenser to cool the steam from the turbine.
[47] U5 – East Reference Cell #2 South pipe, Reference Cell #4 North pipe, U5 – West Anodes 21, 22, 23 & 24 North pipe
[48] WO# 08-335468, #08-335462, and #08-335472

OBSERVATION 3.9 – THE PLANT IS WELL-STAFFED IN A NUMBER OF AREAS.

The plant has staff in the operational, maintenance, and technical area. The plant employs six engineers, five planners, and has dedicated trainers, environmental and safety specialists. Twenty-five Total Western maintenance staff, including a foreman, work full-time at the plant. The plant employs a full-time chemist and a document-control clerk. During each shift, a supervisor directs the work of a staff of three for each pair of units: a control operator, assistant control operator, and an auxiliary operator.

OBSERVATION 3.10 – THE PLANT VERIFIES CONTRACT EMPLOYEES' QUALIFICATIONS.

The plant verifies contract employees' qualifications. The plant employs 25 contract employees who work for Total Western. These employees work full time onsite. The plant relies on them for many of its maintenance and repairs. While contract employees get their training from Total Western, the plant does due-diligence to verify whether the training actually took place. For example, contract employees clean the traveling screens regularly. The plant keeps a record that shows who received the proper training and, therefore, can do the job. Additionally, the plant checks to ensure contract employees are competent to do their jobs. For example, Total Western has welders whose welding skills meet American Society of Mechanical Engineers (ASME) specifications. The plant verifies the welders' certification before it allows the welders to weld.

OBSERVATION 3.11 – THE PLANT INSPECTS ITS CRANES AND FORKLIFTS REGULARLY.

The plant inspects its cranes and forklifts and maintains records of those inspections. An auditor selected two records at random and verified that the plant has inspected its cranes and forklifts within the last year.

OBSERVATION 3.12 – THE PLANT CONTROLS AND UPDATES ITS EQUIPMENT DIAGRAMS.

The plant manages its equipment diagrams and has a well-defined process to update them. The plant stores its drawings and schematics at one central location and assigns a clerk to manage them. The room has copiers and plotters so staff can make copies of drawings and not take the originals away. The plant keeps those drawings electronically, but also maintains a set of hardcopies. The plant keeps its drawings organized and maintains a catalog of those drawings.

The plant has a well-defined process to update its drawings. If the plant upgrades or replaces a piece of equipment, it also updates its drawing to reflect the changes. The plant maintains two sets of drawings. It keeps a set of "as-built" master drawings and a set of "working" drawings. If new equipment or an upgrade changes the plant's configuration, technicians make the

necessary changes on the "working" drawings. Engineers must review and approve the changes before the technician can replace the "as-built" masters with the new drawings.

The plant keeps its drawings organized and maintains a catalog of those drawings. The plant catalogs its "as-built" drawings both electronically and on paper. The drawings themselves are also available electronically and on paper. An auditor asked to see the drawing of Unit 4's cathodic protection system.[49] The clerk and the engineer searched the two cataloging systems at the same time, and within seconds they both located the electronic and hard-copy drawing.

[49] Project # 13-7972, Drawing E-101, Revision C. "Condenser Cathodic Protection Conduit Run and Wiring Diagram"

ATTACHMENT B

DOCKET NO: 07-AFC-6

CENTER FOR BIOLOGICAL DIVERSITY'S NOTICE OF DOCUMENTS THAT MAY BE USED DURING CROSS EXAMINATION

California ISO
Your Link to Power

2009 RMR / Black Start / Dual Fuel Contract Status
(Based on CAISO Actions and FERC Filings by Unit Owners)

RMR Unit Extension Status (Modified December 1, 2008) *Extended RMR Contracts are effective January 1, 2009 thru December 31, 2009* *Released RMR Contracts terminate effective Midnight on December 31, 2008*				
Owner	***RMR Contract***	***Unit***	***MW[1]***	***Status***
CalPeak Power – Border, LLC	Border	Border Unit	43.8	Extended
CalPeak Power – El Cajon, LLC	El Cajon	El Cajon Unit	42.2	Extended
CalPeak Power – Enterprise, LLC	Enterprise	Escondido Unit	45.5	Extended
Geysers Power Company, LLC (Calpine)	Geysers Main	Geysers Main, Units 6	40	Released
Gilroy Energy Center, LLC (Calpine)	Gilroy EC	Feather River EC Unit	45	Extended
		Gilroy EC, Unit 1	45	
		Gilroy EC, Unit 2	45	
		Yuba City EC Unit	45	
Los Medanos Energy Center, LLC (Calpine)	LMEC	Los Medanos Energy Center	556	Extended
Mirant Potrero, LLC	Potrero	Potrero, Unit 3	206	Extended
		Potrero, Unit 4	52	
		Potrero, Unit 5	52	
		Potrero, Unit 6	52	
Dynegy Oakland, LLC	Oakland	Oakland, Unit 1	55	Extended
		Oakland, Unit 2	55	
		Oakland, Unit 3	55	
Dynegy South Bay, LLC	South Bay	South Bay, Unit 1	145	Extended
		South Bay, Unit 2	149	
		South Bay, Unit 3	174	
		South Bay, Unit 4	221	
		South Bay, CT	13	
Cabrillo Power II LLC (NRG)	Cabrillo II	Kearny 2A CT	14	Released
		Kearny 2B CT	14	
		Kearny 2C CT	14	
		Kearny 2D CT	13	
		Kearny 3A CT	15	
		Kearny 3B CT	14	
		Kearny 3C CT	14	
		Kearny 3D CT	14	
		Miramar 1A CT	17	
		Miramar 1B CT	16	

[1] Capacity values shown indicate the summer maximum net dependable capacity (MNDC) values for the combustion turbines with both summer and winter MNDC values specified in the Cabrillo I, Cabrillo II, and South Bay RMR contracts.

California ISO
Your Link to Power

2009 RMR / Black Start / Dual Fuel Contract Status
(Based on CAISO Actions and FERC Filings by Unit Owners)

Black Start Units Extension Status (Modified December 1, 2008) *Extended Black Start Contracts are to be effective January 1, 2009 thru December 31, 2009*				
Pacific Gas and Electric Company	Humboldt Bay	Humboldt Bay, MEPP 2	15	Extended
		Humboldt Bay, MEPP 3	15	
	Kings River WS	Kings River Watershed II Units	335.8	Extended
	San Joaquin WS	San Joaquin Watershed Units	214.7	Extended
Southern California Edison		Hoover	525	Extended
		Big Creek Physical Scheduling Plant	368.9	
		Barre Peaker	47	
		Center Peaker	47	
		Grapeland Peaker	46	
		Mira Loma Peaker	46	
Cabrillo Power I, LLC	Cabrillo I	Encina CT	14	Extended
Cabrillo Power II LLC (NRG)		Kearny 2A CT	14	New
		Kearny 2C CT	14	
		Kearny 3A CT	15	
		Kearny 3C CT	14	
		Miramar 1A CT	17	
Dual Fuel Agreement Unit Extension Status (Modified December 1, 2008) *Extended Dual Fuel Contracts are to be effective January 1, 2009 thru December 31, 2009*				
Pacific Gas and Electric Company	Humboldt Bay	Humboldt Bay, Unit 1	52	Extended
		Humboldt Bay, Unit 2	53	
Cabrillo Power I LLC	Cabrillo I	Encina Unit 1	106	Terminated
		Encina Unit 2	103	
		Encina Unit 3	109	
		Encina Unit 4	299	
		Encina Unit 5	329	

ATTACHMENT C

DOCKET NO: 07-AFC-6

CENTER FOR BIOLOGICAL DIVERSITY'S NOTICE OF DOCUMENTS THAT MAY BE USED DURING CROSS EXAMINATION

2008 RMR / Black Start / Dual Fuel Contract Status

(Based on CAISO Actions and FERC Filings by Unit Owners)

RMR Unit Extension Status *Extended RMR Contracts are effective January 1, 2008 thru December 31, 2008* *Released RMR Contracts terminated effective Midnight on December 31, 2007*				
Owner	***RMR Contract***	***Unit***	***MW[1]***	***Status***
CalPeak Power – Border, LLC	Border	Border Unit	43.8	Extended
CalPeak Power – El Cajon, LLC	El Cajon	El Cajon Unit	42.2	Extended
CalPeak Power – Enterprise, LLC	Enterprise	Escondido Unit	45.5	Extended
Geysers Power Company, LLC (Calpine)	Geysers Main	Geysers Main, Units 6	40	Extended
Gilroy Energy Center, LLC (Calpine)	Gilroy EC	Feather River EC Unit	45	Extended
		Gilroy EC, Unit 1	45	
		Gilroy EC, Unit 2	45	
		Yuba City EC Unit	45	
Los Medanos Energy Center, LLC (Calpine)	LMEC	Los Medanos Energy Center	556	Extended
Dynegy Oakland, LLC	Oakland	Oakland, Unit 1	55	Extended
		Oakland, Unit 2	55	
		Oakland, Unit 3	55	
Dynegy South Bay, LLC	South Bay	South Bay, Unit 1	145	Extended
		South Bay, Unit 2	149	
		South Bay, Unit 3	174	
		South Bay, Unit 4	221	
		South Bay, CT	13	
Cabrillo Power I LLC (NRG)	Cabrillo I	Encina Unit 1	106	Released, Dual Fuel Agreement executed in lieu of RMR
		Encina Unit 2	103	
		Encina Unit 3	109	
		Encina Unit 4	299	
		Encina Unit 5	329	
		Encina CT	14	Released, Black Start Agreement executed in lieu of RMR
Cabrillo Power II LLC (NRG)	Cabrillo II	El Cajon CT	13	Released
		Kearny 1 CT	15	
		Kearny 2A CT	14	Extended
		Kearny 2B CT	14	
		Kearny 2C CT	14	
		Kearny 2D CT	13	
		Kearny 3A CT	15	
		Kearny 3B CT	14	
		Kearny 3C CT	14	
		Kearny 3D CT	14	
		Miramar 1A CT	17	
		Miramar 1B CT	16	
Mirant Delta, LLC	Contra Costa	Contra Costa, Unit 4	0[2]	Released
		Contra Costa, Unit 5	0[2]	

[1] Capacity values shown indicate the summer Maximum Net Dependable Capacity (MNDC) values for the CTs with both summer and winter MNDC values specified in the Cabrillo I, Cabrillo II, and South Bay RMR Contracts.

[2] Unit is a synchronous condenser.

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2008 RMR / Black Start / Dual Fuel Contract Status

(Based on CAISO Actions and FERC Filings by Unit Owners)

Mirant Potrero, LLC	Potrero	Potrero, Unit 3	206	Extended
		Potrero, Unit 4	52	
		Potrero, Unit 5	52	
		Potrero, Unit 6	52	
Northern California Power Agency	NCPA CTs	Alameda, Unit 1	22.5	Released
		Alameda, Unit 2	22.5	
Black Start Units Extension Status *Extended Black Start Contracts are to be effective January 1, 2008 thru December 31, 2008*				
Pacific Gas and Electric Company	Humboldt Bay	Humboldt Bay, MEPP 2	15	Extended
		Humboldt Bay, MEPP 3	15	
	Kings River WS	Kings River Watershed II Units	335.8	Extended
	San Joaquin WS	San Joaquin Watershed Units	214.7	Extended
New Interim Black Start Agreement Units *New Black Start Contracts are to be effective January 1, 2008 thru December 31, 2008*				
Southern California Edison		Hoover	525	New
		Big Creek Physical Scheduling Plant	368.9	
		Barre Peaker	47	
		Center Peaker	47	
		Grapeland Peaker	46	
		Mira Loma Peaker	46	
Cabrillo Power I, LLC	Cabrillo I	Encina CT	14	New
Dual Fuel Agreement Unit Extension Status *Extended Dual Fuel Contracts are to be effective January 1, 2008 thru December 31, 2008*				
Pacific Gas and Electric Company	Humboldt Bay	Humboldt Bay, Unit 1	52	Extended
		Humboldt Bay, Unit 2	53	
New Dual Fuel Agreement Units *Extended Dual Fuel Contracts are to be effective January 1, 2008 thru December 31, 2008*				
Cabrillo Power I LLC	Cabrillo I	Encina Unit 1	106	New
		Encina Unit 2	103	
		Encina Unit 3	109	
		Encina Unit 4	299	
		Encina Unit 5	329	

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ATTACHMENT D

DOCKET NO: 07-AFC-6

CENTER FOR BIOLOGICAL DIVERSITY'S NOTICE OF DOCUMENTS THAT MAY BE USED DURING CROSS EXAMINATION

October 15, 2010

Via Fed-Ex & E-mail

Mr. Randy Hickok
Managing Director Asset Management & Trading
Dynegy, Inc.
4140 Dublin Boulevard, Suite 100
Dublin, CA 94568

Dear Mr. Hickok:

By letter dated September 29, 2010, the California Independent System Operator Corporation (ISO) notified Dynegy, Inc. that it was extending the Reliability Must Run (RMR) Agreement applicable to Dynegy's South Bay Units 1, 2 and the CT (collectively, the South Bay units). Since then, the ISO has received new information about projected power demand in the San Diego local area, showing that local power requirements are lower than the California Energy Commission (CEC) had previously projected in its 2009 forecasts used in the ISO's 2011 Local Capacity Technical Analysis for 2011 and 2012. Additionally, on September 27, 2010, the San Diego area experienced a record peak demand of 4,684 MW. ISO staff analyzed the weather conditions behind this peak load event in light of the lower CEC forecast. This analysis reinforces the ISO's confidence in the accuracy of the recent, lower power demand projections for the area.

For these reasons, the ISO is pleased to inform Dynegy of its decision to rescind the September 29, 2010 notice of extension and the RMR status of the South Bay units will, therefore, terminate on December 31, 2010. We understand that RMR designation caused Dynegy some concern given, among other things, the age of the facilities and the community's long-standing desire and expectation to see the units closed and removed. With this notice, Dynegy is now free to proceed with decommissioning and demolition in accordance with its lease agreement with the Port of San Diego beginning January 1, 2011.

As you know, on June 11, 2010, the ISO filed a petition for review of the decision of the California Regional Water Quality Board for the San Diego Region denying an administrative extension of the National Pollutant Discharge Elimination System (NPDES) permit for South Bay Units 1 and 2. We will take steps promptly to withdraw that petition.

As you also know, a hearing on Dynegy's pending NPDES permit application for operation beyond December 31, 2010 is scheduled for November 17, 2010. We will be submitting comments on Monday, October 18, indicating that the ISO has reassessed the local reliability

need for the South Bay units beyond 2010 and has determined that these units are no longer needed for RMR service beyond the current contract year.

The ISO appreciates the RMR service the South Bay units have provided over the years and we are pleased to be able to release them from service at the end of this year.

Sincerely,

Steve Berberich
Vice President and Chief Operating Officer

SBB/ag

cc: Joseph M. Paul (Dynegy, Inc.)
Daniel P. Thompson (Dynegy, Inc.)
R. Alan Padgett (Dynegy, Inc.)
James Walsh (SDG&E)
Victor Kruger (SDG&E)
Larry Chaset (CPUC)
The Honorable Cheryl Cox (City of Chula Vista)

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File

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K. Casey
A. Ulmer
C. Mamandur
P. Pettingill
G. Vanpelt
G. DeShazo
C. Micsa
A. Bhaumik
D. Timson
R. Kott
G. Grotta
J. Chipman

bcc: (Documentum)
Cabinet: Operations Support
Folder: Reliability Contracts\LARS\ 2011 LARS\Notices\
Filename: 100929 Dynegy South Bay RMR Extension

ATTACHMENT E

DOCKET NO: 07-AFC-6

CENTER FOR BIOLOGICAL DIVERSITY'S NOTICE OF DOCUMENTS THAT MAY BE USED DURING CROSS EXAMINATION

SOUTHERN CALIFORNIA EDISON
An EDISON INTERNATIONAL Company

Akbar Jazayeri
Vice President of Regulatory Operations

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ADVICE 2547-E
(U 338-E)

PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA
ENERGY DIVISION

SUBJECT: Submission of Contracts for Procurement of Renewable Energy Resulting from Renewables Standard Contracts Program

I. INTRODUCTION

A. Purpose of the Advice Letter

Southern California Edison Company ("SCE") submits this Advice Letter in compliance with Cal. Pub. Util. Code § 399.11 *et seq*. (the "RPS Legislation") seeking approval of 20 Renewables Portfolio Standard ("RPS") power purchase agreements ("RSC Contracts") resulting from SCE's 2010 Renewables Standard Contracts ("RSC") Program.

The following table summarizes the RSC Contracts:

Seller	Generation Type	Contract Capacity (MW AC)	Estimated Annual Energy (GWh)	Forecasted Initial Operation Date	Point of Delivery	Term of Agreement (Years)
Lancaster Dry Farm Ranch B LLC	Solar: PV	5.0	12.2	4/2014	PNode	20
Sierra Solar Greenworks LLC	Solar: PV	20.0	41.2	4/2014	PNode	20
Lancaster WAD B LLC	Solar: PV	5.0	12.4	4/2014	PNode	20

Central Antelope Dry Ranch B LLC	Solar: PV	5.0	10.2	4/2014	PNode	20
Central Antelope Dry Ranch C LLC	Solar: PV	20.0	40.8	4/2014	PNode	20
Victor Dry Farm Ranch A LLC	Solar: PV	5.0	10.3	4/2014	PNode	20
Victor Dry Farm Ranch B LLC	Solar: PV	5.0	10.3	4/2014	PNode	20
North Lancaster Ranch LLC	Solar: PV	20.0	40.8	4/2014	PNode	20
American Solar Greenworks LLC	Solar: PV	15.0	30.9	4/2014	PNode	20
Sierra View Solar V LLC	Solar: PV	19.0	50.0	12/2013	PNode	20
Sierra View Solar IV LLC	Solar: PV	19.0	49.4	12/2013	PNode	20
Nicolis, LLC	Solar: PV	20.0	50.1	9/2013	PNode	20
Blythe Solar Power Generation Station 1, LLC	Solar: PV	4.7	12.2	6/2013	PNode	20
Littlerock Solar Power Generation Station 1, LLC	Solar: PV	5.0	13.6	4/2013	PNode	20
Garnet Solar Power Generation Station 1, LLC	Solar: PV	4.8	11.3	6/2013	PNode	20
Lucerne Solar Power Generation Station 1, LLC	Solar: PV	14.0	37.6	3/2014	PNode	20
Tropico, LLC	Solar: PV	14.0	36.2	9/2013	PNode	20
Clear Peak Energy, Inc.	Solar: PV	8.5	23.6	12/2013	PNode	20
RE Columbia 3 LLC	Solar: PV	10.0	24.9	1/2014	PNode	20
RE Columbia Two LLC	Solar: PV	20.0	49.3	1/2014	PNode	20

SCE requests that the California Public Utilities Commission ("Commission" or "CPUC") issue a resolution containing findings in the form requested in this Advice Letter no later than July 29, 2011.

In accordance with General Order ("GO") 96-B, the confidentiality of information included in this Advice Letter is described below. This Advice Letter contains both confidential and public appendices as listed below:

Confidential Appendix A:	Consistency with Commission Decisions and Rules and Project Development Status
Confidential Appendix B:	2010 RSC Program Solicitation Overview and 2009 Solicitation Workpapers
Confidential/Public Appendix C:	Independent Evaluator Report
Confidential Appendix D:	Contract Summaries
Confidential Appendix E:	RSC Contracts' Contribution to RPS Goals
Appendix F:	SCE's Written Description of RPS Proposal Evaluation and Selection Process and Criteria
Confidential Appendix G:	AMF Calculators
Confidential Appendix H.1:	Lancaster Dry Farm Ranch B PPA
Confidential Appendix H.2:	Comparison of Lancaster Dry Farm Ranch B PPA to 2010 RSC Pro Forma
Confidential Appendix I.1:	Sierra Solar Greenworks PPA
Confidential Appendix I.2:	Comparison of Sierra Solar Greenworks PPA to 2010 RSC Pro Forma
Confidential Appendix J.1:	Lancaster WAD B PPA
Confidential Appendix J.2:	Comparison of Lancaster WAD B PPA to 2010 RSC Pro Forma
Confidential Appendix K.1:	Central Antelope Dry Ranch B PPA
Confidential Appendix K.2:	Comparison of Central Antelope Dry Ranch B PPA to 2010 RSC Pro Forma
Confidential Appendix L.1:	Central Antelope Dry Ranch C PPA
Confidential Appendix L.2:	Comparison of Central Antelope Dry Ranch C PPA to 2010 RSC Pro Forma
Confidential Appendix M.1:	Victor Dry Farm Ranch A PPA
Confidential Appendix M.2:	Comparison of Victor Dry Farm Ranch A PPA to 2010 RSC Pro Forma
Confidential Appendix N.1:	Victor Dry Farm Ranch B PPA

Confidential Appendix N.2:	Comparison of Victor Dry Farm Ranch B PPA to 2010 RSC Pro Forma
Confidential Appendix O.1:	North Lancaster Ranch PPA
Confidential Appendix O.2:	Comparison of North Lancaster Ranch PPA to 2010 RSC Pro Forma
Confidential Appendix P.1:	American Solar Greenworks PPA
Confidential Appendix P.2:	Comparison of American Solar Greenworks PPA to 2010 RSC Pro Forma
Confidential Appendix Q.1:	Sierra View Solar V PPA
Confidential Appendix Q.2:	Comparison of Sierra View Solar V PPA to 2010 RSC Pro Forma
Confidential Appendix R.1:	Sierra View Solar IV PPA
Confidential Appendix R.2:	Comparison of Sierra View Solar IV PPA to 2010 RSC Pro Forma
Confidential Appendix S.1:	Nicolis PPA
Confidential Appendix S.2:	Comparison of Nicolis PPA to 2010 RSC Pro Forma
Confidential Appendix T.1:	Blythe Solar Power Generation Station 1 PPA
Confidential Appendix T.2:	Comparison of Blythe Solar Power Generation Station 1 PPA to 2010 RSC Pro Forma
Confidential Appendix U.1:	Littlerock Solar Power Generation Station 1 PPA
Confidential Appendix U.2:	Comparison of Littlerock Solar Power Generation Station 1 PPA to 2010 RSC Pro Forma
Confidential Appendix V.1:	Garnet Solar Power Generation Station 1 PPA
Confidential Appendix V.2:	Comparison of Garnet Solar Power Generation Station 1 PPA to 2010 RSC Pro Forma
Confidential Appendix W.1:	Lucerne Solar Power Generation Station 1 PPA
Confidential Appendix W2:	Comparison of Lucerne Solar Power Generation Station 1 PPA to 2010 RSC Pro Forma
Confidential Appendix X.1:	Tropico PPA

Confidential Appendix X.2:	Comparison of Tropico PPA to 2010 RSC Pro Forma
Confidential Appendix Y.1:	Clear Peak Energy PPA
Confidential Appendix Y.2:	Comparison of Clear Peak Energy PPA to 2010 RSC Pro Forma
Confidential Appendix Z.1:	RE Columbia 3 PPA
Confidential Appendix Z.2:	Comparison of RE Columbia 3 PPA to 2010 RSC Pro Forma
Confidential Appendix AA.1:	RE Columbia Two PPA
Confidential Appendix AA.2:	Comparison of RE Columbia Two PPA to 2010 RSC Pro Forma
Confidential Appendix BB:	Project Viability Calculators
Appendix CC:	Confidentiality Declaration
Appendix DD:	Proposed Protective Order

B. Subject of the Advice Letter

SCE's 2010 RSC Program offered two different contracts which vary depending on the size of the generating facility – one for facilities with capacities not greater than 5 MW and one for facilities with capacities greater than 5 MW but not greater than 20 MW. The RSC Contracts were offered to RPS-eligible resources for terms of 10, 15, and 20 years. The contracts were based on a simplified version of the Pro Forma Renewable Power Purchase and Sale Agreement for SCE's 2010 RPS solicitation.[1]

On September 15, 2010, SCE received a large number of offers for the 2010 RSC Program, representing over ten times the program's goal of 250 MW. SCE conducted a competitive solicitation using a reverse auction. All interested parties were allowed to comment on the pro forma contract and SCE incorporated many suggested changes prior to accepting offers. Project offers were submitted by offerors at a bid price they determined. Projects were then ranked by levelized price and selected from lowest to

[1] SCE filed its 2010 RPS Procurement Plan on December 19, 2009. SCE subsequently filed two motions to amend its plan, accompanied by amended versions of the 2010 RPS Procurement Plan, on April 9, 2010 and June 17, 2010. The approval of the 2010 RPS Procurement Plan is pending at the CPUC.

highest levelized price up to the 250 MW program cap. SCE seeks approval in this Advice Letter for 20 contracts executed through the 2010 RSC Program.[2]

All of the RSC Contracts are for 20-year terms and are for solar photovoltaic ("PV") projects constructing new facilities. Solar PV is a mature and proven renewable energy technology that has been supplying a substantial amount of renewable energy to SCE and other California load-serving entities ("LSEs") for several years. All RSC Contracts are priced below the approved 2009 market price referents ("MPRs"), the most current MPRs available when the offers for the RSC Contracts were received.[3]

The table below provides information regarding each of the 20 RSC Contracts. Additional information regarding the owners and developers of the 20 projects can be found in section III.A.

Project name	**Technology**	**General Location**	**Interconnection Point**	**Owner(s) / Developer(s)**	**Project background**	**Source of agreement**
Lancaster Dry Farm Ranch B	Solar PV	Lancaster	Switchgear on site	Silverado Power	New Project	RSC RFO
Sierra Solar Greenworks	Solar PV	Lancaster	Switchgear on site	Silverado Power	New Project	RSC RFO
Lancaster WAD B	Solar PV	Lancaster	Switchgear on site	Silverado Power	New Project	RSC RFO
Central Antelope Dry Ranch B	Solar PV	Lancaster	Switchgear on site	Silverado Power	New Project	RSC RFO
Central Antelope Dry Ranch C	Solar PV	Lancaster	Switchgear on site	Silverado Power	New Project	RSC RFO
Victor Dry Farm Ranch A	Solar PV	Victorville	Switchgear on site	Silverado Power	New Project	RSC RFO
Victor Dry Farm Ranch B	Solar PV	Victorville	Switchgear on site	Silverado Power	New Project	RSC RFO
North Lancaster Ranch	Solar PV	Lancaster	Switchgear on site	Silverado Power	New Project	RSC RFO
American Solar	Solar PV	Lancaster	Switchgear on site	Silverado Power	New Project	RSC RFO

[2] A total of 21 contracts were originally executed through the 2010 RSC Program. One contract was subsequently terminated.

[3] The 2009 MPRs were approved on December 17, 2009, in Resolution E-4298. No 2010 MPRs have been issued by the CPUC.

Project name	Technology	General Location	Interconnection Point	Owner(s) / Developer(s)	Project background	Source of agreement
Greenworks						
Sierra View Solar V	Solar PV	Mojave	Lancaster-Goldtown 66kV Line	juwi solar Inc.	New Project	RSC RFO
Sierra View Solar IV	Solar PV	Lancaster	Antelope - Neenach 66kV Line	juwi solar Inc.	New Project	RSC RFO
Weldon Solar	Solar PV	Weldon	Weldon substation	Foresight Renewables, LLC	New Project	RSC RFO
Blythe Solar Power Generation Station, 1 LLC	Solar PV	Blythe	Wedge / 12kV	Amonix, Inc.	New Project	RSC RFO
Littlerock Solar Power Generation Station, 1 LLC	Solar PV	Littlerock	Caliber 12kV line	Amonix, Inc.	New Project	RSC RFO
Garnet Solar Power Generation Station, 1 LLC	Solar PV	North Palm Springs	Pierson/33kV	Amonix, Inc.	New Project	RSC RFO
Lucerne Solar Power Generation Station, 1 LLC	Solar PV	Lucerne Valley	Lucerne Circuit / 33kV	Amonix, Inc.	New Project	RSC RFO
Great Lakes	Solar PV	Rosamond	Great Lakes substation	Foresight Renewables, LLC	New Project	RSC RFO
Holiday Solar Array	Solar PV	Rosamond	Neenach/12kV	Clear Peak Energy, Inc.	New Project	RSC RFO
RE Columbia 3	Solar PV	Mojave	12kV Line on Purdy Ave	Recurrent Energy	New Project	RSC RFO
RE Columbia Two	Solar PV	Mojave	66kV Line between Goldtown and Lancaster	Recurrent Energy	New Project	RSC RFO

C. General Project Description

The following table provides a general overview of the 20 RSC Contracts:

Project Name	Various
Technology	Solar PV
Capacity (MW)	Ranging from 4.71 MW to 20 MW
Capacity Factor	Ranging from 23% to 32%
Expected Generation (GWh/Year)	Total 567 GWh/Year
Initial commercial operational date	Ranging from April 3, 2013 to April 30, 2014
Date contract Delivery Term begins	Commercial Operation Date
Delivery Term (Years)	20
Vintage (New / Existing / Repower)	New
Location (city and state)	Various within California
Control Area (e.g., CAISO, BPA)	CAISO
Nearest Competitive Renewable Energy Zone (CREZ) as identified by the Renewable Energy Transmission Initiative (RETI)	18 projects – N/A 2 projects in Tehachapi CREZ: - Sierra View Solar V - Holiday Solar Array
Type of cooling, if applicable	None
Price relative to MPR (i.e. above/below)	Below

The table below provides specific details for each of the 20 RSC Contracts individually:

Project Name	Technology	Capacity (MW)	Capacity Factor	Expected Generation (GWh/Year)	Initial commercial operational date	Date contract Delivery Term begins	Delivery Term (Years)	Vintage	Location (all in CA)	Control Area	Nearest Competitive Renewable Energy Zone (CREZ) as identified by the Renewable Energy Transmission Initiative (RETI)[1]	Type of cooling, if applicable	Price relative to MPR
Lancaster Dry Farm Ranch B	Solar: PV	5.00	30.1%	12,230	4/2014	Commerical Operation Date	20	New	Lancaster	CAISO	N/A	None	below
Sierra Solar Greenworks	Solar: PV	20.00	23.5%	41,240	4/2014	Commerical Operation Date	20	New	Lancaster	CAISO	N/A	None	below
Lancaster WAD B	Solar: PV	5.00	30.1%	12,360	4/2014	Commerical Operation Date	20	New	Lancaster	CAISO	N/A	None	below
Central Antelope Dry Ranch B	Solar: PV	5.00	23.5%	10,200	4/2014	Commerical Operation Date	20	New	Lancaster	CAISO	N/A	None	below
Central Antelope Dry Ranch C	Solar: PV	20.00	23.5%	40,800	4/2014	Commerical Operation Date	20	New	Lancaster	CAISO	N/A	None	below
Victor Dry Farm Ranch A	Solar: PV	5.00	23.5%	10,290	4/2014	Commerical Operation Date	20	New	Victorville	CAISO	N/A	None	below
Victor Dry Farm Ranch B	Solar: PV	5.00	23.5%	10,290	4/2014	Commerical Operation Date	20	New	Victorville	CAISO	N/A	None	below
North Lancaster Ranch	Solar: PV	20.00	23.5%	40,810	4/2014	Commerical Operation Date	20	New	Lancaster	CAISO	N/A	None	below
American Solar Greenworks	Solar: PV	15.00	23.5%	30,930	4/2014	Commerical Operation Date	20	New	Lancaster	CAISO	N/A	None	below
Sierra View Solar V	Solar: PV	19.00	27.3%	49,974	3/2014	Commerical Operation Date	20	New	Mojave	CAISO	Tehachapi	None	below
Sierra View Solar IV	Solar: PV	19.00	27.0%	49,391	3/2014	Commerical Operation Date	20	New	Lancaster	CAISO	N/A	None	below
Weldon Solar	Solar: PV	20.00	28.6%	50,120	9/2013	Commerical Operation Date	20	New	Weldon	CAISO	N/A	None	below
Blythe Solar Power Generation Station, 1 LLC	Solar: PV	4.71	25.1%	12,157	6/2013	Commerical Operation Date	20	New	Blythe	CAISO	N/A	None	below
Littlerock Solar Power Generation Station, 1 LLC	Solar: PV	5.00	26.4%	13,608	4/2013	Commerical Operation Date	20	New	Littlerock	CAISO	N/A	None	below
Garnet Solar Power Generation Station, 1 LLC	Solar: PV	4.78	23.0%	11,313	6/2013	Commerical Operation Date	20	New	North Palm Springs	CAISO	N/A	None	below
Lucerne Solar Power Generation Station, 1 LLC	Solar: PV	13.97	26.1%	37,587	3/2014	Commerical Operation Date	20	New	Lucerne Valley	CAISO	N/A	None	below
Great Lakes	Solar: PV	14.00	29.6%	36,240	9/2013	Commerical Operation Date	20	New	Rosamond	CAISO	N/A	None	below
Holiday Solar Array	Solar: PV	8.50	31.6%	23,552	12/2013	Commerical Operation Date	20	New	Lancaster	CAISO	Tehachapi	None	below
RE Columbia 3	Solar: PV	10.00	28.4%	24,901	1/2014	Commerical Operation Date	20	New	Mojave	CAISO	N/A	None	below
RE Columbia Two	Solar: PV	20.00	28.1%	49,293	1/2014	Commerical Operation Date	20	New	Mojave	CAISO	N/A	None	below

D. General Deal Structure

The general deal structure for all 20 RSC projects is the same, and is based on a simplified version of the Pro Forma Renewable Power Purchase and Sale Agreement for SCE's 2010 RPS solicitation. SCE is purchasing all electric energy produced by the RSC projects throughout the contract terms, including all green attributes, capacity attributes, and resource adequacy benefits generated by, associated with, or attributable to, the output from the generating facilities.

All 20 RSC Contracts have 20-year terms, which begin on their respective commercial operation dates. The term start date must occur within three years of CPUC approval.[4] Each producer will post development security. For producers with a project not greater than 5 MW, the development security will be $30 per kW of the contract capacity. For producers with a project greater than 5 MW but not greater than 20 MW, the development security will be $60 per kW of the contract capacity.[5] Performance assurance is required for producers with a project greater than 5 MW but not greater than 20 MW; the performance assurance amount ranges, during the term, from 3 percent to 6 percent of total project revenues but will not be less than $1 million.

There are no firming or shaping costs in the RSC Contracts. All of the interconnection points and delivery points are within California and the California Independent System Operator ("CAISO")-controlled grid. Additional information regarding the deal structure of the RSC Contracts is provided in Appendix D.

E. RPS Statutory Goals

By providing renewable energy from an eligible renewable energy resource ("ERR") as defined under the RPS Legislation, the RSC projects are consistent with, and contribute to, the RPS program's statutory goals. Among other things, by supporting new renewable energy generation projects in California, the RSC Contracts help to ensure stable electricity prices, protect public health, improve environmental quality, stimulate economic development, and create new employment opportunities.

F. Confidentiality

SCE is requesting confidential treatment of Appendices A-B, D-E, and G-BB, as well as the confidential version of Appendix C. The information for which SCE is seeking

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[4] This term start date, however, is subject to an extension as a result of force majeure.

[5] One-half of the development security will be due within 30 days following the effective date; the other half will be due within 30 days following CPUC approval. If, by the term start date, each producer has installed all of the equipment necessary for the generating facility to operate, deliver product, and satisfy the contract capacity of the generating facility, SCE will return the development security to the producer.

confidential treatment is identified in Appendix CC hereto. The confidential version of this Advice Letter will be made available to appropriate parties (in accordance with SCE's Proposed Protective Order, as discussed below) upon execution of the required non-disclosure agreement. Parties wishing to obtain access to the confidential version of this Advice Letter may contact Joni Templeton in SCE's Law Department at Joni.Templeton@sce.com or (626) 302-6210 to obtain a non-disclosure agreement. In accordance with GO 96-B, a copy of SCE's Proposed Protective Order is attached hereto as Appendix DD. It is appropriate to accord confidential treatment to the information for which SCE requests confidential treatment in the first instance in the advice letter process because such information is entitled to confidentiality protection pursuant to Decision ("D.") 06-06-066 and is required to be filed by advice letter as part of the process for obtaining Commission approval of RPS power purchase agreements ("PPAs").

The information in this Advice Letter for which SCE requests confidential treatment, the pages on which the information appears, and the length of time for which the information should remain confidential are provided in Appendix CC. This information is entitled to confidentiality protection pursuant to D.06-06-066 (as provided in the Investor-Owned Utility ("IOU") Matrix). The specific provisions of the IOU Matrix that apply to the confidential information in this Advice Letter are identified in Appendix CC.

II. CONSISTENCY WITH COMMISSION DECISIONS

A. SCE's RPS Procurement Plans

1. SCE's 2009 RPS Procurement Plan Was Approved by the Commission and SCE Adhered to Commission Guidelines for Filing and Revisions

In D.09-06-018, the Commission conditionally approved SCE's 2009 RPS Procurement Plan, including the solicitation materials for SCE's 2009 RPS solicitation. The Commission also ordered SCE to make certain changes to its 2009 RPS Procurement Plan and to file the amended documents with the Director of the Energy Division, and serve such documents on the service list, by June 22, 2009. On June 22, 2009, SCE filed and served its Amended 2009 RPS Procurement Plan, including its amended 2009 solicitation materials. On June 26, 2009, SCE filed and served its Second Amended 2009 RPS Procurement Plan, including its further amended 2009 solicitation materials. Consistent with the schedule set forth in D.09-06-018, SCE issued its 2009 request for proposals ("RFP") on June 29, 2009.

On June 19, 2009, the Commission issued D.09-06-050, which approved a fast-track review process allowing for the use of Tier 2 advice letter filings for short-term RPS contracts of less than 10 years duration that meet certain criteria set forth in the decision. The Commission also directed the IOUs to submit their pro forma short-term contracts as amendments to their 2009 RPS Procurement Plans within 14 days from the

date of the decision. Pursuant to D.09-06-050 and an extension of time granted by the Commission's Executive Director, on July 17, 2009, SCE filed and served its Third Amended 2009 RPS Procurement Plan, including its very short-term pro forma confirmations and certain other further amended 2009 solicitation materials. As SCE's Third Amended 2009 RPS Procurement Plan was not suspended by the Commission's Executive Director or Energy Division Director by July 24, 2009, SCE used its short-term pro forma confirmations and other further amended 2009 solicitation materials in its 2009 RFP as of that date.

2. Summary of SCE's Assessment of Portfolio Needs

SCE's 2009 RPS Procurement Plan indicated that SCE planned to seek eligible renewable energy resources ("ERRs") to the extent necessary to ensure that SCE meets the overall goal of 20 percent renewables as soon as possible. SCE also noted that it intended to procure based on a High Need Case procurement scenario in order to account for potential project success rates and other contingencies. Furthermore, SCE indicated that it has both a near-term and long-term need for renewable energy, and that SCE's evaluation criteria favor proposals for renewable energy sales from generating facilities with near-term deliveries. SCE also stated its evaluation criteria consider the benefits of projects locating near approved transmission infrastructure, such as the Sunrise Powerlink Transmission Project and Tehachapi Renewable Transmission Project.

SCE's 2009 RFP solicited proposals to supply electric energy, as well as all attributes, including, but not limited to, green attributes, capacity attributes, and resource adequacy benefits from ERRs. SCE solicited standard products, moderately short-term products, and very short-term products. SCE stated that it would consider all timely proposals to sell products to SCE from either a new or existing generating facility that can be certified by the California Energy Commission ("CEC") as an ERR or multiple ERRs. Additionally, SCE noted that if the generating facility is not, or cannot be, fully certified as an ERR, then only the electric energy produced by the renewable fuel will be considered as electric energy produced by an ERR, as determined by the CEC.

SCE's 2009 RPS Procurement Plan included SCE's voluntary 2009 RSC Program, which offered two standard contracts for the purchase of renewable energy from facilities located within the CAISO-controlled grid with capacities of (1) not-greater-than 5 MW and (2) greater than 5 MW but not-greater-than 20 MW. Both contracts were based on SCE's 2009 Pro Forma Renewable Power Purchase and Sale Agreement, although the not-greater-than 5 MW contract lowered the requirements for development security and removed the requirements for performance assurance deposits.

SCE filed its 2010 RPS Procurement Plan on December 18, 2009. Subsequently, on April 9, 2010 and June 17, 2010, SCE filed motions to amend its 2010 RPS Procurement Plan, which included amended versions of the 2010 RPS Procurement Plan as attachments. As amended, SCE's 2010 RPS Procurement Plan noted that SCE planned to initiate a 2010 RSC Program with a goal of 250 MW. SCE also stated

that it would award contracts based on a request for offers ("RFO"). The Commission has not yet acted on SCE's 2010 RPS Procurement Plan.

3. The RSC Contracts Conform to SCE's Portfolio Needs

Although the RSC Contracts are separate and apart from the agreements executed as a result of SCE's annual solicitation, the RSC Contracts fall within the criteria identified in SCE's 2009 and 2010 RPS Procurement Plans, are expected to contribute significantly toward achievement of SCE's RPS procurement goals, and are consistent with SCE's portfolio needs. Specifically, the 20 RSC projects satisfy SCE's need for eligible renewable energy with a total capacity of 239 MW over a 20-year term. Moreover, the RSC Contracts satisfy SCE's locational preferences and delivery requirements.

4. The RSC Contracts Meet the Project Characteristics for SCE's 2009 RPS Solicitation

SCE's 2009 RFP requested proposals with a minimum capacity of 1.5 MW. As discussed above, SCE preferred proposals for renewable energy sales from generating facilities with near-term deliveries. SCE also considered the benefits of projects locating near approved transmission infrastructure, such as the Sunrise Powerlink Transmission Project and Tehachapi Renewable Transmission Project.

SCE's locational preferences included: (1) California or (2) outside California if the seller complies with all requirements pertaining to "Out-of-State Facilities" as set forth in the CEC RPS Eligibility Guidebook. SCE stated that it prefers in-state facilities.

Additionally, SCE indicated that the delivery point for generating facilities interconnected to the CAISO Control Area must be: (1) the point where the generating facility connects to the CAISO controlled grid if SCE is the scheduling coordinator; or (2) at a point to be determined by SCE. For generating facilities interconnected outside the CAISO Control Area, SCE stated the delivery point must be: (1) the intertie point where seller's transmission provider ties to the CAISO Control Area and seller's scheduling coordinator schedules energy to SCE, as scheduling coordinator within the CAISO Control Area, via an Inter-SC Trade (also known as a scheduling coordinator-to-scheduling coordinator trade); (2) a liquid power trading hub or hubs outside of the CAISO Control Area (e.g., Mid-Columbia); (3) at the generating facility's first point of interconnection with the respective transmission provider's transmission grid, provided, however, that seller has (or will have) firm transmission rights to a liquid trading hub or CAISO for the duration of the term of the agreement that is acceptable to SCE; or (4) at a point to be determined by SCE.

Although the RSC Contracts were not part of the 2009 RPS solicitation, they meet all project characteristics for SCE's 2009 RFP. Specifically, all of the RSC projects are located in California, deliver to the CAISO-controlled grid, and commence operation within three years from CPUC approval of the RSC Contracts. The RSC Contracts

meet SCE's near-term and long-term need for RPS-eligible energy and contribute significantly to the State's RPS goals.

B. The RSC Contracts Comply With the Commission's Decisions on Bilateral Contracting

In D.06-10-019, the Commission held that LSEs may enter into bilateral contracts with RPS-eligible generators, as long as the contracts are at least one month in duration. The Commission stated that IOUs' bilateral RPS contracts must be submitted to the Commission for approval by advice letter, and that bilateral RPS contracts are not eligible for supplemental energy payments.[6] In addition, the Commission held that while bilateral contracts are not subject to the MPR, they must be reasonable.

In D.09-06-050, the Commission held that bilateral contracts should be reviewed according to the same processes and standards as contracts that come through a solicitation. Additionally, the Commission found that the MPR should be used as a price benchmark for the evaluation of long-term bilateral contracts. The Commission also held that the contract review standards and processes set out in D.09-06-050 for very short-term contracts and moderately short-term contracts govern both bilateral contracts and contracts that are the result of a solicitation.

As discussed throughout this Advice Letter, the RSC Contracts comply with the requirements of D.06-10-019 and D.09-06-050. In particular, the RSC Contracts are all at least one month in duration and SCE is submitting the contracts for approval via an advice letter. The RSC Contracts are also reasonable based on the same review standards and processes applicable to solicitation contracts as set forth in D.09-06-050. As discussed in more detail below and in the confidential appendices, a least-cost/best-fit ("LCBF") analysis demonstrates that the RSC contracts are reasonable.

The RSC Contracts were pursued through the 2010 RSC Program, which was designed to provide smaller renewable projects with opportunities to contribute to the State's RPS goals. SCE voluntarily initiated the RSC Program in 2007 (then called the "Biomass Program") to support then-Governor Arnold Schwarzenegger's goal to promote energy production from biomass fuel sources.[7] Through this program, SCE has sought to remove some of the barriers that smaller projects may have had when participating in SCE's annual solicitations and increase opportunities for such projects to execute contracts with SCE. In 2009, SCE made the RSC Program available to any facility with capacity of 20 MW or less that meets the ERR certification criteria established by the CEC.

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[6] Supplemental energy payments were eliminated under Senate Bill ("SB") 1036. Pursuant to SB 1036, the Commission now approves above-market funds for RPS contracts.

[7] *See* Executive Order S-06-06.

In D.09-06-018, the Commission accepted SCE's 2009 RSC Program as part of SCE's 2009 RPS Procurement Plan, although it reached no judgment on the standard contracts. The Commission also recognized SCE's initiative and innovation with its RSC Program. The Commission approved 12 contracts executed through the 2009 RSC Program in Resolution E-4359.

The 2009 RSC Program offered standardized contracts for projects up to 20 MW priced at the MPR. Applicants submitted applications to the program and were accepted on a first-come-first-served basis until the 250 MW program cap was satisfied. As indicated in SCE's 2010 RPS Procurement Plan, for the 2010 RSC Program, SCE continued to utilize standardized contracts for projects up to 20 MW; however, SCE conducted a competitive solicitation.[8] SCE utilized a reverse auction for the solicitation. All interested parties were allowed to comment on the pro forma contract and SCE incorporated many suggested changes prior to accepting offers. Project offers were submitted by offerors at a bid price they determined. Projects were then ranked by levelized price and selected from lowest to highest levelized price up to the 250 MW program cap.[9]

In D.10-12-048, the Commission adopted the Renewable Auction Mechanism ("RAM"), which is a Commission-mandated program requiring all IOUs to provide a standardized procurement process for projects up to 20 MW in size. Per D.10-12-048, SCE is required to discontinue the RSC Program going forward to conform to the framework of the RAM, but Commission-approved contracts executed under SCE's 2010 RSC Program will count towards the capacity cap set by D.10-12--048.

C. Least Cost Best Fit ("LCBF") Methodology and Evaluation

As explained above, SCE issued its 2009 RFP on June 29, 2009 in compliance with D.09-06-018 and SCE's Commission-approved solicitation materials. On July 24, 2009, SCE expanded its 2009 RFP to include very short-term and moderately short-term products and very short-term pro forma confirmations pursuant to D.09-06-050. In accordance with SCE's Commission-approved solicitation materials, sellers were required to submit their proposals in response to SCE's 2009 RFP on August 21, 2009. SCE submitted its 2009 Solicitation Short List Report to the Commission on December 4, 2009.

SCE evaluates and ranks proposals based on LCBF criteria that comply with criteria set forth by the Commission in D.03-06-071 and D.04-07-029 (the "LCBF Decisions"). The LCBF analysis evaluates both quantitative and qualitative aspects of each proposal to estimate its value to SCE's customers and its relative value in comparison to other proposals. The LCBF analysis was used to evaluate the proposals SCE received in its

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[8] As stated above, the Commission has not yet acted on SCE's 2010 RPS Procurement Plan.

[9] For a detailed explanation of the competitive solicitation procedures for the 2010 RSC Program, see Appendix C.

2009 RPS solicitation.[10] SCE applied these criteria to the proposals received in its 2009 solicitation in order to establish a "short list" of proposals from sellers with whom SCE would engage in contract discussions.

While assumptions and methodologies have evolved slightly over time, the basic components of SCE's evaluation and selection criteria and process for RPS contracts were established by the Commission's LCBF Decisions. Consistent with those LCBF Decisions, the three main steps undertaken by SCE are: (i) initial data gathering and validation, (ii) a quantitative assessment of proposals, and (iii) adjustments to selection based on proposals' qualitative attributes.

Prior to receiving proposals, SCE finalizes major assumptions and methodologies that drive valuation, including power and gas price forecasts, existing and forecast resource portfolio, and capacity value forecast. Other assumptions, such as the Transmission Ranking Cost Report ("TRCR"), are filed with the Commission for approval prior to the release of solicitation materials.

Once proposals are received, SCE begins an initial review for completeness and conformity with the solicitation protocol. The review includes an initial screen for required submission criteria such as conforming delivery point, minimum project size, and submission of particular proposal package elements. Sellers lacking in any of these items are allowed a cure period to remedy any deficiencies. Following this initial screen, SCE conducts an additional review to determine the reasonableness of proposal parameters such as generation profiles and capacity factors. SCE works directly with sellers to resolve any issues and ensure data is ready for evaluation.

After these reviews, SCE performs a quantitative assessment of each proposal individually and subsequently ranks them based on the proposal's benefit and cost relationship. Specifically, the total benefits and total costs are used to calculate the net levelized cost or "renewable premium" per each complete and conforming proposal. Benefits are comprised of separate capacity and energy components, while costs include the contract payments, integration costs, transmission cost, and debt equivalence. SCE discounts the annual benefit and cost streams to a common base year. The result of the quantitative analysis is a merit-order ranking of all complete and conforming proposals' renewable premiums that helps define the preliminary short list.

In parallel with the quantitative analysis, SCE conducts an in-depth assessment of each proposal's qualitative attributes. This analysis utilizes the Commission's prescribed Project Viability Calculator to assess certain factors including the company/development team, technology, and development milestones. Additional attributes such as transmission area/cluster, seller concentration, portfolio fit of commercial on-line date, project size, and dispatchability and curtailability are also considered in the qualitative analysis. These qualitative attributes are then considered to either eliminate non-viable

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[10] SCE has compared the RSC Contracts to the proposals received in its 2009 RPS solicitation since that was the most recent information available to SCE at the time the RSC Contracts were negotiated and executed. Therefore, SCE discusses its LCBF methodology for the 2009 solicitation in this Advice Letter.

proposals or add projects with high viability to the final short list of proposals, or to determine tie-breakers, if any.

Following its analysis, SCE consults with its Procurement Review Group ("PRG") regarding the final short list and specific evaluation criteria. Whether a proposal selected through this process results in an executed contract depends on the outcome of negotiations between SCE and sellers. Periodically, SCE updates the PRG regarding the progress of negotiations. SCE also consults with its PRG prior to the execution of any successfully negotiated contracts. Subsequently, SCE executes contracts and submits them to the Commission for approval via advice letter filings.

A complete discussion of SCE's RPS Proposal Evaluation and Selection Process and Criteria is provided in Appendix F.

The RSC Contracts were executed as part of SCE's RSC Program and not an SCE solicitation. However, SCE performed an LCBF evaluation of the RSC Contracts in comparison to the proposals SCE received in its 2009 RPS solicitation in accordance with Resolution E-4199 and D.09-06-050. Details regarding the LCBF analysis of the RSC Contracts are provided in Appendix A.

D. Compliance with Standard Terms and Conditions

In D.04-06-014, the Commission established a number of "modifiable" and "non-modifiable" standard terms and conditions to be used by LSEs when contracting for RPS-eligible resources. In D.07-11-025, the Commission reduced the number of "non-modifiable" terms to the following four terms: (1) "CPUC Approval;" (2) "RECs and Green Attributes;" (3) "Eligibility;" and (4) "Applicable Law." The remaining "non-modifiable" terms were converted to "modifiable." In D.08-04-009, the Commission compiled the standard terms and conditions in one document and deleted the "modifiable" standard term and condition on supplemental energy payments from the standard terms and conditions. In D.08-08-028, the Commission revised the "non-modifiable" "RECs and Green Attributes" standard term and condition.

The RSC Contracts include the four "non-modifiable" terms identified above without change.

Pursuant to D.04-06-014, D.07-11-025, and D.08-04-009, SCE is permitted to modify the "modifiable" terms. With the RSC Program standard contracts, few, if any, of the terms in SCE's pro forma RSC PPAs are modified during the negotiation process with the sellers. Accordingly, the RSC Contracts contain only limited modifications necessary to accommodate project specific requirements. These modifications include the same principles and serve the same purpose as the standard terms, and are consistent with the law and government regulations. Thus, the modifications contained in the RSC Contracts are permissible.

In D.10-03-021, as modified by D.11-01-025, the Commission established two additional "non-modifiable" terms relating to renewable energy credits. As the RSC Contracts were already executed when D.11-01-025 was issued, they do not currently include the additional standard terms. SCE is currently working to amend the contracts pursuant to D.11-01-025.

E. Unbundled Renewable Energy Credit ("REC") Transactions

SCE is purchasing bundled RPS-eligible energy and green attributes under the RSC Contracts. Moreover, the RSC projects all have a first point of interconnection with a California balancing authority. Accordingly, the RSC Contracts are not unbundled REC transactions under D.10-03-021, as modified by D.11-01-025.

F. Minimum Quantity

In D.07-05-028, the Commission held that, beginning in 2007, each LSE obligated under the RPS program must enter into long-term contracts[11] or short-term contracts with new facilities[12] for energy deliveries equivalent to 0.25% of that LSE's prior year's retail sales, in order to be able to count for RPS compliance energy deliveries from short-term contracts with existing facilities. The Commission also ruled that RPS-obligated LSEs may carry forward contracted energy in long-term contracts and short-term contracts with new facilities that is in excess of the 0.25% requirement in the year such contracts are signed, to be used for compliance for the minimum-quantity requirement in future years.

The 20 RSC Contracts are long-term PPAs associated with new generation facilities. Therefore, the minimum-quantity requirement does not apply.

G. MPR

The RSC Contracts have levelized prices below the 2009 MPRs, which are the most current MPRs available. The RSC Contracts, moreover, have no firming and shaping costs, so the total prices remain below the 2009 MPRs.

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[11] Long-term contracts are contracts of at least 10 years duration. *See* Cal. Pub. Util. Code § 399.14.

[12] New facilities are facilities that commenced commercial operations on or after January 1, 2005. *See* Cal. Pub. Util. Code § 399.14.

H. Above Market Funds ("AMFs")

The RSC Contracts have levelized prices below the 2009 MPRs. Therefore, no AMFs are required based on the energy prices for the RSC Contracts in comparison to the 2009 MPRs. The AMF Calculators and a summary are included in Appendix G.

I. Interim Emissions Performance Standard

The California Legislature passed Senate Bill ("SB") 1368 on August 31, 2006 and Governor Schwarzenegger signed the bill into law on September 29, 2006. Section 2 of SB 1368 adds Public Utilities Code section 8341(a), which provides that "No load-serving entity or local publicly owned electric utility may enter into a long-term financial commitment unless any baseload generation supplied under the long-term financial commitment complies with the greenhouse gases emission performance standard established by the commission, pursuant to subdivision (d)."[13]

In order to institute the provisions of SB 1368, the Commission instituted Rulemaking 06-04-009. This proceeding resulted in the establishment of a greenhouse gas ("GHG") emissions performance standard ("EPS"), for carbon dioxide ("CO_2"). The Commission noted, "SB 1368 establishes a minimum performance requirement for any long-term financial commitment for baseload generation that will be supplying power to California ratepayers. The new law establishes that the GHG emissions rates for these facilities must be no higher than the GHG emissions rate of a combined-cycle gas turbine (CCGT) power plant."[14]

The decision further explains:

> SB 1368 describes what types of generation and financial commitments will be subject to the EPS ("covered procurements"). Under SB 1368, the EPS applies to "baseload generation," but the requirement to comply with it is triggered only if there is a "long-term financial commitment" by an LSE. The statute defines baseload generation as "electricity generation from a power plant that is designed and intended to provide electricity at an annualized plant capacity factor of at least 60%." . . . For baseload generation procured under contract, there is a long-term commitment when the LSE enters into "a new or renewed contract with a term of five or more years."[15]

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[13] Cal. Pub. Util. Code § 8341(a).

[14] D.07-01-039 at 2-3.

[15] *Id*. at 4.

The RSC Contracts are exempt from EPS regulations because they have expected annualized capacity factor ranging from 23 percent to 32 percent, well below the threshold baseload capacity factor of 60 percent, above which the EPS rules would apply.

J. PRG Participation

SCE's PRG was formed on or around September 10, 2002. Participants include representatives from the Commission's Energy and Legal Divisions, the Division of Ratepayer Advocates, The Utility Reform Network, the Natural Resources Defense Council, California Utility Employees, the Union of Concerned Scientists and the California Department of Water Resources.

Offers for the 2010 RSC Program were received September 15, 2010. On September 29, 2010, SCE briefed the PRG concerning the 2010 RSC Program. On November 10, 2010, SCE updated the PRG concerning the status of the RSC Contracts, which were then executed on November 15, 2010.

K. Independent Evaluator ("IE")

The IE for the 2010 RSC Program was Merrimack Energy Group, Inc. The IE joined and contributed to a number of conference calls and negotiation sessions. In addition, the IE reviewed email traffic, the draft pro forma RSC contract, and other documents exchanged by the parties. The IE also participated in the PRG review of the RSC Contracts on November 10, 2010. The IE Report is included as Appendix C.

III. PROJECT DEVELOPMENT STATUS

A. Company / Development Team

The developers who participate in the RSC Program have varying degrees of experience in the field of renewable energy project development. Specific information on the six developers for the 20 RSC Contracts is provided below.[16]

- Amonix, Inc. ("Amonix"): Amonix, the parent company of Blythe Solar Power Generation Station, 1 LLC, Garnet Solar Power Generation Station, 1 LLC, Littlerock Solar Power Generation Station, 1 LLC, and Lucerne Solar Power Generation Station, 1 LLC, is a leading designer and manufacturer of concentrated photovoltaic ("CPV") solar power systems. Amonix CPV technology has been operated at 16 locations throughout the Southwestern United States, and in Spain. Founded in 1989, Amonix is headquartered in Seal Beach, California, with additional facilities in Torrance, California. Amonix's executive team includes:

[16] This information is based on documents submitted by the developers to SCE, and has not all been independently verified by SCE.

- Brian Robertson, CEO. Previously, Mr. Robertson was co-founder and former President of SunEdison, where he oversaw the construction, financing, and operation of over 150 commercial, industrial, and utility-scale solar PV projects.
- Guy Blanchard, Senior Vice President, Corporate Development. Mr. Blanchard has extensive capital markets experience with a focus on energy and renewable energy investments.
- Matthew Meares, Director of Project Finance. Mr. Meares has closed over $382 million in solar transactions and over $1 billion in wind project financings.

Amonix has substantial prior experience both developing its own projects using its CPV technology and supplying its CPV technology with value-added support for deployment by other project developers. Amonix has supplied its technology to nearly 75 percent of the world's CPV installations, including five projects of 1 MW to 5.8 MW that are operating in Spain, and 4 projects smaller than 1 MW operating in the United States. Amonix is co-developing its RSC projects with one of the largest heavy civil construction contractors in the United States

- Clear Peak Energy, Inc. ("Clear Peak"): Clear Peak is a publicly traded Nevada Corporation organized to develop and operate clean solar electric power plants incorporating proven, lower-cost, PV technology. Clear Peak partnered with Aubrey Silvey Enterprises, Inc. ("Silvey"), which will serve as general contractor for the proposed project.

  Silvey is a global leader of technical, project, and operational support services and provides comprehensive services to the power industry in all aspects of renewable project execution including civil engineering and design, electrical engineering and design, construction, interconnection, commissioning and maintenance. Silvey has nearly 40 years of history with large utility scale power and renewable energy projects for major clients throughout the United States that include utilities such as SCE, Los Angeles Department of Water and Power, Pacific Gas and Electric Company, and San Diego Gas & Electric Company.

  Silvey's Renewable Energy Division develops renewable energy-specific projects throughout the United States. The division has successfully completed or is currently working on over 275 MW of wind power generation projects since 2007, with 120 MW currently in progress. In addition, Silvey's staff has engineered and designed 38 MW of solar PV projects since 2008. Silvey's current and recent projects include balance of plant services for wind projects in states including Oregon, Utah and Idaho.

- Foresight Renewables, LLC ("Foresight"): Foresight, the parent company of Tropico LLC and Nicolis LLC, has nearly 3,500 MW under development through Foresight Wind and over 200 MW through Foresight Solar. Foresight's founder and CEO, Warren Byrne, has over 20 years experience in power development, having started his career at Caithness Energy in 1987. Several Vice Presidents also have over 20 years of experience, including Paul Andrae, former director of

transmission and distribution development for PNM and John Fedorko, former Senior Vice President for Airtricity. Foresight's principals have played lead roles in the development of over 1,235 MW of operating electricity projects. The projects include Foresight Wind's 100 MW High Lonesome Mesa wind project in New Mexico, currently owned by Edison Mission Wind, and Airtricity's 900 MW Roscoe project, now owned by E.On.

- juwi solar Inc. ("juwi solar"): juwi solar, the parent company of Sierra View Solar V LLC and Sierra View Solar IV LLC, is a developer and turnkey engineering, procurement, and construction contractor of solar power plants throughout North America. Its majority shareholder is juwi Holding AG, which ranks among Europe's leading renewable energy companies. The juwi solar team, with combined experience of over 75 years, has developed, financed and built energy projects involving wind, hydropower, solar PV, geothermal, combined-cycle and coal-fired technologies, the aggregate of which have a generation capacity in the thousands of megawatts. Specifically, juwi solar has been involved in the development, design, construction and operation of more than 1,000 PV projects, with a current total generation capacity of 300 MW. Its project experience covers the full range of project development activities, including development, design engineering, energy generation modeling, project permitting, project finance, legal support, project construction, commissioning, operation and maintenance.

  Key members of the juwi solar team who will implement the projects include:

  - Michael Martin, Managing Director. Mr. Martin joined juwi solar in April of 2008. He has over 20 years experience that includes senior level finance and development positions for renewable energy generation companies. At Morgan Stanley, he was involved in the development and execution of over $3 billion in equity and debt-related financings. At Deutsche Bank, he covered the Latin American Electric Utilities sector. At Econergy International PLC, he managed a pipeline of wind, hydro and solar projects through development and construction stages in the United States and Latin America.
  - Steve Ihnot, Chief Financial Officer. Mr. Ihnot has 15 years of experience in the electric power business in various roles in finance and development both in the United States and internationally.
  - Scott Leach, Business Development Associate. Mr. Leach has seven years of experience working within the business and financial structures of renewable energy projects. In 2009, he helped lead the development of over 45 MW of solar energy generation facilities that are currently in operation or under construction, including the 12 MW Wyandot Solar project (Ohio), 16 MW Jacksonville Solar project (Florida) and 16 MW Blue Wing Solar project (Texas).

  There are five operating solar PV projects greater than 1 MW built by the juwi solar team in the United States.

- Recurrent Energy: Recurrent Energy, the parent company of RE Columbia 3 LLC and RE Columbia Two, LLC, is a leading solar development company. Recurrent Energy was venture capital funded and was recently acquired by Sharp Corporation. Recurrent Energy has a portfolio of over 370 MW of contracted projects and an established development pipeline of 2 GW. Four projects greater than 1 MW are operating (26 MW total).

  Recurrent Energy's leadership team brings more than 100 years of solar and energy project experience with various companies. Specific to the development team, Recurrent Energy has over 30 years combined experience in conventional and renewable power development. Key leaders of the development team are discussed below.

  - Sheldon Kimber, Senior Vice President, Development. Mr. Kimber leads all North American project development, expansion, and origination activities. Formerly the Vice President of Finance at Recurrent Energy, he was instrumental in developing and negotiating the company's existing projects, fundraising efforts, and joint venture agreements. Previously, he spent five years at Calpine Corporation, working on gas-fired power projects and power purchase agreements with large energy customers. He also worked as an investment banker at Goldman Sachs, and in Accenture's strategy consulting practice.
  - Tiffany Elliott, Vice President, Origination and Structuring. Ms. Elliott has over 11 years industry experience leading the origination and structuring of tailored commodity transactions. Prior to joining Recurrent Energy, she served as Executive Director at Amerex Energy Consulting, where she was engaged by several renewable companies developing solar, wind, and biomass projects. She was a Director at Citigroup Energy where she was responsible for the execution of structured power and natural gas. She worked at Calpine Energy Services for over 6 years where she structured, originated and subsequently monetized several profitable transactions.
  - André DeVilbiss, Director, West Region Development. Mr. DeVilbiss has over eight years of financial transaction experience, and three years experience specific to solar development at Recurrent Energy. He has been involved in the development of the company's California projects as well as the Arizona projects which are slated to come on-line in 2011. He is responsible for identifying sites, obtaining permits and interconnection agreements, and negotiating PPAs. Prior to Recurrent Energy, he was a Vice President at Bank of America Securities LLC.

- Silverado Power ("Silverado"): Silverado, the parent company of American Solar Greenworks, LLC, Central Antelope Dry Ranch B, LLC, Central Antelope Dry Ranch C, LLC, Lancaster Dry Farm Ranch B, LLC, Lancaster WAD B, LLC, North Lancaster Ranch, LLC, Sierra Solar Greenworks, LLC, Victor Dry Farm Ranch A, LLC, and Victor Dry Farm Ranch B, LLC, is a joint venture between a group of industry veterans and Martifer Solar, a large European energy and infrastructure company. The Silverado Power team has over 50 years of collective development

experience for over 500 MW of solar development, financing and construction, including industry-leading green field utility scale and commercial projects.

Silverado's experienced team is designed to provide solutions to the biggest challenges facing renewable energy development, typically permitting, interconnection, and financing. The team includes utility engineers, land development professionals, and capital finance experts.

The Martifer Group is a multinational infrastructure company based in Portugal, with a focus on construction and renewable energy. Martifer was founded in 1990, and presently has more than 4,000 employees. The group's holding company, Martifer SGPS, SA (Euronext: MAR) has been publicly traded on the Euronext Lisbon since June 2007.

Martifer Solar is a wholly owned subsidiary of the Martifer Group. The core business of Martifer Solar is to offer turnkey PV solutions, including development, engineering services, module and solar tracker production, facility construction, operation and maintenance. The company operates in 16 countries and has constructed more than 100 MW in PV energy worldwide. Martifer's list of "finished installations and ongoing projects" since 2007 shows 27 projects 1 MW or larger.

Three of the key principals of Silverado are listed below.

- John Cheney, CEO and co-founder of Silverado. Mr. Cheney has founded and served as CEO or Managing Partner of several companies including Varitel Video, RTE One, Avenue Technologies and RocketFiber. In his previous role as Vice President of Sales and Business Development for MMA Renewable Ventures, he helped turn the company into the largest financier of solar PV installations in the United States. After completing $450 Million of solar installations across the country, MMA Renewable Ventures was sold to FRV of Spain.
- Hans Isern, Vice President Engineering. Mr. Isern brings to Silverado a combination of electrical energy industry experience across all stages of power plant development. He has led teams in diverse roles including utility engineering, power trading, regulatory affairs, and generation development and finance. Prior to his current role, he led development in Southern California for Recurrent Energy. He created a 350 MW pipeline, led negotiations for 50 MW of solar projects with SCE, and oversaw interconnection and permitting processes for a wide range of projects.
- Jim Howell, Vice President Development. Mr. Howell has an extensive background in asset creation through structuring and contract negotiations. He is responsible for Silverado's regional development strategies, resource deployment and policy for entering new renewable energy markets. He also came to Silverado after a successful stint with Recurrent Energy.

B. Technology

1. Technology Type and Level of Technology Maturity

All of the RSC projects will utilize proven and mature solar PV technology. Solar PV technology is well-established and has been supplying a substantial amount of renewable energy to SCE and other California LSEs for several years

2. Quality of Renewable Resource

The RSC projects are located throughout Southern California, an area well-recognized for its robust solar resources as demonstrated by several sources of solar generation throughout the region.

SCE believes that each RSC project will be able meet the terms of the contract given SCE's independent understanding of the quality of the renewable resources.

3. Other Resources Required

The RSC projects will require water for use in ancillary road maintenance or blade/panel cleaning. The water will be provided by local water providers. SCE expects that water used for the site roads will be absorbed into the ground and back into the natural underground aquifers, where it will be recycled naturally.

C. Development Milestones

1. Site Control

Each RSC project has secured 100% site control to support its respective project including full site and substation access. Additional information regarding site control is included in Appendix A.

2. Equipment Procurement

Each RSC Contract is at a different stage of procuring equipment. Most RSC projects are negotiating contracts with suppliers for equipment. RSC Contracts are required to have a commercial operation date no later than three years after CPUC approval of this advice letter. This requirement allows enough time for each RSC project to determine its equipment needs and procure them from a supplier before the start-up deadline. As discussed above, each developer has many years of development experience and a good history in its ability to procure equipment.

Specific information on the equipment procurement of the six developers for the 20 RSC Contracts is provided in Appendix A.

3. Permitting / Certifications Status

Information regarding permitting/certifications status is included in Appendix A.

4. Production Tax Credit ("PTC") / Investment Tax Credit ("ITC")

Information regarding PTCs and ITCs is provided in Appendix A.

5. Transmission

Several projects will incur costs for substation upgrades or construction in order to interconnect to the distribution system. The final gen-tie and network upgrades and the related costs required to interconnect the RSC projects are not yet known. It is not known how issues relating to other generating facility projects in the transmission queue may affect the RSC projects.

All transmission-related upgrades must be completed to allow the RSC projects to come on-line within three years of CPUC approval. If there is a delay in completing the necessary transmission-related upgrades caused only by the CAISO or the transmission provider, the commercial operation deadline shall be extended on a day-for-day basis until completion.

Additional information regarding transmission is provided in Appendix A.

D. Financing Plan

Specific information on the financing plans of the six developers for the 20 RSC Contracts is provided in Appendix A.

IV. CONTINGENCIES AND MILESTONES

Specific information regarding the terms of the RSC Contracts can be found in Appendices D and H.1 through AA.2.

V. REQUEST FOR COMMISSION APPROVAL

The terms of the RSC Contracts are conditioned on the occurrence of "CPUC Approval," as it is defined in the RSC Contracts. To satisfy that condition with respect to the RSC Contracts, SCE requests that the Commission issue a resolution no later than July 29, 2011, containing:

1. Approval of the RSC Contracts in their entirety;

2. A finding that any electric energy sold or dedicated to SCE pursuant to the RSC Contracts constitutes procurement by SCE from an ERR for the purpose of determining SCE's compliance with the RPS Legislation or other applicable law concerning the procurement of electric energy from renewable energy resources;

3. A finding that all procurement under the RSC Contracts counts, in full and without condition, toward any annual procurement target established by the RPS Legislation or the Commission that is applicable to SCE;

4. A finding that all procurement under the RSC Contracts counts, in full and without condition, toward any incremental procurement target established by the RPS Legislation or the Commission that is applicable to SCE;

5. A finding that all procurement under the RSC Contracts counts, in full and without condition, towards the requirement in the RPS Legislation that SCE procure 20% (or such other percentage as may be established by law) of its retail sales from ERRs by 2010 (or such other date as may be established by law);

6. A finding that the RSC Contracts, and SCE's entry into the RSC Contracts, are reasonable and prudent for all purposes, including, but not limited to, recovery in rates of payments made pursuant to the RSC Contracts, subject only to further review with respect to the reasonableness of SCE's administration of the RSC Contracts;

7. A finding that all procurement under the RSC Contracts counts, in full and without condition, towards SCE's capacity cap under the RAM pursuant to D.10-12-048; and

8. Any other and further relief as the Commission finds just and reasonable.

VI. TIER DESIGNATION

Pursuant to D.07-01-024, Energy Industry Rule 5.3, SCE submits this Advice Letter with a Tier 3 designation (effective after Commission approval).

VII. EFFECTIVE DATE

This Advice Letter will become effective July 29, 2011.

VIII. NOTICE

Anyone wishing to protest this Advice Letter may do so by letter via U.S. Mail, facsimile or electronically, any of which must be received by the Energy Division and SCE no later than 20 days after the date of this Advice Letter. Protests should be mailed to:

Akbar Jazayeri
Vice President of Regulatory Operations
Southern California Edison Company
2244 Walnut Grove Avenue, Quad 3D
Rosemead, California 91770
Facsimile: (626) 302-4829
E-mail: AdviceTariffManager@sce.com

Bruce Foster
Senior Vice President, Regulatory Affairs
c/o Karyn Gansecki
601 Van Ness Avenue, Suite 2030
San Francisco, California 94102
Facsimile: (415) 929-5540
E-mail: Karyn.Gansecki@sce.com

Marc Ulrich
Senior Vice President, Power Procurement
c/o Mike Marelli
Southern California Edison Company
2244 Walnut Grove Avenue, Quad 4D
Rosemead, CA 91770
Facsimile: (626) 302-1103
E-mail: Mike.Marelli@sce.com

With a copy to:

Joni A. Templeton
Attorney
Southern California Edison Company
2244 Walnut Grove Avenue, 3rd Floor
Rosemead, CA 91770
Facsimile: (626) 302-1935
E-mail: Joni.Templeton@sce.com

There are no restrictions on who may file a protest, but the protest shall set forth specifically the grounds upon which it is based and shall be submitted expeditiously.

In accordance with Section 4 of GO 96-B, SCE is furnishing copies of this Advice Letter to the interested parties shown on the attached R.08-08-009, R.06-02-012, and GO 96-B service lists. Address change requests to the GO 96-B service list should be directed to AdviceTariffManager@sce.com or (626) 302-2930. For changes to any other service list, please contact the Commission's Process Office at ProcessOffice@cpuc.ca.gov or (415) 703-2021.

Further, in accordance with Public Utilities Code section 491, notice to the public is hereby given by filing and keeping this Advice Letter at SCE's corporate headquarters. To view other SCE advice letters filed with the Commission, log on to SCE's web site at http://www.sce.com/AboutSCE/Regulatory/adviceletters/.

All questions concerning this Advice Letter should be directed to Laura Genao at Laura.Genao@sce.com or (626) 302-6842.

Southern California Edison Company

Akbar Jazayeri

AJ/na
Enclosures

CALIFORNIA PUBLIC UTILITIES COMMISSION

ADVICE LETTER FILING SUMMARY
ENERGY UTILITY

MUST BE COMPLETED BY UTILITY (Attach additional pages as needed)

Company name/CPUC Utility No.: Southern California Edison Company (U 338-E)

Utility type:	Contact Person: James Yee
☑ ELC ☐ GAS	Phone #: (626) 302-2509
☐ PLC ☐ HEAT ☐ WATER	E-mail: James.Yee@sce.com
	E-mail Disposition Notice to: AdviceTariffManager@sce.com

EXPLANATION OF UTILITY TYPE

ELC = Electric GAS = Gas
PLC = Pipeline HEAT = Heat WATER = Water

(Date Filed/ Received Stamp by CPUC)

Advice Letter (AL) #: 2547-E Tier Designation: 3

Subject of AL: Submission of Contracts for Procurement of Renewable Energy Resulting From Renewables Standard Contracts Program

Keywords (choose from CPUC listing): Compliance, Contracts, Procurement

AL filing type: ☐ Monthly ☐ Quarterly ☐ Annual ☑ One-Time ☐ Other

If AL filed in compliance with a Commission order, indicate relevant Decision/Resolution #:

Does AL replace a withdrawn or rejected AL? If so, identify the prior AL:

Summarize differences between the AL and the prior withdrawn or rejected AL[1]:

Confidential treatment requested? ☑ Yes ☐ No

If yes, specification of confidential information: See Appendix CC
Confidential information will be made available to appropriate parties who execute a nondisclosure agreement.
Name and contact information to request nondisclosure agreement/access to confidential information:

Joni Templeton, Law Department, at (626) 302-6210 or Joni.Templeton@sce.com.

Resolution Required? ☑ Yes ☐ No

Requested effective date: 7/29/11 No. of tariff sheets: -0-

Estimated system annual revenue effect: (%):

Estimated system average rate effect (%):

When rates are affected by AL, include attachment in AL showing average rate effects on customer classes (residential, small commercial, large C/I, agricultural, lighting).

Tariff schedules affected: None

Service affected and changes proposed[1]:

Pending advice letters that revise the same tariff sheets:

[1] Discuss in AL if more space is needed.

Protests and all other correspondence regarding this AL are due no later than 20 days after the date of this filing, unless otherwise authorized by the Commission, and shall be sent to:

CPUC, Energy Division
Attention: Tariff Unit
505 Van Ness Ave.,
San Francisco, CA 94102
jnj@cpuc.ca.gov and mas@cpuc.ca.gov

Akbar Jazayeri
Vice President of Regulatory Operations
Southern California Edison Company
2244 Walnut Grove Avenue
Rosemead, California 91770
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Bruce Foster
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Marc Ulrich
Senior Vice President, Power Procurement
c/o Mike Marelli
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2244 Walnut Grove Avenue, Quad 4D
Rosemead, California 91770
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With a copy to:

Joni A. Templeton
Attorney
Southern California Edison Company
2244 Walnut Grove Avenue, 3rd Floor
Rosemead, California 91770
Facsimile: (626) 302-1935
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Confidential Appendix A

Consistency with Commission Decisions and Rules and Project Development Status

Confidential Protected Materials – Public Disclosure Prohibited

Confidential Appendix B

2010 RSC Program Solicitation Overview and 2009 Solicitation Workpapers

Confidential Protected Materials – Public Disclosure Prohibited

Public Appendix C

Independent Evaluator (IE) Report and Appendix B of IE Report

Southern California Edison Company

2010 Renewable Standard Contracts Program

Request for Offers

Report of

Independent Evaluator

January 2011

Prepared by
Merrimack Energy Group, Inc.

Merrimack
M
Energy

and

New Energy Opportunities, Inc.

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Confidential Appendix A: Description and Summary of Proposals Received and Short list Selection

Appendix B: Description of Southern California Edison Company's Least Cost Best Fit Methodology Used in the 2009 Renewable Energy RFP

I. Introduction

A. Overview

Southern California Edison Company ("SCE") is seeking approval of 20 power purchase agreements ("PPAs") for the purchase of approximately 567 GWh of estimated energy annually from approximately 239 MW of installed capacity under SCE's 2010 Renewable Standard Contract ("RSC") program. All 20 contracts are for renewable energy produced by solar photovoltaic ("PV") projects.

On August 2, 2010, SCE issued its 2010 Renewable Standard Contracts Program Request for Offers ("2010 RSC RFO"). SCE solicited offers from owners of eligible renewable resource ("ERR") generating facilities not greater than 20 MW in size to supply up to 250 MW of electrical energy, green attributes and resource adequacy benefits under standard power purchase and sale agreements for execution in 2010.[1] SCE's stated goal for the RSC Program was to provide a "standardized procurement process for projects not greater than 20 MW that leads to quick execution relative to other procurement processes."[2]

The 2010 RSC Program was a voluntary initiative of SCE and differed from its 2009 RSC Program in several important respects. First, the 2010 RSC Program was a competitive solicitation—with winning bidders being paid their bid prices. Under the 2009 RSC Program, sellers under the standard contract obtained a predetermined price based on the applicable 2009 Market Price Referent ("MPR"). Second, projects under the 2010 RSC Program must have forecasted commercial operation dates within three years of approval by the California Public Utilities Commission ("CPUC" or "Commission") of the power purchase agreements ("PPAs"). The 2009 RSC Program had no similar requirement. There were also a variety of changes to the terms and conditions of the renewable standard contracts.

[1] Specifically, the product requested was all energy produced by the generating facility, net of Station Use, and all Green Attributes, Capacity Attributes, and Resource Adequacy Benefits (as those terms are defined in the standard contracts).
[2] RFO Participant Instructions (Revision 2—August 16, 2010) at 1, http://asset.sce.com/Documents/Shared/100816_RSC_RFO_ParticipantInstructions.pdf.

Pursuant to regulatory requirements of the Commission, SCE retained Merrimack Energy Group, Inc. ("Merrimack Energy") as the Independent Evaluator ("IE") for the 2010 RSC Program.[3]

This IE report is submitted in conformance to the requirements of the CPUC and is designed to be consistent with the requirements outlined in the CPUC's November 2010 IE Report Template, as adjusted to reflect the particular features of this solicitation.

B. Program Background

The 2010 RSC Program represents an evolution of SCE's voluntary standard contract program over a number of years. In 2007, SCE initiated a biomass generation renewable standard contract program to support Governor Schwarzenegger's plan to promote energy production from biomass fuel sources in California. The program allowed smaller projects the opportunity to execute standard contracts at the MPR price structure then in effect.[4]

The biomass standard contracts program was originally designed to remain open until the earlier of December 31, 2007 or until such time as SCE signed contracts totaling 250 MW. In early 2008, SCE extended the program into 2008 and kept the 250 MW cap in place.

In 2009, SCE proposed that the biomass standard contracts would be available, with some modifications, for all types of ERRs under California's Renewable Portfolio Standard program of up to 20 MW in size. Under the 2009 RSC Program, SCE executed 13 PPAs for the purchase of 458 GWh of estimated energy from 190.3 MW of installed capacity, including amendments to two pre-existing PPAs with landfill gas projects. In March 2010, SCE filed an advice letter seeking approval of these PPAs.[5]

At the time of its filing of its 2010 RPS Procurement Plan in December 2009, SCE was in the process of addressing the proposals under its 2009 RSC Program, which represented, at that time, almost double the program's goal of 250 MW.[6] SCE stated that it was suspending the RSC Program and reviewing options for restarting the program in 2010.[7] In April 2010, SCE amended its 2010 RPS procurement plan to, among other things,

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[3]Merrimack Energy also served as IE for SCE's 2009 RSC Program and for the 2009 Renewable Portfolio Standards RFP. As before, New Energy Opportunities, Inc. has served as a subcontractor to Merrimack Energy.

[4] In 2007 and 2008, SCE offered three different contracts which varied depending on the size of the generating facility. These contracts applied to facilities with capacities of less than 1 MW, 1 MW through 5 MW, or greater than 5 MW through 20 MW. All three contracts were offered to RPS-eligible biomass resources for terms of 10, 15, and 20 years, and at an energy price set at the MPR, multiplied by energy allocation factors for SCE's TOU periods.

[5] Submission of Contracts for Procurement of Renewable Energy Resulting from Renewable Standard Contracts, Advice 2457-E (March 29, 2010), as amended by Advice 2457-E-A (June 15, 2010).

[6] SCE's (U 338-E) 2010 RPS Procurement Plan, R. 08-08-009 (December 18, 2009) at 28. In other words, SCE received had received many more proposals for renewable standard contracts at MPR-based rates than the 250 MW allotted for the 2009 RSC program.

[7] *Id.*

provide for a 2010 RSC program based on a RFO process to be conducted twice a year, rather than offering MPR-based energy prices.[8]

C. Launch of the 2010 RSC RFO; Participant Instructions

On July 22, 2010, SCE issued to its email distribution list a notice that it would officially launch the 2010 RSC RFO on August 2, 2010 through a posting on its website. SCE also announced that it would be holding a web conference for the RSC RFO on August 10, 2010.

On August 2, 2010, SCE posted on its website the RFO Participant Instructions, an offer template, a draft standard contract for offers from facilities of not more than 20 MW ("RSC20"), a draft standard contract for offers from facilities of not more than 5 MW ("RSC5"), a form non-disclosure agreement, and other pertinent information.[9]

The RFO Participant Instructions, as amended on August 16, 2010, set forth the requirements for prospective Offerors, the evaluation framework, and the schedule for submission of offers, SCE review, execution of PPAs, and submittal of advice letters for CPUC approval.

Participants were allowed to submit offers from ERRs in one or more of the following categories:

- For projects not greater than 5 MW, RSC5;
- For projects not greater than 20 MW, RSC20.

RSC5 and RSC20 contain similar terms and conditions, with a few notable exceptions. RSC5 has a lower development security deposit than RSC20--$30 per kW for intermittent facilities and $60/kW for baseload facilities compared to $60 per kW for intermittent facilities and $90/kW for baseload facilities under RSC20. There is no requirement to post Performance Assurance under RSC5, while Performance Assurance under RSC20 is an average of 5% of total project revenues (the percentage varies by contract year).

Generating facilities associated with all RSC proposals would be subject to the following eligibility and threshold requirements:

- The facility could be new or existing, but an existing facility must be certified by the California Energy Commission as an ERR prior to the offer due date;

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[8] Southern California Edison Company's (U 338-E) Amended 2010 RPS Procurement Plan, R. 08-08-009 (April 9, 2010) at 28-30, See also SCE's Second Amended 2010 RPS Procurement Plan, R. 08-08-009 (June 17, 2010) at 29-30.

[9] These documents, as subsequently, revised, are at http://www.sce.com/EnergyProcurement/renewables/renewables-standard-contracts.htm.

- The facility must be located within the electric power system of the California Independent System Operating Corporation ("CAISO");

- The facility must be scheduled to commence operation within three years from CPUC approval of the RSC.

The standard contracts, once finalized after general opportunity for comment, would not be subject to negotiation, except for changes that are unique to an Offeror's particular project.[10] Offerors could propose contract durations for RSC5 and RSC20 for 10, 15, or 20 years.

Participants were allowed to submit comments on, or proposed revisions to, the pro forma RSCs through August 18, 2010. SCE posted the final pro forma RSCs on September 1, 2010. A web conference was held on September 3, 2010 to review the final pro forma RSCs, including certain changes made by SCE to the RSCs following the receipt of comments.

Evaluation and selection of eligible Offers was to be based on levelized Product Price—i.e., Offers would be ranked from lowest to highest levelized price for each offer and selected based on the levelized price in $/MWh AC—up to a maximum total capacity of 250 MW.[11] Eligible lower-priced Offers would be accepted ahead of eligible higher-priced Offers. SCE also stated that it "reserves the right to evaluate and select offers on other quantitative and qualitative metrics depending on market response."[12]

The deadline for submission of Offers was September 15, 2010. Offers were required to be submitted by email and sent to both SCE and the IE. Offers were required to include an executed Offer Template, including the Revenue Calculator, a redlined RSC with all proposed project-specific changes, and times that the Offeror would be available for a meeting or conference call, if shortlisted, to discuss project-specific terms and conditions to be included in a RSC. SCE stated that it planned to notify each Offeror by email by September 30, 2010 whether or not their Offer had been shortlisted. During October 2010, SCE would work with shortlisted Offerors to finalize RSCs for particular proposed ERRs, with execution of final RSCs by November 15, 2010. SCE indicated that it would submit to the Commission by January 31, 2011 a Tier 3 advice letter seeking approval of the RSCs entered into pursuant to the RSC RFO.

D. Submittal, Evaluation and Selection of Offers; Interaction with the Commission's Renewable Auction Mechanism Decision

Between the time that the RSC RFO was launched and Offers were submitted to SCE, a Proposed Decision was issued by the Commission adopting the Renewable Auction Mechanism ("RAM") proposed by Energy Division. In an August 24, 2010 Proposed

[10] RFO Participant Instructions at 5.
[11] The ranking would be before time-of-delivery price adjustments.
[12] RFO Particpant Instructions at 4-5.

Decision of ALJ Mattson, a mandatory competitive procurement process for renewable resources up to 20 MW in size was described using standardized contracts under which, if made final, SCE would be required to procure approximately 500 MW of renewable resources under long-term contracts.[13] The proposed RAM was similar to SCE's 2010 RSC RFO in certain respects but different in other respects. Of course, one key difference is that RAM was proposed to be a mandatory program, while the RSC Program was a voluntary program initiated by SCE. While SCE had argued that resources procured under the RSC Program should count toward meeting any RAM requirement, this position was not accepted in the Proposed Decision.[14]

On September 8, 2010, a week before bids were due, SCE issued a statement to prospective bidders regarding the potential impact of the proposed RAM decision on the RSC RFO.

> On August 24, the CPUC issued a proposed decision for a new program known as the Renewable Auction Mechanism (RAM). The focus of this program targets the same projects (<20 MW renewable technologies) and includes many of the same features as the current Renewables Standard Contract (RSC) program operated by SCE. The proposed decision, as currently drafted, would have a negative impact on SCE's completion of the current RSC solicitation. SCE will submit comments on the RAM proposed decision as part of the regulatory process with the desired outcome being the continuation of the current RSC solicitation. At this time, SCE will accept offers on September 15 according to schedule. If, however, the RAM proposed decision is not satisfactorily resolved by November 15, then SCE will not execute contracts from this solicitation. In the meantime we will continue with all other RSC solicitation efforts as outlined in the posted RFO Participant Instructions. We will keep RSC participants informed of any changes or updates to the RSC solicitation as the RAM regulatory proceeding evolves. Please feel free to contact the SCE RSC team if you have questions.

On September 15, 2010, SCE received an extremely robust response to the RFO. Details are provided in Confidential Appendix A to this report.

On September 27, 2010, SCE submitted comments to the Commission recommending rejection of the Renewable Auction Mechanism as described in the Proposed Decision.[15] Referring to its launch of the 2010 RSC solicitation, SCE stated:

> Over 350 participants were involved in the 2010 RSC solicitation's bidder's conference. Unfortunately, the release of the PD has already undermined SCE's competitive procurement efforts for the upcoming solicitation. The RAM PD has created an uncertainty in the market over whether the RSC Program will be

[13] Proposed Decision, Decision Adopting the Renewable Auction Mechanism, R. 08-08-009 (August 24, 2010).
[14] Proposed Decision at 103-04.
[15] Comments of Southern California Edison Company on Proposed Decision Adopting the Renewable Auction Mechanism, R. 08-08-009 (September 27, 2010).

> replaced by the RAM. Given that the proposed RAM targets the same market as the RSC Program, SCE would likely terminate its RSC program if the RAM PD is implemented to avoid duplicative efforts directed at providing opportunities for the same segment of the renewable market.[16]

As described more fully in the confidential appendix, SCE decided to create two short lists. The first—approximately 250 MW—would, based on appropriate contract finalization, be executed in accordance with the RSC Participant Instructions, regardless of the outcome of the RAM proceeding. A second provisional shortlist contained proposals SCE was willing to execute if the CPUC were to allow credit under a final decision adopting the Renewable Auction Mechanism program.

On October 4, 2010, SCE informed Offerors that their offers were shortlisted, provisionally shortlisted, or not shortlisted. Offers that were provisionally shortlisted were informed that SCE would consider finalizing a RSC with them if (a) one or more short-listed Offerors were unable to execute RSCs or (b) SCE elects to execute RSCs for more than 250 MW from this solicitation.

On November 19, 2010, SCE announced that pursuant to the RSC RFO it had signed 21 PPAs for renewable energy from nearly 259 of installed capacity from renewable energy projects of up to 20 MW. The contracts had been executed on November 15, 2010, as planned. The specific projects, the sellers, project location, technology, capacity, and estimated online date are summarized below.

[16] *Id.* At 2.

CONTRACTS SIGNED BY SCE FOR 2010 RENEWABLE STANDARD CONTRACTS RFO				
Project Sponsor	Project	Location	Capacity (MW AC)	Est. Online Date
Amonix, Inc.	Blythe Solar Power Generation Station 1 LLC	Blythe	4.7	June-13
Amonix, Inc.	Garnet Solar Power Generation Station 1 LLC	North Palm Springs	4.8	June-13
Amonix, Inc.	Littlerock Solar Power Generation Station 1 LLC	Littlerock	5.0	Apr-13
Amonix, Inc.	Lucerne Solar Power Generation Station 1 LLC	Lucerne Valley	14.0	Mar-14
Clear Peak Energy, Inc.	Holiday Solar Array	Lancaster	8.5	Dec-13
Foresight Renewables, LLC	Nicolis, LLC	Weldon	20.0	Sep-13
Foresight Renewables, LLC	Tropico, LLC	Rosamond	14.0	Sep-13
juwi solar inc.	Sierra View Solar IV	Lancaster	19.0	Dec-13
juwi solar inc.	Sierra View Solar V	Mojave	19.0	Dec-13
Recurrent Energy	RE Columbia 2	Mojave	20.0	Jan-14
Recurrent Energy	RE Columbia 3	Mojave	10.0	Jan-14
Silverado Power	American Solar Greenworks	Lancaster	15.0	Apr-14
Silverado Power	Cemtral Antelope Dry Ranch B	Lancaster	5.0	Apr-14
Silverado Power	Cemtral Antelope Dry Ranch C	Lancaster	20.0	Apr-14
Silverado Power	Lancaster Dry Farm Ranch B	Lancaster	5.0	Apr-14
Silverado Power	Lancaster WAD B	Lancaster	5.0	Apr-14
Silverado Power	North Lancaster Ranch	Lancaster	20.0	Apr-14
Silverado Power	Sierra Solar Greenworks	Lancaster	20.0	Apr-14
Silverado Power	Victor Dry Farm Ranch A	Victorville	5.0	Apr-14
Silverado Power	Victor Dry Farm Ranch B	Victorville	5.0	Apr-14
Spinnaker Energy, LLC	Cabazon West Wind	Cabazon	19.5	Sep-12
# of Contracts	21			
# of Project Sponsors	7			
# of MWs	258.5			
Technology: All Projects are Solar PV except for Cabazon West Wind, which is a wind energy project.				

Subsequently, the power purchase agreement ("PPA") with Spinnaker Energy, LLC was terminated. As a result, SCE is seeking approval for 20 RSCs for projects with 239 MW of installed capacity.

On November 10, 2010, SCE had informed provisionally short-listed Offerors that if the Commission were to approve the RAM decision before the end of the year in a manner that would provide SCE with sufficient credit for executing additional contracts toward RAM goals, SCE would execute additional contracts. For Offerors willing to hold their offers open through the end of the year, SCE indicated that its intent would be to execute RSCs by the end of the year if it received a satisfactory CPUC decision. If not, the RSC would be concluded without the execution of any additional contracts.

On December 17, 2010, the Commission issued its Decision Adopting the Renewable Auction Mechanism.[17] With respect to SCE's RSC Program, the Commission addressed the issue of the relationship between RAM and the SCE's RSC Program and the credit that would be given for contracts entered into pursuant to the 2010 RSC Program.

> Our intent in establishing RAM is to create a standardized procurement process for projects up to 20 MW in size in order to promote robust competition and reduce the administrative burden associated with these projects. Going forward, RAM should be the primary procurement vehicle for projects in this size range, though projects may still participate in other Commission-authorized programs such as the annual RPS solicitations and Commission-approved utility solar photovoltaic programs. It is contrary to the intent of this program to allow projects in this size range to use other procurement options, in particular voluntary programs that target the same market segment or bilateral negotiations. Thus, going forward, SCE shall conform its Renewable Standard Contract (RSC) program to the guidance and framework provided herein. However, SCE may count contracts already executed pursuant to its 2010 RSC toward its capacity cap to the extent they are approved by the Commission. Furthermore, SCE may submit additional contracts resulting from its 2010 RSC solicitation via a Tier 3 advice letter for Commission approval, however, these additional contracts will not further reduce SCE's procurement obligation under the RAM program.[18]

On December 17, 2010, SCE notified provisionally short-listed bidders that it was concluding the 2010 RSC RFO without executing any additional RSCs.

E. Issues Addressed in This Report

This report addresses Merrimack Energy's assessment and conclusions regarding the following issues identified in the CPUC's IE Report Template:

1. Describe in detail the role of the IE through the solicitation and negotiation process.

2. How did the investor-owned utility ("IOU") conduct outreach to bidders, and was the solicitation robust?

[17] Decision 10-12-048, R. 08-08-009 (December 17, 2010).
[18] D.10-12-048 at 3-4.

3. Describe the IOU's Least Cost Best Fit ("LCBF") methodology. Evaluate the strengths and weaknesses of the IOU's LCBF methodology.[19] (This should include a thorough analysis of the RFO results.)

4. Evaluate the fairness of the IOU's bidding and selection process (i.e. quantitative and qualitative methodology used to evaluate bids, consistency of evaluation methods with criteria specified in bid documents, etc.).

5. Describe project-specific negotiations. Highlight any areas of concern including unique terms and conditions.

6. If applicable, describe safeguards and methodologies employed by the IOU to compare affiliate bids or utility-owned generation ownership offers.

7. Based on the complete bid process, are the IOU's contracts the best overall offers received by the IOU?

8. If the contract does not directly reflect a product solicited and bid in the RFO, is the contract superior to the bids received on the products solicited in the RFO? Explain.

9. Is the contract a reasonable way of achieving the need identified in the RFO?

10. Based on your analysis of the RFO bids, the bid process, and the overall market, does the contract merit Commission approval? Explain.

These issues are addressed in this report.

II. Description of the Role of the IE

A. Regulatory Requirements for the IE

The requirements for participation by an IE in RPS solicitations are outlined in Decisions ("D").04-12-048 (Findings of Fact 94-95, Ordering Paragraph 28), D.06-05-039 (Finding of Fact 20, Conclusion of Law 3, Ordering Paragraph 8) of the CPUC, and D.09-06-050.

In D.04-12-048 (December 16, 2004), the CPUC required the use of an IE by investor-owned utilities (IOUs) in resource solicitations where there is an affiliated bidder or bidders, or where the utility proposed to build a project or where a bidder proposed to sell a project or build a project under a turnkey contract that would ultimately be owned by a

[19] The nature of this process was designed to rank offers based on the levelized price of the offers. The traditional IOU Least Cost Best Fit methodology was not applied in the evaluation and selection process. However, SCE, on an after-the fact basis, has applied its LCBF methodology to the RSCs for which approval is sought on a simplified basis and compared the results to the shortlisted projects in the 2009 RPS RFP shortlist. Our assessment focuses on the evaluation methodology used in the RSC ranking and selection process, but also addresses SCE's renewable premium/LCBF methodology.

utility. The CPUC generally endorsed the guidelines issued by the Federal Energy Regulatory Commission ("FERC") for independent evaluation where an affiliate of the purchaser is a bidder in a competitive solicitation, but stated that the role of the IE would not be to make binding decisions on behalf of the utilities or administer the entire process.[20] Instead, the IE would be consulted by the IOU, along with the Procurement Review Group ("PRG") on the design, administration, and evaluation aspects of the Request for Proposals ("RFP"). The Decision identifies the technical expertise and experience of the IE with regard to industry contracts, quantitative evaluation methodologies, power market derivatives, and other aspects of power project development. From a process standpoint, the IOU could contract directly with the IE, in consultation with its PRG, but the IE would coordinate with the Energy Division.

In D.06-05-039 (May 25, 2006), the CPUC required each IOU to employ an IE regarding all RFPs issued pursuant to the RPS, regardless of whether there are any utility-owned or affiliate-owned projects under consideration. In addition, the CPUC directed the IE for each RFP to provide separate reports (a preliminary report with the shortlist and final reports with IOU advice letters to approve contracts) on the entire bid, solicitation, evaluation and selection process, with the reports submitted to the utility, PRG, and CPUC and made available to the public (subject to confidential treatment of protected information). The IE would also make periodic presentations regarding its findings to the utility and the utility's PRG consistent with preserving the independence of the IE by ensuring free and unfettered communication between the IE and the CPUC's Energy Division, and an open, fair, and transparent process that the PRG could confirm.

In D.09-06-050 issued on June 18, 2009 in Rulemaking 08-08-009, Order Instituting Rulemaking to Continue Implementation and Administration of California Renewables Portfolio Standard Program,[21] the CPUC required that bilateral contracts should be reviewed according to the same processes and standards as contracts that come through a solicitation. This includes review by the utility's PRG and its IE, including a report filed by the IE.

B. Detailed Description of the Role of the IE

SCE selected Merrimack Energy to serve as IE for the 2010 Renewable Standard Contracts Program. The objective of the role of the IE is to ensure that the solicitation process is undertaken in a fair, consistent, unbiased, and objective manner and that the best resources are selected and acquired consistent with the solicitation requirements.

In addition to the requirements identified in CPUC Orders, the Purchase Order between Merrimack Energy and SCE identifies the tasks to be performed by the IE. These include the following tasks:

[20] Decision 04-12-048 at 129-37. The FERC guidelines are set forth in Ameren Energy Generating Company, 108 FERC ¶ 61,081 (June 29, 2004).
[21] Decision Establishing Price Benchmarks and Contract Review Processes for Short-Term and Bilateral Procurement Contracts for Compliance with the California Renewable Portfolio Standard.

- Consult with SCE on the design, administration, and evaluation of the competitive procurement solicitation process and protocols to ensure that no SCE affiliate has an undue advantage over non-affiliates in the solicitation;

- Ensure the solicitation process is open, transparent, and free from anti-competitive behavior;

- Provide recommendations concerning the precise definition of products sought and price and non-price evaluation criteria, so that all aspects of the products are clearly understood and all Sellers may effectively respond to the solicitation;

- Review the comprehensive quantitative and qualitative bid evaluation criteria and methodologies and assess whether these are applied to all bids in a fair and non-discriminatory manner;

- Assess whether SCE's final selection was fair and was not unduly influenced by its affiliate relationships;

- Provide periodic presentations as requested to SCE management and to the PRG concerning the IE's findings;

- Report on the outcome of the RFP to the CPUC using the appropriate CPUC Independent Evaluator Report Template.

With regard to the role of the IE, our objective is to ensure that the process is undertaken in a fair and equitable manner and that the results of the offer evaluation and selection are accurate, reasonable and consistent. This role generally involves a detailed review and assessment of the evaluation process and the results of the quantitative and, to the extent applicable to the particular solicitation, qualitative (non-price) analysis.

This report provides an assessment of SCE's RSC procurement process from development of the process through selection of the projects subject to contract approval. It is organized based on the template provided by the CPUC's Energy Division.

C. Description of IE Oversight Activities

In performing its oversight role, the IE participated in and undertook a number of activities in connection with the RFO, including submitting comments and clarification questions on the draft RFO protocol, attending the web conferences regarding the RFO and the pro forma renewable standard contracts, organizing and summarizing the offers submitted, reviewing evaluation results at each stage in the process, monitoring the status of short-listed and provisionally short-listed offers, monitoring communications with Offerors, attending conference calls with short-listed and provisionally short-listed Offerors regarding project-specific changes to the RSCs, participating in SCE project team meetings, and attending meetings with the SCE's Risk Management Committee ("RMC") and PRG. Merrimack Energy was retained by SCE one week prior to the

launch of the RFO and therefore had a limited opportunity to review and comment on the RFO and the RSC pro forma contracts before they were posted on SCE's website on August 2, 2010.[22] A list of the activities of the IE during the procurement process is described below.

1. Participated in Renewable and Alternative Power ("RAP") Committee Meetings

After Merrimack Energy was retained by SCE one week prior to the launch of the RFO, Merrimack Energy was invited by SCE's management team to participate in meetings of the RSC program team and other meetings during the RSC solicitation implementation phase, including bi-weekly RAP meetings. This allowed the IE to monitor the major activities and issues that were being debated and assessed by SCE's RSC project team during this phase of the process.

2. Submitted Comments and Clarifying Questions on the Draft RSC RFO

The IE submitted a few comments on the draft RSC RFO in late July and also submitted several clarifying questions designed to make the document clearer to prospective Offerors.

3. Monitored Web Conference Held on August 10, 2010

Merrimack Energy submitted comments on the draft presentation for the 2010 RSC RFO Conference and monitored the conference, which was conducted as a web conference on August 10, 2010. SCE provided an overview of the RFO, the RFO instructions, the offer template and revenue calculator, the evaluation criteria, the RFO schedule, and key terms and conditions in the RSCs. In addition, SCE provided an overview of the interconnection process, both at the distribution level and at the transmission level. Following SCE's presentation, there was a question and answer period. SCE's presentation, a document summarizing the questions and answers, and an audio recording of the web conference were all posted on SCE's website.[23]

4 Monitored SCE Internal Communications Involving Revisions to RFO Participant Instructions

The IE monitored internal SCE communications pertaining to revisions to the RFO instructions regarding Offeror redlining of the RSC pro forma and the Offeror's availability for specific times to address project-specific contract language if the Offereor was shortlisted and desired to have a meeting or conference call to discuss these matters. A revision to the RFO Participant Instructions was posted on SCE's website on August 16, 2010. On September 8, 2010, the RSC Offer Template was revised to require that four contract prices be submitted in the context of defined curtailment cap provisions.

5. *Review of Comments on the Draft Pro Forma RSCs*

[22] A draft of the RSC RFO Participant Instructions was provided to Merrimack Energy on July 29, 2010.
[23] http://www.sce.com/EnergyProcurement/renewables/rsc-web-conference.htm.

SCE provided prospective bidders with the opportunity to submit comments on the draft pro forma RSCs in the form of a redline. Comments were due by August 18, 2010. Over a dozen prospective bidders submitted comments. The IE reviewed the bulk of the comments submitted. In addition, the IE compared the 2010 RSC pro forma contracts to the 2009 RSC contracts. Merrimack Energy followed up with a conference call with SCE's RSC project manager and lead counsel regarding suggested changes to the pro forma contracts. On September 1, 2010, SCE posted final RSC20 and RSC5 pro forma contracts.

6. Monitored Web Conference Held on September 3, 2010—Review of Pro Forma RSC

On September 3, 2010, SCE held a web conference in which the company provided an overview of the final pro forma RSCs, addressed the curtailment provisions in some detail as well as the seller's obligation to seek full deliverability status in the interconnection process, and summarized certain contract provisions that had been modified. In addition, a question and answer session was held. The presentation, a recording of the web conference, and a Q&A document was posted on SCE's website. The IE monitored the web conference.

7. Monitored Communication with Bidders

Prospective Offerors had the opportunity to submit questions to SCE regarding the RFO via SCE's RSC RFO website and through direct contact with SCE project team members. The RFO required that the IE should be copied on all correspondence between SCE and the prospective Offeror. The IE reviewed the email traffic between SCE and Offerors to assess if any issues were emerging and whether all Offerors were treated fairly and equitably.

8. Receipt of Offers and Required Information

The Offers were received on September 15, 2010 as required. Offers were sent to both SCE and the IE via email. SCE reviewed and compiled the information submitted and began to organize and summarize the offers received.

9. Evaluation and Short List Selection; Attendance at RMC and PRG Meetings

Offers were reviewed and evaluated in terms of their levelized $/MWh price based on the best offer of the four submitted with regard to the curtailment options allowed. A few offers were determined to be either ineligible or not viable for the following reasons:

- One project was not located in the CAISO control area;

- A number of projects were located in transmission constraints areas which would not allow the project to achieve commercial operation within the timeframe set forth in the RSC RFO.[24]

The IE reviewed SCE's ranking based on price and SCE's basis for determining that certain projects were not eligible or could not meet the minimum online date requirement set forth in the RFO. Another matter that the IE reviewed was SCE's plan to apply supplier concentration risk parameters to the ranking of bids.

The IE attended by telephone RMC and PRG meetings both of which were held on September 29, 2010. RAP provided an overview of the number of offers received, the quantity in terms of MWs and GWhs, price and estimated notional value. RAP recommended a short list comprised of 259 MW of RSC projects, regardless of the outcome of the RAM decision by the Commission.[25] In light of the attractive pricing received, RAP recommended the provisional shortlisting of additional MW if the Commission were to allow credit toward meeting the RAM requirements.

10. Participate in Contract Negotiations

The IE monitored the bulk of the project-specific contract negotiations that took place in October 2010. Due to the number of negotiations and the short period of time allotted for them, SCE established two teams of negotiators, which were monitored by two Merrimack Energy representatives. Initially, SCE scheduled meetings of the two internal teams to assure that they were acting consistently, but only one meeting was held after it was concluded that there were relatively few material issues to address.

11. Final RMC and PRG Meetings—November 9-10, 2010

By early November, there were a number of changes to the short list, although the amount of shortlisted MW remained at 259 MW. Some previously short-listed projects were removed as a result of withdrawn offers or transmission constraints. Also, project substitution was proposed by the same Offerors for projects that were either subject to transmission and interconnection constraints or were more viable projects. Other projects on the provisional short list were moved up to take the place of projects originally on the short list that were withdrawn. Merrimack Energy attended a RMC meeting on November 9, 2010 at which approval was given for the execution of 21 RSC contracts, as well as a PRG meeting held the following day at which the RSC contract awards were discussed. The provisional shortlist, which itself had shrunk in size due to similar issues facing projects on the initial shortlist, was put on hold pending the Commission's decision on the RAM.

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[24] Another project was considered non-viable for multiple reasons, including a schedule that was deemed infeasible.

[25] The reason for 259 MW was that the project that was included to reach 250 MW was sized so that its inclusion resulted in the total of shortlisted projects equaling 259 MW.

The 21 RSC contracts were executed by SCE on November 15, 2010, the scheduled date for contract execution. Following the Commission's RAM decision on December 16, 2010, SCE informed Offerors on the provisional shortlist that SCE was concluding the RSC RFO without executing additional contracts.

III. Adequacy of Outreach to Prospective Bidders and Robustness of the Solicitation

SCE's outreach activities for the 2010 Renewable Standard Contract program were substantial and although there wasn't as much advance notice provided to the prospective bidder community as in many competitive procurements, the result was a very competitive solicitation. The other factor that contributed to the robustness of the solicitation was the simplicity of the process and perhaps the relative dearth of threshold requirements, such as the filing of an interconnection request and demonstration of site control.

On April 9, 2010, SCE included in its first amendment to its 2010 RPS procurement plan a statement that it was planning a RSC procurement for 2010 with a goal of purchasing 250 MW from eligible renewable energy projects under long-term contracts.[26] SCE also provided notice that it would be doing so under a RFO process rather than offering to purchase at the MPR.[27]

On July 22, 2010, SCE issued to its email distribution list a notice that it would officially launch the 2010 RSC RFO on August 2, 2010 through a posting on its website. SCE also announced that it would be holding a web conference for the RSC RFO on August 10, 2010.

Over the years, SCE has developed a large list of potential bidders based on contacts from previous renewable solicitations and business relationships it has developed. This list is periodically updated. SCE used this list with over 1,100 contacts as the database for prospective bidder contact and outreach. SCE sent emails to all contacts on this list informing them of the launching of the RSC RFO process, the web conferences, and the setting up and updating of the 2010 RSC RFO website.

SCE established a website for the program—on August 2, 2010, which was subsequently supplemented and revised—and included all relevant documents on the website. The website contains the following documents:

[26] Southern California Edison Company's (U-338-E) Amended 2010 RPS Procurement Plan (April 9, 2010) at 29-30.
[27] *Id.* The plan to conduct the 2010 was also discussed in SCE's Second Amended 2010 RPS Procurement Plan filed on June 17, 2010 (pp. 28-30).

- RFO participant instructions;
- Renewables standard contracts—5 MW and 20 MW versions;
- Offer template and revenue calculator;
- TOD and payment allocation table;
- Audio recordings, PowerPoint presentations and written questions and answers from the two web conferences held on August 10, 2010 and September 3, 2010;
- Link to website on WDAT tariff and WDAT generator interconnection reform process;
- Form non-disclosure agreement;
- Contact information for SCE and the IE.

The website has been in place for several years going back to the initiation of the RSC program in 2007. It was updated in 2010 in connection with the changes in the renewable standard contract program for 2010.[28]

Once the process was initiated, SCE provided useful information to prospective bidders through two web conferences. The first web conference addressed the basic design of the RFO process, the schedule, what Offerors would be required to submit, some important terms of the renewable standard contracts, including security requirements and curtailment provisions, the process by which SCE would be obtaining feedback on the standard contracts and posting final pro forma standard contracts, and a summary of SCE's Wholesale Distribution Access Tariff ("WDAT") interconnection process and cost allocation provisions as well as those of CAISO's Small Generator Interconnection Process ("SGIP") and the applicability of the respective generator interconnection processes for generators.

At the second web conference held on September 3, 2010, SCE summarized the schedule for the next steps in the process:

- Submission of offers, including redlining the appropriate standard contracts with "project-specific" changes (September 15, 2010);
- SCE notification of Offerors regarding short list status (September 30, 2010);
- SCE submits draft RSCs and NDAs to short-listed Offerors (October 5, 2010);
- Meeting/conference calls with short-listed Offerors, if desired by the Offeror (October 6-15, 2010);
- Offerors submit executed RSCs (November 5, 2010);
- SCE executes final RSCs (November 15, 2010).

The key substantive part of the second web conference was a summary of certain major provisions of the pro forma standard contracts which had been revised from the draft pro forma standard contracts initially posted on SCE's web site. The draft pro forma

[28] In addition, SCE personnel had provided general notice of the 2010 RSC solicitation to potential bidders through other, less formal means, such as responses to email and telephone requests following the conclusion of the 2009 RSC program and through attendance at various workshops and conferences.

contracts had been the subject of comments from prospective Offerors. A substantial part of the presentation focused on the curtailment provisions, which are complex and which had undergone several changes. One change was to give Offerors the option of submitting Offers where on-peak hours would not be included in the curtailment cap.

Another change pertained to steps required of Offerors to obtain full deliverability status as part of the CAISO interconnection process if that option becomes available under CAISO rules for small generators (up to 20 MW) and to pay for deliverability network upgrades, subject to a cost cap of $100,000 per MW of Contract Capacity. The revised pro forma RSC only required Sellers to take such steps as would not reasonably jeopardize Seller's achievement of the Commercial Operation Date and put other limits on Seller's obligations.

Other changes, in response to bidder feedback, included:

- Limited extension of the Commercial Operation Date due to Force Majeure and other specified causes;
- An indication that it would consider changes to the section on termination rights (Section 2.04);
- The performance obligation for solar PV projects was revised to 170% of expected energy production over two years (85% annually averaged over two years) rather than 90% per year

On September 8, 2010, one week before Offers were to be submitted, SCE updated its offer template to require four offers, instead of two price offers:

- On-peak hours included in curtailment cap: 50 hour curtailment cap multiplier
- On-peak hours included in curtailment cap: 100 hour curtailment cap multiplier
- On-peak hours not included in curtailment cap: 50 hour curtailment cap multiplier
- On-peak hours not included in curtailment cap: 100 hour curtailment cap multiplier

This change was highlighted on the web site and in an email sent to prospective Offerors on SCE's distribution list. Through that same email, SCE notified prospective Offerors of the CPUC's proposed RAM decision and stated:

> At this time, SCE will accept offers on September 15 according to schedule. If, however, the RAM proposed decision is not satisfactorily resolved by November 15, then SCE will not execute contracts from this solicitation. In the meantime we will continue with all other RSC solicitation efforts as outlined in the posted RFO Participant Instructions. We will keep RSC participants informed of any changes or updates to the RSC solicitation as the RAM regulatory proceeding evolves. Please feel free to contact the SCE RSC team if you have questions.

The response to the program has been extremely robust. Specific information regarding the number of offers received and the associated amount of installed capacity is in Confidential Appendix A to this report.

Given the highly robust response to the solicitation, we are of the opinion that SCE's outreach to bidders was adequate, if not very good to superior. The website contained the necessary documents and other information, which were clearly stated. The web conferences were, in our opinion, a very useful tool in providing information to prospective bidders and in providing answers to questions. SCE allowed prospective bidders to comment on the draft pro forma contracts, and in light of the comments received made various changes in finalizing the pro forma contracts. Written responses to questions were posted on the website. The very strong response of the market to SCE's RSC RFO is evidence that the outreach activities of SCE were effective and Sellers felt they had an adequate opportunity to receive a contract from the process. However, we do have reservations with the manner in which SCE communicated to prospective bidders regarding the Company's willingness to go forward with the RSC process to contract execution and the relationship to the pending Commission decision on RAM, which is addressed in Section V.B of this report.

SCE issued surveys to participants at the RFO web conferences requesting that they respond with their views regarding the conferences. Overall, the responses were very favorable. There were a number of suggestions for future improvements, including providing more notice prior to the date of the web conference, posting the questions on the web prior to the answers being given, and providing examples for some of the matters addressed.

IV. Fairness and Appropriateness of the Bid Evaluation and Selection Design

A. Framework and Principles for Evaluating SCE's 2010 RSC Methodology

This section of the report addresses the principles and framework underlying Merrimack Energy's review of SCE's methodology for the RSC RFO proposal evaluation and selection. Key areas of inquiry by the IE and the underlying principles used by the IE to evaluate the methodology include the following:

- Were the procurement targets, products solicited, principles and objectives clearly defined in SCE's RFO and other materials?

- Were the bid evaluation and selection process and criteria reasonably transparent such that bidders would have a reasonable indication as to how they would be evaluated and selected?

- Was SCE's bid evaluation based on and consistent with the information requested in the RFO to be submitted by bidders in their proposal documents?

- Did the evaluation methodology reasonably identify the quantitative and qualitative criteria and describe how they would be used to qualify and rank offers?

- Does the price evaluation methodology allow for consistent evaluation of bids of different sizes and in-service dates?

- Did the bid evaluation criteria and evaluation process contain any undue or unreasonable bias that might influence project ranking and selection results or in any way favor affiliate bids?

- Was the RFO clear and concise to ensure that the information required by SCE to conduct its evaluation was provided by project sponsors?

B. Description of SCE's Evaluation Methodology

1. The 2010 RSC Evaluation Methodology

This section of the report provides an overall description of SCE's evaluation methodology and criteria applicable to the 2010 RSC RFO. SCE used a levelized cost methodology to evaluate and rank all offers. SCE described the offer evaluation and selection process in the RFO Participant Instructions and at the first web conference. SCE devised the evaluation methodology and selection process in the context of its stated goal—"to provide a standardized procurement process for projects not greater than 20 MW that leads to quick execution (relative to other procurement processes)."[29]

The RSC RFO provided for a single stage bidding process where bids would be evaluated from a price perspective solely on the basis of levelized costs. The more complex evaluation methodology used in connection with the 2009 RPS RFP (and proposed to be used in connection with the 2010 RPS RFP) would not be utilized. The RPS RFP least-cost best-fit methodology is based on a $/MWh renewable premium approach—which compares the levelized $/MWh costs of a proposal, including the bid energy costs, costs associated with transmission network upgrades (transmission adders) and debt equivalence, to the levelized estimated market value of the energy and capacity (resource adequacy) benefits associated with a proposal.

The RSC RFO also differed in several important respects from the Solar Photovoltaic Program RFO ("SPVP RFO") conducted by SCE earlier in 2010. In this program,

[29] RFO Participant Instructions at 1. As previously noted, the traditional least cost best fit methodology used by SCE for other renewable solicitations was not applicable to the RSC RFO process, which was designed largely to facilitate the development of smaller renewable energy projects with installed capacities of 20 MW or less.

primarily oriented to solar rooftop proposals of approximately 2 MW or less, the RFO had an indicative bidding stage and a final binding bid stage. In addition, applicants were required to have submitted an interconnection request and to have demonstrated, or at least to have certified that they had, site control. In the SPVP RFO, Offeror were required to provide a schedule such that the expected commercial operation date would occur within 18 months of CPUC approval, while in the RSC RFO, the scheduled expected commercial operation date would occur within 36 months of CPUC approval. Like the SPVP RFO, however, the price evaluation was based solely on levelized cost in $/MWh.

As stated in the RSC RFO Participant Instructions, participants could either submit a proposal for (a) a standard contract for projects not greater than 5 MW ("RSC5") or (b) a standard contract for not less than 20 MW ("RSC20"). The standard contracts are identical except with respect to project development security and performance assurance (operating period security). For RSC5, development security is $30/kW for intermittent projects (wind and solar PV) and $60/kW for baseload projects (biomass). There is no performance assurance. For RSC20, development security is $60/W for intermittent projects and $90/kW for baseload projects; performance assurance is an average of 5% of total project payments. Offerors also had the ability to make proposals for 10, 15 or 20 year contracts.

From an evaluation standpoint, proposals for RSC5 and RSC20 contracts, regardless of contract term, were to be treated in the same fashion. All projects were to be ranked on a $/MWh price basis, regardless of size, term, or projected commercial operation date.

However, to be ranked, each offer would need to meet certain specified eligibility and threshold requirements:

- Offers must be for the output from an eligible renewable resource ("ERR"), a generating facility that satisfies the criteria set forth in the California Renewable Portfolio Standard and the California Energy Commission's RPS eligibility guidebook; existing generating facilities must be certified by the California Energy Commission as an ERR;

- The ERR must be located within the CAISO control system;

- The ERR must be scheduled to commence operation within three years from CPUC approval of the RSC.[30]

With regard to evaluation and short-listing of offers, SCE stated that it would rank offers based on levelized price (lowest offers ranked highest) up to a maximum capacity of 250 MW. However, SCE reserved the right to use other criteria to make selection determinations. As stated in the Participant Instructions, "SCE reserves the right to evaluate and select offers on other quantitative and qualitative metrics depending on

[30] RFO Participant Instructions at 2.

market response."[31] In response to questions at the first web conference on offer evaluation and selection, SCE stated:

- "We reserve the right to select or deselect projects based on uniquely good or bad attributes (qualitative factors), such as project viability or supplier concentration risk."
- "Commercial operation date may be considered as a qualitative factor when evaluating offers."
- In response to a question as to whether there is a limit on the number of projects a single sponsor may propose, SCE stated: "No. However, supplier concentration risk may be a qualitative factor used when evaluating offers."[32]

There were also a number of process-oriented requirements for Offerors. These included the timely submission of the Offer Template and a redline to the applicable renewable standard contract (RSC5 or RSC20). SCE stated that it was "willing to consider changes to the draft RSC that are **unique** to the Project."[33] As indicated previously, Offerors were requested to make four separate price offers per project, based on specified provisions applicable to curtailment.

2. Renewable Premium Analysis and 2009 RPS RFP Least Cost Best Fit ("LCBF") Methodology

Following the receipt of bids in the RSC RFO, SCE conducted a modified renewable premium analysis so that the selected projects could be compared to the shortlist from SCE's 2009 RPS RFP. SCE used the same renewable premium evaluation methodology and forecast as had been used in the 2009 RPS RFP, except that a generalized estimate was used for the locational capacity value and transmission adder for all of the projects, rather than a project-specific estimate. A comparison of the renewable premiums for the RSCs for which approval is being sought to the renewable premiums of the projects shortlisted in the 2009 RPS RFP is set forth in Confidential Appendix A to this report. SCE's LCBF methodology used in the 2009 RPS RFP is described in Appendix B to this report.

C. Evaluation of the Strengths and Weaknesses of SCE's Methodology in This Solicitation

Strengths of Evaluation and Ranking Methodology

As described, if an offer meets the eligibility requirements, the key selection criterion is price. SCE's price ranking and evaluation methodology is designed to be relatively simple and straightforward. Offers are ranked based on the levelized price of the offer

[31] RFO Participant Instructions at 5.
[32] Q&A from RSC RFO Web Conference #s 46, 47 and 59, http://asset.sce.com/Documents/Shared/100818_RSC_RFO_WebConferenceQandA.pdf.
[33] RFO Participant Instructions at 5 (emphasis in original).

using a 10 percent discount rate. Offerors are provided the flexibility with respect to length of term (10, 15 of 20 years) and to offer a fixed price over the contract term or a price which escalates by a fixed escalation factor. The conceptual approach was simple and the Offer Template provided by SCE for bidders to use was relatively easy for Offerors to follow and complete. Offerors appeared to have little or no difficulty with this process.

The 2010 RSC program allowed developers of small projects the opportunity to obtain relatively expeditiously and with low transaction costs long-term PPAs to support further development and financing of construction of their projects. Strengths of the program are its simplicity, short time between RFO launch and contract execution—a little more than three months—and the competitiveness of the process resulting in attractive market-driven pricing. Another strength was the role of project development security, whose levels depended on project size (up to 5 MW vs. up to 20 MW) as a partial substitute for project viability analysis. Several developers who applied for a RSC either withdrew their applications, did not execute contracts or did not post development period security either because of a known project development problem or presumably because of some other issue affecting project viability not communicated to SCE or the IE. Project development security has the effect of facilitating the weeding out of projects with serious project development problems by the bidders themselves.

Other strengths were the ability to apply other qualitative factors in the evaluation of Offers—specifically, supplier concentration risk and the ability of a project sponsor to achieve commercial operation of the project within three years of CPUC approval. The latter factor allowed SCE to address project viability concerns to an extent in the context of a large bidder response and an aggressive timeframe for bid evaluation, negotiation and contract execution.

The target of up to 250 MW in renewable standard contracts was a reasonable one and was in line with the program goals in 2009. The RSC program design treated all ERRs in a technology neutral manner and treated all applicants in a similar manner, regardless of whether or not they were affiliated with SCE.

Finally, it was also useful both to SCE and developers that a significant amount of incremental renewable energy projects could be contracted with a relatively small amount of time and effort expended on contract negotiations.

Weaknesses of the Evaluation and Ranking Methodology

The 2010 RSC program also had a number of weaknesses, many of which are related to its strengths. First, the price evaluation mechanism does not take into consideration indirect costs, in particular the costs associated with transmission upgrades. Hence, the simplicity of the pricing approach comes at the cost of accuracy in terms of assessment of customer costs and benefits. However, in light of the size of the projects, this tradeoff seems reasonable in the context of the benefits of expedition and lower transaction costs.

Another weakness is the relatively low level of requirements and evaluation factors pertaining to project viability. There was no requirement that an Offeror had to demonstrate site control (or certify that it had site control) or that it was pursuing the interconnection process. The only applicable requirement—not in the 2009 RSC RFO—was that the scheduled commercial operation date had to be within three years of CPUC approval (or about four years after bid submittal).

Another area that this type of solicitation process could be improved pertains to the clarity by which the evaluation/selection criteria could be articulated. While SCE reserved the right to consider such factors as supplier concentration risk and whether the scheduled commercial operation date is within three years of commercial operation, it was not very clear how SCE would apply these criteria. A number of improvements in the process (which might be applicable in future RAM solicitations) are suggested below.

Strengths and Weaknesses of SCE's LCBF Evaluation Methodology

SCE's LCBF methodology allows for an evaluation of different types of renewable resources and different terms in a consistent manner by accounting for both the costs and benefits of each proposal. The LCBF methodology also accounts for qualitative factors including viability and project development status, which are important factors in the ultimate success rate for these projects.

The primary metric used in the LCBF evaluation was the renewable premium metric – the difference (in $/MWh) between the levelized nominal costs associated with a proposal and the levelized nominal benefits. In our experience, the renewable premium metric is a commonly accepted and appropriate measure of comparative value.

While the LCBF methodology is designed to allow for an assessment of all reasonable costs, and compare it to the value of the products bid, there were several weaknesses in applying the the quantitative evaluation in the context of the 2009 RPS RFP that in our view should be explored by SCE for improvements in future solicitations.

In applying the 70% exceedance methodology for assessing capacity value of intermittent resources, there were issues with the evaluation of certain proposals because the production profile provided by certain bidders represented average hourly generation rather than an estimate of generation for each hour in the year. While these issues were satisfactorily addressed in the 2009 RPS RFP in our view, in the future SCE should ask for hourly generation estimates or explain the methodology used by SCE to ensure that all bids can be consistently evaluated relative to their capacity value.

The quantitative evaluation of out-of-state projects, especially wind projects, proved to be difficult for SCE and the IE in the 2009 Renewable RFP process. A significant variety of out-of-state proposals were submitted that were difficult to compare to each other and to in-state projects on a consistent basis. Initially, while the Renewable RFP Procurement Protocol and other RFP documentation appeared clear regarding requirements pertaining

to delivery points and pricing, there were many proposals that were not in conformance with those requirements and this made it difficult to evaluate and compare all proposals on a consistent basis.

D. Recommended Future Improvements in the Evaluation and Ranking Process

In future solicitations of this nature, the standards for supplier concentration could be set forth in the RFO protocol document itself. Specifically, a maximum MW or MWh amount or percentage limitation or permissible range could be specified. A number of competitive solicitations of which we are aware have supplier concentration limits as part of the RFO program design. Our recommendation is that SCE do so in the context of future solicitations similar to the RSC RFO. It will help simplify and expedite the evaluation and selection process and will provide fair notice to prospective bidders regarding the rules to be applied regarding supplier concentration limits.

In the future, SCE should also provide a clearer notice to prospective bidders that it would be evaluating the reasonableness of the Offeror's ability to achieve commercial operation within a certain timeframe. In addition, bidders should be required to provide a project milestone schedule, which would assist SCE in making its evaluation.

While for purposes of this RSC it was arguably reasonable to not impose overly restrictive requirements for Offerors in terms of meeting project development requirements at the time of bid submission, it is reasonable in the future to require that short-listed bidders provide a demonstration of site control and that they have commenced the interconnection process by submitting an interconnection request, at least prior to the execution of a PPA. This approach would provide a reasonable tradeoff, in our opinion, between requiring that certain project development milestones be satisfied at the time bids are submitted versus not requiring that they be satisfied at all (except as a contract compliance matter). This approach would provide a degree of assurance regarding project viability, while mitigating the costs and risks for developers of small projects in submitting bids and perhaps reducing the burden on the generator interconnection process at the CAISO and utility levels.

Another area for improvement is the manner in which the standard contracts were developed. SCE started with its most recent RPS pro forma PPA, which is approximately 200 pages in length. While it had used a more simplified standard contract in the 2009 RSC process, SCE did not include some of the more simplified or at least acceptable contract provisions from a project developer standpoint in the initial draft pro formas (apparently, last year's RSC pro formas were not even reviewed in preparing the initial pro forma contracts posted on the RSC RFO website). This led to more effort on the part of SCE and the prospective bidders than was perhaps necessary. However, SCE was developing these standard contracts only weeks after it had worked to incorporate revised curtailment provisions and provisions pertaining to sellers seeking full capacity interconnections in its pro forma RPS contract. Hence, the task was difficult and the time

was short. Moreover, SCE did solicit comments on the pro forma contracts and did make some changes after having taken the comments into consideration.

V. Fairness of SCE's Administration of the Evaluation and Selection Process

A. Principles and Guidelines Used to Determine Fairness of Process

In evaluating SCE's performance in implementing the 2010 RSC RFO process, Merrimack Energy has applied a number of principles and factors, which incorporate those suggested by the Commission's Energy Division as well as additional principles that Merrimack Energy has used in its oversight of other competitive bidding processes. These include:

- Were all Offerors treated the same regardless of the identity of the Offeror?
- Were Offerors' questions answered fairly and consistently and the answers made available to all?
- Was the economic evaluation of the bids fair and consistent?
- Were the requirements listed in the Procurement Protocol applied in the same manner to all proposals?
- Was there evidence of any undue bias regarding the evaluation and selection of different types of product, project structures, or bid sizes that cannot be reasonably explained?
- Did all bidders have access to the same information?

B. SCE's Administration of the RSC RFO Process

As previously discussed, the IE was actively involved in all phases of the process. The IE was copied on all emails exchanged between SCE and Offerors including receiving copies of all offers, supporting documents, and contracts. The IE was also included in project team meetings to discuss the status of the process and issues which were raised.

SCE received proposals from several dozen project sponsors, with a number of project sponsors making offers for multiple projects. Projects were evaluated and ranked based on their levelized cost. In addition, several initial screens were run to evaluate the bids.

- SCE's transmission and distribution business unit was asked to assess whether any projects could not be interconnected in a four-year period; based on this

analysis, SCE initially determined that several projects would not be able to achieve commercial operation within three years of CPUC approval;

- Another proposed project was not located within the CAISO control area and, hence, was determined not to be eligible.

In addition, a price screen was applied which eliminated more than 50 percent of the highest-priced offers. One project sponsor proposed several dozen projects involving hundreds of megawatts of installed capacity. In order to manage supplier concentration risk, SCE decided to limit the projects on the short list to a total of approximately 100 MW, which represents 40 percent of the 250 MW target for the solicitation. A provisional short list of several hundred MW of additional projects was established. The purpose of the provisional short list was twofold:

1. As a back up to the short list if projects were to fall out of the short list (for example, if there was a failure to execute the applicable RSC); and

2. As an additional short list if the CPUC were to allow SCE to "count" contracts for more than 250 MW toward meeting SCE's obligations under a final RAM decision.

A total of 21 projects totaling 259 MW were initially shortlisted by SCE. There were several hundred megawatts of projects placed in the provisional shortlist. Following project-specific contract discussions and further review by SCE, there were a number of changes to the shortlist and provisional shortlist but a total of 21 projects totaling 259 MW remained on the short list and ultimately were the subject of executed contracts. Based on further review by SCE, more projects were considered to be transmission constrained and unlikely to be able to achieve commercial operation within three years of CPUC approval.[34] Offers for contracts from existing projects with remaining contract terms were revalued to take into consideration the ratepayer costs associated with replacing power sold under an existing contract with a higher-priced new contract. Once this revaluation was conducted, the existing projects fell out of the short list. Finally, several Offerors withdrew their offers.

As part of this process, a few Offerors, some with multiple projects on the short list, proposed to substitute projects with those on the provisional shortlist that were considered by the Offeror and/or SCE as being more viable. After discussion with the IE, SCE permitted project swaps for viability reasons as long as it did not result in an increase in the weighted average price of projects that would receive contracts.

The net result was that the number of projects and the total MWs in the short list remained the same although some projects had fallen out of the original short list and

[34] Where SCE viewed the ability to go through the interconnection process in a timely matter as being uncertain, the Offeror was given the benefit of the doubt.

some projects had moved up from the provisional short list. In addition, the amount of projects and MWs on the provisional shortlist had dropped substantially.[35]

Based on our involvement, our assessment is that SCE reasonably followed the criteria set forth in the RFO Participant Instruction in the evaluation and selection process portion of the solicitation. As stated previously, our recommendation is that in future solicitations that (a) the seller concentration limits be explicitly addressed in the RFO program design documents so that all bidders are informed of them before bids are submitted and (b) the analysis that would be conducted regarding ability to achieve commercial operation by a specified date be explained before the submission of bids. With that being said , we believe that the evaluation that was conducted was consistent and equitable among different Offerors and proposed projects. No evidence of bias was present.

Based on our assessment of the evaluation process relative to the above criteria, it is our opinion that all Offerors were treated fairly and consistently and all generally had access to the same amount and quality of information.

As indicated previously, SCE maintained a website dedicated to the 2010 RSC RFO and posted the RFO documents on the website as well as presentations from the two web conferences, questions and answers and audio recordings of the web conferences. We observed no difference in the treatment of Offerors regarding clarification questions, correspondence and communications with Offerors, and follow-up contacts.

We did have concerns, however, with the way that SCE communicated the relationship between its willingness to go forward with the RSC program to contract execution and the pending Commission decision on RAM. SCE's statement to prospective bidders one week before offers were due that "SCE will not execute contracts from this solicitation" "if . . . the RAM proposed decision is not satisfactorily resolved by November 15" raised a number of questions from the IE's perspective. Would making such a statement shortly before offers were due discourage prospective bidders from participating in the solicitation and produce a suboptimal level of competition? On the other hand, since the RSC was a voluntary program and SCE was considering not going forward with it unless it would receive "credit" from the CPUC toward its obligations under a RAM decision, would it have been inappropriate for SCE *not* to provide notice to prospective bidders regarding the potential for conclusion of the RSC RFO without signed contracts? Assuming that it was appropriate to provide notice to prospective bidders, did SCE do it in a reasonable fashion by stating that it "will not" execute contracts if it did not receive a satisfactory RAM decision?

Importantly, the market's response to the solicitation was very strong—the solicitation was highly competitive. There is no indication that any prospective bidder in fact decided not to submit an offer due to SCE's statements prior to the due date for offers. Further, we concur with SCE's decision to inform prospective bidders regarding the potential for not executing contracts as a result of the solicitation due to the interaction

[35] As indicated previously, one project for which a PPA was executed is not the subject of SCE's advice letter because the PPA was subsequently terminated.

with a decision in the RAM proceeding. It was appropriate to provide this information to prospective bidders, who could make their own judgments about whether or not to participate in the RSC RFO. Nor do we take issue with whether the statement at the time it was made reflected SCE's thinking at the time. Finally, we do not take issue with whether SCE had the legal right not to proceed with the 2010 RSC program.

We do, however, think that it was unnecessary for SCE to state that it *will not* execute any RSC contracts unless it was satisfied with an ultimate RAM decision. To our knowledge, a firm decision at that time had not been made by SCE's management, and, ultimately, SCE decided—rightly, in our opinion—to go forward with 250 MW of RSC contracts from this solicitation regardless of the outcome of the CPUC's RAM proceeding. A more qualified statement to prospective bidders—that SCE *may not* execute contracts—would have been more appropriate and would have been consistent with the position that SCE ultimately reached.

Overall, the IE's assessment is that the proposal evaluation process was fairly administered with respect to all proposals. Since there were no affiliate offers, issues associated with affiliate offers were not a factor in the assessment.

VI. Project-Specific Contract Negotiations

Of the contracts executed as a result of this solicitation, eight were RSC5 contracts and 13 were RSC20 contracts. The IE monitored the contract negotiations between SCE and the Offeror—under the RFO Participant Instructions limited to project-specific matters—and did not detect any unfairness on the part of SCE. SCE acted in an evenhanded manner and the parties reached agreement within a reasonable timeframe and contracts were executed by the target date set forth in the RFO Participant Guidelines. Further details are provided in the Confidential Appendix to this IE Report.

In addition, SCE negotiated contracts with provisionally shortlisted bidders with the understanding that those on the provisional shortlist would only obtain executed contracts if one or more projects on the shortlist dropped out or if SCE obtained, from its perspective, a favorable RAM decision. SCE presented this opportunity in a fair manner and acted consistently and responsively with those bidders on the provisional short list that chose to pursue this opportunity.

VII. Whether the Contracts Merit Approval and Other Matters

A. If Applicable, Describe Safeguards and Methodologies Employed by the IOU to Compare Affiliate Bids or Utility-Owned Generation Ownership Offers.

This was not applicable in this solicitation since utility-owned generation ownership offers were not eligible and no affiliate bids were submitted.

B. Based on the Complete Bid Process, are the IOU's Contracts the Best Overall Offers Received by the IOU?

From a price standpoint, lower priced bids would have been accepted for contract execution but for the 100 MW limit on supplier concentration. However, in the IE's opinion, it was reasonable for SCE to impose such a limit and within its discretion under the RFO Participant Instructions. In the future, however, supplier concentration limits (or criteria for determining those limits) should be set forth as part of the RFO design and communicated to prospective bidders before bids are submitted.

SCE, in the IE's opinion, also made assessments pertaining to project viability, although the depth of its inquiry was modest given the nature of the RSC RFO design, which is oriented toward simplicity, expedition, and low transaction costs. All in all, it is the IE's view that based on the entire solicitation process, SCE contracted for the best overall offers in the context of the guidelines set forth by SCE for the solicitation.

C. Did any Contract Reflect a Product Not Solicited and Bid in the RFO?

No.

D. Is the Contract a Reasonable Way of Achieving the Need Identified in the RFO?

The need identified in the RFO is to provide a process that will lead to quick execution of contracts for projects not greater than 20 MW. From the launch of the RSC RFO in early August 2010, it took approximately 3 and one-half months to hold two bidders conference (by web conference), obtain comments on the RSC pro forma contracts and then finalize them, receive a very large number of bids, evaluate the bids, short list bidders, and negotiate and execute 21 renewable standard contracts for 259 MW of renewable energy projects. This is an impressive feat. Based on the stated goals, the contracts are a reasonable way of achieving the need identified in the RFO.[36]

E. Do the Contracts Merit Commission Approval?

Based on our analysis of the RFO bids and the solicitation process, it is our opinion that the 20 contracts for which SCE is seeking approval warrant Commission approval. While the RSC RFO solicitation design and execution was not perfect, it was a reasonable means of testing the market, obtaining very attractive pricing, and applying modest but real viability criteria in the project evaluation. SCE acted fairly, in our opinion, in the evaluation and selection phases of the process. We also note that the results of the 2010 RSC were competitive with those projects on the 2009 RPS RFP

[36] One area for improvement is the process related to the drafting of the pro forma standard contracts, the finalization of the pro forma standard contracts and the negotiation of "project-specific" issues. This part of the process could be simplified and expedited if the utility were to start with a form of standard contract that is somewhat less complex and more "middle of the road."

shortlist based on the application of SCE's renewable premium analysis.[37] In our opinion, the resulting contracts merit approval.

VIII. Conclusions

For the reasons stated herein, Merrimack Energy concludes that the offer selection decisions by SCE in the 2010 Renewable Standard Contracts RFO process were reasonable and were based on the requirements and evaluation criteria set forth in the RFO Participant Instructions. The offers selected and contracts executed were the result of a competitive solicitation process with a highly robust response. In implementing the process, SCE was fair and reasonable to all Offerors and acted in an unbiased fashion. The information provided to prospective bidders through the two web conferences, questions and answers and other means of communication appeared to be very helpful to Offerors as a whole and were not provided preferentially to any Offeror. Merrimack Energy recommends approval of the 20 contracts executed by SCE through the 2010 RSC RFO process that are the subject of SCE's advice letter.

[37] The comparison is addressed in the confidential appendix to this report.

Appendix B
Description of Southern California Edison Company's Least Cost Best Fit Methodology Used in the 2009 Renewable Energy RFP

Overview

For the 2009 RPS RFP, SCE applied the Renewable Premium methodology as the primary evaluation metric to evaluate and rank proposals. The Renewable Premium is equal to levelized costs minus levelized benefits associated with each proposal in nominal $/MWh.

SCE has also developed a detailed process for evaluating and selecting proposals for the short list which is comprised of a number of pre-defined steps from receipt of bids through determination of the final short list. Prior to receiving proposals, SCE finalizes major assumptions and methodologies that drive the valuation, including power and natural gas price forecasts, existing and forecast resource portfolio, and firm capacity value forecast. Once proposals are received, SCE begins an initial review for completeness and conformity with the solicitation protocols. After the initial review is complete, SCE performs the quantitative assessment of each proposal individually. The result of the quantitative analysis is a relative ranking of proposals in preparation for selecting the preliminary short list. Proposals in the 2009 solicitation were evaluated and then ranked based on the Renewable Premium metric.

In parallel with the quantitative analysis, SCE conducts an assessment of each proposal's qualitative attributes. For the 2009 Renewable RFP, both SCE and the IE conducted a detailed evaluation of each proposal using the Commission's Project Viability Calculator. This analysis assesses a project's technical viability, development status and milestones and the developer's experience. These qualitative attributes are then considered to either eliminate non-viable proposals or add projects with high viability to the final short list of proposals. The Project Viability Calculator was not used with respect to the RSC applications.

Quantitative Assessment

SCE evaluates the quantifiable attributes and costs of each proposal individually and ranks proposals based on the Renewable Premium metric. For the quantitative analysis, benefits are comprised of separate capacity and energy components based on the calculated value of these products, while costs include the contract bid price, integration costs, transmission costs, performance assurance adder if applicable, and debt equivalence. SCE relies on the generation profile of the bid in its evaluation assessment. SCE discounts the annual benefit and cost streams to a common base year prior to calculating the Renewable Premium for each proposal. In developing its relative ranking of proposals, SCE's evaluation methodology incorporates information provided by the seller (such as the generation profile) and assumptions prescribed and set by the CPUC, with its own internal methodologies and forecasts of market conditions. The objective of the quantitative assessment and relative ranking is to develop a preliminary short list that is further refined based on non-quantifiable attributes.

Each of the components of the benefit and cost side of the analysis is described below. Both benefits and costs are levelized prior to calculating the Renewable Premium.

Benefits

Capacity Benefit

Each proposal is assigned capacity benefits based on SCE's forecast of net capacity value and a peak capacity contribution factor.

SCE's gross capacity value forecast consists of a combustion turbine ("CT") proxy. The CT proxy is based on the annual deferral value of a General Electric 7FA simple-cycle combustion turbine. The gross capacity value is then reduced by the expected profits that the assumed proxy plant would make from the energy markets to create the net capacity value.[1]

Peak capacity contribution factors are calculated in a manner consistent with the Commission's Resource Adequacy accounting rules (D.09-06-028) utilizing a 70% exceedance factor methodology. Peak capacity contribution factors will be both technology and location-specific. Technological differentiation does not refer to the fuel source, but rather the method of converting other energy sources into electricity (e.g., solar trough, photovoltaic). For proposals with dispatchable capabilities at SCE's control, the peak capacity contribution factor will be based on the availability of the proposed project.

Monthly capacity benefits are the product of SCE's net capacity value forecast, the total monthly proposed alternating current nameplate capacity of the project, SCE's relative loss-of-load probability factors, and the peak capacity contribution factor. The monthly capacity benefits are aggregated to annual capacity benefits.

Energy Benefit

SCE measures the energy benefits of a proposal by evaluating its effect on the total production cost of SCE's forecasted resource portfolio to serve its bundled customer load. The evaluation of the energy benefits is performed with a base portfolio and system that is consistent with SCE's most recent Long-Term Procurement Plan ("LTPP"), with some updates to account for the latest natural gas price and load forecast and the results of recent procurement activities.

SCE uses Ventyx's ProSym model to compare the hourly production costs of SCE's base resource portfolio with the hourly production costs when a baseload energy block is individually added to the base portfolio. Each energy block is added to the resource portfolio as a no-cost, must-take flat generation profile.

ProSym performs an hourly, least cost dispatch with SCE's known resource portfolio and generic generation to meet customer demand. Generic generation is added to the portfolio to ensure that RPS goals and resource adequacy requirements are satisfied and customer load can be met. A

[1] Energy profits are the difference between market revenues and variable cost of generation, as determined by performing a least-cost dispatch of the proxy station against SCE's power price forecast.

series of ProSym runs are performed with varying size blocks with the base proposal as the reference case. The ProSym runs consist of an hourly, least-cost dispatch of the base portfolio plus the generic energy block against SCE's current demand and price forecasts. The difference in hourly production costs between the two cases is the hourly energy benefit for each energy block. The energy benefit for each proposal is then calculated by taking the seller provided generation profile and interpolating the hourly energy benefit from the energy block runs. The difference between the interpolated hourly production cost and the reference case hourly production cost is the hourly energy benefit for the proposal.

SCE's resource portfolio is dispatched against an SCE area power price forecast. For out-of-area resource proposals, additional congestion charges may be added to calculate the net energy benefits based on SCE's internal congestion pricing forecasts. SCE's gas price forecast is based on a near-term market view and a longer-term fundamental view of prices, while power price forecasts are based on a fundamental view.[2]

Costs

1. Payments

The primary costs associated with each proposal are the payments that SCE pays to the seller for the expected renewable energy deliveries under the terms of the contracts. Proposals include an all-in price for delivered renewable energy, which is adjusted in each time-of-delivery period by energy payment allocation factors ("TOD factors"). The total estimated payments are then determined using the TOD-adjusted generation profile provided in the proposal and adjusted for electric energy loss factors (to calculate the delivered amount of electric energy).

2. Integration Costs

Integration costs are the additional system costs required to provide load following and regulation as a result of integrating various resources. The integration cost adder for all proposals is currently zero for purposes of calculating the Renewable Premium consistent with applicable CPUC rulings.[3]

3. Transmission Cost

For resources that do not have an existing interconnection to the electric system or a completed facility study, system transmission upgrade costs are estimated using SCE's Transmission Ranking Cost Report ("TRCR") methodology and specific details provided by Sellers in the RFP process. Network upgrade costs and scope from interconnection studies are used to the extent

[2] SCE's LCBF quantitative evaluation inherently captures the impact of portfolio fit. For example, as different proposals are added to the overall portfolio, the resultant residual short or net long position is impacted. Projects that more often increase SCE's net long positions are assigned less energy benefits than those projects that are more often filling net short positions. As such, a project that provides more energy when it is most needed and less energy in periods of low need will be evaluated as providing greater energy benefit.

[3] D.04-07-029, as clarified by D.07-02-011.

they are available and applicable. To the extent studies are not available, transmission cost adders for new generation are based on unit cost guides used in interconnection cluster studies.

Transmission cost adders were not used in the RSC evaluation or selection process. SCE estimated transmission cost adders for the Renewable Standard Contracts on a generalized basis for purposes of the renewable premium evaluation.

4. Debt Equivalence

"Debt Equivalence" is the term used by credit rating agencies to describe the fixed financial obligations resulting from long-term purchased power contracts. In November 2008, the CPUC issued D.08-11-008, which authorized the IOUs to recognize the effects of debt equivalence when comparing power purchase agreements in their bid evaluations, but not when a utility-owned generation project is being considered. Since no utility-owned generation was proposed in the 2009 RPS RFP, SCE considered debt equivalence as part of the evaluation.

Debt equivalence was not quantified or otherwise evaluated in the RSC evaluation or selection process. SCE has provided a Debt Equivalence evaluation for each Renewable Standard Contract as part of the Renewable Premium evaluation, which is set forth in Confidential Appendix A.

5. Credit and Collateral Requirements – Performance Assurance Adder

In the 2009 Renewable RFP, SCE requested that Sellers provide pricing based on the seller providing performance assurance during the operating period equal to 5% of contract payments.[4] The Company expressed a strong preference for this amount of performance assurance. However, Sellers had the option to propose different pricing for different performance assurance levels. SCE developed a methodology to assess the additional performance assurance exposure to SCE in cases where Sellers offered less than the proforma 5% performance assurance amount. SCE used this methodology to establish comparable pricing for use in ranking proposals.

Since for Renewable Standard Contracts of 5 MW and under no performance assurance was required and for over contracts up to 20 MW 5 percent performance assurance was required, performance assurance adders were inapplicable to either RSC evaluation/selection or the Renewable Premium assessments of these contracts.

Project Viability Assessment

To assess project viability in the Renewable RFP, SCE used the project viability calculator ("PVC") developed by the CPUC's Energy Division. The PVC contains three major evaluation categories and several sub-categories as criteria for evaluating bids. Also, each major category contains a weight for the major category overall. In addition, each criterion is ranked in one of four categories: (1) very high (in terms of importance); (2) high; (3) medium; and (4) low. The weights for each criteria range from 4 for the "very high" criteria to 1 for the "low" criteria. The

[4] For very short-term products, a different standard was set forth in the Procurement Protocol.

total project viability score for each bid is a function of the weight for the categories overall, the weights for each criteria and the score awarded for each bid within each criteria.

A list of the categories and criteria used in the project viability assessment is provided in Table 1 below:

Table 1 Project Viability Criteria

Category	Criteria
A. Company Development Team	
	1. Project Development Experience 2. Ownership/O&M Experience
B. Technology	.
	1. Technical Feasibility 2. Resource Quality 3. Manufacturing Supply Chain
C. Development Milestones	
	1. Site Control 2. Permitting Status 3. Project Finance Status 4. Interconnection Progress 5. Transmission Requirements 6. Reasonableness of COD

As mentioned previously, the PVC was not used for RSC applicants and project viability was not an eligibility requirement or an evaluation criterion. However, SCE has addressed project viability for the RSC projects in its advice letter filing and it is also addressed in our report.

Other Qualitative Factors

In addition to the identified benefits and costs that are quantified in the evaluation, SCE assesses in its Renewable RFP non-quantifiable characteristics of each proposal. These qualitative attributes are used to consider the inclusion of additional bids on the SCE short list or the exclusion of bids from the short list due to the relative weakness of highly ranked proposals due to (a) strength of a particular seller's proposal; or (b) the relative weakness of the high ranked proposals.

The attributes that SCE considers in the Renewable RFP context include, but are not limited to:

1. Extent of Seller's contractual concerns relating to SCE's Pro Forma Agreement;

2. SCE portfolio concentration risk;

3. Status of project development efforts;

4. Timing and progress towards gaining access to transmission;

5. Technology and economic viability, including viability and commercial experience of the technology;

6. Seller's capability to perform all of its financial and other obligations under the pro forma agreement;

7. Seller's ability to deliver energy in the near term; and

8. Performance assurance amount that the seller intends to post.

In addition, the 2009 Renewable RFP Procurement Protocol provides for SCE to assess additional non-quantifiable characteristics of each proposal that are used to determine tie-breakers. The pertinent attributes that SCE considers include, but are not limited to:

- If (i) the generating facility's first point of interconnection is within the Tehachapi area (namely, in the vicinity of the existing Antelope or Vincent substations; or in the vicinity of the future substations of Highwind, Windhub, Cottonwood, or Whirlwind); and (ii) such generating facility is dispatchable during on-peak periods;

- Environmental impacts of Seller's proposed project on California's water quality and use;

- Resource diversity;

- Benefit to minority and low income communities;

- Local reliability; and

- Environmental stewardship.

Pursuant to D.04-07-029, the presence of demonstrated qualitative attributes may justify moving a proposal onto SCE's short-list of proposals if (a) the initial proposal rank is within reasonable valuation proximity to those selected for the shortlist and (b) SCE receives support from its PRG to elevate the proposal based on qualitative factors.

Confidential Appendix D

Contract Summaries

Confidential Protected Materials – Public Disclosure Prohibited

Appendix E

RSC Contracts' Contribution to RPS Goals

Confidential Protected Materials – Public Disclosure Prohibited

Appendix F

SCE's RPS Proposal Evaluation and Selection Process and Criteria

Southern California Edison Company's ("SCE") Written Description of Renewables Portfolio Standard ("RPS") Proposal Evaluation and Selection Process and Criteria ("LCBF Written Report")

I. Introduction

A. Note relevant language in statute and CPUC decisions approving LCBF process and requiring LCBF Reports

Under the direction of the California Public Utilities Commission (the "Commission" or "CPUC"), SCE conducts annual solicitations for the purpose of procuring power from eligible renewable energy resources to meet California's RPS. SCE evaluates and ranks proposals based on least-cost/best-fit ("LCBF") principles that comply with criteria set forth by the Commission in Decision ("D.") 03-06-071 and D.04-07-029 ("LCBF Decisions"). *See also* Pub. Util. Code Section 399.14(a)(2)(B).

B. Goals of proposal evaluation and selection criteria and processes

The LCBF analysis evaluates both quantitative and qualitative aspects of each proposal to estimate its value to SCE's customers and its relative value in comparison to other proposals.

II. Proposal Evaluation and Selection Criteria

While assumptions and methodologies have evolved slightly over time, the basic components of SCE's evaluation and selection criteria and process for RPS contracts were established by the Commission's LCBF Decisions. Consistent with those LCBF Decisions, the three main steps undertaken by SCE are: (i) initial data gathering and validation, (ii) a quantitative assessment of proposals, and (iii) adjustments to selection based on proposals' qualitative attributes.

Prior to receiving proposals, SCE finalizes major assumptions and methodologies that drive valuation, including power and gas prices forecasts, existing and forecast resource portfolio, and capacity value forecast. Other assumptions, such as the Transmission Ranking Cost Report ("TRCR"), are filed with the Commission for approval prior to the release of solicitation materials.

Once proposals are received, SCE begins an initial review for completeness and conformity with the solicitation protocol. The review includes an initial screen for required submission criteria such as conforming delivery point, minimum project size, and submission of particular proposal package elements. Sellers lacking in any of these items are allowed a cure period to remedy any deficiencies. Following this initial screen, SCE conducts an additional review to determine the reasonableness of proposal parameters such as generation profiles and capacity factors. SCE works directly with sellers to resolve any issues and ensure data is ready for evaluation.

After these reviews, SCE performs a quantitative assessment of each proposal individually and subsequently ranks them based on the proposal's benefit and cost relationship. Specifically, the total benefits and total costs are used to calculate the net levelized cost or "Renewable Premium" per each complete and conforming proposal. Benefits are comprised of separate capacity and energy components, while costs include the contract payments, integration costs, transmission cost, and debt equivalence. SCE discounts the annual benefit and cost streams to a common base year. The result of the quantitative analysis is a merit-order ranking of all complete and conforming proposals' Renewable Premiums that helps define the preliminary short list.

In parallel with the quantitative analysis, SCE conducts an in-depth assessment of each proposal's qualitative attributes. This analysis utilizes the Commission's prescribed Project Viability Calculator to assess certain factors including the company/development team, technology, and development milestones. Additional attributes such as transmission area/cluster, seller concentration, portfolio fit of commercial on-line date, project size, and dispatchability and curtailability are also considered in the qualitative analysis. These qualitative attributes are then considered to either eliminate non-viable proposals or add projects with high viability to the final short list of proposals, or to determine tie-breakers, if any.

Following its analysis, SCE consults with its Procurement Review Group ("PRG") regarding the final short list and specific evaluation criteria. Whether a proposal selected through this process results in an executed contract depends on the outcome of negotiations between SCE and sellers. Periodically, SCE updates the PRG regarding the progress of negotiations. SCE also consults with its PRG prior to the execution of any successfully negotiated contracts. Subsequently, SCE executes contracts and submits them to the Commission for approval via advice letter filings.

A. Description of Criteria[3]

1. List and discuss the quantitative and qualitative criteria used to evaluate and select proposals. This section should include a full discussion of the following:

QUANTITATIVE ASSESSMENT

SCE evaluates the quantifiable attributes of each proposal individually and subsequently ranks them based on the proposal's benefit and cost relationship, specifically the net levelized cost of the project or Renewable Premium. SCE maintains the same individual quantitative components it used in 2008 – capacity benefits, energy benefits, contract payments, debt equivalence mitigation costs, integration costs, and transmission costs. In developing its relative or merit order ranking of proposals, SCE's evaluation methodology incorporates information provided by sellers and assumptions prescribed and set by the Commission with its internal methodologies and forecasts of market conditions. The objective of the quantitative assessment and relative Renewable Premium ranking is to develop a preliminary short list that is further refined based on the non-quantifiable attributes discussed below. Each of the elements for the RPS quantitative analysis is described briefly below.

Benefits

- Capacity Benefit

Each proposal is assigned capacity benefits based on SCE's forecast of net capacity value and a peak capacity contribution factor.

SCE's gross capacity value forecast consists of a combustion turbine ("CT") proxy. The CT proxy is based on the annual deferral value of a General Electric 7FA simple-cycle combustion turbine. The gross

[3] This LCBF Written Report discusses SCE's proposal evaluation and selection criteria in a different order than in the Energy Division's LCBF Template in order to more accurately explain SCE's evaluation and selection process; however, all elements in the LCBF Template are addressed.

capacity value is then reduced by the expected profits that the assumed proxy plant would make from the energy markets to create the net capacity value.[4]

Peak capacity contribution factors are calculated in a manner consistent with the Commission's Resource Adequacy accounting rules (D.09-06-028) utilizing a 70% exceedance factor methodology. Peak capacity contribution factors will be both technology and location-specific. Technological differentiation does not refer to the fuel source, but rather the method of converting other energy sources into electricity (e.g., solar trough, photovoltaic). For proposals with dispatchable capabilities at SCE's control, the peak capacity contribution factor will be based on the availability of the proposed project.

Monthly capacity benefits are the product of SCE's net capacity value forecast, the total monthly proposed alternating current nameplate capacity of the project, SCE's relative loss-of-load probability factors, and the peak capacity contribution factor. The monthly capacity benefits are aggregated to annual capacity benefits.

- Energy Benefit

SCE measures the energy benefits of a proposal by evaluating its effect on the total production cost of SCE's forecasted resource portfolio to serve its bundled customer load. The evaluation of energy benefits is performed with a base portfolio and system that is consistent with SCE's most recent Long-Term Procurement Plan ("LTPP"), with some updates to account for the latest gas price and load forecasts and the results of recent procurement activities.

For proposals with must-take energy, SCE calculates the energy benefits of a proposal based on the impacts of additional blocks of no-cost, must-take, flat-profile energy on the hourly production cost as compared to the hourly production cost of SCE's base resource portfolio. The impacts are assessed through the use of Ventyx's ProSym model. A series of ProSym runs are performed with varying size blocks with the base portfolio, described above, as the reference case. The ProSym runs consist of an hourly, least-cost dispatch of the base portfolio plus the generic energy block against SCE's current demand and price forecasts. The hourly production cost for each proposal is then calculated by taking the seller provided generation for the hour and interpolating the hourly production cost based on the results of the generic energy block runs. The difference between the interpolated hourly production cost and the reference case hourly production cost is the hourly energy benefit for the proposal.

For proposals with dispatchable capabilities at SCE's control, SCE calculates the net energy benefits based on the impacts of the proposed additional resource on the hourly production cost as compared to the hourly production cost of SCE's base portfolio. ProSym is run with the base portfolio and the proposed resource to determine the annual production cost. The net energy benefits for the unit are calculated as the difference in annual production costs between the reference case and the proposed case.

SCE's resource portfolio is dispatched against an SCE area power price forecast. For out-of-area resource proposals, congestion charges may be applied to calculate the net energy benefits based on SCE's internal congestion pricing forecasts. SCE's gas price forecast is based on a near-term market view and a longer-term fundamental view of prices, while power price forecasts are based on a fundamental view.

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[4] Energy profits are the difference between market revenues and variable cost of generation, as determined by performing a least-cost dispatch of the proxy station against SCE's power price forecast.

The simulation model, and hence the energy benefit calculation, captures additional quantitative effects that SCE has been asked to consider by the Commission, including dispatchability. The dispatchability benefits are implied in the energy benefit and are not addressed separately.

SCE's LCBF quantitative evaluation process inherently captures the impact of portfolio fit. For example, as different proposals are added to the overall portfolio, the resultant residual net short or net long position is impacted. Projects that more often increase SCE's net long positions are assigned less energy benefits than those projects that are more often filling net short positions. As such, a project that provides more energy when it is most needed and less energy in periods of low need will receive the greatest energy benefit.

Costs

- Debt Equivalence

"Debt equivalence" is the term used by credit rating agencies to describe the fixed financial obligation resulting from long-term purchased power contracts. Pursuant to D.04-12-048, the Commission permitted the utilities to recognize costs associated with the effect debt equivalence has on the utilities' credit quality and cost of borrowing in their evaluation process. In D.07-12-052, the Commission reversed this position. However, SCE filed a petition for modification of D.07-12-052. In November 2008, the Commission issued D.08-11-008, which authorized the investor-owned utilities ("IOUs") to recognize the effects of debt equivalence when comparing power purchase agreements in their bid evaluations, but not when a utility-owned generation project is being considered. Given the new decision, SCE considers debt equivalence in the evaluation process.

- Contract Payments

The primary costs associated with each proposal are the contract payments that SCE makes to sellers for the expected renewable energy deliveries.

Proposals typically include an all-in price for delivered renewable energy, which is adjusted in each time-of-delivery period by energy payment allocation factors ("TOD factors"). SCE develops and submits its TOD factors for each solicitation to the Commission for approval prior to the issuance of the Request for Proposals ("RFP"). Total payments are then determined using the TOD adjusted generation, based on the generation profile provided in the proposal, and the contract price. For projects that include a capacity-related payment in addition to an energy price, the total payments are determined by using the TOD adjusted generation based on the generation profile provided in the proposal, the energy price, and the capacity payment.

- Integration Costs

Integration costs are the additional system costs required to provide load following and regulation as a result of integrating various resources. Pursuant to D.04-07-029, as clarified in D.07-02-011, the integration cost adder for all proposals is zero.

- Transmission Cost

For resources that do not have an existing interconnection to the electric system or a completed facilities study, system transmission upgrade costs are estimated utilizing the TRCR methodology and specific proposal details provided by sellers in the RFP process. Network upgrade costs and scope from interconnection studies are used to the extent they are available and applicable. To the extent studies are not available, transmission cost adders for new generation are based on unit cost guides used in interconnection cluster studies.

- **Discuss how much detailed transmission cost information the IOU requires for each project**

Other than the assumptions provided in a seller's proposal, SCE does not require additional transmission information, unless the seller has completed a transmission provider study. If one or more transmission provider studies have been completed with respect to the proposed project, then the seller must provide the results.

- **Discuss whether cost adders are always imputed for projects in transmission-constrained areas, or whether and how costs for alternative commercial transactions (i.e., swapping, remarketing) are substituted**

SCE uses the best available information it can find when determining the cost of potential upgrades for projects in transmission-constrained areas. For those projects outside SCE's service area, the TRCRs of Pacific Gas and Electric Company or San Diego Gas & Electric Company are used as appropriate. SCE applies the required upgrade costs to get the project delivered to the nearest defined market (e.g., NP15, SP15, ZP 26 Generation Trading Hubs). For projects with an assumed delivery point outside the California Independent System Operator ("CAISO"), SCE applies a power swapping methodology, where the power is assumed to be sold into the local market.

QUALITATIVE ASSESSMENT

In addition to the benefits and costs quantified during SCE's evaluation, SCE assesses non-quantifiable characteristics of each proposal by conducting a comprehensive analysis of each project's qualitative attributes. These qualitative attributes are used to consider inclusion of additional sellers on the short list due to the strength of a particular seller's proposal. Pursuant to D.04-07-029, the presence of demonstrated qualitative attributes may justify moving a proposal onto SCE's short list of proposals if (a) the initial proposal rank is within reasonable valuation proximity to those selected for the short list and (b) SCE consults with, and receives general support from, its PRG prior to elevating the proposal based on qualitative factors.

This assessment may also result in the exclusion of proposals from the short list due to the relative weakness of highly-ranked proposals or other identified issues such as potential seller and/or supply chain concentration concerns.

In other instances, where there are weaknesses in some of these factors (although these may not be significant enough to exclude a proposal from the short list), SCE utilizes additional contract requirements to manage these issues during the development of the project.

Each of the elements for the qualitative analysis is described briefly below.

Project Viability

SCE assesses the following attributes using the Commission's prescribed Project Viability Calculator:

- Company/Development Team
  - Project Development Experience
  - Ownership/O&M Experience
- Technology
  - Technical Feasibility
  - Resource Quality
  - Manufacturing Supply Chain
- Development Milestones
  - Site Control
  - Permitting Status
  - Project Financing Status
  - Interconnection Progress
  - Transmission Requirements
  - Reasonableness of Commercial Operation Date ("COD")

Additional Qualitative Attributes

Following the Project Viability Calculator qualitative assessment, SCE considers additional qualitative characteristics to determine advancement onto the short list or tie-breakers, if any. These additional characteristics may include:

- Transmission area (e.g., Tehachapi, Sunrise, within SCE's load pocket)
- Portfolio fit of COD
- Seller concentration
- Expected generation (GWh/year)
- Dispatchability and curtailability
- Contract price
- Alternative Renewable Premium (i.e., Renewable Premium including integration costs)
- Environmental impacts of seller's proposed project on California's water quality and use
- Resource diversity
- Benefits to minority and low income communities
- Local reliability
- Environmental stewardship

OTHER CONSIDERATIONS

Out-of-State Projects

- **Discuss how evaluation process differs for out-of-state projects**

The overall evaluation methodology is applied consistently to projects regardless of location. Energy benefits for those projects outside of the CAISO will be based on the pricing at the seller-elected

liquid trading hub or CAISO intertie according to SCE's fundamental price forecast for hubs across the Western Electricity Coordinating Council ("WECC"). For projects that deliver at the busbar, SCE will evaluate the energy benefits based upon the regional price forecast where the energy is likely to be managed. Capacity benefits will be based on SCE's forecast of the regional capacity value, the nameplate capacity of the project, and the peak capacity contribution factor of the project.

For those projects within or connected directly to the CAISO, SCE applies the cost to customers of new CAISO network upgrades required for deliverability of the new project. SCE customers are not liable for any network upgrades outside of the CAISO (outside of any costs that may be imbedded within the contract pricing) so transmission cost adders are zero for out-of-state projects.

B. Criteria Weightings

1. If a weighting system is used, please describe how each LCBF component is assigned a quantitative or qualitative weighting compared to other components. Discuss the rationale for the weightings.

SCE does not apply a weighing system in its LCBF evaluation.

2. If a weighting system is not used, please describe how the LCBF evaluation criteria are used to rank proposals

SCE's LCBF quantitative evaluation of the proposals incorporates energy and capacity benefits with contract payments, transmission and integration costs, and debt equivalence to create individual benefit and cost relationships, namely, the Renewable Premium. It is the Renewable Premium that is used to rank and compare each project. Qualitative attributes of each proposal are then considered to further screen the short list and determine tie-breakers to arrive at a final short list of proposals.

3. Discuss how the IOU LCBF methodology evaluates project commercial operation date relative to transmission upgrades required for the project

As part of the qualitative assessment, SCE considers sellers' proposed on-line dates for the project in conjunction with a variety of critical project milestones. Such milestones include network upgrade status and scope, status of major equipment procurement and lead times, and permitting status. For those projects which SCE has concerns over the viability of the timeframe, a range of on-line dates (and transmission facilities availability) are evaluated to determine the sensitivity of the results to the timing. If the project ranking does not change in a manner that would change its original selection status over a range that SCE deems reasonable, then the original assessment is used. For projects whose selection is dependent on the timing of the project and the availability of upgraded transmission facilities, further analysis of the timing of the projects is required.

4. Discuss how the LCBF methodology takes into account proposals that may be more expensive, but have a high likelihood of resulting in viable projects

SCE's LCBF methodology incorporates project viability in a qualitative assessment after the preliminary ranking of proposals has been completed and in determining the size of the short list. Proposals that are more expensive tend to be lower on the quantitative ranking of projects, and, therefore, may fall beyond the initial short list cut-point. SCE may pull such projects onto the short list if, from its qualitative

assessment, it determines the project maintains high viability and the initial proposal rank is within reasonable valuation proximity to those selected for the short list. In this situation, the quantitative ranking is still considered as part of the overall decision, but the viability becomes the key driver.

C. Evaluation of utility-owned, turnkey, buyouts, and utility-affiliate projects

1. Describe how utility-owned projects are evaluated against power purchase agreements ("PPAs")

SCE views utility-owned cost-of-service generation as a necessary and good option for customers to have. SCE does not evaluate proposed utility-owned projects against PPAs, as utility-owned generation and contracted-for generation are fundamentally different products. As such, any attempt to do a numerical comparison of them is unworkable. This topic is discussed in detail in the Supplemental Testimony to SCE's 2006 LTPP (Section I.B, pgs 2-5). Moreover, approval of a utility-owned project would not be submitted through the solicitation process, but through a formal application.

2. Describe how turnkey projects are evaluated against PPAs

Turnkey projects are similar to utility-owned projects. Refer to the response above.

3. Describe how buyout projects are evaluated against PPAs

The 2009 RFP Procurement Protocol specified that the objective of the solicitation was to purchase the output from projects developed and owned by independent power producers. SCE received an overwhelming response of proposals from independent power producers consistent with this type of structure. SCE did receive one proposal for a design, build, buyout, but that proposal was subsequently withdrawn by the seller after a discussion between SCE and the seller.

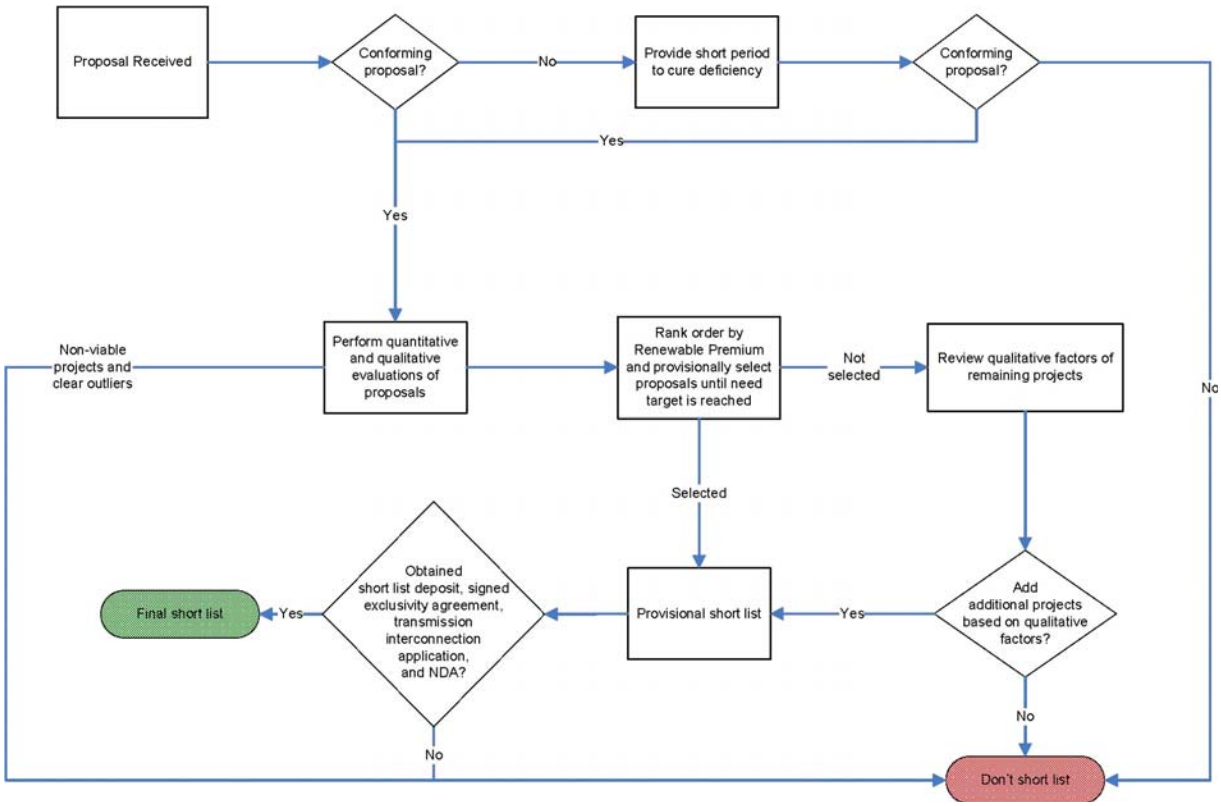
4. Describe how utility-affiliate projects are evaluated against non-affiliate projects

Utility-affiliate projects are evaluated in the same manner as non-affiliate projects. In addition, evaluation of utility affiliate projects would be subject to review by the Independent Evaluator, the PRG, and the Commission through the application approval process.

II. <u>Proposal Evaluation and Selection Process</u>

A. What is the process by which proposals are received and evaluated, selected or not selected for short list inclusion, and further evaluated once on the short list?

2009 RPS RFP Short-List Process



B. What is the typical amount of time required for each part of the process?

The typical amount of time required for the short listing process depends on the volume of proposals received by SCE during a solicitation. Historically, it has taken SCE no more than eight weeks to complete the LCBF evaluation process, which includes quality control of sellers' information, transmission assessment, quantitative assessment, qualitative assessment, management review, and PRG meetings. Many of the components in the overall process overlap and may require additional time if clarification from sellers is needed.

C. How is the size of the short list determined?

The size of SCE's short list is determined largely by an assessment of the attractiveness of RPS-eligible energy proposals and a desire for a robust, inclusive set of developer proposals. The short list is expanded well beyond the point that is needed for SCE to meet its RPS goals, as there is an expectation that some projects that are selected will not join the short list and that negotiations will not be successful with some short listed sellers.

D. Are sellers that are not selected to be short listed told why they were not short listed? If so, what is the process?

Sellers are informed by e-mail that their proposals were not short listed. The e-mail does not contain specific reasons for a seller's proposal not being selected for short listing. However, sellers often contact

SCE to obtain specificity regarding their projects and what can be improved for future solicitations. In such cases, SCE refers the seller to the RFP documentation in conjunction with a discussion of the seller's project quantitative and qualitative scoring.

E. Were any proposals rejected for non-conformance? If so, how many and what were the non-conforming characteristics?

SCE did not reject any proposals as non-conforming.

F. Describe involvement of the Independent Evaluator

The Independent Evaluator monitors SCE's RPS solicitations, provides an independent review of SCE's process, models, assumptions, and the proposals it may receive, and helps the Commission and SCE's PRG participants by providing them with information and assessments to ensure that the solicitation was conducted fairly and that the most appropriate resources were short listed. The Independent Evaluator also provides an assessment of SCE's RPS solicitation from the initial phase of the solicitation (i.e., the publicizing of the issuance of the RFP) through the development of a short list of proposals with whom SCE has commenced negotiations.

G. Describe involvement of the Procurement Review Group

SCE consults with its PRG during each step of the renewable procurement process. Among other things, SCE provides access to the solicitation materials and pro forma contracts to the PRG for review and comment before commencing the RFP; informs the PRG of the initial results of the RFP; explains the evaluation process; and updates the PRG periodically concerning the status of contract formation.

H. Discuss whether and how feedback on the solicitation process is requested from sellers (both successful and unsuccessful) after the solicitation is complete

SCE regularly receives feedback during the normal course of its solicitation process. Shortly after the 2009 RPS RFP bidders conference, SCE solicited feedback from participants via a web based survey. The results of this feedback was shared with SCE's PRG. In addition, SCE anticipates it will formally solicit feedback either through a survey, workshop or other similar method from participants in the 2009 solicitation.

Appendix G

AMF Calculators

Confidential Protected Materials – Public Disclosure Prohibited

Appendix H.1

Lancaster Dry Farm Ranch B PPA

Confidential Protected Materials – Public Disclosure Prohibited

Appendix H.2

Comparison of Lancaster Dry Farm Ranch B PPA to 2010 RSC Pro Forma

Confidential Protected Materials – Public Disclosure Prohibited

Appendix I.1

Sierra Solar Greenworks PPA

Confidential Protected Materials – Public Disclosure Prohibited

Appendix I.2

Comparison of Sierra Solar Greenworks PPA to 2010 RSC Pro Forma

Confidential Protected Materials – Public Disclosure Prohibited

Appendix J.1

Lancaster WAD B PPA

Confidential Protected Materials – Public Disclosure Prohibited

Appendix J.2

Comparison of Lancaster WAD B PPA to 2010 RSC Pro Forma

Confidential Protected Materials – Public Disclosure Prohibited

Appendix K.1

Central Antelope Dry Ranch B PPA

Confidential Protected Materials – Public Disclosure Prohibited

Appendix K.2

Comparison of Central Antelope Dry Ranch B PPA to 2010 RSC Pro Forma

Confidential Protected Materials – Public Disclosure Prohibited

Appendix L.1

Central Antelope Dry Ranch C PPA

Confidential Protected Materials – Public Disclosure Prohibited

Appendix L.2

Comparison of Central Antelope Dry Ranch C PPA to 2010 RSC Pro Forma

Confidential Protected Materials – Public Disclosure Prohibited

Appendix M.1

Victor Dry Farm Ranch A PPA

Confidential Protected Materials – Public Disclosure Prohibited

Appendix M.2

Comparison of Victor Dry Farm Ranch A PPA to 2010 RSC Pro Forma

Confidential Protected Materials – Public Disclosure Prohibited

Appendix N.1

Victor Dry Farm Ranch B PPA

Confidential Protected Materials – Public Disclosure Prohibited

Appendix N.2

Comparison of Victor Dry Farm Ranch B PPA to 2010 RSC Pro Forma

Confidential Protected Materials – Public Disclosure Prohibited

Appendix O.1

North Lancaster Ranch PPA

Confidential Protected Materials – Public Disclosure Prohibited

Appendix O.2

Comparison of North Lancaster Ranch PPA to 2010 RSC Pro Forma

Confidential Protected Materials – Public Disclosure Prohibited

Appendix P.1

American Solar Greenworks PPA

Confidential Protected Materials – Public Disclosure Prohibited

Appendix P.2

Comparison of American Solar Greenworks PPA to 2010 RSC Pro Forma

Confidential Protected Materials – Public Disclosure Prohibited

Appendix Q.1

Sierra View Solar V PPA

Confidential Protected Materials – Public Disclosure Prohibited

Appendix Q.2

Comparison of Sierra View Solar V PPA to 2010 RSC Pro Forma

Confidential Protected Materials – Public Disclosure Prohibited

Appendix R.1

Sierra View Solar IV PPA

Confidential Protected Materials – Public Disclosure Prohibited

Appendix R.2

Comparison of Sierra View Solar IV PPA to 2010 RSC Pro Forma

Confidential Protected Materials – Public Disclosure Prohibited

Appendix S.1

Nicolis PPA

Confidential Protected Materials – Public Disclosure Prohibited

Appendix S.2

Comparison of Nicolis PPA to 2010 RSC Pro Forma

Confidential Protected Materials – Public Disclosure Prohibited

Appendix T.1

Blythe Solar Power Generation Station 1 PPA

Confidential Protected Materials – Public Disclosure Prohibited

Appendix T.2

Comparison of Blythe Solar Power Generation Station 1 PPA to 2010 RSC Pro Forma

Confidential Protected Materials – Public Disclosure Prohibited

Appendix U.1

Littlerock Solar Power Generation Station 1 PPA

Confidential Protected Materials – Public Disclosure Prohibited

Appendix U.2

Comparison of Littlerock Solar Power Generation Station 1 PPA to 2010 RSC Pro Forma

Confidential Protected Materials – Public Disclosure Prohibited

Appendix V.1

Garnet Solar Power Generation Station 1 PPA

Confidential Protected Materials – Public Disclosure Prohibited

Appendix V.2

Comparison of Garnet Solar Power Generation Station 1 PPA to 2010 RSC Pro Forma

Confidential Protected Materials – Public Disclosure Prohibited

Appendix W.1

Lucerne Solar Power Generation Station 1 PPA

Confidential Protected Materials – Public Disclosure Prohibited

Appendix W.2

Comparison of Lucerne Solar Power Generation Station 1 PPA to 2010 RSC Pro Forma

Confidential Protected Materials – Public Disclosure Prohibited

Appendix X.1

Tropico PPA

Confidential Protected Materials – Public Disclosure Prohibited

Appendix X.2

Comparison of Tropico PPA to 2010 RSC Pro Forma

Confidential Protected Materials – Public Disclosure Prohibited

Appendix Y.1

Clear Peak Energy PPA

Confidential Protected Materials – Public Disclosure Prohibited

Appendix Y.2

Comparison of Clear Peak Energy PPA to 2010 RSC Pro Forma

Confidential Protected Materials – Public Disclosure Prohibited

Appendix Z.1

RE Columbia 3 PPA

Confidential Protected Materials – Public Disclosure Prohibited

Appendix Z.2

Comparison of RE Columbia 3 PPA to 2010 RSC Pro Forma

Confidential Protected Materials – Public Disclosure Prohibited

Appendix AA.1

RE Columbia Two PPA

Confidential Protected Materials – Public Disclosure Prohibited

Appendix AA.2

Comparison of RE Columbia Two PPA to 2010 RSC Pro Forma

Confidential Protected Materials – Public Disclosure Prohibited

Appendix BB

Project Viability Calculators

Confidential Protected Materials – Public Disclosure Prohibited

Appendix CC

Confidentiality Declaration

DECLARATION OF GEORGE WILTSEE REGARDING THE CONFIDENTIALITY OF CERTAIN DATA

I, George Wiltsee, declare and state:

1. I am an Energy Contract/Trading Specialist in the Renewable and Alternative Power department of Southern California Edison Company ("SCE"). As such, I had responsibility for preparing and supervising the preparation of this Advice Letter ("Protected Materials"). I make this declaration in accordance with Decision ("D.") 06-06-066, the Administrative Law Judge's Ruling Clarifying Interim Procedures for Complying with D.06-06-066, issued on August 22, 2006 in California Public Utilities Commission ("Commission" or "CPUC") Rulemaking ("R.") 05-06-040, and D.08-04-023. I have personal knowledge of the facts and representations herein and, if called upon to testify, could and would do so, except for those facts expressly stated to be based upon information and belief, and as to those matters, I believe them to be true.

2. I have reviewed the Protected Materials. Listed below are the data in the Protected Materials for which SCE is seeking confidential protection and the categories on the Matrix of Allowed Confidential Treatment Investor Owned Utility ("IOU") Data ("Matrix") to which these data correspond.

Data	Page	Matrix Category	Period of Confidentiality
Consistency with Commission Decisions and Rules and Project Development Status	Appendix A	VII.F/VII.G RPS Contracts VII.H Score sheets, analyses, evaluations of proposed RPS projects VIII.A Bid Information VIII.B Specific quantitative	RPS contracts confidential for three years, or until one year following expiration, whichever comes first. Score sheets, analyses, evaluations of proposed RPS projects confidential for three years. For bid information,

		analysis involved in the scoring and evaluation of participating bids	total number of projects and megawatts bid by resource type public after final contracts submitted to CPUC for approval. Specific quantitative analysis involved in the scoring and evaluation of participating bids confidential for three years after winning bidders selected.
2010 RSC Program Solicitation Overview and 2009 Solicitation Workpapers	Appendix B	VII.F/VII.G RPS Contracts VII.H Score sheets, analyses, evaluations of proposed RPS projects VIII.A Bid Information VIII.B Specific quantitative analysis involved in the scoring and evaluation of participating bids	RPS contracts confidential for three years, or until one year following expiration, whichever comes first. Score sheets, analyses, evaluations of proposed RPS projects confidential for three years. For bid information, total number of projects and megawatts bid by resource type public after final contracts submitted to CPUC for approval. Specific quantitative analysis involved in the scoring and evaluation of participating bids confidential for three years after winning bidders selected.
Independent Evaluator Report	Confidential Version of Appendix C	VII.F/VII.G RPS Contracts VII.H Score sheets, analyses, evaluations of proposed RPS projects	RPS contracts confidential for three years, or until one year following expiration, whichever comes first. Score sheets, analyses,

		VIII.A Bid Information VIII.B Specific quantitative analysis involved in the scoring and evaluation of participating bids	evaluations of proposed RPS projects confidential for three years. For bid information, total number of projects and megawatts bid by resource type public after final contracts submitted to CPUC for approval. Specific quantitative analysis involved in the scoring and evaluation of participating bids confidential for three years after winning bidders selected.
Confidential Contract Summaries	Confidential Appendix D	VII.F/VII.G RPS Contracts VII.H Score sheets, analyses, evaluations of proposed RPS projects VIII.A Bid Information VIII.B Specific quantitative analysis involved in the scoring and evaluation of participating bids	RPS contracts confidential for three years, or until one year following expiration, whichever comes first. Score sheets, analyses, evaluations of proposed RPS projects confidential for three years. For bid information, total number of projects and megawatts bid by resource type public after final contracts submitted to CPUC for approval. Specific quantitative analysis involved in the scoring and evaluation of participating bids confidential for three years after winning bidders selected.

RSC Contracts' Contribution To RPS Goals	Confidential Appendix E	V.C LSE Total Energy Forecast – Bundled Customer	LSE total energy forecast – bundled customer front three years of forecast data confidential.
AMF Calculators for the RSC Contracts	Confidential Appendix G	VII.F/VII.G RPS Contracts VII.H Score sheets, analyses, evaluations of proposed RPS projects VIII.B Specific quantitative analysis involved in the scoring and evaluation of participating bids	RPS contracts confidential for three years, or until one year following expiration, whichever comes first. Score sheets, analyses, evaluations of proposed RPS projects confidential for three years. Specific quantitative analysis involved in the scoring and evaluation of participating bids confidential for three years after winning bidders selected.
Power Purchase Agreements for RSC Contracts between SCE and Various Sellers/Comparisons of RSC Contracts to 2010 RSC Pro Forma	Confidential Appendices H.1-AA.2	VII.F/VII.G RPS Contracts	RPS contracts confidential for three years, or until one year following expiration, whichever comes first.
Project Viability Calculators[1]	Confidential Appendix BB	VII.F/VII.G RPS Contracts VII.H Score sheets, analyses, evaluations of proposed RPS projects VIII.B Specific quantitative analysis involved in the scoring and evaluation	RPS contracts confidential for three years, or until one year following expiration, whichever comes first. Score sheets, analyses, evaluations of proposed RPS projects confidential for three years.

[1] The Commission concluded that project-specific project viability information should remain confidential in D.09-06-018.

		of participating bids	Specific quantitative analysis involved in the scoring and evaluation of participating bids confidential for three years after winning bidders selected.

3. SCE is complying with the limitations on confidentiality specified in the Matrix that pertain to the data listed in the table above.

4. I am informed and believe and thereon allege that the data in the table above cannot be aggregated, redacted, summarized, masked or otherwise protected in a manner that would allow partial disclosure of the data while still protecting confidential information.

5. I am informed and believe and thereon allege that the data in the table in paragraph 2 above has never been made publicly available.

I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct.

Executed on January 27, 2011, at Rosemead, California.

George Wiltsee

Appendix DD

Proposed Protective Order

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

Submission of Contracts for Procurement of Renewable Energy Resulting From Renewables Standard Contracts Program	)))))	**Advice 2547-E**

PROTECTIVE ORDER

1. Scope. This Protective Order shall govern access to and the use in this proceeding of Protected Materials, produced by, or on behalf of, any Disclosing Party.

2. Modification. This Protective Order shall remain in effect until it is modified or terminated by the Commission or Assigned Administrative Law Judge ("Assigned ALJ"). The parties acknowledge that the identity of the parties submitting Protected Materials may differ from time to time. In light of this situation, the parties agree that modifications to this Protective Order may become necessary, and they further agree to work cooperatively to devise and implement such modifications in as timely a manner as possible. Each party governed by this Protective Order has the right to seek changes in it as appropriate from the Assigned ALJ or the Commission.

3. Definitions.

A. The term "Protected Material(s)" means (i) trade secret, market sensitive, or other confidential and/or proprietary information as determined by the Disclosing Party in accordance with the provisions of D.06-06-066 and subsequent decisions, General Order 66-C and Public Utilities Code Section 454.5(g), or any other right of confidentiality provided by law, or (ii) any other materials that are made subject to this Protective Order by the Assigned ALJ, Law and Motion Administrative Law Judge ("Law and Motion ALJ"), Assigned Commissioner, the Commission, or any court or other body having appropriate authority. Protected Materials also

includes memoranda, handwritten notes, spreadsheets, computer files and reports, and any other form of information (including information in electronic form) that copies, discloses, or compiles other Protected Materials or from which such materials may be derived (except that any derivative materials must be separately shown to be confidential). Protected Materials do not include: (i) any information or document contained in the public files of the CPUC or any other state or federal agency, or in any state or federal court; or (ii) any information that is public knowledge, or which becomes public knowledge, other than through disclosure in violation of this Protective Order or any other protective order.

B. The term "redacted" refers to situations in which Protected Materials in a document, whether the document is in paper or electronic form, have been covered, blocked out, or removed. The term "unredacted" refers to situations in which the Protected Materials in a document, whether in paper or electronic form, have not been covered, blocked out, or removed.

C. The term "Disclosing Party" means a party who initially discloses any specified Protected Materials in this proceeding.

D. The term "Market Participant" ("MP") refers to a party that is:

1) A person or entity, or an employee of an entity, that engages in the wholesale purchase, sale or marketing of energy or capacity, or the bidding on or purchasing of power plants, or bidding on utility procurement solicitations, or consulting on such matters, subject to the limitations in 3) below.

2) A trade association or similar organization, or an employee of such organization,

   a) whose primary focus in proceedings at the Commission is to advocate for persons/entities that purchase, sell or market energy or capacity at wholesale; bid on, own, or purchase power plants; or bid on utility procurement solicitations; or

   b) a majority of whose members purchase, sell or market energy or capacity at wholesale; bid on, own, or purchase power plants; or bid on utility procurement solicitations; or

   c) formed for the purpose of obtaining market sensitive information; or

d) controlled or primarily funded by a person or entity whose primary purpose is to purchase, sell or market energy or capacity at wholesale; bid on, own, or purchase power plants; or bid on utility procurement solicitations.

3) A person or entity that meets the criteria of 1) above is nonetheless not a market participant for purpose of access to market sensitive data unless the person/entity seeking access to market sensitive information has the potential to materially affect the price paid or received for electricity if in possession of such information. An entity will be considered not to have such potential if:

a) the person or entity's participation in the California electricity market is *de minimis* in nature. In the resource adequacy proceeding (R.05-12-013) it was determined in D.06-06-064 § 3.3.2 that the resource adequacy requirement should be rounded to the nearest megawatt (MW), and load serving entities (LSEs) with local resource adequacy requirements less than 1 MW are not required to make a showing. Therefore, a *de minimis* amount of energy would be less than 1 MW of capacity per year, and/or an equivalent of energy; and/or

b) the person or entity has no ability to dictate the price of electricity it purchases or sells because such price is set by a process over which the person or entity has no control, *i.e.*, where the prices for power put to the grid are completely overseen by the Commission, such as subject to a standard offer contract or tariff price. A person or entity that currently has no ability to dictate the price of electricity it purchases or sells under this section, but that will have such ability within one year because its contract is expiring or other circumstances are changing, does not meet this exception; and/or

c) the person or entity is a cogenerator that consumes all the power it generates in its own industrial and commercial processes, if it can establish a legitimate need for market sensitive information.

E. A Market Participant's Reviewing Representatives are limited to persons designated by the Market Participant who meet the following criteria:

1. Are outside experts, consultants or attorneys;

2. Are not currently engaged, directly or indirectly, in (a) the purchase, sale, or marketing of electrical energy or capacity or natural gas (or the direct supervision of any employee(s) whose duties include such activities), (b) the bidding on or purchasing of power plants (or the direct supervision of any employee(s) whose duties include such activities), or (c) consulting with or advising

others in connection with any activity set forth in subdivisions (a) or (b) above (or the direct supervision of any employee(s) whose duties include such activities or consulting); and

3. Are not an employee of a market participant.

F. Persons or entities that do not meet the definition of market participant are non-market participants ("NMPs"), and may have access to market sensitive information through their designated Reviewing Representatives. An attorney or consultant that simultaneously represents market participant(s) and non-market participant(s) may not have access to market sensitive data. If, on the other hand, simultaneous representation is of market participant and non-market participant clients involved in completely different types of matters, there should be no bar (although there may be ethical implications of such representation that we do not address here). If, for example, an attorney represents a market participant in matters unrelated to procurement, resource adequacy, RPS, or the wholesale purchase, sale or marketing of energy or capacity, or the bidding on or purchasing of power plants, or bidding on utility procurement solicitations, in a forum other than this Commission, and simultaneously represents a non-market participant in cases related to these topics before the Commission, there should be no bar to the attorney's receipt of market sensitive data (pursuant to a non-disclosure agreement and protective order) in the latter matter. In close cases, the balance should militate to bar simultaneous representation because of the risks it poses.

H. All Reviewing Representatives are required to execute a non-disclosure agreement and are bound by the terms of this Protective Order.

4. Designation of Materials.

When filing or providing in discovery any documents containing Protected Materials, a party shall physically mark such documents on each page (or in the case of non-documentary materials such as computer diskettes, on each item) as "PROTECTED MATERIALS SUBJECT TO PROTECTIVE ORDER," or with words of similar import as long as one or more of the

terms, “Protected Materials,” “Protective Order,” or “General Order No. 66-C” is included in the designation to indicate that the materials in question are protected.

All materials so designated shall be treated as Protected Materials unless and until (a) the designation is withdrawn pursuant to Paragraph 17 hereof, or (b) an ALJ, Commissioner or other Commission representative makes a determination pursuant to Paragraph 4 hereof changing the designation.

All documents containing Protected Materials that are filed with the Commission or served shall be placed in sealed envelopes or otherwise appropriately protected and shall be endorsed to the effect that they are filed or served under seal pursuant to this Protective Order. Such documents shall be served upon Reviewing Representatives and persons employed by or working on behalf of the state governmental agencies referred to in Paragraph 12 hereof who are eligible and have requested to review such materials. Service upon the persons specified in the foregoing sentence may either be (a) by electronic mail in accordance with the procedures adopted in this proceeding, (b) by facsimile, or (c) by overnight mail or messenger service. Whenever service of a document containing Protected Materials is made by overnight mail or messenger service, the Assigned ALJ shall be served with such document by hand on the date that service is due.

5. Redaction of Documents. Whenever a party files, serves or provides in discovery a document that includes Protected Materials (including but not limited to briefs, testimony, exhibits, and responses to data requests), such party shall also prepare a redacted version of such document. The redacted version shall enable persons familiar with this proceeding to determine with reasonable certainty the nature of the data that has been redacted and where the redactions occurred. The redacted version of a document to be filed shall be served on all persons on the service list, and the redacted version of a discovery document shall be served on all persons entitled thereto.

6. Selection of Reviewing Representatives. Each MP and NMP selecting a Reviewing Representative shall first identify its proposed Reviewing Representative to the Disclosing Party. An attorney or consultant that simultaneously represents market participant(s) and non-market participant(s) may not have access to market sensitive data, subject to the exception in paragraph 3.F. Any designated Reviewing Representative has a duty to disclose to the Disclosing Party any potential conflict that puts him/her in violation of Decision 06-12-030. A resume or curriculum vitae is reasonable disclosure of such potential conflicts, and should be the default evidence provided in most cases.

7. Access to Protected Materials and Use of Protected Materials. Subject to the terms of this Protective Order, Reviewing Representatives shall be entitled to access to Protected Materials. All other parties in this proceeding shall not be granted access to Protected Materials, but shall instead be limited to reviewing redacted versions of documents. Reviewing Representatives may make copies of Protected Materials, but such copies become Protected Materials. Reviewing Representatives may make notes of Protected Materials, which shall be treated as Notes of Protected Materials if they disclose the contents of Protected Materials. Protected Materials obtained by a party in this proceeding may also be requested by that party in a subsequent Commission proceeding, subject to the terms of any protective order governing that subsequent proceeding, without constituting a violation of this order.

8. Maintaining Confidentiality of Protected Materials. Each Reviewing Representative shall treat Protected Materials as confidential in accordance with this Protective Order and the Non-Disclosure Certificate executed pursuant to Paragraph 7 and 8 hereof. Protected Materials shall not be used except as necessary for the conduct of this proceeding, and shall not be disclosed in any manner to any person except (i) Reviewing Representatives who have executed Non-Disclosure Certificates; (ii) Reviewing Representatives' paralegal employees and administrative personnel, such as clerks, secretaries, and word processors, to the extent necessary to assist the Reviewing Representatives, provided that they shall first ensure that such personnel

are familiar with the terms of this Protective Order, and have signed a Non-Disclosure Certificate, (iii) persons employed by or working on behalf of the CEC or other state governmental agencies covered by Paragraph 12. Reviewing Representatives shall adopt suitable measures to maintain the confidentiality of Protected Materials they have obtained pursuant to this Protective Order, and shall treat such Protected Materials in the same manner as they treat their own most highly confidential information. Reviewing Representatives shall be liable for any unauthorized disclosure or use by their paralegal employees or administrative staff. In the event any Reviewing Representative is requested or required by applicable laws or regulations, or in the course of administrative or judicial proceedings (in response to oral questions, interrogatories, requests for information or documents, subpoena, civil investigative demand or similar process) to disclose any of Protected Materials, they shall immediately inform the Disclosing Party of the request, and the Disclosing Party may, at its sole discretion and cost, direct any challenge or defense against the disclosure requirement, and the Reviewing Representative shall cooperate in good faith with such party either to oppose the disclosure of the Protected Materials consistent with applicable law, or to obtain confidential treatment of them by the person or entity who wishes to receive them prior to any such disclosure. If there are multiple requests for substantially similar Protected Materials in the same case or proceeding where a Reviewing Representative has been ordered to produce certain specific Protected Materials, the Reviewing Representative may, upon request for substantially similar materials by another person or entity, respond in a manner consistent with that order to those substantially similar requests.

9. Exception for California Independent System Operator (ISO). Notwithstanding any other provision of this Protective Order, with respect to an ISO Reviewing Representative only, participation in the ISO's operation of the ISO-controlled grid and in its administration of the ISO-administered markets, including, but not limited to, markets for ancillary services, supplemental energy, congestion management, and local area reliability services, shall not be deemed to be a violation of this Protective Order.

10. Non-Disclosure Certificates. A Reviewing Representative shall not inspect, participate in discussions regarding, or otherwise be granted access to, Protected Materials unless and until he or she has first completed and executed a Non-Disclosure Certificate, attached hereto as Appendix A, and delivered the original, signed Non-Disclosure Certificate to the Disclosing Party. The Disclosing Party shall retain the executed Non-Disclosure Certificates pertaining to the Protected Materials it has disclosed and shall promptly provide copies of the Non-Disclosure Certificates to Commission Staff upon request.

11. Return or Destruction of Protected Materials. Protected Materials shall remain available to Reviewing Representatives until the later of the date that an order terminating this proceeding becomes no longer subject to judicial review, or the date that any other Commission proceeding relating to the Protected Material is concluded and no longer subject to judicial review. If requested to do so in writing after that date, the Reviewing Representatives shall, within fifteen days of such request, return the Protected Materials (including Notes of Protected Materials) to the Participant that produced them, or shall destroy the materials, except that copies of filings, official transcripts and exhibits in this proceeding that contain Protected Materials, and Notes of Protected Material may be retained, if they are maintained in accordance with Paragraph 8. Within such time period each Reviewing Representative, if requested to do so, shall also submit to the Disclosing Party an affidavit stating that, to the best of its knowledge, all Protected Materials and all Notes of Protected Materials have been returned or have been destroyed or will be maintained in accordance with Paragraph 8. To the extent Protected Materials are not returned or destroyed, they shall remain subject to the Protective Order and CPUC General Order No. 66-C. In the event that a Reviewing Representative to whom Protected Material are disclosed ceases to be engaged to provide services in this proceeding, then access to such materials by that person shall be terminated. Even if no longer engaged in this proceeding, every such person shall continue to be bound by the provisions of this Protective Order and the Non-Disclosure Certificate.

12. Access and Use by Governmental Entities.

(a) In the event the CPUC receives a request from the CEC for a copy of or access to any party's Protected Materials, the procedure for handling such requests shall be as follows. Not less than five (5) days after delivering written notice to the Disclosing Party of the request, the CPUC shall release such Protected Materials to the CEC upon receipt from the CEC of an Interagency Information Request and Confidentiality Agreement ("Interagency Confidentiality Agreement"). Such Interagency Confidentiality Agreement shall (i) provide that the CEC will treat the requested Protected Materials as confidential in accordance with this Protective Order, (ii) include an explanation of the purpose for the CEC's request, as well as an explanation of how the request relates to furtherance of the CEC's functions, (iii) be signed by a person authorized to bind the CEC contractually, and (iv) expressly state that furnishing of the requested Protected Materials to employees or representatives of the CEC does not, by itself, make such Protected Materials public. In addition, the Interagency Confidentiality Agreement shall include an express acknowledgment of the CPUC's sole authority (subject to judicial review) to make the determination whether the Protected Materials should remain confidential or be disclosed to the public, notwithstanding any provision to the contrary in the statutes or regulations applicable to the CEC.

(b) In the event the CPUC receives a request for a copy of or access to a party's Protected Materials from a state governmental agency other than the CEC that is authorized to enter into a written agreement sufficient to satisfy the requirements for maintaining confidentiality set forth in Government Code Section 6254.5(e), the CPUC may, not less than five (5) days after giving written notice to the Disclosing Party of the request, release such protected material to the requesting governmental agency, upon receiving from the requesting agency an executed Interagency Confidentiality Agreement that contains the same provisions described in Paragraph 12(a) above.

(c) The CEC may use Protected Materials when needed to fulfill its statutory responsibilities or cooperative agreements with the CPUC. Commission confidentiality

designations will be maintained by the CEC in making such assessments, and the CEC will not publish any assessment that directly reveals the data or allows the data submitted by an individual load serving entity ("LSE") to be "reverse engineered."

13. Dispute Resolution. All disputes that arise under this Protective Order, including but not limited to alleged violations of this Protective Order and disputes concerning whether materials were properly designated as Protected Materials, shall first meet and confer in an attempt to resolve such disputes. If the meet and confer process is unsuccessful, the involved parties may present the dispute for resolution to the Assigned ALJ or the Law and Motion ALJ.

14 Other Objections to Use or Disclosure. Nothing in this Protective Order shall be construed as limiting the right of a party, the Commission Staff, or a state governmental agency covered by Paragraph 12 from objecting to the use or disclosure of Protected Material on any legal ground, such as relevance or privilege.

15. Remedies. Any violation of this Protective Order shall constitute a violation of an order of the CPUC. Notwithstanding the foregoing, the parties and Commission Staff reserve their rights to pursue any legal or equitable remedies that may be available in the event of an actual or anticipated disclosure of Protected Materials.

16. Withdrawal of Designation. A Disclosing Party may agree at any time to remove the "Protected Materials" designation from any materials of such party if, in its opinion, confidentiality protection is no longer required. In such a case, the Disclosing Party will notify all other parties that the Disclosing Party believes are in possession of such materials of the change of designation.

17. Interpretation. Titles are for convenience only and may not be used to restrict the scope of this Protective Order.

Entered: _____
Administrative Law Judge

Date: _____

APPENDIX A TO PROTECTIVE ORDER

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

Submission of Contracts for Procurement of Renewable Energy Resulting From Renewables Standard Contracts Program	)))))	**Advice 2547-E**

NON-DISCLOSURE CERTIFICATE

I hereby certify my understanding that access to Protected Materials is provided to me pursuant to the terms and restrictions of the Protective Order in this proceeding, that I have been given a copy of and have read the Protective Order, and that I agree to be bound by it. I understand that the contents of the Protected Materials, any notes or other memoranda, or any other form of information that copies or discloses Protected Materials shall not be disclosed to anyone other than in accordance with that Protective Order. I acknowledge that a violation of this certificate constitutes a violation of an order of California Public Utilities Commission.

By: _____
Title: _____ _
Representing: _____
Date: _____ _

SOUTHERN CALIFORNIA
EDISON
An *EDISON INTERNATIONAL* Company

James W. Yee
Supervisor of Advice Letters
James.Yee@sce.com

February 2, 2011

California Public Utilities Commission
505 Van Ness Avenue, 4th Floor
San Francisco, CA 94102

Attn: Honesto Gatchalian
Energy Division

Re: Substitute Sheets for Southern California Edison Company's Advice 2547-E

Dear Mr. Gatchalian:

Enclosed are an original and three copies of substitute sheets for SCE Advice 2547-E filed on January 31, 2011 entitled, Submission of Contracts for Procurement of Renewable Energy Resulting from Renewables Standard Contracts Program. Appendix DD-Proposed Protective Order is being replaced to include the advice letter number in the captions of the document.

Please include these additional sheets in your master file for Advice 2547-E and distribute the copies to the appropriate people reviewing Advice 2547-E

Should you have any questions, please contact me at (626) 302-2509.

Sincerely,

James W. Yee

JWY:jm
Enclosures

cc: Don Lafrenz, Energy Division
Parties on SCE's GO 96-B service list
Parties in R.06-02-012 and R.08-08-009 service lists.

P.O. Box 800 2244 Walnut Grove Ave. Rosemead, California 91770 (626) 302-2509 Fax (626) 302-4829

ATTACHMENT F

DOCKET NO: 07-AFC-6

CENTER FOR BIOLOGICAL DIVERSITY'S NOTICE OF DOCUMENTS THAT MAY BE USED DURING CROSS EXAMINATION

California ISO
Shaping a Renewed Future

Summary of Preliminary Results of 33% Renewable Integration Study – 2010 CPUC LTPP Docket No. R.10-05-006

May 10, 2011

SECTION 1: INTRODUCTION AND OVERALL STATUS

Contents of Presentation

1. Introduction and Overall Status
2. Operational Requirements (Step 1)
3. Production Simulation results for Trajectory, Environmental Constrained, Cost Constrained and Time Constrained (Step 2)
4. further analysis of fleet flexibility in 2020
5. Recommendations and Next Steps
6. Appendix: CPUC specified assumptions, Non CPUC specified assumptions, model and methodology modifications

Introduction and Study Background:

- In a coordinated effort, the IOUs, E3, Plexos Solutions, Nexant, and the ISO conducted Step 1 and Step 2 modeling for the four renewable portfolio scenarios described in 12/3/10 Ruling:
  - Trajectory
  - Time Constrained
  - Cost Constrained
  - Environmentally Constrained
- The study results are dependent upon the scenario modeling assumptions described in the 12/3/10 CPUC scoping memo, with database modifications described in this presentation
- These preliminary results being provided according to schedule established in 3/1/11 Ruling
- ISO will conduct additional sensitivity analysis to validate preliminary results
- Final results will be provided with June 3 testimony

Study Coordination

- April 29 results were produced through a collaborative process between the IOUs and the ISO (and their contractors)
- ISO Activities:
  - Condition Step 1 and Step 2 input data. Contractor: Nexant
    - ISO also requested analytical support from E3, PLEXOS Solutions and IOUs. ISO made final decision on all Step 1 and Step 2 inputs.
  - Calculate Step 1 results. ISO using PNNL software
  - Calculate Step 2 results. Contractor: PLEXOS Solutions
    - ISO directed production of Step 1 and Step 2 results for all scenarios (IOUs did not produce Step 1 or Step 2 results independently of ISO)
- IOU Activities:
  - Calculate Step 3 results. Contractor: E3

Objectives of the 33% Renewable Integration Study and Role of the ISO

1. Identify operational requirements and resource options to reliably operate the ISO controlled grid (with some assumptions about renewable integration by other Balancing Authorities) 33% RPS in 2020
   - Provide estimates of operational requirements for renewable integration (measured in terms of operational ramp, load following and Regulation capacity and ramp rates, as well as additional capacity to meet operational reliability requirements)
   - Analyze sensitivity variables that affect the results
     - Impact of different mixes of renewable technologies and other complementary policies
     - Load growth
     - Impact of forecasting error and variability

Objectives of the 33% Renewable Integration Study and Role of the ISO (cont.)

2. Inform market, planning, and policy/regulatory decisions by the ISO, State agencies, market participants and other stakeholders
   - Support the CPUC to identify long-term procurement planning needs, costs and options
   - Inform other CPUC, and State agency, regulatory decisions (for example, Resource Adequacy, RPS rules, once through cooling [OTC] schedule)
   - In coordination with the CPUC, inform ISO and state-wide transmission planning needs to interconnect renewables up to 33% RPS
   - Inform design of ISO wholesale markets for energy and ancillary services to facilitate provision of integration capabilities

Study approach – overview of modeling tools utilized and proposed for LTPP methodology

- *Step 1* – Statistical Simulation to Assess Intra-Hour Operational Requirements
  - Estimates added intra-hour requirements under each studied renewable portfolio due to variability and forecast error
  - Calculates the following by hour and season: Regulation Up and Regulation Down capacity, load-following up and down capacity requirements, and operational ramp rate requirements
- *Step 2* – Production Simulation
  - Optimizes commitment and dispatch of resources in an hourly time-step to meet load, ancillary services and other requirements at least cost.
  - Uses Step 1 Regulation and load following capacity requirements to reflect intra-hourly operations
  - Calculates production cost-based energy prices, emissions, energy and ancillary services provided by units, violations of system constraints and additional capabilities required to eliminate violations

Status of ISO Methodology and Simulations

- Step 1 methodology under review for assumptions about solar forecast error
- Step 2 methodology reflects modified assumptions discussed in prior workshop (and reviewed in these slides) and additional modifications based on LTPP analysis
- Preliminary Step 2 simulation results now available for review
- Opportunities for further refinement of both Step 1 and Step 2 methodology prior to next batch of CPUC scenario assumptions
- Would like to continue working with the IOUs on an All Gas case, High Load Growth case and a 2011 base case

This presentation builds on prior ISO presentations at CPUC LTPP workshops

- These slides reference:
  - ISO August 24-25, 2010 presentation
  - ISO October 22, 2010 presentation

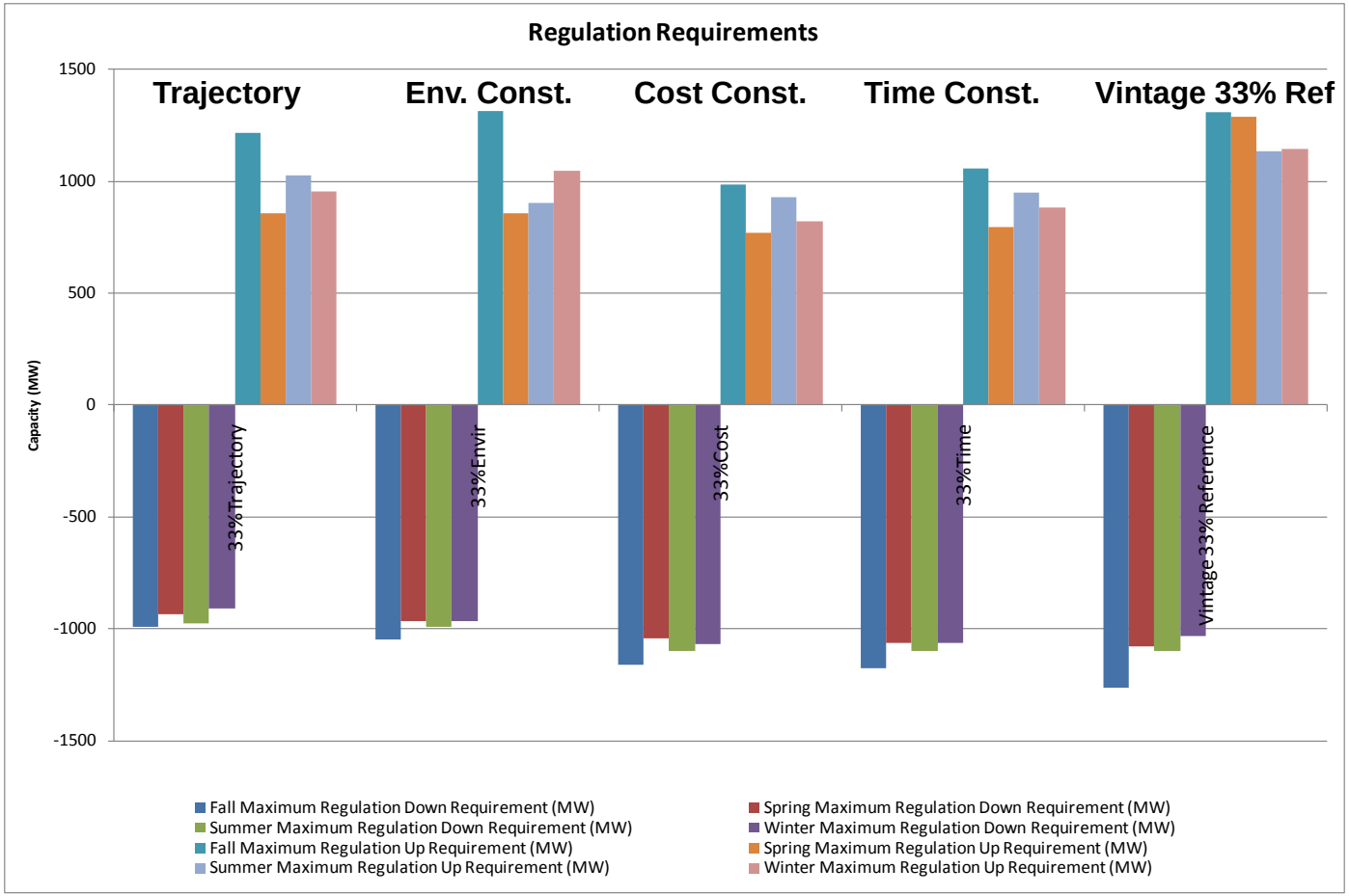
- Prior ISO slides available at
  - http://www.cpuc.ca.gov/PUC/energy/Renewables/100824_workshop.htm

SECTION 2: OPERATIONAL REQUIREMENTS RESULTS (STEP 1)

Step 1 Operational requirement results

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

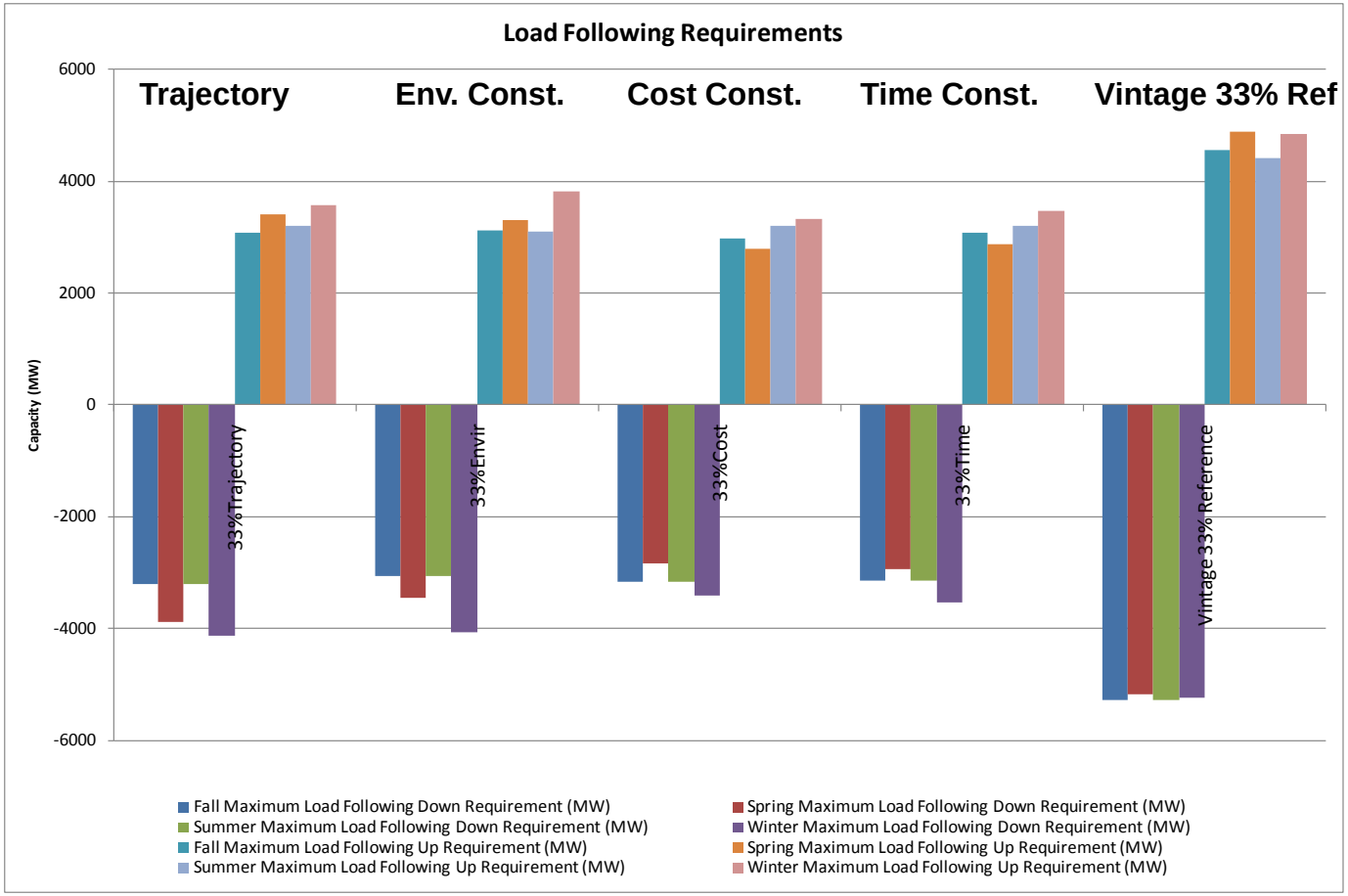
Step 1: Hourly regulation capacity requirements, by scenario



Notes:

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

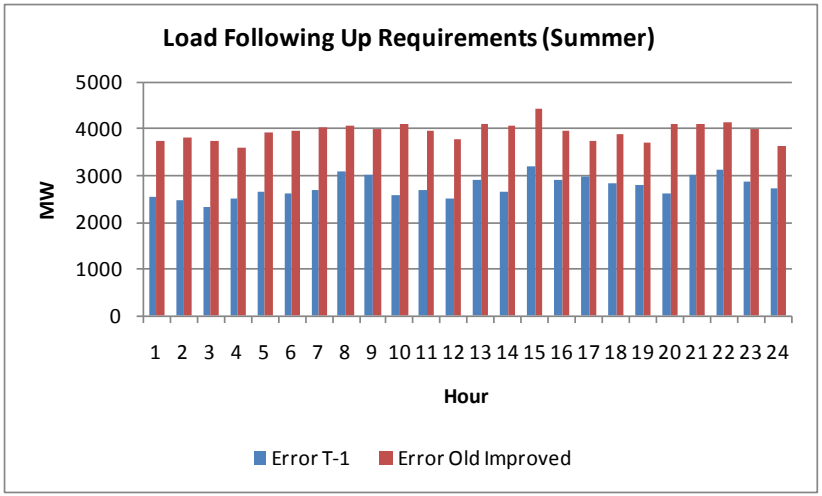
Step 1: Hourly load-following capacity requirements, by scenario

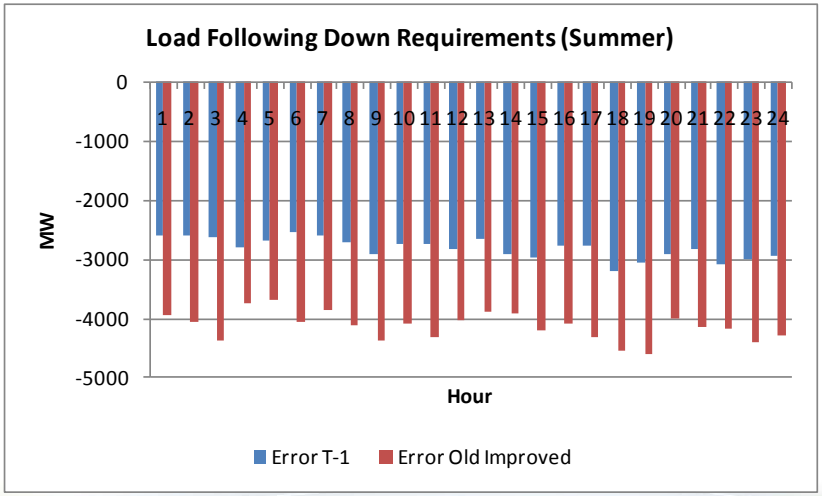


Notes:

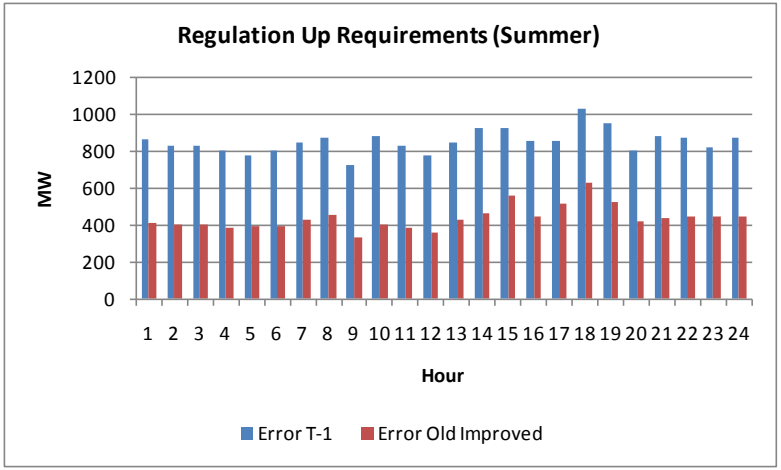
- For purposes of comparison, the figures show the single highest hourly seasonal requirement from Step 1 for each season (using the 95th percentile)
- The actual cases use the maximum monthly requirement by hour for need determination and hourly value for production cost and emissions
- Discussion of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

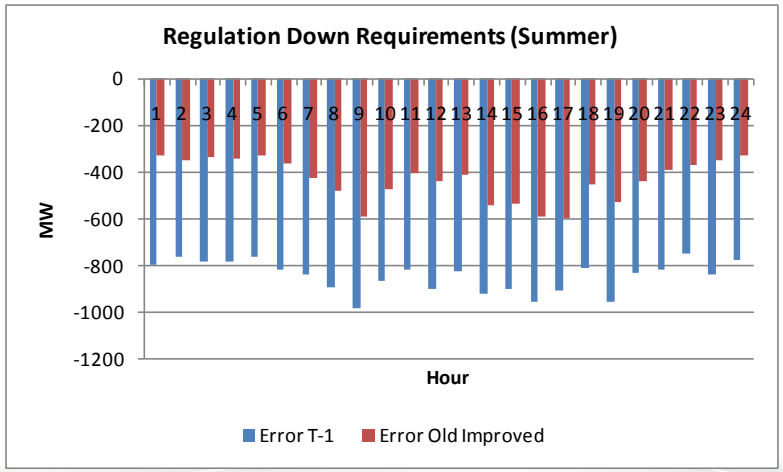
Comparison of load following requirements using refined and previous forecast error. Decrease in load following requirements reflect decrease in T-1 hour forecast errors.



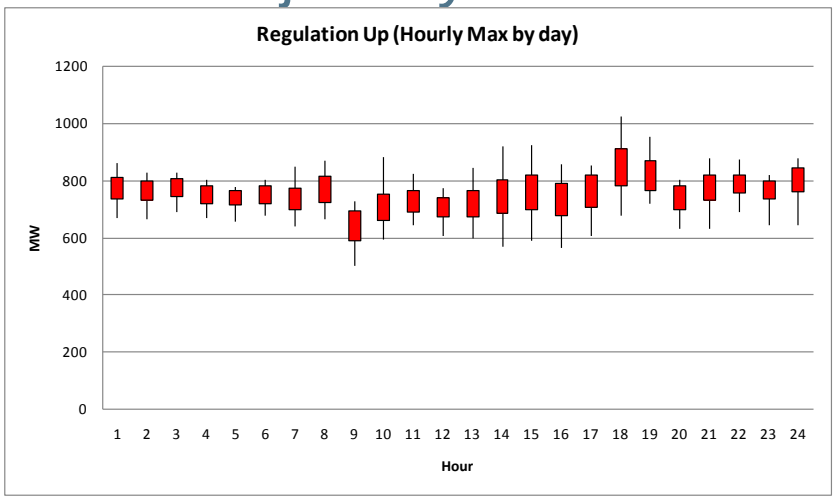


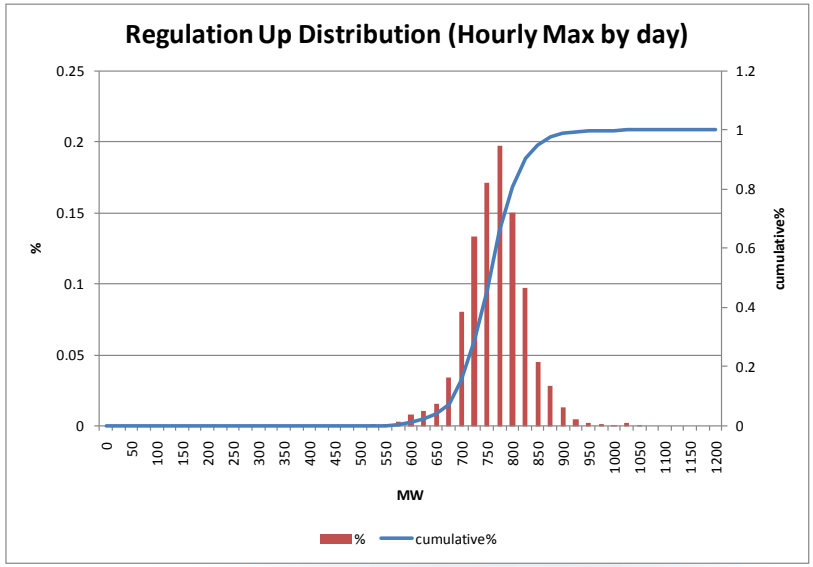
Comparison of regulation requirements using new and previous forecast error. Higher regulation requirement reflects 2010 actual T-7.5 forecast error high then 2006 assumption.



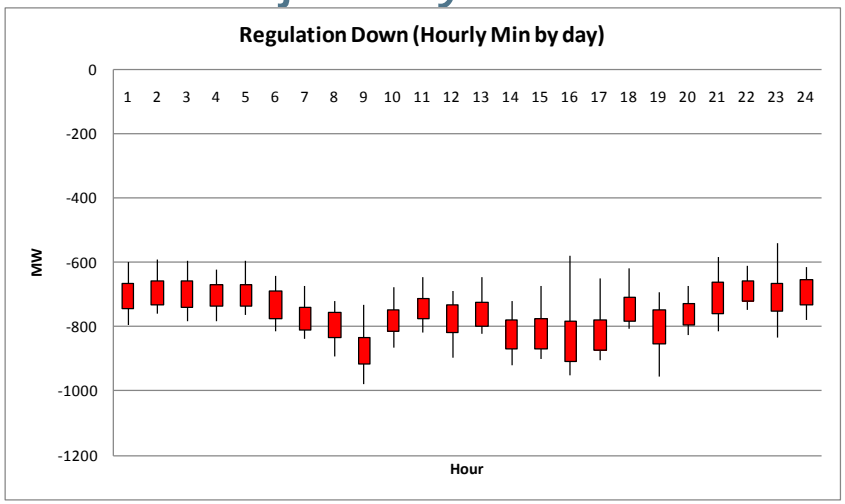


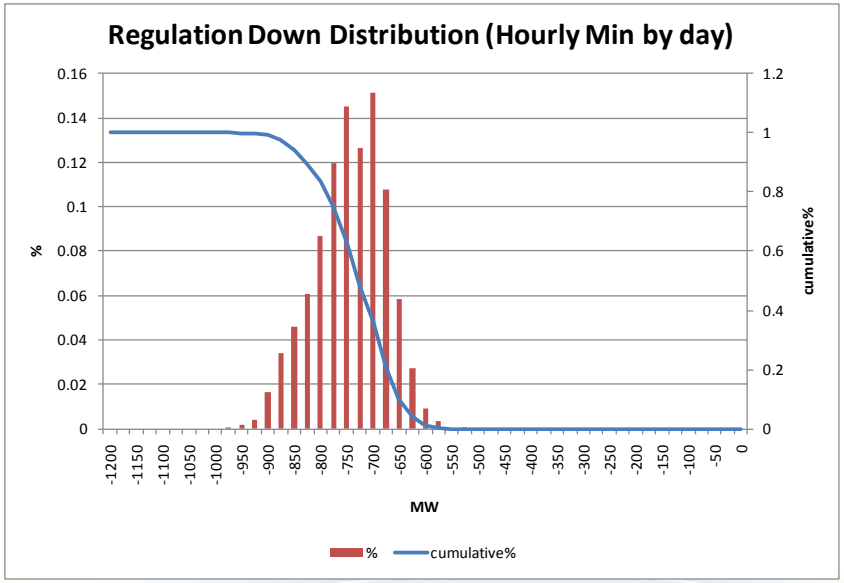
Summer 2020 regulation up capacity requirement – distributions of – 33% Trajectory



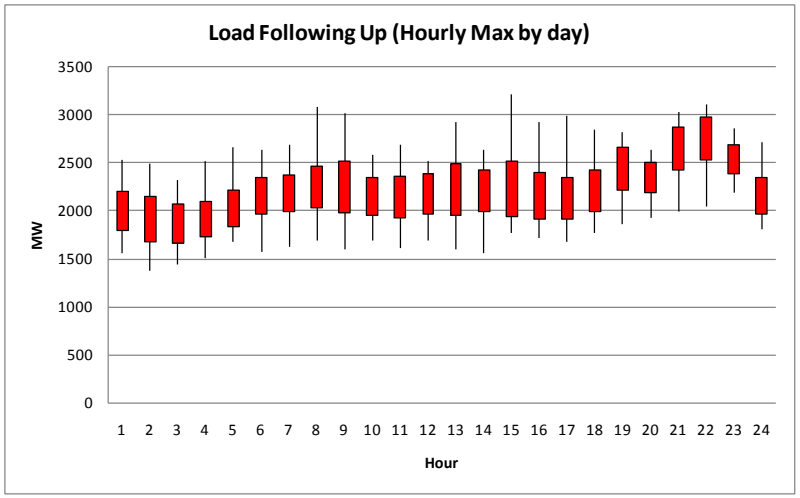


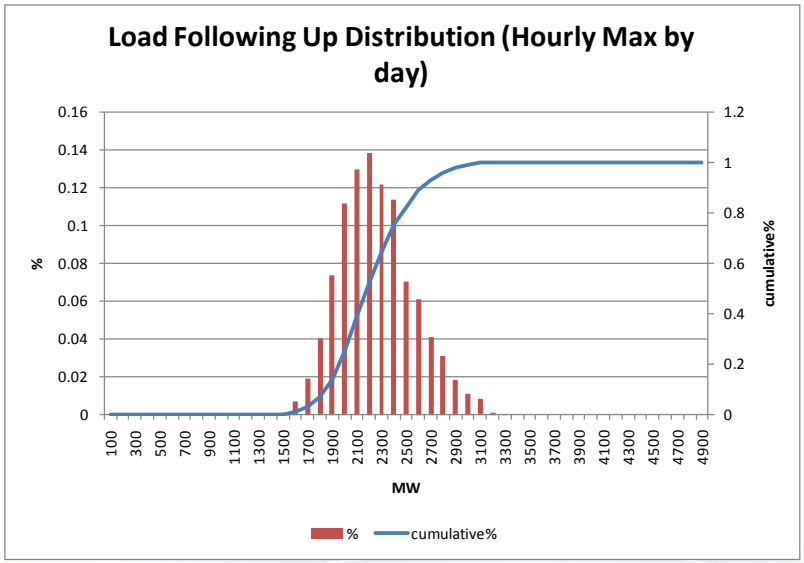
Summer 2020 regulation down capacity requirement – distributions of – 33% Trajectory



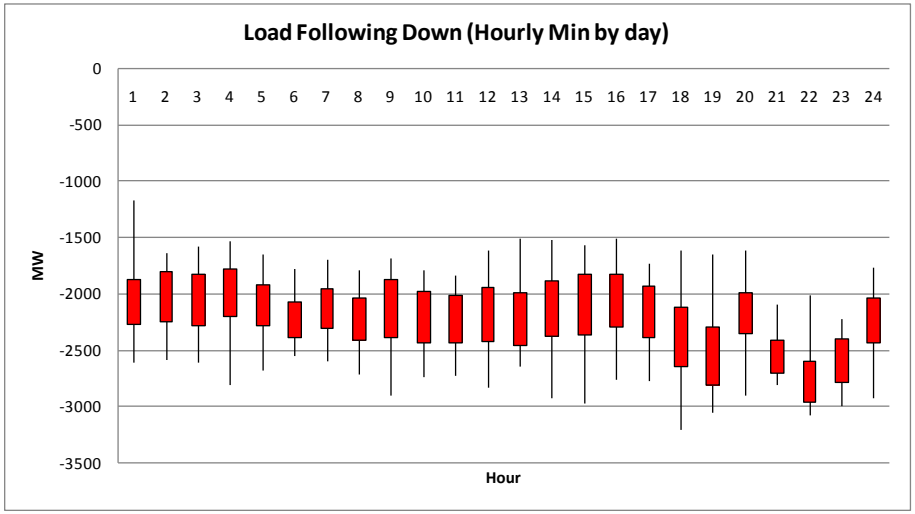


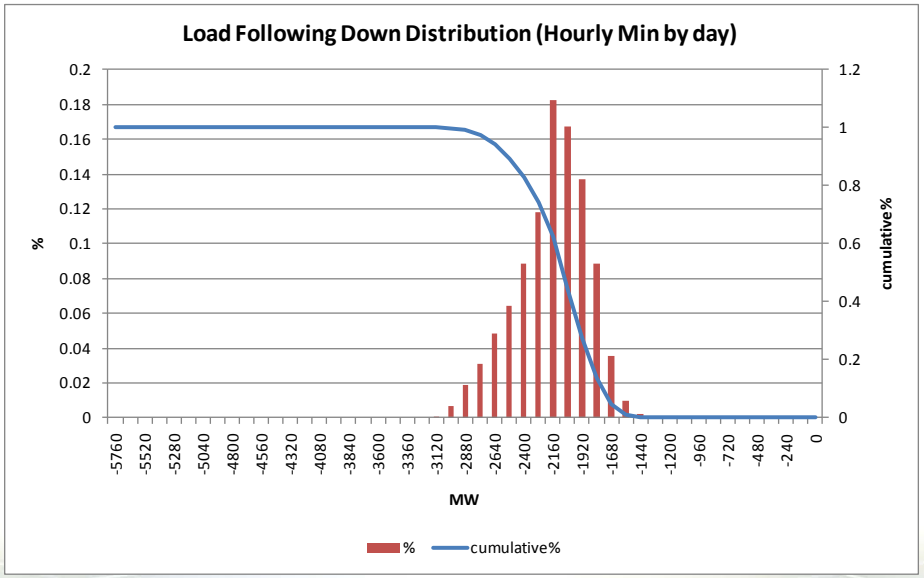
Summer 2020 load following up capacity requirement – distributions of – 33% Trajectory





Summer 2020 load following down capacity requirement – distributions of – 33% Trajectory





SECTION 3:
PRODUCTION SIMULATION RESULTS FOR TRAJECTORY, ENVIRONMENTAL CONSTRAINED, COST CONSTRAINED AND TIME CONSTRAINED (STEP 2)

Initial comments on method and results

- The focus of the presentation is on initial results for four scenarios:
  - Trajectory, Environmental Constrained, Cost Constrained and Time Constrained
  - Review of these results continues to be conducted
- Results are function of assumptions load, renewable portfolio and forecast error which warrant sensitivity analysis
  - E.g., what range of operational requirements to model and how to interpret the implications
- Some results are a function of *ex post* processing of model outputs; alternative methods will yield different results within a range
  - E.g, allocation of import production costs to California load

Key common assumptions for production simulation cases

- WECC-wide model using latest PC0 dataset from the Transmission Expansion Planning Policy Committee (TEPPC) at WECC
- CPUC 2010-LTPP scenarios (renewable portfolios, load forecasts, planned retirements/additions)
- Conventional dispatchable generation modeled with generic physical operating parameters
  - Inventory of operational flexibility capability – load following, regulating ranges – reviewed in Section 4
- Import constraints enforced
- Path 26 and SCIT constraints enforced
- Out of state renewables:
  - 15% dynamic - 15% intra-hour (15 minute),
  - 40% hourly scheduled - 30% unbundled RECs where

Renewable portfolios for 2020: 2010 LTPP Scenarios

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

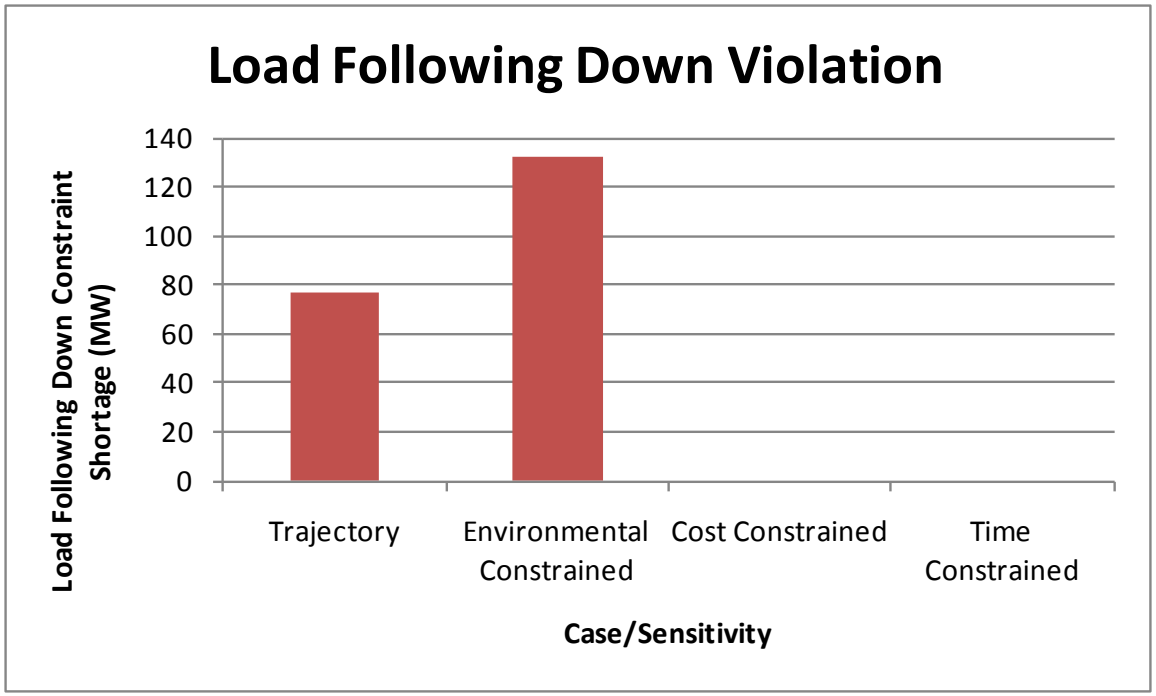
Production simulation results in this section reflect certain assumptions

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

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

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

Under CPUC Scoping Memo assumptions, there are no upward constraints violations. There a few hours of load following down constraint violations. (Updated with revised outage profile)



Notes:

1. Consideration of other measures including curtailment should be considered to address load following down shortages
2. Based on limited hours and magnitude of load following down violations the traditional practice of adding generic proxy resources to relieve violation is NOT reflective of needs. However to relieve downward violations, 200MW, 300MW, 0MW and 0MW were introduced in simulations, for the respective trajectory, environmental, cost and time constrained cases

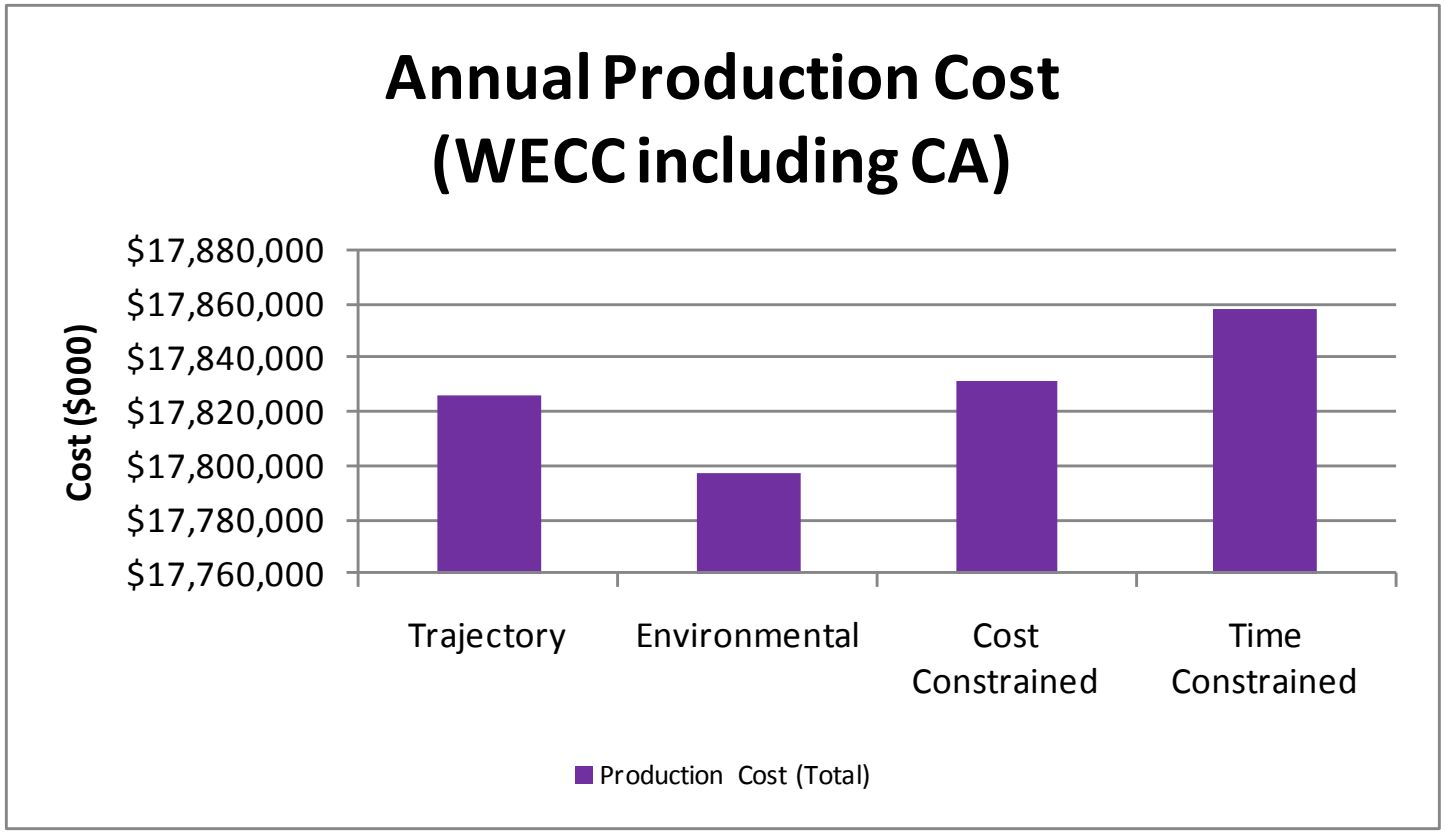
Discussion of results on additional resources

- No upward violations identified in the 2010 Trajectory, Environmental, Cost Constrained and Time Constrained scenarios due to combination of lower loads and reduced requirements
- Limited number of hours and magnitude of load following down violations warrant curtailment or other measures to resolve
- Results are sensitive to assumptions about load level, requirements based on forecast error, mix of resources, and maintenance schedules

Production costs and fuel consumption by scenario

- Production costs based primarily on generator heat rates and assumptions about fuel prices in 2020
- Trends in production costs related to fuel burn and variable O&M (VOM) costs are thus closely related
- Production costs have to be assigned to consuming regions by tracking imports and exports
- Costs associated with emission are tracked separately from fuel and VOM costs

Annual production costs ($) for California and rest of WECC by scenario



Notes:
1. Note scale differences are small
2. Values are in 2010$

Components for calculating California production costs

CA GENERATION COSTS

+

(**CA IMPORTS** — **CA EXPORTS**)

- Dedicated Resources
  - Renewables
    - Firmed
    - Non-Firmed
  - Conventional Resources
    - i.e. Hoover, Palo Verde
- Undesignated (or non-dedicated) Resources
  - Marginal resources in various regions

- Undesignated (or non-dedicated) Resources
  - Marginal resources within CA regions

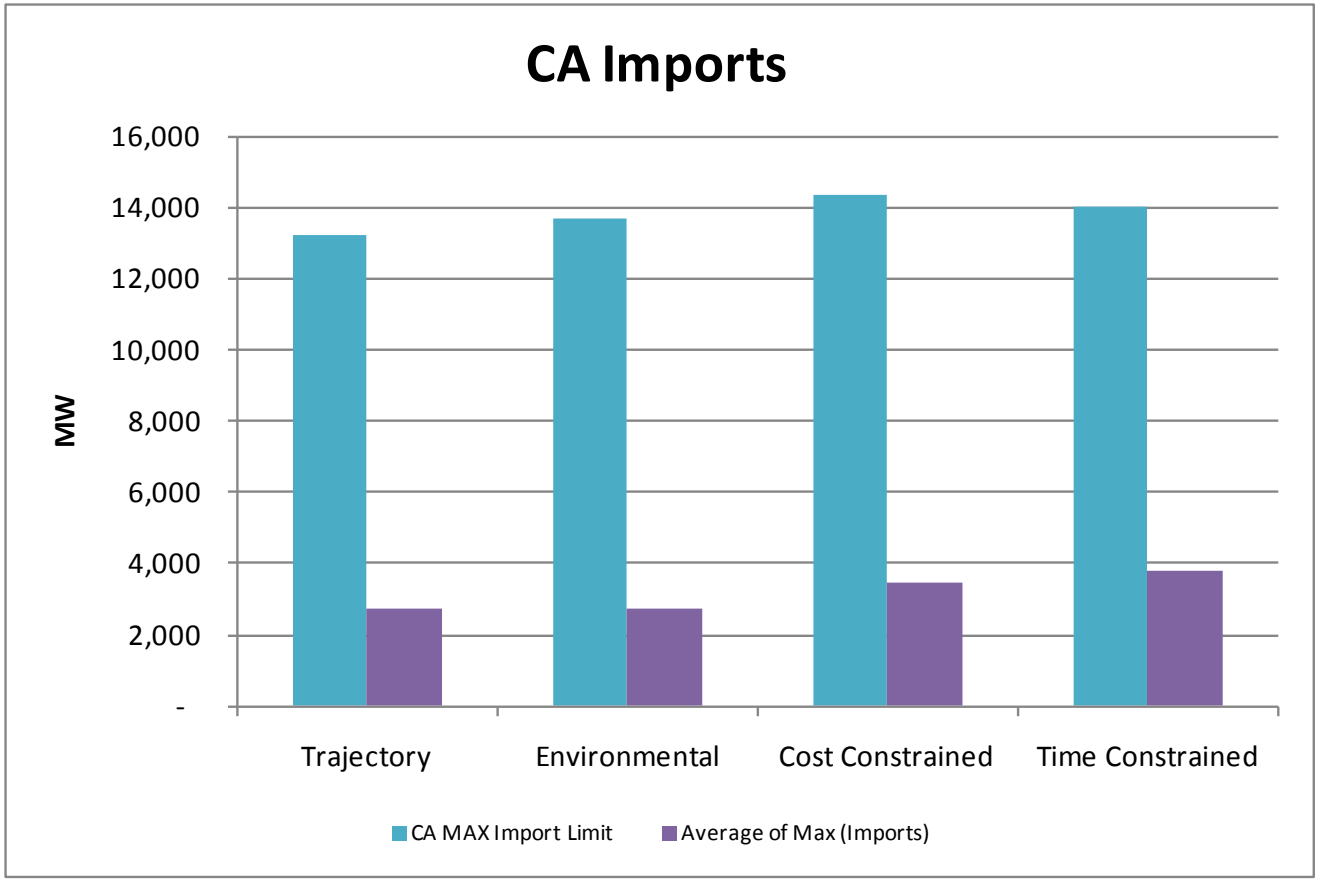
Calculating total California production costs

+ **CA Generation Costs**
  - Costs to operate CA units (fuel, VOM, start costs)
+ **Cost of Imported Power (into CA)**
  - Dedicated Import Costs
  - Undesignated (or non-dedicated) Import Costs
  - Out of State renewables (zero production cost)
– **Cost of Exported Power (out of CA)**
  - Undesignated (or non-dedicated) Export Costs

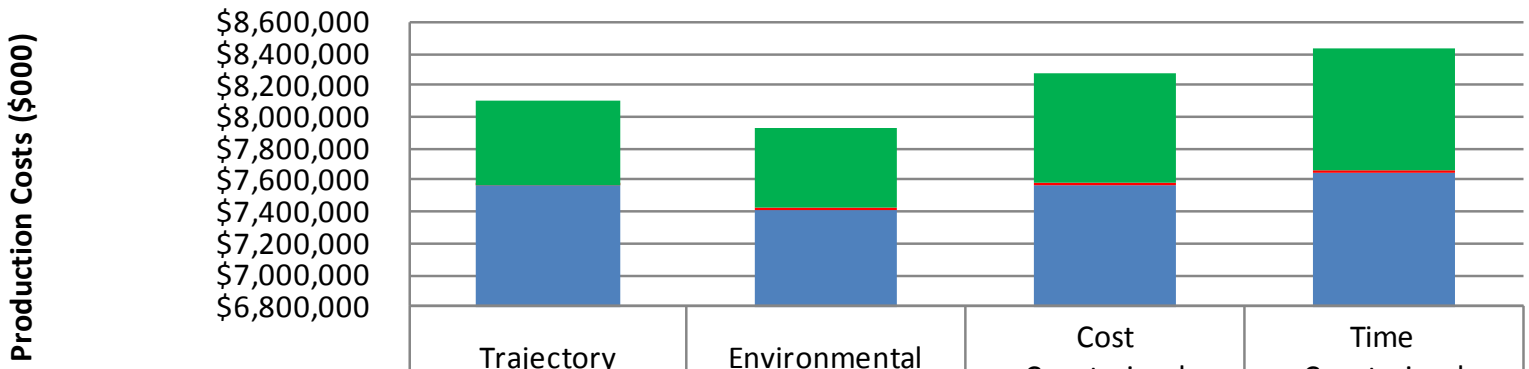
= **Total Production Cost of meeting CA load**

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

Net Import results by scenario



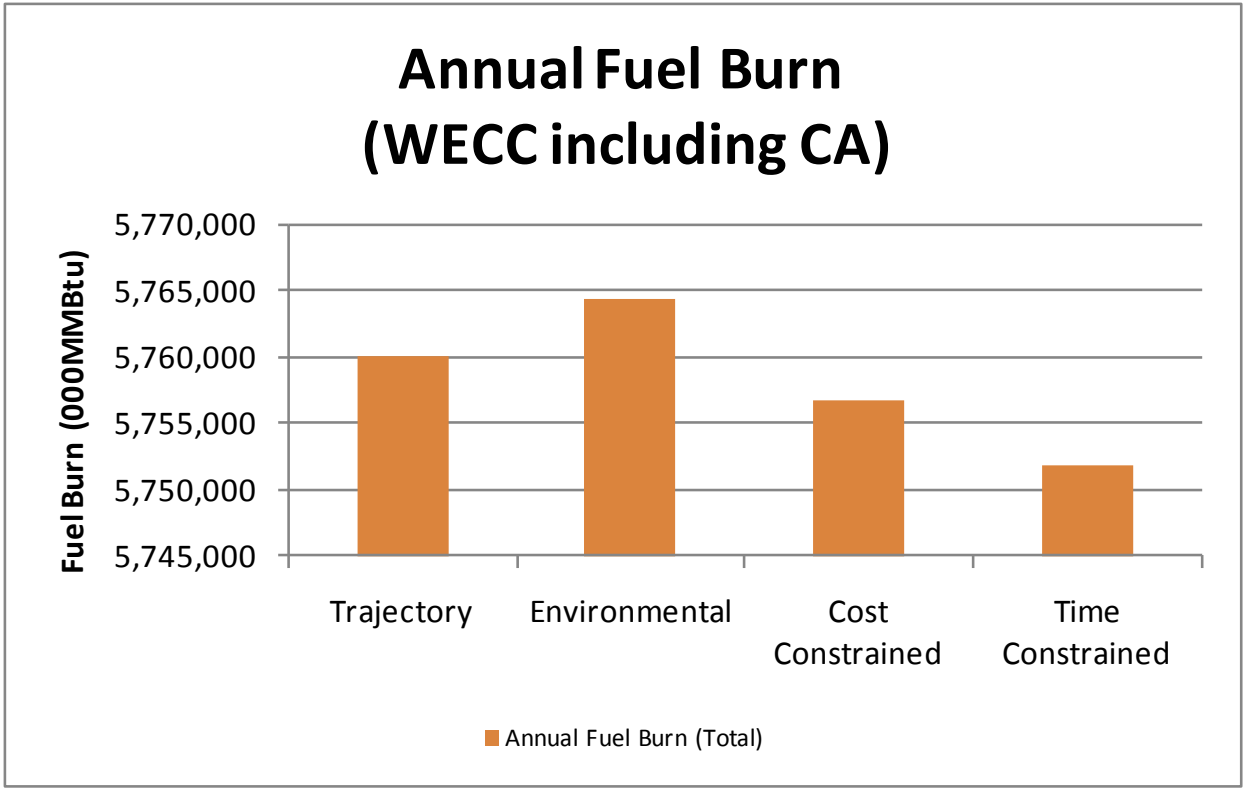
Total annual production costs ($) associated with California load (accounting for import/exports), by scenario



	Trajectory	Environmental	Cost Constrained	Time Constrained
Non-Dedicated	$529,620	$511,919	$698,702	$769,998
Dedicated	$9,195	$12,055	$9,649	$21,864
CA Generation Prod Costs	$7,566,554	$7,408,596	$7,570,102	$7,644,021

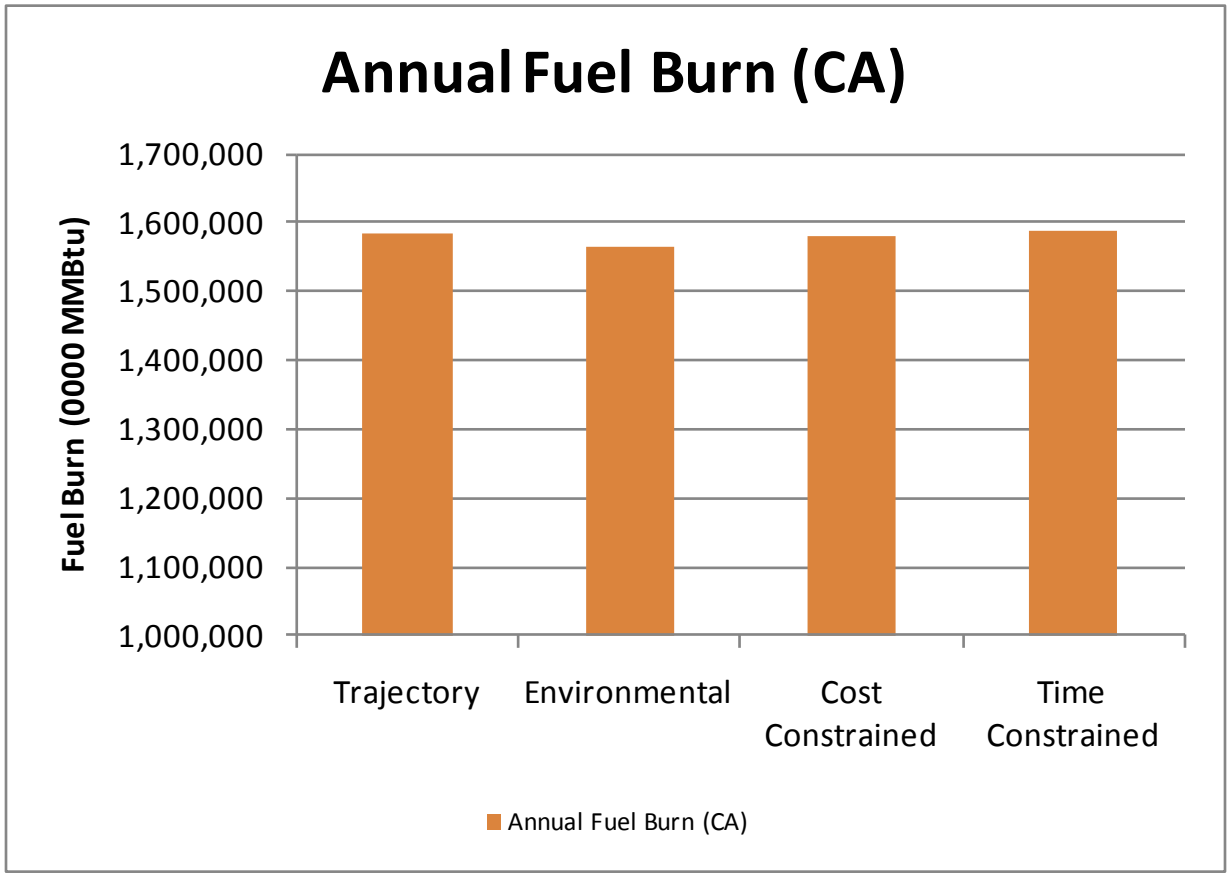
Note: IOUs have a step 3 accounting. This slide reflect vintage method for accounting imports/exports. Energy credit for RECs is not accounted for in this. When the IOU do their Step 3 analysis this will be accounted for.

Total WECC (including CA) fuel burn (MMBTU), by scenario



MMBTU = million BTU for conventional/fossil resources

Total fuel burn (MMBTU) for in-state generation in California, by scenario



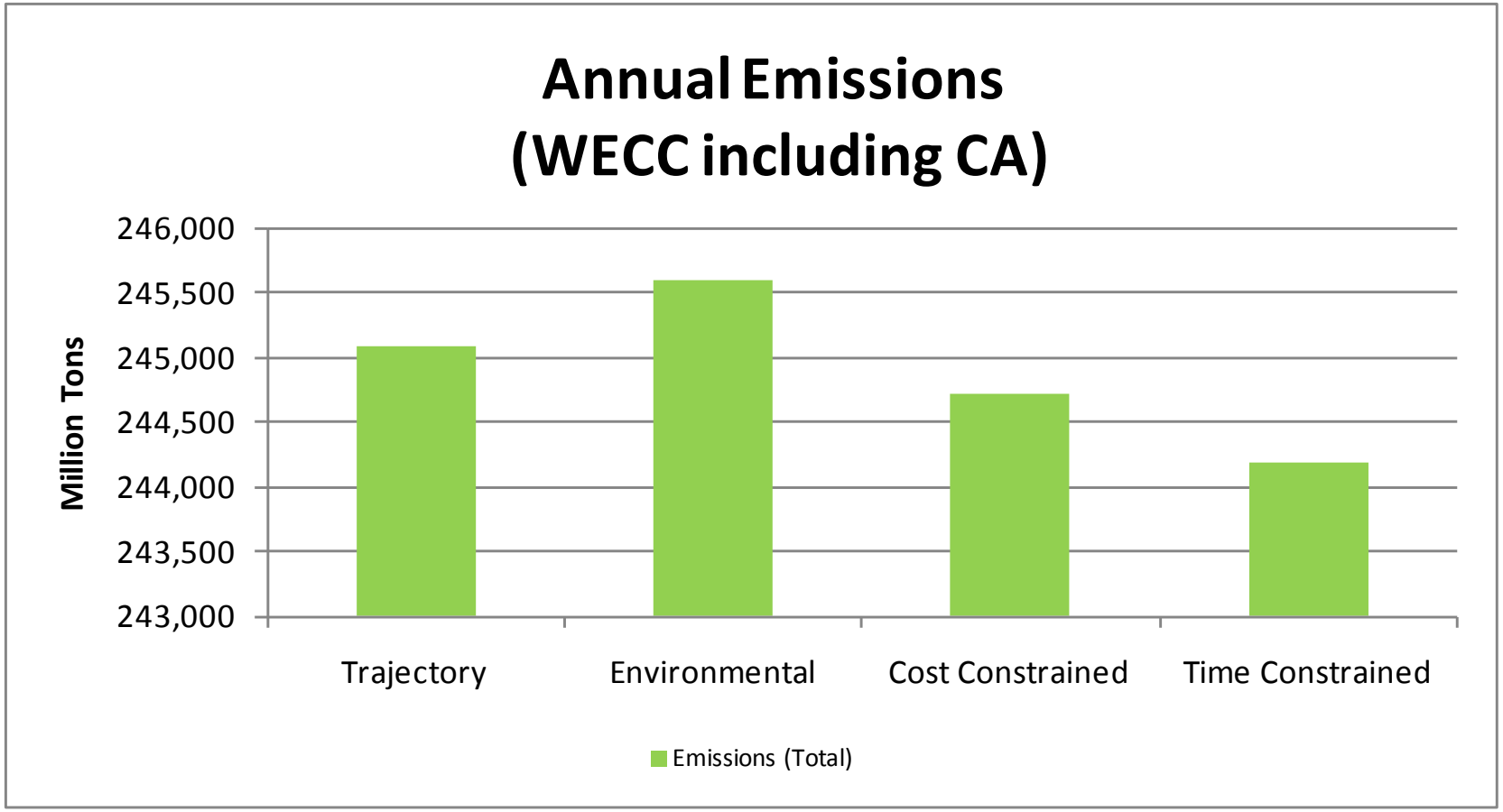
MMBTU = million BTU for conventional/fossil resources

GHG emissions calculations

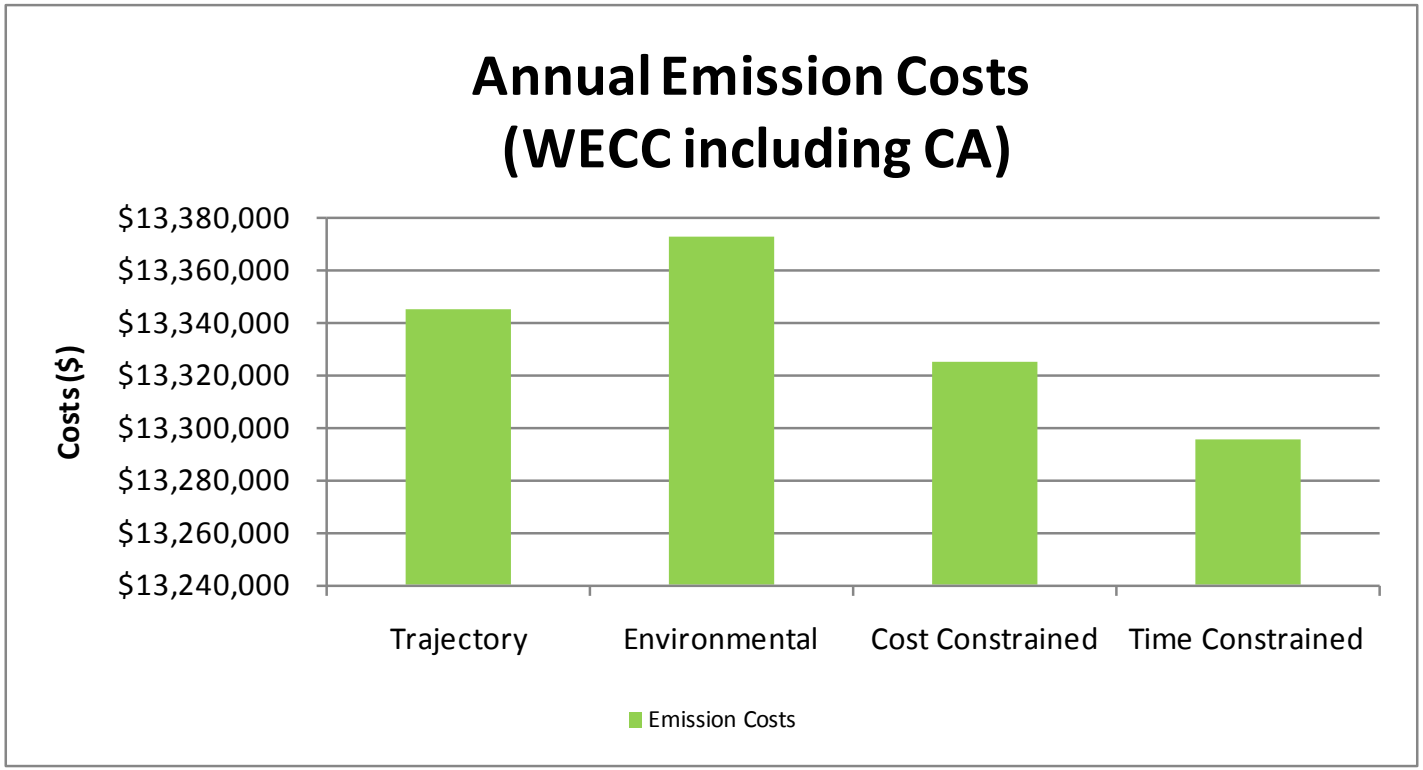
- GHG emissions are calculated by heat rate (MMBTU/MWh) × fixed emissions factor (lbs/MMBTU)
- Plants with multiple-step heat rate curves will have different emissions/MWh depending on their output in each hour of the simulation (two actual plants in table below)

Supply curve:		Segment 1	Segment 2	Segment 3
Plant 1	MW	68	170	340
	Heat rate	11750	10100	9600
Plant 2	MW	263	394	525
	Heat rate	8000	7300	7000

Annual WECC emissions by scenario



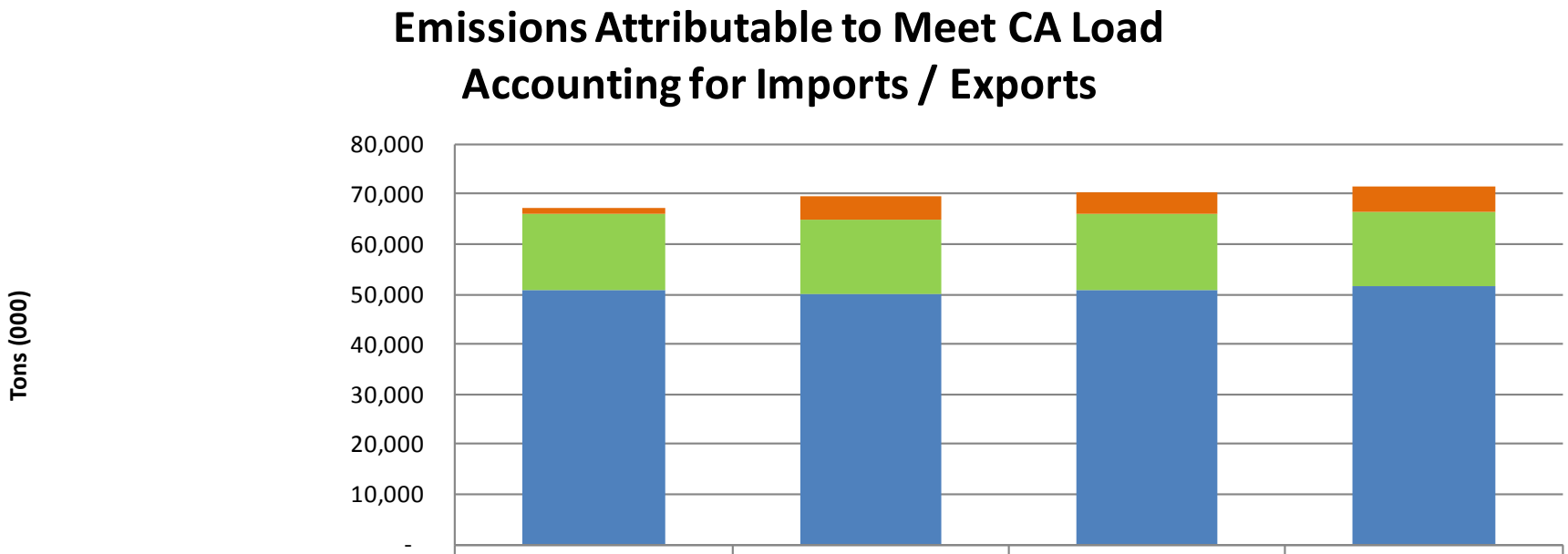
Annual WECC emission costs by scenario



Calculation of emissions associated with California

- Production simulation modeling output includes GHG emissions (tons/MMBTU) per generator to capture WECC-wide emissions reductions, but:
  - The model solves for the WECC without considering contractual resources specifically dedicated to meet California load
  - Not all OOS RPS energy dedicated to CA may "flow" into CA for every simulated hour as it could in actual operations (thus reducing emissions in CA)
- To ensure that the emissions benefit of OOS RPS energy dedicated to California is counted towards meeting California load, the study uses an *ex post* emissions accounting method (next slide)

Emissions attributed to meet California load (accounting for Import/Exports[1]), by scenario and emissions source



	Trajectory	Environmental	Cost Constrained	Time Constrained
Emissions from Non-Dedicated Import	1,464	4,696	4,471	5,223
Emissions from Dedicatied Imports	14,932	14,923	14,897	14,929
CA Emissions	51,013	49,912	51,035	51,561

1. Emissions associated with non-specified imports are attributed to CA based on an assumed emissions rate of .44 metric tons/MWh

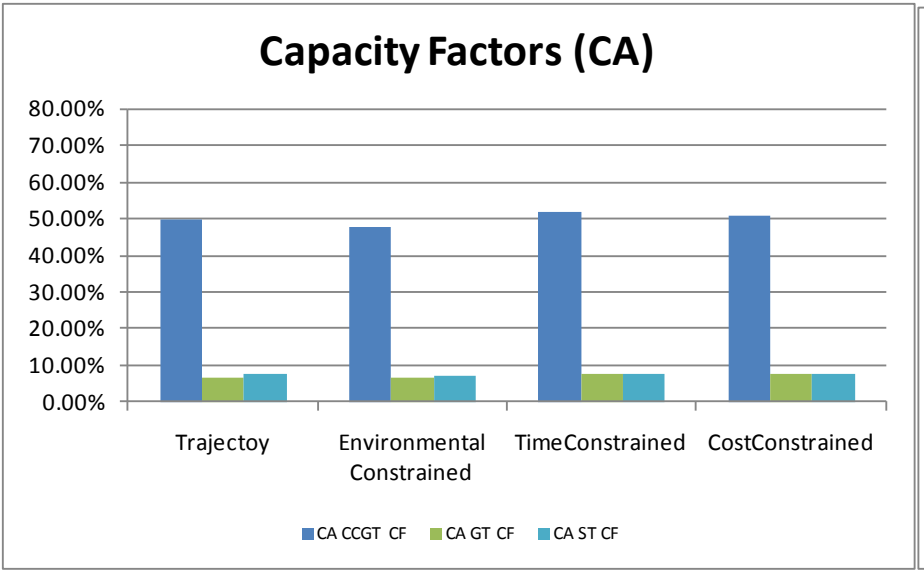
Discussion of emissions results

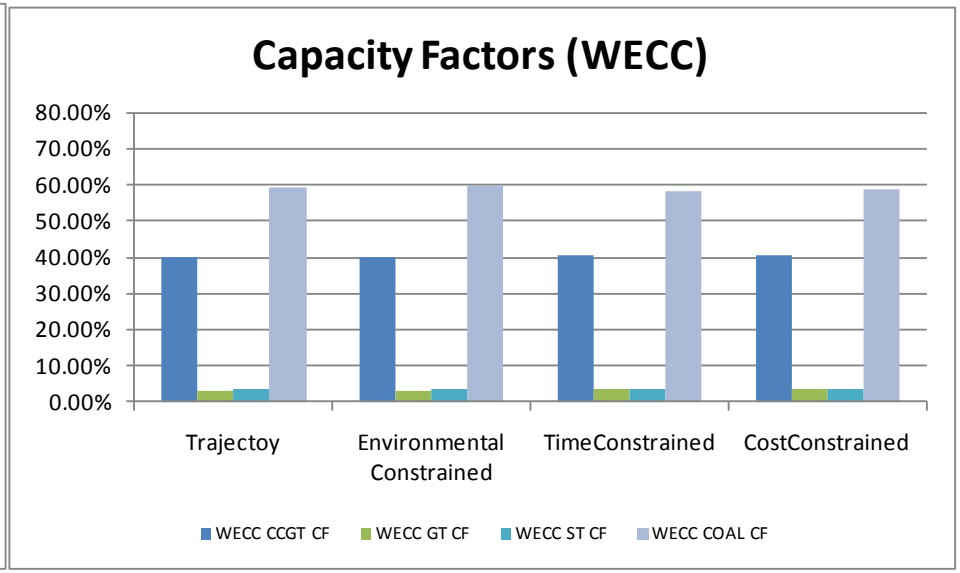
- Total emissions reduction assigned to California includes contribution of imports
- Emissions impact from California in-state generation is due in part to operational requirements associated with integration
  - Total emissions from California generators are lower in the sensitivity analysis on operational requirements discussed in Section 3
- Results are sensitive to method for allocating renewable energy imports to California load

Changes to fleet operations

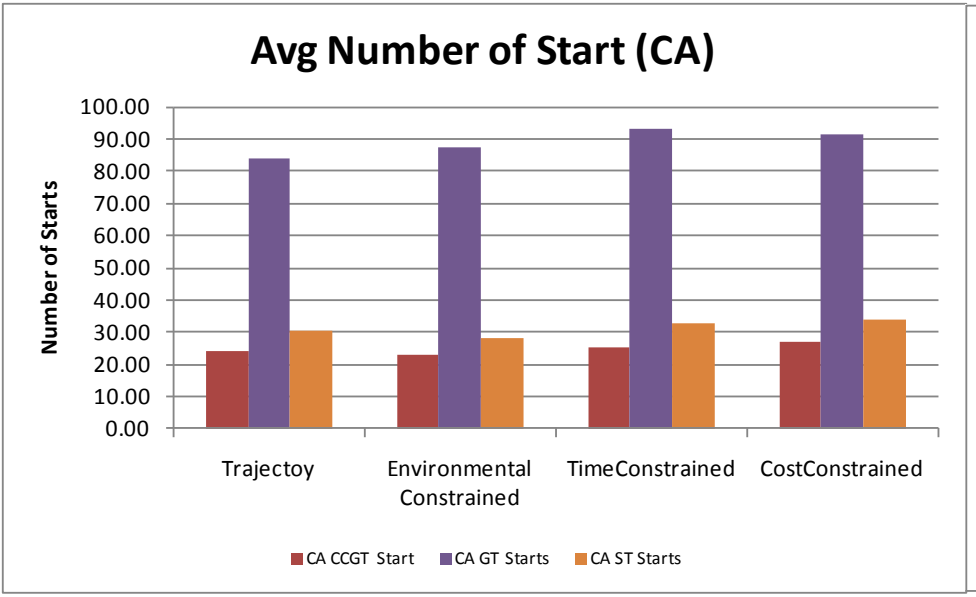
- Changes in capacity factors, number of starts by unit type and location
- California within-state results are influenced by integration requirements within state
- Linked to production costs and emissions, as shown in earlier slides

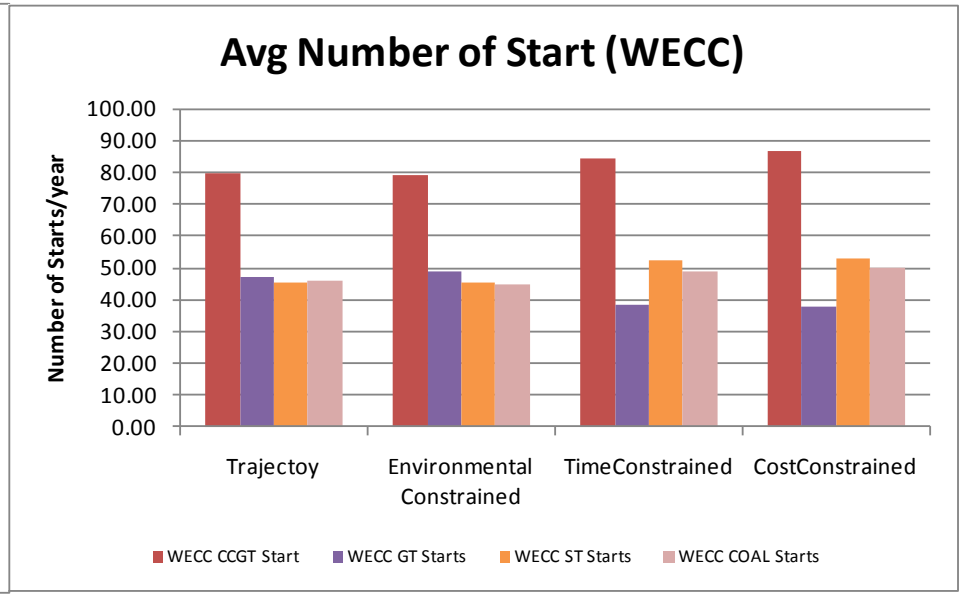
Changes to Capacity Factors, by scenario





Changes to number of Start-ups, by scenario





Comparison of CA and WECC (exclusive of CA) Results (2)

Comparison of Dispatchable Resources (CA versus WECC) (Trajectory)

Technology	CA		WECC		Difference (CA-WECC)	
	Avg CF	Avg Unit S	Avg CF	Avg Unit S	Avg CF	Avg Unit Starts
CCGT	49.71%	24.00	40.19%	79.69	9.52%	-55.69
Coal	N/A	N/A	59.14%	45.92	N/A	N/A
GT	6.86%	84.23	3.07%	47.35	3.79%	36.88
ST	7.47%	30.69	3.57%	45.28	3.90%	-14.59

Comparison of Dispatchable Resources (CA versus WECC) (Environmental Constrained)

Technology	CA		WECC (Excl CA)		Diff(CA-WECC)	
	Avg CF	Avg Unit Starts	Avg CF	Avg Unit Starts	Avg CF	Avg Unit Starts
CCGT	47.82%	22.72	40.18%	79.29	7.64%	-56.57
Coal	N/A	N/A	59.58%	44.71	N/A	N/A
GT	6.67%	87.59	3.06%	48.83	3.61%	38.76
ST	7.37%	28.00	3.56%	45.51	3.81%	-17.51

Comparison of Dispatchable Resources (CA versus WECC) (Time Constrained)

Technology	CA		WECC (Excl CA)		Diff (CA-WECC)	
	Avg CF	Avg Unit Starts	Avg CF	Avg Unit Starts	Avg CF	Avg Unit Starts
CCGT	51.60%	25.56	40.70%	84.34	10.90%	-58.79
Coal	N/A	N/A	58.40%	48.77	N/A	N/A
GT	7.63%	92.89	3.35%	38.49	4.28%	54.40
ST	7.51%	33.00	3.74%	52.06	3.77%	-19.06

Comparison of Dispatchable Resources (CA versus WECC) (Cost Constrained)

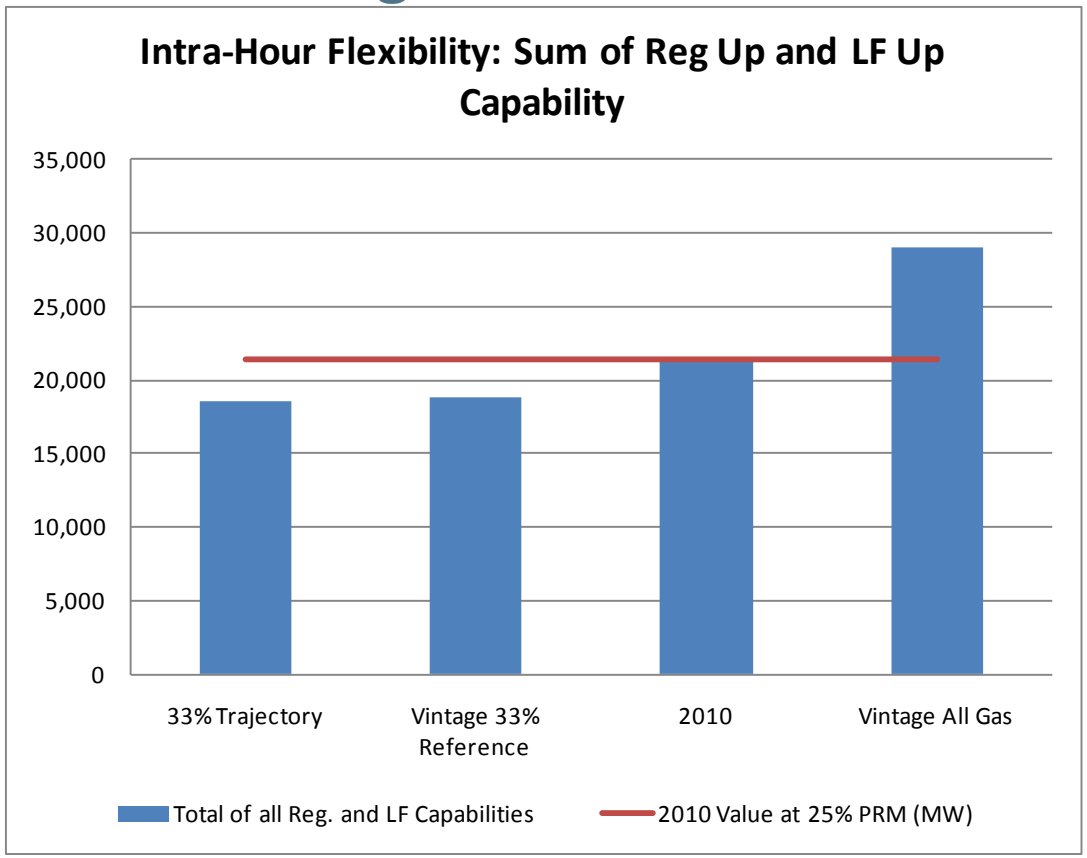
Technology	CA		WECC (Excl CA)		Diff (CA-WECC)	
	Avg CF	Avg Unit Starts	Avg CF	Avg Unit Starts	Avg CF	Avg Unit Starts
CCGT	50.78%	27.07	40.59%	86.43	10.19%	-59.35
Coal	N/A	N/A	58.90%	50.30	N/A	N/A
GT	7.72%	91.39	3.42%	37.82	4.30%	53.58
ST	7.64%	34.00	3.82%	52.99	3.82%	-18.99

SECTION 4:
FURTHER ANALYSIS OF FLEET FLEXIBILTY IN 2020

Analysis of generation fleet flexibility in 2020

- Prior presentations provided analysis of fleet flexibility
- Updated fleet flexibility analysis for 2010-CPUC LTPP trajectory scenario
- The following compares the fleet flexibility with vintage “33% reference” and “all gas” cases as well as 2010 existing

Analysis of generation fleet flexibility in 2020, with comparison with vintage cases and 2010



- The blue bar reflects the fleet flexibility of the resource fleet in the trajectory case and fleet to meet PRM in the vintage cases
- Fleet flexibility decreases as OTC resources are replaced by renewables

SECTION 5:
RECOMMENDATIONS AND NEXT STEPS

Preliminary observations

- Assuming CA achieves demand side objectives preliminary results indicate most operational requirements can be satisfied with potential need for measures to address some over-generation conditions
- Operational requirements are dependent on load, wind and solar forecast error assumptions, mix of renewable resources and outages
  - Initial sensitivities using vintage regulation and higher load following requirements indicate potential for shortages including load following up

Recommendations and next steps

- Recommend updating analysis in future years as assumptions evolve and more is known
- Continue to evaluate forecast error with actual data as additional data is available
- Recommend running additional sensitivities to:
  - Assess higher loads
  - Assess changes to forecast error and requirements
  - Evaluate generation outages
  - Assess resources needed for local capacity requirements
  - Additional evaluation storage, pump hydro and demand response
  - Assess different assumptions of dynamic transfers

APPENDIX:
PRODUCTION SIMULATION MODEL CHANGES

Overview of Step 2 Database and Modeling

- To conduct the LTPP Step 2 analysis, an up-to-date PLEXOS database was required
- ISO used the 33% operational study PLEXOS database as a starting point
- Input data from this database were changed to align with the assumptions in the CPUC scoping memo
- Non-specified assumptions were updated by the ISO to reflect operational feasibility and to include the best publically available data
- To ensure the April 29th deadline was met, PLEXOS implemented several modeling enhancements to improve simulation efficiency

Key Inputs

- Two sets of key inputs: CPUC specified assumptions and non-specified assumptions updated by the ISO
- Assumptions stated in the CPUC Scoping Memo
  - Load forecast that includes demand side reductions
  - Renewable resource build-out
  - Existing, planned and retiring generation
  - Maximum import capability to California
  - Gas price methodology for California
  - CO_2 price assumption
- Non-specified assumptions updated by the ISO
  - Allocation of reserve requirements between ISO and munis
  - Generator operating characteristics and profiles
  - Operational intertie limits
  - Loads, resources, transmission and fuel prices outside of California

CPUC SPECIFIED ASSUMPTIONS

Load – Load Profiles

- Nexant created a load profile that was consistent with the CPUC's forecasted load for the analysis of the four LTPP scenarios
- Load profile adjustment made to the CPUC specified demand side resources
  - Energy efficiency
  - Demand side CHP
  - Behind-the-meter PV – modeled as supply
  - Non-event based DR

Generation - CPUC Generation Dataset

- CPUC provided data on existing, planned and retiring generation facilities
- Existing resources specified by the CPUC were drawn from two resources:
  - 2011 NQC as of August 2nd, 2010
  - ISO master generation list
- Additions and non-OTC retirements are drawn from the ISO OTC scenario analysis tool; other additions are resources with CPUC approved contracts that do not have AFC permits approved
  - CCGTs in CPUC planned additions were modeled with generic unit operating characteristics taken from the MPR
- OTC retirements taken from the State Water Board adopted policy with several CPUC modifications

CPUC Supply Side CHP and DR Specifications

- Existing CHP and DR bundles in the 33% operational study PLEXOS database were scaled to match the incremental supply side CHP and DR goals in the CPUC scoping memo
- 761 MW of incremental supply side CHP was assumed to be online in 2020 with a heat rate of 8,893 Btu/kWh per the CPUC scoping memo
- 4,817 MW of incremental DR was modeled as supply in 2020 (including line losses)
  - Non-event based DR was included in the load profiles and not in the Step 2 database as supply side resource

Load and Resource Balance with CPUC assumptions

- The CPUC Scoping Memo assumptions estimate a 17,513 MW surplus above PRM in 2020 in the ISO

Load and Resource Balance in the ISO using CPUC Resource Assumptions (MW)

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Load										
ISO Summer Peak Load	49,143	49,902	50,678	51,283	51,913	52,555	53,246	53,905	54,571	55,298
Total Demand Side Reductions	(3,432)	(4,712)	(5,650)	(6,374)	(7,187)	(8,036)	(8,936)	(9,874)	(10,776)	(11,651)
Net ISO Peak Summer Load	45,711	45,190	45,028	44,909	44,726	44,519	44,310	44,031	43,795	43,647
Resources										
Existing Generation	52,435	52,435	52,435	52,435	52,435	52,435	52,435	52,435	52,435	52,435
Retiring Generation	(1,260)	(1,425)	(1,425)	(2,434)	(4,694)	(5,646)	(10,378)	(11,329)	(12,280)	(14,357)
Planned Additions (Thermal, RPS, CHP)	1,747	4,388	6,728	7,336	10,558	11,280	12,207	12,283	13,471	13,547
Net Interchange (Imports - Exports)	16,955	16,955	16,955	16,955	16,955	16,955	16,955	16,955	16,955	16,955
Summary										
Total System Available Generation	69,877	72,353	74,693	74,292	75,254	75,024	71,219	70,344	70,581	68,580
Total System Capacity Requirement (PRM)	53,482	52,872	52,683	52,544	52,329	52,087	51,843	51,516	51,240	51,067
Surplus	**16,395**	**19,480**	**22,010**	**21,748**	**22,924**	**22,936**	**19,376**	**18,827**	**19,340**	**17,513**

Updating Generation Data in 33% Operational Database

- **The generation data in the 33% operational database were updated to reflect the specified existing, planned and retiring facilities in the CPUC scoping memo**
- **ISO also solicited feedback from the working group, stakeholders via market ISO market notice and also all parties on the LTPP service list on generator operating characteristics which was incorporated into the Step 2 database**
- **ISO found some discrepancies in the CPUC generation assumptions which it has corrected in its Step 2 database and accounting:**
  - Double-counting of the Ocotillo facility
  - Renewable resource capacity additions above what is chosen in the 33% RPS calculator
  - Double counting of several resources as both imports and resources

Ocotillo/Sentinel Generation

- CPUC scoping memo includes two separate facilities in its planned additions for Ocotillo (455 MW) and Sentinel (850 MW)
- Ocotillo is a subset of the Sentinel facility (units 1-5)
  - SCE signed a contract with Sentinel for an additional three units in 2008
- ISO Step 2 database only includes eight Sentinel units (850 MW) because Ocotillo (455 MW) is already accounted for in Sentinel's nameplate capacity

RPS Resources above 33%

- CPUC included 287 MW of RPS resources in its planned additions that are not included in the 33% RPS scenarios:
  - CalRENEW-1(A) (5 MW)
  - Copper Mountain Solar 1 PseudoTie-pilot (48 MW)
  - Vaca-Dixon Solar Station (2 MW)
  - Blythe Solar 1 Project (21 MW)
  - Calabasas Gas to Energy Facility (14 MW)
  - Chino RT Solar Project (2 MW)
  - Chiquita Canyon Landfill (9 MW)
  - Rialto RT Solar (2 MW)
  - Santa Cruz Landfill G-T-E Facility (1 MW)
  - Sierra Solar Generating Station (9 MW)
  - Celerity I (15 MW)
  - Black Rock Geothermal (159 MW)
- If included, these resources will create RPS scenarios that are above 33% RPS
- These resources were not profiled in the Step 1 analysis
- ISO did not include these resources in the Step 2 database

Existing Generation/Imports Discrepancies

- The 2011 NQC list includes 2,626 MW of resources that are imports to the ISO
  - APEX_2_MIRDYN (505 MW)
  - MRCHNT_2_MELDYN (439 MW)
  - MSQUIT_5_SERDYN (1,182 MW)
  - SUTTER_2_PL1X3 (500 MW)
- The CPUC's original L&R tables counted the capacity of these resources twice:
  1. Directly, as specified resources with NQC capacity
  2. Indirectly, by assuming full transmission capability into the ISO
- For accounting purposes and to avoid double accounting, ISO has removed these resources from the available generation but maintains the assumption of full transmission capability into the ISO

Load and Resource Balance After Assumption Modifications

- Accounting for all of these modifications, the load and resource balance has a surplus of 14,144 MW above PRM in 2020, compared to 17,513 MW above PRM using the CPUC assumptions

Load and Resource Balance in the ISO using CAISO Resource Modifications (MW)

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Load										
Summer Peak Load	49,143	49,902	50,678	51,283	51,913	52,555	53,246	53,905	54,571	55,298
Total Demand Side Reductions	3,432	4,712	5,650	6,374	7,187	8,036	8,936	9,874	10,776	11,651
Net Peak Summer Load	45,711	45,190	45,028	44,909	44,726	44,519	44,310	44,031	43,795	43,647
Resources										
Existing Generation	49,809	49,809	49,809	49,809	49,809	49,809	49,809	49,809	49,809	49,809
Retiring Generation	(1,260)	(1,425)	(1,425)	(2,434)	(4,694)	(5,646)	(10,378)	(11,329)	(12,280)	(14,357)
Planned Additions (Thermal, RPS, CHP)	1,618	4,259	6,440	7,048	9,815	10,537	11,464	11,540	12,728	12,804
Net Interchange (Imports - Exports)	16,955	16,955	16,955	16,955	16,955	16,955	16,955	16,955	16,955	16,955
Summary										
Total System Available Generation	67,122	69,598	71,779	71,378	71,885	71,655	67,850	66,975	67,212	65,211
Total System Capacity Requirement (PRM)	53,482	52,872	52,683	52,544	52,329	52,087	51,843	51,516	51,240	51,067
Surplus Above PRM with CAISO Modifications	13,640	16,726	19,096	18,834	19,556	19,568	16,007	15,459	15,972	14,144
Surplus Above PRM with CPUC Assumptions	16,395	19,480	22,010	21,748	22,924	22,936	19,376	18,827	19,340	17,513
Difference in Surplus between CPUC and CAISO	***2,755***	***2,755***	***2,914***	***2,914***	***3,369***	***3,369***	***3,369***	***3,369***	***3,369***	***3,369***

MPR Gas Forecast Methodology

- CPUC Scoping Memo specifies that the LTPP proceeding use a gas forecast calculated using the same methodology as the Market Price Referent (MPR) using NYMEX data gathered from 7/26/2010 – 8/24/2010
  - MPR methodology provides a transparent framework to derive a forecast of natural gas prices at the utility burner-tip in California
  - In the near term (before 2023), the forecast is based on:
    1. NYMEX contract data for natural gas prices at Henry Hub and basis point differentials between HH and CA
    2. A municipal surcharge, calculated as a percentage of the commodity cost
    3. A gas transportation cost based on the tariffs paid by electric generators

CA Gas Forecast

- 2020 natural gas forecast for CA delivery points (2010$/MMBtu)

Zone	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Gas - PGE_Citygate	$ 5.95	$ 5.92	$ 5.75	$ 5.31	$ 5.29	$ 5.34	$ 5.41	$ 5.45	$ 5.47	$ 5.54	$ 5.79	$ 6.04
Gas - PGE_Citygate_BB	$ 6.07	$ 6.04	$ 5.87	$ 5.43	$ 5.41	$ 5.46	$ 5.53	$ 5.57	$ 5.59	$ 5.66	$ 5.92	$ 6.17
Gas - PGE_Citygate_LT	$ 6.23	$ 6.20	$ 6.03	$ 5.59	$ 5.57	$ 5.62	$ 5.69	$ 5.73	$ 5.75	$ 5.82	$ 6.08	$ 6.33
Gas - SoCal_Border	$ 5.74	$ 5.70	$ 5.54	$ 5.13	$ 5.11	$ 5.16	$ 5.23	$ 5.27	$ 5.29	$ 5.36	$ 5.58	$ 5.83
Gas - SoCal_Burnertip	$ 6.18	$ 6.15	$ 5.98	$ 5.57	$ 5.54	$ 5.60	$ 5.67	$ 5.71	$ 5.72	$ 5.80	$ 6.02	$ 6.28

CO_2 Price

- A \$36.30/short ton of CO_2 (2010\$) cost was used in the PLEXOS simulations per the CPUC scoping memo

NON-SPECIFIED ASSUMPTIONS UPDATED BY ISO

Allocation of Reserves Between ISO and Munis

- Step 1 analysis created statewide load following and regulation requirements
- Step 2 is an ISO-wide analysis that requires an allocator to split the load following and regulation requirements between the IOUs and Munis
- Allocator calculated using two parts:
  - 50% of allocator = ratio of peak load between the ISO (83%) and Munis (17%)
  - 50% of allocator = fraction of wind and solar resources delivered to California that are integrated by the ISO (94%) and Munis (6%)
- This results in the following allocation of the reserve requirements: 88.5% to the ISO and 11.5% to the Munis

Update of Generator Operating Characteristics

- ISO received feedback from 5 stakeholders on information in the 33% operational study PLEXOS database
  - Comprehensive list of changes came from SCE and included updated information on individual generator operating characteristics and SP15 hydro dispatch
  - Calpine submitted a new start profile for CCGTs
- CT planned additions and generic units were mapped to the operating characteristics of an LMS100 or LM6000 depending on plant size

Helms modeling

- PG&E updated the maximum capacity of the Helms reservoir to 184.5 GWh
- PG&E provided end of spring reservoir energy storage target and summer monthly energy usage schedules
- ISO consulted with PG&E to develop the appropriate pumping windows in 2020
  - availability in the summer months, Helms pumping was restricted to 1 pump between May and September
  - 3 pumps were assumed to be available for October through April
- Continued discussions with PG&E suggest that three pump capability in 2020 in non-summer months may not be possible; may warrant additional sensitivities

Transmission Import Limits to CA

- ISO defined simultaneous import limits to CA
- ISO used a model developed by the ISO to estimate the Southern California Import Transmission (SCIT) limit based on
  - planned thermal additions
  - OTC retirements
  - renewable resources additions
  - neighboring transmission path flows into and around the SCIT area

Import Limits by Scenario and Time

Transmission Limits (MW)	Summer Pk	Summer Off Pk	Winter Pk	Winter Off Pk
Trajectory Case				
S. Cal Import Limit to be used for study	12,416	10,709	10,928	8,823
Total California Import Limit	13,216	11,509	11,728	9,623
Environmental Case				
S. Cal Import Limit to be used for study	12,901	10,735	11,237	8,851
Total California Import Limit	13,701	11,535	12,037	9,651
Cost Case				
S. Cal Import Limit to be used for study	13,523	10,735	11,726	8,851
Total California Import Limit	14,323	11,535	12,526	9,651
Time Case				
S. Cal Import Limit to be used for study	13,221	10,735	11,499	8,851
Total California Import Limit	14,021	11,535	12,299	9,651

Assumptions of Gas Forecast Outside of CA

- The MPR methodology provides a forecast of gas prices for generators inside of California
- In order to avoid skewing the relative competitive position of gas fired generators inside and outside of California, WECC-wide gas prices outside of California must be updated to reflect the same underlying commodity cost of gas embedded in the MPR forecast

Gas Forecast Outside of CA (cont'd)

- Created an MPR-style forecast for gas prices elsewhere in the WECC drawing upon available NYMEX contract data over the same trading period (7/26/10 – 8/24/10):
  - In addition to the California gas hubs (PG&E Citygate and Socal Border), forecast hub prices at Sumas, Permian, San Juan, and Rockies hubs using the NYMEX basis differentials
  - For each bubble (geographic area), add appropriate delivery charges (based on TEPPC delivery charges) to the appropriate hub price to determine the burnertip price
- Two specific changes were made to this methodology based on IOU feedback:
  - Arizona gas hub was moved from Permian to SoCal Border
  - Delivery charge was removed from Sumas hub to British Columbia

Gas Forecast Outside of CA

- 2020 natural gas forecast for delivery points outside of California (2010$/MMBtu)

Zone	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Gas - AECO_C	$ 5.49	$ 5.46	$ 5.29	$ 4.72	$ 4.69	$ 4.75	$ 4.82	$ 4.86	$ 4.88	$ 4.95	$ 5.34	$ 5.59
Gas - Arizona	$ 6.06	$ 6.02	$ 5.85	$ 5.42	$ 5.39	$ 5.45	$ 5.52	$ 5.57	$ 5.58	$ 5.66	$ 5.89	$ 6.16
Gas - Baja	$ 5.74	$ 5.70	$ 5.54	$ 5.13	$ 5.11	$ 5.16	$ 5.23	$ 5.27	$ 5.29	$ 5.36	$ 5.58	$ 5.83
Gas - Colorado	$ 6.08	$ 6.04	$ 5.88	$ 5.42	$ 5.39	$ 5.45	$ 5.52	$ 5.56	$ 5.57	$ 5.65	$ 5.92	$ 6.17
Gas - Idaho_Mont	$ 6.00	$ 5.97	$ 5.81	$ 5.23	$ 5.21	$ 5.26	$ 5.33	$ 5.37	$ 5.39	$ 5.46	$ 5.85	$ 6.10
Gas - Kern_River	$ 5.74	$ 5.70	$ 5.54	$ 5.13	$ 5.11	$ 5.16	$ 5.23	$ 5.27	$ 5.29	$ 5.36	$ 5.58	$ 5.83
Gas - Malin	$ 5.98	$ 5.95	$ 5.79	$ 5.10	$ 5.07	$ 5.13	$ 5.20	$ 5.24	$ 5.26	$ 5.33	$ 5.83	$ 6.08
Gas - Pacific_NW	$ 6.11	$ 6.08	$ 5.91	$ 4.98	$ 4.95	$ 5.01	$ 5.08	$ 5.12	$ 5.14	$ 5.21	$ 5.96	$ 6.21
Gas - Permian	$ 5.58	$ 5.54	$ 5.38	$ 5.01	$ 4.99	$ 5.04	$ 5.11	$ 5.15	$ 5.17	$ 5.24	$ 5.42	$ 5.67
Gas - Rocky_Mntn	$ 5.49	$ 5.46	$ 5.29	$ 4.72	$ 4.69	$ 4.75	$ 4.82	$ 4.86	$ 4.88	$ 4.95	$ 5.34	$ 5.59
Gas - San_Juan	$ 5.52	$ 5.49	$ 5.32	$ 4.86	$ 4.84	$ 4.89	$ 4.96	$ 5.00	$ 5.02	$ 5.09	$ 5.37	$ 5.62
Gas - Sierra_Pacific	$ 6.12	$ 6.08	$ 5.92	$ 5.48	$ 5.46	$ 5.51	$ 5.58	$ 5.62	$ 5.64	$ 5.71	$ 5.96	$ 6.21
Gas - Sumas	$ 6.02	$ 5.98	$ 5.82	$ 4.89	$ 4.86	$ 4.92	$ 4.99	$ 5.03	$ 5.04	$ 5.11	$ 5.86	$ 6.11
Gas - Utah	$ 5.76	$ 5.73	$ 5.56	$ 4.99	$ 4.97	$ 5.02	$ 5.09	$ 5.13	$ 5.15	$ 5.22	$ 5.61	$ 5.86
Gas - Wyoming	$ 6.05	$ 6.01	$ 5.85	$ 5.27	$ 5.25	$ 5.30	$ 5.37	$ 5.41	$ 5.43	$ 5.50	$ 5.89	$ 6.14

TEPPC PC0 Case

- PC0, a recent TEPPC database, was used to populate the PLEXOS database with loads, resources and transmission capacity for zones outside of California
- Embedded in this case were several coal plant retirements
- ISO incorporated several adjustments to this case:
  - Included several additional coal plant retirements that were announced but not included in PC0
  - Excluded the resources assumed to contribute to California's RPS portfolio that are located outside of California

Exclusion of RPS Resources from PC0

- TEPPC's PC0 case includes enough renewables to meet RPS goals in California and the rest of the WECC
  - The portfolio for California is very similar to the Trajectory Case specified for the LTPP, which includes out-of-state renewables
- To develop consistent scenarios for LTPP, the RPS builds for CA in PC0 must be adjusted according to the following framework:

	WECC-Wide RPS Resources in PC0
–	PC0 RPS Resources in CA
–	PC0 OOS RPS Resources Attributed to CA
+	CPUC RPS Portfolio (Traj/Env/Cost/Time)
=	**RPS-Compliant LTPP Scenario**

State	Resource	MW	GWh
New Mexico	Biomass	39	231
Idaho	Geothermal	27	198
Nevada	Geothermal	76	561
Utah	Geothermal	120	885
British Columbia	Small Hydro	90	442
Oregon	Small Hydro	13	50
Nevada	Solar Thermal	285	933
Arizona	Solar PV	319	737
Nevada	Solar PV	23	41
Alberta	Wind	1,565	4,843
Colorado	Wind	517	1,298
Montana	Wind	262	818
Oregon	Wind	871	2,373
Washington	Wind	1,252	3,004
Wyoming	Wind	86	344
Total		5,544	16,760

OOS resources to remove from PC0

Coal retirements by 2020

- PC0 includes the following coal plant retirements:
  - **AESO:** Battle Units 3 & 4 and Wabamun Unit 4 **(586 MW)**
  - **NEVP:** Reid Gardner Units 1-3 **(330 MW)**
  - **PSC:** Arapahoe Units 3 & 4 and Cameo Units 1 & 2 **(216 MW)**
- Based on conversations with Xcel and announced retirements, ISO included the following retirements:
  - Arapaho Unit 4 repowers as a natural gas combined cycle **(109 MW)**
  - Cherokee Units 1-4 retire **(722 MW)**; unit 4 repowers as a natural gas combined cycle **(351 MW)**
  - Four Corners Units 1-3 retire **(560 MW)**
  - Valmont Unit 5 retires **(178 MW)**

REFINEMENTS OF THE STATISTICAL MODEL OF OPERATIONAL REQUIREMENTS (STEP 1)

Step 1 inputs and analysis of the four scenarios results are available

- Aggregate minute and hourly profile data
- Load, wind and solar forecast error
- Monthly and daily regulation and load following requirements
- Data available at: http://www.caiso.com/23bb/23bbc01d7bd0.html

Refinements to load profiles

- Load peak demand and energy adjusted to conform to CPUC scoping memo based on 2009 CEC IEPR
- LTPP net load reduction of approximately 6,500 MW in 2020 relative to “vintage” 33% reference case due to demand side programs specified in the CPUC scoping memo
- Statewide peak load in CPUC Trajectory Case is 63,755 MW versus 70,180 MW in vintage 33% ISO Operational Study reference case

Refinements to load forecast error

- Updated load forecast error based on 2010 actual load and forecast data
- Hour ahead forecast data based on T-75 minutes in updated LTPP analysis versus T-2 hours in vintage case
- 5-minute data shows increased forecast error based on actual load data

Comparison of Load Forecast Errors

LTPP Analysis

Season	HA STD 2010 ADJUSTED For PEAK (based on 2010 data)	RT (T-7.5min) STD 10% Improve 2020 (based on 2010 data)	HA autocorr	RT Autocorr
Spring	545.18	216.05	0.61	0.86
Summer	636.03	288.03	0.7	0.92
Fall	539.69	277.38	0.65	0.9
Winter	681.86	230.96	0.54	0.85

Vintage Analysis

Season	HA STD 10% Improve 2020 (based on Vitage 2006 data)	RT (T-7.5min) STD 10% Improve 2020 (based on Vitage 2006 data)
Spring	831.11	126
Summer	1150.61	126
Fall	835.11	126
Winter	872.79	126

Refinements to wind profiles

- Wind sites were expanded to include quantity and locations consistent with CPUC scoping memo
- For new plants, wind plant production modeling based upon NREL 10 minute data production was expanded to include 21 distinct locations in California and 22 locations throughout the rest of WECC.

Refinements to wind forecasting errors

- Recalibrated wind forecast errors using profiled data

- Applied a *t-1hr* persistence method for estimating forecast errors

Comparison of Wind Forecast Errors

Region	Case	Technology	MW	Persistent	Hour	Spring	Summer	Fall	Winter
CA	33%Base	Wind	9436	T-1	All	0.040	0.038	0.032	0.031
					Vintage Cases	0.050	0.045	0.044	0.041

Note: Actual wind forecast error based on existing PIRP resources is higher than forecast *t-1hr* based on profiles

PIRP Forecast Error								
Region	Tech	MW	Persistent	Hour	Spring	Summer	Fall	Winter
CA	Wind	1005	T-2	All	11.1%	10.8%	8.1%	6.0%
CA	Wind	1005	T-1	All	8.4%	7.1%	5.3%	3.9%
CA	Wind	1005	PIRP	All	10.5%	8.9%	8.4%	6.7%

Refinements to solar profiles

- Profiles for 2010 scenarios are developed based on satellite irradiation data[1] rather than rather than NREL land based measurement data used previously.
- Variability was introduced based on a plant footprint rather than a single point
- Better represents diversity of resources
- Expanded use of 1 minute irradiance data to use three locations:
  - Sacramento Municipal Utility District (SMUD) in Sacramento
  - Loyola Marymount University in Los Angeles, and
  - in Phoenix, AZ

[1] The Solar Anywhere satellite solar irradiance data can be found at: https://www.solaranywhere.com/Public/About.aspx

Extended approach to profile small solar

- Extended method to profiling of small solar
- Define geographic boundaries of the 20 grids in Central, North, Mojave, and South area
- Choose each rectangular grid to represent an appropriate area. Each grid will have a different size rectangle
- Average the data on an hourly basis for each rectangle
- Follow similar process for developing solar profiles and adding 1-minute variability

Refinements to solar forecast errors

- Determined errors by analyzing 1-minute "clearness index" (CI) and irradiance data using *t-1hr* persistence
- To address issues that arise using the *t-1h* persistence during early and later hours of the day, use 12-16 persistence to determine solar forecast error
- Results on next slide
  - CI persistence method for Hours 12-16 similar in outcome to "improved" errors
- Recommendations:
  - Since forecast errors are based on profiles and not actual production data, recommend calibrating the simulated to the actual forecast errors when more solar data is available
  - Continue to develop forecasting error for early and later hours of the day

Comparison of solar forecast error with persistence

Comparison of Solar Forecast Errors

Region	Case	Technology	MW	Persistent	Hour	0<=CI<0.2	0.2<=CI<0.5	0.5<=CI<0.8	0.8<=CI<=1
CA	33%Base	PV	3527	T-1	Hour12-16	0.035	0.069	0.056	0.023
CA	33%Base	ST	3589	T-1	Hour12-16	0.060	0.109	0.108	0.030
CA	33%Base	DG	1045	T-1	Hour12-16	0.022	0.047	0.039	0.018
CA	33%Base	CPV	1749	T-1	Hour12-16	0.016	0.033	0.031	0.016
		All			Vintage Cases	0.05	0.1	0.075	0.05

IMPROVEMENTS TO SIMULATION EFFICIENCY

Modeling Improvements

- The model was modified to improve accuracy of modeling and efficiency of simulation while not compromising quality of results
- The major modifications implemented are:
  - Separation of spinning and non-spinning requirements
  - Generator ramp constraints for providing ancillary services and load following capacity
  - Simplified topology outside of California
  - Mixed integer optimization in California only
  - Tiered cost structure in generic resources in determining need for capacity

Separation of spinning and non-spinning requirements

- In the previous model, non-spinning includes spinning in both requirements and provision
- Spinning and non-spinning are separated in this model
  - The requirements for spinning and non-spinning are all 3% of load
  - The provision of non-spinning of a generator does not include its provision of spinning
- The separation is consistent with the ISO market definition and is needed to implement the ramp constraints as discussed below

Generator ramp constraints for providing ancillary services and load following capacity

- 60-minute constraint
  - The sum of intra-hour energy upward ramp, regulation-up, spinning, non-spinning, and load following up provisions is less than or equal to 60-minite upward ramp capability of the generator
  - The sum of intra-hour energy downward ramp, regulation-down, and load following down provisions is less than or equal to 60-minite downward ramp capability of the generator

Generator ramp constraints for providing ancillary services and load following capacity (cont.)

- 10-minute check constraint
  - The sum of upward AS and 50% of load following up provisions is less than or equal to 10-minite upward ramp capability
  - The sum of regulation-down and 50% of load following down provisions is less than or equal to 10-minite downward ramp capability

Generator ramp constraints for providing ancillary services and load following (cont.)

- 10-minute AS constraint
  - The sum of upward AS provisions is less than or equal to 10-minite upward ramp capability
  - Regulation-down provision is less than or equal to 10-minite downward ramp capability
- 20-minute constraint
  - The sum of upward AS and load following up provisions is less than or equal to 10-minite upward ramp capability
  - The sum of regulation-down and load following down provisions is less than or equal to 10-minite downward ramp capability

Simplified topology outside of California

- The topology was simplified by combining transmission areas (bubbles) outside CA according to the following rules:
  - The areas have no direct transmission connection to CA
  - The areas are combination by state or region (Pacific Northwest)
- There will be no transmission congestion within each of the combined areas

Mixed integer optimization in California only

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

Tiered cost structure in generic resources in determining need for capacity

- In the run to determine need for capacity, generic resources have high operation costs set up in a tired structure such that:
  - The generic resources will be used only when they are absolutely needed to avoid violation of requirements
  - The use of generic resources will be in a progressive way (fully utilizing the capacity of one generic unit before starting to use the next one)
- The model using this method can determine the need for capacity in one simulation

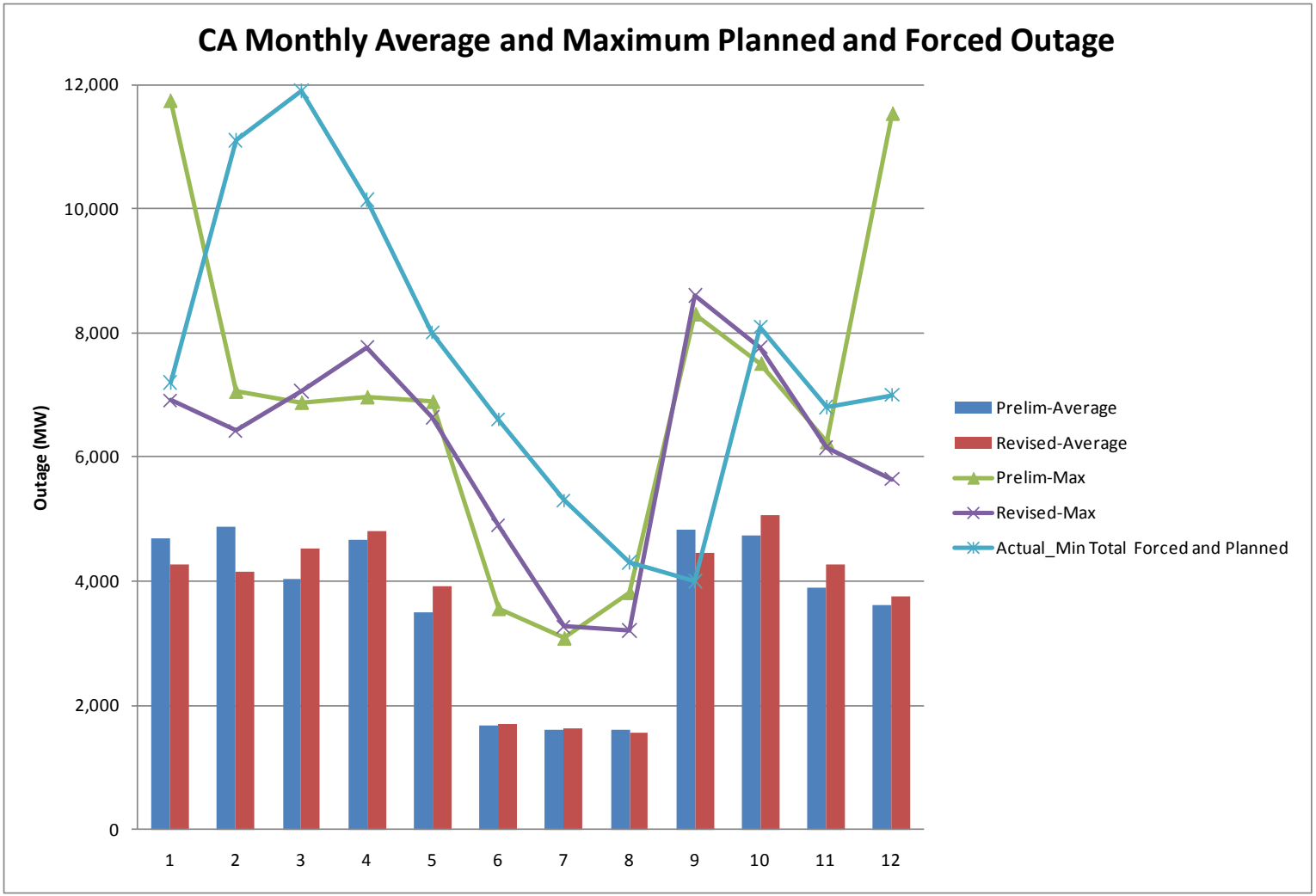
Tiered cost structure in generic resources in determining need for capacity (cont.)

- The VOM cost and the cost to provide AS or load following of the generic resources are set up as

  Tier 1 – $10,000/MW Tier 2 - $15,000/MW

  Tier 3 – $20,000/MW Tire 4 - $25,000/MW
- In the run to determine the need for capacity startup costs of all generators are not considered for the method to work properly
- The run uses the monthly maximum regulation and load following requirements for each hour

Review of outage profile.



Note: Outage profiles need further consideration

ATTACHMENT G

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Solar PV Becoming Cheaper than Gas in California?

By Stephen Lacey, Editor | February 8, 2011

The latest round of proposed contracts from a California utility for 250 MW of solar PV projects comes in below the projected price of natural gas.

California -- We hear it every day: "Solar is too expensive." Well, not according to the California utility Southern California Edison.

In a recent filing to the state's Public Utilities Commission, SCE asked for approval of 20 solar PV projects worth 250 MW – all of which are expected to generate a total of 567 GWh of electricity for less than the price of natural gas.

Although the exact details of the 20-year contracts for the projects are kept confidential for a few years, the utility reports that all winning solar developers issued bids for contracts below the Market Price Referent, which is the estimated cost of electricity from a 500-MW combined-cycle natural gas plant.

What does that mean? It means that a large number of solar PV project developers believe they can deliver solar electricity at a very competitive price. And these aren't mega-projects either. All of the installations will be between 4.7 MW and 20 MW – a sweet spot for PV projects.

Although the price of natural gas has plummeted in recent years because of excessive production and lower demand for power, the cost of solar projects and the price of solar electricity has dropped in tandem. With stong solar requirements in states like California, demand for PV has stayed strong.

"Solar energy is a natural hedge against rising energy costs – a hedge that regulators and utilities are turning to lower electricity costs for their customers," said Rhone Resch, president and CEO of the Solar Energy Industries Association.

California regulators seem to agree that mid-sized solar PV installations, which capture economies of scale but suffer fewer regulatory and transmission constraints, are an important part of the market.

These latest projects were solicited through SCE's Renewables Standard Contracts program, a reverse auction mechanism implemented by the utility in 2010. The program is a precursor to California's Reverse Auction Mechanism (RAM) that was approved last December. That 1-GW program requires California's three largest utilities to hold auctions twice a year to solicit bids from developers of mid-sized (i.e. 1-20 MW) solar PV projects.

The 250 MW of contracts sent to the CPUC for approval is in addition to a 500-MW solar program initiated by SCE in 2009.

According to SCE's filing, the utility seems to be genuinely positive about the prospects for solar PV:

"Solar PV is a mature and proven renewable energy technology that has been supplying a substantial amount of renewable energy to SCE and other California load-serving entities ("LSEs") for several years."

While large-scale concentrating solar power projects have been gaining ground in California and other southwestern states, PV is looking like the better option in many cases. Due to the steady declines in the cost of production and price of modules, as well as improvements in Balance of Systems technologies (i.e. power electronics, racking and wiring) that make installations more efficient, solar PV is leading the way.

"The solar industry has done a great job in bringing down costs – long a promise, now a reality," said Adam Browning, executive director of the Vote Solar Initiative, in a response to the recent SCE announcement. "These are price-points that can really scale, and will encourage policymakers to think big."

In a recent report from GTM Research comparing similar-sized CSP and PV projects, the authors forecast that electricity from utility-scale PV plants will be considerably lower than some CSP technologies. In the next decade, the research firm projects CSP plants will be generating electricity in the $0.10 to $0.12 per kWh range and PV will be producing electricity in the $0.07 to $0.08 kWh range. (On the flip side, CSP technologies can offer storage capabilities and hybrid natural gas components, providing value that PV can't necessarily deliver.)

With high peak demand, lots of expensive "spinning reserve" power plants and ample sunlight, California is the likely place for PV to compete. But with project costs continuing to drop and utilities promoting the technology, the steady march toward grid parity will spread to other markets as well, said Vote Solar's Browning.

"Though California does have world-class sunlight, solar is modular and adaptable, and similar results can be had throughout the country."

http://www.renewableenergyworld.com/rea/news/article/2011/02/solar-pv-becoming-cheaper-than-gas-in-california

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