BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

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Application of Southern California Edison Company (U-338-E) for a Commission Finding that its Procurement-Related and Other Operations for the Record Period January 1 through December 31, 2009 Complied with its Adopted Procurement Plan; for Verification of its Entries in the Energy Resource Recovery Account and Other Regulatory Accounts; and for Recovery of $29.947 Million Recorded in Four Memorandum Accounts.	)	Application No. 10-04-002 (Filed April 1, 2010)

OPENING BRIEF OF SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E)

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APPLICATION OF SOUTHERN CALIFORNIA EDISON COMPANY (U-338E) IN ITS APRIL 2007 ENERGY RESOURCE RECOVERY ACCOUNTY (ERRA) PROCEEDING

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I.

INTRODUCTION AND EXECUTIVE SUMMARY

Pursuant to Rule 13.11 of the California Public Utilities Commission's (Commission) Rules of Practice and Procedure and the procedural schedule set forth by Administrative Law Judge (ALJ) Gamson on March 4, 2011, Southern California Edison Company (SCE) hereby submits its opening brief in its April 2010 Energy Resource Recovery Account (ERRA) Review proceeding. In its application and supporting testimony, SCE sets forth its procurement-related operations from January 1, 2009 through December 31, 2009 (Record Period). SCE requests the Commission to find that during the Record Period: (1) its fuel and purchased power expenses complied with SCE's Commission-approved procurement plan and were recorded accurately; (2) its contract administration, management of utility-retained generation, dispatch of generation resources, and related spot market transactions complied with Standard of Conduct Four (SOC 4) in SCE's procurement plan; and (3) all other SCE activities subject to Commission review in this ERRA Review proceeding complied with applicable Commission decisions and resolutions.

In addition, SCE requests the Commission to find that $34.9 million (including franchise fees and uncollectibles) associated with under-collections in the three memorandum accounts were recorded accurately and are recoverable in rates: (1) the Market Redesign and Technology Upgrade Memorandum Account (MRTUMA); (2) the Litigation Cost Tracking Account (LCTA); and (3) the Project Development Division Memorandum Account (PDDMA).

The Division of Ratepayer Advocates (DRA) submitted its Report on SCE's application (DRA Report) setting forth DRA's review of SCE's 2009 activities in four areas: (1) Utility-Retained Generation; (2) Qualifying Facility (QF) Contract Administration and Costs; (3) Non-QF Contract Administration and Costs; and (4) ERRA and Non-ERRA Balancing/Memorandum Account Review. DRA's Report recommends that the Commission: (1) disallow approximately $19.50 million in replacement power costs associated with four outages[1] that it contends are unreasonable and (2) disallow recovery of $0.077 million associated with the MRTUMA.

SCE submitted rebuttal testimony in response to DRA's Report and further addressed DRA's disallowance recommendations at the January 19 and February 10, 2011 hearings. In its rebuttal testimony and at the hearings, SCE explained that the Commission should reject each of DRA's recommendations for the following reasons:

- **Utility-Retained Generation:** SCE submitted unrefuted evidence demonstrating that the forced outages at San Onofre Nuclear Generating Station (SONGS) Unit 2, Big Creek 3 Unit 1, Mammoth Pool Unit 2, and Four Corners Generating Station (Four Corners) Unit 4 were reasonable and do not constitute a violation of the Commission's SOC 4 standard. SCE's witnesses offered extensive testimony evaluating each outage under the Commission's reasonable manager standard, and explained why plant personnel acted reasonably given the

[1] In its Report, DRA initially recommended that the Commission disallow approximately $25.75 million associated with nine outages. However, DRA withdrew five of its disallowance recommendations in an email that it sent to ALJ Gamson on January 14, 2011.

facts that were known at the time of each outage. DRA, on the other hand, did not provide relevant evidence in support of its disallowance recommendations. DRA did not provide any analysis of these outages under the Commission's reasonable manager standard. Instead, it simply copied or paraphrased selected statements taken from cause evaluations conducted by or for SCE and summarily concluded that these outages were unreasonable. The Commission should reject DRA's unsupported claims and conclude that SCE's evidence conclusively demonstrates that these outages were reasonable and consistent with prudent administration under SOC 4.

- **MRTUMA:** The Commission should adopt SCE's request to recover $11.2 million associated with certain incremental and verified O&M and capital-related revenue requirements recorded in this account. In its Report, DRA did not dispute that SCE provided sufficient testimony and workpapers to support this amount; rather, it objected to SCE's methodology for calculating a portion of its incremental O&M costs. DRA does not understand that SCE calculated its O&M costs in a manner that reduces its revenue requirement request by approximately $5.658 million. The Commission should therefore reject DRA's recommended disallowance. In addition, the Commission should reject DRA's claim that SCE cannot request "further reimbursements for MRTU costs prior to the end of year 2009" in future ERRA Review applications,[2] because it is directly contrary to the Commission's ratemaking process and the scope of review established for this proceeding.

Below, SCE first discusses the disputed issues in this proceeding and then briefly discusses the uncontested issues. SCE has also included proposed findings of fact, conclusions of law, and ordering paragraphs in Attachment A to this opening brief.

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[2] Exhibit DRA-1, p. 5-6, lines 1-3.

II.

SCE'S RESPONSE TO ISSUES RAISED IN DRA'S REPORT

A. Utility-Retained Generation

DRA claimed that four forced outages (at SONGS Unit 2, Big Creek 3 Unit 1, Mammoth Pool Unit 2, and Four Corners Unit 4) were unreasonable and merit a disallowance of $19.50 million in replacement power costs. SCE addressed DRA's arguments in its written and oral testimony, explaining why these outages were reasonable and also explaining the inherent flaws in DRA's evaluation of these outages and its disallowance methodology. SCE's uncontroverted evidence supports a finding by the Commission that these outages were reasonable under the Commission's relevant standard.

1. SCE Met Its Burden of Proof in This ERRA Review Proceeding

As the applicant, SCE must establish that the outages at issue in this proceeding were reasonable by a preponderance of the evidence.[3] This means showing that its actions (or the actions of its agents) with respect to these outages complied with the Commission's reasonable manager standard. Under this standard:

> [U]tilities are held to a standard of reasonableness based upon the facts that are known or should have been known at the time. The act of the utility should comport with what a reasonable manager of sufficient education, training, experience, and skills using the tools and knowledge at his or her disposal would do when faced with a need to make a decision and act.[4]

SCE clearly met its burden of proof in this proceeding by presenting substantial testimony evaluating each outage under the Commission's reasonable manager standard. That is, for each outage SCE examined the specific decisions made by plant personnel in light of the

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[3] D.10-07-049, p. 4.

[4] Id., p. 13. The Commission also provided a series of guidelines that can be applied to analyzing utility decisions under the reasonable manager standard in pages 14-16 of D.90-09-088.

facts that were known or should have been known at the time the decision was made. SCE then explained why these decisions were reasonable at the time they were made—without the benefit of additional information obtained after the outage event. SCE's evaluation of these outages avoids hindsight bias, adheres to the Commission's established standard for this proceeding, and supports a finding that these outages were reasonable.

DRA, on the other hand, has not met its burden of producing any relevant evidence to support its disallowance recommendations.[5] In its Report, DRA did not evaluate any outages under the Commission's reasonable manager standard; instead, it relied exclusively on selected findings and conclusions contained in SCE's and Arizona Public Service's (APS) after-the-fact cause evaluations. DRA's Report contains simple block quotes or paraphrased findings taken from these evaluations, followed by summary conclusions that plant personnel acted unreasonably. It does not attempt to provide any context for the decisions that were being made or the actions being taken. DRA's superficial and distorted treatment of the facts of the contested outages in this ERRA Review proceeding is completely inappropriate. The Commission expressly stated on page 13 of D.10-07-049 that cause evaluation findings must be evaluated carefully under the reasonable manager standard before drawing conclusions about the prudency of utility actions:

> We recognize the purpose of the [Root Cause Evaluation] as described by SCE. We also recognize that inappropriate actions, root causes, or apparent causes contained in RCEs may not translate directly into unreasonable actions on the part of SCE for the purposes of this [ERRA] proceeding. <u>Such actions or causes must be evaluated in conjunction with the "reasonable manager" standard in determining whether the outage is reasonable or unreasonable for the purposes of this proceeding</u>.

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[5] Although SCE has the burden of proof in this proceeding, this does not mean that DRA is not obligated to provide relevant evidence to support its disallowance recommendations. As noted on page ten of SCE's rebuttal testimony, Exhibit SCE-7, the Commission has held that a party challenging a utility's showing of reasonableness has "the burden of producing evidence in support of such challenge and in support of its adoption of [its] recommended ratemaking disallowance or adjustment . . . ." <u>See</u> D.94-03-050, 53 C.P.U.C. 2d 481, 1994 Cal. PUC LEXIS 221, at *27 (citing <u>Pacific Bell</u>, D.87-12-067, 27 C.P.U.C. 2d, 145 (1987).

In the following sections, SCE summarizes the evidence that has been presented with respect to each of the outages at issue in this proceeding.

2. Nuclear Generation

The Commission should allow SCE to recover all its fuel and purchased power costs associated with SONGS.[6] SCE explained in its direct testimony that both nuclear facilities performed well during the Record Period. Specifically, SONGS Units 2 and 3 generated a combined total of 15,498 MWh, and Unit 3 ran the entire year without an outage.[7] With respect to the single outage in question, DRA is seeking a disallowance based on a 48-hour extension of an outage that DRA admits was otherwise reasonable. As described in greater detail below, this outage involved a valve motor failure of a type that had never happened before at SONGS or any other nuclear facility in the United States. Moreover, the extension of the outage by 48 hours was primarily due to SCE taking a more conservative, safety-minded approach to making the repair. Overall, even with the 48-hour extension, the outage was extended only 18 days, which is an excellent outcome considering the unexpected and unprecedented nature of the failure. Despite such performance, DRA would have the Commission apply what amounts to a strict liability standard to this outage and penalize SCE for taking an approach that reasonably emphasized safety over costs.

In addition to explaining the overall performance of its nuclear facilities, SCE has also presented substantial evidence refuting DRA's use of cause evaluations as the basis for its disallowance recommendations. SCE's expert witness Dr. Bruce Mallett—a former Nuclear Regulatory Commission (NRC) senior executive—explained that DRA's analysis of these

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6 DRA is no longer challenging SCE's costs associated with Palo Verde. Like SONGS, Palo Verde performed well during the Record Period. Indeed, Palo Verde Units 1 and 3 generated 11,589,723 MWh and 9,562,606 MWh, respectively—levels far exceeding their respective five-year averages of 8,022,130 MWh and 8,876,002 MWh. See Exhibit SCE-1 (K. Murray), p. 112, Table VII-33 and VII-34. Palo Verde Unit 2 underwent a refueling and maintenance outage during the Record Period, yet still performed near its five-year average of 9,895,836 MWh, generating 9,509,522 MWh. See id., p. 113, line 18 to p. 114, line 12.

7 Exhibit SCE-1 (K. Murray), p. 107, line 1 to p. 108, line 8. SONGS Unit 2 generated less than its five-year average; however, this was primarily due to the scheduled Refueling/Steam Generator Replacement outage that started on September 26, 2009 and remained in progress at the end of the Record Period.

outages was fatally flawed because it relied exclusively on findings contained in after-the-fact nuclear cause evaluations. Following Dr. Mallett's testimony, SCE's nuclear experts Timothy Clepper, James Peattie, and Clay Williams each explained why the outages being challenged by DRA were reasonable under the Commission's established standard.

Notwithstanding SCE's contrary evidence, DRA continues to argue that nuclear cause evaluations and internal audit reports can—and should—be used to directly assess the reasonableness of nuclear operations. Indeed, at the end of the February 10 hearing in this proceeding, DRA amended its Report to argue that NRC Inspection Reports also can be used to document "imprudent actions" at SONGS.[8] Using these documents as its only evidence, DRA continues to argue that SCE imprudently managed SONGS during the Record Period and that an outage at SONGS Unit 2 was unreasonable. For the reasons set forth below, the Commission should reject DRA's arguments.

a) **<u>Nuclear Cause Evaluations Cannot and Should Not Be Used to Make Direct Assessments Under the Reasonable Manager Standard</u>**

SCE previously explained the purpose and use of nuclear cause evaluations in its April 2009 ERRA Review proceeding, A.09-04-002. In that proceeding, SCE explained that the NRC requires nuclear plant operators to perform stringent, after-the-fact evaluations of events to determine their cause and develop appropriate preventive measures to prevent the event from recurring in the future. Because these evaluations are prepared after the fact and are intended to be self-critical, SCE urged the Commission not to draw a direct correlation between their findings and the reasonable manager standard. SCE's position is summarized on pages 11-13 of the Commission's final decision in that proceeding, D.10-07-049.

The Commission adopted SCE's characterization of these evaluations in D.10-07-049. In its decision, the Commission held that nuclear cause evaluations "can only be used to determine

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[8] Hearing Transcript Vol. 2 (A. Mazy), p. 283, line 23 through p. 284, line 9.

the reasonableness of a plant operator's actions related to a nuclear plant outage, <u>if each of the RCE identified actions or causes is evaluated in light of the 'reasonable manager' standard</u>."[9] This is the appropriate way to use these evaluations in the ERRA Review proceeding. Indeed, the NRC's former Deputy Executive Director of Operations, Dr. Mallett, has testified that the Commission's conclusion is reasonable.[10]

Notwithstanding the Commission's clear instruction in D.10-07-049, DRA continues to treat these evaluations as though they represent direct assessments of the prudency of utility decisions and actions during an outage under the Commission's reasonable manager standard. In its Report, DRA did not evaluate any of these outages under the Commission's adopted standard or in keeping with the Commission's ruling as to the appropriate use of cause evaluations. DRA instead simply copied or paraphrased the findings in SCE's and APS's cause evaluations and then summarily concluded that plant personnel acted unreasonably. As Dr. Mallett observed, DRA's Report "does not provide any detailed, reasoned analysis of the facts against the governing standard."[11] Instead, "DRA appears to simply assume that the conclusions in cause evaluations, developed through hindsight and a one-sided, self-critical analytical process, can be directly translated into findings under the reasonable manager standard."[12] This, of course, is directly contrary to the Commission's ruling in D.10-07-049 and should be rejected.

It is imperative that the Commission clarify—once and for all—that nuclear cause evaluations cannot be used as the sole basis for assessing the reasonableness of nuclear outages in the ERRA Review proceeding. Instead of using cause evaluations to support its disallowance recommendation, DRA should be required to present an analysis of the facts of each outage under the Commission's reasonable manager standard based on what was known at the time decisions were made and actions were taken. Absent such clarification, DRA will continue to inappropriately use cause evaluations as the basis for disallowances as to any outage, regardless

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[9] D.10-07-049, p. 21 (emphasis added).
[10] Exhibit SCE-7 (B. Mallett), p. 14, lines 5-6.
[11] <u>Id.</u>, p. 13, lines 21-22.
[12] <u>Id.</u>, p. 13, line 22 through p. 14, line 1.

of whether or not the reasonable manager standard is violated. Since cause evaluations are designed to understand the events that led to an outage, regardless of what was known at the time of the outage and whether management was reasonable, under DRA's approach every outage would be subject to a disallowance. Because outages happen, regardless of the reasonableness of the actions taken at the time of the outage, disallowances cannot be based on cause evaluations alone. Doing so constitutes a strict liability standard for outage-based ERRA disallowances, which is contrary to the reasonable manager standard.

SCE retained Dr. Mallett to help clarify this issue for the Commission. As his resume shows, Dr. Mallett is fully qualified to offer testimony on this subject.[13] He has over 30 years of experience with the NRC and, as noted previously, recently retired as the agency's Deputy Executive Director for Operations responsible for overseeing all four NRC Regional Offices. Prior to that, Dr. Mallett served as the Regional Administrator for the NRC's Region IV Office (from 2003-2007) and the Deputy Regional Administrator for the NRC's Region II Office (from 2000-2007). Crucially, Dr. Mallett was one of the executive team leaders who led the NRC to revamp its reactor oversight process to enhance its oversight and assessment of licensees' performance toward safe operations. In these positions, Dr. Mallett has implemented NRC policies, evaluated licensee programs, and directed oversight of licensee operations to identify, assess, and see that appropriate corrective actions were taken to improve performance and ensure safe operations.

The scope of Dr. Mallett's testimony in this proceeding covered five areas: (1) explaining the role of cause evaluations in the safe operation of a nuclear power plant; (2) comparing this role to the Commission's reasonable manager standard; (3) evaluating DRA's use of SCE's and APS's nuclear cause evaluations in its Report; (4) explaining the potential negative consequences of the misuse of cause evaluations; and (5) evaluating DRA's use of SCE's internal corporate audit reports. Dr. Mallett's testimony is summarized below.

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[13] For a copy of Dr. Mallett's qualifications and resume, see the "Witness Qualifications" section of Exhibit SCE-7, pp. 1-4.

(1) Cause Evaluations Are a Vital Part of the NRC's Corrective Action Program for Nuclear Power Plants

As Dr. Mallett has explained, the NRC's mandate is to ensure the safe operation of nuclear power plants in the United States.[14] In order to meet this mandate, the NRC considers it "vital" that its licensees have strong corrective action programs in place to identify and fix issues at nuclear power plants.[15] A licensee cannot have an effective corrective action program without performing thorough and complete cause evaluations. Indeed, Dr. Mallett stressed that the NRC routinely reviews its licensees' cause evaluations to ensure they are thoroughly identifying and correcting problems:

> A key part of the NRC's program for evaluation of a licensee's performance is to assess the effectiveness of their corrective action program in identifying and addressing problems. This includes an assessment of how complete, detailed, and critical the licensee's evaluations are. This is so important that the NRC has included review of licensee evaluations and the corrective action programs as a key component of the reactor oversight program. For example, following an occurrence at a nuclear power plant where an after-the-fact analysis is justified, licensees undertake an extensive and time-consuming hindsight investigation of the event to determine whether improvements in actions or in processes can be identified and implemented going forward. The NRC expects, and experience has shown, that evaluations such as these identify lessons learned to help avoid similar or more serious issues in the future.[16]

Dr. Mallett explained that the primary purpose of cause evaluations is to improve safety at nuclear power plants by identifying ways to prevent events from recurring in the future.[17] They are not—as DRA assumes in its Report—intended to judge the reasonableness of decisions

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[14] Hearing Transcript Vol. 1 (B. Mallett), p. 24, lines 14-17.

[15] Id., p. 26, lines 14-15.

[16] Exhibit SCE-7 (B. Mallett), p. 7, lines 8-17.

[17] Id., p. 11, line 24 through p. 12, line 2: "The NRC uses the results from cause evaluations to determine whether the licensee is identifying, correcting, and preventing problems and whether the licensee is protecting the public health and safety by complying with NRC regulations."

made at the time of the event under this Commission's standard.[18] At the January 19 hearing, Dr. Mallett elaborated on the purpose of these evaluations after being asked if they ever consider facts that were known or should have been known at the time of the event:

> Q: Do the cause evaluations ever consider what was known or should have been known by the plant at the time of the event?
>
> A: I'll answer it this way. The cause evaluations, based on my experience in looking at them not only at this facility but others and based upon what the procedures most of these facilities have, look at several parts. They look at the sequence of events that occurred and they looked at the, what might be the causes of those sequence of events or the actions that occurred.
>
> They're looking not so much at the -- whether the decision made at the time was correct. They are looking in hindsight [if there is] a way of preventing the next one. That's the main reason for having the cause evaluations.
>
> If you look in Part 50, Appendix -- I think I called it A before, Appendix B is the correct reference, it talks about looking timely at events to try and understand what the causes were but in the mode of prevention, looking for the next one. So it's not really an -- looking at for the decision at the time made. So although they may cover that, that's not the intent.[19]

Dr. Mallett's testimony makes clear that the NRC expects its licensees to perform cause evaluations as critically as possible in order to find problems and prevent them from recurring in the future. Thus, the Commission should conclude that it is neither fair nor appropriate to use a licensee's cause evaluation against it in a prudency proceeding absent any relevant evidence, such as an expert's evaluation of the facts of the outage under a standard of reasonableness.

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[18] Id., p. 12, lines 2-3: "The NRC does not use cause evaluations as evidence to assess whether any particular outage was reasonable or prudent."

[19] Hearing Transcript Vol. 1 (B. Mallett), p. 28, line 9 through p. 29, line 6.

(2) <u>The NRC's Regulatory Standards Are More Stringent Than the Commission's Reasonable Manager Standard</u>

For this proceeding, SCE asked Dr. Mallett to review the Commission's reasonable manager standard and compare it to the NRC's requirements for nuclear power plant operators.[20] In SCE's rebuttal testimony, Dr. Mallett summarized the Commission's decisions articulating the reasonable manager standard, and observed that "based on the guidelines listed, the crucial question is whether the [utility's] actions were made with prudence and logic, based on the information at hand when faced with a need to make the decision."[21] He then contrasted the reasonable manager standard with the NRC's expectation that licensees "perform thorough cause evaluations and correct problems to improve performance and prevent potential future safety issues."[22] With this critical distinction in mind, Dr. Mallett clarified why it is inappropriate to argue that isolated passages from cause evaluations describing "inappropriate actions" or "causes" evidence unreasonable actions:

> Cause evaluations conducted by nuclear power plant licensees are not simply after-the-fact reviews, but are intended to be self-critical and one-sided. The NRC expects licensees to rigorously identify deficiencies, including contributing causes, so that a problematic occurrence is not repeated. The descriptions of "inappropriate actions" or "causes" are not evenhanded assessments of the reasonableness of a particular decision, but are focused on any event or action that now, in retrospect, can be seen to have contributed to a problem. For example, the SONGS procedure governing the preparation of RCEs requires the RCE Team Leader to "[c]ompare causes and actions found in internal and external operating experience to the circumstances of the current problem to look for past missed prevention opportunities or to consider mimicking proven successful preventive actions." In other words, the authors of a RCE are required to use both time and information not available to the managers at the time of an event to second-guess the decisions of individuals involved, so that

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[20] <u>Id.</u>, p. 21, lines 3-11.
[21] Exhibit SCE-7 (B. Mallett), p. 10, lines 8-9.
[22] <u>Id.</u>, p. 10, lines 16-17.

> it might be prevented in the future. Thus, it is neither fair nor logical to assess the reasonableness or prudence of a utility's decisions regarding an outage by referencing isolated passages from a cause evaluation. The NRC uses the results from cause evaluations to determine whether the licensee is identifying, correcting, and preventing problems and whether the licensee is protecting the public health and safety by complying with NRC regulations. The NRC does not use cause evaluations as evidence to assess whether any particular outage was reasonable or prudent.[23]

DRA does not give any consideration to the purpose and use of nuclear cause evaluations as articulated by Dr. Mallett or as recognized by the Commission in D.10-07-049. Rather, as explained in the following section, DRA continues to try and draw a direct correlation between intentionally self-critical conclusions in these evaluations and assessments under the Commission's reasonable manager standard.

(3) DRA Continues to Improperly Draw a Direct Correlation Between Cause Evaluations and the Reasonable Manager Standard

Dr. Mallett examined the cause evaluations for the outages being challenged by DRA and found them to be generally thorough and consistent with the NRC's expectations and regulatory requirements.[24] He also reviewed DRA's use of these evaluations in its Report, and explained that DRA was not using these evaluations appropriately in this ERRA Review proceeding:

> The DRA Report provides only selected quotations from the conclusions of cause evaluations to claim that four outages at SONGS and Palo Verde could have been foreseen and prevented, and were therefore unreasonable. In general, DRA's discussion of each outage consists of simple block quoting or paraphrasing of SONGS and Palo Verde documents without any explanation of context. The Report does not acknowledge that cause evaluations are fundamentally based on an after-the-fact analysis and are not

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[23] Id., p. 11, line 11 through p. 12, line 3.
[24] Id., p. 13, lines 8-9.

> contemporaneous reflections of what management knew or should have known at the time. DRA also does not explain why it should be acceptable to use after-the-fact analyses to evaluate facts against the reasonable manager standard. Following a recount of selected and disjointed quotations, DRA concludes each section on an outage event by simply announcing that it is "clear" that SCE's actions were imprudent. DRA's Report does not provide any detailed, reasoned analysis of the facts against the governing standard. DRA appears to simply assume that conclusions in cause evaluations, developed through hindsight and a one-sided, self-critical analytical process, can be directly translated into findings under the reasonable manager standard. As the Commission recognized in last year's ERRA decision, this superficial use of cause evaluations is inappropriate.[25]

As noted above, the Commission has already rejected the notion that cause evaluation findings can be directly equated to assessments under the reasonable manager standard. DRA, however, ignores this decision and continues to proceed as if these findings can be directly interpreted as judgments regarding the prudency of utility actions. As a result, DRA's Report provides no relevant, credible evidence for the Commission to use in assessing the reasonableness of nuclear outages. Because DRA refuses to acknowledge the purpose of cause evaluations as explained by Dr. Mallett and previously recognized by this Commission, SCE requests that the Commission reject DRA's disallowance recommendations and clarify that cause evaluations cannot be used in the superficial manner advocated by DRA.

(4) Misusing Nuclear Cause Evaluations in the ERRA Review Proceeding Could Be Detrimental to Nuclear Safety Culture

Nuclear safety considerations also warrant the Commission's rejection of DRA's superficial treatment of cause evaluations in this ERRA Review proceeding. Dr. Mallett has testified that DRA's attempt to base its disallowance recommendations exclusively on self-critical statements in cause evaluations is directly at odds with the NRC's effort to promote a strong nuclear safety culture by encouraging its licensees to perform thorough and self-critical

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[25] Id., p. 13, line 12 through p. 14, line 2 (emphasis original).

evaluations.[26] He noted at the January 19 hearing that the NRC "has raised for years"[27] its concern that State public utility commissions should not use nuclear cause evaluations in this simplistic manner because it could have a chilling effect on licensees' corrective action programs, and offered the following example:

> A: If you take a position that because somebody did a thorough cause evaluation and a very critical one of themselves, which is what the NRC expects them to do to learn, if you took that on the surface of that statement and simply said that means they're a poor performer or that means that they -- against reference to the reasonable manager standard that it's unreasonable, it might cause a problem in future evaluations where people wouldn't provide all of the information that you need in these cause evaluations.
>
> A predication of these is that people will come forth and talk about all the type things that could be anticipated as a reason for the event to have occurred or the issue. And if you -- you may chill that or cause them to not bring that forward, they may just -- if they think that that's going to be used against them later. That makes sense.
>
> It's really -- what I was trying to say is that, you use the example that, would I expect that people would operate the facility unsafely, in my words. No. I would expect they would always operate it safely. But what I was referring to here, it could serve as a disincentive to people talking about out-of-the-box issues or thinking to try and get to the best way of preventing this from occurring in the future.[28]

As an example of the NRC's efforts to raise awareness of this issue, Dr. Mallett cited the NRC's 1991 Policy Statement on the "Possible Safety Impacts of Economic Performance Incentives." The Policy Statement is included in Dr. Mallett's prepared testimony and states the NRC's concern:

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[26] Id., p. 14, lines 12-21: "[DRA's] approach takes the robust, self-critical safety culture that has been carefully fostered throughout the commercial nuclear industry and employs it directly against the licensee. The NRC has long been concerned [about] this approach . . . ."

[27] Hearing Transcript Vol. 1 (B. Mallett), p. 50, lines 15-21.

[28] Id., p. 51, line 6 through p. 52, line 9.

> about any State public utility commission's undue reliance on a utility's corrective actions following an incident to justify the disallowance of costs related to the incident. . . .
>
> For example, where a State public utility commission observes that a utility has modified its procedures following an incident, infers from the utility's actions that the original procedures must have been inadequate, and then disallows certain costs on the basis of such inadequacies, the utility will have a strong disincentive voluntarily to enhance or improve its operations and procedures in the future. Such State public utility commission action can discourage utilities from making needed improvements in procedures and operations and, thus can be detrimental to the long-term safety of operations.[29]

Based on the foregoing safety considerations, Dr. Mallett encouraged the Commission to reject DRA's simplistic approach to using nuclear cause evaluations in this proceeding. As Dr. Mallett explained, the Commission's adoption of DRA's approach would be a distortion of the fair use of cause evaluations and could have a negative impact on what has been a robust nuclear safety culture.

(5) SCE's Internal Audit Reports Are Irrelevant to the SONGS Outages Being Reviewed in This Proceeding

In its Report, DRA attempted to buttress its disallowance recommendations for SONGS outages by citing self-critical findings in three SCE internal audit reports regarding the following SONGS programs: 1) performance of the Nuclear Oversight Division; 2) the Confined Space Program; and 3) the Corrective Action Program. DRA has not, however, explained how these documents demonstrate unreasonable actions taken in regards to the SONGS outages that it challenged in this proceeding. Nor can it. Dr. Mallett reviewed each of these audit reports on pages 15-19 of Exhibit SCE-7 and showed that they have absolutely no connection to these outages.

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[29] Exhibit SCE-7, p. 15, lines 1-12.

DRA tries to circumvent this fact by arguing in its Report that the self-critical findings in these audits evidence "less than desirable conclusions"[30] and show "that SCE had imprudently allowed management systems within SONGS to deteriorate."[31] As with its discussion of cause evaluations, DRA merely provides selective block quotes of these findings and then—again without providing any supporting analysis—summarily concludes that they evidence imprudent actions. Dr. Mallett explained that this is a completely inappropriate way to use these documents, and urged the Commission not to adopt DRA's approach because it could have a chilling effect on the internal audit process:

> Like the nuclear cause evaluations discussed above in Section B, SCE's internal audits represent the results of the company's efforts to carefully critique and improve its performance. As indicated in Section B, these type of audits are vital to operation of nuclear power plants with a focus on safety and finding and correcting problems. DRA reviewed the results of SCE's frank and candid efforts to improve its performance, selectively identified various self-critical statements, and now uses those unrelated statements—divorced from their original context—to indicate that the audit report findings "buttress" the conclusion that notable management issues at SCE led directly to the two outages at SONGS. SCE's own statements are the <u>only</u> evidence of alleged imprudence that DRA presents. DRA acknowledges this point in its own Report when it states that, "DRA is indebted to SCE's Audit Services Department for conscientious documentation of ongoing problems associated with SCE's management of its retained generation facilities." If the Commission were to accept DRA's use of the audit reports to make general conclusions without showing a direct relationship to the outages, utilities would be discouraged from conducting thorough internal audits due to concerns that the text of audit reports will later be taken out of context and used against them in a proceeding.[32]

It is important for the Commission to reject DRA's disallowance recommendations and clarify that it is inappropriate to use internal audit reports to justify disallowances in this ERRA

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[30] Exhibit DRA-1, p. 2-23, line 12.
[31] <u>Id.</u>, p. 2-24, lines 21-22.
[32] Exhibit SCE-7 (B. Mallett), p. 16, line 12 through p. 17, line 1.

Review proceeding without first drawing a direct connection between the audit reports and the specific outages under review and evaluating the findings in these reports under the reasonable manager standard. As Dr. Mallett testified, licensees' internal audit reports—like cause evaluations—are part of the overall effort to carefully critique and continually improve performance at nuclear power plants. He explained that the NRC considers audit reports to be "vital" to the safe operation of nuclear power plants, and encourages licensees to be frank and candid in their assessments in these reports.[33] The Commission should acknowledge the importance of internal audit reports as stated by Dr. Mallett, and summarily reject DRA's superficial treatment of these documents.

(6) NRC Inspection Reports Do Not Contain Judgments Under the Commission's Reasonable Manager Standard

At the conclusion of the February 10 hearing, DRA sought to amend its Report to introduce, as an additional exhibit, the NRC's May 4, 2009 Inspection Report for SONGS.[34] In its amended testimony, DRA claims that this NRC inspection report documents "all of [the] imprudent actions" taken in regards to the December 28, 2009 outage at SONGS Unit 2.[35] SCE could have objected to DRA's attempt to introduce a new exhibit at the conclusion of the hearings, nearly a month after SCE's expert nuclear witnesses had been excused, but elected not to do so. Dr. Mallett's testimony in this proceeding clearly shows that that these inspection reports, like nuclear cause evaluations, cannot be used by DRA as a substitute for analyzing specific outages under the reasonable manager standard.

Dr. Mallett has explained that the NRC's regulatory mandate is to ensure safe operations at nuclear power plants and that its requirements and expectations are more stringent than the Commission's reasonable manager standard. With this distinction in mind, Dr. Mallett stressed

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33 Id., p. 16, lines 13-15.
34 Hearing Transcript Vol. 2 (A. Mazy), p. 283, line 23 through p. 284, line 9.
35 Id.

that the Commission should not draw conclusions about the reasonableness of utility decisions based solely on the findings and conclusions in NRC documents. Dr. Mallett's testimony demonstrates that there is no absolutely no basis for DRA to summarily conclude that findings in NRC inspection reports document "imprudent actions" at SONGS without any further support. Indeed, the NRC makes clear in the first page of its May 2009 Report that it is not conducting a prudency assessment of plant personnel's actions at SONGS by stating that its inspectors "examined activities conducted under [SCE's] license as they relate to <u>safety and compliance with the [NRC's] rules and regulations and with the conditions of [SCE's] license</u>."[36] The DRA Report does not acknowledge this statement of purpose.

SCE is troubled by DRA's continued attempts to base disallowance recommendations for SONGS and Palo Verde on findings taken directly from NRC documents and documents prepared to meet NRC requirements, without providing any supporting analysis under the Commission's reasonable manager standard. SCE's burden of proof in this proceeding does not excuse DRA from explaining to the Commission why the outages that it is challenging are unreasonable under the Commission's reasonable manager standard, beyond simply quoting from various documents created for entirely different purposes. SCE's nuclear witnesses should not continually be forced to devote substantial time and effort to evaluating each of DRA's numerous cut-and-pasted cause evaluation findings—findings that were developed as intentionally self-critical, hindsight-based conclusions under the unique standards of NRC safety regulations—under the reasonable manager standard, and explaining why plant personnel actions with respect to these findings were prudent. SCE therefore urges the Commission to reject DRA's disallowance recommendations and clarify that DRA cannot rely solely on these documents to recommend disallowances in this proceeding, and that instead DRA must support its disallowance recommendations with an evaluation of the facts under the Commission's reasonable manager standard.

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36 Exhibit DRA-7, p. 1 (emphasis added).

b) The December 28, 2008 Outage at SONGS Unit 2 Was Reasonable

On December 28, 2008, SONGS Unit 2 was manually shut down for a scheduled 30-day mid-cycle outage.[37] The purpose of this outage was to complete pressurizer dissimilar metal weld overlays, in order to meet SCE's commitments to the NRC, as well as other maintenance work.[38] SCE follows a rigorous planning process for these outages, usually beginning preparations approximately two years in advance.[39] During this time, plant personnel engage in such tasks as writing maintenance orders, training and qualifying personnel, building equipment, performing necessary testing, and developing an accurate outage schedule.[40]

As Unit 2 was shutting down, the drive motor of the control element drive mechanism (CEDM) #22 unexpectedly malfunctioned and had to be replaced.[41] Each CEDM lifts and lowers one control element assembly (CEA) to safely shut down (or start) a unit. There are 92 CEDMs and CEAs per unit at SONGS,[42] and they have a life expectancy of 40-45 years.[43] Similar motors are installed at approximately seven other plants in the United States, and these motors—which are designed to not require periodic maintenance—<u>had not experienced any motor-related failures prior to this incident</u>.[44] As Mr. Clepper explained, although SCE does account for emergent work when preparing for planned outages at SONGS, it simply could not have foreseen (much less prepared or accounted for) a major equipment problem such as this one.[45]

The failure of CEDM #22 presented unprecedented challenges to SCE's outage team, who now had to add the safe replacement of the drive motor for CEDM #22—a major reactor

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37 Exhibit SCE-1 (K. Murray), p. 110, lines 2-3.
38 <u>Id.</u>, p. 110, lines 3-7.
39 Hearing Transcript Vol. 1 (T. Clepper), p. 68, lines 7-22.
40 <u>Id.</u>
41 Exhibit SCE-7 (T. Clepper), p. 20, lines 14-17.
42 Exhibit SCE-1 (K. Murray), p. 110, lines 9-11
43 Exhibit SCE-7 (T. Clepper), p. 20, line 26.
44 <u>Id.</u>, p. 20, line 26 through p. 21, line 3.
45 Hearing Transcript Vol. 1 (T. Clepper), p. 70, lines 10-14: "You do not allow this planning process for a major equipment failure that's never occurred anywhere in the industry before. There would be no reason to plan for that as…one of your contingencies."

component—to the already significant list of planned tasks for the outage. Mr. Clepper explained the extensive efforts that the outage team took to plan and organize replacement of the motor:

> This equipment failure occurred on the day we were shutting down the plant, not two years earlier when we started planning for this outage but on the day we shut down. At that point that day, we start responding to this failure. And our response is using the same people who are now in the process of executing an outage safely, correctly and efficiently that we've planned for two years. And we have to now incorporate the planning, safely, correctly and efficiently repairing, replacing this CEDM drive motor which is a major reactor component and takes a great deal of effort to plan, coordinate, contract for services, build mock-ups, training people, qualifying people, build new equipment, test that equipment, so forth. And we're doing that at the same time we're executing the outage that we've taken two years to plan.[46]

As this work had never been done before, it was not possible for SCE or its contractors to say with certainty how long it would take to replace the drive motor and safely restart Unit 2.[47] They developed an ambitious plan for this work and expected an outage extension of approximately 16 days. SCE came close to meeting this ambitious schedule and completed the work in 18 days. SCE needed an additional 48 hours to evaluate and safely repair the vent valve for CEDM #22, which began leaking after the unit was pressurized and in the startup mode.

Because the unit was in the startup mode, it would have been acceptable for SCE to have seal welded the leak shut and resumed start-up activities for Unit 2. Indeed, at the January 19 hearing Mr. Clepper noted that the vent valves had experienced leaks in the past and had been seal welded by SCE.[48] This would have reduced a substantial portion of the 48-hour delay to bring Unit 2 back online.[49] However, as it had never performed this specific CEDM motor

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[46] Id., p. 70, line 15 through p. 71, line 6.

[47] Id., p. 71, lines 7-20: Mr. Clepper described the outage schedule as an "educated guess" and noted that "since nobody's ever done [this repair] before, you don't really know exactly how long things are going to take."

[48] Id., p. 28, line 28 through p. 113, line 15: "So at other plants, even at [SONGS], an acceptable method to prevent that leak or to stop that leak is to go in and do a seal weld on the top of the valve and then just go ahead and start up the plant and then cut that weld and fix it later when you do another outage."

[49] Exhibit SCE-7 (T. Clepper), p. 25, lines 3-5.

repair before, SCE determined that it was in the best interest of nuclear safety to drain the reactor coolant system and investigate the source of the leak.[50] SCE's investigation revealed that the steel ball in the vent valve had been left on top of the valve stem for foreign material exclusion (FME) purposes, instead of in its final configuration position under the valve stem. SCE reassembled the vent valve and proceeded to safely restart the unit.

Consistent with its commitment to nuclear safety, SCE performed a cause evaluation to determine the root and contributing causes of this incident and define corrective measures. The cause evaluation notes that a first line supervisor thought he had been instructed to install the ball, o-ring, and housing nut for FME purposes only—not to perform final reassembly of the vent valve.[51] The cause evaluation states that this occurred towards the end of the night shift and after Westinghouse had finished welding activities on CEDM #22.

As Dr. Mallett has explained, cause evaluations are intended to be highly self-critical in order to identify lessons learned and prevent events from recurring in the future. SCE's cause evaluation of this event is no different—it is critical of many steps that led to the vent valve leak, including the supervisor's decision to install the ball, o-ring, and housing nut for FME purposes. This does not, however, mean that the first line supervisor's decision was unreasonable at the time it was made. Indeed, Mr. Clepper noted that the first line supervisor's function in containment that evening was to be the refueling group FME supervisor.[52] Mr. Clepper also explained that there is no "right or wrong" way to install the ball, o-ring, and housing nut for FME purposes only, and that placing the ball on top of the vent valve stem for FME purposes is a good practice to prevent the ball from being damaged.[53] In Mr. Clepper's opinion, the first line

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[50] Hearing Transcript Vol. 1 (T. Clepper), p. 112, lines 25-27: "The decision to not weld the valve was made from more of a nuclear safety standpoint." See also, p. 113, lines 19-25: "We needed to fully understand what the cause of this leak was rather than just going in and making a weld repair, because a weld repair is something you would do when you are quite certain that it is the little ball that is causing the problem."

[51] ACE Assignment 800245890, attached as Appendix D to Exhibit SCE-8.

[52] Hearing Transcript Vol. 1 (T. Clepper), p. 101, lines 22-24: "[h]is function in containment that evening was to be the refueling group FME supervisor. So his job was FME that evening."

[53] Id., p. 102, lines 1-10: Mr. Clepper noted that the Bechtel craftspeople who did the FME work on the valve "had very good knowledge of the valve" and that it was his belief that the craftspeople understood "that if they

Continued on the next page

supervisor was reasonably acting within the scope of his assigned responsibilities and in the best interests of nuclear safety by ensuring that the vent valve was properly protected from foreign material.[54]

The Commission should not impose a disallowance for this outage simply because it was extended two days beyond SCE's original estimated schedule, and solely based on findings in its self-critical cause evaluation regarding the vent valve leak. At the January 19 hearing, Mr. Clepper emphatically stated that it was a "huge success" for the outage team to have safely and correctly accomplished this major emergent component repair within just two days of the 16-day estimated schedule.[55] He said that SCE "met the requirements for good planning, excellent response to an emergent activity, and very good overall management of the work."[56]

Mr. Clepper is well-qualified to evaluate the overall reasonableness of this outage for the Commission. [57] As he explained at the January 19 hearing, he has over 30 years experience in the nuclear industry, and began his career in the United States Navy Nuclear Power Program as a reactor operator and electronics technician. He has held numerous supervisory roles at SONGS and is currently the plant's outage manager. In addition, he is just one of a small number of managers to have supervised the decommissioning of a large-scale nuclear power plant in the U.S.[58]

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put the ball on the seat and tightened it down for FME purposes, that they could damage the ball and cause it to leak at a later point in time."

[54] Id., p. 96, lines 18-27: "So when [the first line supervisor] thought he was being given a request to close this valve for [FME], in his mind that was a reasonable request. The work—the welding work was done for the day. There was no reason to have this component open at the time. So he was closing it for foreign material exclusion purposes. He was maintaining nuclear safety of the plant by doing so, in his mind." (Emphasis added)

[55] Id., p. 71, lines 21-26.

[56] Id., p. 76, lines 4-7.

[57] See "Witness Qualifications" Section of Exhibit SCE-7, p. 5. Mr. Clepper also discussed his extensive qualifications at the January 19 hearing beginning at p. 71, line 27 and continuing to p. 72, line 16.

[58] Hearing Transcript Vol. 1 (T. Clepper), p. 72, lines 10-12. Although the number of managers to have decommissioned a large-scale nuclear power plant in the U.S. is small, it is greater than three as Mr. Clepper indicated at the January 19 hearing. What Mr. Clepper intended to state at the hearing was that only three plants have been decommissioned, at SONGS, Maine Yankee, and Connecticut Yankee.

In summary, SCE's overall actions in completing emergent repairs to the CEDM #22 drive motor within 18 days were a "huge success" and therefore well within the spectrum of reasonableness. Based on Mr. Clepper's testimony, the Commission should be pleased with how SCE's outage team handled this unusually complex, first-of-its-kind event and reject DRA's ill-considered recommended disallowance for this outage.

3. Hydroelectric Generation

Approximately 86% of SCE's hydro generation is provided by SCE's Northern Hydro Division.[59] The precipitation levels recorded in 2009 in Northern Hydro were only 83% of a normal year. Precipitation levels in 2008 were even lower, with run-off of only 64% of normal.[60] Notwithstanding two consecutive years of below-average precipitation levels, SCE's hydro generation during the Record Period was over 90% of the long-term historic annual average. Specifically, SCE's hydro plants generated approximately 3,828,000 MWh in 2009 compared to a long-term historic average of approximately 4,234,000 MWh.[61]

SCE submits that the foregoing demonstrates that it appropriately managed its water resources during the Record Period. DRA, however, ignores these production statistics and claims that two extended outages that occurred on two of SCE's hydro generating units, Big Creek 3 Unit 1 and Mammoth Pool Unit 2, were unreasonable. The Commission should reject DRA's recommended disallowances for these outages. As explained below, the evidence in this proceeding shows that both outages were reasonable.

a) The Big Creek 3 Unit 1 Outage of December 14, 2008 Was Reasonable

DRA recommends a $10.2 million disallowance for replacement power costs associated with the Big Creek 3 Unit 1 outage on December 14, 2008 that occurred when the unit "tripped" (i.e., automatically disconnected from the grid) after the differential protection circuitry detected

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[59] Exhibit SCE-1 (A. Kurpakus), p. 42, line 19.
[60] Id., p. 50, lines 13 to 15.
[61] Id., p. 43, Table III-5.

an electrical fault.[62] The after-the-fact Incident Investigation Report (Report) identified that it had rained the day prior to and at the time the electrical fault occurred, and that "weather conditions were wet with moist air and fog in the canyon."[63] As a result of the fault, the Unit 1 generator stator windings required rewinding and the 15 kV transfer switch (switch) was damaged and removed from service. SCE was not able to determine precisely where or why the electrical fault first occurred, but identified two possible initiating events: (1) an electrical fault initiated in the 15kV transfer switch; or (2) an electrical fault initiated in the generator.[64] The evidence presented in this proceeding supports the conclusion that SCE plant personnel acted reasonably at all times related to the instant outage. DRA has not proffered any credible evidence in support of a contrary finding.

The switch that faulted was specified and installed for outdoor service in the 1970s.[65] For personnel protection,[66] the switch is located within a seven feet tall 15 kV switch cabinet.[67] The cabinet is one of many pieces of equipment that is surrounded by a much larger oil containment barrier (i.e., a low curb) covering a fairly large area. That barrier was installed in the early 1990s around the perimeter of the equipment pursuant to regulatory requirements governing oil spill prevention.

The Report indicates the fault may have initiated in the switch based on the fact that the switch's insulation appeared to be compromised and there was evidence of partial discharge tracking on unfaulted insulators.[68] It is unknown whether the noted damage was present before

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62 Hearing Transcript Vol. 2 (A. Kurpakus), p. 261, lines 3-5 (A. Kurpakus) ("'Fault' generally refers to when electricity goes to ground and causes an outage.").

63 Exhibit SCE-8 (A. Kurpakus), Appendix L.

64 Exhibit SCE-7 (A. Kurpakus), p. 69, lines 13-16.

65 Id., p. 67, lines 14-15; p. 68, line 19 through p. 69, line 3.

66 See Hearing Transcript Vol. 2 (A. Kurpakus), p. 263, lines 12-25: Mr. Kurpakus explained that the cabinet was not designed to be waterproof: "[T]his switchgear could be out in the rain if you wanted it to be. [It] was designed really to keep personnel away."

67 Id., p. 206, lines 5-17: Mr. Kurpakus testified that the cabinet was designed to provide a level of protection from outdoor elements, "but that's not its main function." Id., p. 201, line 23 through p. 202 line 9: "The [containment area]. . . [is] probably ten or 20 times larger than the size of the cabinet . . . It includes the transformer for the station light and power equipment and other large step-down transformers."

68 Exhibit SCE-8, Appendix L.

the fault and contributed to its occurrence or appeared because of the fault itself.[69] Five months earlier the switch was operated during testing of an emergency generator. If obvious compromise or corrosion were present at this time, such degradation would have been repaired.[70] However, absent obvious degradation, personnel had no basis to conclude that the insulation needed repair or replacement. It was suspected here that final electrical failure of the switch was the result of moisture leaking into the switch as a result of the rainstorm. The rainstorm made it easier for water to leak along the length of the electric cables into the switch cabinet, and those leaks might have accelerated a final insulation failure in power grid electrical equipment nearing the end of its service life.[71]

After the rainstorm, one inch of standing water was measured in the cabinet three to four feet below the switch and other energized elements.[72] As a matter of practice, standing water that accumulated in the containment area would have been drained as soon as practicable following a rainstorm.[73] The switch had obviously been subjected to other rainstorms and fog episodes since it was installed in the 1970s and since the oil containment curbs were installed in the 1990s.[74] Personnel understood that, as with all outdoor electrical equipment, fog and rainstorm episodes could contribute to the switch's overall long term degradation. However, large portions of the power grid must be located outdoors because of economic necessity.[75] SCE personnel had no record prior to this event that standing water had ever been present in the

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69 See Hearing Transcript, Vol. 2 (A. Kurpakus), p. 190, line 19-26: "[I] t isn't even certain that this switch was the component that caused . . . the failure. It's possible that this evidence appeared because of the event itself."

70 Exhibit SCE-7 (A. Kurpakus), p. 73, lines 11-13; Hearing Transcript, Vol. 2 (A. Kurpakus), p. 190, lines 1-28.

71 Id., p. 69, lines 1-11.

72 See Hearing Transcript Vol. 2 (A. Kurpakus), p. 169, line 24 through 170, line 4; Exhibit SCE-7 (A. Kurpakus), p. 70, lines 11-13; and, Appendix M to Exhibit SCE-8, SCE Response to DRA-SCE-20, Question 20.1.4.

73 Id., p. 167, lines 22-27: "After rainfall events, the water is drained from the containment area and therefore it is removed from the cabinet . . . ." See also Exhibit SCE-7 (A. Kurpakus), p. 72, lines 1-3.

74 See Hearing Transcript Vol. 2 (A. Kurpakus), p. 264, lines 23-25.

75 Exhibit SCE-7 (A. Kurpakus), p. 69, footnote 112.

cabinet before[76] and had no reason to believe that this particular switch would fail during this particular rainstorm.[77]

Personnel also recalled an event in the switchgear cabinet in 1988-89, but there is no basis to conclude that lessons learned from that event could have been used by plant personnel as a means to prevent the instant outage.[78] Additionally, the repair and replacement work following the 1988-89 event was performed in a satisfactory manner given that the switch then operated for twenty years without any known problems.[79]

Finally, the generator stator that faulted was known to be approximately thirty years old and its windings were scheduled to be replaced in 2012. It is suspected that the switch faulted first, which caused an electrical fault that resulted in the generator also faulting.[80] In December 2007, the Unit 1 generator was inspected, passed operability testing, and was expected to operate through the time for its planned rewind. There is no basis to conclude that SCE could have done anything other than maintain, test, and operate the generator consistent with its historic practices to prevent this outage. The evidence presented has shown that personnel actions taken before, during, and after the outage in maintenance, inspection, and operation of the equipment at issue were prudent, reasonable, and consistent with standard practices at hydroelectric plants.

b) **The Mammoth Pool Unit 2 June 2008 Outage Was Reasonable**

DRA recommends a $7.7 million disallowance for the Mammoth Pool Unit 2 outage of June 2008, which occurred when SCE determined that the unit's 18-year-old stator windings required rewinding after they failed a high potential (HiPot) integrity test.[81] The HiPot test

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[76] See Hearing Transcript Vol. 2 (A. Kurpakus), p. 264, lines 23-25.
[77] See id., p. 264, lines 23-25.
[78] Exhibit SCE-7 (A. Kurpakus), p. 72, line 4 through p. 73, line 2.
[79] Id.; See also Exhibit SCE-8, p. 71, line 20 through p. 72, line 1 (explaining that the switch, installed in the 1970s, had been exposed to the elements long before the oil containment curb was installed).
[80] Id.
[81] The test followed a planned outage for a turbine overhaul, stator winding cleaning, and other work.

followed a scheduled turbine overhaul, stator cleaning, and other work.[82] The two after-the-fact investigation reports of this incident[83] make clear that thermal aging (being subjected to operating temperatures over long periods of time) and thermal cycling (being subjected to repeated heating and cooling cycles) were the major contributors to the stator's HiPot test failure, but their precise effect on stator life expectancy is unknown.[84] The typical lifespan of windings is approximately thirty-years, but this average can vary significantly due to factors outside plant personnel's control.[85] All actions taken by plant personnel related to this event were prudent, reasonable, and consistent with the plant's historic operating and maintenance practices.

Unit 2 has been operating since 1960 and was rewound in 1980 as part of an up-rating from approximately 65 MW to 95 MW.[86] To allow for higher operating temperatures inherent in the up-rated MW output,[87] the winding insulation was increased from Class B (130˚C maximum operating temperature) to Class F insulation (155˚C maximum temperature rating).[88] The effects of thermal aging increase at a higher rate whenever temperatures exceed 90˚C, but the winding manufacturer <u>recommended</u> an operating temperature of 100˚C on hot days to achieve the longest winding life, while accommodating production needs.[89]

The operator's choice to run at greater than 100˚C temperatures on some seasonal peak days was necessary[90] to increase generation production and capture more excess bypass water flow at this Mammoth Pool location, which typically experiences more spilled water than other

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82 Exhibit SCE-7 (A. Kurpakus), p. 76, footnote, 133. (In this vertically oriented unit, "the generator stator is located directly above the turbine, so stator cleaning was not possible during the turbine overhaul work.")

83 <u>See</u> SCE's Northern Hydro Region, "Stator Winding Failure Executive Summary," attached as Appendix O to Exhibit SCE-6 (SCE Summary Report); <u>see also</u> Voith Hydro, "Assessment of the Stator Coils Taken from the Unit Prior to Rewind in 2009," attached as Appendix P to Exhibit SCE-6 (Voith Report).

84 Exhibit SCE-7 (A. Kurpakus), p. 79, lines 5-6.

85 <u>Id.</u>, p. 76, lines 15-17.

86 <u>See</u> Appendix S to Exhibit SCE-8, SCE Responses to DRA-SCE-20, Question 20.1.5.

87 Exhibit SCE-7 (A. Kurpakus), p. 79, lines 5-6.

88 <u>See</u> Appendix Q to Exhibit SCE-6, SCE Responses to DRA-SCE-20, Questions 20.1.7 and 20.1.8.

89 Exhibit SCE-7 (A. Kurpakus), p. 79, lines 5-23.

90 Mr. Kurpakus explained that operating temperature chosen is dictated by "market demands. . . . [W]hat makes sense one day may differ from another day depending on supplying the market. And it becomes a balancing act between running the equipment and supplying energy that's required by Cal ISO versus exactly what temperature we run the equipment at." Hearing Transcript Vol. 2 (A. Kurpakus), p. 232, lines 1-14.

Big Creek powerhouses.[91] Thus, in the early to mid-1990s, Unit 2 may have run at 110-115˚C on some hot summer afternoons when operating at or near full-rated load.[92] For the majority of the time, however, the unit operated at much lower temperatures during those same years on non-peak days.[93] While the stator coils might have lasted longer had SCE chosen to operate below 100˚C at all times (there is no evidence to confirm this), the lower temperature certainly would have reduced the MWh output to the detriment of SCE's customers.[94]

SCE had no reason to conclude that the generator windings were approaching the end of their service life, possibly as a result of maximizing production to accommodate grid needs during peak demand in the early to mid-1990s. In fact, the opposite is true. HiPot integrity tests were performed in conjunction with other detailed inspections in 1993, 1996, and 2003 and did not raise any concerns regarding the remaining life expectancy of the windings.[95] Moreover, while there were two prior winding failures that were due to manufacturing defects of the windings in 1983 and 1990, respectively, there was no relationship between these incidences and the instant 2008 winding failure.[96] Indeed, SCE retained Westinghouse Electrical Corporation to conduct an electrical and mechanical study on the generator components in connection with the 1980 up-rating and was provided no information that would lead SCE to conclude that winding life would not be generally consistent with the typical life expectancy of windings at other Big Creek units.[97] SCE had no historical or practical basis to conclude that the windings would fail at the point they did or that unanticipated heat-related damage was occurring to the coils.[98]

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91 Exhibit SCE-7 (A. Kurpakus), p. 79, lines 10-12 and p. 80, lines 7-10. See also, Id., p. 81, lines 8-18 (explaining tradeoff between maximized production output achievable through higher operating temperatures on hot days or when operating at or near full rated output and potentially reduced equipment life).

92 Id., p. 79, lines 3-7; "As the generators are cooled with ambient air, generator stator operating temperature increases in approximate direct proportion to ambient air temperature. For a given generator, it also increases as a function of generator MW output. It was the differences in these two key factors . . . that caused the temperatures to be higher in the early to mid-1990s compared to subsequent years." Id., p. 80, lines 1-5.

93 Exhibit SCE-7 (A. Kurpakus), p. 81, lines 3-18.

94 Id., p. 81, lines 3-18.

95 Id., p. 76, lines 11-21.

96 Id., p. 76, lines 12-21.

97 Exhibit SCE-9 (A. Kurpakus), p. 1: Westinghouse concluded that the new winding installed as a result of the up-rating could be estimated to have "an expected life of five times that of the present winding operated at the same load." See also, Hearing Transcript Vol. 2, (A. Kurpakus), p. 250, line 17 through 251, line 1:

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Finally, the generator stator was appropriately cleaned and tested at the conclusion of the turbine overhaul in accordance with normal operating and maintenance procedures. The HiPot integrity test here followed a scheduled cleaning to address the stator dirtiness inherent following standard long term operation. Because stator cleaning always results in an outage and risks damage to the equipment during the cleaning process,[99] it is only undertaken when it is clearly appropriate. For example, the stator had previously been cleaned in 1991 when oil was introduced into the generator after a journal bearing oil seal failed.[100] Neither investigation report of this incident identifies coil dirtiness as a material factor in thermal aging and fatigue or the resulting HiPot test failure.[101] To conclude otherwise would be mere conjecture. SCE has demonstrated that all plant personnel actions associated with this outage meet the requirements of the reasonable manager standard.

4. Coal Generation

SCE has also shown that Four Corners Units 4 and 5 performed well in 2009. These units produced a combined total of 11,301,314 MWh of generation (SCE's share).[102] Indeed, Units 4 and 5 recorded the second highest annual total recorded over the past six years. Based on these statistics and the reasons set forth below, the Commission should reject DRA's

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"Westinghouse thought that this uprate was going to be successful and there [would] be no issues. Now, granted the coils were changed in 1990. However, if anything, those coils were better than the ones put in back in 1983. So that would have given SCE even more belief that they could perhaps get a 30-year life out of these units and that SCE certainly had no idea that the life could be shortened by overheating because that wasn't expressed in this report or any other that I'm aware of."

98 See Appendix S to Exhibit SCE-8, SCE Responses to DRA-SCE-20, Question 20.1.5.

99 The generator rotor must be removed for access to the stator coil surfaces and runs the risk of damage to either the rotor or stator windings while removing or replacing the rotor. Thus, the work is generally planned well in advance to occur during extended outages for other work items, such as major turbine overhauls, as was the case prior to the instant outage. See Exhibit SCE-7 (A. Kurpakus), p. 82, line 16 through p. 83, line 2.

100 See Exhibit SCE-7 (A. Kurpakus), p. 83, lines 3-9.

101 See Voith Report, p. 5 ("The machine was steam cleaned. They were dried out afterwards, but it is hard to move the moisture inside of the coils through the dry out process after steam cleaned. This may have contributed to the first group of hipot failures, but overall insulation aging is the main cause of the second group of failures;" see also SCE Summary Report, stating that "[t]he winding cleaning process may have also contributed to the cause of the damage to the winding but does not appear to be cause of the insulation failure at this time." (SCE Summary Report, p. 3.)

102 Exhibit SCE-1 (S. Messer), p. 68, Table IV-12.

disallowance recommendation and conclude that Four Corners was operated reasonably during the Record Period.

a) The Four Corners Unit 4 Outage of January 17, 2009 Was Reasonable

DRA recommends a $0.05 million disallowance associated with the Four Corners Unit 4 outage beginning January 17, 2009, that occurred when a power feed circuit breaker to a motor control center (MCC) failed and damaged the digital processor-based control system for coal conveyer equipment (control system). The MCC was equipped with overload devices that did not mitigate the power surge sufficiently to prevent damage to the local control system. The breaker was quickly repaired and power was restored before the outage began, but the control system could not be repaired before the local stockpile of coal was depleted, resulting in the instant outage.[103] The evidence presented in this proceeding demonstrates that all actions taken by personnel related to this outage were consistent with the reasonable manager standard.

It is important to note that the after-the-fact evaluation for this event is a single-page document, known as an Opportunity Improvement Alert (Alert), that is used by APS (operator of the coal-fired Four Corners plant) as a means of preliminarily alerting personnel to a problem and initiating further investigation of an incident to prevent its reoccurrence.[104] As a result of its limited purpose, it often contains errors or omissions that become obvious as the Alert works its way through review by various personnel at the plant.[105] The Alert is not amended to document later-discovered information or latent errors.[106]

Moreover, while equipment items on the conveyor and control system have been replaced or upgraded during years of operation, "the basic process and layout of the coal conveying equipment . . . [has] been in place since the plant was designed and constructed approximately 40

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[103] Exhibit SCE-7 (S. Messer), p. 56, lines 9 through 16.
[104] SCE provided extensive background regarding the purpose of an Alert in Exhibit SCE-7, e.g., Exhibit SCE-7 (S. Messer), p. 45, line 1 through p. 47, line 21.
[105] Id., p. 48, lines 3-11.
[106] Id., p. 48, line 17 through p. 49, line 2.

years ago."[107] Specifically, the plant's coal conveyor system includes three stockpiles of coal located in between coal conveying equipment so that when equipment is removed from service for emergency repairs the steady supply of coal from the railcar delivery to the inlet of the coal pulverizers does not interrupt generation if a repair is made before a stockpile is depleted.[108] This contingency for online emergency repairs is usually successful in keeping the units from outrunning their coal supply during inspection, troubleshooting, and repair of systems and equipment. Indeed, conveyor system failures at Units 4 and 5 have caused only two outages, including the instant outage.[109] Forty years of operation had not revealed that the surge created by the instant breaker failure could damage the control system in a manner where repair would not be possible before the local coal stockpile was exhausted.

Consistent with its intended function, the Alert lists "lessons learned" and "recommendations" as a preliminary catalog of problems and solutions related to the instant outage, including no backup uninterruptible power supply (UPS) and 480V power. These items would not have prevented the outage because the outage did not occur because of an extended local power failure.[110] Instead, the outage was a result of the fact that repair of the control system that was damaged by the power surge took longer to finish than the operational time that the coal stockpile reserve provided. This is why the Alert recommends that the MCC breaker overloads be upgraded (i.e., surge protection).[111] Personnel at the plant were not aware prior to the incident that the existing power surge protection overload devices would fail to prevent the instant outage.[112]

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[107] Id., p. 56, lines 4-7.
[108] Id., p. 55, lines 8-14.
[109] Id., p. 56, footnote 77.
[110] Id., p. 59, lines 3-7. Nonetheless, "prior to the event, the station was already in the process of designing a backup power feed to the MCC (which failed at the time of the event) since operators felt that this area of the plant merited a higher level of backup contingency than that provided by the original plant design. . . . [E]ven if this installation had been completed ahead of the event, it would not have prevented the electrical damage to the control system when the power feed breaker failed."
[111] See Exhibit SCE-8, Appendix J (S. Messer).
[112] Exhibit SCE-7 (S. Messer), p. 58, lines 4-12.

Similarly, the Alert's recommendation to keep a "matched pair of Allen Bradley processors (updated firmware) in stock at the Warehouse"[113] is in response to the fact that time was spent loading the most current firmware and software into the spare processor when it was installed during the repair effort for the instant outage. While the station had a spare processor in the warehouse at the time of the event, the Alert's recommendation is intended to shorten the time required for future repairs by regularly updating the software and firmware of the spare units while they are in storage in the warehouse. The station is still determining whether to make the change based on operational practicality and cost effectiveness.[114]

Finally, the Alert recommends that a manual control feature be installed, but the station has determined that it would not be cost effective to install a true full manual control system. If installed, it would require the reinstallation of outdated analog controls and expensive maintenance to keep operable.[115] While personnel are considering other digital enhancements to the control system, the availability of such enhancements prior to the outage would not have prevented this particular event because the entire digital control system was out of service, "so any 'manual' features programmed into it would not have been operable."[116]

As explained above, at the time of the outage plant personnel were not aware of anything that could have been done differently to prevent its occurrence. The evidence presented has shown that personnel actions taken before, during, and after the outage were prudent, reasonable, and consistent with standard practices at coal-fired plants. DRA has not presented any evidence that this outage was unreasonable, and the Commission should therefore reject DRA's disallowance recommendation.

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113 Exhibit SCE-8, Appendix J (S. Messer).

114 See Exhibit SCE-7 (S. Messer), p. 59, footnote 87: "Firmware and software updates to operational power plant control systems are a frequent occurrence. Loading this software and firmware entails certain operational checks and tests as part of the process if installing the spare and placing it into service. It might not be practical to routinely load firmware and software updates onto the spare processors maintained in the plant warehouse; the assessment continues."

115 See id., p. 59, line 18 through p. 60, line 6.

116 See id., p. 60, lines 1-10.

5. Replacement Power Costs

a) DRA Grossly Miscalculated "Lost Energy" for SCE's Hydro Units

DRA recommends disallowances of $10.2 million for the Big Creek 3 Unit 1 outage on December 14, 2008 and $7.7 million for the Mammoth Pool Unit 2 outage of June 2008. In its Report, DRA claims that the Big Creek 3 Unit 1 and Mammoth Pool Unit 2 outages resulted in the need to purchase 297,840 MWh and 231,840 MWh of replacement power, respectively.[117] DRA's loss values are drastically inflated above the units' practical output limit and should be rejected by the Commission.

SCE's witness Thomas Watson has explained that DRA's calculations assume a totally unrealistic 100% capacity factor for these units (i.e., that the Big Creek Project has sufficient water resources to operate all of the hydroelectric units 24 hours per day for 365 days of the year).[118] For Big Creek 3 Unit 1, DRA reached its calculation of 297,840 MWh by multiplying the 34 MW capacity of Big Creek 3 Unit 1 by 8,760 hours in one year. In a similar manner, DRA arrived at the 231,840 MWh value for Mammoth Pool Unit 2 by multiplying the unit's approximate capacity of 80 MW by 2,898 hours, which corresponds to the time from January 1 through May 1 when the unit returned to service. SCE's witnesses Mr. Watson and Mr. Kurpakus have explained that SCE's hydro units never run at 100% capacity throughout the year. Indeed, Mr. Watson explained that the average capacity factor for the Big Creek project over the last 25 years has been 38%.[119] Mr. Kurpakus also stated during hearings that the annual average capacity factor of Big Creek 3 is approximately 50% and for Mammoth Pool it is approximately 33%.[120]

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[117] Exhibit DRA-1, p. 2-4.
[118] Exhibit SCE-7 (T. Watson), p. 88, lines 6-10.
[119] Id., p. 88, lines 15-16.
[120] Hearing Transcript Vol. 1 (A. Kurpakus), p. 148, lines 9-24

DRA's calculation of replacement power costs for these outages is also flawed because it ignores the concept of "outage bypassed energy" at SCE's hydro units. Outage bypassed energy represents the MWh loss when a hydro unit is out of service and the water cannot be stored or used by other powerhouses or units.[121] However, as Mr. Watson explained, an outage at one of its hydro units does not automatically result in outage bypassed energy because SCE has the ability to utilize water at its hydro facilities by: (1) storing water in upstream reservoirs for later use; (2) running water through alternate powerhouses; (3) running water through other generating units at the same powerhouse, such as the other generating units that were available at both the Big Creek 3 and Mammoth Pool powerhouses during the outages in question; or 4) utilizing a combination of the foregoing three options.[122]

SCE utilizes daily water storage and flow records to determine outage bypassed energy for outages. These records show that the Big Creek 3 Unit 1 outage incurred a loss of 70,089 MWh and that Mammoth Pool Unit 2 incurred a loss of 29,477 MWh.[123] They also show that Big Creek 3 Unit 1 experienced water loss only during the spring run-off, during April-July, and that Mammoth Pool Unit 2 likewise only lost water in April.[124] SCE's records demonstrate a loss of energy from these two outages that is 19% of the total loss assumed in DRA's flawed calculation.

b) <u>DRA's Methodology Is Significantly Flawed</u>

SCE has explained that it is not possible to calculate the exact cost of the economic loss due to a specific outage; however, it is possible to estimate the value of "lost energy" (i.e., the energy's opportunity cost).[125] This is done by considering appropriate published energy price indices and the unit's avoided variable cost of production.[126] In SCE's rebuttal testimony, Mr.

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[121] Exhibit SCE-1 (A. Kurpakus), p. 43, lines 7-9.
[122] Exhibit SCE-7 (T. Watson), p. 88, line 21 through p. 89, line 2.
[123] <u>Id.</u>, p. 89, lines 6-10.
[124] <u>Id.</u>, p. 89, lines 8-10.
[125] <u>Id.</u>, p. 90, lines 1-3.
[126] <u>Id.</u>, p. 90, lines 3-5.

Watson noted that DRA continues to ignore these important considerations in its simplified methodology, and proceeded to explain how these considerations significantly impact the Commission's calculation of replacement power costs for the outages being challenged by DRA.[127] Based on these considerations, Mr. Watson explained that the replacement power costs associated with the outages being challenged by DRA amounted to the following:

Maximum Replacement Energy Value

Facility	2009 Date Outage Began	Upper Limit of Energy Not Available: MWh	Upper Limit of Replacement Energy Value: Thousand $
Big Creek 3 Unit 1	Jan 1	66,232	$2,149.3
Mammoth Pool Unit 2	Jan 1	27,069	$693.8
Four Corners Unit 5	Jan 17	5,040	$50.9
SONGS Unit 2	Jan 27	40,169	$1,442.2
Total		138,510	$4,336.2

As noted in Mr. Watson's testimony, SCE served DRA and the Commission with detailed workpapers showing SCE's replacement power costs for these outages.[128] Although it was provided with SCE's rebuttal testimony and workpapers in advance of the hearings in this proceeding, DRA did not cross-examine Mr. Watson about his calculations and also did not present any evidence refuting Mr. Watson's detailed replacement power cost calculations. Therefore, to the extent the Commission would consider adopting any of DRA's disallowance recommendations, the calculations provided by Mr. Watson in SCE's rebuttal testimony should be the basis for any such calculation—not the results of DRA's flawed methodology.

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127 Id., pp. 90-92.
128 Id., p. 92, fn. 175.

B. Market Redesign and Technology Upgrade Memorandum Account

1. SCE Has Fully Supported Its Request to Recover $11.2 Million of Its Recorded Costs in the MRTUMA

In this proceeding, SCE is requesting Commission approval to recover approximately $8.685 million of its incremental and verifiable O&M costs recorded in the MRTUMA from 2007-2009.[129] In addition, SCE is requesting: (1) approval of $56.2 million of MRTU-related direct capital costs incurred on the MRTU project through the initial market implementation and (2) approval that these capital costs and associated overhead costs are the appropriate capital base to use in determining the capital revenue requirement recorded in the MRTUMA that will be recovered over the life of the project.[130] SCE explained in its direct testimony that, based on the associated capital additions, it has recorded a capital-related revenue requirement (i.e., depreciation, return on rate base, and taxes) in the MRTUMA in the amount of $2.45 million in 2009.[131]

SCE's requested incremental O&M and capital revenue requirements are summarized in the following table:

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[129] Exhibit SCE-7 (D. Snow), p. 96, Table III-3.
[130] Exhibit SCE-2 (D. Snow), p. 140, lines 8-13.
[131] Id., p. 140, lines 12-13.

Requested Incremental O&M and Capital Revenue Requirements
2007 through 2009
($000)

		2007	2008	2009	Total
1.	Incremental O&M	2,477	2,611	3,597	8,685
2.	Capital Revenue Requirement 1/	-	-	2,450	2,450
3.	Interest 2/	10	62	4	76
4.	Total	2,487	2,673	6,051	11,211

1/ Includes Depreciation, Taxes, and Return on Rate Base.
2/ DRA did not include the 2007 and 2008 related-interest in its Report. See Exhibit DRA-1, p. 5-5, Table 1-1.

The Commission has required SCE to present substantial testimony demonstrating the "incremental" and "verifiable" nature of its recorded costs in the MRTUMA.[132] To meet this requirement, SCE served the Commission and DRA with substantial testimony explaining its extensive efforts to implement the MRTU project and breaking down in detail its MRTU core workstream activities and related costs. SCE also served the Commission and DRA with detailed workpapers supporting its recorded costs in the MRTUMA. In its Report, DRA explains that it reviewed SCE's supporting materials and concedes that SCE met its burden in this proceeding by "provid[ing] sufficient data to support [its] request."[133]

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[132] See Exhibit SCE-2 (K. Pickrahn), p. 136 (citing D.09-12-021). By ensuring in the ERRA proceedings that the costs recorded in the MRTUMA were incurred in order to implement the MRTU mandate and the costs are incremental (i.e., not already recovered in rate levels) the Commission assures that SCE only recovers MRTU-related costs once (i.e., there is no double recovery).

[133] Exhibit DRA-1 (J. Tolbert), p. 5-4, lines 27-29.

2. SCE's Calculation of Its Incremental O&M Costs Benefits Its Customers

Although DRA agrees that SCE met its burden of proof in this proceeding, it nonetheless recommends a disallowance of approximately $0.077 million. DRA does not explain how it calculated this disallowance in its Report—it simply argues that it is warranted because SCE incorrectly determined which of the foregoing costs are incremental to SCE's currently-authorized General Rate Case (GRC) revenue requirements for funding the MRTU initiative. Specifically, DRA argues that SCE used the wrong approach to compute its incremental Power Procurement Business Unit (PPBU) MRTU costs recorded in the MRTUMA. DRA notes that the "difference between [SCE's] PPBU costs and authorized costs includes embedded costs for other operating activities other than MRTU implementation costs."[134]

The Commission should reject DRA's argument and approve SCE's method for calculating its incremental PPBU O&M costs because it benefits SCE's customers. SCE's witness Doug Snow has explained that SCE's incremental PPBU O&M costs in 2009 were much higher than $0.295 million,[135] which is what SCE is requesting to recover in this proceeding. On pages 98-99 of SCE's rebuttal testimony, Exhibit SCE-7, Mr. Snow shows how SCE calculated how much of its recorded MRTU O&M expenses were incremental to the total PPBU O&M expenses authorized in the 2009 GRC. Because the total recorded PPBU O&M expenses were less than authorized, SCE was able to reduce its MTRU O&M request from $5.954 million to just $0.296 million by absorbing most of these MRTU costs through its non-MRTU cost savings, which totaled $5.658 million. This is a reasonable approach. Indeed, as Mr. Snow has noted, under DRA's suggested approach SCE should not include the costs for other non-MRTU

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[134] Id., p. 5-5, lines 4-7.

[135] The total incremental O&M cost for 2009 is $3.597 million. Of this amount, $0.295 million is related to PPBU and the remainder is related to SCE's IT Department's incremental recorded costs and FERC jurisdictional costs. For a breakdown of these costs, please see Exhibit SCE-2, p. 203, Table XV-56, lines 6-9.

operating activities in its calculation and instead request to recover $5.954 million in MRTU-related PPBU O&M costs for 2009.[136]

3. SCE Is Entitled to Recover the Revenue Requirement Associated With Implementing MRTU Over Several Years

In this proceeding, SCE is asking the Commission to find that the $56.2 million of direct capital expenditures that SCE incurred up to and including December 31, 2009 are incremental and have been verified. If the Commission approves these costs, then SCE is entitled to recover this revenue requirement (i.e., depreciation, taxes, and return on rate base) over the life of the project. In its Report, DRA takes issue with this, and argues that SCE should not be allowed to request "further reimbursements for MRTU costs prior to the end of year 2009" in future ERRA Review applications.[137] The Commission should summarily reject DRA's assertion, as it is directly contrary to the Commission's ratemaking process and the scope of review established for the ERRA Review proceeding.

Recovery of SCE's $56.2 million investment will be over several years depending on the type of asset.[138] As shown in the table above, SCE is only seeking to recover $2.45 million of the capital revenue requirement during the 2007 through 2009 period associated with the $56.2 million of capital expenditures that it has asked the Commission to review and approve in this proceeding. Mr. Snow has noted that in future ERRA Review proceedings, as it does for other Commission-authorized accounts, SCE will seek recovery of the associated on-going capital revenue requirement (i.e., depreciation, taxes, and return on rate base) recorded in the MRTUMA.[139] Having already reviewed and approved the $56.2 million of capital expenditures

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[136] As Mr. Snow has explained, SCE does not understand the basis for DRA's requested disallowance of approximately $77,000. DRA did not provide a detailed calculation in its Report, nor did it fully explain its methodology. Instead, as noted above, DRA only stated that SCE's incremental PPBU O&M costs were incorrectly calculated. See Exhibit SCE-7, p. 99, fn. 183.

[137] Exhibit DRA-1 (J. Tolbert), p.5-6.

[138] Exhibit SCE-7 (D. Snow), p. 100, lines 5-6.

[139] Id., p. 100, lines 8-10.

in this proceeding, the Commission will only need to conduct an audit review of SCE's revenue requirement requests to ensure that SCE has recorded the correct amount of depreciation, taxes, and return. This is not unusual.

III.
SUMMARY OF UNDISPUTED ISSUES

A. Gas-Fueled Generation

In Chapter 5 of Exhibit 1, SCE demonstrated that gas-fueled facilities, which include four peaker generating units (known as the SCE Peakers) and the Mountainview Generating Station (Mountainview), were operated in a prudent manner during the Record Period. In its Report, DRA does not claim that that these facilities incurred any unreasonable outages during the Record Period. Accordingly, SCE requests the Commission to find that the SCE Peakers and Mountainview were operated reasonably during the Record Period.

B. Other Generation

In Chapter 6 of Exhibit 1, SCE demonstrated the reasonableness of its diesel fuel and transportation costs for Santa Catalina Island, and prudent operation of its utility-owned solar photovoltaic (PV) generating facilities. As DRA does not take issue with SCE's showing in its Report, SCE requests the Commission to find that its Santa Catalina Island fuel-related costs were reasonable, and that its solar PV facilities were prudently operated.

C. Utility Contract Administration and Costs (Non-QF Contract Administration)

In Chapter 8 of Exhibit 1, SCE showed that in administering its procurement contracts during the Record Period, it acted consistent with the contract terms and conditions, in good faith, and in accordance with the Commission's directives and recommendations. In this chapter, SCE included a discussion of its net collateral fees incurred during the Record Period, which totaled $7.944 million.[140]

DRA reviewed the administration and costs of SCE's non-qualified facilities (Non-QF) contracts and stated that it had "no objection to SCE's non-QF contract administration processes, contract activity, and training programs for the Record Period."[141] Accordingly, the Commission should find that SCE's Non-QF contract administration activities were reasonable.

D. PURPA Contract Administration and Costs

In Chapter 9 of SCE's direct testimony, Exhibit 2, SCE demonstrated that it administered its PURPA[142] contracts in a reasonable manner and in accordance with Commission standards. DRA reviewed SCE's management and administration of its PURPA contracts, and stated that it does not object to SCE's administration of these contracts during the Record Period.[143] Accordingly, SCE requests the Commission to find SCE's administration of its PURPA contracts was reasonable.

E. Renewable Portfolio Standards Contract Administration and Costs

SCE originates certain power purchase agreements pursuant to California's renewable portfolios standard (RPS) legislation, which became effective on January 1, 2003. For ease of reference, these agreements are referred to as "RPS contracts." As noted in Chapter 10 of Exhibit 2, "The Commission resolutions approving the RPS contracts typically provide for the recovery of all payments made pursuant to those contracts, subject to the Commission's review of the reasonableness of SCE's contract administration."[144]

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[140] Exhibit SCE-1 (R. Drummond), p. 145, Table VIII-45.
[141] Exhibit DRA-1 (C. Eustace), p. 4-1, lines 7-8.
[142] PURPA stands for Public Utility Regulatory Policies Act of 1978. PURPA contracts are also known as Qualifying Facility Contracts.
[143] Exhibit DRA-1 (T. Hortinela), p. 3-3, lines 16-19.
[144] Exhibit SCE-2 (D. Cox), p. 38, lines 11-13.

Accordingly, in Chapter 10 of Exhibit 2, SCE set forth its RPS contract-related expenses, described its RPS contract development and administration activities during the Record Period, and demonstrated that such activities were reasonable and in accordance with all applicable standards. In its Report, DRA states that it "does not object to SCE's request that the Commission find reasonable [SCE's] RPS contract administration activities."[145]

F. Operation of Ratemaking Accounts

As it has in prior ERRA Review proceedings, SCE has presented the operation of 16 regulatory accounts (i.e., balancing and memorandum accounts) to the Commission for review.[146] In Chapters 6 and 7 of its Report, DRA reviewed SCE's entries in all of these accounts except for the DOELMA[147] and found SCE's entries to be "consistent with Commission Decisions and Resolutions, accurately recorded and supported by relevant workpapers."[148] DRA also concluded that SCE's request to recover $19.409 million associated with the Litigation Cost Tracking Account (LCTA) and $3.912 million associated with the Project Development Division Memorandum Account (PDDMA) is reasonable.[149] Accordingly, the Commission should approve SCE's recorded operation of these accounts, as well as SCE's request to recover $23.321 million associated with the LCTA and PDDMA.

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145 Exhibit DRA-1 (C. Eustace), p. 4-6, lns. 16-17.

146 See Exhibit SCE-2, Chapters XII and XIII.

147 In its direct testimony, Exhibit SCE-2, SCE presented the operation of the Department of Energy Litigation Memorandum Account (DOELMA) for Commission review, and requested to recover the balance of $0.232 million recorded in this account during 2009. After SCE submitted this request, the Commission issued its decision in SCE's April 2009 ERRA Review proceeding (A.09-02-004), D.10-07-049, which held that SCE should seek disposition of this account until after the litigation has been completed and all costs and proceeds are known. Id., p. 58. Accordingly, SCE has withdrawn its request.

148 Exhibit DRA-1 (N. Rogers), p. 6-14, lns. 11-14.

149 Id., p. 6-14, lns. 14-19.

G. Least-Cost Dispatch

In Chapter II of Exhibit SCE-1, SCE demonstrated that it complied with least-cost dispatch (LCD) principles and requirements as specified by applicable Commission orders before and after the California Independent System Operator (CAISO) implemented the Market Redesign and Technology Upgrade (MRTU) on April 1, 2009 (the Pre- and Post-MRTU Periods, respectively). On page 1-1 of its Report, DRA states that it included LCD within the scope of its review in this proceeding; however, the rest of its Report is silent on this topic. SCE therefore requests that the Commission find that all LCD-related activities that SCE performed during the Record Period were in compliance with the Commission's established standard, Standard of Conduct 4.

H. CAISO-Related Costs

As set forth in Chapter XI of Exhibit SCE-2, SCE incurred approximately $399.3 million in CAISO-related costs during the Record Period.[150] The majority of these CAISO-related costs were unavoidable. Those costs that SCE had limited discretion to control were managed consistent with the objective of minimizing costs to bundled service customers.[151] DRA has not challenged SCE's request that the Commission find all CAISO-related costs incurred during the Record Period to be reasonable. Accordingly, the Commission should make such a finding.

I. Special Sales Contract Administration and Costs

In Chapter XIV of Exhibit SCE-2, SCE presented the results of its administration of its two remaining Self-Generation Deferral Rate (SDGR) agreements with ExxonMobil and Tosco (also known as ConocoPhillips). In this chapter, SCE explained how it administered these agreements for the benefit of its customers. DRA did not take issue with these SDGR

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[150] Exhibit SCE-2 (T. Watson), p. 54, line 4.
[151] Id., p. 59, line 24 through p. 60, line 1.

agreements in its Report, and the Commission should therefore find that SCE's administration of these agreements during the Record Period was reasonable.

IV.

CONCLUSION

For the reasons stated above, SCE respectfully requests the Commission to grant the relief it has requested on all the issues discussed above, and to adopt the proposed findings of fact, conclusions of law, and ordering paragraphs set forth in Appendix A.

Respectfully submitted,

/s/ Connor J. Flanigan________________________
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March 29, 2011

Attachment A

ATTACHMENT A

Findings of Fact

1. Southern California Edison Company (SCE) filed this Energy Resource Recovery Account (ERRA) Application (A.)10-04-002 on April 1, 2010. The application appeared in the Commission's Daily Calendar on April 7, 2010.

2. SCE's application seeks Commission review of its utility retained generation (URG) expenses, its administration of power purchase agreements, its least-cost dispatch activities and related spot market transactions, and its procurement-related revenue and expenses recorded in its ERRA Balancing Account, for the period beginning January 1, 2009 and ending December 31, 2009 (Record Period).

3. As of the close of the Record Period, SCE's ERRA Balancing Account reflected $3.433 billion in expenses and an over-collection of $45.861 million.

4. SCE seeks recovery of a net under-collected balance of $34.932 million (including franchise fees and uncollectibles) associated with three memorandum accounts authorized by the Commission: (1) the Market Redesign and Technology Upgrade Memorandum Account (MRTUMA); (2) the Litigation Cost Tracking Account (LCTA); and (3) the Project Development Division Memorandum Account (PDDMA).

5. SCE seeks a Commission finding that the amounts shown in the above accounts, as well as all other regulatory accounts set forth in Exhibit SCE-2, Chapters XII and XIII, are reasonable, appropriate, correctly stated, and in compliance with all relevant Commission decisions.

6. On May 10, 2010, the Division of Ratepayer Advocates (DRA) filed a protest to SCE's application. In its protest, DRA questioned the appropriateness of the Commission's continued review of "non-ERRA" balancing and memorandum accounts in the ERRA Review proceeding.

7. SCE filed its reply to DRA's protest on May 20, 2010 in which SCE explained that the Commission was already considering the appropriateness of reviewing SCE's non-ERRA accounts in SCE's April 2009 ERRA Review proceeding, A.09-04-002. Therefore, SCE urged the Commission to reject DRA's request to re-litigate this issue and find that these non-ERRA accounts are appropriately reviewed in the ERRA Review proceeding pending a contrary finding in A.09-04-002.

8. On July 13, 2010, the Commission issued its Scoping Memo in which it ruled that the question of whether non-ERRA balancing accounts should be considered in the scope of this proceeding would depend upon what the Commission decided in A.09-04-002. The Commission's Scoping Memo also noted that SCE and DRA had reached an agreement to remove reasonableness review of the Mohave Balancing Account (MBA) from the scope of A.10-04-002.

9. On August 4, 2010, Administrative Law Judge (ALJ) Gamson issued his Ruling Clarifying Scope of Proceeding. In his ruling, ALJ Gamson noted that the Commission had issued its decision in A.09-04-002 (D.10-07-049) and denied DRA's request to address non-ERRA accounts in separate or consolidated proceedings with Pacific Gas and Electric Company and San Diego Gas and Electric Company. Given the Commission's recent order, ALJ Gamson clarified that all of the accounts in SCE's application were within the scope of this proceeding.

10. On October 6, 2010, DRA submitted its Report on SCE's application (DRA Report). In its Report, DRA reviewed SCE's 2009 operations in four areas: (1) Utility-Retained Generation; (2) Qualifying Facility (QF) Contract Administration and Costs; (3) Non-QF Contract Administration and Costs; and (4) Balancing Account Review (ERRA and non-ERRA accounts).

11. DRA has recommended that the Commission: (1) disallow approximately $19.50 million in replacement power costs associated with four generation facility outages during the Record Period that DRA argued were unreasonable and (2) disallow recovery of $0.077 million associated with the MRTUMA that DRA argued represented embedded costs for other operating activities other than MRTU implementation costs.

12. On November 16, 2010, SCE filed its rebuttal testimony, Exhibit SCE-7, in which it responded to DRA's recommendations.

13. Regarding DRA's recommended $19.50 million disallowance, SCE has explained that each of the nine outages being challenged by DRA was appropriate under the Commission's "reasonable manager" standard. SCE also explained that DRA had not provided any relevant evidence to support its disallowance recommendations because—instead of analyzing each outage under the Commission's reasonable manager

standard—DRA simply copied selected negative findings from after-the-fact cause evaluations conducted by or for SCE and then summarily concluded that these outages were imprudent. Finally, SCE noted that DRA's methodology for calculating the cost of replacement power associated with generation outages was significantly flawed.

14. Regarding DRA's recommended $0.077 million disallowance, SCE has explained that it calculated its incremental MRTU costs in a manner that recovers only costs that are not included in rates, reducing its MRTU O&M request from $5.954 million to $0.296 million by absorbing most of these MRTU costs through its non-MRTU cost savings, which totaled $5.658 million.

15. DRA took no exception to SCE's operation and costs of its gas-fueled generation facilities during the Record Period.

16. DRA took no exception to SCE's Catalina Island diesel operations and costs and its solar photovoltaic operations and costs incurred during the Record Period.

17. DRA took no exception to the administration and costs of SCE's Non-QF contracts during the Record Period.

18. DRA took no exception to the administration and costs of SCE's QF contracts (also known as PURPA[152] contracts) during the Record Period.

19. DRA took no exception to the administration and costs of SCE's Renewables Portfolio Standards (RPS) contracts during the Record Period.

20. With the exception of the MRTUMA, DRA took no exception to any of SCE's ratemaking account operations and entries set forth in Chapters XII and XIII of Exhibit SCE-2.

21. DRA did not address SCE's least-cost dispatch (LCD) related activities during the Record Period.

22. DRA did not address SCE's administration of its Self-Generation Deferral Rate (SGDR) agreements with ExxonMobil and Tosco (also known as ConocoPhillips).

23. DRA did not address SCE's California Independent System Operator (CAISO)-related costs incurred during the Record Period.

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[152] PURPA stands for Public Utility Regulatory Policies Act of 1978.

Conclusions of Law

1. During the Record Period SCE consistently dispatched the resources and contracts under its control and made spot market transactions in a manner that complied with the Commission's adopted standard, SOC 4.

2. SCE's administration of its procurement contracts during the Record Period was prudent and complied with SOC 4.

3. SCE's URG facilities were operated in a prudent manner during the Record Period and complied with SOC 4.

4. SCE's cost of replacement power incurred during the Record Period was reasonable and recoverable.

5. SCE prudently administered its Non-QF contracts during the Record Period. SCE's costs associated with the administration of its Non-QF contracts during the Record Period were reasonable and recoverable.

6. SCE administered its QF contracts prudently and in accordance with the Commission's established standards. SCE is thus entitled to recover its costs associated with the administration of its QF contracts, which totaled $1.569 billion during the Record Period.

7. SCE prudently and reasonably administered its RPS contracts during the Record Period. SCE is thus entitled to recover its costs associated with its RPS contracts, which totaled $187.78 million during the Record Period.

8. SCE's CAISO-related costs incurred during the Record Period, which total approximately $399.3 million, are reasonable and recoverable.

9. SCE's ERRA Balancing Account and all other regulatory account entries set forth in Chapters XII and XIII of Exhibit SCE-2 are accurately stated and reasonable.

10. SCE's costs recorded in the PDDMA, which total $3.912 million, were incurred for the activities identified in D.06-05-016 and are reasonable and recoverable.

11. SCE's request to recover 90% of the amount recorded in the LCTA, which totals $19.409 million, is adequately supported in SCE's submitted materials, reasonable, and recoverable. This amount reflects the accumulated balance in the LCTA as of December 31, 2009, and includes costs that were incurred prior to

the 2009 Record Period. Specifically, this amount includes $16.259 million of recorded costs incurred prior to 2009 that have already been reviewed without disallowance in prior ERRA Review proceedings.

12. The Commission has already ruled that it is appropriate for the MRTUMA to be included in the ERRA Review proceeding. In Resolution E-4087, the Commission required SCE to seek recovery of costs recorded in the MRTUMA in this proceeding.

13. DRA's request for a consolidated review of SCE and the other investor-owned utilities' (IOUs) cost to implement MRTU is unreasonable. DRA has not presented any new evidence or arguments to justify revisiting the Commission's conclusion in D.10-07-049 that a consolidated proceeding is unnecessary.

14. SCE has presented substantial testimony supporting its request to recover $11.2 million associated with the incremental and verifiable O&M and capital revenue requirements recorded in the MRTUMA and this amount is therefore recoverable.

15. SCE has demonstrated that the $56.2 million of direct capital expenditures that it recorded in the MRTUMA up to and including December 31, 2009 are incremental and verifiable. Pursuant to the Commission's established ratemaking process, SCE is entitled to recover this revenue requirement (i.e., depreciation, taxes, and return on rate base) over the life of the project. DRA's assertion that SCE should not be allowed to request further reimbursements for MRTU costs prior to the end of year 2009 in future ERRA Review applications is rejected.

16. SCE's requested revenue increase of $34.932 million (including FF&U) associated with the LTCA, MRTUMA, and PDDMA is reasonable and should be adopted.

17. SCE's administration of its SGDR agreements during the Record Period was reasonable.

18. Information placed under seal should remain sealed.

19. This decision should be effective today, in order to allow the docket to be closed expeditiously.

ORDER

IT IS ORDERED that:

1. SCE's least-cost dispatch activities for the Record Period complied with SOC 4.

2. SCE's administration of its power purchase agreements was prudent and complied with SOC 4.

3. SCE's URG facilities were prudently managed in accordance with SOC 4. DRA's recommendation for a disallowance associated with four outages that occurred during the Record Period is denied.

4. SCE's fuel and purchased power costs incurred during the Record Period were recorded accurately and are fully recoverable.

5. SCE's costs associated with the administration of its Non-QF contracts incurred during the Record Period were reasonable and recoverable.

6. SCE's costs associated with the administration of its QF contracts were reasonable and recoverable.

7. SCE is entitled to recover its costs associated with its RPS contracts.

8. SCE's CAISO-related costs incurred during the Record Period were reasonable and recoverable.

9. DRA's request for a consolidated review of SCE's and the other IOUs' cost to implement MRTU is denied.

10. SCE's requested revenue increase of $34.932 (including FF&U) million associated with its three ratemaking accounts (the LCTA, PDDMA, and MRTUMA) is reasonable and should be adopted. DRA's recommendation for a disallowance of the $0.077 million associated with the MRTUMA is denied.

11. All information placed under seal shall remain sealed.

12. Application 10-04-002 is closed.

This order is effective today.

Dated _____________, at San Francisco, California.

CERTIFICATE OF SERVICE

I hereby certify that, pursuant to the Commission's Rules of Practice and Procedure, I have this day served a true copy of **OPENING BRIEF OF SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E)** on all parties identified on the attached service list(s). Service was effected by one or more means indicated below:

Transmitting the copies via e-mail to all parties who have provided an e-mail address. First class mail will be used if electronic service cannot be effectuated.

Executed this **29th day of March, 2011**, at Rosemead, California.

/s/ Melissa A.S. Hernandez____________________
Melissa A.S. Hernandez
Project Analyst
SOUTHERN CALIFORNIA EDISON COMPANY

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