Decision 10-07-049 July 29, 2010

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Southern California Edison Company (U338E) for a Commission finding that its Procurement-Related and Other Operations for the Record Period January 1 through December 31, 2008 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 $35.796 Million Recorded in Four Memorandum Accounts.	Application 09-04-002 (Filed April 1, 2009)

DECISION ON SOUTHERN CALIFORNIA EDISON COMPANY ENERGY RESOURCE RECOVERY ACCOUNT COMPLIANCE AND REASONABLENESS REVIEW

TABLE OF CONTENTS

Title **Page**

DECISION ON SOUTHERN CALIFORNIA EDISON COMPANY 2
ENERGY RESOURCE RECOVERY ACCOUNT COMPLIANCE 2
AND REASONABLENESS REVIEW 2
1. Summary 2
2. Background 3
3. Least-Coach Dispatch 4
3.1. SCE Trigger Filing 6
3.1.1. Discussion 7
3.2. Monthly Average Price Comparisons 8
3.2.1. Discussion 9
4. URG 10
5. URG – Nuclear Generation 10
5.1. Root Cause Evaluations 11
5.1.1. Discussion 13
5.2. SONGS Unit 2 Stator Water Low Flow Trip 14
5.2.1. Positions of the Parties 14
5.2.2. Discussion 21
5.3. Palo Verde, Unit 3 - Steam Generator Outage 22
5.3.1. Positions of the Parties 22
5.3.2. Discussion 24
6. URG – Hydroelectric Generation 26
7. URG – Coal Generation 27
8. URG - Peakers 27
9. URG – Catalina Diesel Operations 28
10. Replacement Power Costs 28
10.1. Positions of the Parties 28
10.2. Discussion 32
11. Utility Contract Administration and Costs 33
12. QF Contract Administration and Costs 33
13. Renewable Portfolio Standards Contract Administration and Costs 34
14. CAISO-Related Costs 34
15. Special Sales Contract Administration Costs 35
16. Operation of Ratemaking Accounts 35

Title **Page**

16.1. MRTUMA 37
16.1.1. SCE's Request 39
16.1.2. DRA's Position 40
16.1.3. Discussion 43
16.2. DRA Proposal for a Consolidated Proceeding for MRTU Costs 45
16.2.1. SCE's Response 46
16.2.2. Discussion 49
16.3. PDDMA 50
16.3.1. Positions of the Parties 52
16.3.2. Discussion 53
16.4. DOELMA 54
16.4.1. Positions of the Parties 55
16.4.2. Discussion 57
16.5. DRA Proposal for a Consolidated Proceeding for Non-ERRA Accounts 59
16.5.1. SCE's Response 61
16.5.2. Discussion 62
16.6. DRA's Internal Audit Recommendation 64
17. Comments of Proposed Decision 64
18. Assignment of Proceeding 64
Findings of Fact 65
Conclusions of Law 69
ORDER 72
APPENDIX – Forecast ERRA Revenue Requirement and Recorded Procurement Costs

DECISION ON SOUTHERN CALIFORNIA EDISON COMPANY ENERGY RESOURCE RECOVERY ACCOUNT COMPLIANCE AND REASONABLENESS REVIEW

1. Summary

This decision addresses compliance, verification and reasonableness issues related to Southern California Edison Company's (SCE's) Energy Resource Recovery Account for the Record Period January 1 through December 31, 2008. Among other things, the decision:

- Determines that all dispatch-related activities SCE performed during the Record Period complied with Commission orders and SCE's procurement plan.
- Determines that the September 27, 2008 Palo Verde Nuclear Generating Station Unit 3 forced outage was not reasonable and ratepayers should not pay for the associated replacement power cost, estimated to be $615,000.
- Determines that, with the exception of the September 27, 2008 Palo Verde Nuclear Generating Station Unit 1 forced outage, SCE's utility retained generation operations were reasonable.
- Determines that all aspects of SCE's contract administration during the Record Period were reasonable.
- Authorizes rate recovery of $26,051,000 contained in the New System Generation Memorandum Account, $3,910,000 contained in the Project Development Division Memorandum Account, and $347,000 in associated franchise fees and uncollectibles.
- Defers consideration of the reasonableness of $5.1 million in Market Redesign and Technology Upgrade expenses to SCE's Energy Resource Recovery Account Review application for the 2009 Record Period.
- Denies the Division of Ratepayer Advocates request for a consolidated proceeding with Pacific Gas and Electric

Company and San Diego Gas and Electric Company to address Market Redesign and Technology Upgrade costs.

- Determines that SCE should request disposition of the Department of Energy Litigation Memorandum Account after all costs and proceeds are known.
- Denies the Division of Ratepayer Advocates request for a consolidated proceeding with Pacific Gas and Electric Company and San Diego Gas and Electric Company for non-Energy Resource Recovery Account reasonableness review.

2. Background

In Decision (D.) 02-10-062 and D.02-12-074, the Commission determined that certain procurement related operations should be reviewed annually in the Energy Resource Recovery Account (ERRA) proceeding. This review includes utility retained generation (URG) expenses, Southern California Edison's (SCE's) administration of existing qualifying facility (QF) contracts, bilateral contracts, inter-utility power contracts, renewable resource contracts, natural gas tolling agreements, and California Department of Water Resources contracts allocated to SCE's customers in D.02-09-053. In addition, the Commission requires SCE to demonstrate that its least-cost dispatch operations and related spot market transactions during the Record Period complied with Standard of Conduct No. 4 (SOC 4) in its Commission-approved procurement plan, as clarified in D.05-01-054. In this application, SCE has set forth its procurement related operations for the Record Period January 1, 2008 through December 31, 2008 (Record Period) for such review and demonstration.

Also, as required by D.02-10-062, SCE has set forth the entries recorded in the ERRA Balancing Account and other regulatory accounts for review. SCE requests that the Commission find its operations and entries related to these regulatory accounts to be appropriate, correctly stated, and in compliance with the relevant Commission decisions. SCE also seeks to recover the net under-collected balance of $35,386,000 recorded in four of these accounts.

On May 6, 2009, a protest to the application was filed by the Division of Ratepayer Advocates (DRA), the only other party to this proceeding. SCE filed a reply to the protest on May 18, 2009.

A prehearing conference was held on June 2, 2009. The assigned Commissioner's Ruling and Scoping Memo (Scoping Memo) was issued on June 24, 2009. DRA testimony was served on August 27, 2009. A second prehearing conference was held on October 1, 2009 to discuss and set a revised procedural schedule. SCE rebuttal testimony was served on October 8, 2009. Evidentiary hearing was held on October 29, 2009. Opening briefs were filed on December 3, 2009, and reply briefs were filed on December 22, 2009, at which time this matter was submitted for decision.

SCE, as the applicant, has the burden of affirmatively establishing the reasonableness of all aspects of its request and proving that it is entitled to the Commission actions and relief in rates that it is requesting. As with most utility related matters, the standard of proof that the applicant must meet is that of a preponderance of evidence. It is with these principles in mind that we review the various aspects of SCE's request.

3. Least-Coach Dispatch

SCE's least cost dispatch obligations are explained in D.05-01-054 where the Commission states that in conducting the daily economic dispatch of energy, utilities must comply with SOC 4 as follows:

> The utilities shall prudently administer all contracts and generation resources and dispatch the energy in a least-cost manner. Our definitions of prudent contract administration and least-cost dispatch are the same as our existing standard.[1]

The Commission elaborated on this standard in D.02-12-074, where it placed the following explanation of SOC 4 in the utilities' approved procurement plans:

> Prudent contract administration includes administration of all contracts within the terms and conditions of those contracts, to include dispatching dispatchable contracts when it is most economical to do so. In administering contracts, the utilities have the responsibility to dispose of economic long power and to purchase economic short power in a manner that minimizes ratepayer costs. Least-cost dispatch refers to a situation in which the most cost-effective mix of total resources is used, thereby minimizing the cost of delivering electric services.... The utility bears the burden of proving compliance with the standard set forth in its plan.[2]

Once this definition of SOC 4 was placed in the utilities' procurement plans, it became the "upfront standard" under Assembly Bill (AB) 57 regarding prudent contract administration and the daily dispatch of energy. The question to be addressed in the ERRA proceeding regarding least-cost dispatch is whether the utility has complied with this standard -- that is, (1) whether the utility has dispatched the dispatchable contracts under its control "when it is most economical to do so," (2) whether it has "disposed of economic long power and purchased economic short power in a manner that minimizes ratepayer costs,"

---

1 D.02-10-062, Conclusion of Law 11.

2 D.02-12-074, Ordering Paragraph 24b. The ellipsis indicates language deleted by D.03-06-076, at 27 and Ordering Paragraph 16.

and (3) whether it has used "the most cost-effective mix of its total resources, thereby minimizing the cost of delivering electrical services." In its testimony, SCE addresses these questions in detailing how it complied with SOC 4 during the Record Period.

In its opening brief, DRA indicates that it does not take issue with SCE's least-cost dispatch record in this proceeding.

Based on the testimonies of SCE and DRA, we conclude that all dispatch-related activities SCE performed during the Record Period complied with Commission orders and SCE's procurement plan.

3.1. SCE Trigger Filing

DRA is no longer pursuing recommendations with respect to an ERRA trigger application (Application (A.) 08-09-011)[3] filed by SCE pursuant to Pub. Util. Code § 454.5(d)(3) and then withdrawn shortly thereafter.[4] However, DRA indicates that it is concerned that SCE may not be prudently anticipating its revenue requirement, resulting in unnecessary rate adjustments to its customers. DRA states that although it recognizes that fuel and purchase power costs are difficult to predict, it is still incumbent on the IOU to avoid rate increases as much as possible by minimizing the frequency of ERRA revenue requirement adjustments it seeks.

---

[3] In Exhibit 9, DRA had recommended that $255 million associated with A.08-09-011 be found unreasonable or this proceeding be bifurcated to determine the reasonableness and compliance associated with the $255 million.

[4] The purpose of the trigger application is to "adjust rates or order refunds, as necessary [and] to promptly amortize a balancing account" to "balance the utilities need for timely cost recovery and the consequences of frequent rate adjustments on consumer behavior." (D.02-10-062, at 71, Finding of Fact 24.)

In response, SCE states that the evidence in this proceeding shows that SCE acted prudently in withdrawing its December 2008 ERRA Trigger Application to avoid an unnecessary rate increase to its customers. According to SCE, DRA's statement that it is "concerned" about unnecessary customer rate increases ignores SCE's testimony on this subject. To the extent DRA's criticism concerns perceived flaws in SCE's forecast methodology, SCE notes that its methodology for forecasting its ERRA revenue requirement is sound, and has been repeatedly reviewed and approved by the Commission on an annual basis in SCE's ERRA Forecast proceedings. SCE adds that, to the extent that there are large variations in SCE's forecast of its ERRA revenue requirement, these are usually driven by factors beyond SCE's control, such as unexpected swings in the price of natural gas. Based on the foregoing, SCE urges that the Commission find DRA's concern regarding "unnecessary rate adjustments" to SCE's customers to be unsupported and therefore without merit.

3.1.1. Discussion

DRA's concern that SCE may not be prudently anticipating its revenue requirement, resulting in unnecessary rate adjustments to its customers, is not supported by the record. DRA has not provided any specific information regarding rate changes that it feels could have been avoided, if SCE had more prudently anticipated its revenue requirement. The trigger application in question was withdrawn, so there was no associated rate adjustment. SCE acted prudently in first filing the trigger application as required and then in withdrawing the trigger application when more recent information indicated that the threshold would not be exceeded. DRA has not documented any historic problems related to, or made clear how SCE might more prudently anticipate, its revenue requirement. Forecasted ERRA revenues requirements are reviewed and approved by the Commission in the annual ERRA forecast proceedings based on the best information available at the time of the reviews. To the extent that DRA's concerns relate to SCE's ERRA forecasts, DRA should pursue such concerns in those proceedings.

Even though DRA's recommendation with respect to the trigger filing has been withdrawn, SCE requests that this decision discuss the differences between the ERRA forecast, review and trigger applications. While we believe such differences are clear, SCE's rebuttal testimony (Exhibit 4) provides a summary of the Commission's processes for review and approval of a utility's forecasted fuel and purchased power expenses for the purpose of setting rates (ERRA forecast proceeding and ERRA trigger mechanism) and the processes for the review and approval of recorded utility procurement costs (long-term procurement plan proceeding, quarterly compliance report advice letter filings and the ERRA review proceeding). SCE's characterization of the different processes is correct, should be used to determine where specific ERRA related issues should be addressed, and is summarized in the Appendix to this decision.

3.2. Monthly Average Price Comparisons

SCE states that DRA's least cost dispatch testimony repeats the same kind of inappropriate monthly average price comparisons that DRA made in past ERRA proceedings, asserting that DRA has calculated monthly average purchase and sales prices for SCE transactions and compared them with "hybrid" prices reported by the ICE for power delivered to the CAISO's SP-15 location. In its rebuttal testimony,[5] SCE describes why this is inappropriate and why the use of such "hybrid" monthly average price data for electricity product, at one delivery point in making price comparisons with spot transactions of different electricity products at multiple delivery points produces misleading, if not erroneous, results. SCE requests that the Commission determine that such comparisons should not be used to review SCE's compliance with SOC 4 in this or any future ERRA Review proceedings.

DRA did not respond directly to SCE's criticisms of its comparisons in either its opening or reply briefs. However, in light of SCE's request that the Commission rule on the validity of various approaches to analyzing least-cost dispatch, DRA suggests that the Commission institute a rulemaking to address the preferred methodology for evaluating least cost dispatch.

3.2.1. Discussion

SCE's criticisms of DRA's monthly average price comparisons appear to be valid, and this decision does not make use of such comparisons in any determinations. While we will not dictate the substance of future DRA showings, we suggest that DRA take into consideration the points made by SCE in its rebuttal testimony. If DRA continues to make use of such comparisons in future ERRA Review proceedings, it should explain why such comparisons are meaningful or relevant, in light of the points made by SCE.

With respect to DRA's suggestion that the Commission institute a rulemaking to address a preferred methodology for evaluating least cost dispatch, we decline to do so. The utility has the burden to demonstrate compliance with SOC 4, and we will leave it up to the utility to determine how that should best be done. DRA and SCE are encouraged to explore the development and use of supplemental information or techniques that may be

---

[5] Exhibit 4, at 12-17.

valuable in evaluating future SCE ERRA Review filings, but that can be done informally. A separate rulemaking is not necessary do so.

4. URG

This decision addresses SCE's Record Period URG operations and fuel procurement activities related to nuclear generation, hydroelectric (hydro) generation, coal generation, peakers, and Catalina diesel operations. Both SCE and DRA provided testimony in each of these areas. In its testimony, DRA identified one coal generation outage, three nuclear generation outages and two hydro generation outages, which were determined by DRA to be unreasonable. At that time, DRA recommended that the Commission disallow $12,473,040, which is the amount DRA calculates that SCE paid for additional purchased power in order to compensate for lost power resulting from these outages. In its rebuttal testimony, SCE addressed each identified "unreasonable" outage as well as DRA's calculation of replacement power costs.

In its opening brief, DRA recommends disallowances of $4,715,000 associated with a San Onofre Nuclear Generating Station (SONGS) Unit 2 outage and $615,000 associated with a Palo Verde Nuclear Generating Station (Palo Verde) Unit 3 outage, and has apparently withdrawn its recommendation for disallowances associated with the other outages identified in its testimony.

5. URG – Nuclear Generation

SCE owns a 78.21 percent share of SONGS, Units 2 and 3, located in North San Diego County. The nameplate ratings of SONGS 2 and 3 are 1070 Megawatt (MW) and 1080 MW, respectively.

SCE owns 15.8 percent share of Palo Verde Units 1, 2, and 3, located 45 miles west of Phoenix, Arizona. Arizona Public Service (APS) is the operating agent of Palo Verde. The rated capacities of Palo Verde 1, 2, and 3 are 1,311 MW, 1,314 MW and 1,317 MW, respectively. SCE implements its ownership responsibilities through participation in administrative, engineering and operations, and audits committees.

In its testimony, SCE sets forth its reasonableness showing for SONGS and Palo Verde generation and nuclear fuel expenses incurred by SCE during the Record Period.

In its testimony, DRA found that three nuclear forced outages were unreasonable. The outages included a SONGS Unit 2 stator water low trip outage, a Palo Verde Unit 1 safety injection tank nitrogen leak outage, and a Palo Verde Unit 3 steam generator outage. SCE addressed all three outages in its rebuttal testimony; and, in its opening brief, DRA only recommended disallowances associated with the SONGS Unit 2 and Palo Verde Unit 3 outages.

5.1. Root Cause Evaluations

In its analysis of outages at SONGS and Palo Verde, DRA based its recommendations for disallowances on root cause evaluations (RCEs) performed by the plant operators. SCE explains the purpose of RCEs as follows:

> Whenever SCE or APS experiences any failure, malfunction, deficiency, or non-conformance at SONGS or Palo Verde, respectively, Nuclear Regulatory Commission (NRC) regulations require the plant operator to perform a stringent after-the-fact evaluation of the event. These evaluations are commonly referred to as RCEs, Apparent Cause Evaluations (ACEs), and Common Cause Analyses (CCAs). The purpose of the evaluation is to determine the cause of the event, and to define the corrective actions required to prevent the event from occurring in the future. These evaluations are based on hindsight, using information and results available at the time the report was written – not just information that was available at the time of the incident. This stringent evaluation process reflects the high standards that are enforced both internally (by

> plant operators) and externally (by the NRC and other organizations) in the commercial nuclear industry, in order to achieve excellent safety and operating performance. These high standards are reflected in the performance of SCE's nuclear facilities, SONGS and Palo Verde, which generally experience fewer forced outages than SCE's other URG operations. (Exhibit 4, at 19-20.)

Accordingly, SCE asserts that the RCEs that it supplied to DRA regarding the forced outages at SONGS and Palo Verde should not be confused with an assessment of the reasonableness of plant personnel's actions for the purposes of this proceeding. SCE notes that the RCE that SCE supplied for the outage at SONGS specifically states that it should not be confused with such an assessment. The SONGS RCE begins with a "Clarification of Purpose," that states that the evaluation "does not attempt to make a balanced judgment of the prudence or reasonableness of any actions or decisions taken…." SCE adds that the RCE is clear that (1) the information and result therein were not available to the organization and personnel during the time frame in which relevant actions were taken and decisions were made, (2) the purpose of using such an approach is to provide the most comprehensive analysis possible for improving future performance to the highest attainable level, and (3) use of this approach is imperative in the nuclear power industry and cannot be compromised or confused with an assessment of management or personnel prudence.

According to SCE, DRA does not acknowledge this statement of purpose in its report, or otherwise attempt to view these evaluations in the proper context, but instead relies exclusively on these evaluations to justify a finding that the outages at SONGS and Palo Verde could have been foreseen and prevented, and were thus unreasonable. SCE asserts that this is inappropriate, and is a "hindsight bias," which causes those who know what happened after the fact to misunderstand what others who lacked that knowledge could have known at the time the events occurred. It is SCE's position that one cannot draw a direct correlation between these stringent and comprehensive after-the-fact evaluation findings, and the Commission's reasonableness standard, and the Commission's analysis of these outages should focus on whether plant personnel at SONGS and Palo Verde acted reasonably, and in accordance with industry standards, given the information that was known or could have been known by them at the time of these outages (i.e., without the benefit of hindsight and careful after-the-fact analysis).

5.1.1. Discussion

We recognize the purpose of the RCE 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 proceeding. Such actions or causes must be evaluated in conjunction with the "reasonable manager" standard[6] in determining whether the outage is reasonable or unreasonable for the purposes of this proceeding. The outages at SONGS and Palo Verde are discussed below with this principle in mind.

[6] Briefly, by the "reasonable manager standard, utilities 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." (See D.09-09-088, 37 CPUC2d 488, 499.)

5.2. SONGS Unit 2 Stator Water Low Flow Trip

This SONGS 2 forced outage was caused by a stator water low flow trip that occurred when a check valve briefly stuck open and then closed causing a pressure spike that opened a relief valve, thus diverting flow from the generator.[7] As a result, SONGS 2 was offline a total of 4.1 days, from June 5, 2008 until June 10, 2008.

5.2.1. Positions of the Parties

DRA states that it reviewed the maintenance records provided for this outage and RCE, and finds the outage to be unreasonable. According to DRA, the RCE indicated that there were several avoidable mistakes made over the previous seven years leading to the forced outage. In its testimony,[8] DRA identifies and discusses a number of "inappropriate actions," "root causes," and "apparent causes" that were included in the RCE. It is DRA's position that lack of accountability, training, analysis, and oversight identified by the RCE led to the forced outage on June 11, 2008; and thus it is an unreasonable forced outage.

SCE states that at the time of the outage, SONGS personnel could not have reasonably foreseen the failure of the stator cooling water check valve. The Unit 2 stator cooling water system had operated properly for over 20 years without a plant trip prior to this incident. The check valves had also been visually inspected during the SONGS 2 refueling outage in December 2007, and no deficiencies were found.

---

[7] SCE notes that this is the logical conclusion of the RCE based on the most likely scenario – not on absolute proof since the check valve, when disassembled, was not found in the stuck open position.

[8] Exhibit 9, at 3-23 - 3-26.

It is SCE's position that DRA has inappropriately used the RCEs in determining that SCE's actions were unreasonable with respect to outage at SONGS. SCE states that DRA ignores the fact that the RCE findings were made in hindsight, with the benefit of information and results that were not available to SONGS personnel during the time frame in which relevant actions were taken and decisions were made. According to SCE, this is a crucial consideration in evaluating whether SONGS operating decisions were reasonable, and must be taken into account by the Commission before reaching a determination of the reasonableness of the outage. In its rebuttal testimony,[9] SCE addressed each of the RCE actions and causes discussed by DRA within this context, to explain why they do not support a finding that this outage was unreasonable.

In response to SCE's criticism of its use of RCEs, DRA states that SCE makes the mistake that because ultimate conclusions contain some facts learned after the event, none of the facts known before the event can be considered. DRA lists a number of facts that were known by SCE before the June 2008 outage,[10] and asserts that taken together, these facts, more then support a finding that SCE violated the 'reasonable manager' standard because of what it knew or should have known before the outage occurred, and a disallowance of $4,715,000 is fully justified.

With respect to the facts listed by DRA, SCE states that DRA provides no further supporting analysis, fails to address SCE's rebuttal testimony, and ignores the successful operating history of the stator water

---

9 Exhibit 4, at 22 - 26.

10 DRA Opening Brief, at 4.

cooling system which was routinely tested and ran reliably for over 20 years without causing a unit outage.

Following are the facts listed by DRA. After each is the information and argument provided by SCE[11] to support its position that it acted reasonably:

1. June 25, 2001 -- a similar valve was found leaking.

   SCE Response: The relief valve that was found leaking in 2001 was different from the valve that caused the outage in 2008, which was a check valve. The RCE includes a discussion of the relief valve leaking in 2001 because it led to an investigation by SONGS personnel of the low system pressure operating margin. At that time, SONGS personnel resolved the operating margin issue by raising the pressure set point at which these relief valves would open. This was a reasonable response at the time. It wasn't until the event in 2008 that SCE realized the amount of flow through the relief valves when they were activated would cause a unit shutdown. Accordingly, SCE's 2008 evaluation identified as an "inappropriate action" the system engineering staff's failure to adequately manage the limited operating margin of the stator cooling water system, and concluded that SCE "incorrectly believed that changing the relief valve set points would eliminate the challenge to the system after the 2001 event." This demonstrates the "lessons learned" nature of these evaluations, that is, the fact that the relief valve set points were not correctly adjusted in 2001 could not have been known until after the root cause evaluation that followed the unit shutdown in 2008.

[11] SCE Reply Brief, at 10 -15, which is heavily based on SCE rebuttal testimony, Exhibit 4, at 21-27.

2. May 2002 -- a vulnerability study identified the check valve as a "vulnerability," which meant that it be incorporated into a test program. The RCE noted that incorporation into this type of test program was not the appropriate direction, but that inspecting for critical tolerances and dimensions would have been a better approach.

   SCE Response: This "better approach" was only identified after the outage occurred, and then only after a significant inspection and evaluation by a check valve specialist. Also, the RCE identified a manufacturing defect that was unique to this particular valve. Without this specific knowledge, obtained after the outage took place, the conclusion of the May 2002 Vulnerability Study to incorporate the valve into a test program was reasonable at the time. The RCE's identification of a "better approach" is an example of how these after-the-fact, hindsight evaluations are utilized within the nuclear industry to evaluate lessons learned, improve processes and procedures, and improve equipment reliability.

3. May 2002 -- low pressure in the same cooling system caused a test to be aborted.

   SCE Response: In May 2002, during a monthly low flow test of the stator water cooling system, it was noted the system was not responding as normal. Specifically, the system's pressure was at 65 pounds per square inch (psig), as opposed to the normal system pressure of 95 psig. Because of the pressure abnormality, SONGS personnel aborted the monthly low flow test to vent the standby pump as directed by the procedure. This was reasonable at the time. Once the pump was vented, the stator water system was returned to its pre-test configuration. The low pressure condition did not cause a unit shutdown nor did it affect any other part of Unit 2's operation. The actions SCE took during this 2002 event were prudent actions and demonstrate that SONGS was routinely testing the stator water cooling system and timely addressing problems that it encountered during these inspections.

4. May 2002 -- a similar check valve malfunctioned during a test.

   SCE Response: This is the same situation described immediately above.

5. May 2002 -- initial identification of critical nature of check valve; and March 2003 -- the "vulnerability" identification was finally added into the "Corrective Action Program."

   SCE Response: In May 2002, the check valves were first identified as a critical component within the vulnerability study. In March 2003, the vulnerability study recommendations were added to the SONGS Corrective Action Program (CAP). Adding the valves to the CAP system meant that certain routine inspections would be conducted every third refueling outage, beginning with the Unit 2 Cycle 15 refueling outage that was scheduled for November 2007. The delay in adding the valves to the CAP did not contribute to this outage in 2008.

6. May 2003 -- gaps in vulnerability study were found.

   SCE Response: The notation on Page 5 of the RCE regarding "May 2003 gaps in vulnerability study" is misleading. This notation is regarding a gap analysis that the SONGS engineering group performed to verify whether all of the issues identified in the vulnerability study were mapped to the existing and planned corrective actions. During this gap analysis the stator water cooling system check valves were added into the preventative maintenance program. This is not an unusual or unreasonable occurrence and allows SONGS personnel the opportunity to review, validate, and assign actions as required.

7. December 2003 -- it was discovered that problems with the check valves may have been masked.

   SCE Response: The RCE's statement that problems with the check valves "may have been masked" does not mean these problems were "covered up" by SONGS personnel. The RCE points out that in December 2003 the cooling system pump did not exhibit adequate discharge pressure. Given what was known at the time, the SONGS engineering group assessed that the low pressure resulted from gas binding. It was only after performing the root cause analysis that followed the unit shutdown during the 2008 Record Period that SCE was able to say that the assessment of the low discharge pressure in December 2003 may have masked the problems with the check valve that were encountered in 2008. However, this is not a conclusive finding.

8. April 2005 -- gaps in vulnerability study were found again, specifically, "there was no preventative maintenance actions associated with the Stator Water Cooling System pump discharge check valves."

   SCE Response: The RCE clearly identifies that the preventative maintenance was generated in May 2003; however, the repetitive task to visually inspect the system was not added until September 2005. Once the repetitive task was incorporated, it was scheduled to take place every third outage beginning with Cycle 15 in November 2007. In fact, no deficiencies were found during the Cycle 15 outage, when SCE used the updated preventative maintenance actions, which included a visual inspection. DRA does not acknowledge this fact in its opening brief, but it is important to the Commission's finding that SONGS personnel acted prudently.

9. March 2007 -- check valves were designated as a "Critical - A" component, the top characterization.

   SCE Response: SCE's evaluation states that "the maintenance order for the check valve [MO 06121745] did not identify it as a Critical-A Component. The work plan therefore did not contain the barriers set up to decrease human performance errors that are required for Critical-A Components." At the time MO 06121745 was developed, in February 2007, the valve had not been declared a Critical-A component. Accordingly, the procedure in use at the time MO 06121745 was written, SO123-I-1.7 did not contain specific guidance for developing work plans for Critical-A components. However, the valve was declared a Critical-A component one month later, in March 2007. Procedure SO123-I-1.7 was subsequently revised in March 2008 to include such guidance. As the evaluation notes, there was an expectation that all outage-related maintenance orders for Critical-A components contain human performance barriers. And, as the evaluation also found, 85% of maintenance orders did in fact contain these barriers. MO 06121745 did not because it was written before the check valve was declared a Critical-A component. But had these barriers been in place in MO 06121745, there is still no assurance that they would have prevented this outage. As explained above, the system failure was quite complex. Indeed, it took multiple attempts over a two-hour period for SCE's engineering valve expert to recreate the failure mode and ultimately determine that the problem with the valve was a deficiency in both design and manufacture.

10. December 2007 -- visual inspection of check valves failed to identify the failure mechanism.

    SCE Response: Prior to the event, SONGS personnel had been testing the system on a routine tests basis

> using the maintenance orders and training known at the time. After the event, and as a result of the RCE, the maintenance work orders were reassessed and a recommendation was made regarding training qualifications of the personnel. Although DRA has suggested that personnel with additional training qualifications might have been able to identify the defect in the check valve prior to the outage, this is speculative at best. As SCE explained in its rebuttal testimony, it took SCE's engineering expert multiple attempts over a two-hour period to recreate the failure mode and ultimately determine that the problem with the valve was a deficiency in both design and manufacture. This is another example of how an RCE enables a nuclear plant to improve its processes, procedures, and training. It does not constitute evidence of unreasonable actions on the part of plant personnel.

5.2.2. Discussion

As discussed in Section 5.1.1, for the purposes of this proceeding, the results of the RCE can only be used to determine the reasonableness of a plant operator's actions related to a nuclear plant outage, if each of the RCE identified actions or causes is evaluated in light of the "reasonable manager" standard. Such evaluations do not appear in DRA's testimony. SCE does make such evaluations in its rebuttal testimony. With respect to DRA list of facts that were known by SCE at the time of the outage, DRA evaluations of such facts, in light of the reasonableness standard, are again missing; while SCE's responses that are based on its rebuttal testimony are for the most part compelling in that respect. The evidence supports SCE's position that its actions related to this outage were reasonable, and we will not adopt DRA's recommended disallowance with respect to the SONGS 2 outage.

5.3. Palo Verde, Unit 3 - Steam Generator Outage

On September 27, 2008, Palo Verde Unit 3 began a 2.1-day forced outage. The unit was manually shut down to address high sulfates in the steam generators resulting from a resin leak into the generators (resin is used to purify water before it enters the steam generators).

5.3.1. Positions of the Parties

In response to a DRA data request, SCE stated the following regarding the Palo Verde Unit 3 outage:

> This outage incident was probably foreseeable and preventable. A similar, yet much less severe, situation occurred on Unit 2 in 2007. A resin leak path in Unit 2 was identified, but corrective actions were not implemented to avoid identifying and preventing the resin intrusion in Unit 3. (Exhibit 9, at A-(34)1.)

According to DRA, the fact that "a similar, but less severe situation occurred," earlier than the subject outage more than satisfies the reasonable manager standard articulated by the Commission. DRA indicates that APS should have known that a similar outage might occur and should have taken precautionary measures. It is DRA's position that the Commission's analysis need only rely on the prior act and conduct, adding that the Commission need not also rely on SCE's evaluation that the outage was probably foreseeable and preventable. Therefore, DRA's position is that the Unit 3 outage was unreasonable and a disallowance of $615,000 is justified.

DRA also notes that according to SCE's response, APS is considering using ultrasonic testing on the valves to check the integrity of the valves. If this proves successful, APS will perform this task once per cycle.

It is SCE's position that DRA is using the results of the RCE and the wording of SCE's data response in a very simplistic and inappropriate way and ignoring the purpose of these evaluations as learning and performance improvement tools. In rebuttal testimony, SCE provides the following explanation:

> In this instance, Palo Verde personnel identified a problem with one of 28 small air operated valves. This problem was initially identified on Unit 2 and resulted in resin leaking past a valve seat of one of these small valves. The RCE indicates it was inspected, a slow leak was found, and the valve was repaired. Unit 2 experienced another unexpected sulfate increase a couple of months following the valve repair. The source could not be determined but small holes were found in a resin trap and repaired. As a learning tool and performance improvement tool, the RCE suggests that as part of the initial repair of the Unit 2 valve, APS should have asked whether or not similar valves on the Unit 2 polishers system or on Units 1 and 3 should be inspected. This is referred to as addressing the "Extent of Condition." APS did address the extent of condition following the Unit 2 event by instituting a process to routinely inspect several of these valves. However, DRA fails to understand the significance of APS considering the use of ultrasonic testing of these valves for leak-through. As DRA discusses it its Report, APS will test this method and, if effective, will conduct this testing going forward. This seems to SCE to be a reasonable set of next steps in an effort by APS to resolve the problem of detecting when these valves may be leaking. The fact that APS does not yet know the outcome of this testing suggests that the process of applying lessons learned is continuing, that it is working, and that new approaches are being utilized. SCE's conclusion in its Data Request response that this outage was "probably foreseeable and preventable" is

> only valid with the advantage of perfect hindsight. SCE's use of these terms in its response to data request 4.1.5 did not suggest that reasonable and prudent operation of Palo Verde by APS must equate to perfection; it only implied that the plant operator, APS, is learning from the things it finds through the use of hindsight. (Exhibit 4, at 30-31.)

SCE states that after the Unit 2 incident, APS updated its processes to include routine ultrasonic valve testing to check for leak-through conditions. At the time of the event, APS's management believed this would avoid future complications. SCE adds that in hindsight, it was suggested that the Unit 2 event should have undergone an RCE analysis to have fully understood the root cause of the incident, but this does not suggest that the Unit 3 outage event would not have occurred.

5.3.2. Discussion

With respect to SCE's statement that the Unit 3 outage was "probably foreseeable and preventable," we recognize that it is based, at least in part, on the RCE suggestion that as part of the initial repair of the Unit 2 valve, APS should have asked whether or not similar valves on the Unit 2 polishers system or on Units 1 and 3 should be inspected. However, we are not convinced that the need to address the "extent of condition" could only have been reasonably determined through perfect hindsight after the completion of the RCE for the Unit 3 outage. There were two separate prior incidents related to resin leaking into the generators. The first was resin leaking past a valve seat of one of these small valves. The second may have been caused by small holes that were found in a resin trap. While both situations were corrected before a forced outage occurred, APS should then (in 2007) have been aware of potential problems related to leaking resins and high sulfate levels in the generators. At that time, APS should also have known that such problems could lead to forced outages if the situations became more severe. There is no good evidence or reasoning as to why a reasonable manager should not have been aware of the resin leak problems or the potential effect of the problems, prior to the Unit 3 forced outage.

Due to the potential repercussions of such resin leaks, a reasonable course of action, even in the absence of the RCE for the Unit 3 outage, would have been for APS to inspect all similar valves as well as the resin traps for all three units as soon as possible after the incidents occurred. While APS apparently instituted "a process to routinely inspect several of these valves,"[12] a more reasonable approach would have been to inspect all similar valves for all three units as soon as possible and then conduct routine inspections, whether by ultrasonic testing or other method.

While there is no way to know for sure whether or not prompt inspections would have prevented the Unit 3 outage, SCE's statement that it was "probably foreseeable and preventable" indicates that there is a good chance that would have been the case. Therefore, based on all the discussion above, we conclude that the Unit 3 forced outage was not reasonable and ratepayers should not pay for the associated replacement power cost.

To be clear, our decision on this issue is not based on the hindsight results of the RCE, but is instead based on the determination that, with the knowledge of the two previous Unit 2 incidents of resin leaking into the

[12] SCE does not indicate exactly how many valves would be inspected or when they would be inspected. Also, it is not clear which units were inspected or were intended to be inspected.

generators, a reasonable manager would have instituted inspections for similar problems in the other similar units, as soon as possible. Had that been the case, we further determine that it is likely that the Unit 3 outage at issue would have been prevented. SCE has not provided evidence to convince us otherwise.

With the exception of the Palo Verde Unit 3 forced outage, the generation, nuclear fuel expenses, and fuel material and services that SCE purchased for both SONGS and Palo Verde during the Record Period were reasonable.

6. URG – Hydroelectric Generation

During the Record Period, SCE operated and maintained 33 hydroelectric (hydro) generating plants including 33 dams, 43 stream diversions, and approximately 143 miles of tunnels, conduits, flumes and flow lines. These resources have an aggregate 1,175 MW of nameplate generating capacity. SCE has provided information on the characteristics of its hydro generation resources, organization of the Hydro Division, recorded hydro production, and operating results of its facilities.

In its testimony, DRA found that two hydro forced outages were unreasonable. The outages included Bishop 6 Unit 1, caused by disrepair of portions of turbine waterwheel buckets and Bishop 4 Unit 3, caused by failure of portions of turbine waterwheel buckets. SCE addressed both outages in its rebuttal testimony; and, in its opening brief, DRA did not recommend disallowances associated with either outage.

Based on the testimonies of SCE and DRA, we conclude that the SCE hydro facilities were operated reasonably during the Record Period. This includes actions taken with respect to the two forced outages described above.

7. URG – Coal Generation

SCE's coal-fired generating resources consist of (1) Four Corners Generating Station (Four Corners) Units 4 and 5, of which SCE has a 48% ownership interest, and (2) Mohave Generating Station Units 1 and 2, of which SCE has a 56% ownership interest. Arizona Public Service operates the Four Corners Plant. The Mohave Plant did not operate during the Record Period. SCE provided information on Four Corners Coal costs and performance during the Record Period.

In its testimony, DRA determined that a 2.5 day forced outage at Four Corners Unit 5 caused by (1) failure of the baghouse air pollution control equipment, (2) a control problem on the boiler feed pump due to excessive sediment in the hydraulic oil, and (3) problems with the auxiliary steam controls due to excessive moisture was unreasonable. SCE addressed the outage in its rebuttal testimony; and, in its opening brief, DRA did not recommend a disallowance associated with the outage.

Based on the testimonies of SCE and DRA, we conclude that the Four Corners Units 4 and 5 were operated reasonably during the Record Period. This includes actions taken with respect to the Unit 5 forced outage described above.

8. URG - Peakers

During the record period, SCE operated and maintained four peaker generating plants (peakers), each consisting of a single generator of 49 MW rated capacity. SCE has provided testimony to demonstrate that its peaker facilities are operated in a prudent manner during the Record Period. In its testimony, DRA indicates that the forced outages that occurred at SCE's peakers were not unreasonable.

Based on the testimonies of SCE and DRA, we conclude that the SCE peakers were operated reasonably during the Record Period.

9. URG – Catalina Diesel Operations

During the Record Period, SCE purchased 57,806 barrels of diesel fuel and burned approximately 55,000 barrels of diesel for electric generation at Santa Catalina Island. The average total cost per barrel was $146.39. SCE purchased fuel from a major supplier, Southern Counties Oil Company (Orange, CA), under a long-term (3 year) contract. SCE states considering the contract structure, which is the lowest competitive pricing available, and the integrity of the supply, its diesel purchases should be found reasonable. SCE contracts with Catalina Freight Lines to provide the truck and barge transportation from the refinery to the generating facility. SCE indicates that the bulk wholesale rate is less than the tariff rate normally charged for deliveries to the island and should be found reasonable.

In its testimony, DRA generally agrees with SCE's assertions and does not find the costs to be unreasonable. DRA also indicates that it reviewed the one forced outage during the Record Period which lasted longer than 24 hours and did not find the outage to be unreasonable.

Based on the testimonies of SCE and DRA, we conclude that SCE's Catalina diesel operations during the Record Period were reasonable.

10. Replacement Power Costs

10.1. Positions of the Parties

In its testimony, DRA recommends that the Commission disallow $12,473,040, which is the amount DRA calculated that SCE paid for additional purchased power in order to compensate for lost power resulting from various forced outages. DRA states that despite three data requests, SCE failed to provide the cost of replacement power for forced outages. The methodology used by DRA for the recommended disallowance is based on the following assumptions:

1. Outages begin at the beginning of the first hour and end at the end of the last hour. If DRA did not have the beginning hour of the outage, it was assumed that the outage began at 08:00.
2. Effective lost capacity is the product of actual nameplate rating, the record period capacity factor, and proportionate ownership share. For hydro facilities, nameplate and capacity factor were derived from the bypassed MWh provided in SCE's testimony. Nameplate ratings and the capacity factors for other facilities were provided in SCE's testimony.
3. All outages are total; no partial output mitigated calculated total losses.
4. Replacement energy cost would be the marginal prices actually paid by utility for replacement energy; not having this data, DRA uses hourly average energy prices from CAISO.
5. Replacement cost would be mitigated by actual avoided costs during the outage; not having this data, DRA uses $0.
6. All outages are presumed to be equal energy lost per hour for duration of outage.

Based on this methodology, DRA calculates the disallowance related to the Palo Verde Unit 3 outage to be $615,000.

SCE asserts that DRA's replacement cost methodology is flawed for many reasons including:

- Because SCE utilizes least cost dispatch, the absence of any economic or "in-the-money" resource (like a nuclear, coal, or hydro unit) does not necessarily mean that SCE must or even should buy power to replace it.

That decision is determined by SCE's residual net position (RNP) (i.e., the difference between the economic dispatch of all resources and SCE's forecast of customer load) after the outage is taken into account. The absence of an economic energy source would either make SCE's RNP less long, move the RNP from long to short, or make the RNP more short. Although it is not possible to calculate the exact cost of the economic loss due to a specific outage in any of these, one can estimate the value of the "lost energy," or opportunity cost, by considering appropriate published energy indices (with adjustments made, as necessary, for product type, delivery period, delivery point, and the bid-ask spread) and the unit's variable cost of production (fuel and variable O&M). DRA's simplified methodology ignores many of these considerations.

- The appropriate market value of lost energy is reflected at the delivery point of the unit in question. DRA ignores this consideration in its methodology, and instead uses only California (CAISO) prices for all of the outages, even though Four Corners is in New Mexico and Palo Verde is in Arizona; both of which are adjacent to trading hubs with published day-ahead index prices.
- DRA's methodology is further flawed by its use of only CAISO Real-Time Imbalance Market price data. By using this price data, DRA implicitly assumes that all of the energy transacted – whether sales if the RNP was long, or purchases if the RNP was short – was transacted as CAISO Imbalance Energy. This assumption is incorrect. Because the CAISO Real-Time Imbalance Market is subject to low liquidity and high volatility, SCE specifically strives to close out its energy positions in advance of real time by using a combination of hour-ahead, day-ahead, and beyond day-ahead transactions. Indices reflecting these transactions would be the more appropriate benchmarks to use; however, reliable prices are not published regularly for the hour-ahead markets and

published forward prices tend to be for calendar months, quarters, and years, which do not correspond to the outages in question here.

- For the outages in question, the most appropriate prices to benchmark against would be the published day-ahead indices for power, albeit with a few adjustments. This is for a number of reasons. First, the published day-ahead prices are for "Firm LD Energy," and, in the case of non-CAISO energy, Firm LD with ancillary services or WSPP Schedule C. In the case of Four Corners and Palo Verde, the power they provide is unit contingent (WSPP Schedule B) energy, which doesn't include ancillary services. This energy trades at a significant discount (a few to several dollars/MWh, depending on the unit producing it) to the liquidly traded product published by the indices due to its unit contingent nature. In addition, as the published index prices represent an average, or "mid," of the transactions executed on that day, they should be adjusted for the "bid-ask" spread. The magnitude of the bid-ask spread depends on the liquidity of the product at the delivery point in question, and can vary between a few cents and a few dollars/MWh. Therefore, for this analysis, when SCE is purchasing, the published index price should be adjusted up by one-half the bid-ask spread, and conversely, should be adjusted down by one-half the bid-ask spread when SCE is selling.
- Although DRA acknowledges that a replacement cost methodology should include a credit for the fuel cost SCE avoids during the outage, DRA has assumed a credit of zero in its disallowance calculation. In addition, all generating units incur variable O&M costs when operating (covering consumables such as water, chemicals, lube oil, filters, run-hour based maintenance contracts, etc.) that DRA did not consider.

10.2. Discussion

Both DRA and SCE have put the Commission in an awkward position with respect to determining replacement power costs. While DRA has described its methodology and has calculated the replacement power costs for its proposed outage disallowances, it did not respond to any of SCE's specific criticisms of the methodology. On the other hand, SCE, while criticizing DRA's methodology and suggesting alternatives, did not provide any alternative data or calculations on which the Commission can rely in making replacement power cost adjustments. Also, SCE did not indicate whether DRA's methodology resulted in replacement power costs that were either too high or too low.

It would be pointless for the Commission to address and determine the reasonableness of forced outages, if financial consequences of unreasonable outages cannot be calculated and imposed. In order to do that for this proceeding, we will adopt DRA's calculated disallowance of $615,000 for the Palo Verde Unit 3 outage, the only unreasonable outage determined for this Record Period. We recognize that DRA's methodology may be flawed, but it provides the only quantification of replacement power costs. Absent anything better, we will use the results as an approximation of the replacement power cost associated with the Palo Verde Unit 3 outage. In doing so, we are not adopting the use of DRA's methodology and calculations for future proceedings. In the future, we would prefer that parties work towards an agreement on a methodology for calculating replacement power costs. In the absence of such agreement, parties should recognize that the Commission will determine such costs, if needed, based on the best available record evidence.

11. Utility Contract Administration and Costs

As used in this section, "contract administration" means activities implementing the exercise of contract rights and the performance of contract obligations subsequent to either contract execution by SCE or allocation by the Commission to SCE of certain Department of Water Resources power purchase agreements in accordance with AB 57. SCE indicates that during the Record Period it administered 152 bilateral contracts related to electric purchases, sales, and exchanges. Administration of QF and renewable contracts are addressed separately.

DRA states that its review of the Record Period indicates that SCE prudently and diligently administered its Non-QF contracts, and no information was uncovered that cast any suspicion on the company's processes, staff, or results. Consequently, DRA recommends that the Commission grant SCE's request that its Non-QF contract administration activities be found reasonable.

Based on the testimonies of SCE and DRA, we conclude that SCE's contract administration activities were reasonable.

12. QF Contract Administration and Costs

SCE has provided testimony to demonstrate that it administered its QF, contracts in a reasonable manner and in accordance with Commission standards. Based on its review, DRA recommends that the Commission find SCE's management and administration of its QF contracts reasonable.

Based on the testimonies of SCE and DRA, we conclude that SCE's administration and management of its QF contracts during the Record Period was reasonable.

13. 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. Commission resolutions approving these 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. Accordingly, SCE provided testimony to set forth its RPS contract-related expenses, describe its RPS contract development and administration activities during the Record Period, and demonstrate that such activities were reasonable and in accordance with all applicable standards.

As indicated above, DRA recommends that that the Commission grant SCE's request that its Non-QF contract administration activities, which include that related to RPS contracts, be found reasonable.

Based on the testimony of SCE and DRA, we conclude that SCE's administration and management of its RPS contracts during the Record Period was reasonable, and the associated RPS costs are recoverable.

14. CAISO-Related Costs

SCE indicates that it incurred approximately $476.0 million in CAISO-related costs during the Record Period, asserting that the majority of these CAISO-related costs were unavoidable. SCE adds that those costs that SCE had limited discretion to control were managed consistent with the objective of minimizing costs to bundled service customers. DRA has not challenged SCE's request that the Commission find all CAISO-related costs incurred during the Record Period to be reasonable.

We have reviewed SCE's testimony on CAISO-related costs incurred during the Record Period and conclude they were reasonably incurred.

15. Special Sales Contract Administration Costs

SCE presented the results of its administration of its two remaining Self Generation Deferral Rate agreements with ExxonMobil and Tosco (also known as ConocoPhillips). DRA reviewed these agreements as part of its review of SCE's Non-QF contract activity and did not take issue with either agreement, noting that the Commission has, in all past record periods, found both agreements reasonable based on the calculation of the contribution to margin.

Based on the testimony of SCE and DRA, we conclude that SCE's administration of these remaining agreements during the Record Period was reasonable.

16. Operation of Ratemaking Accounts

SCE has provided testimony to the review of the following accounts:

- ERRA;
- Base Rate Revenue Requirement Balancing Account (BRRBA);
- Nuclear Decommissioning Adjustment Mechanism (NDAM);
- Public Purpose Programs Adjustment Mechanism (PPPAM);
- CARE Balancing Account (CBA);
- Energy Settlements Memorandum Account (ESMA) and Litigation Cost Tracking Account (LCTA);
- Automated Meter Infrastructure Memorandum Account and Automated Meter Infrastructure Balancing Account (AMIBA)/SmartConnect Balancing Account;
- Demand Response Balancing Account;
- Department of Energy Litigation Memorandum Account (DOELMA);

- Market Redesign and Technology Upgrade Memorandum Account (MRTUMA);
- New Systems Generation Memorandum Account (NSGMA);
- Project Development Division Memorandum Account (PDDMA);
- Results Sharing Memorandum Account (RSMA); and
- Demand Response Programs Balancing Account.

In this proceeding, SCE requests cost recovery of $265,000 for the DOELMA, $5,160,000 for the MRTUMA, $26,051,000 for the NSGMA, $3,910,000 for the PDDMA, and $410,000 for associated franchise fees and uncollectibles, all of which total $35,796,000.

In its prepared testimony, DRA indicates that it reviewed all of the accounts and noted no exceptions, except for the four accounts where SCE requested cost recovery. However, in its opening brief, DRA indicates that, based on additional workpapers that SCE provided in rebuttal testimony, it now recommends that SCE be allowed to recover the full NSGMA amount. In addition, DRA recommends that in the future, non-ERRA balancing and memorandum accounts for SCE, Pacific Gas and Electric Company (PG&E) and San Diego Gas & Electric Company (SDG&E) be combined together and submitted in a separate reasonableness review proceeding.

Based on the testimonies of SCE and DRA regarding the amounts and dispositions of the ratemaking accounts, we have determined the following for the Record Period:

1. The operation of and entries in the ERRA, BRRBA, NDAM, PPPAM, and CBA as presented by SCE in Exhibit 2 are appropriate, correctly stated, and in compliance with Commission decisions.

2. The amounts recorded in the ESMA and the LCTA are appropriate, correctly stated, consistent with Commission orders, and reasonably incurred.
3. The entries recorded in the RSMA are appropriate, correctly stated, and in compliance with prior Commission decisions.
4. The amounts recorded in the NSGMA totaling $26,051,000 (representing $25,854,000 of expense and $197,000 of interest) are reasonable, correctly stated, in compliance with Commission decisions, and recoverable.
5. The recorded demand response program costs for the 2006 - 2008 program cycle, as shown in Exhibit 2, Table XII-34, are consistent with prior Commission decisions and reasonable.
6. The Phase II and Phase III costs recorded in the AMIBA and SmartConnect Balancing Account were properly recorded, consistent with the categories adopted in D.07-07-042 and D.08-09-039, and recoverable. Also, SCE should be granted authority to eliminate the AMIBA ratemaking mechanism from its tariffs.

Issues relating to the MRTUMA, PDDMA, DOELMA and DRA's proposal for a separate review process for non-ERRA accounts are discussed below.

16.1. MRTUMA

Through a series of orders issued by the Federal Energy Regulatory Commission (FERC), the CAISO began an overhaul of its approach to managing transmission congestion and began to engage in a more comprehensive redesign of its market structure, including the creation of a day-ahead energy market to replace the defunct California Power Exchange markets. The FERC orders provided direction to the CAISO on further development of a new MRTU market design to address structural flaws in the current CAISO's electricity markets.

The MRTU design involves a comprehensive overhaul of the electricity markets administered by the CAISO, and adoption of a new network model that will accurately reflect operations of the CAISO-controlled grid. SCE must undertake major internal computer system changes to ensure integration with the new MRTU systems.[13]

On February 9, 2006, the CAISO filed its MRTU tariff with the FERC. The MRTU tariff was filed as a result of years of study, stakeholder input, coordination with state authorities, and FERC guidance to address the structural flaws in the CAISO's current electricity markets. Market participants, including SCE, are bound to comply with the ultimate FERC-approved MRTU tariff. Furthermore, SCE must also comply with the MRTU tariff to conform with FERC regulations and existing legal agreements of the CAISO.

On May 24, 2007, the Commission issued Resolution E-4087 authorizing SCE to establish the MRTU Memorandum Account to record its incremental costs associated with the CAISO MRTU initiative. Incremental costs represent the amounts SCE has recorded in the MRTUMA that are in addition to the portion of SCE's current authorized General Rate Case (GRC) revenue requirements for the funding of the CAISO's MRTU initiative. In SCE's 2006 GRC decision, D.06-05-016, the Commission adopted SCE's $4.4 million request for software and hardware expenditures associated with the CAISO's MRTU initiative. To ensure that it does not double recover its MRTU expenditures, SCE states that it will reduce its actual recorded MRTU capital expenditures by the Commission-authorized expenditures reflected in SCE's GRC rate levels.

---

[13] Background information on the MRTU and MRTUMA is provided by SCE in Exhibit 2 and by DRA in Exhibit 9 and in its opening brief.

16.1.1. SCE's Request

SCE states that no incremental capital-related revenue requirement was recorded in the MRTUMA during 2007 and 2008. During this time, SCE recorded O&M expenses in the MRTUMA associated with the MRTU-related costs associated with the incremental activities.[14] Specifically, after May 24, 2007, SCE incurred $3.4 million for consultants and related information technology efforts. In addition, $0.8 million of internal labor was incurred in MRTU design and development efforts. Of these amounts, $2.5 million was incremental to GRC-authorized amounts. In 2007, SCE indicates that it incurred non-incremental O&M expenses of $35.1 million prior to recording the $2.5 million incremental MRTU-related O&M expenses in the MRTUMA.

During the 2008 Record Period, SCE states that a total of $4.2 million was incurred in MRTU design and development efforts, of which $2.6 million was incremental to GRC-authorized amounts. In 2008, SCE incurred non-incremental O&M expenses of $36.3 million prior to recording the $2.6 million incremental MRTU O&M expenses in the MRTUMA.

SCE requests the Commission to find that the $5,160,000 in costs recorded in the MRTUMA are reasonable, indicating that upon a Commission finding that these costs are recoverable, SCE will transfer the ending balance, with accrued interest through the date of transfer, to the generation sub-account of the BRRBA.

---

[14] According to SCE, these are primarily labor costs associated with training, CAISO stakeholder activities, organizational readiness, data migration to the new systems, modification of user developed application interfaces to the new MRTU systems, and other business process development activities that did not qualify to be capitalized into the new systems.

16.1.2. DRA's Position

DRA believes the reasonableness of the $5.1 million being requested by SCE is inextricably linked to the total cost of implementing MRTU. SCE stated in Data Request Response 2.6.4 and 4.6.1, "SCE did not request recovery of any capitalized software or capitalized hardware costs in support of MRTU for 2007 or 2008 in its April 1, 2009 ERRA application, A.09-04-002. Instead, SCE will request recovery of these costs in its April 1, 2010 ERRA application—after the work orders for these costs are closed. In light of the foregoing, SCE is not providing the requested information at this time because it is outside the scope of this proceeding." DRA disagrees with that assertion and believes a full assessment of the reasonableness of MRTUMA costs cannot be made without all incremental MRTU costs should being accumulated in MRTUMA for reasonableness. DRA states that it has not been provided the details of all incremental expenditures to determine, for example, the extent of capitalization of any other O&M expense or possible capital impacts of these costs, which it believes is critical information needed in the determination of prudency and reasonableness of SCE's MRTUMA request. Therefore, DRA recommends that:

- The Commission deny SCE's $5.1 million request for O&M cost recovery in this proceeding;
- The $5.1 million request for O&M cost recovery be combined with SCE's Application in a separate proceeding after all current work orders for 2007 and 2008 have been closed;
- All expense amounts related to MRTU activates be recorded in FERC accounts by labor, non-labor and other expenses and outside services contracts be recorded in FERC Account 923; and

- All expenditures associated with MRTU be submitted as required in by the Commission in D.09-03-025.

In response to DRA's recommendations, SCE makes the following points:

- SCE does not record its direct capital expenditures in the MRTUMA because SCE does not recover capital expenditures in the same manner as it recovers an expense. Rather, SCE recovers the capital costs over the life of the project (i.e. each month SCE records the depreciation, return on rate base, and associated taxes). During the construction phase, the capital expenditures are recorded in a capital work order and an Allowance For Use During Construction (AFUDC) is added, among other items. These capital expenditures accumulate in the work order and are recorded on SCE's balance sheet as Construction Work In Progress (CWIP). Once the capital project goes into service, SCE starts to depreciate the asset and AFUDC ceases to be added. At that time, SCE begins to record the depreciation, return on the rate base, and associated taxes in the MRTUMA. Therefore, during the 2008 Record Period, the MRTU-related revenue requirement recorded in the account only included the incremental O&M and not any capital since there was not a capital-related revenue requirement until the project went into service in April 2009.
- Language in Resolution E-4087 (at 5-7) makes clear that the Commission intends that: (1) SCE should be allowed to request recovery of any amounts recorded in the MRTUMA on an annual basis in its ERRA Review proceedings; (2) costs associated with the implementation of MRTU will be incurred over several years; (3) there is no need to defer recovery of O&M or other costs recorded in any given year until the capital project orders related to that year

have closed; and (4) SCE has made specific arrangements to protect against double recovery of MRTU-related costs from year to year. The fact that future costs remain uncertain is what prompted the Commission to authorize the recovery of recorded costs through a memorandum account once SCE has demonstrated that the recorded costs are reasonable. With this approval process in place, no purpose would be served by adopting DRA's proposal that SCE should be prevented from requesting recovery of any costs related to a given year until all capital-related project work orders for that year have closed.

- In D.09-03-025, the Commission did not rule that SCE must await recovery of any MRTU costs until all costs over the multi-year development period of the program have been recorded. Rather, it ruled that SCE must record all categories of MRTU costs (i.e., capital-related, O&M, and others) in the account to be reviewed for reasonableness before they can be recovered. This applies both to 2007-2008 costs, and to 2009-2011 costs. But the fact that the costs are to be reviewed in the annual April ERRA proceedings (that is, each year), clearly indicates that the costs will be reviewed as they are recorded – recovery in one year need not wait for costs in subsequent years to be incurred and recorded.

In summary, SCE states that in accordance with Resolution E-4087, it has recorded MRTU-related incremental O&M for 2007 and 2008 in the MRTUMA and is seeking recovery of those costs in this ERRA proceeding. SCE has not requested recovery of capital-related revenue requirements for 2007 and 2008 in this proceeding, since no capital projects were closed during those years and no capital-related revenue requirement amounts were recorded. The capital-related revenue requirements for 2007 and 2008 were recorded once the project work orders closed in April 2009 and will be included in the April 2010

ERRA (covering the 2009 Record Period). The MRTUMA as presented in this proceeding includes all MRTU related costs that were incurred during 2007 and 2008, in compliance with the Commission's directives. SCE also states that it has submitted all relevant information to demonstrate that these costs are incremental and reasonable.

16.1.3. Discussion

In general, there is logic to DRA's recommendation that capital project costs and associated expenses be reviewed together. It cannot be known if such costs were prudently incurred until it is at least known that the project itself has been completed and is accomplishing what it was intended to do. Also, until the project is completed, it is not known whether additional similar expenses will be necessary. That is, it would be difficult to determine whether certain costs to accomplish certain tasks are reasonable, until it is known with certainty what the final amount of the cost are. However, it is not be necessary to wait several years until MRTU is completed in order to determine whether such costs were reasonably incurred. This can be accomplished as certain phases are completed or even on a work order basis, if the expenses are related to the capital costs in that manner. While there may be expenses that are not linked or related to specific capital projects, the record is insufficient to make that determination. Without information on the capital projects or work orders it is not possible to determine whether any of the expenses are associated with specific capital work and would be better reviewed as such.

Moreover, in this proceeding, there is insufficient record evidence for the Commission to determine whether or not the requested costs were reasonably incurred. While SCE has generally explained what the expenses were for (primarily labor associated with certain activities), it does not provide an accounting of the incremental costs associated with each activity or a description of what was specifically accomplished with the incremental funds for each of the activities.[15] SCE's showing is insufficient to determine whether the expenses at issue were reasonably incurred to implement the CAISO's MRTU initiative.

Therefore, as recommended by DRA, we will defer addressing the reasonableness of the $5.1 million in expense requested by SCE and allow SCE to include that request and make an appropriate showing in its already filed ERRA Review application for the 2009 Record Period, where SCE has indicated its capital revenue requirement associated with capital costs that were incurred in 2007 and 2008 will be addressed. In that way, if necessary, capital costs and related expenses can be analyzed together.

With respect to DRA's recommendation that MRTU expenses be recorded in FERC accounts, that is generally the case for all utility related expenses. We assume the process to record expenses by FERC account is already in place; but, if not, SCE should do so.

With respect to DRA's recommendation that all expenditures associated with MRTU be submitted as required by the Commission in D.09-03-025, there is no need to make any changes to what SCE is currently doing and plans to do. DRA is apparently troubled because capital costs are not being reflected in the MTRUMA. SCE explains that as capital projects are

---

[15] In its July 19, 2010 Comments on the Proposed Decision, SCE indicates that such information could be found in workpapers or data request responses. However that information has not be entered as evidence in this proceeding. Therefore, the Commission cannot consider it in determining whether SCE has met its burden of proof with respect to its showing on this aspect of its request. Also, while DRA did dispute this issue on a policy level, it never indicated that it agreed that the O&M costs, as presented by SCE, were incremental and verifiable.

completed, the capital related revenue requirements associated with those projects will be booked into the MRTUMA. This is appropriate because it is the capital related revenue requirements that directly translate to rates. Moreover, recovery of the capital related costs does not begin until the project is completed and in service.

16.2. DRA Proposal for a Consolidated Proceeding for MRTU Costs

DRA states that it is troubled by the inconsistent applications for recovery of MRTU and ISO New Market costs by the IOU's (SCE, PG&E and SDG&E). According to DRA, because of the newness of the 'ISO New Market Model' and the common factors driving all three IOU's reasonableness requests, their applications should be reviewed at the same time in a consolidated proceeding that is separate from the instant application. DRA states that (1) the MRTU and 'ISO New Market' projects are unique, and although the implementation costs for each IOU are different, they are driven by common factors namely CAISO directives and common FERC Tariff and comparable technical requirements; (2) neither the costs nor the cost/benefit effectiveness were considerations in project design; (3) not only are complete implementation cost showings for SCE not available for capital and O&M for 2007 and 2008, the ability to forecast Long-Run Marginal Price from these investment are years away; and (4) the MRTU project is complex and its future performance is currently are unknown. Therefore, DRA asserts that it is imperative for the Commission to track MRTU project costs and its impacts in order facilitate a comprehensive reasonableness review of MRTU implementation.

DRA argues that the best approach for a comprehensive review would be to treat the MRTU Release 1 costs incurred by all of the IOU's in a consistent manner, best achieved by having an MRTU specific application from each IOU and considering those applications in a single consolidated proceeding.[16] DRA asserts that this approach is not new, in that it has been used in Resource Adequacy, Demand Response, Energy Efficiency, and Low Income cases, and such a consolidated approach better ensures that the Commission treats similar issues in a similar fashion, and best protects ratepayer interests. DRA believes SCE's request is premature and recommends a consolidated proceeding for the major IOUs be scheduled for June or July of 2010. This would allow time for DRA to develop a consistent format and set of Master Data Request questions for all three IOUs to address. Both SCE and PG&E filed their requests before they had completely closed their books on MRTU Release 1, while PG&E combined their request in a forecast proceeding format, it was still incomplete.

16.2.1. SCE's Response

SCE opposes DRA's proposal for a consolidated proceeding for MRTU costs, arguing that the Commission has already ruled that it is appropriate for the MRTUMA to be included in the ERRA Review proceeding. Specifically, in Resolution E-4087, the Commission required SCE to seek recovery of costs recorded in the MRTUMA in this proceeding, and SCE states this issue should be considered settled.

With respect to DRA's argument that a comparative review of the IOUs' costs is appropriate because "the IOUs are driven by common directives,

---

[16] DRA states that the implementation approach that the CAISO described to FERC involves three major releases: Release 1, which is the initial implementation that occurred on April 1, 2009; Release 1A, which includes Convergence Bidding, to be implemented within 12 months of Release 1; and Release 2 to be implemented within three years of the initial implementation date.

tariff structure[s], and technical requirement[s]," SCE states this is not entirely accurate. According to SCE, it is true that all market participants are driven by common factors and the CAISO tariff; however, the manner in which each IOU approaches the requirements can be wholly different. As an example, CAISO provides a portal to submit MRTU market bids and information, known as "Scheduling Infrastructure Business Rules" (SIBR). According to SCE, market participants can manually enter their bid and schedule data in SIBR; alternatively, they can streamline the process through an application programming interface that can be used to interface with the participants' internal systems. In this case, SCE states it implemented the latter solution for a number of reasons, not the least of which is the sheer volume of resources and transactions for which SCE is responsible. However, SCE adds that other participants made their own decisions on internal solutions based on their unique requirements, and it is incorrect to assume that all participants' implementation costs should be comparable, simply because the same CAISO rules apply to everyone.

SCE also argues that DRA's argument should be rejected, because it overstates the "commonality" of the IOUs' implementation efforts. According to SCE, a direct comparison of the IOUs' MRTU implementation efforts is inappropriate because the three IOUs had different resource portfolios, customer demands, reliability issues, and information systems in place prior to MRTU that had to be modified or replaced.

SCE is also concerned that DRA is interested in having the Commission perform a much broader assessment than the one prescribed in Resolution E-4087. SCE cites DRA's testimony where DRA initially proposed a set of 16 factors that it claimed should be considered as part of the Commission's reasonableness review of SCE's and the other IOUs' cost to implement MRTU. SCE notes that although DRA does not reference these factors in its opening brief, it nonetheless continues to assert that a "comprehensive" review of MRTU is required and that the IOUs' respective MRTU software must be verified, validated, and reviewed by the Commission. It is SCE's position that this kind of review is totally inappropriate as it is beyond the scope of the review prescribed in Resolution E-4087. SCE notes that the Commission recently reaffirmed the limited scope of review of the IOUs' MRTU-related recorded costs in its final decision in PG&E's June 2009 ERRA Forecast proceeding (A.09-06-001), D.09-12-021:

> Although this decision denies PG&E's Motion to include MRTU-related costs on procedural grounds and defers the issue to PG&E's ERRA Compliance filing (or separate application), the Commission notes that the scope of its review of PG&E's MRTU costs is not necessarily a traditional reasonableness review. The MRTU project is a project mandated by regulatory and reliability requirements of the California Independent System Operator and Federal Energy Regulatory Commission. Therefore, the Commission expects the review of these costs to primarily focus on whether the costs can be verified and are incremental. (At 3, footnote 2).

According to SCE, the Commission has not required that IOUs make a broader showing to recover their costs associated with the implementation of MRTU, and the "comprehensive" review that DRA is advocating would seek to second-guess the policies and decisions adopted by the CAISO and FERC in a federally-mandated program under which SCE is required to operate. SCE states that such review is inappropriate, and risks introducing confusion and uncertainty into a complex, federally-mandated program, and the Commission should therefore continue to restrict its role to determining whether the costs recorded in the IOUs' MRTU memorandum accounts are incremental and verifiable.

16.2.2. Discussion

While there is commonality in most costs incurred by the three IOUs for their electric operations, the review of such costs are generally performed on utility specific bases, mainly due to the need to establish separate rates for each of the IOUs. In establishing such rates, the particular circumstances of each utility are considered and, in general, such consideration overrides direct comparisons with other utilities. However, there may be value in developing common programs and requirements for a number of utilities in a single proceeding. DRA cites the examples of resource adequacy, demand response, energy efficiency and low income cases where the Commission has done so.

In determining whether or not we should consolidate the evaluation of MRTU Release 1 costs for the three IOUs in a single consolidated proceeding, we considered three points. First, MRTU is the result of numerous CAISO stakeholder processes and FERC orders. We do not intend to assess the reasonableness of MRTU or the associated requirements imposed on the IOUs. Consequently, there is no need for a single comprehensive proceeding to do so.

Additionally, while the IOUs' MRTU efforts are driven by common directives, tariff structures, and technical requirements, SCE's assertion that the manner in which each IOU approaches the requirements can be wholly different is not disputed by DRA. Based on the available evidence, we see little benefit, at this time, in consolidating the IOUs' MRTU related proceedings and then having to determine the reasonableness of each particular utility's actions when considering each utility's particular circumstances, such as resource portfolios, customer demands, reliability issues, and information systems in place prior to MRTU.

For these reasons, we will deny DRA's request for the review of all three IOUs MRTU Release 1 costs in a single proceeding. At this point, we are satisfied that reviewing SCE's MRTU Release 1 costs in its ERRA compliance filing for the 2009 record period is reasonable. However, we recognize this determination is based on the record of this proceeding, which does not include any showings related to any of the IOUs MRTU Release 1 capital costs. Without such showings it is not possible to say for certain that a consolidated proceeding would not be beneficial. For this reason, while we address DRA's request now based on the available evidence, today's decision does not preclude a different outcome with respect to consolidation, if requested in subsequent ERRA Review filings.

16.3. PDDMA

In A.04-12-014, SCE requested $4,950,000 in expenses to fund its Project Development Division (PDD). PDD's primary identified function was to analyze, develop, and propose for Commission approval, cost-effective, utility-owned generation opportunities consistent with SCE's long-term procurement plan. These opportunities could include new plant construction, repowering, joint-ventures, purchasing shares in new or existing facilities, or other commercial arrangements. Secondarily, PDD would provide the Resource Planning and Strategy organization with data regarding construction costs, project economics and the commercial feasibility of future resource supply levels, as requested, to assist in long-term procurement forecasting.

In D.06-05-016, the Commission denied base rate recovery of PDD expenses that were associated with specific proposed projects. Such costs should instead be included in the capital costs of the project and recovered if and when the project is completed. This would subject SCE to the same risks as independent producers whose development costs for unsuccessful projects are not recoverable from ratepayers. However, the Commission agreed with SCE that to an extent PDD would support the future of new generation in California even if they do not develop any projects. Such support functions include: (1) identifying locations for new generation, (2) evaluating generation technologies, (3) tracking regulatory and legislative generation-related initiatives, and (4) the development of the "Best Option Outside Negotiation" for future generation needs. These support functions were determined to be desirable and the Commission concluded that SCE should be allowed rate recovery for these costs. However, since these particular costs had not been segregated and identified, they could not be included in rates on a forecast basis. Therefore, the Commission authorized the establishment of a memorandum account to accumulate the costs, indicating that the costs could be recovered in future rates to the extent they are incurred, to the extent that SCE can justify their supportive nature, and to the extent that the total recorded PDD costs do not exceed SCE's forecasted amount of $4,950,000 for the PDD.[17]

16.3.1. Positions of the Parties

In this proceeding, SCE requests a finding of reasonableness for $3,910,000 in expenses associated with PDD for 2008. In its testimony, DRA stated that this is a 38% increase over 2007, asserted SCE has not provided enough supporting and detailed evidence concerning the costs and expenditures to warrant ratepayer recovery, and recommended the cost be disallowed because SCE failed to meet its burden of proof.

In rebuttal, SCE states that its request is supported by the testimony, workpapers and data request responses, and that the supporting information is the same as that provided in prior ERRA Review applications.

In its opening brief, DRA now recommends a disallowance of $587,928, asserting that this amount represents costs that are associated with three capital projects and should be recovered through the capital recovery of those three projects, if approved by the Commission. DRA is apparently no longer pursuing its argument that SCE has failed to meet its burden of proof.

In reply briefs, SCE states that these costs were incurred before the applications for the three projects were filed and consisted of support functions that the Commission authorized in D.06-05-016. SCE further states that the Commission drew a distinction between PDDMA-eligible supportive costs, which may or may not result in a proposed new project, and non-eligible costs that are in fact associated with a proposed project. SCE adds that this DRA proposal whereby SCE would wait to recover costs associated with support

---

[17] See, D06-05-016, Conclusion of Law 8.

activities that do lead SCE to pursue a specific project until (and only) if the Commission approves the related decisions, renders the entire purpose of the PDDMA moot.

SCE also takes issue with DRA introducing its new argument after the evidentiary record for this proceeding has concluded. It is SCE's position that it is inappropriate and the Commission should disregard DRA's new argument for a disallowance.

16.3.2. Discussion

With respect to DRA's initial recommendation related to burden of proof, DRA did not explain what aspects of SCE's showing were deficient. However, as noted above, D.06-05-016 specified three requirements for rate recovery of PDD costs. The costs must be incurred, they must be supportive in nature and not project specific costs, and in any year they must total less than $4,950,000. The recorded cost for 2008 is $3,834,930 for 2008. Also, workpapers for SCE's testimony[18] include a description of the various PDD costs for 2008. The descriptions generally are for identifying locations for new generation and evaluating generation technologies and appear consistent with the allowable functions identified in D.06-05-016. SCE's showing is sufficient and meets its burden of proof obligations.

With respect to DRA's disallowance recommendation that is described in its opening brief, we will clarify the purpose and intent of the

---

18 Exhibit 5, Appendix D, at 185-230.

Commission's determinations in D.06-05-016.[19] The purpose of the PDDMA is to allow SCE cost recovery of appropriate supportive costs that are not associated with a specific project. The Commission saw value in the support functions identified in D.06-05-016 and determined they should be funded in rates. It was recognized that SCE might not propose a project as a result of the supportive expenditures, and even if did, its proposal might never be authorized. However, the Commission's intent in D.06-05-016 was that, regardless of whether or not SCE proposed or built a project, SCE should be given the opportunity to recover those supportive costs that meet the requirements identified in the decision. Use of the PDDMA for all appropriate supportive costs meets that intent. Therefore, we will not adopt DRA's recommendation, and conclude that SCE should be allowed recovery of $3,834,930 in PDD costs for 2008.

16.4. DOELMA

SCE filed a complaint against the DOE in the Federal Court of Claims on January 29, 2004, alleging that DOE had breached its contracts with SCE under which the DOE agreed to take title to, and dispose of SONGS spent nuclear fuel beginning on January 31, 1998. SCE had entered into standard contracts for such disposal with the DOE as a condition of SONGS operating licenses with the NRC.

The Court of Claims determined that the DOE had breached its standard contracts with SCE and other nuclear utilities. As a result of the DOE

[19] Since (1) SCE was able to respond to DRA's revised proposal in its reply brief and (2) we are merely clarifying a previous decision and applying that here, it is not necessary to ignore DRA's new argument as requested by SCE.

breach, SCE is entitled to recover damages though litigation and retain outside legal counsel to pursue such damages.

On January 4, 2007, SCE filed Advice Letter 2085-E to request Commission authority to establish the DOELMA. In accordance with the advice letter, SCE records the difference between the incremental litigation costs incurred, and damages and other proceeds received from the federal government. These expenses include, but are not limited to, the following:

- Outside counsel incremental costs;
- Expert witnesses incremental costs;
- Other outside litigation-related costs; and
- Proceeds and damages received from the federal government.

SCE incurred costs of $0.265 million in 2007 and 2008 for DOELMA activities, including interest related to the DOELMA monthly balances.

16.4.1. Positions of the Parties

SCE requests that the Commission find the costs recorded in the DOELMA are properly recorded, consistent with Advice Letter 2085-E, and are reasonable and recoverable.

Although DRA does not take issue with the reasonableness of the expenditures in this account, it believes that a determination regarding this account is not and should not be a part of this Application.

The Resolution (E-4066, March 15, 2007) that authorized the opening of the account, along with the underlying Advice Letter, authorizes SCE to recover the funds as follows:

> At a future date, SCE shall make a proposal to dispose of the net amount recorded in the DOELMA in an application before the Commission. In its application,

> SCE shall also justify the reasonableness of its incremental litigation costs recorded in the DOELMA.

Thus, it is DRA's position that the Commission did not order that this account be addressed in ERRA, but by way of "an application." This is different from other accounts, like the PDDMA and the NSGMA, which were ordered to be addressed in an ERRA related application. The Commission's stated in the Scoping Memo that:

> Since the Commission has previously determined that certain non-ERRA accounts should be included in SCE's ERRA compliance filing, it is appropriate for SCE to do so and appropriate for the Commission to address these accounts as part of this proceeding.

DRA asserts that DOELMA is not one of those accounts, and SCE should be ordered to submit its request for recovery of this litigation account when the litigation is concluded and in a separate application.

SCE explains that the Commission specifically required three non-ERRA accounts to be presented in this proceeding (i.e., the MRTUMA, NSGMA, and PDDMA). While the Commission has not required SCE to present its remaining non-ERRA accounts for review here, SCE decided to include these accounts in its ERRA Review application based on prior Commission decisions that have confirmed the ERRA Review proceeding as an appropriate forum for reviewing non-ERRA accounts. Based on these Commission decisions, as well as prior practice, SCE elected to include the DOELMA in its April 2009 ERRA Review Application. SCE indicates that this is not inconsistent with the statement in Advice Letter 2085-E that SCE must present its recorded costs for review in "an application," since this proceeding is an application.

SCE adds that in the Scoping Memo, the Commission left it to DRA to justify why non-ERRA accounts should be presented for review in the future, via a separate application:

> DRA may include this issue as part of its direct testimony, with the understanding that any Commission determined changes as to where, or how, these non-ERRA accounts are reviewed would only relate to the timeframe of future SCE ERRA compliance filings, not to the instant proceeding. (At 5.)

According to SCE, the Commission's ruling makes clear that in the present ERRA Review proceeding it is appropriate to review SCE's non-ERRA accounts, including the DOELMA. Since DRA has now indicated that it has reviewed this account and does not take issue with SCE's costs recorded therein, SCE asserts that the Commission should therefore find that SCE's costs recorded in this account are reasonable and recoverable.

16.4.2. Discussion

With respect to the disposition of amounts recorded in the DOELMA, SCE proposed:

> At a future date, SCE will file an application with the Commission proposing disposition of the net amount recorded in the DOELMA. In its application, SCE will also justify the reasonableness of incremental litigation costs recorded in the DOELMA. Thus, the Commission and interested parties will have an opportunity in a formal proceeding to conduct a thorough review of amounts recorded in the DOELMA.
> (Advice Letter 2085-E at 2.)

In Resolution E-4066, dated March 15, 2007, the Commission determined that, "SCE shall file a formal application to address the disposition of the DOELMA." (At 7.)

It is clear that disposition of the DOELMA account should be done by application primarily to accommodate review of the recorded amounts. However, SCE proposed, and the Commission determined, that disposition would be through <u>an application</u>, indicating one application and one review, and not a number of applications and reviews that are necessitated by SCE's current request that reflects only a portion of the costs and no proceeds. Furthermore, SCE itself proposed that its application would dispose of <u>the net amount recorded in the DOELMA</u>. Disposition of the net amount cannot occur until after the litigation has been completed and all costs and proceeds are known. Finally, in requesting establishment of DOELMA, SCE asserted that the proceeds would far exceed the incremental litigation costs. The Commission stated a similar expectation in authorizing the DOELMA and providing cost recovery of the litigation costs. It would be premature to authorize incremental cost recovery at this time since there is no assurance that proceeds in excess of costs will be realized. SCE should request disposition of the DOELMA after all costs and proceeds are known. We will allow SCE to do so in a future ERRA Review proceeding or by separate application.[20]

With respect to SCE's claim that the Scoping memo precludes DRA's recommendation, we disagree. The point of the identified scoping memo

---

[20] In its July 19, 2010 Comments on the Proposed Decision, SCE requested that it be allowed to present its trial costs in its April 2011 ERRA Review Application and present its appellate costs after the litigation has reached its final conclusion in a future ERRA Review application. However, it is not clear when the proceeds would be reflected in rates by this proposal. If that were not to happen until litigation of the appeal were completed, SCE's request would not address our concern regarding authorizing incremental cost recovery when there is no assurance that proceeds in excess of costs will be realized. For that reason, we will not adopt SCE's request at this time.

discussion was to indicate that non-ERRA requests by SCE in this proceeding would be addressed in this proceeding and DRA's idea of a consolidated proceeding for non-ERRA accounts would apply prospectively only. DRA's recommendation is based on its assertion that SCE's request should never have been filed in this proceeding at all, which is different and appropriate for consideration now.

16.5. DRA Proposal for a Consolidated Proceeding for Non-ERRA Accounts

DRA identifies several non-ERRA accounts that have been ordered through Commission Decisions to be addressed in SCE's ERRA proceedings. These accounts include BRRBA, CARE, DRPBA, NSGBA, NDAM, PPPAM, PDDMA, RSMA, and SCBA. Additionally, through Commission Resolutions the ESMA, LCTA, MRTUMA and DOELMA are to be addressed in ERRA proceedings.

DRA believes it would be appropriate to address many non-ERRA accounts collectively for all three IOUs. DRA seeks clarification from the Commission regarding the appropriateness of including non-ERRA accounts in the ERRA proceeding and urges that a consistent mechanism or approach be adopted and makes recommendations along those lines. Specifically, DRA recommends that SCE, PG&E, and SDG&E should not submit non-ERRA balancing and memorandum accounts in any ERRA proceeding. Instead, these non-ERRA accounts should be combined together and submitted in a separate reasonableness review proceeding. DRA recommends that all three IOUs be ordered to file these non-ERRA account review applications simultaneously and that they then be consolidated. According to DRA, such a system would allow similar accounts to be compared across IOUs, for these same accounts to be addressed faster than if they were added to the individual IOU's General Rate Case, and would take them out of the ERRA process.

To support its position, DRA surveyed all balancing and memorandum accounts used by SCE, PG&E, and SDG&E.[21] The survey of SCE showed that of the 50 accounts it identified, it anticipates it may submit as many as 33 different accounts for review in its annual ERRA Compliance proceedings. The survey of SDG&E showed that of the 37 accounts SDG&E identified, SDG&E anticipates it may submit for review in its future annual ERRA Compliance proceedings for as many as 6 different accounts. For 2008, DRA indicates that SCE submitted 14 non-ERRA accounts for review, PG&E submitted the ERAA balancing account only, and SDG&E submitted two non-ERRA accounts for review.

DRA acknowledges that each IOU has included many non-ERRA balancing and memorandum accounts pursuant to Commission approval. Although the IOUs usually obtained Commission approval to submit these additional accounts in the ERRA Compliance proceedings, these approvals were over a period of several years. The total number of these non-ERRA accounts included in the ERRA Compliance proceedings has grown and continues to grow. Generally, PG&E and SDG&E each submit non-ERRA accounts in other proceedings such as the Annual Electric True-Up (AET) Proceeding, Low Income Energy Efficient, and Energy Efficiency Proceeding.

DRA states that all non-ERRA balancing accounts and memorandum accounts require reasonableness reviews, the scope of which is different from a

---

[21] Detailed results are included in Exhibit 9.

compliance review, and believes reviews of the IOU's non-ERRA accounts are best suited for reasonableness review proceedings.

16.5.1. SCE's Response

SCE does not agree with DRA and recommends that the Commission should continue to examine non-ERRA Accounts in the ERRA review proceeding. SCE explained why the Commission's review of these accounts in the ERRA Review proceeding was appropriate in its reply to DRA's protest to the application. In particular, SCE explained that the Commission and DRA had reviewed these accounts in at least the past four ERRA Review proceedings. SCE also cited certain Commission decisions and resolutions that require review of these accounts in the ERRA Review proceeding. Finally, SCE noted that the Commission-approved tariff language in all but one of the accounts that SCE presented for review in this proceeding specifies that they are to be reviewed in the ERRA Review proceeding.

Additionally, SCE notes that the Scoping Memo left it to DRA to develop a record justifying why these accounts should be removed from the ERRA Review proceeding and consolidated for review in a separate proceeding. In particular, the Commission observed the following issues that would need to be addressed before such a finding could be made: (1) the extent of the problems related to addressing non-ERRA accounts in the ERRA proceeding; (2) where and how the other IOUs address each of the non-ERRA accounts presented by SCE in this proceeding; and (3) why it would be appropriate to override previous Commission determinations that certain non-ERRA accounts should be addressed in SCE's ERRA Review proceeding.

It is SCE's position that DRA has either ignored or failed to sufficiently address these issues in its Report. Furthermore, DRA has not explained the extent of problems related to addressing these non-ERRA accounts in this proceeding. Instead, it just observes that the number of non-ERRA accounts in SCE's ERRA proceedings "has grown and continues to grow." According to SCE, this observation by itself does not justify the Commission finding that review of these non-ERRA accounts is problematic, especially when DRA has not stated that it is having difficulty reviewing these non-ERRA accounts in this proceeding, and has successfully reviewed these accounts in past ERRA proceedings.

Finally, with respect to DRA's argument that these accounts should be removed from this proceeding because they require reasonableness review, instead of compliance review, by the Commission, SCE explains that the Commission has not limited the ERRA Review proceeding to only a review of the utility's compliance with its procurement plan and SOC 4. For example, the Commission has considered the reasonableness of forced outages in prior ERRA Review proceedings, as well as in this proceeding. In addition, the Commission also reviews the reasonableness of SCE's administration of various contracts in the ERRA Review proceedings.

16.5.2. Discussion

We will not adopt DRA's recommendation that SCE, PG&E, and SDG&E should not submit non-ERRA balancing and memorandum accounts in any ERRA proceeding, but that instead, these non-ERRA accounts should be combined together and submitted in a separate reasonableness review proceeding.

First of all, we do not fully understand DRA's recommendation. DRA has not specified which accounts should be included in its proposed consolidated reasonableness review proceeding. It is not clear that each and every balancing or memorandum account that is identified (50 for SCE, 77 for PG&E and 37 for SDG&E) requires a reasonableness review. Also, there may be accounts where costs are being recorded or accumulated but a separate application is required for cost recovery. If DRA's recommendation is that non-ERRA accounts that are, or are anticipated to be, submitted in ERRA proceedings should instead be reviewed in a separate consolidated proceeding, that recommendation does not appear justified. DRA's information indicates that while SCE may include as many as 33 non-ERRA accounts in future ERRA compliance review filings, PG&E, in general, does not submit non-ERRA accounts in ERRA proceedings and SD&GE only submitted two in its 2008 ERRA compliance review proceeding and anticipates possibly six in future reviews. The value of consolidating review for the three utilities would be minimal under those circumstances. More importantly, in either case, DRA has not adequately justified the need for a consolidated review for the three IOUs.

DRA was able to review the non-ERRA accounts submitted by SCE in this proceeding as it has apparently been able to do in the last four proceedings. Other than indicating that the number of non-ERRA accounts are growing, DRA has not demonstrated (1) the extent and types of analyses that would be required for each of the accounts and why it would be a burden to continue to do such analyses in the ERRA for SCE; (2) any problems in reviewing and analyzing non-ERRA accounts for PG&E and SDG&E, whether in ERRA proceedings or elsewhere; and (3) what aspects of its analyses for each account is common for all three IOUs, and even if there were common analyses why it would be reasonable, necessary, or desirable to compare the results for the three IOUs.

In summary, we do not adopt DRA's recommendation because it is vague, and there is insufficient reason to disregard the current cost recovery mechanisms for each of the three IOUs and consider non-ERRA accounts in a consolidated reasonableness review proceeding.

16.6. DRA's Internal Audit Recommendation

DRA recommends that SCE's Audit Service Department (ASD) audit the ERRA balancing account at least once every three years. Currently, no audits are done, and DRA states the revenues, costs and expenses are material and have a significant rate impact on SCE's customers. SCE states that although it believes ASD's limited resources would be better spent reviewing potentially higher-risk areas, it is nonetheless willing to have ASD conduct an audit of the ERRA balancing account once every three years. DRA's recommendation is reasonable, acceptable to SCE, and will be adopted.

17. Comments of Proposed Decision

The proposed decision of the Administrative Law Judge (ALJ) in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed on July 19, 2010, and reply comments were filed on July 27, 2010 by SCE and DRA. To the extent that the comments merely reargued the parties' positions taken in their briefs, those comments have not been given any weight. The comments which focused on factual, legal or technical errors have been considered, and, if appropriate, changes have been made.

18. Assignment of Proceeding

Timothy Alan Simon is the assigned Commissioner and David Fukutome is the assigned ALJ in this proceeding.

Findings of Fact

1. DRA does not take issue with SCE's least-cost dispatch record in this proceeding.

2. SCE's methodology for forecasting its ERRA revenue requirement has been reviewed and approved by the Commission on an annual basis in SCE's ERRA Forecast proceedings.

3. To the extent that there are large variations in SCE's forecast of its ERRA revenue requirement, these are usually driven by factors beyond SCE's control, such as unexpected swings in the price of natural gas.

4. DRA did not respond directly to SCE's criticisms of its monthly average price comparisons.

5. DRA and SCE can informally explore the development and use of supplemental information or techniques that may be valuable in evaluating future SCE ERRA Review filings.

6. In its testimony, DRA found that three nuclear forced outages were unreasonable. However, in its opening brief, DRA only recommended disallowances associated with the SONGS Unit 2 and Palo Verde Unit 3 outages.

7. RCEs are based on hindsight, using information and results available at the time the report was written – not just information that was available at the time of the incident.

8. For the June 5, 2008 SONGS Unit 2 forced outage, DRA does not provide an evaluation of the RCE in light of the "reasonable manager" standard. SCE does provide such evaluation.

9. There is no good evidence or reasoning as to why a reasonable manager should not have been aware of the potential for resin leak problem or the

potential effect of the problem, prior to the September 27, 2008 Palo Verde Unit 3 forced outage.

10. While there is no way to know for sure whether or not prompt inspections would have prevented the Palo Verde Unit 3 outage, SCE's statement that it was "probably foreseeable and preventable" indicates that there is a good chance that would have been the case.

11. With respect to SCE's operation and maintenance of its hydro facilities, in its testimony, DRA found that two hydro forced outages were unreasonable. However, in its opening brief, DRA did not recommend disallowances associated with either outage.

12. With respect to SCE's coal generation resources, in its testimony DRA found that a Four Corners Unit 5 forced outage was unreasonable. However, in its opening brief, DRA did not recommend a disallowance associated with this outage.

13. DRA indicates that SCE reasonably operated its peakers.

14. DRA indicates that SCE reasonably operated its Catalina diesel operations.

15. DRA proposed a replacement power cost methodology and calculated the replacement power costs for its proposed outage disallowances.

16. SCE criticized DRA's proposed replacement power cost methodology, but did not provide any alternative data or calculations on which the Commission can rely in making replacement power cost adjustments.

17. DRA did not directly respond to SCE's criticisms of its replacement power cost methodology.

18. DRA recommends that the Commission grant SCE's request that its Non-QF contract administration activities, including that related to RPS contracts, be found reasonable.

19. DRA recommends that the Commission find SCE's management and administration of its PURPA contracts reasonable.

20. DRA found SCE's administration Non-QF contracts, including RPS contracts, during the Record Period to be reasonable.

21. DRA found SCE's administration QF contracts during the Record Period to be reasonable.

22. DRA has not challenged SCE's request that the Commission find all CAISO-related costs incurred during the Record Period to be reasonable.

23. DRA reviewed the Self Generation Deferral Rate Agreements with ExxonMobil and Tosco and does not take issue with either agreement.

24. With respect to the operation of ratemaking accounts, DRA reviewed all of the accounts and, in testimony, noted no exceptions, except for the DOELMA, NSGMA, MRTUMA, and PDDMA. In its opening brief, DRA indicates that, based on additional workpapers that SCE provided in rebuttal testimony, it now recommends that SCE be allowed to recover the full NSGMA amount.

25. There is logic to DRA's recommendation that capital project costs and associated expenses be reviewed together.

26. With respect to SCE's MRTUMA request, there is insufficient record evidence for the Commission to determine whether or not the requested costs were reasonably incurred.

27. As capital projects are completed, the capital related revenue requirements associated with those projects will be booked into the MRTUMA.

28. MRTU is the result of numerous CAISO stakeholder processes and FERC orders. There is no need for a single comprehensive proceeding to assess the reasonableness of MRTU or the associated requirements imposed on the IOUs.

29. While the IOUs' MRTU efforts are driven by common directives, tariff structures, and technical requirements, SCE's assertion that the manner in which each IOU approaches the requirements can be wholly different is not disputed by DRA.

30. SCE's PDDMA request of $3,834,930, excluding interest, is less than the maximum of $4,950,000 indicated in D.06-05-016.

31. Workpapers for SCE's testimony include a description of the various PDD costs for 2008. The descriptions generally are for identifying locations for new generation and evaluating generation technologies and appear consistent with the allowable functions identified in D.06-05-016.

32. The purpose of the PDDMA is to allow SCE cost recovery of appropriate supportive costs that are not associated with a specific project.

33. The Commission's intent in D.06-05-016 was that, regardless of whether or not SCE proposed or built a project, SCE should be given the opportunity to recover those supportive PDD costs that meet the requirements identified in the decision. Use of the PDDMA for all appropriate supportive PDD costs meets that intent.

34. SCE proposed, and the Commission determined, that disposition of the net amount in the DOELMA would be through an application, indicating one application and one review, and not a number of applications and reviews that are necessitated by SCE's current request that reflects only a portion of the costs and no proceeds.

35. Disposition of the net amount cannot occur until after the litigation has been completed and all costs and proceeds are known.

36. Whether or not DOELMA proceeds will be far exceed incremental costs cannot be determined until after the litigation has been completed and all costs and proceeds are known.

37. DRA's proposal for a consolidated proceeding for non-ERRA accounts is vague, and there is insufficient reason to disregard the current cost recovery mechanisms for each of the three IOUs and impose such consolidation and review.

Conclusions of Law

1. All dispatch-related activities SCE performed during the Record Period complied with Commission orders and SCE's procurement plan.

2. SCE acted prudently in first filing trigger application, A.08-09-011, as required and then in withdrawing the trigger application when more recent information indicated that the threshold would not be exceeded.

3. If DRA continues to make use of monthly average purchase and sales price comparisons in future ERRA Review proceedings, it should explain why such comparisons are meaningful or relevant, in light of the criticisms made by SCE in this proceeding.

4. A rulemaking to address a preferred methodology for evaluating least-cost dispatch is unnecessary.

5. RCEs must be evaluated in conjunction with the "reasonable manager" standard in determining whether a nuclear outage is reasonable or unreasonable for the purposes of this proceeding.

6. The evidence supports SCE's position that its actions, with respect to the June 5, 2008 SONGS Unit 2 forced outage, were reasonable.

7. Due to the potential repercussions of resin leaks, a reasonable course of action, even in the absence of the RCE for the Palo Verde Unit 3 outage, would

have been for APS to inspect all similar valves as well as the resin traps for all three units as soon as possible after the incidents occurred.

8. The September 27, 2008 Palo Verde Unit 3 forced outage was not reasonable and ratepayers should not pay for the associated replacement power cost.

9. With the exception of the September 27, 2008 Palo Verde Unit 3 forced outage, the generation, nuclear fuel expenses, and fuel material and services that SCE purchased for both SONGS and Palo Verde during the Record Period were reasonable.

10. SCE's hydro facilities were operated reasonably during the Record Period.

11. Four Corners Units 4 and 5 were operated reasonably during the Record Period.

12. SCE's peakers were operated reasonably during the Record Period.

13. SCE's Catalina diesel operations were operated reasonably during the Record Period.

14. It is reasonable to use DRA's calculated amount of $615,000 for the Palo Verde Unit 1 outage replacement power cost, because there is no better quantification of the disallowance on the record.

15. All aspects of SCE's contract administration during the Record Period were reasonable.

16. RPS costs incurred during the Record Period are recoverable.

17. SCE's CAISO-related costs incurred during the Record Period were reasonably incurred.

18. SCE's administration of its two remaining Self Generation Deferral Rate agreements during the Record Period was reasonable.

19. The operation of and entries in the ERRA, BRRBA, NDAM, PPPAM, and CBA as presented by SCE in Exhibit 2 are appropriate, correctly stated, and in compliance with Commission decisions.

20. The amounts recorded in the ESMA and the LCTA are appropriate, correctly stated, consistent with Commission orders, and reasonably incurred.

21. The entries recorded in the RSMA are appropriate, correctly stated, and in compliance with prior Commission decisions.

22. The amounts recorded in the NSGMA totaling $26,051,000 are reasonable, correctly stated, in compliance with Commission decisions, and recoverable.

23. The recorded demand response program costs for the 2006 - 2008 program cycle, as shown in Exhibit 2, Table XII-34, are consistent with prior Commission decisions and reasonable.

24. The Phase II and Phase III costs recorded in the AMIBA and SmartConnect Balancing Account were properly recorded, consistent with the categories adopted in D.07-07-042 and D.08-09-039, and recoverable.

25. SCE should be granted authority to eliminate the AMIBA ratemaking mechanism from its tariffs.

26. It is reasonable to defer addressing the reasonableness of the $5.1 million in MRTU expenses requested by SCE and allow SCE to include that request and make an appropriate showing in its already filed ERRA Review application for the 2009 Record Period.

27. MRTU expenses should be recorded in FERC accounts.

28. With respect to DRA's recommendation that all expenditures associated with MRTU be submitted as required by the Commission in D.09-03-025, there is no need to make any changes to what SCE is currently doing and plans to do.

29. Based on the record evidence, DRA's request that there be a consolidated proceeding for MRTU costs should be denied. This does not preclude a different outcome with respect to consolidation, if requested in subsequent ERRA Review filings.

30. With respect to the PDDMA, SCE's showing is sufficient and meets its burden of proof obligations.

31. SCE should be allowed recovery of $3,910,000, including interest, in PDD costs for 2008.

32. SCE should request disposition of the DOELMA after all costs and proceeds are known.

33. DRA's request that there be a consolidated proceeding for review of non-ERRA accounts should be denied.

34. DRA recommendation that SCE's Audit Service Department +audit the ERRA balancing account at least once every three years is reasonable.

O R D E R

IT IS ORDERED that:

1. Southern California Edison Company shall appropriately reflect a $615,000 disallowance, associated with the September 17, 2008 Palo Verde Nuclear Generating Station Unit 3 forced outage, in its Energy Resource Recovery Account.

2. Southern California Edison Company is authorized rate recovery of $26,051,000 contained in the New System Generation Memorandum Account, $3,910,000 contained in the Project Development Division Memorandum Account, and $347,000 in associated franchise fees and uncollectibles.

3. Southern California Edison Company is granted authority to eliminate the Automated Meter Infrastructure Balancing Account ratemaking mechanism from its tariffs.

4. Southern California Edison Company may seek cost recovery of the $5,160,000 contained in the Market Redesign and Technology Upgrade Memorandum Account in its Energy Resource Recovery Account Review Application for the 2009 Record Period.

5. The Division of Ratepayer Advocates' request that there be a consolidated proceeding for Market Redesign and Technology Upgrade costs is denied.

6. Southern California Edison Company shall seek appropriate disposition of the Department of Energy Litigation Memorandum Account once all costs and proceeds are known. Such request can be made either through a future Energy Resource Recovery Account Review proceeding or separate application.

7. The Division of Ratepayer Advocates' request that there be a consolidated proceeding for review of non-Energy Resource Recovery Accounts is denied.

8. Southern California Edison Company's Audit Service Department shall audit the Energy Resource Recovery Account balancing account at least once every three years.

9. Application 09-04-002 is closed.

This order is effective today.

Dated July 29, 2010, at San Francisco, California.

MICHAEL R. PEEVEY
President
DIAN M. GRUENEICH
JOHN A. BOHN
TIMOTHY ALAN SIMON
NANCY E. RYAN
Commissioners

APPENDIX

The Commission Process for Review and Approval of the Forecast ERRA Revenue Requirement and the Recorded Procurement Costs

The Commission has established the following processes for review and approval of a utility's *forecasted* fuel and purchased power expenses for the purpose of setting rates:

- **ERRA Forecast Proceeding:** The utility submits a forecast of its procurement expenses for the following year to the Commission for review and approval. The utility's forecast is based on its best estimate of such factors as its projected sales and load, natural gas and power prices, etc., during the forecast year. The adopted forecast value is used to establish procurement[17] related rates, but it does not determine which procurement-related costs are eligible for cost recovery. Actual fuel and purchased power costs must be reviewed by the Commission and found eligible for cost recovery.
- **ERRA Trigger Mechanism:** ERRA Trigger applications are a Commission-mandated vehicle to ensure that utility ERRA balancing account balances (i.e., the differences between revenues and actual costs incurred – or over- and under-collections) do not reach excessive levels. In a trigger application, the utility requests Commission approval either to increase or decrease rates in order to reduce a large difference in the balancing account between revenues and recorded costs. This "trigger" application is to include a projected account balance 60 days or more from the date of filing, depending upon when the balance will reach the Commission established five percent threshold. The trigger application is to propose an amortization period of not less than 90 days to ensure timely recovery (or refund) of the projected ERRA balance.

The Commission does not review or approve the utilities' actual recorded procurement costs as part of the ERRA Forecast or ERRA Trigger proceedings, because in these proceedings costs are forecasted and, as such, have yet to be incurred by the utilities.

The Commission has established the following processes for the review and approval of *recorded* utility procurement costs:

- **Long-Term Procurement Plan Proceeding**: Approximately every two years (subject to change by Commission order), the utility submits a procurement plan to the Commission for its review and approval. The Commission-approved procurement plan establishes the "upfront" standards and criteria that will guide the utility's procurement activities. The utility must execute its transactions in compliance with these approved procurement plan standards and criteria to gain a finding that its procurement-related expenses are eligible for cost recovery, or subject the transactions to traditional after-the-fact reasonableness review. If any transaction does not fit within the Commission-approved procurement authority and the procurement plan standards, the utility must seek the Commission's pre-approval via a separate application.
- **Quarterly Compliance Report (QCR) Advice Letter Filings**: For each quarter of the year, the utility submits a QCR advice letter detailing all transactions that it executed during the quarter. The Commission's audit team reviews these transactions to determine if they were in compliance with the utility's procurement plan, and forwards its recommendations to the Energy Division for approval. If the Energy Division approves the QCR, the utility's transactions are deemed to be in compliance with the utility's Commission-approved procurement plan and the related procurement costs are deemed recoverable through the ERRA balancing account. On the other hand, if the audit team finds any transaction to be non-compliant with the utility's procurement plan, the utility would need to justify that transaction's reasonableness via a separate application.
- **ERRA Review Proceeding**: In the ERRA Review proceeding, the Commission conducts the following

> reviews: (1) a compliance review to determine if the utility's daily energy dispatch decisions and related short-term procurement activities (i.e., daily and hourly spot market transactions) were consistent with the least cost dispatch principles set forth in Standard of Conduct No. 4; (2) an accounting review to determine if the utility accurately recorded the procurement expenses that are eligible to be recovered through the ERRA balancing account; and (3) a reasonableness review to determine if the utility reasonably administered its QF and non-QF contracts, and if the operation of its utility-retained generation units, including maintenance outages, was reasonable.

In the ERRA Review proceeding, the Commission also reviews entries recorded in the ERRA balancing account to ensure that such entries are accurate and consistent with Commission decisions. The recorded year-end ERRA balancing account over- or under-collection (i.e. "true-up") is included in the following forecast year's rate change.

(End of Appendix)