STATE OF CALIFORNIA EDMUND G. BROWN JR., *Governor*

PUBLIC UTILITIES COMMISSION
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TO PARTIES OF RECORD IN APPLICATION 10-04-002

This is the proposed decision of Administrative Law Judge (ALJ) David M. Gamson, previously designated as the presiding officer in this proceeding. It will not appear on the Commission's agenda sooner than 30 days from the date it is mailed. This matter was categorized as ratesetting and is subject to Pub. Util. Code § 1701.3(c). Upon the request of any Commissioner, a Ratesetting Deliberative Meeting (RDM) may be held. If that occurs, the Commission will prepare and publish an agenda for the RDM 10 days beforehand. When the RDM is held, there is a related ex parte communications prohibition period. (See Rule 8.3(c)(4).)

When the Commission acts on the proposed decision, it may adopt all or part of it as written, amend or modify it, or set it aside and prepare its own decision. Only when the Commission acts does the decision become binding on the parties.

Parties to the proceeding may file comments on the proposed decision as provided in Article 14 of the Commission's Rules of Practice and Procedure (Rules), accessible on the Commission's website at www.cpuc.ca.gov. Pursuant to Rule 14.3, opening comments shall not exceed 15 pages.

Comments must be filed pursuant to Rule 1.13 either electronically or in hard copy. Comments should be served on parties to this proceeding in accordance with Rules 1.9 and 1.10. Electronic and hard copies of comments should be sent to ALJ Gamson at dmg@cpuc.ca.gov and assigned Commissioner. The current service list for this proceeding is available on the Commission's website at www.cpuc.ca.gov.

/s/ KAREN V. CLOPTON
Karen V. Clopton, Chief
Administrative Law Judge

KVC:gd2

Attachment

Decision **PROPOSED DECISION OF ALJ GAMSON** (Mailed 6/28/2011)

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, 2009 Complied with its Adopted Procurement Plan; for Verification of its Entries in the Energy Resource Recovery Account and Other Regulatory Accounts; and for Recovery of $29.947 Million Recorded in Four Memorandum Accounts.	Application 10-04-002 (Filed April 1, 2010)

DECISION ON SOUTHERN CALIFORNIA EDISON COMPANY 2009 ENERGY RESOURCE RECOVERY ACCOUNT COMPLIANCE AND REASONABLENESS REVIEW

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DECISION ON SOUTHERN CALIFORNIA EDISON COMPANY 2009 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, 2009. Among other things, the decision:

1. Disallows $1,442,200 associated with the December 28, 2008 San Onofre Nuclear Generating Station Unit 2 outage

2. Disallows $979,350 disallowance associated with the June 11, 2008 Mammoth Pool outage.

3. Authorizes rate recovery of $19.409 million for the Energy Settlement Memorandum Account and Litigation Costs Tracking Account, $3.912 million for the Project Development Division Memorandum Account, and $343,000 in franchise fees and uncollectibles.

4. Determines that all dispatch-related activities SCE performed during the Record Period complied with Commission orders and SCE's procurement plan.

5. Determines that all aspects of SCE's contract administration during the Record Period were reasonable.

6. Determines that SCE's Market Redesign and Technology Upgrade expenses for 2007 through 2009 were incremental and recoverable, subject to refund based upon an audit.

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, 2009 through December 31, 2009 (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's ERRA expenses for the record period of January 1, 2009 to December 31, 2009 were $3.433 billion, while the ERRA revenues for the period were $3.875 billion. Together with the previous year's undercollection, interest and various adjustments for the record period, the ERRA ending balance as of December 31, 2009 has an over-collection of $45.861 million. SCE also seeks to recover the net under-collected balance of $29,947,000 recorded in four of these accounts.

On May 10, 2010, 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 20, 2010.

A prehearing conference was held on June 21, 2010. The assigned Commissioner's Ruling and Scoping Memo (Scoping Memo) was issued on July 13, 2010. DRA testimony was served on October 6, 2010. SCE rebuttal testimony was served on November 16, 2010. Evidentiary hearings were held on January 19 and February 19, 2011. Opening briefs were filed on March 29, 2011, and reply briefs were filed on April 15, 2011, 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 were explained in D.02-10-062 (Conclusion of Law 11), where the Commission stated 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.

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.[1]

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," 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.

The California Independent System Operator (CAISO) implemented its Market Redesign and Technology Upgrade (MRTU) on April 1, 2009. According to SCE, the CAISO's MRTU implementation changed the LCD landscape in two important ways: 1) it shifted more responsibility for making economic dispatch decisions away from the utility to the CAISO; and 2) it reduced the need for SCE to manage a large share of its near-term CAISO electrical energy positions via

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

over-the-counter trading activity. SCE provides a summary of the procurement-related differences in the CAISO market as a result of MRTU implementation in its testimony. The main differences are in the following areas:

- Supply Scheduling/Resource Dispatch
- Ancillary Services
- The Day-Ahead Market and Spot Electrical and Natural Gas Transactions
- The Hour-Ahead and Real-Time Markets
- Spot Markets
- The CAISO's Daily Dispatch Decisions

Before April 1, 2009, SCE's least-cost dispatch process was specifically designed to economically optimize the selection of its resources. In doing so, SCE compared the forecast variable operating cost of each dispatchable resource with the relevant forecast market price of power at the time of dispatch. SCE then submitted schedules to the CAISO for all dispatchable resources whose variable costs were below the market price of power. Overall, SCE utilized a number of processes and software tools to help ensure that its decisions resulted in the most cost-effective mix of total resources, thereby minimizing the cost of delivering electric services.

After MRTU implementation in April 2009, the CAISO's scheduling process was superceded by a requirement to submit demand bids to acquire energy from the grid to serve customer load, and supply bids to make energy available from SCE's resource portfolio to the grid. SCE describes in detail the strategies and processes it used after April 1, 2009 to implement the supply and demand bids.

SCE submits that the record shows that its scheduling and bidding processes and actions enabled the CAISO to dispatch SCE's dispatchable resources in an economic manner throughout the Record Period. SCE claims that it consistently followed prudent procurement processes and practices in order to satisfy SOC 4.

DRA does not indicate that it takes issue with SCE's least-cost dispatch record in this proceeding.

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

4. Utility Retained Generation (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 three peaker plant generation outages, four 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 $25,753,510, 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 $1,516,417 associated with a San Onofre Nuclear Generating Station (SONGS) Unit 2 outage, $49,456 associated with an outage at the Four Corners coal plant, $10,240,844 associated with an outage at the Big Creek 3 hydroelectric plant, and

$7,691,411 associated with an outage at the Mammoth Pool Generator. In total, DRA recommends disallowances of $19,498,188. DRA has 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.

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

In its testimony, DRA found that four nuclear plant forced outages were unreasonable. In its opening brief, DRA withdrew its recommendations regarding three nuclear plant outages. The remaining contested outage involved a planned outage at SONGS Unit 2 which was scheduled for 30 days starting December 28, 2008, but was extended for an additional 18 days due to an unexpected need to replace a drive mechanism and make subsequent fixes. SCE addressed all four outages in its rebuttal testimony.

5.1. Root Cause Evaluations

In its analysis of the contested outage at SONGS, DRA based its recommendations for disallowances on root cause evaluations (RCEs) performed by the plant operators. SCE reiterates its explanations from A.09-04-002 (the 2008 ERRA) of 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. (A.09-04-002, Exhibit 4, at 19-20.)

Accordingly, SCE asserts that the RCEs that it supplied to DRA regarding the forced outages at SONGS should not be confused with an assessment of the reasonableness of plant personnel's actions for the purposes of this proceeding. SCE urges the Commission not to draw a direct correlation between their findings and the reasonable manager standard. 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 outage at SONGS 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 the Commission's analysis of the outage should focus on whether plant personnel at SONGS 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[2] in determining whether

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[2] 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.)

the outage is reasonable or unreasonable for the purposes of this proceeding. The outage at SONGS is discussed below with this principle in mind.

SCE argues that nuclear cause evaluations cannot be used as the sole basis for assessing the reasonableness of nuclear outages in the ERRA proceeding.[3] We disagree. SCE would inappropriately limit the application of the reasonable manager standard to circumstances where independent analysis beyond the RCE is available. We clarify that RCEs in fact may be the sole basis for assessing reasonableness. We acknowledge that the purpose of an RCE is, as SCE states "to perform stringent, after-the-fact evaluations of events to determine their cause and develop appropriate preventative measures to prevent the event for recurring in the future."[4] It is not inconsistent with this purpose that an RCE may provide clear evidence that the utility acted unreasonably.

SCE cites D.10-07-049 at 21 as standing for the proposition that the Commission has "rejected the notion that cause evaluation findings can be directly equated to assessments under the reasonable manager standard."[5] Here, SCE tries to conflate the correct notion that RCEs are not, in and of themselves, the same as an evaluation under the reasonable manager standard with the incorrect claim that RCEs may not be used as evidence in evaluating the utility's actions under the reasonable manager standard. Whether an RCE is the sole documentation in the record or not, a disallowance would only be appropriate if the actions of the utility were inconsistent with the reasonable manager standard.

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[3] SCE Opening Brief, at 8.

[4] *Id*. at 7.

[5] *Id*. at 14.

5.2. SONGS Unit 2 Outage

This SONGS Unit 2 nuclear reactor outage started as a planned outage which was scheduled for 30 days starting December 28, 2008. The purpose of the outage was to complete pressurizer dissimilar weld overlays, as well as other maintenance work. However, the outage was extended first, by 16 days due to an unexpected need to replace a control element drive mechanism, and second by approximately an additional two days because a vent valve began leaking after the unit was pressurized an in startup mode.

5.2.1. Positions of the Parties

DRA states that SCE imprudently allowed management systems within SONGS to deteriorate. DRA claims the repair of the vent valve added at least 48 hours to the existing outage. DRA calculates that the outage extension caused 40,168 MWh of additional lost energy, costing approximately $1,516,000 to replace.

SCE maintains that it would have been acceptable for SCE to have seal welded the leaking vent valve shut and resumed start-up activities for Unit 2. SCE witness Clepper testified that the vent valves had experienced leaks in the past and had been seal welded by SCE.[6] If SCE had done this, it would have reduced a substantial portion of the delay to bring Unit 2 back online.[7] However, SCE had never performed this specific repair before, and claims that it decided that it was in the best interest of nuclear safety to drain the reactor coolant system and investigate the source of the leak.[8] SCE then identified the problem –

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[6] RT, 115:9-15

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

[8] RT,112:25-27

the steel ball in the vent valve had been left on top of the valve stem for foreign material exclusion purposes, instead of in its final configuration position under the valve stem. SCE then fixed the problem and proceeded to restart the unit.

SCE performed a cause evaluation to determine the root and contributing causes of the incident and define corrective measures. The cause evaluation notes that a first line supervisor thought he had been instructed to leave the valve in a state short of final assembly.[9]

DRA contends that SCE admitted the end result of its actions resulted in miscommunication, incorrect assembly and incomplete documentation.[10] DRA refers to multiple organizational and procedural mistakes that were detailed in the RCE. DRA claims the focus of SCE's actions that should be considered imprudent is that the vent valve was reassembled wrong and required two days to correct. DRA contends that the proper test for imprudence is "the event[] is to be reviewed based on facts that are known or should have been known by utility management at the time."[11] DRA contrasts this standard to SCE's claim that the event was not imprudent because of what the supervisor knew at the time, given the facts that were known to him at the time.[12]

SCE's position is that DRA inappropriately used the RCE in determining that SCE's actions were unreasonable with respect to this outage at SONGS. SCE claims 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

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[9] See Appendix D to Exhibit SCE-8.

[10] SCE Rebuttal Testimony, at 24, lines 14-15.

[11] D.90-09-088, at 21.

[12] SCE Rebuttal Testimony, at 24, lines 9-21.

personnel during the time frame in which relevant actions were taken and decisions were made. Further, SCE claims that while the cause evaluation is critical of many steps that led to the vent valve leak, this does not mean that the supervisor's decision was unreasonable. SCE witness Clepper argues that the supervisor's actions were reasonable given his understanding of the situation.[13]

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. In this situation, there is uncontroverted evidence that a supervisor erred in not properly ensuring the valve was in the proper final assembly state. The evidence is provided in the RCE. This error, in turn, led to the outage in Unit 2 being prolonged by approximately two days.[14]

The question is whether the evidence shows that this error was unreasonable in light of the reasonable manager standard. The error of the supervisor did not occur in a vacuum; he did not properly understand instructions. Put another way, management did not clearly communicate instructions to the supervisor. SCE has admitted such miscommunication, stating

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13 RT 96;18-27.

14 SCE's claim that it could have restarted the plant without a delay of two days is irrelevant; SCE did not do so. SCE's claim that penalizing SCE for not restarting the plant without the delay is a disincentive for the utility to take prudent actions for safety purposes is misdirected. Had SCE restarted the plant immediately, SCE would have risked that an even greater problem would have developed, with potential resulting litigation regarding the reasonableness of that action.

that the RCE "identified the direct causes of the problem to be a failure to recognize that vent valve work required a formal work authorization and work plan, and subsequent miscommunication and failures to follow plant procedures." [15]

We find that SCE's actions in this instance were unreasonable under the reasonable manager standard. The reasonable manager standard includes the following concept: "The action taken should logically be expected, at the time the decision is made, to accomplish the desired result at the lowest reasonable costs consistent with good utility practice."[16] It is not reasonable to conclude that SCE management thought the actions of the supervisor were consistent with good utility practice at the time the decision was made. SCE management should have clearly communicated the proper instructions, ensured that proper procedures were followed, and ensured that the supervisor understood these instructions and procedures. If these appropriate management systems had been followed, the outage would not have been prolonged.

DRA recommends a disallowance of approximately $1,516,000 for the outage related to the valve at Unit 2. SCE places the upper limit of replacement energy at $1,442,200. Both estimates are based on an estimated loss of 40,169 MWh. The difference between the calculations is related to DRA's use of a simpler calculation methodology as compared to SCE. SCE explains that it is not possible to calculate the exact cost of the economic loss due to a specific outage. SCE used a methodology considering published energy price indices and the

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[15] SCE Rebuttal Testimony, at 23.

[16] D.90-09-088, at 21.

unit's avoided variable cost of production, while DRA simply used the day-ahead values for all hours.

We find that SCE's calculation for replacement energy for the outage at SONGS Unit 2 is reasonable and more accurate than DRA's simplified methodology, because SCE uses information more precisely calibrated to the hours of the outage. We will disallow $1,442,200 for this outage.

6. URG – Hydroelectric (Hydro) Generation

During the Record Period, SCE operated and maintained 33 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 1,176 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. Approximately 86% of SCE's hydro generation is provided by SCE's Northern Hydro Division. Despite below-average precipitation levels in 2009, SCE's hydro plants generated over 90% of the long-term historic annual average.

In its testimony and brief, DRA found that two hydro forced outages were unreasonable. The first was an outage in Northern Hydro, also known as Big Creek, which took place on December 14, 2008 in Big Creek 3, Unit 1. The second was an outage at the Mammoth Pool Generator which lasted from June 11, 2008 until May 1, 2009.

DRA does not challenge any other SCE hydro operations as unreasonable. Based on the testimonies of SCE and DRA, we also conclude that all other SCE hydro facilities were operated reasonably during the Record Period.

6.1. Big Creek 3, Unit 1 Outage

The Big Creek 3 powerhouse relayed off-line on December 14, 2008 apparently due to a 15 KV transfer switch fault in a Station Service Transformer switch cubicle. The outage lasted approximately one year. The switch (which is several cubic feet in size) is housed in a metal enclosure, located outside in a cabinet on the transformer deck just outside the powerhouse. The switch fault may have been the cause of a fire in Unit 1 generator stator. The fire caused damage to the stator coils and iron core, requiring a generator stator rewind.[17] DRA contends that SCE's failure to maintain a dry environment around high-voltage switchgear, failure to be mindful of equipment history, and imprudent design at the plant led to approximately $10.2 million in power replacement costs, which should be disallowed.

DRA claims that the record shows the following:

- Because the transfer switch was outside and exposed to inclement weather, decades of service can cause deterioration or corrosion to the equipment.
- The 15 kV transfer switch showed evidence of corrosion and moisture, which can accelerate a final insulation failure.
- The cabinet is surrounded by an oil containment barrier which the switchgear was never designed to be placed in.
- An inch of standing water in the cabinet containing the transfer switch was coincident with the ongoing rainstorm at the time of the failure.
- The fact that high voltage switchgear had standing water in it is not a good practice by design.

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[17] Exhibit SCE-8, Appendix L.

- The transfer switch gear was compromised, and corrosion and moisture were present.

Therefore, DRA concludes that SCE knew or should have known that this combination of factors could cause any number of problem situations in the electrical system, up to and including a fire in a generator. DRA lists several precautions SCE could have taken to protect the transfer switch and, in turn, the generator.

SCE states that its report on the incident indicates that the fault <u>may</u> have initiated in the switch, but that this has not been established conclusively. While SCE agrees with the basic facts laid out by DRA (which stemmed from SCE's exhibits), SCE also adds the following:

- Large portions of the power grid must be located outdoors because of economic necessity.
- The switch had been subjected to other rainstorms and fog episodes since it was installed in the 1970s and since the oil containment curbs were installed in the 1990s.
- It is unknown whether the switch's compromised insulation was present before the fault or appeared because of the fault itself. Absent obvious degradation, SCE personnel had no basis to conclude the insulation needed repair or replacement.
- SCE personnel had no record prior to this event that standing water had ever been present in the cabinet before and had no reason to believe that this particular switch would fail during this particular rainstorm.
- The windings in the generator stator that faulted were scheduled to be replaced in 2012. The generator was inspected, passed operability testing, and was expected to operate through the time for its planned rewind.

Based on these additional facts, SCE claims that there is no basis to conclude that SCE could have done anything other than maintain, test, and operate the generator consistent with its historic practices to prevent this outage.

6.2. Discussion

There is persuasive evidence that the failed switch caused the fire and outage in Unit 1, given that considerable damage to the switch was found around the switch concurrent with the damage to the generator. On the contrary, there is no persuasive evidence that the alternative suggested by SCE – an electrical fault initiated within the generator -- was the most likely cause of the fire and outage. We conclude the failed switch most likely was the cause of the outage.

The question is whether SCE, in the context of the reasonable manager standard, acted reasonably in the time period before the switch failed based on information available at the time. The main questions are whether SCE should have been aware of corrosion in the insulation, and should have known that a rainstorm resulting in an inch of standing water could cause a compromised switch to fail.

DRA in its brief suggests SCE should have taken more precautions to protect the transfer switch and, in turn, the generator. DRA contends that SCE could have covered the outdoor switch cabinet to protect it from the elements. Certainly, this is true, but it cannot be considered unreasonable for SCE to locate this equipment outdoors, since accepted industry practice has been to place many types of equipment (including this type of transfer switch) outdoors over many years. DRA contends SCE could have inspected the equipment more often. Again, this is true, but DRA offers no evidence that SCE failed to timely or properly inspect the equipment at issue. DRA suggests SCE could have replaced the transfer switch more often, but offers no rationale for why SCE should have done so in this case.

If SCE had known that the equipment was at risk, it would have been unreasonable to not take corrective action. SCE is incorrect that there was nothing it could have done to prevent the incident from occurring. But there is not sufficient evidence that SCE had information before the incident upon which a reasonable manager should have acted. Therefore we cannot conclude SCE's actions were unreasonable on this point.

More troubling is the presence of one inch of standing water in the cabinet at the time of the incident. SCE's investigators recommended forward-going redesigns so that contaminants and water cannot cause a phase-to-ground fault. SCE agrees that, as a matter of practice, standing water that accumulates in the containment area should be drained as soon as practicable following a rainstorm. SCE is correct to apply such redesigns now; the question is whether SCE should have proactively designed or redesigned its equipment before such an incident could occur.

If SCE had known that there was a reasonable likelihood that standing water could cause a fault in the switch, SCE should have taken proactive measures to prevent this situation from occurring. It is possible that SCE was aware of, or should have been aware of, this possibility, given that a similar event occurred in the 1988-1989 winter season in a different location. However, DRA has not shown that lessons from the incident 20 years before should have or could have been applied to this incident, or that applying such lessons would have prevented the incident from occurring. Because SCE is now aware that such a circumstance can occur, it is likely that application of the reasonable manager standard in the future would result in a disallowance in similar circumstances if proactive measures are not now taken.

We conclude that SCE's actions were reasonable with regard to the Big Creek 3, Unit 1 outage.

6.3. Mammoth Pool Outage

Mammoth Pool is a powerhouse that includes two hydro generating units, each with 95 MW capacity. Consistent with most large generators, the Mammoth Pool Generator has two sets of windings, one for the rotor and one for the stator. On June 11, 2008, after a Mammoth Pool Unit 2 turbine overhaul, SCE cleaned Unit 2's stator windings and initiated a three phase test known as a high potential test ("hi-pot") to examine the stator's operability. The Unit 2 stator windings failed the test and had to be replaced. The unit remained out of service until May 1, 2009.

DRA contends that SCE's own internal report investigated the stator winding failure to determine what caused the failure, which occurred approximately 17 years into the equipment's expected 30 year lifetime. DRA claims the report concluded that the stator windings were damaged because the generator was consistently operated at higher than normal temperatures, which escalated the thermal aging of the equipment.

DRA cites SCE's Stator Winding Failure Executive Summary (SCE Summary),[18] which reached three conclusions about the stator winding: 1) The equipment failed prematurely; 2) the premature failure was due to thermal aging that was taking place at escalated levels; and 3) excessive thermal cycling of the

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[18] Exhibit SCE-8, Appendix O.

equipment also contributed to the premature failure of the equipment. DRA contends that these three conclusions point to negligence and unreasonable use and operation of the generator by SCE absent any justification for the manner in which equipment was operated.

Specifically, DRA contends that SCE's unreasonable conduct in the failure of the stator windings was that SCE knew or should have known that operating the generator consistently at 90°C and with frequent or excessive cycling would cause thermal aging which would prematurely damage the stator winding. Further, DRA contends that SCE failed to conduct more frequent planned maintenance of the stator winding given its heightened use and operation.

DRA cites the SCE Summary as stating: "A major contributor to the premature failure of this winding is that thermal aging is taking place at an escalated level. The unit is normally run at and limited by the 100°C temperature limit. Thermal aging does take place at 90°C and above. Thermal aging escalates exponentially with temperature."[19] The SCE Summary also states: "Thermal aging is also a contributor to the premature failure."[20] DRA also cites from SCE's report from Voith Hydro (Voith Report),[21] the manufacturer of the stator winding, which investigated the reasons for the outage, to support its recommendations. DRA's brief quotes the Voith Report as stating: "For a period of 4-5 years, the unit operated with a stator winding temperature of 110 -115°C, but more recently, the unit operated around 100°C, with an alarm at 115°C."[22]

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19 *Id*, at 3

20 *Ibid.*

21 Exhibit SCE-8, Appendix P.

22 *Id*, at 2.

DRA contends that SCE claims that it may have run the generator excessively to meet customer demand, but that there is no evidence to support this claim. Further, even if that was the case, DRA contends that SCE had a duty to maintain its equipment at a level consistent with the usage that the equipment is subject to. DRA also contends that SCE provided no evidence that it made efforts to balance longer life versus higher output.

SCE contends that all actions taken by plant personnel related to the outage were prudent, reasonable and consistent with the plant's historical operating and maintenance practices. SCE agrees that two after-the-fact reports of the outage make clear that thermal aging and thermal cycling were the major contributors to the stator's failure. However, SCE contends that the precise effect of these factors on stator life expectancy is unknown.

SCE agrees that the effects of thermal aging increase at a higher rate whenever temperatures exceed 90^{o}C, but claims that the winding manufacturer recommended an operating temperature of 100^{o}C on hot days to achieve the longest winding life, while accommodating production needs. SCE argues that running the generator at more than 100^{o}C on some seasonal peak days was necessary to increase generation production and for other operational factors. Because of these factors, SCE agrees that it ran the generator at 110 -115^{o}C in the early to mid 1990s on some hot summer afternoons.

SCE contends that it had no reason to conclude that the generator windings were approaching the end of their service life, because tests performed in 1993, 1996, and 2003 did not raise any concerns about remaining life expectancy. SCE contends that two prior winding failures in 1983 and 1990 were due to manufacturing defects and unrelated to the 2008 failure.

In its Reply Brief, SCE contends that it had no reason to believe that occasionally operating the generator above 90ºC would cause the windings to fail several years before a more typical winding service life. Thus, SCE claims it had no reason to conduct such an analysis because SCE had no reason to expect the windings to deliver a service life that would be significantly different than that of all SCE's other hydro generators.

6.4. Discussion

The Voith Report shows that the Mammoth Pool Unit 2 generator operated with a stator winding temperature of 110-115ºC for a period of 4-5 years. In more recent years, the unit operated at temperatures around 100ºC, with limited periods at higher temperatures. Two post-failure analyses concluded that the Mammoth Pool Unit 2 generator stator windings likely failed the hi-pot test due in part to degradation from time periods when operating temperature exceeded 90ºC. The question is whether SCE acted as a reasonable manager in the period before the failure of the hi-pot test. Specifically, we seek to determine whether SCE knew or should have known that operating the generator at high temperatures would cause thermal aging and premature failure.

SCE is correct that the post-failure analyses findings were not known to SCE at any other time leading up to the 2008 winding failure experienced during routine operability testing. However, the record shows that SCE did have information available at the time which it should have considered when setting the temperature at the generator.

SCE in its Rebuttal Testimony states: "The standard design temperature of 110ºC follows a generic rule-of-thumb for balancing generator winding life (that degrades whenever temperatures exceed 90ºC) with generator MW output on hot days."[23] SCE further states that "both longer life and higher MW output have economic value, and the operator must balance the two factors."[24]

SCE was aware that it was running the generator at higher than recommended temperatures over several years. SCE claims that it ran the unit at these higher temperatures in order to achieve higher output, but SCE does not show that it performed any studies to determine if the higher output was worth a shorter plant life, either to shareholders or to ratepayers. We conclude that SCE, in the absence of such studies, unreasonably chose to operate the generator at higher than recommended temperatures for extended periods, thus knowingly diminishing the life of the plant. While the particular failure was unexpected, a reasonable manager should have known that, by running the generator at higher than recommended temperatures for extended periods, the generator was likely to fail far in advance of its expected useful life. SCE should have taken measures to mitigate this outcome, including adhering to temperature guidelines from the manufacturer and consideration of an earlier stator rewind.

DRA recommends a disallowance of approximately $7,691,411 for the outage related to the valve at Unit 2. SCE places the upper limit of replacement energy at $693,800. DRA's estimate is based on an estimated upper limit of loss of 231,840 MWh. SCE's estimate is based on an estimated upper limit of loss of 27,069 MWh. One difference between the calculations is related to the capacity factor used for the generator. DRA uses a capacity factor of 100% (i.e., DRA assumes the plant runs 100% of the time), while SCE witness Kurpakus testified

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[23] Exhibit SCE-7, at 79:16-17.

[24] Exhibit SCE-7, at 79:16-17.

that the annual capacity factor for Mammoth Pool is approximately 33%.[25] The other difference arises because SCE claims that when one hydro unit is out of service, SCE has the ability to utilize water from other sources in the overall Mammoth Pool Generator project, thereby continuing to produce electricity,[26] known as "outage bypass energy."

In its Reply Brief, DRA accepts SCE's annual average capacity factor of 33% for the Mammoth Pool generator. DRA also accepts a 50% reduction to take into account seasonal factors and outage bypassed energy. Thus, DRA calculates a lost energy value of 38,254 MWh, and a disallowance of $979,350. We will accept DRA's modified calculation for this disallowance.

7. URG – Coal Generation

SCE's current coal-fired generating resources consist of Four Corners Generating Station (Four Corners) Units 4 and 5, of which SCE has a 48% ownership interest. Arizona Public Service operates the Four Corners Plant. SCE provided information on Four Corners Coal costs and performance during the Record Period. These units produced over 11 million MWh of generation for SCE.

DRA originally recommended disallowances associated with three outages at the Four Corners Unit 4. DRA has dropped two of its recommendations, and now recommends a $50,000 disallowance associated with an outage beginning January 17, 2009 that occurred when a power feed circuit breaker to a motor control center failed and damaged the digital processor-based control system

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[25] RT Vol. 1, at 148, 9-24.

[26] Exhibit SCE-7, at 88, line 21 through at 89, line 2.

for coal conveyer equipment. DRA contends that the outage was due to SCE's imprudent maintenance and an unreasonable design failure in not having backup power, backup feed systems, and updated backup stocks of single-point-of-failure coal system controls.

Appendix J to Exhibit SCE-6 is an Improvement Opportunity Alert (Alert) titled "U4&5 Coal Systems Control Power Failure – RCD 2009-004." The Alert's "lessons learned" section lists a number of problems and solutions related to the outage event. These include:

- No back up UPS power feed to the coal system controls;
- No 480V back up feed to the coal system;
- 480V motor control center (MCC) Coal breaker overloads need to be upgraded;
- Coal system manual operation is needed so operations can continue feeding coal to the silos while technicians are troubleshooting; and
- Keep a matched pair of Allen Bradley processors (updated firmware) in stock at the warehouse.

SCE admits that the MCC was equipped with overload devices which did not mitigate the power surge sufficiently to prevent damage to the local control system. However, SCE contends that correction of either or both of the back up power systems noted in the Alert would not have prevented the outage, because the outage did not occur due to an extended local power failure. SCE also contends that the outage occurred because diagnosis and repairs to the control system due to damage caused by the power surge took longer to finish than the operational time that the coal stockpile reserve provided. SCE claims that DRA fails to address the actual reason for the outage, and that DRA misunderstands the information provided in the Alert.

SCE maintains that the design of the coal conveyer system already included a contingency for online emergency repairs. Regarding Allen Bradley processors, SCE claims that the station did have a spare processor in the warehouse at the time of the event, which was installed as part of the repair. SCE says that it is still considering the cost-effectiveness of updating firmware and software when the spare is installed and placed into service, versus while in warehouse storage. Finally, SCE claims it is not cost-effective to install a true manual control system. Even if a manual control system did exist at the time of the outage, SCE contends this would not have prevented the outage because the entire digital control system was out of service, which would have made any manual features inoperable as well.

7.1. Discussion

We find that SCE acted reasonably with respect to the January 17, 2009 outage at the Four Corners Unit 4. In hindsight, it appears possible that SCE could have taken measures which would have prevented the outage. However, SCE had already taken preventative measures ahead of the outage, including having a spare Allen Bradley processor available and having analyzed the cost-effectiveness of manual control system. DRA has not presented clear evidence of any violation of the reasonable manager standard, while SCE has presented substantial evidence of reasonableness.

8. Other Operations

During the record period, SCE operated and maintained a variety of other fuel and generation operations which are subject to review in this application. These operations include four peaker generating plants (each consisting of a single generator of 49 MW rated capacity), as well as purchases of 54,393 barrels of diesel fuel for electric generation at Santa Catalina Island. SCE has provided testimony to demonstrate that its facilities were operated in a prudent manner during the Record Period. In its testimony, DRA does not take issue with SCE's showing its Report on other fuel and generation operations.

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

9. 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 200 bilateral contracts related to electric purchases, sales, and exchanges. Administration of QF and renewable contracts are addressed separately.

In D.87-05-071, the Commission authorized the electric utilities to develop special electric rate contracts to allow them to continue to serve load to large customers who demonstrated their intent to bypass the utility's system by building self-generation projects. In D.88-03-088 and D.88-07-058 the Commission set policy principles and established the guidelines the utilities would adhere to in developing and administering Self-Generation Deferral Rate (SGDR) agreements. We review the reasonableness of SGDR agreements in this proceeding. SCE requests that the Commission find that SCE's administration of both remaining SGDR agreements during the Record Period was reasonable.

DRA states that it has no objections to SCE's non-QF contract administration processes, contract activity, and training programs for the Record Period, including the SGDR agreements. Based on the testimonies of SCE and

DRA, we conclude that SCE's contract administration activities and SGDR agreements were reasonable.

10. 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 does not object to SCE's Application regarding how it exercised its contract management, compliance and general administration of the QF related costs it incurred.

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.

11. 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. SCE entered into 32 new RPS contracts and executed 29 amendments with renewable energy counterparts (22 of which were submitted for review in this proceeding[27]) during the Record Period. None of the contract amendments filed for review in this application resulted in a price increase. SCE also reported four RPS contract assignments, and no activity

[27] SCE either had filed or planned to file advice letters for the remaining contract amendments.

related to dispute resolution and litigation. 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 does not object to the Commission granting SCE's request that its Non-QF contract administration activities, which include those related to RPS contracts, be found reasonable. However, DRA recommends that SCE explain the contract administration processes for its renewable generation contracts in its next annual ERRA compliance filing, because SCE did not report the administrative processes for its RPS contracts in its testimony this year.

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. SCE should consult with DRA to determine how to assist DRA in understanding the contract administration processes for renewable generation contracts in SCE's next annual ERRA compliance filing.

12. CAISO Related Costs

SCE indicates that it incurred approximately $399.3 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. SCE notes that its request is 16% less than for the 2009 Record Period, but that the cost levels are not directly comparable due to changes in CAISO invoicing. 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.

13. 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);
- SmartConnect Balancing Account;
- Department of Energy Litigation Memorandum Account (DOELMA);
- Medical Program Balancing Account (MPBA)
- Market Redesign and Technology Upgrade Memorandum Account (MRTUMA);
- New Systems Generation Balancing Account (NSGBA);
- Palo Verde Balancing Account (PVBA);
- Pension Costs Balancing Account (PCBA) and Post Employment Benefits Other than Pensions Balancing Account (PBOP BA);
- Project Development Division Memorandum Account (PDDMA);
- Results Sharing Memorandum Account (RSMA); and

- Solar Photovoltaic Program Memorandum Account (SPVPMA).

For the majority of these accounts, SCE is not seeking recovery or refund as the recorded costs have already been recovered from or refunded to customers. In this proceeding, SCE requests cost recovery of $19.409 million for the ESMA/LCTA, and $3.912 million for the PDDMA. SCE also seeks recovery of $343,000 in FF&U. In its Reply Testimony, SCE withdrew its request to recover $232,000 for costs incurred in 2007 through 2009 in the DOELMA. In total, SCE now seeks recovery of $29,715,000. SCE also requests that it be allowed to transfer the $2,865,000 balance of the SPVPMA to the newly-created Solar Photovoltaic Program Balancing Account (SPVPBA), and to eliminate the SPVPMA as no longer needed.

In its prepared testimony, DRA indicates that it reviewed all of the balancing and memorandum accounts and concludes that the costs recorded for the various accounts are consistent with Commission Decisions and Resolutions. DRA does not recommend any disallowances.

Based on the testimonies of SCE and DRA and our review 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, NSGBA and CBA as presented by SCE in Exhibit SCE-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 Phase III costs recorded in the SmartConnect Balancing Account were properly recorded, consistent with the categories adopted in D.08-09-039, and recoverable.

5. SCE should be allowed to transfer the $2,865,000 balance of the SPVPMA to the newly-created SPVPBA, and to eliminate the SPVPMA.

6. SCE and DRA agree that is it reasonable to defer consideration of the DOELMA until all costs and proceeds are known. SCE should request disposition of the DOELMA at that time.

14. 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.[28]

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,

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[28] 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.

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.

In D.10-07-049, the Commission deferred addressing the reasonableness of $5.1 million in expenses requested by SCE for MRTU and allowed SCE to include that request and make an appropriate showing in this ERRA Review application for the 2009 Record Period. This was done so that SCE's capital revenue requirement associated with capital costs that were incurred in 2007 and 2008 can be addressed and analyzed together with 2009 activities.

14.1. DRA Proposal for a Consolidated Proceeding for MRTU Costs

On May 18, 2011, DRA filed a Motion to bifurcate the MRTU implementation cost recovery portions of ERRA compliance proceedings and consolidate those portions into a single and separate proceeding.[29] DRA calls for MRTU expenses to be examined across all IOUs. DRA contends that because of changes presented by the MRTU system and the common factors driving all utilities' reasonableness requests, the applications of each of the IOUs on this topic should be reviewed at the same time in a consolidated proceeding that is separate from future and pending ERRA applications. DRA argues that resolving these issues in a consolidated fashion will be efficient, fair and in the Commission's, utilities and ratepayer's interests.

DRA's Motion was opposed by SCE. 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.

D.10-07-049 addressed this issue as follows:

> (W)e 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

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[29] DRA also simultaneously filed this Motion in the 2010 Compliance ERRA dockets for Pacific Gas and Electric Company (PG&E) (A.10-02-012), San Diego Gas & Electric Company (SDG&E) (A.10-06-011), and the 2010 ERRA applications of SCE (A.11-04-001) and PG&E (A.11-02-011).

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.

An ALJ Ruling was issued on June 23, 2011 denying DRA's Motion. Below we consider SCE's request regarding MRTU costs and revenue requirement.

14.2. SCE's Request

SCE requests recovery of $8.685 million of incremental and verifiable O&M costs recorded in the MRTUMA from 2007 through 2009. In addition, SCE requests $56.2 million of MRTU-related direct capital costs incurred on the MRTU Project through the initial market implementation and approval that these capital costs and associated overhead are the appropriate capital base to use in determining the capital revenue requirement recorded in the MRTUMA that will be recovered over the life of the project. Based on the capital addition, SCE states that it recorded a capital-related revenue requirement in the MRTUMA of $2.45 million in 2009.

14.3. DRA's Position in Testimony

The Commission in D.09-12-021 required SCE to present substantial testimony demonstrating the incremental and verifiable nature of its recorded costs in the MRTUMA. While DRA requested bifurcation of MRTUMA issues in its Motion, DRA also served testimony on this issue. In its testimony, DRA reviewed SCE's supporting material and concludes that SCE met its burden in this proceeding by providing sufficient data to support its request. However, in its testimony DRA recommends a disallowance of $77,000.

SCE responds that DRA did not explain how it calculated this disallowance, but simply argues that SCE incorrectly determined which costs are incremental to SCE's currently-authorized GRC revenue requirement for funding the MRTU initiative. SCE calls for rejection of the DRA argument. In addition, SCE argues that its actual incremental costs in 2009 were much higher than what it is requesting to recover in this proceeding, because SCE was able to reduce its expenses by over $5 million from levels below those authorized in the 2009 GRC.

14.4. Discussion

In its Opening Brief, DRA does not recommend the $77,000 disallowance for MRTU. After review of SCE's testimony and supporting documentation, we find SCE's 2007 through 2009 MRTU expenses and capital costs to be incremental and reasonably incurred. However, we cannot for certain determine the verifiability of SCE's figures at this time.

We therefore authorize the recovery the expenses and capital costs recorded in SCE's MRTUMA for the years 2007, 2008, and 2009, subject to refund based upon an audit of the MRTUMA. This audit must be completed within 12 months from the effective date of this decision. This audit will be paid for by SCE, and performed by an independent auditor chosen by the Commission's Division of Water and Audits – Utility Audit, Finance, and Compliance Branch (DWA). The resulting audit report must be filed by DWA as a compliance filing in SCE's 2010 or 2011 ERRA proceeding (or a consolidated proceeding addressing MRTU costs) and served on the service list of that proceeding. Within 30 days of the audit being filed, SCE must file and serve a response to the audit. DRA and any interested party may then file and serve a reply to such response within 20 days of SCE's response.

The audit must include but not be limited to the following items:

1. Compliance with requirements of the Resolution in which the MRTUMA was authorized (Resolution E-4087);

2. Verification that amounts recorded in the MRTUMA since inception have been spent on the incremental costs of the MRTU program;

3. Verification that amounts recorded in the MRTUMA since inception are incremental to the amounts otherwise authorized by this Commission for SCE's Information Technology program;

4. Verification that amounts recorded in the MRTUMA since inception have not been spent on non-MRTU Information Technology programs; and

5. Verification that amounts recorded in the MRTUMA are separately identified in SCE's accounting system.

15. 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 _________, and reply comments were filed on ___________ by ___________________. 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.

16. Assignment of Proceeding

Michel Peter Florio is the assigned Commissioner and David M. Gamson is the assigned ALJ in this proceeding.

Findings of Fact

1. On April 1, 2009, the CAISO began implementation of the Market Redesign and Technology Upgrade, which substantially changed the least-cost dispatch processes of SCE and other utilities.

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

3. 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.

4. 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.

5. In its testimony, DRA found that three nuclear forced outages were unreasonable. However, in its opening brief, DRA only recommended disallowances associated with a SONGS Unit 2 outage.

6. 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.

7. For the December 28, 2008 SONGS Unit 2 outage which lasted approximately 18 days more than anticipated, DRA provides an evaluation of the RCE in light of the reasonable manager standard.

8. There is evidence that a reasonable manager should have been aware that the steel ball in the vent valve had been left on top of the valve stem for foreign material exclusion purposes, instead of in its final configuration position under the valve stem, or should have been aware of the potential effect of the problem, prior to the December 28, 2008 SONGS Unit 2 outage.

9. With respect to SCE's operation and maintenance of its hydro facilities, in its testimony DRA recommends disallowances for forced outages at Big Creek 3 Unit 1 on December 14, 2008 and Mammoth Pool Unit 2 on June 11, 2008.

10. Evidence shows that it most likely was a failed switch which caused the December 14, 2008 fire and outage in Big Creek 3 Unit 1, given that considerable damage to the switch was found around the switch concurrent with the damage to the generator.

11. There is not sufficient evidence that SCE had information before the Big Creek 3 Unit 1 outage upon which a reasonable manager should have acted to prevent the outage, either with regard to corrosion in the insulation or to standing water in the cabinet at the time of the incident.

12. Two reports prepared by or for SCE show that the Mammoth Pool Unit 2 generator was run at temperatures significantly exceeding the recommended maximum for extended periods of time.

13. By running the Mammoth Pool Unit 2 generator at temperatures significantly exceeding the recommended maximum for extended periods of time, SCE reduced the expected life of the plant.

14. With respect to SCE's coal generation resources, in its testimony DRA found that three outages at Four Corners Units 4 and 5 were unreasonable. However, DRA withdrew its recommendations for disallowances except for a forced outage at Four Corners Unit 4 on January 17, 2009.

15. There is no evidence that a reasonable manager should have taken any specific steps that would have prevented the forced outage at Four Corners Unit 4 on January 17, 2009.

16. DRA indicates that SCE reasonably operated all of its other fuel and generation activities.

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

18. SCE has shown that DRA's proposed replacement power cost methodology for the SONGS Unit 2 outage and the Mammoth Pool Unit 2 outage was incorrect.

19. SCE's proposed disallowance level for the SONGS Unit 2 outage of December 28, 2008 is reasonable.

20. DRA's modified proposal for a disallowance for the Mammoth Pool outage is reasonable.

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

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

23. DRA found SCE's administration of contracts during the Record Period to be reasonable.

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

25. DRA has not challenged SCE's administration of its Self Generation Deferral Rate Agreements with ExxonMobil and Tosco during the Record Period.

26. D.10-07-049 did 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.

27. With respect to the operation of ratemaking accounts, DRA reviewed all of the accounts and, in testimony, noted no exceptions, except for the DOELMA and MRTUMA.

28. With respect to SCE's MRTUMA request, there is sufficient record evidence for the Commission to provisionally determine whether or not the requested costs were incremental and reasonably incurred. However, there is a need for a Commission audit to verify SCE's request.

29. With respect to the DOELMA, SCE withdrew its request.

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

31. MRTU is the result of numerous CAISO stakeholder processes and FERC orders. A Ruling on June 23, 2011 determined that for the 2009 Record Period there is no need for a single comprehensive proceeding to assess the reasonableness of MRTU or the associated requirements imposed on the IOUs.

32. SCE's PDDMA request of $3,907,000 excluding interest, is less than the maximum of $4,950,000 indicated in D.06-05-016.

33. DRA and SCE agreed to defer reasonableness review of SCE's Mohave Balancing Account to SCE's 2010 ERRA Compliance and Reasonableness Review proceeding.

Conclusions of Law

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

2. 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.

3. The evidence supports DRA's position that SCE's actions, with respect to the 18 day extension of the December 28, 2008 SONGS Unit 2 planned outage, were not reasonable.

4. With the exception of the December 28, 2008 SONGS Unit 2 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.

5. The evidence supports SCE's position that its actions, with respect to the December 14, 2008 Big Creek 2 forced outage, were reasonable.

6. The evidence supports DRA's position that SCE's actions, with respect to the June 11, 2008 Mammoth Pool Unit 2 forced outage, were not reasonable.

7. Aside from the June 11, 2008 Mammoth Pool Unit 2 forced outage, SCE's hydro facilities were operated reasonably during the Record Period.

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

9. All other of SCE's fuel and generation operations were operated reasonably during the Record Period.

10. It is reasonable to use SCE's calculated amount of $1,442,200 for the SONGS Unit 2 outage replacement power cost.

11. It is reasonable to use DRA's modified calculated amount of $979,350 for the Mammoth Unit 2 outage replacement power cost.

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

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

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

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

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

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

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

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

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

21. SCE's MRTU expenses and associated revenue requirement for 2007 through 2009 are incremental to its general rate case expenses.

22. It is necessary for there to be an audit to ensure that SCE's MRTU expenses and associated revenue requirement for 2007 through 2009 are appropriate, correctly stated, consistent with Commission orders, and reasonably incurred.

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

24. SCE should be allowed recovery of $3,912,000 including interest, in PDD costs for 2009.

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

26. Reasonableness review of SCE's Mohave Balancing Account should be deferred to SCE's 2010 ERRA Compliance and Reasonableness Review proceeding.

O R D E R

IT IS ORDERED that:

1. Southern California Edison Company shall appropriately reflect a $1,442,200 disallowance associated with the December 28, 2008 San Onofre Nuclear Generating Station Unit 2 outage, in its Energy Resource Recovery Account.

2. Southern California Edison Company shall appropriately reflect a $979,350 disallowance, associated with the June 11, 2008 Mammoth Pool Unit 2 forced outage, in its Energy Resource Recovery Account.

3. Southern California Edison Company is authorized rate recovery of $19.409 million for the Energy Settlement Memorandum Account and Litigation Costs Tracking Account, $3.912 million for the Project Development Division Memorandum Account, and $343,000 in franchise fees and uncollectibles.

4. Southern California Edison Company shall transfer the $2,865,000 balance of the Solar Photovoltaic Program Memorandum Account to its Solar Photovoltaic Program Balancing Account, and to eliminate the Solar Photovoltaic Program Memorandum Account.

5. Southern California Edison Company (SCE) is authorized to recover the expenses and capital costs recorded in its Market Redesign and Technology Upgrade Memorandum Account (MRTUMA) for 2007 through 2009, subject to refund based upon a Commission audit, to be completed within 12 months of the

effective date of this decision. The audit must include, but not be limited to, the following items:

1. Compliance with requirements of the Resolution in which the MRTUMA was authorized (Resolution E-4087);
2. Verification that amounts recorded in the MRTUMA since inception have been spent on the incremental costs of the MRTU program;
3. Verification that amounts recorded in the MRTUMA since inception are incremental to the amounts otherwise authorized by this Commission for SCE's Information Technology program;
4. Verification that amounts recorded in the MRTUMA since inception have not been spent on non-MRTU Information Technology programs; and
5. Verification that amounts recorded in the MRTUMA are separately identified in SCE's accounting system.

The audit shall be filed and served in the then-current proceeding considering SCE's MRTU expenses and capital costs.

6. Application 09-04-002 is closed.

This order is effective today.

Dated ______________________, at San Francisco, California.

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)