Decision **PROPOSED DECISION OF ALJ DeANGELIS (Mailed 11/18/ 2008)**

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of SOUTHERN CALIFORNIA EDISON COMPANY (U338E) for Authority to, Among Other Things, Increase Its Authorized Revenues For Electric Service in 2009, And to Reflect That Increase In Rates.	Application 07-11-011 (Filed November 19, 2007)
And Related Matter.	Investigation 08-01-026

(See Appendix A for a list of appearances.)

DECISION ON TEST YEAR 2009 GENERAL RATE CASE FOR SOUTHERN CALIFORNIA EDISON COMPANY

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DECISION ON TEST YEAR 2009 GENERAL RATE CASE FOR SOUTHERN CALIFORNIA EDISON COMPANY

1. Summary

This decision authorizes a $4.644 billion base revenue requirement for test year (TY) 2009 for Southern California Edison Company (SCE). We find that the authorized revenue requirement provides SCE with sufficient funding to provide safe and reliable service at just and reasonable rates. The adopted revenue requirement represents a 23.9% increase over the 2006 authorized revenue requirement of $3.749 billion, a 13.1% increase over SCE's 2006 recorded base revenues of $4.106 billion, a 7.1% increase over the projected revenue at present rates of $4.334 billion, and an 10.78% reduction from the 2009 revenue requirement requested by SCE of $5.205 billion,[1] which represented a 20.1% increase over the projected revenues at present rates. The adopted methodology for calculating post-test year revenue requirement results in a revenue requirement for 2010 of $4.783 billion and for 2011 of $4.927 billion. As a result of our decision today, SCE's projected total company revenue requirement for 2009 is approximately $12.4 billion. This proceeding is closed.

1.1. Forecast Test Year Ratemaking

Our decision today is guided by a fundamental tenet of forecast test year ratemaking that inclusion of a particular expense category in a general rate case (GRC) authorization does not create a specific obligation for the utility to spend

[1] When SCE filed its request for a TY 2009 revenue requirement with the Commission on November 19, 2007, it requested a revenue requirement of $5.199 billion. In May 2008, SCE reduced parts of its request by approximately $13 million to reflect the economic downturn. Exhibit SCE-24A, p. 37. Later, in SCE's update testimony filed on September 4, 2008, SCE presented an updated revenue requirement of $5.205 billion.

the authorized amount during the test year. Utility management is generally provided discretion regarding use of funds and is not bound by the adopted forecast. However, as we have observed in prior decisions, there are limits to that management discretion and when a utility's GRC expense estimate includes the performance of a task it had planned to accomplish with previously authorized funds, the Commission wants to know why the utility did not spend its funds as planned and we will be hesitant to charge ratepayers twice for the same expense.[2]

In this proceeding, SCE seeks additional funds for activities explicitly authorized by the Commission in the past. SCE seeks funds to redress maintenance postponed due to unanticipated load and customer growth in 2006-2007. To address this unforeseen customer and load growth, SCE diverted millions of dollars in capital replacements[3] away from its Infrastructure Replacement project, including funds for preventative maintenance of distribution and substation equipment, such as circuit breakers and other similar equipment. SCE also seeks funds related to the July 2006 "heat storms," when approximately 1,300 distribution transformers were either damaged or destroyed.[4] Because of these and other circumstances, SCE spent approximately $300 million[5] more than authorized in its 2006 GRC, with a large percentage of

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[2] *See, e.g.,* D.07-04-044 (PG&E 2007 GRC), D.04-07-022 (SCE 2003 GRC), D.04-05-055 (PG&E 2003 GRC), D.82-12-055 (SoCalGas GRC).

[3] Exhibit SCE-3A, p. 7.

[4] Exhibit SCE-3A, p. 8.

[5] Exhibit SCE-3A, p. 1.

this amount related to unanticipated customer growth needs.[6] In considering that SCE spent above amounts authorized in test year 2006, we also take into consideration that SCE's authorized rate of return for 2006 was 8.77% and its recorded rate of return for 2006 was 8.70%. This 0.07% difference equals approximately $8.4 million.

SCE asks the Commission to find SCE's explanation, unforeseen customer and load growth, justifies, in part, the magnitude of its requested increases. SCE explains, for example, that recorded 2006 capital additions were $1.463 billion and for 2009 SCE seeks $3.201 billion, an over 200% increase, to address, among other things, matters deferred because SCE directed funds to other areas impacted by unanticipated load and customer growth. SCE does not quantify the specific amount of funds diverted or identify any additional costs resulting from this decision to defer routine maintenance.

In the past we have found circumstances, such as the unanticipated scope of Year 2000 (Y2K) projects, to justify deferral of certain maintenance work. The circumstances surrounding Y2K and the related Y2K projects were one-time events and, as such, unique. In contrast, we do not find customer and load growth, even when unanticipated, to create unique circumstances. Load growth and customer growth are routine aspects of any rate case. If the adopted forecast overestimates expenses we do not ask a utility to return funds to ratepayers. Similarly, if an adopted forecast underestimates expenses, we do not go back and

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[6] Exhibit SCE-3A, p. 7; Exhibit SCE-3A, p. 6: "The increase above adopted 2006 expenditures was due primarily to: (1) actual meter sets being 15,796 (or 22 %) higher than what we had forecasted, and (2) the actual cost per meter set being $611 higher than forecast."

give the utility funds to complete projects that should have been addressed in the prior GRC cycle. In short, errors in forecasting occur and we do not go back and fix these errors.

Our policy has been explained by Justice Clark, *dissenting*, in *Southern Cal. Edison Co. v. Pub. Util. Comm.*, (1978) 20 Cal.3d 813, 836, Justice Clark addressed matters related to errors in forecasting as follows: "If the estimated revenues were too high or the estimated costs too low, the utility will bear the loss and fail to recover the projected rate of return. On the other hand, if the estimated revenues are lower than those that actually occur or the estimated costs higher than actual costs, the utility will benefit. Because so many circumstances exist significantly affecting expense and revenue, it is to be anticipated that estimated costs and revenues will rarely, if ever, equal actual ones and that the utility will realize more or less than the predicted rate of return."

It is also our policy that it would be unjust and unreasonable to make ratepayers responsible for expenses directly attributable to deficient or unreasonably deferred maintenance or to make ratepayers pay a second time for activities explicitly authorized by the Commission in the past. As we stated in Decision No. (D.) 82-12-055:

> "For us to authorize Edison's recovery of deferred maintenance expense would establish an undesirable precedent, whereby the utility is effectively guaranteed that it can earn (or exceed) its authorized rate of return, regardless of its operating efficiency or inefficiency, simply by curtailing current maintenance activities, in the assurance that they could be refinanced later through recovery of deferred maintenance expenses in a succeeding rate case."

In *Southern California Edison, supra,* the Justice Clark expressed the same concern and cautioned that shifting "the risk of error in estimating costs and revenues from the utility to the consumer," reduces the utilities' incentive for efficiency. Consistent with our policy regarding deferred maintenance, in certain instances in this decision, we adopt reductions to SCE's forecast for operation & maintenance and capital expenditures to reflect our finding that unanticipated load and customer growth does not justify SCE's decision to, among other things, defer maintenance.

In other instances, our reductions to SCE's requested revenue requirement are consistent with SCE's May 2008 downward adjustment to its request to reflect the economic downturn. The financial markets in the United States continue to suffer significant upheaval in large part due to the home mortgage lending market crisis which directly led to the failures or mergers of many long-standing financial institutions. We do not yet know the long-term implications of this financial crisis. In these circumstances, it remains our obligation to use our best judgment, knowledge and experience to authorize a revenue requirement that provides SCE with sufficient funding to provide safe and reliable service at just and reasonable rates.

The authorized base revenue requirement in this case should also be considered within the context of the Commission's regulation of the expenses of the entire company. The revenues from SCE's GRC represent approximately 36% of SCE's total company revenues. The remaining 64% of SCE's total company revenues is determined in various other proceedings before this Commission, many of which are governed by balancing accounts, and include fuel and purchased power, the Department of Water Resources Power and Bond Charge, Federal Energy Regulatory Commission (FERC) jurisdictional costs, and funding for Public Purpose Programs.

A significant percentage, approximately 44%, of SCE's total company revenues is determined by SCE's fuel and purchased power costs. The Commission reviews these amounts in the Energy Resource Recovery Account (ERRA) proceedings. SCE's most recent ERRA filing, Application (A.) 08-09-011, requests a 2009 ERRA revenue requirement of $4.639 billion effective January 1, 2009. SCE's total company revenue requirement also consists of amounts approved by FERC which are associated with transmission. The Commission incorporates these costs into California rates and SCE's total company revenue requirement. This case also does not adopt a cost of capital. We address cost of capital in a separate proceeding. The most recent cost of capital proceeding, A.07-12-049, authorized an 8.75% cost of capital. In phase II of this general rate case process, which is a separate proceeding, A.08-03-002, the Commission uses the revenue requirement authorized in this proceeding and divides it up between the various customer classes.

In short, the expenses authorized in this proceeding, $4,643,839,000, do not amount to all the costs included in rates. The authorized amount does, however, provide SCE with sufficient funding to provide safe and reliable service at just and reasonable rates.

1.2. Procedural History

On November 19, 2007, SCE filed its test year (TY) 2009 GRC application. In support of its application, SCE provided over 8,500 pages of testimony, 53,000 pages of workpapers and sponsored more than 100 witnesses. The prehearing conference in this proceeding was held on January 15, 2008. The presiding officer, Administrative Law Judge (ALJ) Regina M. DeAngelis, and the assigned Commissioner, President Michael R. Peevey, attended. SCE proposed a procedural schedule based on the Commission's 1989 Rate Case Plan, as modified by numerous subsequent decisions, the most recent being D.07-07-004. The Division of Ratepayer Advocates (DRA) and The Utility Reform Network (TURN) proposed a more extended schedule similar to the schedules adopted by the Commission for other large energy utility general rate cases for the last ten years. In the end, the assigned Commissioner adopted a schedule with the goal of presenting the full Commission with a proposed decision for consideration before the end of 2008.

The assigned Commissioner, knowing the adopted schedule was ambitious, strongly encouraged parties to engage in alternative dispute resolution. Consistent with the assigned Commissioner's statements at the prehearing conference regarding settlement, the procedural schedule specifically incorporated a mechanism for alternative dispute resolution and the Commissioner urged the parties to rely on the settlement process when appropriate. While parties made minor efforts in this regard, nothing notable was accomplished. In future general rate cases, we expect parties to make more of an effort to engage in the resolution of GRC matters.

SCE's application generated a significant amount of interest from customers residing in SCE's service area. In response to this interest, the Commission held public participation hearings between April 14, 2008 and June 19, 2008 in Palm Springs, Visalia, Long Beach, Santa Ana, San Bernardino, Compton and San Clemente. Evidentiary hearings were held in Los Angeles on May 29 - May 30, 2008 and continued in San Francisco through June 16, 2008. In an effort to make the hearings more accessible, the Commission video webcast the hearings held in San Francisco. Parties submitted concurrent opening and reply briefs on July 25, 2008 and August 8, 2008, respectively. This consolidated proceeding was submitted on October 6, 2008 after the conclusion of update hearings. The Commission held an oral argument on December 9, 2008. TURN filed a motion to reopen the evidentiary record on January 12, 2009. TURN's motion argued that the economic downturn required the Commission to consider new evidence on the accuracy of SCE's forecasts. SCE and others responded to this motion. TURN's motion is denied.

1.3. Burden of Proof

The Commission is charged with the responsibility of ensuring that all rates demanded or received by a public utility are just and reasonable: "no public utility shall change any rate... except upon a showing before the Commission, and a finding by the Commission that the new rate is justified."[7] As the applicant, SCE must meet the burden of proving that it is entitled to the relief it is seeking in this proceeding.[8] SCE has the burden of affirmatively establishing the reasonableness of all aspects of its application. Other parties do not have the burden of proving the unreasonableness of SCE's showing.

1.4. Standard of Proof

With the burden of proof placed on the applicant in rate cases, the Commission has held that the standard of proof the applicant must meet is that of a preponderance of evidence, which the Commission has, at times, incorrectly referred to as "clear and convincing" evidence.[9] Evidence Code § 190 defines

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[7] Pub. Util. Code § 451 and § 454.

[8] *Opinion on Southern California Edison Company's Test Year 2006 General Rate Case Increase Request*, D.06-05-016, p. 7.

[9] *In the Matter of the Application of California Water Company*, D.03-09-021, p. 17.

"proof" as the establishment by evidence of "a requisite degree of belief."[10] We have analyzed the record in this proceeding within these parameters.

2. Generation Expenses

2.1. Nuclear Generation

2.1.1. SONGS 2 & 3 Operation and Maintenance

SCE is the operating agent and 78.21% co-owner[11] of San Onofre Nuclear Generating Station Unit Nos. 2 & 3 (SONGS 2 & 3).[12] SONGS 2 & 3 entered commercial operation on August 8, 1983 and April 1, 1984 and provide SCE with a maximum capacity of 837 MW and 845 MW (SCE 78.21% share). For TY 2009, SCE forecasts base O&M expenses[13] of $264.2 million (100% level) (constant 2006$) or $206.4 million (SCE share). SCE's request of $206.4 million represents a 1.4% increase over 2006.[14] SCE's forecast for base O&M expenses excludes refueling and maintenance outage expenses. SCE requests an additional $39.6 million for refueling and maintenance outage O&M.

DRA recommends removing from SCE's TY 2009 request $4.4 million associated with a proposed Nuclear Regulatory Commission (NRC) license renewal study and $0.340 million, representing 50% of SCE's Nuclear Energy

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10 *Application of Pacific Gas and Electric Company*, D.00-02-046, p. 38, *quoting Application of PT&T Co. for A General Rate Increase* (1970) 2 CPUC 2d 89, pp. 98-99.

11 SCE acquired City of Anaheim's 3.16% share of SONGS 2 & 3 on December 29, 2006 as approved in D.06-11-025.

12 Exhibit SCE-2A, p. 7.

13 These TY 2009 estimates do not include several support functions or costs required for SONGS 2 & 3 operation, such as payroll taxes, pensions and benefits, information technology, and nuclear communications. Exhibit SCE-2B, p. 1.

14 Exhibit SCE-2A, p. 10.

Institute (NEI) fees. DRA also recommends a reduced forecast of $38.2 million (SCE share) for refueling and maintenance outage O&M, which represents a reduction of $1.5 million from SCE's request of $39.6 million.

2.1.2. NRC License Renewal Feasibility Study – FERC Account 524

SCE's TY 2009 forecast includes $5.6 million (100% level and constant 2006$) or $4.4 million (SCE share) for a SONGS 2 & 3 license renewal feasibility study. The NRC issued operating licenses to SONGS 2 & 3 in 1982 and 1983, respectively, and their licenses expire in 2022.[15] SCE plans to begin studying the feasibility of license renewal in 2009, a process that SCE claims will take about 3 years. SCE explains that it would then file an application with the NRC in late 2012 and would anticipate obtaining a decision from the NRC around 2015,[16] which would be about seven years before the current operating licenses expire. SCE includes the license renewal study costs in FERC Account 524.[17] SCE's proposal to pay for the license renewal study with offsetting O&M cost reductions is unconvincing.[18] SCE is starting its SONGS 2 & 3 license renewal study at just beyond the midpoint of its current licenses and well before the cutoff point of 35 years.

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[15] Exhibit DRA-74, p. 117.

Exhibit DRA-74, p. 120.

[16] Exhibit SCE-16A, p. 1.

[17] Exhibit DRA-75, SCE response to DRA data request DRA-SCE-087-TXB, Q. 3.

[18] Exhibit SCE-2B, p. 8. DRA requested additional workpapers from SCE supporting the offsetting savings, but SCE replied "[t]here are no additional workpapers supporting the $5.6 million forecast savings associated with the SONGS 2 & 3 Strategic Plan Achievement." Exhibit DRA-75, SCE response to DRA data request DRA-SCE-086-TXB, Q.5.

DRA recommends that the Commission reject funding for SCE's NRC license renewal study. DRA asserts that the NRC license renewal study is premature and SCE will have a better understanding of the status of SONGS 2 & 3 closer to the end of the current license period. DRA further points out SCE proposes to replace the steam generators at SONGS in 2009 and 2010,[19] a major capital investment, and suggests that initiating the license renewal study before the steam generator replacements is premature. DRA recommends that SCE propose the license renewal study in its TY 2012 GRC and provide any necessary evidence supporting the study at that time.

We agree with DRA that SCE's replacement of the steam generators will provide SCE with valuable information that is likely to improve the relicensing process. We do not find that SCE must start this relicensing process during 2009-2011. Instead, we find that a later start date will not jeopardize obtaining a NRC license in a timely manner. DRA argues and we agree that SCE does not need to initiate this study until at least 2012. Accordingly, SCE's request to include in the TY 2009 forecast $4.4 million (SCE share) for a SONGS 2 & 3 license renewal feasibility study is not adopted.

2.1.3. Nuclear Energy Institute Fees – FERC Account 517

SCE's TY 2009 forecast includes $0.685 million (constant 2006$ and 100% level) ($0.536 million - SCE 78.21% share) for NEI fees.[20] NEI is the policy organization of the nuclear energy and technologies industry. It promotes the beneficial uses of nuclear energy and technologies in the United States and

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[19] Exhibit SCE-2D, p. 54.

[20] SCE opening brief, p. 13; Exhibit SCE-16A, pp. 3 - 4.

around the world. DRA recommends removal of 50% of SCE's NEI fees from SCE's TY 2009 forecast. DRA points out that in the 2006 SCE GRC, the Commission disallowed 50% of SCE's NEI fee request. In that decision, we found "[f]or ratepayer recovery of NEI dues, in the future, SCE should provide more detailed descriptions of the activities, the associated costs, and the resulting company and ratepayer benefits. With that information, in the future, we can make a more informed decision regarding disallowances."[21]

We agree with DRA. SCE asserts that its participation in NEI programs, committees, and activities helps SCE to address issues important to the nuclear industry. These issues include regulatory reform, management of used nuclear fuel, provision of a stable fuel supply, and license renewal.[22] However, SCE fails to establish that all the benefits of its NEI membership go to its customers. For instance, NEI engages in work that furthers the interests of the nuclear industry. Such work (for example, public relations and image advertising) may not be appropriate for ratepayer funding. SCE estimates that approximately 15% of membership fees are for these types of activities.[23] Other work performed by NEI may benefit the industry rather than ratepayers. For example, DRA points out that "ratepayers should not be paying . . .to support NEI as it goes about '[s]tudying nuclear energy's intrinsic economic value to promote a general understanding of the value of nuclear power by policymakers and the public; and [b]uilding the next generation of nuclear power plants and technologies.'"[24]

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[21] D.06-05-016, pp. 35-36.

[22] Exhibit SCE-16A, p. 3.

[23] Exhibit SCE-16A, p.3.

[24] DRA opening brief, p. 11 *citing to* Exhibit SCE-2D, p. 25.

SCE fails to address the amount of resources allocated to these types of studies. Accordingly, while SCE made further efforts to describe how the work performed by NEI benefits ratepayers, the extent to which NEI's work benefits ratepayers versus the members of the nuclear generation industry remains unclear.

We adopt DRA's recommendation to continue our policy set forth in D.06-05-016[25] of authorizing SCE to recover half of its share of NEI fees, $268,000.

2.1.4. SONGS Refueling and Maintenance Outages – FERC Accounts 517,520, 524, 525, 528, 529, and 532

SCE asks the Commission to adopt its refueling and maintenance outage forecast costs of $39.6 million (SCE share[26] and constant 2006$) per outage per unit. SCE forecasts one refueling and maintenance outage in 2009. However, SCE asserts that since it is difficult to predict with certainty whether zero, one, or two outages will occur in any given year, SCE asks the Commission to continue the flexible outage schedule.

The post-test year ratemaking flexible outage schedule mechanism establishes a standard per unit per outage cost in the GRC and then allows determination of whether zero, one, or two outages will occur in each year of the GRC cycle (2009-2011). The Commission has adopted this mechanism in prior GRCs as the means to most accurately predict PTYR refueling and maintenance outage costs.[27] No parties opposes SCE's request to continue the mechanism.[28] Accordingly, we adopt the mechanism for years 2009-2011.

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[25] D.06-05-016, pp. 35-36.

[26] $50.7 million at the 100% level.

[27] D.06-05-016, p. 36.

SCE developed its TY 2009 refueling and maintenance outage estimate by averaging its estimates for TY 2009 and post-TY 2010 and 2011.[29] SCE expects to replace the SONGS 2 & 3 steam generators in 2009 and 2010,[30] so it did not include the cost of steam generator inspections in those years but added $5.4 million for steam generator inspections in post-TY 2011. Since SCE will not incur steam generator inspection costs in TY 2009, DRA recommends the Commission adopt a TY 2009 refueling and maintenance outage forecast of $38.2 million (SCE share), a difference of $1.5 million.

We find SCE's TY 2009 refueling and maintenance outage O&M forecast of $39.6 million (SCE share) reasonable as it normalizes the 2011 costs over the three-year (2009-2011) GRC period.

2.1.5. Palo Verde - FERC Accounts 517, 519, 520, 523, 524, 528-532

SCE is 15.8% co-owner of Palo Verde Nuclear Generation Stations (Palo Verde).[31] Arizona Public Service Company (APS) is the operating agent of Palo Verde.[32] SCE forecasts Palo Verde O&M costs of $82.5 million (constant 2006$ and SCE share) in TY 2009.[33] To forecast Palo Verde O&M expenses, SCE uses

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[28] SCE opening brief, p. 14.

[29] Exhibit SCE-2D p. 57.

[30] Exhibit SCE-2D p. 54.

[31] Palo Verde consists of three nuclear units with a total output of about 3,870 MW net, located approximately 50 miles west of Phoenix, Arizona. There are six other participants in Palo Verde: APS (29.1%); Salt River Project (17.5%); El Paso Electric (15.8%); Public Service New Mexico (10.2%); Los Angeles Department of Water & Power (5.7%) and Southern California Public Power Authority (SCPPA) (5.9%).

[32] Exhibit SCE-2A, p. 7.

[33] Exhibit SCE-2H, p. 4.

the last recorded year, 2006, adjusted to eliminate one-time expenses, and then applies the necessary future adjustments.[34] SCE does not rely on the APS forecast of O&M expenses because, according to SCE, APS consistently underestimates its O&M expenses by an average $9.9 million per year.[35] Given the uncertainty of the APS forecasts, SCE suggests the Commission adopt a two-way balancing account for Palo Verde O&M costs, beginning with the decision in this proceeding.[36]

DRA recommends the Commission adopt a TY 2009 forecast equal to SCE's estimated 2007 O&M expenses ($64.2 million). DRA's recommendation represents a reduction to SCE's forecast of $18.3 million.[37] DRA's recommendation mainly reflects its concern about significant O&M increases in recent years and a rejection of additional staffing increases proposed by APS. APS's proposed staffing increases seek to reduce backlogs in areas of engineering and elective maintenance. DRA claims these backlogs can be addressed without staff increases.

In support of its request to include staffing increases in the TY 2009 forecast, SCE claims that Palo Verde's engineering backlog has increased significantly because of necessary improvement initiatives in response to NRC oversight, resulting in a 42% increase in work in 2007, and that even with

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[34] Exhibit SCE-2H, pp. 7-10.

[35] Exhibit SCE-2A, pp. 15-19.

[36] Exhibit SCE-16B, pp. 5-6.

[37] Exhibit DRA-73, p. 10.

substantial effort and good progress, APS would be working to reduce backlog items well through 2009.[38]

We find SCE's argument convincing. Furthermore, it appears SCE has historically under-recovered its Palo Verde O&M expenses by an average $9.9 million per year due to APS consistently underestimating its O&M expenses.[39] To address these uncertainties and, to a certain extent, DRA's concerns, we adopt SCE's suggestion of relying on a two-way balancing account for Palo Verde O&M costs, beginning with the decision in this proceeding.[40]

Under SCE's proposal, the Palo Verde Balancing Account (PVBA) would record the difference between: (1) O&M expenses authorized by the Commission in the GRC proceeding; (2) actual O&M expenses billed to SCE by APS under the Palo Verde Operating Agreement for SCE's share of expenses, including refueling outage O&M expense and contractual overheads; and, (3) actual SCE oversight expenses.[41] The balance in the PVBA will be carried forward from month-to-month throughout the year. SCE proposes to transfer the balance recorded in the PVBA annually to the generation subaccount in the base revenue requirement balancing account to be recovered from or returned to customers on an annual basis. SCE suggests that the Commission review the operation of the PVBA in SCE's April ERRA annual reasonableness proceedings.

We find this proposal reasonable. A balancing account will ensure that recorded Palo Verde O&M expenses are recovered from customers, no more and

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[38] Exhibit SCE-16B, p. 4.

[39] Exhibit SCE-2A, pp. 15-19.

[40] Exhibit SCE-16B, pp. 5-6.

[41] Exhibit SCE-2H, p. 5.

no less. This balancing account will address SCE's concern of not recovering actual costs as well as other parties' concerns of over-recovery. We have adopted similar balancing accounts under similar circumstances.[42]

2.2. Coal Generation

2.2.1. Four Corners Generating Station - Staffing Increase Costs-FERC Accounts 500-502, 505-507, and 510-514

Four Corners Generating Station (Four Corners) has five coal-fired units. SCE owns 48% of Units 4 & 5,[43] each rated at 750 MW.[44] APS is the operating agent for Four Corners. APS prepared a Long Range Forecast in 2007, which includes an estimate of 2009 expenses. SCE's forecast, which does not rely on the APS forecast, is $39.171 million (constant 2006$ and SCE share) for Four Corners TY 2009 O&M expenses.[45]

DRA recommends a reduction of $2.1 million to remove SCE's request for 50 additional employees at Four Corners. DRA asserts SCE's proposal to hire additional staff now to address retirements that may happen in 5-10 years is premature.

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[42] *See*, *e.g.*, D.06-11-026 (balancing account adopted for SDG&E's share of SONGS O&M expenses.)

[43] Exhibit SCE-2J, p. 7: "In addition to its 48% share of Units 4 and 5, SCE owns 34.76% of the common systems at the site. Systems and equipment that are common to both units or that provide service to the entire plant include air compressors, bottom ash and fly ash storage and disposal systems, water purification and storage systems, equipment and bearing cooling water systems, and shop and office facilities."

[44] Exhibit SCE-2J, p. 6.

[45] Exhibit SCE-2J, p. 1.

TURN recommends that the estimate for O&M expenses at Four Corners be based on the 2009 Long Range Forecast Budget prepared by APS. TURN explains that APS, as the plant operator, has the responsibility for managing and operating the Four Corners plant. Accordingly, TURN argues that the budget determined by APS is the most reasonable starting point for any forecast of future expenditures. Alternatively, TURN supports DRA's recommendation.

We agree with DRA. It is premature to include additional staff hiring to account for retirements that may happen in 5-10 years.

2.2.2. Mohave Generating Station-FERC Subaccounts 506.013 and 514.013

The Mohave Generating Station (Mohave) ceased operation on December 31, 2005.[46] SCE and the other Mohave owners[47] are currently proceeding with final disposition of the power plant equipment and the site, including physical decommissioning of the plant during the 2009-2011 GRC period.[48] SCE forecasts $4 million ($2.2 million – constant 2006$ and SCE share) for Mohave O&M for TY 2009 to manage the Mohave site during and after decommissioning.[49] This forecast is based on the expectation that Mohave will

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[46] Exhibit SCE-2J, p. 3. The 1999 Mohave Consent Decree required installation of pollution-control equipment or the ceasing of operations using coal fuel in January 2006.

[47] Mohave consists of two 790 MW coal-fired generating units, and is owned by the following companies: SCE – 56%, Salt River Project – 20%, Nevada Power Company-14%, Los Angeles Department of Water and Power – 10%. The plant site is located at the southern tip of Nevada in Laughlin, on a 2490-acre site adjacent to the Colorado River and the State of Arizona.

[48] Exhibit SCE-2J, p. 3.

[49] Exhibit SCE-2J, p.69, SCE expects Mohave "will be decommissioned by 2010."

be decommissioned by 2011. SCE also proposes to continue the Mohave Balancing Account[50] (MBA) for costs recorded through 2011, and possibly beyond. SCE included a 15% contingency in its Mohave O&M cost estimate, totaling $0.530 million in TY 2009 (100% share).

DRA does not object to continuing the MBA but would eliminate the 15% contingency. DRA asserts that a contingency is unnecessary as long as SCE has balancing account treatment. After removing the 15% contingency, DRA recommends a Mohave TY 2009 O&M expense of $3.5 million (100% share) or $2.0 million (SCE share), a difference from the SCE forecast of $0.2 million. SCE states that, given the difficulty of identifying what additional efforts might be needed, this contingency is appropriate and conforms to standard industry practice.[51]

We find continuation of the MBA reasonable for 2009-2011 but reject SCE's request to add a 15% contingency to account for cost uncertainties. Unlike cost forecasting for capital construction projects, an overall contingency is not normally included in O&M cost forecasts. As we found in D.06-05-016, the MBA will give sufficient protection against unknown costs and will continue to be subject to reasonableness review. Accordingly, we adopt a TY 2009 forecast of $2.0 million for Mohave O&M.

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[50] D.06-05-016, Ordering Paragraph 8: "SCE shall establish a two way balancing to record the ongoing expenses and capital related costs associated with the Mohave Generating Station (Mohave)."

[51] Exhibit SCE-16C, p. 16.

2.3. Hydroelectric Generation Forecasting Method – FERC Accounts 535-545

SCE's Hydroelectric (Hydro) Generation facilities are forecasted to provide an aggregate of 1,176 MW in TY 2009. SCE forecasts TY 2009 O&M expenses of $50.4 million (constant 2006$). SCE's O&M expense forecast for TY 2009 of $50.4 million is $12.1 million, or approximately one-third higher than the $38.3 million recorded O&M expenses in 2006.

SCE's forecasting methodology for its 2009 Hydro O&M forecast is composed of two parts, the "base estimate," as it is referred to by SCE, and the increases to this base estimate, referred to as "future adjustments." SCE develops its "base estimate" by using its 2002-2006 recorded expenses adjusted to remove one-time charges and to correct accounting errors. SCE then makes 11 future adjustments to include additional costs to this base estimate. These additional amounts total $13.504 million. DRA, TURN, and Inland Aquaculture Group, LLC (IAG) offer lower forecasts by relying on different forecasting methods or by finding certain expenses unreasonable.

DRA recommends a TY 2009 forecast of $36.8 million, which is SCE's estimate of 2007 expenses, a reduction of $13.6 million to SCE's forecast. DRA asserts SCE's 2007 estimate of Hydro O&M expenses serves as an appropriate basis for the TY 2009 forecast because Hydro O&M expenses have been relatively stable. DRA also presents arguments in opposition to two specific future adjustments identified by SCE, hydro staffing and cloud-seeding activities, that total $2.45 million.

TURN recommends reducing SCE's Hydro O&M forecast by $3.46 million because of lower 2006 base year expenses recorded in the relevant FERC Accounts, the closure of the San Gorgonio hydro project, reductions in labor cost estimates for SCE's proposed new staff, reductions in housing rehabilitation and asbestos abatement expenses, and the capitalization, instead of expensing, of housing rehabilitation and the Agnew Tramway.[52]

IAG also recommends reducing SCE's Hydro O&M forecast. IAG proposes a reduction of $70,000 for the Rush Creek Heliport brush clearing forecast for 2010 and removal of all amounts included for this project in 2009 and 2011. IAG also proposes an annual reduction of $230,000 in 2009, 2010, and 2011 for vegetation management at Big Creek. IAG recommends a reduction of $56,000 for refurbishment of the Poole 3-unit apartment building and a reduction of $66,000 for asbestos abatement at the Poole and Rush Creek projects. IAG recommends disallowing the $2.4 million included in SCE's 2007-2011 capital forecast for the Lundy Reline Conveyance System and requests the Commission order no further action on this item unless SCE obtains FERC approval. Lastly, IAG alleges that SCE committed a Rule 1.1. ethical violation regarding the Lundy Reline Conveyance System by misrepresenting the status of FERC approval.

We find SCE's methodology generally reasonable for determining its TY 2009 forecast for Hydro O&M. However, in response to concerns raised by TURN, DRA, and IAG, we find that the results of SCE's forecasting methodology require minor adjustments. We discuss these adjustments below. We also address the reasonableness of the actual forecasted amount requested, $50.4

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52 During the proceeding, SCE agreed with TURN's recommendations to reduce SCE's Hydro O&M forecast by (1) $543,000 for non-labor regarding FERC Account 536 Water for Power (2) $415,000 regarding the Agnew Tramway Misc. Hydraulic Power Generation Expenses FERC Account 539, as this money will not likely be spent in TY 2009 and the costs should be capitalized, not expensed, and (3) $37,000 for FERC

Footnote continued on next page

million, and the recommendations by DRA, TURN, and IAG to reduce this forecast.

2.3.1. Operations of Reservoirs, Dams and Waterways - FERC Account 537

FERC Account 537 Hydraulic Expenses contains three functional subaccounts. One of these subaccounts is referred to as Operations of Reservoirs, Dams and Waterways. To forecast the TY 2009 expenses for this subaccount, SCE uses expenses from the last recorded year 2006 for non-labor costs, $969,000 (constant 2006$). TURN recommends that SCE's TY 2009 forecast be reduced by $169,000 to reflect a base year adjustment to this subaccount.[53] Specifically, TURN claims a five-year average forecasting methodology is appropriate because non-labor costs in this specific area have fluctuated significantly, mainly due to weather-related events, with no discernable trend over the past five years. TURN acknowledges SCE appropriately forecasted the remainder of the account based on last recorded year. The following table illustrates the non-labor fluctuations in the subaccount.

Account 540 Hydro Rents. Joint Comparison Exhibit, p. 61. We find these results reasonable.

[53] Exhibit TURN-5A, pp. 23-24.

Year	Operation of Reservoirs, Dams and Waterways, Non-Labor Costs
2002	$735,000
2003	$600,000
2004	$1,073,000
2005	$624,000
2006	$969,000
5-year average	$800,200

TURN points out that the five-year average of these non-labor costs is approximately $800,000, a reduction of $169,000 to SCE's TY 2009 base estimate. SCE argues it is inappropriate to utilize a portion of a subaccount to derive an expense reduction.

We adopt TURN's $169,000 reduction in SCE's TY 2009 base estimate for Account 537. Costs that fluctuate based on weather are better forecasted on a historical average basis, rather than last recorded year. Accordingly, it is reasonable to forecast these subaccount costs by estimating them separately, as TURN recommends.

2.3.2. Cloud Seeding – FERC Account 536

SCE's testimony includes $250,000 (constant 2006$) for cloud seeding efficiency improvements. SCE proposes to add this amount to its TY 2009 Hydro base estimate. DRA recommends complete disallowance of this amount based on the lack of scientific agreement on the results of cloud seeding. TURN generally agrees that no consensus exists on this topic in the scientific community but does not dispute the additional amount requested by SCE. We find SCE's request reasonable. However, because the efficacy of cloud seeding is unknown, we direct SCE to provide the Commission additional information regarding this process in SCE's next GRC application, including the policy position of the California Energy Commission.

2.3.3. San Gorgonio Hydro Project – FERC Accounts 536, 537, 538, 540, 542, 543, 544

San Gorgonio is a small hydro project that has not operated since an accident in 1998 destroyed its water tanks. SCE proposes $7 million in capital expenditures to decommission San Gorgonio in 2009. This capital request will be addressed in a separate section of this decision. SCE also requests the TY 2009 O&M forecast include $181,000 (SCE's recorded 2006 expenses and the highest year recorded for 2002-2006) for this project.

Based on SCE's plan to decommission the facility in 2009 and SCE's assertion that it is contractually obligated to perform ongoing O&M until the ownership transfer to Banning Heights Mutual Water Company in 2010, TURN recommends reducing the TY 2009 forecast to protect ratepayers from paying for O&M in 2010 and 2011, at which point the plant will be decommissioned. To normalize SCE's projected 2009 expense of $181,000 over three years, TURN proposes to reduce $181,000 by two-thirds ($120,000) and leave the remaining amount of $61,000 in the TY 2009 forecast.

SCE claims that O&M expenses will be incurred into the foreseeable future and offers an alternative TY 2009 forecast of $123,000, which represents the average recorded O&M expenses for 2002-2006. Because SCE states it will incur O&M into the foreseeable future, we find SCE's alternative proposal reasonable and reduce SCE's TY 2009 Hydro base estimate forecast accordingly. However, we expect this amount to be removed from SCE's next O&M forecast.

2.3.4. Future Adjustment No. 1 Hydro Staffing Increases – FERC Accounts 537, 538, 539, 543, 544, 545

As shown below, SCE's TY 2009 forecast includes a total of 252 active full-time hydro employees by the end of 2009.

Future Adjustments[54]
Hydro Generation Operation And Maintenance Expense

(Constant 2006 $)

Future	Adj.	Accoun	Avg 2009-2011	2009	2010	2011
Staffing Increases						
Hydraulic Expenses		537	1,200,000	1,200,000	1,200,000	1,200,000
Electric Expenses		538	600,000	600,000	600,000	600,000
Miscellaneous Expenses	1	539	700,000	700,000	700,000	700,000
Maintenance Dams & Waterways		543	800,000	800,000	800,000	800,000
Maintenance Electric Plant		544	600,000	600,000	600,000	600,000
Maintenance Miscellaneous		545	400,000	400,000	400,000	400,000
		Total	4,300,000	4,300,000	4,300,000	4,300,000
Employee Recruitment & Retention	2	539	172,000	172,000	172,000	172,000
Company Housing Repair	3	542	544,900	891,600	325,000	418,100
FERC Licensing						
Miscellaneous Expenses	4	539	1,872,500	2,279,600	1,513,000	1,824,900
Maintenance Miscellaneous		545	1,249,400	1,264,600	1,237,200	1,246,400
		Total	3,121,900	3,544,200	2,750,200	3,071,300
Dam Safety	5	535	1,100,000	1,100,000	1,100,000	1,100,000
Safety & Regulatory						
Operation Super & Engineer	6	535	100,000	150,000	150,000	-
Miscellaneous Expenses		539	763,000	955,000	692,000	642,000
		Total	863,000	1,105,000	842,000	642,000
Asbestos Abatement	7	542	1,218,000	1,194,000	1,260,000	1,200,000
SCE Helicopter IMM Increase	8	539	430,000	430,000	430,000	430,000
Sediment Removal	9	543	1,815,000	1,505,000	2,250,000	1,690,000
Cloud Seeding	10	536	250,000	250,000	250,000	250,000
ERP Savings	11	539	(310,843)	(310,843)	(310,843)	(310,843)
Total Future Adjustments			13,503,957	14,180,957	13,368,357	12,962,557
Note: Staffing Increases include both Labor and Materials. All other adjustments include material, contract, or other expense.						

In the 2006 GRC, SCE requested 209 active full-time employees. SCE is seeking an increase of 43 over the 2006 base year. As of January 1, 2007, SCE had 197 hydro employees. To achieve SCE's proposed increase, SCE forecasts the need for an additional $4.3 million (constant 2006$). This additional $4.3 million would be a future adjustment to SCE's TY 2009 base estimate. SCE submits this

54 Exhibit SCE-2L, p. 12, Table III-3.

increase is needed to replace the anticipated wave of baby-boomer retirements and to meet increased work load resulting from both increased regulatory requirements and recently issued FERC licenses as well as licenses expected to be issued in the near future.

DRA recommends the Commission reject SCE's request for an additional $4.3 million and, instead, adopt the estimated 2007 amounts for TY 2009. DRA claims no additional amount is appropriate because the proposed additional staff will perform work unrelated to hydro matters and SCE's proposal to start hiring to replace retirements is premature.

We agree, in part, with DRA. SCE is requesting 23 additional positions (22 apprentices and 1 training position) to prepare for retirements. SCE has failed to adequately explain how retirements will impact the requested additions to the workforce. Accordingly, in the absence of sufficient information from SCE, we reduce SCE's requested amount by 50% as follows: SCE's request for 22 apprentices is reduced to 11 apprentices and SCE's request for a training instructor is eliminated. We discuss our rationale for eliminating the training instructor ($131,000)[55] below in response to TURN's recommendations. After these reductions, we find an additional 11 apprentice positions reasonable to accommodate SCE's preparations for retirements. We make no reductions to the number of positions requested by SCE to accommodate increased work associated with FERC relicensing and refurbishment of hydro infrastructure.

While TURN is not convinced that SCE's proposal to hire an additional 43 employees is reasonable, TURN focuses on reducing the salary amount

[55] Joint Comparison Exhibit, p. 738.

requested by SCE for the additional positions. TURN recommends a total increase of $3,886,000 for these 43 employees, $237,000 less than SCE's request, to reflect the actual wages of the proposed new positions rather than SCE's recommendation to use the average wage of all hydro staff. TURN also recommends removing expenses related to training staff on the basis that training is included in SCE's wage calculation.[56]

We find both of TURN's recommended adjustments reasonable. We adopt these adjustments as applied to the total number of increased hydro positions and find reasonable 11 apprentice positions to address future retirements and 20 positions to address increased work load.

2.3.5. Future Adjustment Nos. 4 & 7 Housing & Asbestos Abatement Project – Poole and Rush Creek - FERC Account 542

SCE's TY 2009 base estimate for FERC Account 542 is $1.21 million (constant 2006$). The average future adjustment for 2009-2011 is $1.76 million (constant 2006$). The base estimate and the average future adjustment results in a TY 2009 forecast of $2.97 million. SCE's future adjustments to FERC Account 542, including future adjustments nos. 4 and 7, reflect housing rehabilitation averaging $544,900 per year and asbestos removal averaging $1.218 million per year.

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[56] Joint Comparison Exhibit, p. 737; Exhibit TURN-5A, p. 25; Exhibit SCE-16D, p. 10: "SCE accepts TURN's reduction in non-labor expense of $35,000 for the rounding up from $26,406 to $27,212 and accepts the reduction in non-labor expense of $131,000 for training double-counting, for a total Staffing reduction of $166,000. This proposed reduction affects accounts 537-539 and 543-545."

TURN suggests $374,000 of these future adjustment expenses are unreasonable and should be removed from SCE's forecast. TURN further recommends the remaining $1.389 million be capitalized instead of expensed.[57] These recommendations would result in a reduction to SCE's total O&M expense for hydro housing and building rehabilitation of $1.763 million, essentially eliminating SCE's two future O&M adjustments. All of these estimates exclude labor costs. Labor expenses associated with these future adjustments are addressed elsewhere in SCE's showing.[58] IAG and TURN also point out that SCE requested $387,000 in its 2006 GRC to demolish housing units at remotely operated power plants at Poole and Rush Creek because, according to SCE, demolition was required by FERC.[59] In this case, SCE seeks to spend $371,000 to rehabilitate these same housing units at Poole and Rush Creek -- $161,500 for housing rehabilitation at Poole, $98,300 for asbestos removal at Poole, and $112,000 for asbestos removal at four Rush Creek houses.[60] In response, SCE explains it intended to demolish this housing but reevaluated this plan when it became clear that, due to the severe lack of affordable housing for existing and new hydro personnel, SCE should instead refurbish the housing.

We agree with TURN and IAG that ratepayers, having funded the proposed demolition of these housing units in SCE's 2006 GRC, should not now have to fund their rehabilitation. We therefore reject as unreasonable $374,000 from SCE's future adjustment nos. 4 and 7. Accordingly, based on the

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[57] Exhibit TURN-5A, p. 32.

[58] Exhibit SCE-2L, pp. 16-17.

[59] Exhibit TURN-5A, p. 30 *citing to* 2006 GRC Exhibit SCE-2L, workpapers 211 and 215.

[60] Exhibit TURN-6, Attachment 3, TURN-SCE-038, Q9 and Q11.

information provided by TURN, we adopt TURN's recommendation that $374,000 in unreasonable expenses be removed from SCE's future adjustments reflected in FERC Account 542. We also find reasonable TURN's recommendation to capitalize the remaining $1.389 million[61] rather than expense it.[62] These changes result in an average reduction to SCE's total O&M expense for hydro housing and building rehabilitation of $1.763 million,[63] an amount equal to the total of SCE's requested future adjustment nos. 4 & 7 to Account 542.

2.3.6. Alleged Discrepancies on Hydro Projects

IAG requests the Commission order SCE to file an explanation of certain alleged discrepancies in amounts requested for various projects.[64] SCE adequately responded to IAG's concerns.[65] While we do not always find SCE's forecasted costs reasonable, we find IAG fails to establish conduct by SCE of sufficient concern to warrant further action under Investigation (I.) 08-01-029.

2.3.7. Alleged Rule 1.1. Violation

IAG requests the Commission find SCE in violation of Rule 1.1. Rule 1.1. provides, in part as follows:

> "Any person who signs a pleading or brief, enters an appearance, offers testimony at a hearing, or transacts business with the Commission. . . agrees. . . never to mislead the Commission or its staff by an artifice or false statement of fact or law."

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[61] The 2009 plant-in-service effect of TURN's capitalization request is $1,773,000.

[62] Exhibit TURN-5A, p. 32.

[63] The adopted TY 2009 figure is $1.773 million.

[64] Exhibit SCE-16D, p. 18.

[65] Exhibit SCE-16D, pp. 56-61.

IAG claims SCE mislead the Commission to believe FERC directed SCE to complete the Lundy Project with this statement: "The project benefit and justification is to comply with a FERC relicensing requirement." In fact, SCE was acting in compliance with a private settlement, referred to as the Lundy Hydroelectric Project Settlement Agreement, dated February 3, 2005.[66] In response, SCE claims IAG uses an overly narrow definition of the phrase "FERC relicensing requirement."[67] SCE further explains that "SCE views the Lundy Project and Settlement, which was entered into as part of obtaining a new FERC license, as a FERC relicensing requirement, regardless of whether it was specifically ordered by FERC or not. SCE has never stated that the Lundy project was an order of the FERC license."[68]

We find IAG's request fails to establish a *prima facie* case of a Rule 1.1. violation. Although SCE's initial statements are cursory on this matter, SCE's explanation in its rebuttal testimony is reasonable and sufficiently clarifies the extent of the involvement of FERC. Based on the existing evidence, no further action will be taken with respect to this matter.

2.3.8. Future Adjustment No. 8 - Hydro Vegetation Management Expenses – FERC Account 539

SCE's TY 2009 base estimate for FERC Account 539 is $13.2 million (constant 2006$). This represents an increase from its recorded 2006 expenses of $9,206,450 (constant 2006$). By future adjustment no. 8, SCE proposes an average increase to its base estimate of $430,000 per year (2009 through 2011) for

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66 Exhibit SCE-16D, p. 48.

67 Exhibit SCE-16D, p. 48.

68 Exhibit SCE-16D, pp. 48-49.

maintenance, inspection, and repair of its helicopter operations. IAG proposes certain reductions to SCE's forecast related to brush clearing. Specifically, IAG requests a reduction of $23,333 for the Rush Creek Heliport Brush Clearing and $230,000 for Big Creek Vegetation Management, for a total reduction of $253,333 to SCE's TY 2009 forecast. In response, SCE explains that the project recorded in FERC Account 539 will involve more than brush clearing. The helicopter landing site must be moved and a new heliport site constructed, which requires that vegetation be removed and the site graded and covered with rock. Based on the information provided by SCE, the amount requested is reasonable.

2.4. Gas–Fired Generation

2.4.1. Mountainview O&M Expenses

Consistent with D.03-12-059, D.04-03-037 and D.04-04-019, SCE acquired Mountainview Power Company, LLC (MVL) as a wholly-owned SCE subsidiary and executed a Power Purchase Agreement (PPA) for cost recovery with MVL for electricity from MVL's Mountainview Generating Station (Mountainview).[69] In this proceeding, SCE asks the Commission for permission to include Mountainview in rate base and allow recovery of Mountainview's operating costs through its TY 2009 forecast. In addition, Mountainview's capital costs would no longer be recovered as purchased power costs, through the operation of the ERRA, but would instead be recovered in SCE's authorized base

[69] Mountainview has a nominal output of 1,050 MW. It went into initial commercial service in December 2005 and full commercial service in January 2006. It also includes two retired units (Units 1 & 2) that SCE plans to decommission in 2009. Mountainview currently recovers capital, and non-fuel O&M expenses and A&G expenses associated with Units 3 & 4 through a FERC approved PPA with SCE. SCE is responsible for dispatching Mountainview, purchasing fuel, and any decommissioning costs.

generation revenue requirement and through rates. The fuel costs and availability and heat rate incentive payments will still be recovered through the annual operation of the ERRA balancing account process. SCE states if the Commission does not approve of its request now, it will not terminate the PPA and, instead, continue to recover its Mountainview operating costs through the FERC-jurisdictional PPA.[70] SCE's TY 2009 forecast for Mountainview O&M is $42.505 million (constant 2006$). SCE made future adjustments totaling $13.779 million to 2006 recorded costs to compute its TY 2009 forecast.

In response to SCE's request to operate Mountainview as a utility-owned generation facility, DRA raises various concerns related to SCE's proposed cost recovery, not to the transfer of ownership. TURN's recommendations for Mountainview are related to SCE's request for peaker O&M and related capital and will be addressed in a separate section of this decision.

DRA recommends $41.5 million in O&M expenses for TY 2009 for Mountainview. DRA reduces SCE's TY 2009 forecast by $1 million to remove $0.454 million for additional staff and $0.5 million for "Additional Future Projects (Unforeseen)."[71] According to DRA, the Commission should not increase funding in TY 2009 for retirements that may occur over "the next several years" and for Additional Future Projects (Unforeseen) that in DRA's view are an unsupported contingency.

SCE defends the cost of seven additional employees, all of whom SCE hired in 2008, to address increased workload at Mountainview. Regarding the

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[70] A.07-11-011, pp. 4-5.

[71] Exhibit SCE-2N, p. 42.

amounts forecasted in Additional Future Projects (Unforeseen), SCE says the funding is needed for projects to address areas of concern that have arisen since mid-2007 and would be reflected in recorded cost history if Mountainview were an older plant.[72]

We find that SCE has adequately explained and justified the additional employees and the Additional Future Projects (unforeseen) O&M projects. Thus, we find SCE's TY 2009 O&M forecast for Mountainview reasonable. However, we do not anticipate approving any amounts for Additional Future Projects (Unforeseen) in SCE's next GRC because historical data should reflect these expenses. In addition, we approve the transfer of ownership. While the Commission in D.03-12-059 found "… that unless Edison decides to purchase Mountainview as utility owned generation, a CPCN is not necessary,"[73] we addressed all necessary CPCN and CEQA matters in A.03-07-032. When finalized, this transfer will place Mountainview under Commission-jurisdictional ratemaking. However, this change in ratemaking cannot occur until FERC issues a decision approving termination of the existing power purchase agreement.

2.4.2. Peaker O&M - FERC Accounts 546, 548, 549, 551, 553, 554

SCE proposes O&M expenses of $9.7 million in TY 2009 to operate its five new peakers (constant 2006$).[74] The TY 2009 forecast includes $3.214 million for

[72] Exhibit SCE-16E, p. 6.

[73] D.03-12-059, p. 22 and p. 57.

[74] SCE filed a separate application in late 2007, A.07-12-029. That application is pending and seeks approval and recovery in rates of the initial capital costs for these five new peakers. This separate application also requests recovery of O&M expenses starting from plant commercial operation up to the effective date of a decision in that

Footnote continued on next page

labor expense. In total, SCE's TY 2009 forecast for non-labor costs, which includes contract labor, materials, and supplies, is $6.488 million. No history of recorded plant O&M costs exists for these peakers. Therefore, SCE's estimate of O&M expenses uses a "zero-based budget."[75] Only four of the five new peakers are commercially operational, as of September 17, 2007. Construction of the fifth peaker, located at McGrath Beach in the City of Oxnard, has been delayed due to permitting issues. During the course of the proceeding, SCE was unable to provide a date certain for operation of the fifth peaker. At the beginning of the proceeding, SCE explained, "It is very difficult to forecast when permit approval will be received"[76] but SCE anticipates the fifth peaker will be operational by the end of 2008. Later, at hearings in June 2008, SCE informed the Commission that the commercial operational date for the fifth peaker is still unclear.[77] In SCE's September 4, 2008 update testimony,[78] SCE suggested that "operation of the fifth

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proceeding. This 2009 GRC considers recovery of (1) the O&M expenses commencing on the effective date of a decision in that proceeding and (2) capital expenditures incurred after start-up.

[75] Exhibit SCE-2O, pp. 10-24. SCE used a budget-based approach to estimate the initial O&M expense requirements for these new SCE facilities. The peaker manager developed the estimate in conjunction with the Operations Manager and the Maintenance Manager. Together, they estimated the labor expense forecast based on the initial staffing plan, hourly labor rates from the IBEW union contract, salary data from SCE's Comprehensive Incentive Plan for management and professional employees, and expected labor support from other SCE resources. Based on their combined experience, judgment and review of equipment manufacturers' recommendations, they estimated the non-labor expenses expected to support continued O&M of plant equipment.

[76] Exhibit DRA-75, SCE response to DRA data request DRA-SCE-021-TXB, Q.2.

[77] RT Vol. 7:479.

[78] Exhibit SCE-54.

peaker could begin as early as August 2009,"[79] At this point, SCE updated its testimony to reflect a 15% reduction in its forecasted peaker O&M up until August 2009, the date SCE hopes the fifth peaker will be operational. SCE's revised request is addressed below. We also address DRA's and TURN's concerns about construction delay, staffing, and the use of a one-way balancing account.

2.4.3. One-Way Balancing Account for Peaker O&M

Due to the uncertainties as to when the fifth peaker will be operational, DRA recommends a one-way balancing account for all peaker O&M. Under DRA's proposal, if the spending target determined by the Commission is not met, the unspent funds are returned to the ratepayers but, if expenditures exceed the target, the amount over the target is not recoverable through rates. In response, SCE explains its TY 2009 O&M forecast assumes operation of all five peaker units and, as a result, SCE has not estimated an appropriate reduction to the peaker TY 2009 O&M forecast if only four units operate during 2009, rather than five units. Although SCE did not forecast O&M for each individual peaker, it claims in direct testimony that its peaker O&M forecast for TY 2009 for the fifth peaker is less than 20% and possibly even less than 10% of its forecast total. Accordingly, SCE argues that placing all O&M in a one-way balancing account is unreasonable.

Instead, SCE suggests if any uncertainty remains regarding the fifth peaker later this year, the Commission can adequately address the uncertainty in its final decision in this proceeding. Should the fifth peaker not be operational

[79] Exhibit SCE-54, p. 20.

by the date the Commission authorizes SCE's 2009 GRC revenue requirement, SCE suggests the Commission rely on the existing Peakers Generation Memorandum Account (PGMA).[80] SCE proposes to modify the existing PGMA to record the difference between the 2009 authorized peaker revenue requirement (i.e., O&M and capital revenue requirement) and the actual recorded peaker revenue requirement. SCE also proposes to record both over-collections and under-collections in the modified PGMA. In update testimony, SCE did not address the merits of a one-way balancing account.

Based on SCE's claim that O&M associated with the fifth peaker is a small percentage of the overall peaker forecasts, we reject DRA's proposal to track all peaker O&M in a one-way balancing account. We also reject SCE's proposal to rely on the PGMA because SCE does not address treatment of overcollections. Finally, we reject SCE's most recent recommendation, to reduce the O&M forecast by 15% until August 2009, because SCE has not shown the permit process is moving forward on a reliable timeline. Instead, based on the existing evidence and the lack of a firm date for the issuance of permits, we reduce SCE's forecast by 10%, an amount equal to SCE's best estimate of the costs associated with the operation of the fifth peaker.

2.4.4. Integration with Mountainview–Staffing & Information Technology – FERC Accounts 546, 548, 549, 551-554

DRA recommends reducing peaker O&M expenses by a total of $81,000 (constant 2006$). DRA would reduce the employee count to reflect integrated SCE operations with Mountainview and would reduce IT costs to reflect one-

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[80] The Commission in Resolution E-4031 established a Peaker Generation Memorandum Account (PGMA).

time expenses. TURN also claims SCE's failure to integrate the operating systems of the new peakers with Mountainview results in unreasonable labor costs. As a result, TURN would reduce peaker O&M expenses by $536,000.

We reject DRA's and TURN's recommendations on employee count. From the information provided by SCE regarding the projected workloads to operate the two control systems, it is not clear that integrating the operating systems of Mountainview and the peakers would be efficient. However, we agree that SCE should continue to explore ways to increase cross-support between the staffs of the peakers and Mountainview.

2.4.5. Information Technology Equipment Purchases–One Time Expenses - FERC Account 549

SCE forecasts $800,000 (constant 2006$) of IT costs for TY 2009 for the new peakers. SCE's forecast includes a one-time $400,000 O&M project for additional plant instrumentation and data collection hardware and software. TURN and DRA recommend reducing SCE's O&M forecast for the peaker units by $267,000 to average one-time expenses across the rate case cycle. They would include only one-third of this project ($133,000) in SCE's TY 2009 forecast for FERC Account 549.

SCE concedes it "has not identified additional specific one-time O&M projects beyond 2009."[81] But it argues that because the peakers are very new plants, the Commission should assume that "similar one-time O&M projects will arise in 2010 and 2011 and authorize SCE to recover the full $400,000 amount in 2009."[82] As support for this request, SCE offers that its "power plant operating

[81] Exhibit SCE-16E, p. 17.

[82] Exhibit SCE-16E, p. 17.

experience is that such one-time O&M projects are likely to arise in 2010 and 2011."[83] Yet SCE apparently cannot predict whether those additional costs would even be related to computer systems, as it refers generally to one-time O&M projects.

We reject SCE's request for a contingency for unknown costs that might possibly occur. SCE has failed to demonstrate the reasonableness of collecting $400,000 each year in the rate case cycle for what it acknowledges are one-time IT costs in 2009. Instead, we adopt TURN's and DRA's proposal to normalize SCE's proposed one-time IT costs over the rate case cycle and remove $267,000 from Account 549.

2.5. Solar Two Decommissioning Project

SCE requests recovery of $4.6 million in capital expenditures for its one-third share of the Solar Two decommissioning project. SCE relied upon a 1999 estimate to forecast costs for this proceeding. This 1999 estimate was prepared for the Department of Energy and found the cost to decommission the site to be $5.7 million (100%). SCE then escalated to 2009 this 1999 estimate and arrived at $7.660 million, of which SCE's share is $4.639 million.[84] No party opposes SCE's request. DRA, however, proposes to limit SCE's cost recovery to $4.6 million,[85] asserting that SCE included contractor profit and overhead and a contingency in

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[83] Exhibit SCE-16E, p. 17.

[84] Exhibit SCE-2N, p. 70.

[85] Exhibit DRA-6, p. 31.

its 1999 cost estimate and, therefore, the Commission should cap that estimate.[86] DRA explains that a cost cap will make SCE accountable for its decommissioning cost estimate. Based on SCE's decision to rely on 1999 cost data for this estimate rather than more recent data, we assume SCE is confident in the accuracy of the results of its analysis. Accordingly, we find a cost cap reasonable and adopt DRA's recommendation.

2.6. Project Development Division–Request to Include RD&D – FERC Accounts 506 and 549

SCE's forecast for TY 2009 O&M for its Project Development Division (PDD) is $26.4 million (constant 2006$). This request consists of $5,012,000 to continue the PDD activities authorized for rate recovery in the 2006 GRC[87] and $21,572,000 to begin generation-related technology demonstration, testing, and evaluation and to fund the incremental staffing required to conduct that work. This $21,572,000 will fund an expansion of the existing responsibilities of the PDD to include what SCE describes as research, development, and demonstration (RD&D). SCE also asks the Commission to permit the entire forecasted amount, including its RD&D, to be recovered through traditional ratemaking, rather than continued use of the PDD Memorandum Account (PDDMA).

DRA and the Western Power Trading Forum (WPTF) oppose SCE's request for RD&D funding. WPTF asserts that the RD&D funding by ratepayers,

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[86] Exhibit DRA-75, SCE response to DRA data request DRA-SCE-046-TXB, Q.10: "An additional 40% of contingency was then added to the escalated 2007 total of $7.221 million to account for the cost concerns discussed above."

[87] D.06-05-016, p. 45, SCE's TY 2006 forecast was $4,950,000.

as requested by SCE, will subsidize utility generation project development and, as a result, is anticompetitive. WPTF also opposes SCE's request to eliminate the memorandum account because, among other reasons, traditional rate recovery will undercut the Commission directive in D.07-12-052 that IOUs are not permitted to recoup from ratepayers any bid development costs associated with losing bids in competitive Request for Offers. DRA asserts that utilities should not use ratepayer funds to invest in RD&D because generation manufacturers, venture capital, developers, and governmental agencies are better suited for such activities. DRA suggests no RD&D funding be approved in the TY 2009 forecast and, instead, the Commission should maintain the memorandum account with a $3 million per year cap.

In D.06-05-016, the Commission approved SCE's request for cost recovery for certain so-called "support" functions associated with SCE's proposed PDD. These "support functions" included the following: (1) analyze generation technologies and costs; (2) locate appropriate sites for potential generation development; (3) monitor and participate in generation-related regulatory and legislative activity; and (4) develop and maintain the best option outside negotiation (BOON) for relevant generation technologies.[88]

The Commission, however, rejected SCE's request to include in rates efforts by the PDD to engage in activities such as "develop and implement plans to advance projects from the development phase to the construction and operations phase." The Commission found such activities to be "development" costs and concluded that "Independent producers' development costs associated

[88] D.06-05-016, pp. 51-53.

with unsuccessful projects are not recoverable from ratepayers. It is a matter of fairness that SCE assume that same risk, if it chooses to participate."[89] In addition, because the Commission had concerns regarding the potential for anti-competitive impacts of funding the "support functions" of the PDD, the Commission required SCE to track all expenses of its PDD in a memorandum account and limited cost recovery to "support" functions.

Currently, RD&D is not a part of the PDD's "support" functions approved by the Commission. However, in this proceeding SCE claims a need for generation-related RD&D.[90] SCE states this need will include a limited amount of generation primary research which would be a minor sub-set of the money requested, but the vast majority of the requested $20 million per year would be used to demonstrate generation-related technologies in general and renewable generation technologies in particular. Specifically, SCE proposes to partner, as appropriate, with technology developers, the California Energy Commission (CEC), the U.S. Department of Energy (DOE), Electric Power Research Institute (EPRI), and others on RD&D related to technologies specifically targeted to generation, generation deployment, and related energy storage.

In D.06-05-016, the Commission adopted the PDDMA, a memorandum account to enable SCE to exclude project development costs for specific projects

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[89] D.06-05-016, p. 52.

[90] The Commission has approved SCE's request to recover up to $46.7 million in rates regarding the feasibility of sequestering carbon dioxide from a proposed "Clean Hydrogen Power Generation" plant. SCE has also recently applied to the Commission for a Renewable Integration and Advancement (RIA) Program "for up to $30 million to evaluate and develop technology, controls, and software solutions to integrate increased levels of renewable generation into the existing transmission and distribution infrastructure." SCE proposes to recover the RIA's costs in distribution rates.

from this 2009 GRC request.[91] SCE has done so but has added $20 million per year to its TY 2009 forecast for RD&D. For the same reasons as set forth in D.06-05-016, we reject SCE's $20 million request for cost recovery of RD&D. In D.06-05-016, the Commission expressed concerns regarding the potential to create an uneven playing field for competitors. The Commission stated, "…from a policy perspective, we feel it is important that the project development costs for proposed new projects should not be specifically included in rates."[92] These same concerns continue to exist. To address these concerns, the Commission excluded SCE's entire PDD request from rates. The Commission allowed rate recovery after review in an ERRA proceeding through a memorandum account of costs that generally support new generation but not those costs associated with actual proposed projects. The Commission directed SCE to track such supportive project development costs in a memorandum account and stated that "Such costs can then be recovered in future rates to the extent that 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."

We agree with DRA and WPTF, and we affirm the procedures and restrictions adopted in D.06-05-016. Under those procedures and restrictions, we

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[91] D.06-05-016, p. 376: "For this GRC SCE's request of $4.95 million in expenses to fund its proposed PDD should be excluded from rates. However, SCE should be allowed rate recovery of costs that support new generation and that are not associated with proposed projects. SCE should track such supportive project development costs in a memorandum account. Such costs can then be recovered in future rates to the extent that 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."

[92] D.06-05-016, p. 53.

stated that, if SCE chooses to do so, it may identify appropriate "support" costs and include the forecast of such costs in its TY 2009 forecast. According to SCE, that amount is $5,012,000. We will continue to rely on the PDDMA and will not include any "support" costs in the forecast. We will not permit rate recovery for any additional functions of the PDD beyond those approved in D.06-05-016.

2.7. Pebbly Beach Generation Station–Catalina Island Forecasting Method – FERC Accounts 548, 549, 553

SCE's TY 2009 forecast for Pebbly Beach Generation Station[93] O&M expense is $5.38 million (constant 2006$). SCE considered the activities contained in each FERC Account, then separately decided on a forecast for labor and non-labor expenses.[94] In support of its forecasting methodology, SCE states each FERC Account is unique and SCE could not apply the same forecast method to all FERC accounts. For example, SCE used 2006 recorded expenses to forecast labor in Account 548. SCE anticipates that the staffing will remain constant at 2006 levels in TY 2009.[95] For Account 553, SCE used a 3-year average of 2003-2006 expenses to forecast labor because SCE found this method to accurately reflect current and future staffing levels. DRA disagrees with SCE's forecast methodology for the O&M recorded to these FERC Accounts. DRA's proposal includes a $739,000 reduction to SCE's forecast. We have reviewed SCE's request

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[93] On May 10, 2007, a major fire started at Catalina Island, north of the city of Avalon near a radio transmission facility. The cause of the fire is still under investigation. Over 4,750 acres were burned and the fire destroyed much of the electrical infrastructure that delivered power from SCE's Pebbly Beach Generating Station to Catalina's inland communities.

[94] Exhibit SCE-2P, p. 4.

[95] Exhibit SCE-16G, p. 2.

and find SCE's forecast methodology is appropriate in this instance. Accordingly, we find SCE's TY 2009 forecast for Pebbly Beach Generation Station O&M expense of $5.38 million reasonable.

3. Transmission & Distribution Expenses – FERC Accounts 560-573 Transmission Expenses; FERC Accounts 580-598 Distribution Expenses

SCE requests $619.334 million (constant 2006$)[96] for TY 2009 Transmission and Distribution (T&D) O&M expenses.[97] SCE's 2006 recorded expenses are $493.322 million. DRA recommends the Commission adopt T&D O&M expenses of no more than $428.9 million.[98] TURN and other parties also recommend reductions to SCE's forecast. Our analysis and findings follow.[99]

3.1. Operations Supervision and Engineering – FERC Account 560

SCE's TY 2009 forecast for its Operation Supervision and Engineering expenses recorded to FERC Account 560 is $16.701 million (constant 2006$).[100] DRA's estimate is $14.239 million.[101] SCE's FERC Account 560 includes three subaccounts: 560.100 Operations Engineering; 560.200 Transmission Systems Operations Supervision; and 560.980 Allocated Division Overhead-Transmission

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96 Exhibit SCE-54.

97 Exhibit SCE-3B, p. 52.

98 Exhibit DRA-5, p. 1. SCE's 2006 recorded expenses for T&D O&M were $428.799 million, but also included incentive awards and bonus pay which DRA recommends removing.

99 When expressing its forecast for TY 2009, SCE at times relies upon averages of its forecasts for 2009-2011. We do not intend to adopt these averages for TY 2009.

100 Joint Comparison Exhibit, p. 219.

101 Exhibit DRA-5, p. 8.

Operation.[102] No disputes exist regarding subaccount 560.200. We address SCE's forecasts for subaccounts 560.100 and 560.980 below.

3.1.1. Operations Engineering - FERC Subaccount 560.100

SCE forecasts $8.211 million (constant 2006$) for TY 2009 expenses for subaccount 560.100. SCE's forecast includes increases over 2006 recorded costs in the following areas: (1) Engineering Advancement Projects; (2) Project Management Organization Work Order Write-Offs; (3) Standards and Publications; (4) Reallocation of Overhead; (5) Engineering Staff; and (6) Engineer's Desktop Software Upgrades. DRA recommends the Commission reject almost all of the increases requested by SCE.[103] These recommendations are discussed below.

3.1.1.1. Engineering Advancement

SCE requests an increase in funding over the 2006 base year for Engineering Advancement as follows: (1) $2.094 million (constant 2006$) for subaccount 560.100 (transmission) and (2) $2.140 million (constant 2006$) for subaccount 580.100 (distribution).[104] SCE explains that the additional funding for subaccount 560.100 will support SCE's efforts to develop and deploy "smart" technologies on the electric grid and that these technologies, when combined with advanced communications and practices, will comprise what is commonly referred to as the "Smart Grid."[105] According to SCE, it uses the soundest

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[102] Exhibit DRA-5, p. 8.

[103] Exhibit DRA-5, p. 9.

[104] Joint Comparison Exhibit, p. 248. Subaccount 580.100 is addressed in a separate section of this decision.

[105] SCE opening brief, p. 78.

possible basis for estimating costs, and SCE cannot reach the next level of specificity in estimating these cost projections until it has actual bids in hand and personnel actually doing the work.[106] Thus, these increased costs simply cannot be developed with more specificity until 2009 and beyond.[107]

DRA would deny the requested increase in funding, arguing that there is inadequate information to support the need for additional funding and inadequate demonstration of the benefits to customers. The California Farm Bureau Federation (CFBF) agrees.[108]

SCE is requesting a significant increase. Without further data and based on the level of detail provided by SCE, we can not approve the full request. We find reasonable 50% of SCE's requested increase for Engineering Advancement in subaccount 560.100.

3.1.1.2. Additional Engineering Staff

SCE requests $285,000 (constant 2006$) to add three civil engineers to handle apparatus design review and substation automation. DRA asserts SCE's workload can be addressed by its current staffing.[109] DRA presents customer and load growth forecasts for 2009 that are lower than 2006 levels. SCE claims, and its evidence shows, the increase in staffing is necessary whether or not SCE experiences customer growth in the test year.[110] SCE explains that new positions are needed for work related to improvements and expansions to the transmission

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[106] SCE opening brief, p. 79.

[107] Exhibit SCE-17G1, p. 53.

[108] Exhibit CFBF-1, p. 6.

[109] Exhibit DRA-5, p. 13.

[110] Exhibit SCE-17B, pp. 3-4.

system and continued expansion of the substation automation system and are necessary to address design issues posed by SCE's transmission and substation systems as they currently exist. We find SCE's request reasonable as the additional staff will address new recently emerging issues not currently addressed in historical costs.

3.1.1.3. Standards and Publications Contract Group

DRA rejects SCE's proposed credit adjustment of $616,000 to reflect the elimination of certain contract resources from SCE's Standards and Publications Contract group. Instead of contract resources, SCE is proposing to rely partially on additional personnel, as reflected by the increase of $285,000 for additional employees, discussed above.[111] Based on the evidence presented and our finding above that SCE's proposal for additional staffing is reasonable, we find SCE's reduction in contract resources reasonable.

3.1.1.4. Reallocation of Overhead

SCE requests a decrease of $1,145,000 (constant 2006$) as a result of a shift of $1,145,000 from O&M to capital. DRA objects to SCE's request.[112] SCE explains this adjustment was a result of an analysis it conducted in 2006 of the cost recording practices for clearing accounts. SCE's analysis showed the need to make changes in the way costs were recorded for several accounts. As a result, SCE incorporated into this GRC these changes in its cost recording practice. The changes are shown in the relevant O&M accounts as an adjustment for overhead allocation. SCE explains that the adjustments must be made to accurately reflect

[111] Exhibit SCE-17B, p. 2.

[112] Joint Comparison Exhibit, p. 257.

the costs that will be recorded on an ongoing basis. SCE claims this modification is solely an accounting adjustment[113] and follows the FERC accounting guideline. We agree and find SCE's request to modify its accounting practices reasonable.

3.1.1.5. Desktop Software Upgrade

SCE requested $500,000 (constant 2006$) to upgrade desktop software.[114] DRA recommends the Commission normalize this increase, proposing one-third of SCE's request be included in the TY 2009 forecast. DRA justifies the normalization "[b]ased on the fact that SCE has embedded costs for software upgrades in its historical expenses…."[115] SCE has established there were no software upgrades in 2006, so there are no upgrade costs embedded in 2006 recorded expenses.[116] SCE provided detailed documentation of the upgrades it needs in 2009, 2010 and 2011, establishing that the upgrade costs are not TY 2009 one-time expenses.[117] We find SCE's request reasonable.

3.1.1.6. Project Management Organization Work Order Write-Offs

SCE requests a $333,000 (constant 2006$) increase for write-offs of work orders in its Project Management Organization.[118] DRA opposes SCE's request, arguing that the recorded 2006 expenses for Project Management Organization

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[113] Exhibit SCE-17G1, p. 28.

[114] The $500,000 figure combines the upgrade for the Primavera Software license and the Engineering Desktop Software upgrades. Exhibit SCE-3C, p. 5, Table VIII-2 and pp. 7-8.

[115] Exhibit DRA-5, pp. 12-13.

[116] Exhibit SCE-17B, p. 3, Attachment 2.

[117] Exhibit SCE-17B, Attachment 3.

[118] Exhibit SCE-17B, p. 6.

write-offs is the high point of the historical period and SCE has not shown that "2006 recorded expenses are insufficient" to meet test year needs.[119] SCE explains that Project Management Organization write-offs vary with the level of Project Management Organization-related capital expenditures. The evidence supports SCE's analysis. DRA has incorrectly connected these expenses to customer growth. As explained in a separate section of this decision, we reduce SCE's request for capital spending by $549.4 million. Accordingly, based on the relationship between capital spending and Project Management Organization write-offs, we find it reasonable to reduce SCE's requested increase in Project Management Organization work order write-offs by 14.56%.

3.2. Allocated Division Overhead to Clearing Accounts – FERC Subaccounts 560.980, 568.980, 580.980, and 590.980

SCE's TY 2009 forecast for subaccount 560.980 is $7.125 million (constant 2006$).[120] SCE's 2006 recorded expenses for this subaccount are $6.285 million. DRA recommends a TY forecast of $5.933 million. SCE's TY 2009 forecast for subaccount 568.980 is $4.701 million. SCE's 2006 recorded expenses for this subaccount are $3.985 million. DRA recommends $3.869 million. SCE's TY 2009 forecast for subaccount 580.980 is $22.432 million. SCE's 2006 recorded expenses for this subaccount are $20.009 million. DRA recommends $19.360 million. SCE's TY 2009 forecast for subaccount 590.980 is $16.115 million. SCE's 2006 recorded expenses for this subaccount are $13.569 million. DRA recommends $13.263 million.

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119 Exhibit DRA-5, p. 14.

120 Joint Comparison Exhibit, pp. 348-351.

Because we are authorizing less of an overall increase than requested by SCE, the increase in clearing account activity should be less as well. In response to concerns expressed by the Commission in the 2006 GRC decision regarding the absence of a proposal by SCE to account for any adjustments in clearing account activity when related O&M or capital costs are adjusted,[121] SCE offers an approach by which reductions to O&M are applied to the associated clearing accounts as a ratio.[122] SCE proposes specific ratios for each FERC account. SCE, explaining that its suggested approach attempts to apply the overall reductions to O&M to the associated clearing accounts as a ratio, states: "For example, the requested increase in sub-account 560.980 is $1.192 million. This increase supports Transmission operations activities recording to accounts 560 through 567, which cumulatively forecast an increase of $32.669 million. The ratio of 1.192 divided by 32.669 is 3.6%. Therefore, if SCE's requested increase in 560 through 567 were reduced by $1,000.00, SCE would accept a reduction to 560.980 of $36.00."[123] SCE presents its recommended ratios in the table reproduced below.

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121 D.06-05-016, pp. 92-94.

122 Exhibit SCE-17G1, p. 21; SCE-17G2, p. A-11, Attachment 1.

123 Exhibit SCE-17G1, p. 21: "SCE claims no methodology is required for capital because clearing accounts are not removed from either historical or projected capital spending. SCE explains that if a specific capital project is reduced by $1,000.00, the associated clearing account costs are also reduced since they are already imbedded in the $1,000.00."

High Level Ratios of Clearing Accounts to Accounts Supported[124]

FERC Accounts	Increase from '06 - '09 (Constant 2006 $000)	Support Ratio
Transmission Operations		
560 through 567	$ 32,669	
560.980	$ 1,192	**3.6%**
Transmission Maintenance		
568 through 573	$ 16,707	
568.980	$ 832	**5.0%**
Distribution Operations		
580 through 589	$ 43,491	
580.980	$ 3,072	**7.1%**
Distribution Maintenance		
590 through 598	$ 24,422	
590.980	$ 2,848	**11.7%**

SCE's analysis is flawed as it fails to explain the relationship between SCE's requested increases in the clearing account to the related total forecasted amount in a corresponding O&M account. We find that the record in the proceeding does not include a reasonable explanation of the relationship between the clearing account activity and O&M and capital costs. However, we will reduce SCE's requested increase in each of the above XXX.980 accounts by 40%[125] to reflect an approximation of the reduction in these clearing account expenses due to reductions in SCE's request for T&D expenses in this decision.

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124 Exhibit SCE-17G2, p. A-13.

125 D.06-05-016, pp. 92-93.

3.3. Transmission Station Expenses - FERC Account 562

SCE's forecast for TY 2009 O&M for Account 562 is $16.287 million (constant 2006$). The 2006 recorded amount for this account is $14.712 million. DRA recommends certain reductions to SCE's forecast in subaccount 562.100 for Vehicle Costs and Grid Operations and in subaccount 562.200 for Vehicle Costs. Vehicle Costs are addressed in a separate section of this decision. Grid Operations are discussed below.

SCE forecasts $12.301 million for subaccount 562.100, which is an increase of $891,000 over 2006 recorded expenses.[126] FERC subaccount 562.100 records the cost of labor, materials, and other expenses to operate transmission substations and switching centers. This proposed increase is made up of $396,000 for 20 additional substation operators and $495,000 for Vehicle Costs.[127] DRA recommends that the Commission adopt expenses in the amount of SCE's 2006 recorded expenses, $11.410 million, for TY 2009.[128] DRA and CFBF assert that the 20 additional substation operators can be funded through a reduction in the overtime costs.[129] Based on SCE's current staff shortages, we find the additional amount requested for substation operators reasonable and expect overtime to be reduced.

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[126] SCE opening brief, p. 46, SCE states "The arguments for substation operators in this transmission Sub-account 562.100 apply equally to distribution Sub-account 582.100."

[127] Exhibit SCE-3C, pp. 34-35.

[128] Exhibit DRA-5, p. 17.

[129] Exhibit DRA-5, p. 20.

3.4. Vehicle Costs Transmission & Distribution Business Unit - FERC Accounts 562, 563, 566, 568, 570, 571, 582, 583, 584, 587, 588, 590, 592, 593, 594, and 596

The Transmission & Distribution Business Unit (TDBU) operates a vehicle and equipment fleet consisting of passenger cars, vans, pick-up trucks, forklifts, trucks with aerial equipment (buckets and cranes), loaders, tractors, stringing equipment, trailers, and other vehicles. TDBU utilizes this fleet to operate and maintain SCE's transmission and distribution facilities, while SCE's Transportation Services Department acquires, maintains, and repairs the fleet. The Transportation Services Department also provides TDBU with Heavy Equipment, Rental, and Crane services (HERC), and helicopter services (Aircraft Operations).

TDBU recorded $56.584 million for the vehicle and equipment fleet expenses in 2006. For TY 2009, SCE forecasts $90.779 million (constant 2006$) in expenses for the fleet, a $34.195 million increase.[130] For TY 2009, the total forecast for the fleet, HERC, and aircraft operations is $95.954 million (constant 2006$), an increase of $37.329 million over year 2006.[131] The components of the total forecast are as follows: (1) $41.048 million for vehicle and equipment replacements; (2) $6.017 million for vehicle and equipment additions; (3) $30.595 million for Transportation Services Department base operations related to the current TDBU fleet; (4) $2.160 million for compliance with the California Air Resources Board rules on certain diesel vehicles; (5) $10.959 million for fuel and fueling; (6) $1.650 million for HERC; and (7) $3.573 for

130 Exhibit SCE-3B, p. 101.

131 Exhibit SCE-3B, pp. 101-102.

aircraft operations.[132] SCE explains that it allocates Vehicle Costs to FERC subaccounts either directly (7%) or based on labor (93%).[133]

DRA claims that based on historical 2002-2006 data, SCE's request is not justified.[134] According to DRA, nothing exists in SCE's direct testimony to support its Vehicle Cost forecast other than the indication that the costs were developed using a budget-based methodology.

In rebuttal, SCE offers explanations why DRA's estimate is low, but SCE still provides insufficient information to justify its request. As SCE showed in direct testimony, approximately 56% of the increased Vehicle Cost represents replacement of vehicles that have exceeded their useful lives and no longer comply with state and federal emission requirements. SCE explains that, because these vehicles must be replaced and the proposed replacement rate exceeds the past replacement rate, the replacement costs exceed the current costs.[135] SCE also explains that its vehicle replacement strategy has been to replace vehicles in a timely manner, thus reducing downtime and repair costs, minimizing vehicle rental expense, and maximizing residual value in the vehicles by aggressively reselling them whenever possible.[136]

It is unclear why SCE's replacement rate is increasing when, according to SCE, its strategy has been to replace vehicles in a "timely manner." Accordingly,

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132 Exhibit SCE-3B, pp. 102-103

133 Exhibit SCE-3E, pp. 29-31 and Appendix B herein, Transportation Cost Allocation Table.

134 Exhibit DRA-5.

135 SCE opening brief, p. 68.

136 SCE opening brief, p. 69 *citing to* Exhibit SCE-17G-1, p. 6.

we find it reasonable to reduce the request by SCE for increases to Vehicle Costs and adopt DRA's recommendation.

3.5. Inspect and Patrol Lines Overhead Line Expenses – FERC Subaccount 563.100

SCE forecasts $16.565 million (constant 2006$) in labor and non-labor expenses recorded to FERC Account 563.[137] This forecast is an increase of $11.310 million, or more than 206%, over SCE's 2006 recorded adjusted expenses of $5.485 million. DRA's forecast is $7.7 million.[138] SCE's Account 563 has one subaccount, 563.100. SCE seeks increases to this subaccount by (1) $10.623 million for its Transmission Line Clearance Study, (2) $1.08 million for Transmission Line patrols, and (3) $487,000 for Vehicle Costs. These increases are partly offset by a reduction of $811,000 for Reallocation of Tool Expense to Overhead.[139] Vehicle Costs are addressed in a separate section of this decision. The remaining three issues are addressed below.

3.5.1. Transmission Line Clearance

SCE requests additional funding of $10.623 million (constant 2006$) for its Transmission Line Clearance Study. DRA uses SCE's 2006 recorded expenses of $5.485 million as a basis for its forecast and recommends $2.215 million in additional funding for SCE's Transmission Line Clearance Study for a total of $7.7 million.[140] CFBF also challenges SCE's request for Transmission Line Clearance Study funding, asserting (1) a purported double-counting of

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[137] Joint Comparison Exhibit, p. 219.

[138] Exhibit DRA-5, p. 22.

[139] Exhibit DRA-5, p. 22.

[140] Exhibit SCE-17B, p. 8.

$1.104 million and (2) a theory that SCE's request is "non-urgent" and will result in "waste and inefficiencies."[141]

SCE's proposed funding is for study, evaluation, and mitigation planning to address potential clearance issues on SCE's transmission and sub-transmission lines.[142] Given the magnitude and complexity of this effort, including the need for additional engineers to oversee this project and to participate in mitigation design during the 2009-2011 period, we find SCE's forecast reasonable.

3.5.2. Transmission Line Patrols

SCE seeks an increase of $781,000 (constant 2006$) in labor and non-labor expenses for additional Transmission Line Patrols. SCE states it "…must increase staffing to perform patrols on transmission lines as required by the Cal-ISO."[143] DRA opposes this increase. According to DRA, the inspection of transmission lines is not a new responsibility and SCE has embedded labor expenses in its historical 2006 expenses for this activity. Moreover, DRA points to SCE's claim that it averaged approximately 42% in overtime rates in the historical period. DRA suggests SCE use the embedded costs of the overtime and premium rates to hire the employees it claims to need. SCE states it is adding circuit miles to its transmission system, and as DRA observed, SCE is already recording excess overtime with its current staffing. SCE argues it must bolster its staffing to carry out patrols on the new circuit miles. Based on SCE's

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141 Exhibit CFBF-1, p. 7.

142 Exhibit SCE-17B, p. 9.

143 Exhibit SCE-17B, p. 46.

projected increase to its transmission system, we find SCE's request reasonable.[144]

3.5.3. Reallocation of Overhead

SCE requests a decrease of $811,000. DRA objects to SCE's request. As described above in reference to FERC Account 560, SCE is requesting certain adjustments as a result of an analysis it conducted in 2006 to review the cost recording practices for clearing accounts. SCE's analysis recognized the need to make changes in the way that costs were recorded for several accounts. SCE explains that the internal account previously used to expense tools was changed to an account that allocates their cost on the basis of the labor of the personnel using the tools, thus capitalizing and expensing them in the same ratio. The result was a shift of $811,000 from O&M to capital.[145] SCE's request to reflect those modifications to its accounting practices is reasonable.

3.6. Safety Meetings-Miscellaneous Transmission Expenses – FERC Subaccount 566.100

In subaccount 566.100, SCE forecasts $3.239 million (constant 2006$) in labor and non-labor expenses for safety meetings. SCE's forecast is an increase of $721,000 or about 28% over its 2006 recorded expenses.[146] In SCE's 2006 GRC,

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144 In rebuttal testimony, SCE states it agrees that the "difference between the total requested increase ($1,011,000) and the forecast cost of the new supervisors ($781,000) could be offset by a reduction in overtime… Although we have not performed a detailed analysis including the cost impact associated with additional line miles, it appears reasonable to assume that the difference of $230,000 could be offset by this reduction in overtime." Exhibit SCE-17B, p. 12.

145 Exhibit SCE-17G1, p. 29.

146 DRA opening brief, pp. 67-68.

SCE was authorized funding of $3.214 million for safety meetings and training for new employees.[147] SCE notes the expenses in this subaccount are primarily for transmission personnel participating in safety meetings. Many of the meetings are mandatory (e.g., CAL-OSHA and environmental regulation meetings). SCE needs additional funding for such safety meetings because it is adding new employees and these new employees will need to participate in the safety-related activities.[148] Based on increased staffing, we find SCE's request reasonable.

3.7. Miscellaneous Transmission Line Expenses – FERC Subaccount 566.200

In subaccount 566.200, SCE forecasts $4.028 million (constant 2006$) in expenses. SCE's forecast is an increase of $1.136 million or approximately 39% over 2006 recorded expenses. DRA notes this increase includes additional funding of (1) $725,000 for increased transmission line maintenance, (2) $87,000 for Employee Recognition, and (3) $324,000 for Vehicle Costs.[149] Vehicle Costs and Employee Recognition are addressed in separate sections of this decision. Regarding the remaining issue, the $725,000 for increased transmission line maintenance, DRA recommends the Commission adopt SCE's 2006 recorded expense level of $2.892 million for this subaccount. DRA asserts these activities are "recurring costs" for "ongoing activities" embedded in SCE's 2006 recorded expenses.[150] We find SCE's request reasonable because the basis for SCE's

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147 Exhibit DRA-5, p. 31 *citing to* D.06-05-016, p. 67.

148 Exhibit SCE-17B, Attachment 8.

149 Exhibit DRA-5, p. 31.

150 Exhibit DRA-5, p. 33.

request is that there will be additional miles of transmission line added, and incremental funding is required for activities supporting those new miles.

3.8. Miscellaneous Expenses from Other Organizations – FERC Subaccount 566.300

SCE forecasts $11.034 million (constant 2006$) in labor and non-labor expenses in subaccount 566.300. SCE's forecast is an increase of $1.963 million or approximately 21% over 2006 recorded expenses. This increase includes additional funding of (1) $971,000 for a Corporate Real Estate Chargeback, (2) $655,000 for IT Products and Services Chargeback, (3) $323,000 for Reallocation of Field Accounting from Overhead, and (4) $3,000 for increased Vehicle Costs.[151] DRA recommends the Commission adopt SCE's 2006 recorded expense level of $2.892 million for this subaccount. Vehicle Costs are addressed elsewhere in this decision. The remaining issues are addressed below.

3.8.1. Corporate Real Estate and Additional IT Costs

DRA opposes SCE's $971,000 increase for additional real estate costs and $665,000 for additional IT costs, asserting that the 2006 GRC decision authorized an increase in maintenance funding for this subaccount and that SCE's requested funding represents ongoing activities already embedded in rates.

Regarding real estate costs, we find SCE's request reasonable as SCE has provided documentation for the increased real estate costs. In addition, SCE has documented the additional IT costs, showing that these increases are driven by increased office and field personnel, who require additional computers,

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[151] Exhibit DRA-5, p. 35.

communication devices, and photocopiers. Accordingly, we also find SCE's requested increase for IT costs reasonable.

3.8.2. Reallocation of Overhead

As described above in reference to Account 560, SCE is requesting certain adjustments as a result of an analysis it conducted in 2006 to review the cost recording practices for clearing accounts. SCE's analysis recognized the need to make changes in the way costs are recorded to several accounts. SCE explains that the transmission and substation portion of the Field Accounting Organization largely supports capital activities, since they perform the accounting for capital work orders throughout TDBU. However, a portion of their work occurs in support of both capital and O&M. As a result, a portion of Field Accounting Organization costs are now being allocated to O&M, which results in a shift of $323,000 from capital to O&M. SCE's request to adjust its TY 2009 forecast to reflect these modifications to its accounting practices is reasonable.

3.9. Regulatory, Planning, and Business Development - FERC Subaccount 566.500

For subaccount 566.500, SCE forecasts $5.605 million (constant 2006$) in labor and non-labor expenses, consisting of $4.861 million in labor costs and $744,000 in non-labor costs. SCE's forecast is an increase of $107,000 above 2006 recorded expense. Six of SCE's adjustments to 2006 recorded expenses are for increased staffing. DRA recommends the Commission use SCE's 2006 recorded labor expenses of $3.385 million and SCE's TY 2009 non-labor forecast of $445,000 for a total of $3.830 million. DRA points out that SCE's requested increase is due in large part to its request to add approximately 22 new positions. DRA argues SCE has not provided documentation to demonstrate that its 2006 recorded expense and staffing levels are insufficient to meet its TY 2009 needs. In response, SCE states its increased staffing levels are needed to support the development and implementation of new projects affecting future system expansion. For instance, SCE notes, one of biggest increases is for staffing to perform Grid Interconnection studies. SCE's workload increased from 72 studies in 2005 to 140 studies in 2006, and has further increased since 2006 to 160 studies.[152] Based on SCE's increased workload, we find SCE's forecast reasonable.

3.10. Training Miscellaneous Transmission Expenses - FERC Subaccount 566.700; Training Miscellaneous Distribution Expenses - FERC Subaccount 588.700

SCE forecasts $13.380 million (constant 2006$) in expenses for subaccount 566.700, Transmission Training, a $4.673 million increase over 2006 recorded expenses of $8.707 million.[153] SCE forecasts $31.632 million in expenses for subaccount 588.700, Distribution Training, a $10.385 million increase over 2006 recorded expenses of $21.247 million.[154] SCE states that, while most of the programs are the same, the employees receiving the training are different.

DRA claims SCE's requests for a 53% increase for subaccount 566.700 and a 48% increase for subaccount 588.700 are excessive. DRA suggests (1) SCE's proposed incremental increases are included in 2006 embedded costs and (2) SCE is requesting duplicative funding for the same or similar training in

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152 Exhibit SCE-17B, pp. 25-30 and Attachment 13.

153 Exhibit SCE-3C, pp. 85-93.

154 Exhibit SCE-3D, pp. 104-112.

subaccounts 566.700 and 588.700.[155] DRA proposes no increase over 2006 recorded figures.[156]

SCE states its forecast is largely proportional to its forecasted hiring increase.[157] According to SCE, the TDBU Full-Time Equivalent employee headcount increased from 5,125 at the end of 2006 to 5,590 as of April 2008,[158] and the TDBU forecast for year-end 2009 is 6,333 Full-Time Equivalent employees.[159] Furthermore, in SCE's opinion, the Commission in the 2006 GRC allowed a 7.7% ratio of training costs to total labor, which included both O&M and capital-related labor.[160] SCE's training request, as a ratio of the TDBU O&M and capital-related labor dollars in TY 2009, results in a similar ratio of 7.76% for the test year.

SCE's analysis of our 2006 GRC decision is not correct. In addition, while we understand SCE's forecast may include incremental costs for new and additional programs, based on SCE's historical expenditures for these two subaccounts we find SCE's request excessive. Accordingly, to provide SCE with incremental funding, we adopt a forecast that includes 50% of SCE's incremental

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155 Exhibit DRA-5, p. 41.

156 Exhibit DRA-5, pp. 40-42, pp. 123-125; Joint Comparison Exhibit, p. 345.

157 SCE opening brief, p. 65.

158 Exhibit SCE-17A, pp. 2-3.

159 Exhibit SCE-17A, p. 3.

160 SCE opening brief, p. 66 *citing to* D.06-05-016, p. 66.

requests ($7.529 million)[161] for these two subaccounts and a total for both subaccounts of $37.483 million.

3.11. Maintenance of Station Equipment - FERC Account 570

SCE forecasts $11.482 million (constant 2006$) for its Maintenance of Station Equipment expenses recorded to FERC Account 570. This forecast is an increase of $3.094 million or 35% over 2006 recorded expenses of $8.748 million. DRA's estimate is $9.359 million. SCE's FERC Account 570 includes four subaccounts. DRA disputes SCE's recommendations for subaccount 570.200 Maintenance of Transmission Circuit Breakers and subaccount 570.400 Maintenance of Miscellaneous Station Equipment.[162]

3.11.1. Routine Maintenance of Transmission Circuit Breakers - FERC Subaccount 570.200

Subaccount 570.200 is for maintenance and repair of transmission circuit breakers. SCE forecasts $2.188 million (constant 2006$) in 2009.[163] DRA proposes $1.757 million based on a five-year average of expenses recorded in this subaccount.[164] DRA states SCE's request is an increase of $633,000 or 40% over 2006 recorded expenses of $1.555 million. DRA proposes reductions to SCE's forecast of $346,000 for circuit breaker maintenance and $287,000 for increased Vehicle Costs.[165]

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161 The sum of $2,336,500 (subaccount 566.700) and $5,192,500 (subaccount 588.700) is $7.529 million.

162 Exhibit DRA-5, pp. 47-48.

163 Exhibit SCE-17C, p. 5.

164 Exhibit DRA-5, pp. 48-50.

165 Exhibit SCE-3E, p. 31.

SCE states it "deferred due to resource constraints" circuit breaker maintenance in 2006 and seeks an increase over 2006 levels to "…perform approximately 660 transmission/sub-transmission MMs[166] in addition to regularly scheduled MMs at an average cost of $460/$690 respectively each."[167] By resource constraints, SCE is referring to what it describes as unprecedented customer growth and SCE's decision to reprioritize certain work described in SCE's 2006 GRC. SCE has the burden to show that its forecasts are fully justified and supported. SCE did not provide specific information on the work deferred as a result of the customer growth issues. Moreover, we find that customer growth issues should not detract from regular maintenance of its transmission system. We find DRA provides convincing evidence that historical expenses are an appropriate methodology for forecasting TY 2009 expenses. We find DRA's estimate based on a five-year average reasonable[168] and remove $346,000 from SCE's forecast and also remove $287,000 to reflect recorded costs for vehicles.

3.11.2. Maintenance of Miscellaneous Station Equipment - FERC Subaccount 570.400

FERC subaccount 570.400 records expenses for maintaining miscellaneous transmission substation equipment. SCE forecasts TY 2009 expenses of $8.805 million (constant 2006$). DRA proposes $6.753 million. According to DRA, SCE's forecast is an increase of $2.297 million or approximately 35.30% over its 2006 recorded expenses of $6.508 million. DRA challenges SCE's request in six areas: (1) Disconnect Repairs; (2) Switchrack Lighting; (3) Cable Trench

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[166] The acronym "MMs" refers to Mechanism Maintenance. Exhibit SCE-3C, p. 113.

[167] Exhibit SCE-3C, p. 123.

[168] Exhibit DRA-5, p. 50.

Covers; (4) Rack Inspections; (5) Capital-related O&M expenses; and (6) Vehicle Costs. With the exception of Vehicle Costs, which are addressed separately, these adjustments are discussed below.

3.11.2.1. Disconnect Repairs

For disconnect repairs, SCE requests an increase of $584,000 (constant 2006$). DRA recommends no increase over the 2006 base year. SCE states it will perform approximately 500 Preventive Maintenance Assessments[169] related to disconnect repairs in the TY 2009. According to DRA, SCE's repair estimate represents an increase of 614% over the historical period.[170] Since the average number of Preventative Maintenance Assessments related disconnect repairs that SCE has performed in the past five years is 70 per year, DRA considers SCE's forecast unrealistic. DRA also points out that, according to SCE, it deferred work in this area for the short-term but must now address the back-log of problems. For this reason, DRA argues SCE's request should be considered deferred maintenance and, on that basis, rejected. In this circumstance, SCE has not satisfactorily explained what events occurred that require the expenditure of a 600% increase.

We do not find SCE explanation that customer growth required it to divert funds to other matters sufficient to explain the dramatic increase in this area. Moreover, based on SCE's testimony, we do not find SCE's decision to defer

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[169] Exhibit SCE-17C, p. 13: "PMAs (Preventive Maintenance Assessments) are comprehensive diagnostic examinations that we perform on all of our substation equipment. PMA repairs, on the other hand, are actions we take to correct the problems we have identified during the PMA."

[170] Exhibit DRA-5, p. 52.

work in this area reasonable. SCE urges the Commission to approve of the increase on the basis that this equipment is crucial to the integrity of the entire transmission system, stating that the failure and "inability of a disconnect switch to conduct or insulate will result in significant loss of the substation's ability to even function, leading to wide outages." However, SCE also states that

> "[T]here is some discretionary amount of time involved in when they [disconnect repairs] must be completed. Accordingly, as discussed in Mr. Kelly's rebuttal testimony, senior management necessarily prioritizes according to good management practices to utilize our limited funds for the most immediately necessary work. We were able to defer the work for the short-term, but we can no longer continue this trend."[171]

SCE's testimony is contradictory. SCE explains that this equipment is essential to the integrity of the network but also explains that deferring maintenance of this essential equipment is reasonable. For these reasons and the fact that SCE's request finds no support in historical data, we find it reasonable to adopt DRA's forecast and reject SCE's requested increase.

3.11.2.2. Switchrack Lighting

SCE is asking for funds to replace lighting, much of which is over 50 years old, at many of its substations. SCE requests an additional $400,000 (constant 2006$) for this activity. DRA recommends $133,000. DRA argues that SCE's embedded costs include this activity. We agree with SCE that the need to replace lighting exists but, again, we do not find SCE's explanation sufficient to explain why it has not maintained this equipment regularly. Accordingly, we find the amount excessive based on DRA's argument. We reduce SCE's request by 50%,

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[171] Exhibit SCE-17D, p. 14.

which provides for an increase over 2006 base level. We find a forecasted amount of $200,000 reasonable for TY 2009.

3.11.2.3. Cable Trench Covers

SCE requests an additional $335,000 (constant 2006$) for this activity. DRA recommends $112,000 (a 67% reduction) on the basis that SCE is already replacing trench covers and, as a result, the costs of those replacements are embedded in SCE's historical expenses. Again, we agree with the need to replace trench covers but find the amount excessive based on DRA's argument which analyzes historical costs. Accordingly, we reduce SCE's request by 50%. We find a forecasted amount of $167,000 reasonable for TY 2009.

3.11.2.4. Rack Inspections

SCE estimates an additional $90,000 (constant 2006$) for rack inspections. DRA recommends no increase. DRA suggests the inspections are part of embedded cost and can be funded through existing expenses. SCE states that its field assessments show a modest increase is warranted in this area. According to SCE, "[o]f particular concern are steel structures located in the coastal part of our service territory. These structures tend to corrode more quickly due to the ocean environment in these locations."[172] SCE also explains that these activities were "deferred" as SCE's non-labor resources were allocated to higher priority activities.[173] We agree with DRA that these activities are included in embedded cost and for the reasons discussed above in connection with disconnect repairs, we reject SCE's request for an additional $90,000 for TY 2009.

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[172] Exhibit SCE-3C, p. 131.

[173] Exhibit SCE-3C, p. 131.

3.11.2.5. Work Order Related Expenses - FERC Account 570.400

SCE requests additional funding for subaccount 570.400. The request includes additional labor of $585,000 partially offset by a non-labor adjustment of $110,000, for a total of $475,000 (constant 2006$). DRA claims SCE has not provided documentation to demonstrate historic expense levels are insufficient to meet its test year requirements. We find the underlying cost drivers for work order expenses are capital projects. In this decision, we reduce SCE's forecasted capital expenditures by $549.4 million or 14.56%. Accordingly, we find it reasonable to reduce SCE's forecasted work order expenses by 14.56%.

3.12. Maintenance of Overhead Lines – FERC Account 571

SCE's FERC Account 571 includes the following three subaccounts: 571.100 Poles and Structures; 571.200 Insulators and Conductors; and 571.300 Transmission Line Rights-of-Way. DRA disputes the increases SCE requests in each of these subaccounts. SCE explains that incremental funding for its Transmission Life Extension Program accounts for the majority of its additional forecasted expense.[174]

3.12.1. Poles and Structures – FERC Subaccount 571.100

In subaccount 571.100, SCE forecasts $13.336 million (constant 2006$) in labor and non-labor expenses, an $8.128 million increase over SCE's 2006 recorded expenses.[175] SCE's forecast includes additional funding of $7.626 million for its Transmission Life Extension Program, $156,000 for Transmission

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[174] SCE opening brief, p. 45.

[175] Exhibit SCE-3C, p. 136.

Intrusive Pole Inspections, and $346,000 for Vehicle Costs.[176] Vehicle Costs are addressed in another section of this decision. DRA recommends the Commission adopt SCE's 2006 recorded expenses of $5.028 million for TY 2009. The issues pertaining to the Transmission Life Extension Program and Intrusive Pole Inspections are addressed below.

Regarding the Transmission Life Extension Program, DRA indicates that SCE's historical expenses have embedded costs in them for the line items identified in SCE's Life Extension Program. DRA asserts that SCE has not shown that its 2006 expense levels are insufficient to address its Life Extension Program activities in the test year.[177]

Although SCE made efforts to specifically identify how its authorized Life Extension funding was spent in prior years and, where appropriate, to remove the costs from SCE's base year,[178] SCE failed to meet the requirements of D.06-05-016 to provide additional detail and clarification on the incremental nature of this request. In addition, since SCE is requesting a significant increase over past expenses, SCE must provide details to support its rejection of the use of historical trends. SCE does not offer such evidence. Accordingly, in the absence of sufficient proof, SCE's request for an additional $7.626 million is denied

SCE requests incremental funding of $156,000 for intrusive inspections of transmission poles. DRA opposes this request, observing that because the number of intrusive inspections in 2006 is relatively high, recorded costs should be sufficient. SCE provides evidence that its request for intrusive inspections is

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[176] Exhibit SCE-29, p. 86.

[177] Exhibit DRA-5, pp. 62-63.

based on a levelized plan to meet GO 165 requirements and that the majority of the additional expenses stem from an increase in a competitively-bid contract.[179] Accordingly, we find this SCE request reasonable.

3.12.2. Insulators and Conductors – FERC Subaccount 571.200

In subaccount 571.200, SCE forecasts $16.643 million (constant 2006$) in labor and non-labor expenses. This forecast is an increase of $9.766 million over 2006 recorded expenses of $6.877 million. SCE's forecast includes additional funding of (1) $2.007 million for Insulator Washing, (2) $4.812 million for Insulator Replacement, (3) $1.524 million for Work Order-Related Expense, and (4) $1.423 million for Vehicle Costs. DRA relies on SCE's 2006 recorded expense for a forecast of $7.385 million.[180] Vehicle Costs are addressed in another part of this decision. The remaining issues are addressed below.

3.12.2.1. Insulator Washing

SCE estimated incremental funding of $2.007 million for insulator washing in the San Joaquin Valley. SCE claims DRA mistakenly finds 2006 recorded costs include insulator washing.[181] According to SCE, the program for insulator washing in the San Joaquin Valley did not begin until 2007, so no costs were recorded in 2006.[182] However, according to D.06-05-016, SCE's efforts to address insulator washing in the San Joaquin Valley were included in SCE's TY 2006

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[178] Exhibit SCE-3C pp. 132-139; RT Vol. 9:748.

[179] Exhibit SCE-17B, p. 35.

[180] Exhibit DRA-5, p. 66.

[181] Exhibit SCE-17B, pp. 39-40.

[182] Exhibit SCE-17B, p. 39.

GRC request.[183] We summarized SCE's position in support of its 2006 request as follows:

> "[A] severe particulate problem exists and that its proposed funding for washing insulators [in San Joaquin Valley] represents an effort to be proactive in maintaining the reliability of the transmission system in the face of a known problem."[184]

In this proceeding, SCE has not explained why amounts requested in the 2006 GRC for a "severe" problem that impacts reliability were not sufficient or whether such maintenance was deferred. Accordingly, we do not adopt SCE's request for incremental funds of $2.007 million.

3.12.2.2. Work Order Related Expenses

SCE proposes an increase of $1.524 million for work order-related expenses to address "…the physical relocation and electrical re-configuration of transmission and sub-transmission line equipment to support the capital additions" due to SCE's anticipated increase in "capital expenditures for infrastructure replacement and load growth projects."[185] DRA argues SCE's customer growth, which is a driver of SCE's capital projects, is forecasted to be below 2006 levels in the test year. In addition, DRA points out that SCE's historical expenses include embedded costs for the "physical relocation and electrical re-configuration of transmission and sub-transmission line equipment." As a result, DRA recommends normalizing SCE's forecast over a three-year

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183 D.06-05-016, p. 76.

184 D.06-05-016, p. 76.

185 Exhibit SCE-3C, pp. 141-142.

period (2009-2011) for an increase of no more than $508,000 for TY 2009.[186] As we noted earlier, the underlying cost drivers for work order expenses are capital projects. In this decision, we reduce SCE's forecasted capital expenditures by $549.4 million or 14.56%. Accordingly, we find it reasonable to reduce SCE's forecasted work order expenses by 14.56%.

3.12.2.3. Insulator Replacement

SCE's forecast also includes a $4.812 million (constant 2006$) increase for insulator replacement as part of its Transmission Life Extension Program. SCE claims that the increase represents the cost of materials and the use of contract crews to supplement SCE's crews for insulator and hardware replacements.[187] DRA claims historical expenses have embedded costs for insulator replacements. According to SCE, some of the circuits it will be replacing are over 90 years old and many of the insulators on its system have exceeded their life expectancies.[188]

Based on the evidence provided, it is unclear how SCE's request constitutes a Life Extension Program, which is designed to extend the life of the asset. In this case, SCE is addressing problems that have resulted from deferred maintenance. In addition, while these types of programs may be a cost-effective way to maintain the integrity of the system and slow the deterioration of capital assets, SCE has not sufficiently addressed our concerns, noted above, about the relationship of these programs to costs embedded in the historic data. In instances where such a significant increase is requested, SCE must provide a

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186 Exhibit DRA-5, p. 71.

187 Exhibit SCE-3C, p. 141.

188 Exhibit SCE-17B, pp. 38-45.

stronger showing which includes the reasons SCE has not performed maintenance of this equipment on a regular basis. Accordingly, SCE's request for $4.812 million to increase its insulator replacement as part of its Life Extension Program is denied.

3.12.3. Transmission Line Rights-of-Way – FERC Subaccount 571.300

SCE forecasts $9.397 million in labor and non-labor expenses for this FERC subaccount.[189] SCE's forecast is an increase of $799,000 or 9.29% over 2006 recorded expenses of $8.598 million. SCE's forecast includes $300,000 for grading in Angeles National Forest, as part of its Life Extension Program, and $499,000 for Vehicle Costs. Vehicle Costs are addressed in another section of this decision. Regarding the grading request, for Angeles National Forest, we find SCE has provided insufficient evidence to fund this activity as part of the Life Extension Program. SCE has not established the connection between grading in a National Forest and the purpose of the Life Extension Program, which is designed to extend the life of an asset. Accordingly, SCE's request is denied.

3.13. Operation Supervision and Engineering- FERC Account 580

SCE's TY 2009 forecast for FERC Account 580 is $51.403 million. In 2006, SCE recorded $38.767 million to this account, which includes several subaccounts: 580.100 Distribution Operations Supervision and Operations; 580.200 Internal Market Mechanism Distribution Operations & Engineering; 580.300 Meter Services Operations and Management; 580.500 Research,

[189] Exhibit SCE-3C, p. 145.

Development & Demonstration; and 580.980 Allocated Division Overheard for Distribution Operations.

3.13.1. FERC Subaccount 580.100

SCE forecasts $10.843 million (constant 2006$) for TY 2009, an increase of $3.482 million or 47% over 2006 recorded expenses of $7.261 million. SCE's forecast includes additional funding of (1) $2.140 million for Engineering Advancement projects, (2) $1.295 million for Project Management Organization Work Order Write-Offs and (3) $174,000 for Customer Service Business Unit Safety Activities. DRA rejects these proposed increases. Instead, DRA's forecast starts with SCE's 2006 recorded expenses of $7.361 million and removes $600,673 related to Awards to Celebrate Excellence and Employee Recognition, leaving $6.760 million. Awards to Celebrate Excellence and Employee Recognition are addressed in a separate section of this decision. The remaining issues are addressed below

3.13.1.1. Engineering Advancement

SCE's forecast includes additional funding of $2.140 million (constant 2006$) for Engineering Advancement projects. We have addressed this issue above in reference to subaccount 560.100. We find the same result reasonable here, namely, we find reasonable 50% of the increased amount requested by SCE.

3.13.1.2. Project Management Organization Work Order Write-Offs

SCE's 2009 estimate of Project Management Organization work order write-offs is based on the historical average ratio of write-offs to capital spending, multiplied by the forecast level of capital spending in the Project

Management Organization-related areas.[190] DRA points to SCE's four year average (2003-2006) for Project Management Organization write-offs, which is $791,000.[191] DRA explains that between 2005 and 2006, SCE's expenses for Project Management Organization write-offs increased from $735,533 to $1.481 million.[192] As explained in this decision, we reduce SCE's request for capital spending by $549.4 million. Accordingly, based on the relationship between capital spending and Project Management Organization write-offs, we find it reasonable to reduce SCE's requested increase in expenses for Project Management Organization write-offs by 14.56%.

3.13.1.3. Customer Service Business Unit Safety Activities

SCE requested $174,000 for additional staff in the Customer Service Business Unit Safety Organization.[193] DRA argues safety is an ongoing responsibility and, in addition, SCE added a number of safety-related personnel in previous years.[194] DRA also states that, because SCE did not provide a cost-benefit analysis to support previous staff additions, the embedded costs in recorded 2006 are sufficient for ongoing operations. SCE claims its request is to "…provide additional safety training classes for our meter readers and to handle an increase in ergonomic assessments."[195] The funding requested is to provide

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[190] Exhibit SCE-17D, p. 3.

[191] Exhibit DRA-5, pp. 79-80.

[192] Exhibit DRA-5, pp. 79-80.

[193] Exhibit SCE-17D, pp. 3-4.

[194] Exhibit DRA-5, p. 80.

[195] Exhibit SCE-17D, p. 4.

training beyond the type offered in the past. Accordingly, we find SCE's request reasonable.

3.13.2. Internal Market Mechanism Distribution Operations & Engineering - FERC Subaccount 580.200

SCE forecasts $9.237 million (constant 2006$) in test year expenses for subaccount 580.200, in which SCE records expenses for services that other departments provide to TDBU.[196] The expenses are recorded through SCE's Internal Market Mechanism charges and are embedded in TDBU's historical costs. For this reason, SCE explains, the expenses are not discussed in the Internal Market Mechanism testimony of the other departments.[197] DRA asserts historical costs should be sufficient to meet relevant future needs.[198] Accordingly, DRA recommends the Commission adopt SCE's 2006 recorded expenses of $6.417 million for this subaccount in TY 2009.[199] We agree with DRA that SCE fails to adequately support this request. No direct testimony was submitted on this issue.[200] However, DRA's analysis fails to take into consideration costs for certain new activities, such as the new ongoing annual costs in response to guidelines from the U.S. Fish and Wildlife Service ($156,000)[201] and facility operation and maintenance costs for new facilities ($1.6

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196 SCE opening brief, p. 74.

197 SCE opening brief, p. 74.

198 DRA opening brief, p. 45.

199 Exhibit DRA-5, pp. 81-82.

200 Exhibit SCE-17G1; SCE opening brief, p. 74.

201 Exhibit SCE-17G1, p. 23.

million).[202] We find reasonable only these two increases. We also reduce the request for costs for new facilities by 14.56% [203] to reflect our decision regarding additional capital spending.

3.13.3. Meter Services Operations and Management - FERC Subaccount 580.300

This subaccount records expenses related to the management and supervision of the Meter Services Organization. SCE notes that since preparing and filing its GRC application, the expected customer growth for 2007-2009 has slowed due to the changing economy.[204] As a result, SCE lowered its customer growth projection in rebuttal testimony, which lowered its forecast for this subaccount. SCE forecasts $2.485 million (constant 2006$). SCE claims that no further reductions are warranted.[205] SCE's 2006 recorded expenses were $2.751 million. DRA recommends a reduction to SCE's forecast to reflect Enterprise Resource Planning implementation productivity for TY 2009 and presents a forecast of $2.429 million.[206] Because SCE has reduced its forecast to reflect the changing economy and, in addition, has included a reduction to its forecast to reflect increased productivity, we find SCE's request reasonable.

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[202] Exhibit SCE-17G1, p. 22. The historical costs in FERC account 580.200 contain no new service centers as it has been two decades since SCE last built a new service center.

[203] Exhibit SCE-17G1, p. 22. SCE seeks to add a total of one-quarter million square feet to TDBU's facility footprint. The facility operation and maintenance costs for new facilities, $1.6 million, are for this one-quarter million square feet.

[204] Joint Comparison Exhibit, p. 383; Exhibit SCE-18, pp. 1-15 and 83.

[205] Exhibit SCE-18, pp. 14-15. Customer growth affects 13 FERC subaccounts as follows: 901; 902; 903.200; 903.300; 903.500; 903.800; 905.100; 580.300; 586.100; 586.400; 587.500; 587.800; and 597.400, plus 5 Other Operating Revenue FERC subaccounts: 450.200; 451.110; 451.200; 451.250; and 451.600.

3.13.4. Research Development and Demonstration

SCE forecasts $5.830 million (constant 2006$) for subaccount 580.500.[207] SCE's 2006 recorded expenses are $2.229 million. SCE's forecast is an increase of $3.601 million over 2006 recorded levels. DRA recommends the Commission adopt a TY 2009 expense level of $2.136 million, which is the average of SCE's spending levels in 2005 and 2006.[208]

SCE states that its estimate is "based on the professional judgment of SCE's engineering and scientific personnel."[209] In addition, SCE provides details and cost estimates for proposed projects,[210] and cites to unprecedented load growth in past years.[211] The evidence is inadequate to support the level of increase requested by SCE. In addition, SCE's request is not supported by historical data. For these reasons, we deny SCE's request and adopt the 2006 base level.

SCE also proposes the continuation of the one-way RD&D Balancing Account that was established in 1988. SCE's proposal to continue the one-way RD&D balancing account is reasonable and will be adopted. SCE's funding under this balancing account is restricted to endeavors that meet the criteria for permissible RD&D projects as stated in Pub. Util. Code § 740.1.

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206 Exhibit DRA-7, pp. 36-37.

207 Exhibit SCE-3D, p. 13, SCE describes these expenses as non-ISO RD&D.

208 Exhibit DRA-5, p. 83.

209 Exhibit SCE-3D, p. 15.

210 Exhibit SCE-3E, pp. 65-81.

211 Exhibit SCE-3E, p. 67.

3.14. Distribution Substations – FERC Account 582

SCE forecasts $17.53 million (constant 2006$) for Distribution Station Expenses recorded to FERC Account 582.[212] SCE's 2006 recorded expenses are $16.269 million. DRA recommends $16.391 million. SCE's FERC Account 582 includes two subaccounts. DRA disputes SCE's estimate in subaccount 582.100, Operation Relay Protection of Distribution Substations.[213]

SCE forecasted $15.603 million (constant 2006$) in expenses for subaccount 582.100.[214] SCE's 2006 recorded expenses are $14.464 million. DRA and CFBF recommend no increase over 2006 base year for this subaccount. SCE requests additional funding of $517,000[215] over 2006 recorded expenses for 20 additional substation operators and $622,000 for Vehicle Costs. As we decided regarding the recommendations of DRA and CFBF on subaccount 562.100, we find that, based on SCE's staff shortages, the additional amount for Grid Operators is reasonable, and we expect overtime to be reduced. SCE's request for an increase of $622,000 for Vehicle Costs is addressed in a separate section of this decision.

3.15. Overhead Line Operations – FERC Subaccount 583.400

SCE's TY 2009 forecast for this subaccount is $25.667 million (constant 2006$). SCE's forecast is based on the last recorded year expenses of 2006 of

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212 Joint Comparison Exhibit, p. 221.

213 Exhibit DRA-5, p. 88.

214 Exhibit SCE-3D, pp. 24-27.

215 Joint Comparison Exhibit, p. 290.

$13.999 million, plus identified incremental costs.[216] DRA bases its estimate of $17.283 million on the average of 2005 and 2006 recorded figures, which is a reduction of $8.83 million from SCE's forecast. DRA contests additional funding of (1) $516,000 for Overhead Detail Inspections, (2) $636,000 for Pre-Construction Site Readiness Checks, (3) $1.21 million for Vehicle Costs, (4) $1.209 million for Troublemen Accounting Changes, and (5) $1.408 million for Distribution Wood Pole Inspections.[217] TURN presents its own arguments for reductions to SCE's forecasts for Intrusive Wood Pole Inspections and Overhead Detail Inspections. With the exception of Vehicle Costs, we address these issues below. Vehicle Costs are addressed in a separate section of this decision.

3.15.1. Overhead Detail Inspections

SCE's TY 2009 forecast for subaccount 583.400 includes Overhead Detail Inspection expenses for SCE's new Distribution Inspection & Maintenance Program, also know as DIMP.[218] SCE is forecasting $0.516 million, which consists of labor expense of $0.901 million and a reduction in non-labor of $0.385 million. The Distribution Inspection & Maintenance Program[219] was created in consultation with the Commission's Consumer Protection and Safety Division to

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[216] Exhibit SCE-3D, p. 50.

[217] Exhibit SCE-3D, p. 47.

[218] According to SCE, DIMP overhead inspections and patrols are both performed on a grid basis, whereas patrols were previously performed on an individual circuit basis. SCE explains that by "performing both overhead detailed inspections and patrols on a grid basis, SCE will eliminate the duplication of work between patrols and detailed inspections."

[219] Exhibit SCE-3E, p. 96, SCE incurred costs to develop and launch the Distribution Inspection & Maintenance Program in 2007 and 2008, and seeks only estimated ongoing program costs in this GRC.

ensure compliance with Commission regulations.[220] The ultimate goal shared by SCE and the Consumer Protection and Safety Division "was to deliver to customers, employees and the general public greater safety and equal reliability for the same or lower cost."[221]

DRA recommends cutting $516,000 for overhead inspections recorded in subaccount 583.400, thus eliminating the net increase in this account associated with SCE's requested 13 additional Electrical System Inspectors to perform grid patrols.[222] TURN supports a reduction to SCE's forecast of $83,000.[223] SCE claims all but $83,000 of the increase is offset by a corresponding reduction in Troublemen charges for patrols.[224]

We find SCE has convincingly demonstrated that its Distribution Inspection & Maintenance Program entails increased work. The program emphasizes a condition's risk to safety and reliability from a much broader perspective than before and the inspectors have greater responsibilities and burdens. SCE explains, going forward, inspectors will assess not only the condition itself but also take into account a great deal of surrounding information, such as the surrounding environment, system conditions,

220 Exhibit SCE-3E, pp. 84-96.

221 Exhibit SCE-3E, p. 84.

222 Exhibit DRA-5, pp. 98-99, arguing that "SCE has not justified or demonstrated that 13 additional employees are required in the test year to perform grid patrols or that the embedded costs incurred for grid controls during the historical years is insufficient. … SCE's grid control duties are not a new responsibility and its 2006 recorded expenses should be sufficient funding for SCE's Electrical System Inspectors positions."

223 Exhibit SCE-17E, pp. 6-7; Exhibit SCE-3E, pp. 84-96.

224 Exhibit SCE-17E, p. 6.

probability and consequence of failure, and so on. The inspectors will also take pictures and provide comments to include in the work orders. Because of the overall increase in the amount of work forecasted related to the Distribution Inspection & Maintenance Program, we find SCE's request reasonable.

3.15.2. Pre-Construction Site Readiness Checks

SCE's forecast for subaccount 583.400 also includes $0.636 million (constant 2006$) for Pre-Construction Site Readiness Checks. SCE states additional labor and non-labor expenses are needed to support load growth and customer growth capital projects in TY 2009.[225] DRA claims SCE did not prepare a cost benefit analysis to determine that additional site readiness checks are needed to support load growth and customer growth projects.[226] In response, SCE again cites to increased workloads but also explains it intends to replace some contract construction/materials coordinators with additional employees. For the reasons presented by DRA, we agree that SCE's forecast is excessive. However, we also find SCE's arguments regarding replacement of contract labor and, in part, load growth, persuasive. For these reasons it is reasonable to reduce SCE's request by 50%.

3.15.3. Troublemen Accounting Changes

SCE's forecast for subaccount 583.400 includes $3.628 million (constant 2006$) to account for adjustments related to the charging practices for Troublemen. SCE proposes to move costs from capital to O&M. SCE says it recently determined that some costs incurred during emergency responses to

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225 Exhibit SCE-3D, p. 48.

226 Exhibit DRA-5, p. 100.

non-storm outages should have been charged to O&M.[227] DRA opposes SCE's request. DRA claims SCE failed to provide any effective means to analyze the detail of expenses included in its proposal and failed to compare expense patterns over a historical period to determine if the identified expenses fluctuated significantly from year to year or remained flat. DRA suggests the Commission normalize SCE's request of $3.628 million over a three-year period and forecasts $1.209 million for TY 2009.[228] Contrary to DRA's contentions, SCE presents data showing its proposal is reasonable.[229] We find SCE's decision to shift $4.061 from capital to O&M appropriate. The net number is $3.628 million because SCE reduces the amount by $433,000 to reflect the shift of annual patrols to Electrical System Inspectors under the new Distribution Inspection & Maintenance Program.

3.15.4. Distribution Wood Pole Inspections

SCE's forecast for subaccount 583.400 also includes an additional $5.030 million (constant 2006$) of expenses and reflects a levelized number of approximately 130,000 wood pole intrusive inspections per year.[230] DRA proposes a reduction of $3.622 million based on a three-year average of historic expenses to perform these inspections.[231] TURN suggests SCE's forecast be

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[227] Exhibit SCE-3D, p. 49.

[228] Exhibit DRA-5, p. 98.

[229] Exhibit SCE-17E, p. 10.

[230] Exhibit SCE-17E, p. 13.

[231] Exhibit DRA-5, p. 101.

reduced by $3.7 million because SCE's forecast reflects an excessive number of planned inspections and excessive costs per inspection.[232]

In support of its forecast, SCE provides evidence that historical costs do not reflect projected 2009 activity. In addition, SCE points to DRA's failure to address SCE's claim that the actual inspection costs will be affected by new cost drivers, including higher inspection costs that became effective on May 1, 2008 following a mandatory contract renegotiation in 2007 based on a competitive bid solicitation process.[233] SCE also shows that TURN was mistaken in asserting some intrusive inspections are undertaken by SCE personnel, as opposed to contract labor, and that TURN's historical cost analysis is not entirely reliable because such costs do not accurately reflect future inspection costs.[234]

However, TURN convincingly demonstrates that the actual number of intrusive inspections forecasted by SCE is excessive.[235] SCE has failed to justify the reasonableness of its proposal to intrusively inspect 130,000 wood distribution poles per year during this rate case cycle.[236] Accordingly, we reduce SCE's forecast of $5.030 million by 17%[237] or $855,000. We adopt a TY 2009 forecast of $4.175 million as reasonable.

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232 Exhibit TURN-3, pp. 3-8.

233 Exhibit SCE-17E, pp. 15-16.

234 Exhibit SCE-17E, p. 17.

235 Exhibit SCE-17E, p. 17.

236 TURN opening brief, pp. 47-58.

237 Exhibit TURN-3, p. 7.

3.16. Underground Line Expenses - FERC Account 584

SCE forecasts $6.138 million (constant 2006$) for expenses recorded to FERC Account 584.[238] SCE's forecast is an increase of $2.348 million or approximately 61% over 2006 recorded expenses of $3.790 million.[239] DRA's forecast is $4.246 million.[240] FERC Account 584 includes several subaccounts. Of these, DRA disputes SCE's forecast for subaccounts 584.200 Transformers In/Out and 584.400 Underground Line Operations. The dispute over subaccount 584.200 concerns Vehicle Costs, which we address elsewhere in today's decision.

SCE forecasts $4.874 million (constant 2006$) for subaccount 584.400, which is an increase of $2.165 million. SCE's forecast is more than 79% over SCE's 2006 recorded expenses of $2.709 million. DRA uses SCE's 2006 recorded expenses as a starting point and forecasts $3.099 million. SCE's request includes an additional (1) $581,000 for Underground Detail Inspections, (2) $1.170 million for Underground Cable/Conduit Inspections, and (3) $414,000 for Vehicle Costs. Vehicle Costs are addressed in a separate section of this decision.

Regarding SCE's forecast of an additional $581,000 to implement the Distribution Inspection & Maintenance Program, we find this amount reasonable, which is consistent with our findings regarding subaccount 583.400. Regarding the additional $1.170 million for Underground Cable/Conduit Inspections, SCE explains in rebuttal testimony that this additional amount will

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238 Exhibit SCE-3D, p. 50.

239 DRA opening brief, p. 53.

240 Exhibit DRA-5, p. 102.

fund a proposed underground cable testing program.[241] We agree with DRA that SCE fails to adequately explain the scope of this program. From SCE's general description, it is difficult to determine the existing, continuing, and new activities as related to this proposed program. Accordingly, we find insufficient support to justify SCE's proposed increase of $1.170 million.

3.17. Meter Expenses - FERC Account 586

SCE forecasted $26.632 million (constant 2006$) for Meter Expenses recorded to FERC Account 586. SCE's 2006 recorded expenses are $26.908 million. DRA recommends $24.903 million. SCE's FERC Account 586 includes two subaccounts. DRA disputes SCE's estimate in subaccount 586.100 of $15.984 million and subaccount 586.400 of $9.525 million.[242] We discuss these issues below.

3.17.1. Meter Turn On and Off Services - FERC Account 586.100

SCE's forecast for subaccount 586.100 is $15.984 million (constant 2006$) for TY 2009.[243] SCE's forecast is based on 2006 recorded expenses of $15.613 million, increased by $316,000 for customer growth and $181,000 for increased Vehicle Costs, and partially offset by a reduction of $126,000 for productivity from GPS-based order dispatch and routing.[244] DRA recommends a

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[241] Exhibit SCE-17E, p. 25; Exhibit SCE-3D, pp. 61-63.

[242] Exhibit DRA-5, p. 88.

[243] Exhibit SCE-18, p. 14. SCE reduced its forecast to reflect a reduction based on updated forecasts for customer growth.

[244] Exhibit SCE-4B, p. 170; Exhibit SCE-17D, pp. 86-87.

forecast less than 2006 recorded.[245] In support of its request, SCE explains that, while costs have remained relatively stable during the historical period, SCE does not expect this trend to continue. We find SCE's request for an increase, as adjusted, of $316,000 for customer growth reasonable. Vehicle Costs are addressed in a separate section of this decision.

3.17.2. Test or Inspect Meters - FERC Subaccount 586.400

Subaccount 586.400 records expenses for the operation, inspection, and testing of meters and associated metering equipment pursuant to Tariff Rule 17 and the Direct Access Standards Metering and Meter Data (DASMMD).[246] SCE forecasts $9.526 million (constant 2006$) for subaccount 586.400.[247] In its rebuttal testimony, SCE reduced this forecast to reflect changes in its customer growth forecast based on the economic downturn.[248] SCE's recorded expenses for 2006 are $9.061 million. DRA recommends a forecast of $7.653 million.[249]

The differences between DRA's snd SCE's forecasts are, in part, driven by SCE's and DRA's use of different forecasting methodologies. DRA's recommendation is based on using the five-year average of recorded expenses (2002-2006) of $7.653 million.[250] SCE relies on the last recorded year plus customer growth for its forecasting methodology.[251] Because SCE has reduced its

245 Exhibit DRA-7, p. 38.

246 Exhibit SCE-4B, p. 173.

247 Exhibit SCE-18, p. 14; Exhibit SCE-4B, p. 24.

248 Exhibit SCE-18, p. 14.

249 Exhibit DRA-7, pp. 38-41.

250 Exhibit DRA-7, pp. 40-41.

251 Exhibit SCE-4B, p. 175.

forecast to reflect changes in economic growth, we find SCE's forecasting methodology reasonable as applied to this subaccount for TY 2009.[252]

DRA also opposes SCE's request for $183,000 for customer growth, $207,000 to replace expected retirees, and $74,000 for increased Vehicle Costs.[253] We address Vehicle Costs elsewhere in today's decision.

We find SCE's request for $183,000 related to customer growth reasonable because SCE reduced its forecast to reflect changing economic circumstances. Regarding the additional $207,000 to replace expected retirees, we agree with SCE that, in this instance, it is prudent to train new hires so they are ready to be dispatched to the field, avoiding vacancies that cannot be quickly filled with qualified employees. We also understand that, due to the specialized technical training requirements of the position, it takes three to five years for a MT1 to progress to a MT5.[254] However, SCE fails to adequately explain the relationship between decreased costs associated with retirements and the increased costs associated with training and new hires. Because SCE has not shown the relationship between its forecasted increase in expenses and the expected retirements, we will not include in the TY 2009 forecast the $207,000 for new hires to replace retirees.

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[252] Joint Comparison Exhibit, p. 323.

[253] Joint Comparison Exhibit, p. 263.

[254] Exhibit SCE-3B, p. 31.

3.18. Miscellaneous Distribution Expenses - FERC Account 588

SCE forecasts $82.735 million (constant 2006$) for FERC Account 588.[255] As explained below, SCE slightly revised this forecast in rebuttal testimony. SCE's forecast represents an increase of $17.623 million or approximately 27% over SCE's 2006 recorded expenses of $65.112 million.[256] DRA's forecast for FERC Account 588 is $60.404 million.[257] SCE's FERC Account 588 includes eight subaccounts. DRA disputes SCE's estimates in five subaccounts: (1) 588.000 Mapping Expense; (2) 588.300 Management and Supervision; (3) 588.700 Training Distribution; (4) 588.800 Miscellaneous Other; and (5) 588.900 Service Guarantees. These issues are discussed below.

3.18.1. Mapping Staff - FERC Subaccount 588.000

SCE forecasts $4.245 million (constant 2006$) for this subaccount. In 2006, SCE recorded $4.505 million to this subaccount. DRA does not dispute SCE's non-labor forecast which decreased from $833,000 (2006 recorded) to $106,000 (TY 2009 forecast). DRA disagrees with SCE's proposal for an additional $467,000[258] in labor expenses for seven more mapping personnel.[259] We find SCE's request reasonable. SCE shows that while its productivity has increased, a significant backlog of map sketches still exists.[260] SCE's forecast assumes

[255] Exhibit SCE-3D, p. 83.

[256] Exhibit DRA-5, p. 112.

[257] Exhibit DRA-5, p. 112.

[258] Joint Comparison Exhibit, p. 333.

[259] Exhibit DRA-5, p. 114.

[260] Exhibit SCE-3D, p. 91; Exhibit SCE-17D, p. 9.

workload will grow at less than half the historical rate of growth and that productivity will increase by 7% per year, which is consistent with past historical data.[261]

3.18.2. Management and Supervision - FERC Subaccount 588.300

SCE's TY 2009 forecast for this subaccount is $30.691 million (constant 2006$).[262] In 2006, the recorded expenses for this subaccount were $21.811 million.[263] DRA's forecast is $20.622 million.[264] DRA proposes the following eight reductions to SCE's forecast: (1) $78,000 for Distribution Construction and Maintenance stand-by time;[265] (2) $1.579 million for Management and Supervision; (3) $547,000 for Safety Activities; (4) $438,000 for Design Joint Pole personnel; (5) $4.424 million for Business Process and Technology Improvement program/job orders; (6) $1.509 million for Field Accounting & Grid Operations costs due to the reallocation of overhead; (7) $27,000 for Vehicles; and (8) $1.503 million for Awards to Celebrate Excellence and Employee Recognition. Vehicle Costs and Awards to Celebrate Excellence/Employee Recognition are addressed in separate sections of this decision. The remaining issues are addressed below.

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261 Exhibit SCE-17D, p. 9.

262 Exhibit SCE-17D, p. 10.

263 The 2006 adopted amount for this account was $34,262,000, a 56% increase over the 2003 recorded amount. D.06-05-016, p. 89.

264 Exhibit DRA-5, p. 115.

265 Generally, stand-by time is an expense to reflect lost time due to inclement weather or vehicle breakdown. Further information regarding this term can be found in Exhibit SCE-17D, p. 11.

3.18.2.1. Distribution Construction and Maintenance Stand-by Time

DRA disputes SCE's request for an additional $78,000 over 2006 recorded amounts for stand-by time. SCE explains two of its eight distribution regions mistakenly did not record any stand-by time in 2006. SCE's forecast corrects this oversight by adding $78,000, as the two regions have since implemented the correct practices to record stand-by time.[266] We find SCE's request reasonable.

3.18.2.2. Management and Supervision

DRA disputes SCE's request for additional funding of approximately $238,000 for a Mapping supervisor and two Joint Pole supervisors.[267] SCE explains the additional Mapping supervisor is needed for new hires noted in reference to Account 588.000. We find SCE's request reasonable. SCE also requests additional funds for two Joint Pole supervisors. SCE claims this increase is attributable to the need to add six additional positions to address a 300% increase in workload for Requests for Pole Attachments, including an enormous number of Pole Attachment Agreements with third parties to provide broadband access to schools using federal funds.[268] Based on SCE's increased workload, we find SCE's request for the additional Joint Pole supervisor positions reasonable.

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[266] Exhibit SCE-17D, p. 11.

[267] Joint Comparison Exhibit, p. 335 and p. 495.

[268] Exhibit SCE-17D, p. 14.

3.18.2.3. Safety Activities

SCE proposes an increase of $511,000 for Safety Activities.[269] SCE claims this additional amount is needed for new personnel, such as a Maintenance Electrician and new Groundmen, to engage in safety-related activities.[270] DRA argues against this requested increase based on SCE's description of these costs as "recurring costs."[271] We find SCE has not adequately explained why this requested increase is not already included in the recorded 2006 base year.

3.18.2.4. Design Joint Pole Staffing

SCE requests a $438,000 increase in labor expenses for the Joint Pole Organization to fund six additional positions. SCE claims the Joint Pole Organization experienced an increase in Joint Pole Agreements from 2006-2007 of 25% and Requests for Pole Attachments have increased by 333% in that same time period.[272] Based on the evidence of increased workload presented, we find SCE's request reasonable.

3.18.2.5. Business Process and Technology Improvement Program/Job Orders

SCE requests an additional $4.424 million for its Business Process and Technology Improvement projects for TY 2009. SCE's 2006 recorded expenses are $12.378 million.[273] SCE's 2009 forecast was developed on a project-by-project

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[269] Joint Comparison Exhibit, p. 336.

[270] Exhibit SCE-17D, p. 13; SCE opening brief, p. 61.

[271] DRA opening brief, p. 76; Exhibit DRA-5, pp. 121-122.

[272] Joint Comparison Exhibit, p. 337; Exhibit SCE-17D, p. 14.

[273] Exhibit SCE-17D, p. 15 *citing to* Exhibit DRA-5, p. 123.

basis by building the forecast from a bottoms-up approach.[274] DRA suggests SCE's 2006 recorded expense levels are sufficient to address these test year needs.[275] SCE fails to provide convincing evidence of the reasonableness of its methodology for forecasting these expenses. Accordingly, SCE's request for additional funding beyond the 2006 base year is denied.

3.18.2.6. Reallocation of Overhead

SCE requests an increase of $1.509 million related to reallocation of overhead. According to SCE, this increase reflects a shift of $1.823 million from capital to O&M. DRA recommends partial funding of $314,000. SCE explains this adjustment is a result of an analysis conducted in 2006 to review the cost recording practices for clearing accounts. SCE's 2006 analysis recognized the need to make changes in the way costs are recorded for several accounts. As a result, SCE incorporated into this rate case these changes in cost recording practices. SCE explains that the adjustments must be made to accurately reflect the costs recorded to this account on an ongoing basis. SCE further claims this modification is solely an accounting adjustment[276] and follows FERC accounting guidelines. Consistent with our finding regarding subaccount 566.300, we find SCE's request to adjust its TY 2009 forecast to reflect modifications to its accounting practices reasonable.

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[274] Exhibit SCE-17D, pp. 15-17.

[275] Exhibit DRA-5, pp. 122-123.

[276] Exhibit SCE-17G1, p. 28.

3.18.3. Miscellaneous Other - FERC Account 588.800

Subaccount 588.800 records expenses SCE incurs for work order write-offs, as well as certain relatively minor charges for non-capital furniture and equipment.[277] SCE forecasts $11.922 million (constant 2006$) for this subaccount for TY 2009.[278] SCE's 2006 recorded expenses are $11.062 million.[279] SCE's forecast includes additional funding over 2006 recorded expenses of (1) $742,000 for Work Order Write-Offs, (2) $89,000 for non-capital furniture & equipment, and (3) $29,000 for Vehicle Costs. DRA recommends the Commission adopt SCE's 2006 recorded expense level of $11.062 million. Vehicle Costs are addressed in a separate section of this decision. We address the other matters below.

3.18.3.1. Work Order Write-Offs

Based on SCE's rebuttal testimony, SCE requests 2006 level. DRA agrees. Accordingly, no disputed issues exist regarding this matter.

3.18.3.2. Non-Capital Furniture & Equipment

SCE requests an additional $89,000 for non-capital furniture & equipment.[280] SCE recorded 2006 expenses are $10,016.[281] SCE claims that this increase is needed due to increased personnel in the Field Accounting Organization.[282] DRA recommends the Commission reject this proposed

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277 Exhibit SCE-3D, p. 112.

278 Exhibit SCE-3D, p. 114.

279 Exhibit SCE-17D, p. 18.

280 Exhibit SCE-17D, p. 18.

281 Exhibit SCE-17D, Attachment 12 (workpapers).

282 Exhibit SCE-3D, p. 115.

increase. SCE fails to adequately explain the reason for an increase of this relative magnitude. Accordingly, the record fails to contain sufficient evidence to support SCE's request, and SCE's request is denied.[283]

3.18.4. Service Guarantees – FERC Subaccount 588.900

SCE proposes an additional $514,000 (constant 2006$) for Service Guarantee Credits, which is part of SCE's tariffed continuing Service Guarantee Program. SCE claims it has submitted sufficient evidence to establish a "baseline level of credits" and refers to the 2006 GRC decision to support its request. SCE notes that its request only addresses two of the four elements of SCE's Service Guarantee Program, the Notification of Planned Outage Standard and the Restoration of Service within 24 Hours Standard.[284] DRA opposes any ratepayer funding.[285] In the past, the Commission has found that SCE's shareholders should pay this amount. The record in this proceeding is insufficient to establish a baseline or to change our previously adopted policy.[286] For these reasons, we continue the approach we adopted in the 2006 GRC and assign the liability for missed commitments to shareholders.

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[283] In support of this request, SCE cites to its workpapers under subaccount 588.800 entitled "Non-Capital F&E for Field Accounting."

[284] SCE opening brief, p. 62 at fn. 356.

[285] Exhibit DRA-5, p. 130.

[286] D.06-05-016, pp. 121-122.

3.19. Maintenance of Station Equipment - FERC Account 592

SCE forecasts $13.038 million (constant 2006$) for expenses recorded to FERC Account 592.[287] SCE's forecast is an increase of $4.360 million or about 50% over 2006 recorded expenses of $8.678 million.[288] DRA's forecast is $9.544 million. SCE's FERC Account 592 includes several subaccounts. DRA disputes SCE's forecasts for subaccounts 592.200 Maintenance of Distribution Circuit Breakers and 592.400 Maintenance of Distribution Substation Equipment.

3.19.1. Maintenance of Distribution Circuit Breakers - FERC Subaccount 592.200

SCE forecasts TY 2009 expenses for subaccount 592.200 to be $3.619 million, which represents a $908,000 increase over the 2006 base year.[289] SCE explains that an increase of $511,000 is needed to support maintenance postponed due to resource constraints.[290] By resource constraints, SCE is presumably referring to what it describes as unprecedented customer growth and SCE's decision to reprioritize certain maintenance work described in SCE's 2006 GRC. We do not find unprecedented customer growth a sufficient reason to postpone maintenance on circuit breakers. SCE's failure to accurately predict customer growth in its prior GRC does not excuse it from performing importance maintenance work on its distribution system. We find DRA provides convincing

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287 Exhibit SCE-3D, p. 138.

288 DRA opening brief, p. 58.

289 Exhibit SCE-3D, p. 148.

290 Exhibit SCE-3D, p. 149, SCE's forecast for this subaccount includes $397,000 for additional funding for Vehicle Costs. This request is addressed in a separate section of this decision.

evidence that historical expenses are an appropriate methodology for forecasting TY 2009 expenses. We find DRA's estimate of $2.857 million based on a five year average reasonable.[291]

3.19.2. Maintenance of Station Equipment - FERC Subaccount 592.400

SCE forecasts $7.421 million (constant 2006$) for subaccount 592.400.[292] SCE uses this subaccount to record expenses incurred to maintain miscellaneous distribution substation equipment. SCE's forecast is an increase of $3.171 million or 74.61% over 2006 recorded expenses of $4.250 million. DRA recommends the Commission adopt $4.689 million for this subaccount. SCE's forecast includes $2.694 million for Miscellaneous Distribution Substation Maintenance, including repairing Switchrack Lighting, replacing Trench Covers, and Rack Inspection, and $477,000 for Vehicle Costs. Vehicle Costs are addressed in a separate section of this decision. We address the remaining issues below. Generally, however, SCE states maintenance activities recorded to this subaccount were reprioritized, that is, non-labor resources were allocated to higher priority maintenance activities. Higher priority work included, according to SCE, work that implicated reliability and safety issues.[293] SCE does not explain the nature of this higher priority work. Nor does SCE offer any evidence to quantify the expenses associated with this reprioritization of work.[294]

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[291] Exhibit DRA-5, p. 137.

[292] Exhibit SCE-3D, p. 155.

[293] Exhibit SCE-3D, p. 157.

[294] RT Vol. 6:218-222.

3.19.2.1. Miscellaneous Substation Maintenance Labor Disconnect Repairs

SCE requests an additional $1.078 million (constant 2006$) in labor expenses for disconnect repairs. SCE's forecast for disconnect repairs is based on the existing backlog and the amount of repairs SCE has historically performed.[295] DRA argues this amount of increase is excessive and not supported by historical costs.[296] SCE fails to offer a sufficient explanation for deferring this maintenance work. Accordingly, we agree with DRA. As a result, we deny SCE's requested increases.

3.19.2.2. Switchrack Lighting

SCE's forecast includes an additional $600,000 over 2006 recorded expenses for repairing and upgrading (transmission) switchrack lighting in its substations. This is in addition to the increase of $400,000 over 2006 recorded expenses SCE seeks in FERC subaccount 570.400 to repair and upgrade its (distribution) switchrack lighting in substations.[297] DRA argues that SCE's embedded costs include this activity.[298] We agree with SCE regarding the need for this work, but we find the requested amount excessive based on DRA's argument and our finding of unreasonable deferred maintenance. Accordingly, we reduce SCE's request by 50%. We find an additional $300,000 reasonable for TY 2009.

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[295] Exhibit SCE-17C, p. 29.

[296] Joint Comparison Exhibit, p. 331.

[297] Exhibit SCE-3C, p. 131.

[298] Joint Comparison Exhibit, p. 327.

3.19.2.3. Trench Covers

SCE's forecast includes an additional $716,000 for replacing trench covers located in its substations.[299] DRA normalized SCE's request of $716,000 over a three year period and forecasted $239,000 for the test year. Consistent with our findings regarding subaccount 570.400, we find that additional work is needed, but we find the requested amount excessive based on DRA's argument and our finding of unreasonable deferred maintenance. Accordingly, we reduce SCE's request by 50%. We find an additional $358,000 reasonable for TY 2009.

3.19.2.4. Steel Structures

SCE's forecast also includes an additional $300,000 for inspecting and repairing steel structures.[300] DRA argues SCE's current level of funding is sufficient and recommends the Commission deny this increase. We find the amount excessive based on DRA's analysis of historical trends and our finding of unreasonable deferred maintenance. Accordingly, we find it reasonable to deny the additional amount requested over 2006 recorded expenses.

3.20. Maintenance of Overhead Lines - FERC Account 593

SCE requests a total of $93.243 million (constant 2006$) for TY 2009 in FERC Account 593, which includes $15.706 million for labor and $77.537 million for non-labor. FERC Account 593 records the maintenance cost of overhead distribution lines, including repairs to conductors, cross-arms, switches, equipment brackets, and ground molding. These activities consist of planned and emergency repair of equipment or apparatus. SCE also records in this

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[299] Exhibit SCE-3C, p. 131.

[300] Joint Comparison Exhibit, p. 247.

account expenses for trimming and removing trees and brush. All overhead line maintenance is booked into this account with the exception of storm-related repairs, pole replacements, apparatus repairs, and transformer repairs. In addition, beginning in 2008, SCE is recording into this account expenses relating to the Distribution Inspection & Maintenance Program, developed in collaboration with the Consumer Protection and Safety Division. SCE divides FERC Account 593 into five subaccounts. Some of these subaccounts are discussed below.[301]

3.20.1. Line Clearing Expenses-Tree Trimming and Removal - FERC Subaccount 593.200

SCE forecasts $39.729 million (constant 2006$) for subaccount 593.200 for line clearing expenses, including both vegetation management (tree trimming and removal) and line clearing around poles.[302] SCE's forecast is an increase of $4.556 million over 2006 recorded expenses of $35.173 million. SCE's forecast includes additional funding of (1) $3.971 million for Vegetation Management, (2) $582,000 for Line Clearing, and (3) $3,000 for Vehicle Costs. Vehicle Costs are addressed elsewhere in this decision. SCE claims that it needs the additional funding to cover forecasted contract increases, additional tree removals or trims, and an increase in mid-cycle trims.[303]

DRA disagrees with all of these proposed increases. Based on historical analysis, DRA recommends that the Commission adopt a TY 2009 forecast of

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301 The dispute between SCE and DRA regarding one of the subaccounts, 593.100, pertains to Vehicle Costs. We resolve Vehicle Costs matters elsewhere in this decision.

302 Exhibit SCE-3D, p. 160.

303 Exhibit SCE-17E, p. 29.

$35.173 million, which is SCE's 2006 recorded expenses. TURN agrees with DRA and also recommends SCE contain tree trimming costs by working towards a system average 2-year trim cycle.[304]

Regarding the increases associated with vegetation management and line clearing, we find SCE's evidence on the increase in labor and non-labor costs sufficient to justify the proposed increase.[305] SCE has raised legitimate concerns regarding the viability of TURN's recommendation regarding using a 2-year trim cycle. Nevertheless, TURN provides sound evidence to support its recommendation. Accordingly, while we are not convinced that SCE's failure rely on such a trim cycle warrants a reduction to its TY 2009 forecast, we direct SCE to research the benefits of the 2-year trim cycle (or similar concept) and provide the Commission with the results of its research in its next GRC.

3.20.2. Overhead Line Maintenance - FERC Subaccount 593.300

FERC subaccount 593.300 records labor and material expenses required for overhead line repairs, whether identified during circuit inspections or as the result of a breakdown. SCE's forecast for subaccount 593.300 is $53.291 million. SCE's recorded 2006 expenses for this subaccount are $37.168 million. DRA proposes a TY forecast of $37.168 million.

DRA excludes most of SCE's incremental requests. DRA argues that funding related to the activities in this account are already embedded in SCE's 2006 recorded expenses and, accordingly, are either not justified or should be normalized over a three-year period. DRA excludes SCE's incremental request

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304 TURN opening brief, p. 65.

305 Exhibit SCE-17E, pp. 29-31.

for (1) Breakdown/Reactive Maintenance expenses of $1.442 million, (2) Work Order Related expenses of $7.781 million, (3) Line Maintenance expenses of $1.538 million, and (4) Vehicle Costs of $2.275 million. The latter costs are addressed elsewhere in this decision. SCE explains that additional funding is needed because its new Distribution Inspection & Maintenance Program is changing the way SCE performs inspections.

While we find SCE will be performing additional work to implement its new Distribution Inspection & Maintenance Program, we are concerned about the deferral of preventive maintenance, as described by SCE:

> "Over the past several years Capital constraints and resource constraints have forced Edison to defer preventive maintenance work, such as planned infrastructure replacement, and at the same time operate existing equipment at higher load levels. This means that SCE is leaving equipment in service longer (age of assets is getting older), while at the same time the amount of stress placed on equipment is increasing. All of these factors support a continuation of the increasing trend for breakdown/reactive maintenance."[306]

It appears this deferral impacts the requested increases in this subaccount but the evidence submitted by SCE on the extent of the impact of deferred

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306 Exhibit SCE-17E, p. 51; Exhibit SCE-3D, p. 170: "The non-labor expense levels for sub-account 593.300 decreased $13.785 million from 2002 to 2003, predominately due to a reduction in maintenance as contract crews were instead utilized for windstorm remediation (early 2003) and firestorm remediation (late 2003). During this time we temporarily deferred some of our maintenance work so that the crews could handle the repair and remediation efforts. From 2003 to 2004, non-labor expense increased $7.025 million as contract crews became available for maintenance activities after completing the storm remediation activities in the previous year. From 2004 to 2005, non-labor expense decreased $6.780 million, predominately due to a reduction in maintenance as contract crews shifted from maintenance work to load growth and customer growth capital projects."

maintenance on its forecast is unclear. Accordingly, we find it reasonable to adopt DRA's recommendation.

3.21. Maintenance of Underground Lines - FERC Account 594

SCE forecasts $18.456 million (constant 2006$) for expenses recorded to FERC Account 594.[307] According to DRA, SCE's forecast of $18.456 million is an increase of $4.018 million or about 27% over 2006 recorded expenses of $14.438 million. SCE developed its forecast by using 2006 recorded expenses plus additional expenses for proposed projects and activities. DRA's forecast for SCE's FERC Account 594 is $15.381 million. SCE's FERC Account 594 includes several subaccounts. DRA disputes SCE's forecast for subaccount 594.300 Underground Line Maintenance.

SCE forecasts $18.041 million (constant 2006$) for subaccount 594.300.[308] SCE's forecast is an increase of $3.965 million or about 28% over 2006 recorded expenses of $14.076 million. DRA uses SCE's 2006 recorded expenses as a basis for its analysis and forecasts $14.966 million for this subaccount.[309] SCE's forecast includes additional funding of $2.670 million for line maintenance to address scheduled/planned maintenance and breakdown/reactive maintenance.[310] SCE states that it has based the portion of its forecast that relates

[307] Exhibit SCE-3D, p. 179.

[308] Exhibit SCE-3D, p. 185.

[309] Exhibit DRA-5, p. 159.

[310] Exhibit SCE-3D, p. 187.

to planned maintenance on its new Distribution Inspection & Maintenance Program.[311]

As we stated previously in this decision, we agree with SCE that, under its new Distribution Inspection & Maintenance Program, it will incur more costs and also perform more comprehensive inspections and repairs. However, DRA's historical analysis shows declining expenditures since 2006. In this instance, we find DRA's analysis convincing. Accordingly, we reject SCE's requested increase of $3.965 million for subaccount 594.300. This subaccount also includes $1.295 million for funding for additional Vehicle Costs. Vehicle Costs are addressed elsewhere in this decision.

3.21.1. Maintenance of Streetlight and Signal System - FERC Subaccount 596.400

SCE's TY 2009 forecast for this subaccount is $7.994 million (constant 2006$).[312] Subaccount 596.400 records expenses related to maintaining and repairing streetlight equipment. SCE's recorded 2006 expenses for this subaccount are $5.947 million. DRA proposes a TY forecast of $6.192 million.[313] DRA proposes three adjustments to SCE's forecasted TY 2009 expenses: (1) eliminate $1.270 million for vehicles; (2) eliminate $184,000 for increased O&M repairs; and (3) reduce SCE's proposed increase for lamp replacements by $348,000.[314] DRA supports its recommendation by citing the slower rate of customer growth, historical trends, and 2006 recorded costs.

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311 Exhibit SCE-3D, p. 187.

312 Exhibit SCE-17D, pp. 24-30.

313 Exhibit DRA-5, p. 164.

314 Exhibit SCE-17D, pp. 24-30.

SCE's expense forecast starts with its estimate of the total number of repairs that will occur in the test year.[315] SCE agrees with DRA that the number of O&M repairs in 2006 was lower than in previous years. According to SCE, lower O&M repairs were a consequence of the fact that SCE performed the highest number of capital fixture replacements for its streetlights. SCE's forecast for 2009 reflects a higher forecast in the total number of streetlights, a higher forecast of streetlight failures, and a significantly lower number of capital fixture replacements.[316]

Based on the evidence presented, we find DRA's recommendation to eliminate the $184,000 for increased O&M repairs and reduce SCE's proposed increase for lamp replacements by $348,000 convincing. SCE's forecasting methodology fails to adequately take into consideration historical trends. Vehicle Costs of $1.270 million are addressed elsewhere in this decision.

4. Customer Service

4.1. Expenses–Operations Division – FERC Accounts 901-905, 580, 586, 587, and 597

The Customer Service Operations Division is a subset of the Customer Service Business Unit. The O&M expenses for Customer Service Operations Division are recorded in FERC Accounts 901 through 905 and as well as 580, 586, 587, and 597. SCE initially forecasted $210.665 million for TY 2009, an increase of $16.536 million over recorded 2006 levels. According to SCE, the major cause of its increase in O&M over 2006 is customer growth and new programs, partially offset by improved performance. In rebuttal testimony, SCE reduced its forecast

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315 Exhibit SCE-17D, p. 25.

by $4.17 million. DRA recommends a forecast of $195.752 million, a $1.622 million increase over recorded 2006.

DRA generally rejects SCE's increase for labor[317] and non-labor costs associated with incremental customer growth. DRA argues that recorded costs did not increase despite increased customers and, therefore, forecasted 2009 expenses should not include additional customer growth costs. In response, SCE points out that during these recorded years it implemented 12 productivity initiatives that produced cost savings. SCE explains that its estimates of additional costs for new customers were reduced by productivity savings where such savings could be identified.[318] As a result, despite the customer growth, SCE maintained stable recorded costs. Furthermore, SCE states this method has been used and adopted by the Commission in each of the last GRC applications.[319] SCE further explains that while SCE reduced its estimated expenses to reflect reduced customer growth,[320] every new customer requires installation of a meter, monthly reading of the meter, and other activities such as phone calls, billing and similar services which add to overall expenses.

We find that SCE's methodology is reasonable in adjusting recorded costs to reflect productivity and forecasting the cost effects of additional customer

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[316] Exhibit SCE-17D, p. 26.

[317] DRA does accept SCE's labor cost growth associated with meter reading. DRA opening brief, p. 88.

[318] Exhibit SCE-18, p. 2.

[319] Exhibit SCE-18, pp. 5-6.

[320] Exhibit SCE-18, p. 1.

growth. Thus, we adopt SCE's revised estimates as reasonable for those expenses affected by customer growth.[321]

4.2. Vehicles – FERC Subaccounts 586.100, 586.400, 902.00, 903.00

Vehicle expenses for Customer Service Business Unit are recorded in Accounts 586.100 Turn On and Off Service, 586.400 Test or Inspect Meters, 902.000 Meter Reading, and 903.200 Credit. SCE's 2006 recorded Vehicle expenses are $10.56 million. SCE is requesting an additional $964,000. As discussed in the T&D O&M expense portion of this decision, our adopted Vehicle costs are consistent with DRA's recommendations to reduce SCE's forecast. For Accounts 586.100, 586.400, 902.000 and 903.200, we adopt the same result.

4.3. Community Choice Aggregation – FERC Account 903

Community Choice Aggregators (CCAs) are groups formed by governmental entities to serve the energy requirements of local residents and businesses. In D.04-12-046, we adopted policies to implement a CCA program to facilitate energy procurement activities by cities and counties. DRA and TURN disagree with SCE regarding the reasonable level of CCA expenses in Accounts 903.200 Credit, 903.500 Billing, 903.700 ESP Services and 903.800 CCCO (Phone Center). SCE points out that CCA expenses are offset by CCA service fees which are recorded as Other Operating Revenues.

As an alternative to including forecasted revenues and expenses in results of operations, TURN recommends recording these fees and costs in a

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[321] Customer Growth is a disputed issue in Accounts 580, 586, 901, 902, 903 and 905.

memorandum account.[322] TURN argues that although limited CCA operations in SCE's service area are likely to begin in 2009,[323] the actual level of CCA fees and costs are too speculative to be included in rates and fees at this time.

We believe that TURN's proposal has merit. With the exception of the San Joaquin Valley Power Authority it is uncertain whether other CCAs will even be established within the period covered by this decision. Furthermore, as TURN points out, even the establishment of the San Joaquin Valley Power Authority CCA will take time. Given this uncertainty, and the protection of ratepayer and shareholder interests accomplished through a memorandum account, we will adopt TURN's proposal.

Therefore, we have excluded estimated CCA fees in Account 456, Other Electric Revenues, CCA expenses in Accounts 903.200, 903.500, 903.700 and 903.800, and a portion of CCA capital spending from our adopted results of operations. SCE is directed to place these amounts in the existing CCA memorandum account which will track CCA-related revenues, expenses, and capital spending. This memorandum account was established in D.04-12-046 and is known as the Community Choice Aggregation Implementation Costs Balancing Account (CCAICBA). Balances in this memorandum account shall be reviewed in SCE's annual ERRA reasonableness proceedings, commencing with the first ERRA proceeding after SCE begins recording costs and revenues in the account.

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322 Exhibit TURN-5A, p. 11.

323 TURN believes it is likely that the San Joaquin Valley Power Authority will begin operations in late 2008 or 2009. Exhibit TURN-5A, p. 11.

4.4. Rural Related Expenses and Ledgers – FERC Subaccount 903.000

SCE requests 10 new positions for a forecasted amount of $730,000 in its Ledgers Organization, stating that the workload and backlog have increased. DRA reviewed the Ledgers Organization and noted that there has been little change in overall staffing[324] or overall expenses (in constant dollars) during the past five years.[325] In addition, the five-year average (2002-2006) for this subaccount is $4,748,000.[326] In consideration of these factors and as we have provided for SCE's customer growth, as discussed above, we will adopt DRA's estimate with regard to this issue.

4.5. Credit Fraud Staffing and GPS – FERC Subaccount 903.200

SCE requested three additional credit fraud employees and to establish a centralized fraud prevention group. SCE states that the new employees are necessary as new payment options are added to SCE's services, opportunities for credit fraud increase.[327] DRA argues that these employees are not necessary as the recorded expenses have not increased despite an increased caseload.[328] SCE points out that there may be some confusion with regard to DRA's reference to caseload which actually occurs in a different account.[329]

[324] Exhibit DRA-5, pp. 165-167.

[325] Exhibit DRA-5, p. 165.

[326] Exhibit DRA-5, p. 165.

[327] Exhibit DRA-5, pp. 27-28.

[328] Exhibit DRA-7, p. 13.

[329] Exhibit SCE-18, pp. 28-29.

In light of new payment options and other activities to be addressed by the additional employees, such as identify theft, we find SCE's request for these employees, and associated non-labor costs, reasonable.

SCE forecasts labor expense savings of $87,000 based on the use of a global positioning satellite project. DRA's estimate, based on using the last recorded year, did not include this saving.[330] We will adopt SCE's estimate, which reduces this account by $87,000.

4.6. Service Guarantee Credits – FERC Subaccount 903.500

Service Guarantee Credits provide bill credits to customers when SCE misses an appointment or presents an inaccurate bill.[331] SCE requests that the estimated costs of these credits be included as customer service expenses. DRA and TURN disagree and recommend that these costs continue to be paid by shareholders. In D.06-05-016, we determined that costs for reimbursing customers would be paid by shareholders.[332] Today, we approve reasonable amounts for expenses for continued administration of this program and we do not change our policy with regard to these credits, which should continue to be paid by shareholders.

TURN also proposes that SCE implement an explicit policy for when a customer's service is disconnected in error and to add erroneous disconnect to SCE's Service Guarantee Program. We find TURN's proposal reasonable and direct SCE to file an advice letter within 90 days to implement a new tariff

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[330] Exhibit SCE-18, pp. 123-124.

[331] Exhibit DRA-7, pp. 19-20.

[332] Exhibit DRA-7, pp. 19-20.

provision. Similar to the procedure relied upon in D.07-03-044, we direct SCE to arrive at a consensus regarding the language of this rule. While SCE argues that its existing internal company policy is sufficient to address erroneous disconnects,[333] we find that a formal tariffed rule is more appropriate to ensure customers are properly noticed of this policy and, similar to our finding in D.07-03-044, ratepayers should not bear the costs of SCE's errors. TURN estimates that its proposal would reduce SCE's forecast by $50,000. We accept TURN's estimate as the reasonable costs for implementing TURN's proposal. Regarding TURN's proposal to increase to credit from $50 to $100, we find the record does not include sufficient evidence to justify this increase.

4.7. Electric Service Provider Services - FERC Subaccount 903.700

DRA agrees with SCE's request to fill vacant positions in the Customer Service Business Unit. However, DRA's estimate is based on recorded 2005 expenses and is $142,000 lower than SCE's estimate of $1.2 million. SCE uses a budget-based approach for its forecast. SCE's 2006 recorded expenses for subaccount 903.700 are $726,000. SCE explains that the lower 2005 recorded expenses are the result of positions which were vacant due to unexpected staff turnover for most of 2005.[334] Accepting SCE's explanation for this difference in 2005 and 2006 recorded costs, we adopt SCE's estimate as reasonable.

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333 Exhibit SCE-18, p. 29.

334 Exhibit DRA-7, pp. 45-46.

4.8. Customer Communication Organization – Phone Center – FERC Subaccount 903.800

SCE requests an increase in phone center costs of $1,276,000 to reflect an increase in call volume growth beyond the call volume attributed to new customers. DRA argues that historical recorded costs do not justify an increase since these costs were stable while the number of customers was increasing.

SCE responds that the recorded costs include application of the productivity measures discussed above, in particular the contract call center and the Meter Process Automation initiatives.[335] SCE contends these productivity measures will not continue to produce cost savings in 2009. SCE explains that the application of the productivity measures means that the recorded costs are lower than the costs would be without these measures.[336]

We note that the average call volume increase of 3.4% [337] during the past 5 years exceeds customer growth.[338] This indicates that even with past productivity measures, future phone call growth apart from customer growth will necessitate additional phone center costs. Therefore, we will adopt SCE's requested increase. Any amounts related to CCAs should be recorded in the memorandum account.

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335 Exhibit SCE-18, pp. 49-50.

336 Exhibit SCE-18, pp. 49-50.

337 Exhibit SCE-18, p. 51.

338 Exhibit SCE-11A, p. 48, year-end customers; Exhibit SCE-3F, p. 11, new meter additions.

4.9. Uncollectible Expense – FERC Account 904

Uncollectible expense represents billed but uncollected revenue and is recorded in Account 904. Uncollectible expense is forecasted as that portion of revenues not collected, estimated by SCE as 0.240% using a ten-year average of recorded uncollectible factors (0.239%) plus 0.01% for Other Operating Revenues increases not reflected in these factors. DRA forecasts the uncollectible factor as 0.134% by averaging the factors recorded in the last three years plus the 0.01% recommended by SCE. The 2006 authorized uncollectible factor is 0.225%.

SCE explains that its ten-year average is supported by averages using the past 15 and 20 year periods.[339] DRA argues that the uncollectible factor has been declining since 1999 when it was 0.348% and that a 3-year average best forecasts the uncollectible factor.[340]

Neither SCE nor DRA sufficiently explain the continuous decline in the uncollectible factor. SCE suggests that extraordinary economic influences, including a healthy regional economy, have helped reduce the factor during the past 5 years, and that recent uncollectible expenses have increased by 73% between 2006 and 2007.[341] SCE also offers a statistical measure that correlates interest rates, lagged by two years, and the uncollectible factor.[342] Using this analysis, SCE would forecast the uncollectible factor as 0.283%.

Despite SCE's arguments for the use of at least a 10-year average, it is apparent from the recorded uncollectible factors from 1999 through 2006 that the

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339 Exhibit SCE-18, p. 54.

340 Exhibit DRA-7, pp. 28-29.

341 Exhibit SCE-18, pp. 53-54.

342 Exhibit SCE-4B, pp. 144-146.

factor has been declining.[343] There may be reasonable explanations for this decline including increased customer service activities, automatic bill payment, improved customer communications, or other factors. A reasonable forecast of the uncollectible factor should reflect the fact that the uncollectible factor has been declining for the last 7 years.

However, we agree with SCE that the current economic outlook, as indicated by the most recent uncollectible expenses, would support a TY 2009 factor above either 2005 or 2006. SCE notes that a 5-year average (2000-2004) was used in D.07-03-044, the PG&E 2007 GRC.[344] As a reasonable forecast we will also use a five-year average of the uncollectible factors during the last five recorded years, 2002-2006, plus 0.01% for Other Operating Revenue. Thus our adopted uncollectible factor is 0.168%.

4.10. Market Research and Communication – FERC Subaccount 905.900

SCE requests an increase of $988,000 for this subaccount over the amount recorded in 2006. This increase includes $500,000 for development of on-line tools, bill inserts and communications informing customers of environmental impacts regarding their cost of energy and $488,000 for planned and unplanned customer outage communications. DRA rejects both of these incremental cost increases and argues these costs are reflected in other FERC accounts, the Public Goods Charges and Demand Response Funding. DRA's forecast is based on 2006 recorded expenses. SCE's recorded 2006 expenses are $5.583 million.

343 Exhibit DRA-7, p. 28.

344 Exhibit SCE-18, p. 55.

A review of the recorded expenses for subaccount 905.900 shows that the total costs in this subaccount have been increasing and that 2006 was the highest recorded amount in the last 5 years, exceeding 2005 by over 20%.[345] Furthermore, as SCE points out, some of the funding is incremental to communications spending in distribution accounts or is intended to provide an enhanced type of outage notice.[346] While such improvements may have benefits, we note that communications funds are provided through other cost mechanisms not included in this GRC. Accordingly, we agree with DRA and adopt an expense level for this subaccount based on the highest recorded amount, which is the 2006 recorded expense.

4.11. Policy Adjustments-Miscellaneous – FERC Subaccount 905.300

Subaccount 905.300 records costs associated with adjusting customer bills. DRA, citing a decline in this expense from a high of $1,573,000 in 2004 to $660,000 in 2006, forecasts $660,000 based on the last recorded year. TURN supports this estimate. SCE notes that the recorded amounts for this expense fluctuate with changes in customer sentiment, weather, and other unpredictable factors. On this basis SCE used an average of the last five years of recorded expense.[347]

Our review of the recorded amounts indicates that there is significant variance in these expenses, such that the recorded amount increased by 200%

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[345] Exhibit DRA-7, p. 33.

[346] Exhibit SCE-18, pp. 61-62.

[347] Exhibit SCE-18, p. 59; Joint Comparison Exhibit, p. 380.

between 2003 and 2004, and then declined by almost 140% towards 2006.[348] According to TURN, the 200% increase is largely the result of a one-time cost resulting from SCE's decision to assign $882,684 in costs related to a downward bill adjustment to subaccount 905.300. In light of this anomaly in cost data included within SCE's proposed forecasting method, we find SCE's forecast unreliable and adopt the last-recorded year of $660,000 as a more reasonable method of forecasting costs for this subaccount.

4.12. Electric Transportation – FERC Subaccount 912.100

Electric Transportation expenses reflect activities related to compliance with certain provisions of the Energy Policy Act, electro-drive system impacts, low-emission and alternative fuel vehicles, and education outreach information on these vehicles.[349] For TY 2009, SCE forecasts $12.776 million in subaccount 912.100, an increase of 157% over 2006 recorded expense of $4.976 million. DRA recommends an increase of 59% over 2006 recorded expenses.[350] The difference between SCE's and DRA's forecasts is due to DRA's rejection of incremental funding for various SCE-proposed Electric Transportation programs and activities as discussed below.

4.13. Energy Policy Act and Other Compliance

SCE requests an additional $298,000 for three additional employees for compliance workload and an additional $400,000 for a Petroleum Reduction and Education Program (PREP).

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348 Exhibit DRA-7, p. 31.

349 Exhibit DRA-7, p. 63.

350 Exhibit DRA-7, p. 64.

DRA rejects both of these increases. DRA notes that the current spending levels for Energy Policy Act compliance have not increased during 2002 - 2006. DRA asserts that PREP is unnecessary as training programs to achieve the same purpose already exist.[351] SCE responds that PREP is not duplicative and is necessary to acquire information and meet SCE's obligations under Pub. Util. Code §§ 740.3, 740.8 and 451.[352]

Our adopted expenses provide the $400,000 for PREP but do not provide for additional employees. We agree with SCE that PREP may reduce overall usage of petroleum products and provide other productivity benefits for ratepayers. However, we note DRA's argument that the number of compliance employees has not varied during the past years,[353] and, in this activity, we expect SCE will utilize existing employee levels to achieve its purpose.

4.14. Load Management & Conservation

SCE requests an additional $909,000 for load management and conservation programs. These programs are intended to shift peak load and promote energy conservation by encouraging customers to engage in efficient and safe practices for the operation and charging of electric Low Emission Vehicles.[354] These programs include improved load management and electric forklift incentives and additional employees.[355] DRA argues that although customers using electric Low Emission Vehicles are required by law to reduce

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[351] Exhibit DRA-7, pp. 65-76.

[352] Exhibit SCE-18, pp. 67-68.

[353] Exhibit DRA-7, p. 66.

[354] Joint Comparison Exhibit, p. 403.

[355] Exhibit DRA-7, p. 71.

emissions, it is unreasonable for ratepayers to provide financial incentives for customers to obey the law.

We do not adopt SCE's additional Electric Vehicle load management program expenses. In other non-GRC proceedings, including proceedings addressing energy efficiency and demand response, the Commission and parties study various load management issues and develop load management information. Rather than provide separate funding here for vehicle load management studies and planning, we expect SCE will include the effects of potential additions of Electric Vehicles to the system as an input to the overall development of load management and conservation in these other proceedings.

Although DRA agrees with SCE's request for differential costs of replacing non-electric forklifts with electric forklifts and similar electric vehicle replacements, DRA rejects SCE's proposal to provide electric forklift incentives for other customers.[356] SCE responds that the intention of the forklift incentives is to change behavior.[357] We reject SCE's forklift incentives proposal. We note that SCE supports its own transition to Electric Vehicles, including forklifts, on the basis of the advantages of these vehicles, including reduced petroleum consumption and fuel costs, fewer moving parts, and no oil changes or smog checks.[358]

356 Exhibit DRA-7, p. 66.

357 Exhibit SCE-18, pp. 78-79.

358 Exhibit DRA-7, pp. 66-67.

4.15. Safety

SCE requests $100,000 to fund certain Electric Vehicle safety studies. DRA argues that such studies should not be funded to assist customers in obeying emission regulations.[359] We will provide the additional $100,000 for such studies since, as discussed below, we have not adopted other requested studies for future Plug-in hybrid vehicles (PHEV). We expect that this amount combined with other adopted expenses described below will provide SCE a sufficient amount for expected electric vehicle activities during the 2009 GRC cycle.

4.16. Customer Outreach

SCE proposes additional Electric Transportation outreach efforts through two additional employees ($143,000) and customer and employee safety education programs ($671,000). DRA contends these additional expenses are unnecessary since no PHEVs are commercially available and no evidence exists that a significant numbers of PHEVs will be operational during the 2009 GRC cycle.[360] SCE responds that it must anticipate and plan for emerging technologies such as PHEVs.[361]

Although PHEVs are not yet commercially available, we recognize that some preparation and planning will likely be necessary during the 2009 GRC cycle. Therefore, we approve $407,000 (50% of SCE's request) for purposes of planning for Electric Transportation Customer Outreach.

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359 Exhibit DRA-7, p. 72.

360 Exhibit DRA-7, pp. 72-73.

361 Exhibit SCE-18, pp. 80-81.

4.17. System Impact

SCE requests an increase of $2,330,000 over 2006 recorded cost, including $0.8 million to fund PHEV studies to assess environmental and economic impacts of PHEVs and $1.53 million to study and evaluate Vehicle to Grid (V2G) and energy storage.[362] DRA argues that these studies are not justified since PHEVs, as noted above, are not commercially available. DRA also argues that ratepayers should not be funding this type of research and that other studies are being conducted on PHEV characteristics by the Department of Energy and as part of the Public Interest Energy Research (PIER) Program. Separate from these studies, however, DRA does recommend funding SCE's request for $0.5 million to test and evaluate truckstop electrification and seaport electrification.

For the reasons stated by DRA, we do not adopt the additional $2.33 million requested by SCE. Specifically, various research projects are being conducted on PHEVs by other entities, and PHEVs are not yet commercially available. In addition, SCE's rates already include research funding through the PIER Program. Furthermore, research of the type proposed by SCE should be conducted on a statewide basis because all utilities will be impacted by PHEVs when these vehicles become more available.

In addition to approving the $500,000 for truckstop and seaport electrification, discussed above, we approve increases for safety planning ($407,000) and electric vehicle safety ($100,000). These amounts provide an increase of over $1,000,000 above the recorded 2006 expenses for studies, planning, and research for PHEVs and other projects in Electric Transportation.

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[362] Exhibit DRA-7, pp. 67-68.

We also provide an increase of $400,000 for PREP. When all of these increases, including the amounts previously recommended by DRA, are included in rates, our adopted expenses for Account 912.100 will increase by almost 90% above amounts recorded in 2006. We find this provides a reasonable amount for SCE's Electric Transportation expenses.

4.18. Other Operating Revenues

4.18.1. Community Choice Aggregation – FERC Subaccount 456.412

As discussed in more detail above, we adopt the recommendation of TURN to continue the memorandum account for Community Choice Aggregation revenues and expenses, known as the CCAICBA. Accordingly, we have removed $2,689,000 from forecasted Other Operating Revenues, which represents the estimated amount of revenues attributable to CCA fees in TY 2009.

4.18.2. Residential Late Payment Charge – FERC Account 450

SCE's TY 2009 forecast for residential late payment charges is $10,170,000 based on applying a two-year (2005-2006) average ratio of late payment charges multiplied by the amount of non-CARE electric revenues. TURN forecasts late payment charge revenues of $10,433,000 using a three-year average (2005-2007) ratio and increases the base residential revenues by $105,000,000 to reflect SCE's recent TY 2009 rate design application, A.08-03-002, in phase II of this GRC process. TURN then multiplies the increased revenues by TURN's 3-year average ratio. We find the later information provided by TURN and the longer period TURN recommends more accurately forecasts late payment charge revenues. Accordingly, we adopt TURN's estimate of $10,433,000 for the residential late payment charge in TY 2009.

4.18.3. Field Assignment Charge – FERC Subaccount 451.600

SCE forecasts Other Operating Revenues from the Field Assignment Charge (FAC)[363] at $8,352,000. SCE's forecast is based on increasing the FAC service fee to $20.00 from the current $13.75 service fee adopted in SCE's 2006 GRC. DRA and TURN object to this increase and recommend that the FAC service fee remain at the current $13.75. DRA and TURN state that the cost to perform a field assignment decreased from $21.30 in 2003 to $19.74 in 2006.[364] They contend that increasing the FAC service fee will make it more difficult for late-paying customers to pay their bills and increase the likelihood of incurring disconnections for these customers. TURN indicates that a slightly higher reconnection charge would be a better way to recover some of the increased costs related to the FAC. SCE argues that increasing the FAC service fee is fair to other ratepayers and reflects the cost-of-service basis for the FAC service charge.[365]

DRA and TURN's arguments are reasonable if we were to only consider the policy of the FAC. However, we must also recognize that the cost of the FAC has increased by about 30% from the $13.75 service charge adopted in 2006.[366] As an alternative, we will adopt a FAC service fee of $17.00. This amount, although less than the $19.74 cost-of- service, will increase the FAC service fee by approximately 24% and is a reasonable balance between the cost of this service,

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[363] As described in SCE's current tariffs, a FAC is a charge collected from a customer for any field visit to the customer's premises due to the failure of the customer to pay a bill.

[364] Exhibit SCE-18, p. 119.

[365] Exhibit SCE-18, p. 120.

[366] Exhibit SCE-18, p.120.

the potential for increasing service disconnections, and the ability of late-paying customers to pay their bills.

4.18.4. Joint Pole Attachment Fees – FERC Account 454.500

SCE agrees with TURN's proposal to maintain the amount of revenue from joint pole attachment fees at current rates. SCE also agrees to update the pole attachment charge when new rates from SCE's negotiations with telecommunications providers are available.[367] Accordingly, as agreed to by SCE, we direct SCE to update the joint pole OOR and the resulting GRC revenue requirement in an advice letter filing in compliance with this decision or, if the new rates are not yet known at the time of this compliance filing, in the annual PTYR advice letter.

4.19. Tariff Rule 17-D Adjustment of Bill for Billing Errors

TURN proposes a modification to SCE's Tariff Rule 17-D to conform the rule to Resolution G-3372 and D.05-09-046. TURN notes that PG&E, SDG&E, and Southern California Gas Company have all update their tariffs to conform with Commission decisions. SCE indicates that, while it views such changes as unnecessary, it will make them if the Commission directs SCE to do so. Accordingly, we direct SCE to file an advice letter within 90 days of the issuance of this decision to conform Rule 17-D to Resolution G-3372 and D.05-09-046 in a manner similar to the above-identified utilities.

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[367] Exhibit SCE-24, p. 44.

5. Information Technology Expenses-Computing Services

5.1. Information Technology Expenses-Computing Services - Outside Services - FERC Account 923

SCE initially estimated 2009 expenses for this account of $19.496 million (non-labor). SCE subsequently reduced its estimate to $18.996 million to correct an error in its calculation. Expense forecasts for 2007, 2008 and 2009 are based on 2006 recorded costs with adjustments for supplemental labor, software maintenance, etc.[368]

DRA recommends a TY 2009 forecast for this account of $14.086 million based on a linear trend using 2003-2006 recorded expenses. DRA explains that its forecast is superior to SCE's because the recorded costs from 2003-2006 show the most consistent trend and SCE's forecast contains inconsistencies.[369]

SCE has corrected its calculation error. Its detailed explanation of its forecast starting with 2006 recorded expenditures is reasonable, and we find that forecast superior to DRA's forecast based on a linear trend because we consider SCE's most recent experience with this category of expenses to be more reliable than data going back to 2003.

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[368] Exhibit SCE-5B, pp. 27-29.

[369] Exhibit DRA-16, pp. 6-7.

5.2. Information Technology Expenses-Computing Services - Salaries, Office Supplies, and Expenses - FERC Accounts 920/921

SCE estimates 2009 expenses for this account of $23.383 million ($12.045 million labor and $11.338 million non-labor).[370] Included in SCE's estimates are expenses related to relocation of its data center. DRA estimates 2009 expenses for this account of $21.993 million.[371]

DRA proposes removal of the 20% contingency of $0.09 million ($0.050 million labor and $0.040 million non-labor) included in SCE's estimate (related to data center relocation). DRA argues the forecast should account for any possible uncertainties in the estimate, a contingency is not necessary, and the estimate includes a sizable increase over 2006 recorded figures.[372]

SCE argues that its contingency is consistent with other major projects of the same size and complexity.[373]

Inclusion of a contingency in a project cost estimate for budgeting purposes is normal. However, there is a difference between setting a budget for a project and estimating what it will likely cost. According to SCE, "best practices state that estimates should include a contingency to cover unforeseen factors that may arise as the project progresses."[374] The key words "may arise" means that it is uncertain whether all of the contingency will be needed.

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[370] Exhibit SCE-19, p. 5.

[371] Exhibit DRA-16, p. 9.

[372] Exhibit DRA-16, p. 8.

[373] Exhibit SCE-19, p. 6.

[374] Exhibit SCE-19, p. 6.

Therefore, we adopt half of the contingency and reduce SCE's estimate by $0.045 million ($0.025 million labor and $0.020 million non-labor).

DRA also proposes a reduction of 13 positions ($1.3 million) because SCE transferred 13 positions from Computing Services to other information technology divisions in 2007.[375] SCE claims that these positions were transferred to another part of its organization due to a reorganization, and that they still perform the same functions.[376] SCE's explanation is reasonable and DRA's reduction is not adopted.

Overall the Commission adopts a reduction from SCE's estimate of $0.045 million ($0.025 million labor and $0.020 million non-labor) for the reasons discussed above. The resulting adopted expenses are $23.338 million ($12.020 million labor and $11.318 million non-labor).

5.3. Information Technology Expenses –NERC Critical Infrastructure Protection

The purpose of these activities is to ensure compliance with the standards mandated by the North American Electric Reliability Corporation (NERC) relating to critical cyber assets and Critical Infrastructure Protection (CIP).[377] SCE requests $1.978 million ($1.404 million labor and $0.574 million non-labor) in expenses in FERC Account 920/921 (Salaries, Office supplies and Expenses).[378]

DRA states that SCE planned to start this effort in 2007 by hiring 14 Full-Time Equivalent positions (FTEs). However, only six FTEs were actually

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[375] Exhibit DRA-16, p. 9.

[376] Exhibit SCE-19, p. 6.

[377] Exhibit SCE-5B, p. 85.

[378] Exhibit SCE-5B, p. 95.

filled. Therefore, DRA recommends funding only the six filled positions for a reduction of $0.920 million (labor) for the test year.[379] SCE states that while it only filled six FTEs because it was unable to find sufficient new hires soon enough, it hired 11 contract employees whose costs were recorded in Account 923 (Outside Services).[380]

SCE and DRA agree on the need for personnel to do this work, and DRA's only dispute is that the positions were not filled. Since SCE did use 17 personnel including contractors to do this work, the positions are needed and will be filled. Therefore, SCE's estimate is reasonable and is adopted.

5.4. Information Technology Expenses -New Technology Evaluation

SCE projects a need for six senior technology analysts at $1.2 million ($0.78 million for labor and $0.42 million non-labor) (constant 2006$) in FERC Account 920/921 (Salaries, Office Supplies and Expenses).[381] The purpose of these positions is to evaluate relevant emerging technologies where the capabilities or underlying architecture are dramatically different from those currently in use. SCE states that the technologies will require long-term, hands-on, and in-depth evaluation and planning. SCE says this type of evaluation is different from short planning horizon evaluations currently being done or research and development work.[382] SCE also projects a need for $0.5 million

[379] Exhibit DRA-16, p. 11.

[380] Exhibit SCE-19, p. 2.

[381] Exhibit SCE-5B, p. 83.

[382] Exhibit SCE-5B, p. 79.

(non-labor) in FERC Account 923 (Outside Services) for contractor and consultant services to assist in the evaluations.[383]

DRA states that the exact nature of the technologies is unknown and the potential benefits are unknown. Additionally, some of this work is being done by other personnel. Therefore, DRA recommends that two positions be funded at a cost of $0.26 million[384] for labor and $0.21 million for non-labor in FERC Account 920/921.[385] For the same reasons, DRA recommends a reduction of $0.25 million in FERC Account 923.[386]

There is no dispute between SCE and DRA as to the need for additional positions. Since these would be new positions with no history, a cautious approach is reasonable and funding will be reduced by half. Funding equivalent to three positions at $0.6 million ($0.390 million labor and $0.21 million non-labor) in FERC Accounts 920/921 and $0.25 million (non-labor) in FERC Account 923 is adopted.

6. Administrative & General Expenses

6.1. Total Compensation Study

A total compensation study compares the utility's total compensation – salaries, short- and long-term incentives, and benefits – to the relevant market.[387] SCE claims the "Total Compensation Study unequivocally demonstrates the

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383 Exhibit SCE-5B, pp. 84-85.

384 Exhibit SCE-19, p. 3, DRA's recommendation would result in removing four analysts at $0.52 million.

385 Exhibit DRA-16, p. 10.

386 Exhibit DRA-16, p. 11.

387 SCE opening brief, p. 93.

reasonableness of SCE's per-employee compensation."[388] SCE argues that, because the Study demonstrates reasonableness, ratepayers must bear the total costs. SCE makes assumptions based on the conclusions of the Study. These assumptions, however, are not addressed by the Study. The Study addresses the narrow issue of whether SCE's compensation is consistent with other similar companies. To clarify, the Study does not address the issue of whether SCE's compensation is "reasonable" or who should bear the costs of this total compensation, e.g., shareholders or ratepayers. The Study never purports to present information from similar companies regarding who bears the cost of employee compensation and makes no finding on this matter relative to SCE.

6.2. Results Sharing - Short Term Incentives for Non-Executives - FERC Accounts 500, 588, 905 and 920/921

Results Sharing is SCE's short-term (annual) incentive compensation program, under which eligible employees, including represented employees, can earn pay based on their job performance and SCE's performance on pre-established goals.[389] About 99% of SCE's workforce earned a Results Sharing payout in 2006.

SCE forecasts Results Sharing expenses of $106,413,000 (constant 2006$) for TY 2009. Costs are recorded in Accounts 500, 588, 905, and 920/921.[390] SCE's

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[388] SCE opening brief, pp. 3-4.

[389] SCE's 2009 forecast for the Results Sharing Program includes costs for a small group of senior managers who are eligible for the Management Incentive Program (MIP) (approximately 7% of all employees) and non-officer executives who are eligible for the Executive Incentive Plan (EIP) (less than 1% of all employees). Exhibit SCE-6B, p. 6.

[390] Joint Comparison Exhibit, p. 485 and p. 772.

2006 recorded expenses are $91,293,000. SCE explains the $15.1 million increase is due to the significant increase in anticipated labor costs.[391] DRA recommends no funding for SCE's Results Sharing and other incentive compensation programs. In the alternative, DRA recommends ratepayer funding be limited to a 5-year average of the historical payout, $86.2 million, or the 2006 base year recorded costs of $91.3 million.[392] TURN recommends either 50/50 sharing of Results Sharing Program costs between ratepayers and shareholders or, alternatively, continuing the mechanism the Commission adopted in SCE's 2006 GRC[393] which provides full funding for incentives along with a one-way balancing account to refund money to ratepayers if the target amount is not met.[394]

The Commission recently investigated certain problems with SCE's Results Sharing Program. On June 15, 2006, the Commission opened an investigation into the alleged manipulation of data used by SCE to calculate revenues and rewards under its Performance Based Ratemaking. On September 18, 2008, the Commission adopted D.08-09-038 which, among other things, ordered SCE to refund to ratepayers that portion of the revenue requirement for Results Sharing attributed to Performance Based Ratemaking data.[395] The Commission summarized its findings as follows:

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[391] Exhibit SCE-6B, p. 18.

[392] Exhibit DRA-9, p. 36.

[393] D.06-05-016, p. 131.

[394] Exhibit TURN-5, p. 79.

[395] The Commission's directive in D.08-09-038 to remove amounts associated with Results Sharing from revenue requirement in 2003-2005 has no impact on SCE's forecasted revenue requirement in this proceeding. RT Vol. 21:2210.

> "This decision concludes that Southern California Edison Company (SCE) employees and management manipulated and submitted false customer satisfaction data, and the data was used to determine Performance Based Ratemaking (PBR) customer satisfaction rewards for a period of seven years. Therefore, SCE is ordered to refund to its ratepayers all $28 million in PBR customer satisfaction rewards it has received and forgo an additional $20 million in rewards that it has requested. The decision also finds that SCE submitted false and misleading health and safety data, and the data was used to determine PBR health and safety rewards for a period of seven years. Therefore, SCE is ordered to refund to its ratepayers all $20 million in PBR health and safety rewards it has received and forgo an additional $15 million in rewards that it has requested. The decision further concludes that SCE should refund the portion of its 2003 to 2005 revenue requirement related to the utility's Results Sharing program that was affected by fraudulent data, which the decision finds to be $32,714,000. Finally, the decision orders SCE to pay a fine of $30 million for violations of the Public Utilities Code."

In this proceeding, SCE reminds us that it extensively redesigned the Results Sharing program in 2006.[396]

We reject SCE's methodology for forecasting costs for the Results Sharing Program. Based on the evidence presented in this proceeding and the Commission's findings in D.08-09-038, we remain concerned about employee incentive compensation proposals, such as the Results Sharing Program, that provide shareholder value without imposing shareholder costs.[397] DRA raises significant concerns about the success of SCE's efforts to redesign this program. We have no data to support funding this program, as redesigned, and to ensure that the redesign successfully addresses the known deficiencies identified in the

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[396] Exhibit SCE-20, pp. 28-31.

[397] D.06-05-016, p. 132.

2006 GRC and in D.08-09-038. Therefore, it is reasonable to reduce SCE's forecast by 50% for TY 2009, consistent with TURN's recommendation. In addition, consistent with our decision in the 2006 GRC, we will continue to require SCE to rely on a one-way balancing account for the Results Sharing Program.[398] This account is known as the Results Sharing Memorandum Account (RSMA). When actual Results Sharing payouts for 2009, 2010, or 2011 are determined, any shortfall in the payment to employees when compared to the authorized amount for that particular year should be credited to the Authorized Base Revenue Requirement Balancing Account.

6.3. Spot Bonus and Awards to Celebrate Excellence Programs – FERC Accounts 566.200, 566.300, 580.100, 588.300, 588, and 920/921

In SCE's opening brief, SCE states it estimated $4.25 million in 2009 for its Spot Bonus and Awards to Celebrate Excellence Programs.[399] For 2006, spot bonus costs were 0.3 % of SCE's payroll dollars, amounting to $3.28 million.[400] Spot bonuses were excluded from the Total Compensation Study because unavailability of data and wide variances exist in the marketplace. For these reasons, DRA and SCE agreed that spot bonuses would not be included in the Total Compensation Study for this GRC.[401] Costs associated with Spot Bonuses

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[398] D.06-05-016, pp. 131-132.

[399] SCE opening brief, p. 97; Joint Comparison Exhibit, p. 491, Exhibit SCE-20, SCE's rebuttal testimony presents a forecast of $4.5 million.

[400] Exhibit SCE-6B, p. 27.

[401] Exhibit SCE-6B, pp. 26-27.

are embedded in the labor and expense forecasts of individual business units and departments.[402]

This estimate presumably does not include costs associated with the Awards to Celebrate Excellence program but the exact amount is not provided. SCE claims in rebuttal testimony that:

> "SCE's historical and forecast expenses for Spot Bonus Programs are summarized in Vol. 2 of Exhibit SCE-06, pp. 26-28 but embedded in the labor and expense forecasts of individual business units and departments. SCE's historical and forecast expenses for the ACE program are included in the miscellaneous benefits section of Vol. 2 of Exhibit SCE-06, pp. 28, 84, 86." [403]

We found no separate forecasts for TY 2009 in SCE's testimony for the Awards to Celebrate Excellence and the Spot Bonus Programs. SCE provided an aggregate figure of $4.25 million but did not adequately explain its methodology for arriving at this combined amount. Therefore, while SCE claims it addressed the issues regarding tracking of these amounts that we raised in our 2006 GRC decision, we disagree based on the absence of evidence. SCE's failure to provide a specific forecast for either of these programs refutes any claim by SCE that accounting concerns have been resolved and that ratepayer interest is served by the amounts awarded under these programs. DRA opposes the entire amount requested. For the reasons stated herein, we do not find reasonable SCE's request to include amounts associated with Spot Bonus or Awards to Celebrate Excellence programs in TY 2009 revenue requirement.

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402 Exhibit SCE-20, p. 33. These FERC Accounts include 566.200, 566.300, 580.100, 588.300, 588, and 920-921.

403 Exhibit SCE-20, p. 33.

6.4. Executive Compensation – FERC Accounts 920/921 and 923

SCE compensates its executive officers with cash compensation, including base salaries, annual bonuses, associated expenses, and short and long-term incentives.[404] SCE is requesting $24.588 million[405] for executive base salaries, related expenses, and short-term bonuses, while SCE's 2006 recorded total is $21.208 million.[406] SCE is also requesting $23.304 million[407] for related expenses, annual bonuses, and long-term incentives. This latter amount, $23.304 million for related expenses, annual bonuses, and long-term incentives, has not previously been included in SCE's revenue requirement. Greenlining, TURN, and DRA recommend adjustments to SCE's requests.

We reject SCE's request to include $23.304 million in long-term incentives in its 2009 TY forecast.[408] As DRA and TURN note, these incentives have not been included in rates in the past and are closely tied to stock performance of the parent company, Edison International, and, therefore, to non-utility activities. We continue the Commission's existing policy of excluding these amounts from revenue requirement.

Regarding SCE's request for $24.588 million for executive base salaries, related expenses, and short-term bonuses, we agree with TURN and DRA that it

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[404] Exhibit TURN-5A, p. 68. Long-term incentives include non-qualified stock options, restricted stock units, and performance shares, the mix of which varies by rank and may change from year to year.

[405] Joint Comparison Exhibit, p. 483.

[406] Exhibit SCE-6A, p. 84.

[407] Exhibit SCE-6A, p. 84; Joint Comparison Exhibit, pp. 482, 777.

[408] Exhibit SCE-15, p. 24.

is premature to include in the TY 2009 forecast an additional officer to implement the SmartConnect program. SCE has not shown that SmartConnect will occur in TY 2009. Accordingly, it is reasonable to reduce SCE's forecast by one officer. In the absence of specific information regarding officer salaries, we reduce SCE's estimate of $24.588 million by $664,540.[409]

In addition, regarding executive short-term incentives, SCE fails to specify the amount for such incentives included in its TY 2009 forecast of $24.588 million ($23.186 million plus $1.402 million for related expenses) for executive compensation. DRA opposes all incentives, including short-term incentives.

Given the lack of information regarding the short-term incentive component within executive compensation in SCE's testimony, we reduce SCE's TY 2009 forecast by 50% or $11.961.[410] This estimate is as accurate as possible based on the evidence presented by SCE regarding the components of executive compensation.

6.5. Board of Directors and Corporate Governance – FERC Account 930.2

Corporate Governance activities recorded in FERC Account 930.2 (Corporate Governance and Miscellaneous) include fees and expenses paid to members of SCE's Board of Directors, expenses associated with the SCE's Annual Shareholder Meetings, contract services, and other proxy-solicitation

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[409] SCE's TY 2009 forecast is based on 37 officers. We subtracted 1/37 from this forecast to reflect our approval of one less officer position. This $664,540 reduction is prorated among FERC Accounts 920, 921, and 923.

[410] This reduction was calculated as follows: $24.588 million minus $664,540 divided by 2 equals $11.961 million.

fees, as well as costs related to filing requirements of the SEC.[411] The labor component of this account refers to the charges made by SCE's various employees for their time spent providing assistance during annual shareholders' meetings. SCE classifies all other expenses, including directors' annual retainer fees, fees for annual meeting attendance, and non-equity compensation, as non-labor. SCE uses 2006 recorded expenses plus a future-year adjustment to forecast overall FERC Account 930.2 (Corporate Governance and Miscellaneous) expenses for TY 2009.[412] SCE's method yields a total forecast of $4.752 million, roughly a 16% increase over its 2006 expenses of $4.108 million.[413]

In support of its requested increase, SCE states only that the additional costs result from the "increasing frequency of corporate reporting required of Corporate Governance and oversight by the Board of Directors in response to increased corporate compliance requirements, public scrutiny, and frequent adoption of new and revised laws, regulations, and rules."[414] TURN recommends the Commission deny all of SCE's requested increase over 2006 base year Account 930.2 expenses for Corporate Governance. In addition, TURN recommends removing $0.884 million from 2006 recorded base year directors' compensation to remove stock-based compensation. TURN argues these requests are unsubstantiated and not adequately tied to ratepayer benefits. We agree. After these reductions, we find reasonable an overall forecast for FERC Account 930.2 (Corporate Governance and Miscellaneous) of $3.224 million.

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411 Exhibit SCE-7B, pp. 31-33.

412 Exhibit SCE-7B, pp. 32-33.

413 Joint Comparison Exhibit, p. 782.

414 Exhibit SCE-7B, p. 33.

6.6. Human Resources Department Expenses – FERC Accounts 920, 921, 923, and 926

SCE's HR Department consists of seven "operating functions": Total Compensation, HR Service Center, Talent Management, HR Client Services, Labor Relations, HR Administration, and Equal Opportunity. The expenses associated with the HR Department are recorded in FERC Accounts 920/921, 923, and 926. SCE forecasts a total of $69.106 million (constant 2006$) for combined HR Department and executive officer activities for TY 2009.[415] SCE's 2006 recorded expenses are $60.867 million. In support of its request for increases above 2006 base year, SCE explains "SCE faces many concurrent challenges. A massive need for infrastructure replacement, growth in our customer base, transmission system expansion, an aging workforce, major technology initiatives all of which require a strategic alignment of our people with our business direction."[416] SCE also states in reference to one of the specific function areas of the HR Department, Talent Management, "SCE's aging infrastructure requires increased staffing levels as we seek to maintain quality electric service for our customers. The impact of both retirement and attrition and the increasing workload in TDBU impact Talent Management directly."[417] SCE's forecasts for three of the operating functions of the HR Department are disputed. We address them below.

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[415] Exhibit SCE-6A, p. 14.

[416] Exhibit SCE-6A, p. 7, fn. omitted.

[417] Exhibit SCE-6A, p. 54.

6.6.1. Talent Management - FERC Accounts 920/921

In FERC Accounts 920/921, SCE relies on budget-based forecasting to propose a TY 2009 forecast of $17.668 million (constant 2006$) for Talent Management.[418] SCE's forecast is an increase of $4.806 million over 2006 recorded costs of $12.862 million.[419]

DRA recommends a $4.651 million reduction to SCE's forecast for TY 2009 and presents a forecast of $13.017 million. DRA notes SCE has already increased its spending for Talent Management by 81% from 2002 to 2006. DRA also relies on our 2006 GRC decision ordering sharing of certain Talent Management program expenses between ratepayers and shareholders.[420] TURN recommends reducing SCE's forecast for Talent Management expenses by $3,428,000 to adjust for declining productivity (total new employee hires per Talent Management staff has decreased since 2002) and the lack of a discernable trend between the increase in SCE's TY 2009 forecast and the relatively constant expenses recorded for 2006 and forecasted in 2007-2008.[421] In response, SCE states that its increased costs are related to increased hiring and that its Leadership Programs are legitimate costs of service and should be fully funded by ratepayers.

In the 2006 GRC, the Commission adjusted SCE's forecast and disallowed 50% of the additional money requested for SCE's Leadership Programs.[422] We find no evidence in the record to support changing this policy. As such, SCE's

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418 Exhibit SCE-6A, p. 51.

419 Exhibit DRA-9, pp. 13-14.

420 Exhibit DRA-9, p. 21.

421 Exhibit TURN-5, pp. 100-102.

422 D.06-05-016, p. 140.

forecast is reduced by $1.644 million (50% of $2.979 million plus 50% of $310,000). In addition, SCE relies upon its hiring forecast to justify the increases over 2006 base level.[423] Based on the arguments presented by TURN and DRA regarding the increases in these accounts for years 2002-2008, we find the 2006 base level of $12.862 million plus $1.644 million for SCE's Leadership Programs, sufficient to cover SCE's projected expenses for Talent Management. The result is $14.506 million.

6.6.2. Outside Services – Total Compensation – Client Services - FERC Account 923

Regarding FERC Account 923, SCE uses a three-year average (2004-2006) of expenses to calculate its TY 2009 forecast of $844,000 for outside services of Total Compensation.[424] TURN suggests SCE's straight, three-year average is inflated because it includes one-time expenses for consultants related to the Fair Labor Standards Act 2004 amendment and fails to account for the periodic nature of much of the remainder of SCE's recorded, outside services expenses concentrated in 2004 and 2005. TURN recommends a $354,000 reduction to SCE's forecast, which results in a TY 2009 forecast of $490,000. In response SCE points out it expects to incur future expenses during 2009-2011 related to continued implementation of the revisions to the Fair Labor Standards Act. Based on SCE's projected need of additional resources, we adopt SCE's forecast.

6.6.3. Client Services - FERC Account 923

TURN recommends a $99,000 reduction to SCE's TY forecast for FERC Account 923 related to the one-time cost of $494,000 for responding to union

[423] Exhibit SCE-20, pp. 4-5.

organizing in 2004. SCE includes the $494,000 expenses and relies on a five-year average of historical costs for forecasting TY 2009 expenses of $263,000. SCE concedes this expense is a one-time cost, stating "the need to resist organizing drives may not be ever present,"[425] but also states it expects to experience future union-sponsored organizing drives. SCE does not explain the level of expenses it would expect to incur. In the absence of adequate information to predict future costs, we find that SCE's historical analysis should be revised to remove this one-time expense. According to TURN, the exclusion of $494,000 from 2004 expenses yields a five-year average forecast of $164,000.[426] We adopt this figure.

6.7. Pension and Benefits - FERC Account 926

SCE is forecasting $52.947 million (nominal $) for TY 2009 pension costs. Pension costs are currently subject to a two-way balancing account. DRA recommends no funding for TY 2009 because SCE's legally-required minimum contribution for 2009 is zero. SCE does not dispute the fact that its legally required minimum contribution for 2009 is zero. SCE explains that the Pension Protection Act of 2006 (PPA) made changes to pension plan minimum funding requirements and to the rules for determining annual maximum tax deductible contributions. SCE further explains the drawbacks to only planning for a minimum contribution, stating:

> "Replacement of SCE's long-standing pension funding and rate recovery policy with PPA minimum contributions would likely reduce or eliminate plan contributions in the short run. But, total

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[424] Exhibit SCE-6A, pp 23-24.

[425] Exhibit SCE-20, p. 9.

[426] Exhibit SCE-20, p. 9.

> long term contributions would significantly increase because PPA minimum funding would reduce both trust fund value and the investment earnings for the trust fund that help to pay the long-term costs of the plan." [427]

In this GRC, SCE also proposes that the Commission continue using the two-way balancing account for pension costs adopted in the 2006 GRC decision.[428] DRA supports the continuation of the balancing account. Under this procedure, the difference between 2006-2008 authorized amounts vs. actual pension contributions under the existing funding policy will be amortized beginning in 2009, and the difference between authorized and actual 2009-2011 pension costs will be amortized beginning in 2012. Annual amortization may be appropriate in certain circumstances and SCE may file an advice letter seeking this process. Any accumulated balances receive interest at the commercial paper rate, consistent with treatment of interest accruals for other SCE balancing accounts.

In the past, we have adopted SCE's forecast if a substantial difference exists between the minimum contribution and its forecast. We decline to follow this reasoning here as it provides SCE with an incentive to overestimate its 2009 contribution. The historical information indicates that SCE estimates exceed actual contributions. We adopt $26.473 million for TY 2009 (nominal $) as this figure falls at the mid-point between the legally required minimum contributions and SCE's forecast. We also continue balancing account treatment of this amount.

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[427] Exhibit SCE-6B, p. 36.

[428] Exhibit SCE-6B, p. 41.

6.7.1. Medical Program

SCE forecasts medical program costs of $115.921 million (nominal $) for TY 2009.[429] SCE projected the revenue requirement for 2009 by applying a 10% escalation to 2006 recorded costs for 2007 and 2009.[430] SCE arrived at the 10% escalation by evaluating numerous factors influencing medical costs for its covered population,[431] analyzing multiple surveys forecasting medical cost trends,[432] and reviewing underwriting projections from its medical plans.[433] The forecast related to escalation charges is approximately $5.9 million.[434]

DRA recommends lower escalation rates for 2007 and 2009. It suggests that 7.30% and 7% are supported by the U.S. Bureau of Labor Statistics and from Towers Perrin.[435] DRA recommends a TY 2009 forecast of $96.034 million, which is $19.893 million less than SCE's forecast.

We agree with SCE's forecasting methodology but, because SCE's forecasted medical expenses are such a significant amount, we adopt a two-way balancing account to protect ratepayers from any overestimating of this amount. This balancing account will function in the same manner as the balancing account applied to PBOPs. SCE is directed to file a Tier 2 Advice Letter

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429 SCE's forecast updated to reflect slightly lower labor forecast per September 4, 2008 update testimony. Exhibit SCE-54.

430 Joint Comparison Exhibit, p. 500. Under SCE's forecasting methodology, no escalation applies to year 2008 due to medical plan changes by SCE. SCE argues that, under DRA's forecasting methodology, a 2008 adjustment is required.

431 Exhibit SCE-6B, pp. 50-59.

432 Exhibit SCE-6B, pp. 57-58.

433 Exhibit SCE-6B, p. 57.

434 Exhibit SCE-20, p. 47 and p. 52.

implementing this medical expenses balancing account, which will also include dental and vision expenses, within 30 days of the issuance of this decision. In addition, the adopted forecast for these programs will be adjusted to account for labor changes adopted in other sections of this decision.

6.7.2. Disability Programs

SCE projects expenses of $23.658 million (nominal $) for disability programs for TY 2009.[436] This includes projected costs for short-term and long-term pay replacement benefits through the Comprehensive Disability Plan and the Long-Term Disability Plan and assistance to help employees with work restrictions find alternative or modified employment through the Return to Work Program.[437] SCE forecast its TY 2009 costs by multiplying the projected number of eligible employees by the projected per-eligible-employee cost. SCE derived the projected number of eligible employees by dividing the forecast labor cost for 2009 (expressed in 2006 dollars) by the 2006 average per-employee labor cost.[438]

DRA asserts that SCE should eliminate its Comprehensive Disability Plan, $4.058 million, and instead simply utilize the State Disability Program.

Based on SCE's assertion that its plans are more cost effective, provide greater protections to employees, and return employees back to work more rapidly,[439] we adopt SCE's forecast and reject DRA's recommendation that SCE

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435 Exhibit DRA-11, p. 7.

436 Exhibit SCE-20, p. 52.

437 Exhibit SCE-20, p. 52.

438 Exhibit SCE-6B, p. 77.

439 Exhibit SCE-20, p. 58.

rely on the State Disability Program. In addition, the adopted forecast for these programs will be adjusted to account for labor changes adopted in other sections of this decision. We also address escalation rates for PTYR in a separate section of this decision.

6.7.3. Miscellaneous Benefit Programs

SCE forecasts 2009 expenses of $7.705 million (nominal $) for Miscellaneous Benefit Programs.[440] SCE's 2006 recorded expenses are $6,129,718. SCE's Miscellaneous Benefit Programs include Electric Service Reimbursement, Awards to Celebrate Excellence, Corporate Relocation, Commuter Programs, Educational Reimbursement, Severance Benefits, and Work Life Balance Assistance.

DRA recommends the exclusion of costs for Awards to Celebrate Excellence and the following programs: Health Resources, Work Life Initiatives, and Environmental Affairs – Management Information Systems. In support of these costs, SCE claims these programs provide benefits to SCE's customers and are a normal cost of service. SCE uses the same forecast methodology as used for its Disability Program. SCE explains that program costs were forecasted by multiplying the projected number of eligible employees by the projected per-eligible-employee composite cost. The projected number of eligible employees was derived by dividing the forecast labor cost for 2009 (expressed in 2006 dollars) by the 2006 average per-employee labor cost. Projected per-eligible-

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[440] Exhibit SCE-6B, p. 81.

employee costs for these programs were assumed to increase at the non-labor escalation rate through 2009 as developed in SCE's testimony.[441]

We find that SCE's request for costs associated with some of these programs is reasonable. They provide benefits to ratepayers in the form of reduced medical costs or are appropriate costs for SCE's Commuter Programs. However, we addressed Awards to Celebrate Excellence in a separate section of this decision and deny all such costs. We extend this ruling to the $896,000 included for Awards to Celebrate Excellence under Miscellaneous Benefits in FERC Account 926.[442] Because it is unclear from the record in this proceeding, SCE is directed to explain in its next GRC why it records amounts for Awards to Celebrate Excellence under Miscellaneous Benefit Programs in FERC Account 926.

In addition, the adopted forecast for these programs will be adjusted to account for labor changes adopted in other sections of this decision.

6.7.4. Executive Pension and Benefits

SCE forecasts 2009 expenses of $23.954 million (nominal $) for Executive Benefits.[443] These Executive Benefits encompass the Executive Retirement Plan that supplements the SCE Retirement Plan, a survivor benefit plan, and other benefits of such negligible costs that SCE does not included such "other benefits" costs in its forecast.[444] DRA opposes the inclusion of any of these Executive

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441 Exhibit SCE-6B, p. 84.

442 Exhibit DRA-11, p. 10 *citing to* SCE-6, Vol. 2, Ch. VI, workpapers, Pt. 3, p. 440.

443 SCE opening brief, p. 113; Exhibit SCE-6B, p. 84.

444 Exhibit SCE-6B, p. 85.

Benefits for TY 2009.[445] SCE supports its request based on the Total Compensation Study. As we have indicated elsewhere in this decision, the scope of the Total Compensation Study does not support SCE's position here. Also, because these Executive Benefits are largely tied to the amount of compensation awarded the executive, we find including 50% of this forecast in rates reasonable after reducing the total amount by one officer. See the discussion above regarding Executive Compensation.

6.7.5. Executive Benefits Retirement Severance Benefits of Top Executives-FERC Accounts 920/921

SCE explains that, if an executive is involuntarily severed not for cause, SCE offers the executive an enhanced retirement severance benefit equal to the added value of one additional year of age and service in the formula used by the Executive Retirement Plan for calculating executive retirement benefits. SCE further explains that senior officers who lose their positions in connection with a change in control of Edison International receive not one, but two additional years of age and service (three for CEOs) in the formula. In addition, severed executives with four or fewer years of service become fully vested in the Executive Retirement Plan.[446]

In connection with these enhanced retirement severance benefits, SCE now responds to the directive in D.06-05-016, to provide information on the present and future "market value" of the retirement severance benefits of its top executives. In Exhibit SCE-6B, pp. 86-87, Exhibit SCE-51 and Exhibit SCE-51WP, SCE provides actuarial present value calculations using hypothetical severance

[445] Joint Comparison Exhibit, p. 503.

[446] Exhibit SCE-51, p. 1.

dates. In Exhibit SCE-51, SCE also explains its view that no market exists for the additional age and service credits in SCE's Executive Retirement Plan that comprise the retirement severance benefit, and no apparent way exists to accurately determine the future "market value" of these additional credits. Accordingly, SCE requests that the valuation requirement regarding SCE's executive retirement severance benefits be clarified to pertain only to, and be satisfied by, actuarial present value calculations using hypothetical severance dates.

In response to SCE's request, we find SCE's additional information satisfactorily responds to our direction in D.06-05-016. This finding has no ratemaking impact.

6.8. Four Corners Pension and Benefits & Participant Credits and Capitalized Pension and Benefit Expense – FERC Accounts 925 and 926

TURN proposes that we use APS's 2009 Four Corners budget forecast (which is part of APS's Long Range Forecast for the period 2009–2017).[447] In a separate section of this decision, we reject the same proposal by TURN when addressing O&M issues related to Four Corners. Consistent with our decision to reject SCE's request for 50 additional employees at Four Corners, we reduce SCE's Four Corners' Pension and Benefits forecast by the appropriate amounts.

Pensions and benefits must be divided between expense and capital labor.[448] As SCE explains, the amount of capitalized pensions and benefits "is

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447 Exhibit TURN-5A, p. 103; Joint Comparison Exhibit, pp. 793-795.

448 Exhibit SCE-7A, p. 59.

recorded as a credit to Account 926.900 (Employee P&B Transferred) and a debit to Account 107 (Construction Work In Progress) and ultimately included in Plant in Service."[449] SCE forecasts total costs in Accounts 925 and 926 of $451,597,000 in 2009, of which $149,930,000 will be capitalized, leaving $301,665,000 in expenses in those accounts.[450]

TURN recommends that SCE's calculation of capitalized P&B be modified to exclude pensions and benefits associated with labor as below-the-line expenditures, rather capitalizing or expensing these costs.[451] TURN originally recommended a reduction of $2.161 million in Capitalized Pensions & Benefits.[452] SCE accepted the principle suggested by TURN that a portion of pensions and benefits costs should be disallowed based on labor costs assigned to Account 426 (below-the-line), but SCE produces a different estimate of the effect on revenue requirements than TURN's estimate.[453] TURN accepts SCE's revised estimate of the treatment of capitalized and disallowed pensions and benefits.[454] TURN's position is that the Commission should adopt TURN's proposal to assign Pension and Benefit costs to the labor costs that SCE records below-the-line by using a rate of .54% applied to the ultimately adopted Accounts 925 and 926

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449 Exhibit SCE-7A, p. 59.

450 Exhibit TURN-5A, p. 105.

451 Exhibit TURN-5A, p. 105.

452 Exhibit TURN-5A, p. 105.

453 Exhibit SCE-21, pp. 13-15.

454 Exhibit TURN-25, p. 1.

amounts.[455] The parties appear to be in agreement on these matters. We find their agreed to positions reasonable and adopt them.

6.9. Law Department Salaries and Related Expenses - FERC Accounts 920/921

For In-House Salaries and related expenses, SCE forecasts $26.278 million (constant 2006$) for TY 2009. According to DRA, this represents an overall increase of 15.9% over 2006 adjusted recorded costs of $22.676 million.[456] SCE calculated its Law Department In-House labor as $21.3 million using the 2006 recorded labor expenses with an incremental adjustment of $2.5 million. This incremental increase for labor is for 31 Full-Time Equivalent employee positions (10 attorneys, 5 Legal Aides, 4 Case Administrators, 11 Office Staff, and 1 Librarian).[457] SCE's Law Department forecasts its non-labor costs using a five-year average ratio of labor to non-labor. The five-year average, 23.26%,[458] is applied to the labor forecast for 2007, 2008 and 2009. SCE's non-labor forecast for TY 2009 was $4.952 million.[459]

DRA recommends reducing SCE's forecast by $3.088 million to eliminate the labor, and nearly all of the non-labor, for the 31 incremental Law Department Full-Time Equivalent employees included in the forecast.[460] We agree.

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455 Joint Comparison Exhibit, p. 792.

456 DRA opening brief, p. 147 *citing to* Exhibit SCE-7B, p. 13.

457 Exhibit SCE-7B, p. 16, Table II-13.

458 Exhibit DRA-8, p. 27.

459 Exhibit SCE-7B, p. 13.

460 Exhibit DRA-8, pp. 26-27.

SCE has failed to support its need for additional amounts beyond the 2006 base year for its Law Department. Based on historical trends, we find no further increase is warranted beyond the 2006 base year amount of $22.676 million (constant 2006$). The incremental work identified by SCE to justify the additional amounts beyond 2006 base year is included in embedded costs. SCE argues that, at a minimum, the incremental expenses attributed to filling vacant positions as of year-end 2006 or to meet Law's technology demands should not be removed from SCE's forecast.[461] However, SCE provides no evidence on the costs associated with filling these vacant positions. Therefore, SCE's request for additional amounts is denied.

We reject DRA's suggestion that a timekeeping system is needed to support any increased expenses by the Law Department. Regarding the timekeeping system, SCE's Hildebrandt International Study concluded that "the substantial expenses and diversion of resources associated with implementing and operating an attorney timekeeping system should not be imposed upon SCE and its customers."[462] We agree. Accordingly, we will not require SCE to implement the type of attorney timekeeping system recommended by DRA.

6.10. Outside Counsel - Outside Service - FERC Account 923

SCE inadvertently included certain outside counsel costs for the Performance-Based Ratemaking matter in its recorded costs for Account 923. SCE agrees with DRA that such costs should be removed from the recorded costs

[461] Exhibit SCE-7B, pp. 14-15.

[462] Exhibit SCE-7B, p. 26.

underlying SCE's forecast of 2009 outside counsel costs.[463] SCE claims the appropriate adjustment should be $1,188,000, rather than $1,597,000 as proposed by DRA, because SCE already removed $424,000 in a Business Unit adjustment.[464] DRA indicates it has not verified the accuracy of SCE's proposed reduction and, therefore, continues to support a reduction of $1,597,000. We find SCE's recommendation reasonable based on SCE's explanation that the difference DRA still identifies is probably accounted for in the related Business Unit adjustment of $424,000.[465]

6.11. Claims

For TY 2009, SCE forecasts for its claims division a total of $15.3 million (constant 2006$) in Administrative & General expenses (including injuries and damages – claims reserves).[466] The 2006 recorded costs are $9.315 million. As discussed below, DRA recommends $5.173 million be removed from SCE's TY forecast.[467]

6.11.1. Additional Claims Personnel - FERC Accounts 920/921

SCE records salaries of claims division personnel to FERC Accounts 920/921 (Administrative and General Salaries and related non-labor expenses). SCE forecasts six new positions for the TY 2009 at an incremental labor cost of $451,102 (constant 2006$).[468] SCE's TY 2009 forecast for additional

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463 Exhibit SCE-21, p. 43.

464 Exhibit SCE-21, p. 43.

465 Exhibit SCE-21, p. 43 and Appendix A, pp. A-11 to A-13.

466 Exhibit SCE-7B, p. 34.

467 Joint Comparison Exhibit, p. 464 and p. 478.

468 Exhibit SCE-7B, p. 39, Table III-6.

non-labor is $86,000 (constant 2006$).[469] SCE explains the claims division labor expenses from 2002-2006 were relatively flat.[470] SCE expects the claims division's claims-related workload to continue to increase consistent with the overall upward trend in total claims cases handled by the division during 2002-2006.[471]

Based on the evidence provided, SCE has not justified its requested increase over 2006 base year. As DRA notes, between 2006 and 2007 the claims division workload increased approximately 1.35% based on the number of claims addressed and completed. DRA further points out, and we agree, that even the transfer of 316 claims investigations from Environmental and Safety does not warrant six new positions.[472] This transfer results in an increase of 3.89%.[473] Lastly, between 2002 and 2006, SCE experienced an average increase in claims filed against SCE of approximately 11.8% while keeping its claims division labor expenses flat.

Based on the projected increased workload for years 2002-2006 of 11.8% together with SCE's statement that it expects workload to increase consistent with the trend in total claims cases handled by the division during 2002-2006,[474] we find SCE fails to justify its requests for costs above 2006 base year. Accordingly, we do not adopt SCE's proposed incremental costs.

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469 Exhibit SCE-7B, p. 39.

470 Exhibit SCE-7B, p. 37.

471 Exhibit SCE-7B, p. 38.

472 Exhibit DRA-8, p. 30.

473 DRA opening brief, pp. 148-149.

474 Exhibit SCE-7B, p. 38.

6.11.2. Additional Claims Reserves - FERC Account 925

The claims division records to FERC Account 925 (Injuries and Damages – Reserves) amounts reserved by SCE as self-insurance for general liability losses resulting from injuries and damages to persons and property that are not covered by SCE's insurance policies. SCE establishes reserves up to its self-insured limit of $2 million per incident. Also included in this account is the amortization of insurance expense for specific coverage of covered losses resulting from injuries and damages to persons and property, such as premiums paid for asbestos-related injuries and damages under the Masters Insurance Program.[475] For TY 2009, SCE forecasts $8.577 million (constant 2006$) for claims reserves based on the five year average of 2002-2006 recorded expenses. SCE's 2006 recorded expenses are $3.855 million.

While SCE provides evidence to support its contention that costs fluctuate over the 2002-2006 period, SCE fails to explain what accounts for this fluctuation. In the absence of this information, the Commission can not determine if such fluctuations were caused by one-time events. In rebuttal testimony, SCE asserts "SCE's experience in 2007 also demonstrates that its forecast of Claims Reserves for Test Year 2009 is reasonable."[476] However, SCE does not explain what this 2007 experience consisted of.

For this reason, we adopt $3.855 million (constant 2006$) and find SCE has failed to prove the need for amounts beyond 2006 base year.

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[475] Exhibit SCE-7B, pp. 36-37.

[476] Exhibit SCE-21, p. 53.

6.12. Workers' Compensation

SCE's forecast for the TY 2009 for its workers' compensation division is $43.162 million (constant 2006$) for workers' compensation, including reserves.[477] SCE's 2006 recorded expenses are $25.557 million, so the forecast represents an overall increase of 68.9% over the 2006 base year. As discussed below, DRA recommends $17.281 million (almost all of the increase) be removed from SCE's TY estimate.[478]

6.12.1. Additional Workers' Compensation Personnel - FERC Account 925

SCE's Workers' Compensation Division has the primary responsibility for administering workers' compensation benefits, providing information to SCE employees regarding such benefits, and determining workers' compensation benefit eligibility. SCE's TY 2009 forecast includes $1.028 million (constant 2006$) associated with 12 additional full-time equivalent employees to its workers' compensation division.[479] SCE's recorded 2006 expenses are $5.346 million and its TY 2009 forecast is $6.374 million.

SCE explains that, at year-end 2006, the Workers' Compensation Division had 39 employees on staff, three vacant positions, and five agency personnel.[480] SCE also notes that the Workers' Compensation Division's labor expenses were relatively flat during the 2002-2006 time period.[481] SCE expects workload to

[477] Exhibit SCE-7B, p. 44.

[478] Exhibit DRA-8, p. 32.

[479] Exhibit SCE-21, p. 54.

[480] Exhibit SCE-7B, p. 50.

[481] Exhibit SCE-7B, p. 54.

increase as the new employee population increases.[482] DRA recommends a reduction to SCE's request of $703,000. According to DRA, funding for 6 Full-Time Equivalent employees is sufficient to address increased workload based on industry standards.[483] DRA recommends four additional Claim Representatives and two Administrative Aides for TY 2009.[484]

We find DRA's argument based on industry standards convincing. SCE has failed to support the full amount of its requested increase. Accordingly, we adopt a $703,000 reduction to SCE's request to reflect approval of 6 rather than 12 additional employees.

6.12.2. Workers' Compensation Reserve - FERC Account 925

For Workers' Compensation Reserves, SCE's TY 2009 forecast is $36.788 million (constant 2006$). SCE calculates its forecast for Workers' Compensation Reserves expenses using a budget-based forecast methodology.[485] SCE's 2006 recorded expenses are $20.210 million. SCE explains that in connection with the 2006 GRC, Workers' Compensation Reserve expenses were forecasted based on the anticipated value (i.e., SCE's exposure) of all new and existing workers' compensation claims for a given year. Under SCE's budget-based approach, the TY 2009 forecast for Workers' Compensation Reserves is based on the ultimate (total) value of anticipated new claims arising from injuries during the 2007-2009 time period.[486]

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[482] Joint Comparison Exhibit, p. 468.

[483] Exhibit DRA-8, p. 33.

[484] Exhibit DRA-8, p. 33.

[485] Exhibit SCE-7B, p. 60.

[486] Exhibit SCE-7B, p. 60.

DRA's forecast is equal to SCE's 2006 recorded costs, $20.210 million. DRA reasons that forecasted employee growth may not be as high as SCE projects and thus SCE's forecast is uncertain. TURN recommends rejecting SCE's increase on the ground that it would provide an unjustified windfall to SCE. Instead, TURN proposes a forecast of $20.535 million based on the same methodology (four-year average of past reserve expenses) used in SCE's 2006 GRC.[487]

We find that relying on our existing methodology for forecasting reserve expenses is reasonable. In addition, SCE fails to demonstrate the reasonableness of its proposed new forecasting methodology for Workers' Compensation reserves and of the amount of reserve expense it seeks from ratepayers. Accordingly, we reject Edison's proposal and, using the existing methodology, we adopt TURN's proposed four-year average of past reserve expenses, a TY 2009 forecast of $20.535 million.

6.13. Ethics and Compliance - FERC Accounts 920/921 and 923

SCE's TY 2009 forecast for Ethics and Compliance is $1.698 million (constant 2006$) for FERC Accounts 920/921 and $0.414 million (constant 2006$) for FERC Account 923, for a total forecast of $2.112 million (constant 2006$). SCE's 2006 recorded costs are $1.347 million. SCE describes the costs recorded to FERC Account 920/921 as, generally, overseeing the Ethics and Compliance Helpline and related investigations; implementing a program to ensure that employees understand relevant standards and how to raise concerns or seek

[487] TURN opening brief, p. 136.

advice; developing a standard Ethics and Compliance Code; and guiding business practices along ethical lines, identifying action that may be needed to limit the opportunity for non-compliance.[488] The primary costs recorded to FERC Account 923 are for the outside vendor that provides the company's helpline service and case management database, as well as costs for the outside consulting firm, Ethical Leadership Group, which has been retained to assist with the development of the company's ethics training, ethics communications, ethics and compliance review process, and other ethics-related matters, as needed.[489] SCE describes its use of a budget-based forecasting methodology for Ethic and Compliance as follows:

> "Given the relatively recent creation of the Ethics and Compliance Department, a budget based forecast methodology, based on the workforce we expect to have in place in 2009, has been used to establish reasonable base expense for FERC accounts 920 and 921 for the 2009 Test Year. The last recorded year forecast methodology has been used to establish a reasonable base expense for FERC account 923 for the 2009 Test Year."[490]

DRA recommends no ratepayer funding for Ethics and Compliance. DRA claims that because the increased costs incurred by this department are directly linked with the circumstances resulting in the Commission's fraud investigation of SCE's PBR, ratepayers should not have to cover these costs. DRA also argues that SCE's Ethics and Compliance Department appears to benefit shareholders,

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488 Exhibit SCE-7B, pp. 68-69.

489 Exhibit SCE-7B, p. 79.

490 Exhibit SCE-7B, p. 74.

and contributes to SCE's corporate image enhancement,[491] but has no defined ratepayer value. For these reasons, DRA recommends that SCE shareholders fund the Ethics and Compliance Department, not the ratepayers.

SCE seeks to justify its forecast, in part, by citing to compliance with the Sarbanes Oxley Act of 2002 and the Federal Sentencing Guidelines revised in 2002, but SCE fails to explain the costs associated with these functions or why these functions would contribute to SCE's requested incremental costs. Moreover, based on the record, it appears that the vast majority of these costs support SCE's response to unethical behavior highlighted in I.06-06-014, the Commission's Performance Based Ratemaking Investigation. The Commission adopted a final decision in I.06-06-014 on September 18, 2008, D.08-09-038, as we summarize above in our discussion regarding Results Sharing. Based on the Commission's finding that fraud occurred, it is reasonable to require SCE to bear the costs of addressing this problem, rather than the ratepayers. In the absence of any specific information regarding the costs associated with the functions of the department beyond addressing the events related to I.06-06-014, we reduce SCE's forecast by the full amount of the request, $2.112 million.

6.14. Regulatory Policy and Affairs Department – FERC Accounts 920/921

SCE estimates $13.414 million (constant 2006$) in 2009 TY O&M expenses for its Regulatory Policy & Affairs department, with a projected increase of

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[491] Exhibit DRA-30, p. 44. For example, in the Edison International/SCE Joint Notice of Annual Meetings of shareholders held in April 2006, the compensation committee concluded that the "key support" of the Chairman, President and CEO of EIX to substantially strengthen ethics and compliance efforts "…significantly contributed to Edison International's strong financial performance in 2005."

$1.471 million over 2006 recorded levels. SCE explains that this increase is primarily due to increased labor costs resulting from a substantial and continuing increase in regulatory workload. SCE's labor forecast includes seven new Full-Time Equivalent employees in 2009, as well as filling vacancies that existed at the end of 2006. In addition, Regulatory Policy & Affairs' TY 2009 forecast includes 100% of the salaries associated with the employees who work on Affiliate Transaction Rules compliance activities[492] and $0.209 million for the Spot Bonus program. We have addressed the latter issue elsewhere in this decision; accordingly, the latter amount is removed from the TY 2009 forecast.

DRA recommends the Commission reduce SCE's forecast by $169,000 by removing $0.038 million as a one-time severance payment and relying on a five-year average of the recorded data for both labor and non-labor. Recorded labor costs have been relatively stable during 2002-2008. As such, SCE has failed to adequately support its request of $1.471 million for its TY 2009 labor forecast. In this instance, we find it reasonable to rely on a five-year average of the recorded data for both labor and non-labor. In addition, we remove the one-time 2002 severance payment of $0.038 million as SCE does not dispute the one-time nature of this payment.

SCE estimates $0.285 million (constant 2006$) in 2009 TY O&M expenses for compliance with the Affiliate Transaction Rules by the Regulatory Policy & Affairs department. DRA recommends this amount be removed from the forecast, noting that the Commission excluded these amounts from revenue requirement in the 2006 GRC. In response, SCE contends that, for approximately

[492] Exhibit SCE-21, p. 72.

two decades, the Commission permitted SCE to recover these costs in rates and the Commission's reversal of policy on this matter in the 2006 GRC was not well-founded.[493] SCE asserts that ratepayers have an interest in SCE maintaining Affiliate Transaction Rule compliance.[494]

We affirm the policy set forth in the 2006 GRC and remove these compliance costs from the forecast. We disagree with SCE's argument that ratepayers should pay because SCE's compliance with these rules protects ratepayers. These compliance costs are incurred to support the operations of SCE's affiliates and, as such, requiring ratepayers to bear those costs would amount to a subsidy of those operations by ratepayers.

6.15. Financial Organizations

6.15.1. Controller's Central Services and Corporate Accounting Groups - FERC Accounts 920/921

SCE's Controller's Organization estimates $16.164 million (constant 2006$) in TY 2009 labor and non-labor expenses for its Central Services and Corporate Accounting groups.[495] DRA suggests removing $1,000 from the Central Services group based on its belief that SCE had requested $500 above the market reference point for a Business Analyst position.[496] It appears DRA's proposed adjustment is based on an error in SCE's workpapers that inadvertently understated SCE's forecast.[497] We find SCE's forecast reasonable.

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[493] Exhibit SCE-21, p. 73; Joint Comparison Exhibit, p. 520.

[494] Exhibit SCE-21, p. 73; Joint Comparison Exhibit, p. 520.

[495] Exhibit SCE-21, p. 1.

[496] Exhibit DRA-8, p. 8.

[497] Exhibit SCE-21, p. 1.

6.15.2. Audit Services - FERC Accounts 920/921

SCE estimates $9.254 million (constant 2006$) in TY 2009 O&M expenses for its Audit Services department, with a projected increase of $1.270 million over 2006 recorded levels. SCE explains this increase is primarily due to increased labor costs resulting from (1) auditing of new construction and systems, (2) an increased emphasis on energy efficiency, safety, and ethics programs, (3) new required compliance auditing, and (4) an increase in non-utility audits (refunded to ratepayers). SCE's labor forecast includes the addition of 7 new auditors by 2009, as well as the filling of current vacancies.[498]

DRA recommends $24,000 be removed from SCE's Audit Services department TY 2009 labor costs for non-recurring severance costs. DRA also proposes $513,000 be removed to reflect the difference between using last recorded year 2006 plus adjustments and a five-year average.

SCE agrees with DRA's proposal to remove $24,000.[499] We agree with DRA that expenses in years 2002-2006 have been relatively stable and SCE's reasons for expecting an increase of approximately 16% over 2006 base year lack specificity because SCE fails to sufficiently explain the nature of all the costs included in the 2006 base year. DRA's forecast is adopted. We also remove the $24,000 severance costs because their one-time nature makes them inappropriate for forecast purposes.

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[498] Exhibit SCE-21, p. 3.

[499] Exhibit SCE-21, p. 3.

6.15.3. Treasurer's Organization - FERC Accounts 920/921 and 930

SCE's Treasurer's Organization is forecasting $10.757 million (constant 2006$) for the TY 2009,[500] a 20.5% increase over SCE's 2006 recorded costs of $8.925 million.[501] SCE forecasts labor to increase by $548,455 for five new positions, inclusive of a 15% salary premium.[502] DRA does not address the need for additional employees but recommends $72,000 be removed from SCE's forecast of $548,455 for salary premiums that should not be funded by ratepayers.

We reject the requested increase insofar as it relates to additional employees. In large part, SCE justifies the five additional positions based on "SCE's unprecedented $17 billion capital investment program projected for 2007 through 2011…."[503] While SCE refers to increases in power procurement activities to justify these new positions, SCE does not quantify the extent to which these activities will rely on additional staff. For reasons we have explained in other parts of this decision, we do not authorize capital projects of the magnitude requested by SCE in this GRC. Accordingly, we find SCE's requested increases unreasonable and reject SCE's requested increase in labor of $548,455 and the related non-labor costs.

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500 Exhibit SCE-7A, p. 34.

501 Exhibit SCE-7A, p. 35.

502 Exhibit SCE-7A, pp. 39-40.

503 Exhibit SCE-7A, p. 39.

6.16. Tax Department

SCE's Tax Department forecasts $2.94 million (constant 2006$) for TY 2009,[504] a 25% increase over SCE's 2006 recorded costs of $2.347 million. SCE forecasts four additional tax specialists at labor cost of $558,400, inclusive of an 8% salary premium.[505]

DRA recommends $40,000 for salary premiums should not be funded by ratepayers. DRA argues that ratepayers should not have to pay salary premiums for new positions that will remain in rates indefinitely. Moreover, DRA states that, since SCE's Tax Department also functions as the EIX tax department and prepares consolidated tax returns for the entire EIX affiliated group, including SCE,[506] it is reasonable for shareholders to cover the costs of salary premiums. DRA does not contest the need for these additional tax specialists, just the salary premiums.

SCE testifies that, to the extent the Tax Department performs work for any entities other than SCE and its regulated subsidiaries, the costs are subject to the affiliate credit mechanism discussed in Exhibit SCE-11, Results of Operations. According to SCE, the mechanism ensures that ratepayers are only charged for costs related to the regulated utility.[507] SCE cites areas of increased work to justify its request for additional positions in the Tax Department, including new tax forms, new electronic filing requirements, new California audit requirements,

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[504] Exhibit SCE-7A, p. 46.

[505] Exhibit SCE-7A, p. 53.

[506] Exhibit SCE-7A, p. 47.

[507] Exhibit SCE-7A, p. 48.

and implementation of a new financial accounting standard for computing income taxes for publicly traded companies – FIN 48.

Based on the evidence presented by SCE, we find its request to include additional expenses in its TY 2009 forecast to reflect the need for increased labor reasonable, including the salary premiums. Accordingly, we adopt SCE's TY 2009 forecast.

6.17. Property and Liability Insurance

6.17.1. Corporate Property Insurance - FERC Account 924

SCE requested $10.042 million (constant 2006$) for property insurance for TY 2009, as compared to 2006 recorded expenses of $7.688 million. The request includes increases of $500,000 for Mountainview and $200,000 for additional SONGS accidental outage insurance. The remainder of the increase is predicated on growth in assets for which, in large part, SCE requests authorization in this proceeding.[508]

DRA does not dispute the forecasted additional costs for the requested $500,000 for Mountainview and $200,000 for additional SONGS insurance, but DRA claims SCE has not fully justified the rest of the requested increase. DRA recommends a total increase of $1.288 million.[509]

We approve the increases related to Mountainview and SONGS, which total of $700,000. Regarding the remaining increases, SCE states its forecast is reasonable because "SCE has justified an intense growth program throughout

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508 Exhibit SCE-21, p. 82; Exhibit SCE-7C, pp. 49-51.

509 Exhibit DRA-8, p. 48.

this application in order to serve our Customers."[510] SCE's assertion lacks sufficient specificity to support the additional amounts requested over 2006 base year of $7.688 million. Therefore, in this decision, we authorize an increase of $700,000 over 2006 recorded expenses.

6.17.2. Corporate Liability Insurance - FERC Account 925

SCE's forecast for Account 925 also includes $11.259 million for corporate liability insurance. The 2006 recorded amount is $9.137 million. SCE includes $78,000 for Mountainview's liability insurance and approximately $329,000 for hull insurance to cover any loss or damage to three additional helicopters requested in this proceeding. The estimated annual cost of hull insurance is at 7% of the value of the helicopters. The value of each helicopter is approximately $4.7 million each. With the exception of the materials presented regarding the helicopters and Mountainview, SCE's assertions in support of this requested increase lack sufficient specificity. Therefore, for the same reasons discussed previously, we adopt recorded 2006 amount of $9.137 million plus amounts for Mountainview and the helicopters. We find these additional amounts reasonable.

6.18. Corporate Communications – FERC Accounts 920/921, 923 and 930

SCE's TY 2009 forecast is $11.264 million (constant 2006$) for Corporate Communications A&G expenses. SCE claims the increase centers around three factors. First, 2006 recorded labor expenses were significantly below budget as

[510] Exhibit SCE-21, p. 82.

several positions remained vacant; also, additional Full-Time Equivalent employees are needed. Second, SCE is expanding its customer facing website. Third, SCE is increasing the frequency of bill inserts from quarterly to monthly. Corporate Communications provides information to SCE customers and other stakeholders (such as public officials, community organizations, and SCE's shareholders, business partners, and suppliers) on a variety of topics.[511] Corporate Communications also researches, develops, and facilitates the delivery of this information to a large and varied group of stakeholders, including residential and business customers, public officials, policymakers, the company's business partners and suppliers, community organizations, shareholders, and other key groups.[512]

6.18.1. Forecast Methodology - FERC Accounts 920/921

SCE used the last recorded year and then applied a future year adjustment for its forecast. SCE determined 2006 was the most representative year and added $657,579 to include eight additional Full-Time Equivalent employees that were authorized in the 2006 GRC decision but never filled due to retirement and attrition.[513] DRA suggests using a five-year average is more appropriate due to the fluctuating nature of the historical costs.[514] In this instance, we prefer SCE's methodology over DRA's because DRA fails to explain why we should take into account these historical fluctuations.

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[511] Exhibit SCE-7C, p. 27.

[512] Exhibit SCE-7C, p. 27.

[513] Exhibit SCE-7C, pp. 32-33.

[514] Joint Comparison Exhibit, p. 506.

DRA also recommends removal of any one-time severance payments, but SCE explains it has effectively removed severance payments from its forecast because 2006 recorded costs do not include any severance payments. DRA also contests the costs associated with SCE's Spot Bonus program. We address SCE's Spot Bonus program in a separate section of this decision. Accordingly, we find SCE's forecast reasonable as adjusted to reflect our findings on Spot Bonuses.

6.18.2. Design Costs - FERC Account 930

SCE estimates $1.465 million in TY 2009 FERC Account 930, which includes the expenses for communications products, including the production, design, and distribution of customer information booklets, brochures, and notices. SCE used the last recorded year and then applied a future year adjustment for its forecast. SCE anticipates these communications costs to remain relatively stable and consistent with 2006 expenses with the exception of an increase of $75,000 in TY 2009 due to an increase in design costs to support customer bill inserts.[515] As above, DRA suggests a five-year average. DRA would also normalize the increased design costs of $75,000. We find SCE provides sufficient evidence to support its claim that 2006 recorded costs are representative of future costs with the addition of the increased design costs. Accordingly, we find SCE's forecast reasonable.

6.19. Power Procurement Business Unit

The Power Procurement Business Unit, the organization responsible for buying and selling power, has four departments: Market Strategy and Resource Planning, Energy Supply and Management, Renewable and Alternative Power,

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515 Exhibit SCE-21, p. 79.

and Power Procurement Finance. SCE forecasts $52,664,000 (excluding Account 926/Pension and Benefits) of A&G expenses for TY 2009. DRA's estimate is $38,206,000,[516] consisting of $2,760,000 for Market Strategy and Resource Planning; $17,403,000 for Energy Supply and Management; $7,348,000 for Renewable and Alternative Power; and $10,696,000 for Power Procurement Finance.

6.19.1. MRTU New Software Applications – FERC Accounts 920/921 and 923

SCE's forecast for its Power Procurement Business Unit includes certain MRTU expenses. Regarding MRTU expenses in general, DRA recommends that costs associated with implementation of MRTU be recorded in the MRTU memorandum account. We address the appropriateness of the memorandum account in a separate section of this decision.

Regarding the amount of these forecasted expenses, SCE forecasts additional O&M costs associated with a new software application of $8.191 million.[517] DRA proposes a reduction of $3.289 million to SCE's TY 2009 forecast for new software to reflect information technology costs associated with MRTU. DRA also proposes various additional reductions to FERC Accounts 920/921 to reflect the removal of MRTU-related costs to the memorandum account.

DRA and SCE disagree on the exact amount of additional expenses related to MRTU but SCE agrees that the costs related to MRTU forecasted in FERC

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516 Exhibit DRA-10, p. 3.

517 Joint Comparison Exhibit, p. 537.

Accounts 920/921 are approximately $5.448 million[518] and $598,000 in FERC Account 923.[519] Regarding DRA's estimate, SCE explains that even if DRA's proposal to remove MRTU-related costs from the GRC was appropriate, DRA's adjustment is incorrect as it includes amounts not related to MRTU.[520]

As we discuss in more detail in a separate section of this decision, we find that labor and non-labor expenses related to MRTU should continue to be recorded in the memorandum account. We also find it appropriate to include all amounts related to MRTU, including outside services recorded to FERC Account 923, in the memorandum account. Accordingly, we adopt DRA's recommended reduction of $3.289 million[521] in information technology MRTU-related costs and an additional approximately $5.448 million to FERC Accounts 920/921. Similarly, SCE's TY 2009 forecast in FERC Account 923 is reduced by $598,000. SCE's update testimony forecasts additional increases associated with O&M expenses for MRTU implementation. The increase to O&M expenses is $1.109 million (constant 2006$)[522] for TY 2009. We adjust our adopted figures accordingly.

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[518] Joint Comparison Exhibit, pp. 535-539.

[519] Joint Comparison Exhibit, pp. 540-542.

[520] SCE opening brief, p. 131.

[521] Exhibit SCE-22, pp. 2-3; Joint Comparison Exhibit, p. 537. SCE increased this amount to $4.397 million in the September 4, 2008 update testimony, Exhibit SCE-54, p. 19.

[522] Exhibit SCE-54, p. 19.

6.19.2. Power Procurement Business Unit - FERC Accounts 920/921 and 923

In addition to the MRTU-related adjustments to SCE's forecast for the Power Procurement Business Unit,[523] DRA recommends the Commission limit SCE's increase above base year 2006 costs. SCE's TY 2009 forecast, represents an increase over 2006 recorded expenses of approximately $16.8 million or 60%. DRA asserts SCE fails to adequately describe the increasing workload and the need for additional employees to meet that workload by 2009.[524] We agree. While SCE claims its forecast is based on the additional staff needed by 2009 to meet rapidly expanding workload, the information provided is not sufficient to justify an approximately 60% increase in costs. DRA's recommendation is consistent with SCE's historical trend for increased costs for 2002-2006.[525] Accordingly, we adopt DRA's recommendation and authorize an increase of approximately 30% ($8.409 million), rather than 60%.

6.20. Risk Control – FERC Accounts 920/921 and 923

The Risk Control Group provides risk governance and oversight over the procurement activities of the Power Procurement Business.[526] SCE's TY 2009 forecast is $4.465 million (constant 2006$) for labor in FERC Account 920 and $0.824 million (constant 2006$) for non-labor in FERC Account 921. SCE's 2006 recorded expenses for Risk Control are $2.240 million for Account 920 and

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[523] Joint Comparison Exhibit, p. 539.

[524] Exhibit DRA-10, pp. 8, 12, 18, and 22.

[525] SCE opening brief, p. 131.

[526] Exhibit SCE-7A, pp. 66-70.

$0.215 million for Account 921. SCE uses year 2006, the last recorded year, for its labor forecast plus future year adjustments.

TURN recommends reducing SCE's estimate of risk control-related expenses by $2,383,000 to maintain staff at 25 Full-Time Equivalent employees and to remove costs for certain consulting expenses, which TURN finds unnecessary based on its productivity analysis.[527] In response, SCE claims the productivity metric offered by TURN is not a valid measurement for determining staffing levels, as the proposed metric does not consider the size, complexities, risks or dollar impact of the transactions.[528]

TURN's metric is sufficient to demonstrate that the record fails to support SCE's request. Consequently, regarding FERC Account 920, we find SCE's request unreasonable based on declining productivity, and we adopt TURN's recommendation. We authorize SCE to increase its Full-Time Equivalent employees up to 25, but we reject SCE's proposal to add 15 additional staff.[529] Regarding non-labor expenses, TURN recommends $651,000 for FERC Account 921, a reduction of $173,000. To reflect our findings related to labor, we adopt TURN's recommendation regarding FERC Account 921.

SCE also forecasts $0.600 million in expenses in Account 923, Outside Services, to address increased needs for recruiting services to fill positions within the Risk Control Group, and to provide consulting services to establish a framework for its Enterprise Risk Management program.[530]

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527 TURN opening brief, pp. 150-151.

528 Exhibit SCE-21, p. 25.

529 Exhibit TURN-5A, p. 109.

530 Exhibit SCE-7A, p. 60

SCE's 2006 recorded expenses are $285,000.[531] TURN recommends reducing SCE's figures by $150,000 for consulting related to the Enterprise Risk Management program that will be complete before TY 2009, and by $176,000 for recruitment consulting to reflect the reduced staffing forecast, for a total reduction of $326,000. TURN's adjustments result in a forecast of $274,000 for this account. We agree with TURN and adopt its recommended adjustments to SCE's forecast.

6.21. Operations Support Business Unit – FERC Accounts 920/921 and 923

SCE requests $78.095 million in TY 2009, an increase over 2006 recorded expenses of $48.008 million[532] SCE relies upon a budget-based estimating method for this forecast.[533] SCE's Operations Support Business Unit supports other SCE business units, such as T&D, Customer Service, and Generation.[534]

Currently, Operations Support Business Unit consists of seven "business lines," which perform different functions within this Unit. For example, Business and Organization Support assists other areas of SCE with drawing management, maintaining the corporate records center, information management, and mailing services.[535] Other functions fall under Corporate Real Estate, which is responsible for all activities related to the management of SCE property and buildings, including the planning, design, construction and

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[531] Exhibit SCE-7A, p. 83.

[532] Exhibit SCE-10A, pp. 2-5.

[533] Exhibit SCE-23, p. 5; Exhibit SCE-10A, pp. 19, 22, 26, 60.

[534] Exhibit SCE-10A, p. 1.

[535] Exhibit SCE-10A, p. 6.

maintenance of 171 non-electric facilities, and which also manages the procurement, sale, and maintenance of all real property owned by SCE.[536] SCE explains this "support" function by stating that Operations Support's employees do not generally interact directly with SCE's customers but, instead, work "behind the scenes" to support other SCE business units.[537]

In direct testimony, SCE summarizes its proposed increases as follows:

2006 Recorded/Adjusted	**Test Year 2009 Forecast**[538]
Accounts 920/921 $31.161 Million	$41.658 Million (constant 2006$)
Account 923 $ 0.118 Million	$ 0.630 Million
Account 925 $ 2.723 Million	$ 4.019 Million
Account 931 $ 6.396 Million	$11.361 Million
Account 935 $ 7.610 Million	$24.397 Million

In support of the increase, SCE asserts that over the past few years, it has experienced unprecedented growth in both new customers and system load, exceeding its authorized spending levels. This has resulted in corporate-wide reallocation or deferral of funding from other projects, and has caused a strain on workforce capacities.[539]

DRA recommends reducing SCE's request to $62 million for TY 2009.[540] TURN makes a number of recommendations to reduce SCE's forecast in

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536 Exhibit SCE-10A, p. 27.

537 Exhibit SCE-10A, p. 1.

538 Exhibit SCE-10A, p. 3. In rebuttal testimony, SCE reduced this initial forecast of $82.065 million by a total of approximately $4 million.

539 Exhibit SCE-10A, p. 1.

540 Exhibit DRA-7, p. 75.

Accounts 920/921 and 923 based on, among other things, SCE's use of a budget-based approach to forecasting which TURN claims is inherently flawed.[541]

We find that DRA and TURN present compelling arguments for reductions. Also, we are concerned with an overarching flaw in SCE's analysis. As TURN points out, SCE relies on budget-based forecasting here. As a result, at least in this instance, SCE presents an unreliable forecast. Based on the record, we cannot identify the full impact of this budget-based forecasting on SCE's specific recommendations. Accordingly, we find the most reliable data to be 2006 recorded expenses for the Operations Support Business Unit, which is $48.008 million and find it reasonable to adopt this amount for TY 2009. SCE's forecast is reduced accordingly.

7. Depreciation

The purpose of depreciation is to recover the original cost of the asset, as well as the net salvage value, over the life of the asset. Thus assets are paid for by the customers who benefit from their use. Under straight line depreciation, the annual depreciation amount and rate are shown by the following formulas:

Annual depreciation = (original cost-net salvage) /asset life

Depreciation rate = annual depreciation/original cost x 100%

Under this method, the annual depreciation is set once and the depreciation remains uniform over the life of the asset. This method works well for a single asset where the net salvage value and life are known in advance. However, depreciation is done by account where there are multiple assets of

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541 TURN opening brief, pp. 155-160.

various ages. In this case most of the assets are partially depreciated, and the useful lives and net salvage vary and are not certain.

As a result, the Commission has historically used a variation of this method called straight line remaining life depreciation. Under this method, the undepreciated asset amount (original cost less accumulated depreciation plus the estimated net salvage) is depreciated over the remaining life of the asset. The net salvage includes the cost of removal of the asset at the end of its useful life as well as any salvage value the asset may have at that time. The original cost of the asset and the net salvage are expressed in nominal dollars. For example, if the end of an asset's useful life is 2010, the net salvage would be expressed in nominal 2010 dollars. Likewise, if the asset was put into service in 2000, its original cost would be in nominal 2000 dollars.

TURN does not oppose SCE's remaining life estimates and accepts SCE's future net salvage estimates.[542] However, TURN provides a different proposal as to how the net salvage value is determined. TURN states that the escalation of net salvage costs has far exceeded inflation.[543] As a result, TURN proposes that net salvage be based on the estimated net salvage that would be incurred if the asset is retired during the test year rather than an estimate of the net salvage cost that will actually be incurred at the end of the asset's life.[544] TURN claims the future effects of inflation on net salvage would be recovered in future depreciation rates.[545]

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542 TURN opening brief, p.163.

543 TURN opening brief, p. 168

544 TURN opening brief, p. 170.

545 TURN opening brief, pp. 170-171.

Under TURN's proposal the net salvage value used to calculate depreciation rates would be calculated as the present value of the estimated future net salvage costs.[546] The present value of a future cost is the amount of money that would have to be invested at a specified interest rate to pay the future cost at the time it is incurred. The basic assumption of a net present value calculation is that the present value amount will earn interest sufficient to accumulate the future amount by the future date the cost is incurred. However, depreciation is recorded in the depreciation reserve at the nominal amount and does not earn interest. As a result future ratepayers will have to make up the shortfall. TURN acknowledges that future ratepayers will pay more in inflated nominal dollars.[547] The fact that the future nominal dollars would be inflated does not address the fact that future ratepayers would be paying what is essentially the interest on the amount paid by past ratepayers in addition to their share of such future costs. Additionally, TURN appears to assume that future ratepayers will have more of the inflated dollars to pay with. This, in turn, assumes that ratepayers' incomes keep up with inflation. The record does not demonstrate that this is necessarily the case, particularly with respect to ratepayers who are on fixed incomes.

Another consequence of TURN's proposal is that current ratepayers will have to pay a return on a larger rate base and income taxes on the larger return.[548] This would offset to some degree the current ratepayer benefit of lower

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[546] TURN opening brief, p. 170, Exhibit TURN-1, p. 25.

[547] TURN reply brief, pp. 45-46.

[548] Since income tax depreciation would not be affected by TURN's proposal, any increased return paid by ratepayers would be fully taxable.

depreciation. In addition, the depreciation reserve would be smaller in the future resulting in a larger rate base with resulting increased return and taxes.

Under the current method, current ratepayers do pay more for net salvage on a net present value basis than future ratepayers. However, this is offset by the fact that rate base is correspondingly reduced, due to a larger depreciation reserve, now and into the future. This means that current ratepayers will pay a smaller return on rate base and less income tax on that return. In the future, ratepayers will continue to pay a smaller return on rate base, less income taxes on that return, and less depreciation expense.

On balance, the record does not demonstrate TURN's proposal is superior to the Commission's longstanding depreciation rate calculation methodology and it is not adopted.

DRA does not oppose SCE's remaining life estimates, but DRA opposes SCE's future net salvage estimates and recommends SCE retain current net salvage estimates.[549] DRA did not perform an account-by-account analysis of depreciation rates.[550] Instead, its recommendations are based on policy reasons.[551] Some of the reasons cited by DRA for its proposal are that (1) SCE has collected $2.7 billion in rates for future costs of removal that is yet to be spent;[552] (2) compared to other California utilities, SCE's current net salvage rates rank among the highest;[553] and (3) for other utilities, net salvage rates have or will

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[549] DRA opening brief, pp. 177, 182-183; Exhibit DRA-18, p. 4.

[550] Exhibit DRA-18, p. 4.

[551] Exhibit DRA-18, p. 4

[552] Exhibit DRA-18, p. 12.

[553] Exhibit DRA-18, p. 13.

remain unchanged for more than the traditional 3-year GRC cycles due to the adoption of longer GRC cycles.[554]

The fact that SCE has accumulated a depreciation reserve attributable for recovery of net salvage in excess of expenditures is no surprise. One of the purposes of depreciation is to accumulate a reserve to fund future net salvage before the expenditures actually occur.

Likewise, the fact that SCE's net salvage rates may be higher than other utilities' rates or that other utilities' net salvage rates may remain unchanged for several years does not mean that SCE's rates are unreasonable. Nevertheless we take the net salvage rates of other utilities into consideration as part of our determination of reasonableness.

DRA's further explanation for its recommendation is the following: "SCE currently accrues negative net salvage at a level sufficiently higher than the annual recorded cost of removal, so the utility will continue to accrue net salvage costs at a positive rate even without the requested increase. Therefore, DRA is recommending that a conservative approach be adopted in addressing this issue which in this case is to retain the negative salvage rates adopted in D.06-05-016, SCE's last GRC."[555]

DRA states recovery of net salvage "is not a critical requirement that impacts the utility's ability to provide safe and reliable services to its customers and therefore is one area where the requested rate increase may be mitigated

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554 Exhibit DRA-18, p. 11.

555 Exhibit DRA-18, p. 16

with no risk or adverse impact to the utility and its shareholders."[556] DRA further states that "SCE and its shareholders are never at risk for cost of removal and are always made whole whether or not the final cost of removal exceeds or is below the amount accrued in the reserve account."[557]

DRA's primary concern appears to be to retain the previously adopted net salvage rates in order to keep SCE's electricity rates down. Based on the current economic downturn, DRA's policy recommendation has merit. SCE performed a comprehensive depreciation study and its proposed depreciation rates were derived following the Commission's longstanding methodology.[558] We find SCE's methodology reasonable but, in an effort to mitigate SCE's requested rate increase, we will retain the net salvage rates adopted in D.06-05-016. Prior to the TY 2006 GRC, the Commission did not modify net salvage rates for approximately 10 years. We will review SCE's net salvage rates in SCE's next GRC. SCE's remaining lives and future net salvage values are not opposed by TURN. As discussed above, DRA does not oppose SCE's remaining lives but does oppose its future net salvage estimates.

DRA also recommends that SCE provide the following information in its next GRC filing:[559]

- The most current balance of pre-funded removal costs.

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[556] Exhibit DRA-18, p. 17.

[557] Exhibit DRA-18, p. 10.

[558] Exhibit SCE-11D, SCE's depreciation study.

[559] Exhibit DRA-18, p. 18.

- A year-by-year projection of (1) when the then-existing balance of pre-funded removal costs will be consumed, and (2) the implicit inflation rate for asset removal costs.
- A five-year projection of the year-end balance of pre-funded removal costs showing for each year the gross additions to the balance, gross expenditures for removal costs, and the net change in the balance of pre-funded removal costs.

DRA states that its request is reasonable because the Commission has imposed similar requirements in previous rate cases. Since DRA is proposing these reporting requirements, it has the burden of demonstrating the usefulness of the requested information. SCE's estimated escalation rates for net salvage would be included in the portion of SCE's GRC workpapers pertaining to future net salvage. As to the other information, DRA has not explained the purpose of the requested information or how the requested information would be used to achieve that purpose. In addition to the above, DRA recommends the Commission require SCE to identify the accruals for cost of removal separately from accruals for depreciation expense in its next annual depreciation rate filing.[560] Here again, DRA has not explained the purpose of the requested information or how the requested information would be used to achieve that purpose. For the above reasons, we do not adopt DRA's proposal. However, by rejecting the proposal, we do not intend to restrict DRA's ability to conduct future discovery.

[560] Exhibit DRA-18, p. 18.

8. Rate Base, Plant-In-Service, and Capital Expenditures

8.1. General Plant-In-Service Issues - Plant Weighting

SCE forecasts a 2009 plant weighting factor of 50.27%. DRA recommends that, after adjusting for two atypical projects, the weighting factor should be no higher than 42.554%.[561] DRA excluded both the Mohave Decommissioning Project and the Enterprise Resource Planning Program from its calculation. These two projects are scheduled to be booked to plant very early in 2009. Because they are atypical projects, totaling over $315 million, they are likely to have a noticeable impact on the weighting percentages.

SCE, acknowledging that atypical projects have an impact on the plant weighting factor, excluded the largest atypical project, the Enterprise Resource Planning Program, from its plant weighting calculation to demonstrate the impact on the overall weighting factor. SCE shows that if the Enterprise Resource Planning Program is excluded from the weighting calculation, its plant weighting factor is 43.57%, a difference of 1.016% from DRA's recommended 42.554%.[562] SCE argues that the 43.57% weighting factor is close to the 42.554% nine-year historical average adopted in SCE's 2003 GRC and to the 41.16% weighting factor adopted in its 2006 GRC.[563]

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561 The weighting percentage of plant is a function of timing of plant additions and retirements. When an asset is placed in service or retired, the costs are added to or removed from the Plant-In-Service balance. Hence, the timing of additions and retirements needs to be considered so that assets are not placed into rate base prematurely or delayed from the time they are actually retired from service.

562 Exhibit SCE-24A, p. 49.

563 Exhibit SCE-24A, p. 49

In prior decisions for SCE, the Commission has found that a 42.554% weighting percentage for plant weighting is reasonable. In D.04-07-022, the Commission stated the following in adopting the 42.554% weighting factor:

> Notwithstanding SCE's claims that its method is more rigorous and sophisticated, and is based on the intimate knowledge of business unit managers, SCE has not demonstrated that rigor, sophistication, and intimacy yield more accurate and reliable forecasts than the historical record. SCE improperly attempts to shift the burden of proof to ORA in this GRC by pointing out that ORA provided no conclusive explanation of why an average of historical weighting percentages better represents the plant weighting than a detailed budget. The more pertinent question, not adequately addressed by SCE, is why its budget-based approach, which suffers from the problem that budgets are not always carried out as planned, is necessarily more accurate and reliable than data based on actual performance over an extended period.[564]

In this GRC, SCE's increased levels of proposed capital expenditures make more problematic the ability of SCE to meet its construction completion forecasts. We also note that in SCE's 2006 GRC, the adopted overall weighting percentage of 41.16% was even lower than the 42.554% previously found reasonable. Moreover, the inclusion of atypical projects in the calculation of a plant weighting factor has a significant impact on the overall weighting factor, a result acknowledged by SCE and shown by the results of SCE's supplemental calculation which excluded the Enterprise Resource Planning Program.[565] As a result, such projects should not be included in calculating the plant weighting factor. Therefore, consistent with previous Commission decisions, and after

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[564] D.04-07-022, p. 236.

[565] Exhibit SCE-24A, p. 49

excluding the two atypical projects, DRA's recommendation to use a plant weighting factor of no higher than 42.554% is reasonable and should be adopted.

8.2. Generation Capital

8.2.1. Nuclear Generation

SCE requests $49.2 million in capital expenditures for SONGS 2 & 3 in TY 2009. DRA does not oppose SCE's forecast.[566] However, DRA's Results of Operations model reduced the nuclear generation plant category by $9.9 million, of which $5.9 million was applicable to SONGS 2007 costs and $4 million to Palo Verde.[567] DRA identified in Exhibit DRA-73 the $5.9 million SONGS 2007 cost as the difference between SCE's 2007 forecasted and actual SONGS costs. DRA also identified $34.3 million in prior years SONGS capital expenditures that have been deferred. There is no mention of Palo Verde capital expenditures in the exhibit. Further, there is no recommended adjustment in Exhibit DRA-73 or in the Exhibit's summary of recommendations. Because SCE's forecast appears uncontested, SCE's capital expenditures forecast for SONGS and Palo Verde should be adopted.

8.2.2. Coal Generation

SCE requests $39.2 million (SCE share) in test year 2009 capital expenditures for Four Corners. The majority of this cost is for reliability, environmental and safety projects. SCE also requests $56 million to decommission its Mohave plant.

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[566] Exhibit DRA-73, p. 8.

[567] SCE opening brief, pp. 148-149. The Palo Verde costs consist of $3.1 million for 2007 and $0.9 million for 2010.

8.2.2.1. Four Corners

Included in the $87.1 million TY 2009 (SCE 48% share is $39.2 million)[568] request for Four Corners is $6 million (SCE share) per year 2009-2011 for "Future Reliability Projects Unallocated." SCE derived this estimate by multiplying the estimated cost of other specifically identified reliability projects by a 10% contingency factor.[569] The $6 million is to be used to fund short-noticed capital projects that are sudden and unforeseen. SCE notes this 10% contingency factor is lower than the 15% contingency factor SCE requested and was authorized in its 2006 GRC. SCE explains that it used this lower 10% contingency factor because it has increased its efforts with APS to better identify future project needs.[570]

DRA contends that the requested $6 million for unforeseen short-noticed projects is excessive based on SCE's annual level of unanticipated reliability-related capital projects, which included $0 for 2007 and $553,000 for 2008. DRA further contends that a 10% contingency factor is unwarranted because SCE already includes an 8.7% contingency in its capital expenditures forecast on all of its specifically-identified projects.[571] According to DRA, SCE's application of a 10% contingency on total project estimates, which already includes an 8.7% contingency factor, effectively provides a "contingency for contingencies" and results in a contingency reserve in excess of 18.7% for specifically identified reliability projects.

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568 Exhibit SCE-16C, p. 1.

569 Exhibit SCE-16C, p. 20.

570 Exhibit SCE-16C, p. 20.

571 Exhibit SCE-16C, p. 21.

Based on SCE's increased efforts with APS to better identify future project needs, we find no justification to set aside an additional 10% contingency reserve for unforeseen short-noticed projects at this time.

Moreover, in R.06-04-009[572] we are considering whether the future capital expenditures identified by SCE associated with its ownership share of Four Corners are allowable under Pub. Util. Code § 8341(d)(1). Because R.06-04-009 is pending, we do not address any of SCE's requested Four Corners capital expenditures for 2009-2011. The issue of whether any Four Corners capital expenditures shall be authorized will be decided in R.06-04-009. Accordingly, we remove $39.2 million (2009) $47.089 million (2010) and $27.398 million (2011) from SCE's forecasted capital expenditures. In R.06-04-009, we will also address the issue of whether the revenue requirement authorized in this decision must be modified to include additional capital expenditures related to Four Corners as a result of the rulemaking. In addition, we may also need to consider whether amounts included in the rate base adopted in this decision should be reduced prospectively to reflect the disallowance of certain Four Corners capital expenditures incurred after the effective date of D.07-01-039.

8.2.2.2. Mohave

SCE forecasts its total share of Mohave decommissioning cost at $55.769 million. SCE's Mohave decommissioning TY 2009 estimate includes $12.8 million or 30% in contingency reserves.[573] The basis of SCE's Mohave

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[572] *Order Instituting Rulemaking to Implement the Commission's Procurement Incentive Framework And to Examine the Integration of Greenhouse Gas Emissions Standards into Procurement Policies* (filed April 30, 2006).
[573] Exhibit SCE-2K, p. 66.

Decommissioning Project cost estimate is SCE's preliminary engineering completed to date.[574] SCE explains that contingency is a standard practice throughout the industry and standard practice in the cost estimating of government construction projects, as noted by the U.S. Department of Energy in publication DOE G-430.101.[575]

Regardless of whether a standard practice exists throughout the industry of providing for contingencies, DRA recommends the disallowance of SCE's 30% contingency. DRA cites to SCE's testimony that SCE will ultimately only collect in rates the final actual cost of the decommissioning through the operation of its Mohave Balancing Account.[576]

There is no dispute that Mohave expenditures are subject to a two-way balancing account approved in SCE's 2006 GRC.[577] There is also no dispute that the inclusion of contingency in some circumstances is standard practice throughout the industry. However, in this instance, SCE has an established balancing account to ensure that SCE recovers its reasonable and necessary costs related to the Mohave decommissioning. Such a balancing account is not consistent with what SCE describes above as standard industry practice. This balancing account fully mitigates the need to provide for a 30% contingency reserve. SCE's TY 2009 $12.8 million Mojave contingency reserves are disallowed.

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[574] Exhibit SCE-16C, p. 23.

[575] Exhibit SCE-16C, p. 23.

[576] Exhibit DRA-6, p. 21.

[577] Exhibit SCE-16C, p. 23.

8.2.3. Hydroelectric Generation

8.2.3.1. Big Creek and Poole Housing Projects

Three adjustments to SCE's Big Creek Housing Project forecast have been proposed. DRA recommends and TURN concurs that the $0.440 million earmarked in the 2009 capital forecast for the construction of new apartments at Big Creek be excluded. TURN also recommends a $0.462 million or 40% overall reduction to SCE's housing capital forecast. TURN's recommendation includes a $1.733 million increase in the overall budget for additional capital improvements, contingent upon SCE's capitalizing the Big Creek housing repairs instead of expensing as proposed in the application.

DRA recommends excluding new apartments at Big Creek because it opposes any expansion of SCE's hydro staff.[578] However, SCE contends that it needs additional housing at Big Creek regardless of whether its hydro staff is increased to retain and replace retiring staff. SCE explains this is because SCE has company housing for only 83 of its 155 employees located at its remote Big Creek site. Other employees unable to find near-by affordable housing must now travel long distances.[579]

SCE's proposed new apartments at Big Creek will mitigate SCE's difficulty in recruiting and retaining employees in this remote location and the need for employees to travel long distances in the absence of affordable local housing. We find SCE's explanation reasonable and do not adopt DRA's recommended reduction.

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578 Exhibit DRA-73, p. 26, DRA opening brief, p. 195.

579 Exhibit SCE-16D, pp. 54-55.

TURN's 40% recommended reduction in the Big Creek housing refurbishment capital projects (2008-2011) was accepted by SCE.[580] Hence, SCE's housing capital budget should be reduced by $0.462 million in 2009, $0.176 million in 2010, and $0.400 million in 2011.

TURN's remaining adjustment is a $1.773 million increase in SCE's housing capital projects contingent upon SCE capitalizing the Big Creek housing repairs that SCE seeks to expense in Account 542.[581] Consistent with our finding in a separate section of this decision regarding Hydro O&M for SCE's Big Creek repairs, SCE's housing capital projects are increased by $1.773 million for TY 2009.

IAG recommends a $0.1 million reduction to SCE's capital forecast designated by SCE for removal of asbestos siding at its Poole housing unit.[582] SCE clarified that the term "siding" was an abbreviation to reference all of the work to the Poole housing unit. This project encompasses replacement of the existing roof containing asbestos and the application of a coating to the exterior of the building to mitigate spalling (chunks of concrete at the surface popping off) due to the freeze and thaw cycles encountered during winter.[583] Based on this clarification, the $0.1 million Poole Housing Project is reasonable.

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580 Exhibit SCE-6D, pp. 53-54.

581 Exhibit TURN-5A, p. 40.

582 Exhibit IAG-1A, pp. 48-50.

583 Exhibit SCE-16D, p. 52.

8.2.4. California Independent System Operator & Western Energy Coordinating Council Projects

SCE proposes approximately $2.8 million in unidentified projects to respond to the CAISO and Western Energy Coordinating Council (CAISO/WECC) requirements. TURN recommends a 50% reduction to SCE's CAISO/WECC projects. SCE agrees to reduce the cost of its CAISO/WECC projects by $1.397 million or 50% for the years 2008 through 2011.[584] We therefore reduce the costs for SCE's CAISO/WECC projects by $0.412 million in 2008, $0.266 million in 2009, $0.438 million in 2010, and $0.282 million in 2011.

8.2.5. Hydro Project Benefit/Cost Ratio

SCE includes small hydro refurbishment projects in its TY 2009 capital budget. These projects include refurbishment or replacement of circuit protection and transformers. The projects also include water turbine refurbishment and replacement of turbine shut-off valves, runners or seals, wicket gates, and governors. SCE identifies these projects based on the condition of the equipment, consideration of replacement prior to the equipment failing while in service (which can damage adjacent equipment), and a benefit-cost analysis.[585]

TURN disagrees with the method SCE uses for its benefit-cost analysis. One problem TURN identifies is that when SCE undertakes a project benefit-cost analysis at a multiple unit hydro turbine plant, the amount of energy loss may be less than SCE estimates if only one turbine cannot operate and SCE is still able to

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[584] Exhibit SCE-16D, p. 44.

[585] Exhibit SCE-16D, p. 63.

operate the remaining turbines.[586] From TURN's own benefit-cost analysis on select SCE projects, TURN concludes that where SCE calculated a benefit-cost ratio of 2.0 or less (2.2 or less with energy production under 25000 MWh per year), proper analysis would yield ratios of only 1.3 or less. TURN recommends removing 12 hydro refurbishment projects totaling $2.768 million from SCE's TY 2009 capital forecast.[587]

SCE's and TURN's recommendations are based on different assumptions of how long equipment can run without replacement before a catastrophic failure occurs. We find SCE's method of assessing its equipment condition, its ongoing maintenance program, its economic analysis (which considers how long an equipment outage will occur, how much customers save if the equipment replacement is delayed, and how long the equipment can run before the equipment fails) and its policy of not running equipment to failure are reasonable.[588] Further, as cited by TURN, projects in which the benefit-cost ratio falls below 2.0 can be approved when the additional replacement is required for safety or other regulatory reasons, or when the benefit-cost ratio is above 1.0 and there is a high degree of confidence in the assumptions used in the benefit-cost calculation.[589] Accordingly, we reject TURN's recommendation to remove 12 hydro refurbishment projects from SCE's TY 2009 small hydro refurbishment projects capital forecast.

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[586] Exhibit TURN-5A, p. 36.

[587] Exhibit TURN-5A, p. 38.

[588] Exhibit SCE-16D, pp. 59-72.

[589] Exhibit TURN-6, Attachment 6.

DRA recommends SCE be required to evaluate the cost-effectiveness of its continued investments in small hydro projects in its next GRC.[590] DRA makes this recommendation because SCE includes capital improvements in this proceeding to its small hydro projects with capacity factors ranging from 15% in 2002 to 75%. According to DRA, these projects appear to be just barely cost-effective, and DRA expresses concern that SCE did not undertake a cost benefit analysis or consider decommissioning any of the projects.[591]

SCE contends DRA's cost-effectiveness recommendation is unnecessary because the requested analysis can be undertaken through the normal GRC discovery process. While the GRC discovery process provides a means for DRA to obtain the necessary information to evaluate the cost effectiveness of SCE's small hydro projects, we find it to be more efficient to require SCE to provide this information as part of its next GRC application.

8.2.6. Lundy Powerhouse Project

SCE includes $2.4 million in its 2007-2011 capital forecast to modify its 3 MW Lundy Powerhouse which discharges water to Wilson Creek. This project entails the upgrading of an earthen ditch from the Lundy Powerhouse to Mill Creek either by application of concrete gunite or by installing a new parallel pipeline to handle the flow rates now mandated.[592] This project is opposed by IAG and TURN.

[590] Exhibit DRA-73, p. 25.

[591] Exhibit DRA-73, pp. 24-25.

[592] Exhibit SCE-2M, p. 82.

SCE has not yet made a formal project design request from its in-house engineering and technical services group.[593] Therefore, SCE does not know whether the project will require gunite, plastic pipe, steel pipe, or something else. Upon completion of the project engineering, which SCE expects to occur in mid-2009, SCE must then submit the project plans to five agencies for review. These agencies include FERC, U.S. Fish & Wildlife, U.S. Forest Service, U.S. Bureau of Land Management, and the County of Mono. The project plans may also need to be submitted to two additional agencies for review, the U.S. Army Corp of Engineers and California State Water Resources Control Board.[594]

SCE did not provide a specific time when it intends to actually undertake this project. However, given that project engineering is not expected to be completed until mid-2009 and that it must then undergo review by at least five separate agencies, we doubt this $2.4 million project can even be completed prior to the 2011. Therefore, this project is excluded from SCE's forecasted capital expenditures.

8.2.7. Gas-Fired Generation

SCE forecasts $34.646 million in capital expenditures for its five peakers. Of this amount, there is a disagreement on $26.237 million, of which $19.134 million pertains to the purchase and installation of new service air and back-up gas compressors at each of its peaker sites for system reliability, and $7.103 million pertains to purchase of a spare combustion turbine.

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[593] RT Vol. 8:578.

[594] Exhibit IAG-4.

8.2.7.1. New Compressors

SCE wants to construct new back-up gas compressors and service air compressors at each peaker site during 2008 through 2010 for system reliability. The gas compressors are estimated to cost $13.299 million and the air compressors $5.835 million.

TURN recommends that this project be reduced by $9.134 million to $10 million because SCE (1) acted with questionable prudence during the construction of the peakers causing a need for new compressors, and then (2) compounded its original errors by choosing a high cost method for installing the new compressors. TURN also claims this installation method, besides being costly, is less reliable than other available equipment and requires more maintenance.[595] TURN's $10 million recommendation represents the cost of buying, but not installing, screw-type air and gas compressors plus the cost of a set of spares as calculated by TURN.

SCE acknowledges that General Electric's standard offering consisted of only a single gas reciprocating unit and single air compressor at each site and that SCE knew the reciprocating units have lower capital cost, but higher maintenance costs and down-time, than screw-type compressors. SCE states it considered alternatives. These alternatives included: purchasing new peakers using the manufacturer's standard design to meet the construction schedule at minimum cost; purchasing spare compressors to reduce peaker downtime (but causing increased operating and maintenance costs); upgrading the original units during the design of the peakers (requiring a redesign and resulting in

[595] Exhibit TURN-5A, pp. 45-46.

increased costs and an extension of the construction schedule); and completing the project using the manufacturer's standard design and then later adding redundant compressors at each site. SCE chose the latter option to enhance reliability. SCE asserts that option is consistent with industry practice for these compressor systems. Redundant screw-type design compressors were selected to reduce operating and maintenance costs.[596] SCE supported its project with benefit-cost analyses showing that air compressors have a 1.9 benefit-cost ratio and gas compressors a 1.8 benefit-cost ratio.

We find that SCE has successfully refuted TURN's criticism of SCE's decisions during construction of the peakers. However, elsewhere in this decision we remove from SCE's request for O&M the expenses associated with operation of the yet-to-be constructed fifth peaker. Accordingly, consistent with this O&M reduction, we remove from SCE's proposed capital projects the approximate costs associated with the fifth set of back-up compressors, $3.426 million.[597] SCE's proposed capital expenditures to construct new back-up gas and service air compressors at four peaker sites during 2008 through 2010 for system reliability are reasonable and are adopted.

8.2.7.2. Spare Combustion Turbine

SCE forecasts $7.103 million to purchase a spare General Electric LM 6000 combustion turbine to sustain peaker reliability and minimize overhaul outage time. Its request to include the spare combustion turbine was based on the

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[596] Exhibit SCE-16E, pp. 20-24.

[597] Exhibit SCE-2O, p. 36; 2009 capital expenditures are reduced by $2.334 million and 2010 capital expenditures are reduced by $1.092 million.

results of its economic analysis that shows a 1.6 benefit-cost ratio and consideration of alternative solutions, such as leasing.[598]

TURN opposes this spare combustion turbine based on the results of its own economic analysis which showed only a 0.7 benefit-cost ratio. However, TURN did not use the turbine manufacturer's specifications. TURN analyzed two scenarios, one based on a 99% peaker availability and the other on 98.1%, both of which exceeded the manufacturer's 96.8% specifications for the combustion turbine. At the manufacturer's (lower) availability level, the usefulness (and hence the cost-effectiveness) of the spare turbine increases. SCE's $7.103 million spare combustion turbine project for the 2010 attrition year is reasonable and is adopted.

8.2.8. Pebbly Beach

SCE forecasts $24.085 million of capital expenditures on Pebbly Beach generating station capital projects. Two of these projects totaling $5.54 million are opposed by DRA, namely, a new administration building and land for an adjacent micro turbine.

SCE forecasts $4.92 million of capital expenditures to construct a new administration building. SCE describes the current administration building as inadequate for health, safety, and security, and lacking sufficient office and parking space. SCE was authorized $3.9 million in its 2006 GRC to fund a new administration building, but it diverted these funds to meet unforeseen load growth during that time period.

[598] Exhibit SCE-2O, p. 38; Exhibit SCE-16E, p. 30.

No party disputes the need for a new Pebbly Beach administration building. However, DRA opposes SCE's request because SCE already obtained funds for this project.[599] While SCE reallocated the administration building funds to an important customer use, load growth, we find no justification for SCE's decision to continue to require employees to work in a facility it describes as inadequate for health and safety. We allocated these funds to SCE in our prior GRC decision, and we expected this project to be completed based on the risks the facility presents to employees. SCE's request for $4.92 million for the Pebbly Beach administration building project is denied.

SCE's micro turbine project involves installing up to 25 micro turbines providing 60 kW to Pebbly Beach customers. These micro turbines will be located on land adjacent to the current Pebbly Beach Generating Plant. Although this land is owned by the Catalina Island Company (Catalina Island) and is being used by a tenant for a container storage facility, SCE has the right to request that Catalina Island provide the land to SCE for electric utility purposes pursuant to a memorandum agreement between SCE and Catalina Island. As a condition for use of the site, Catalina Island requires SCE to design and improve a new site for the storage facility.[600] SCE has included $0.62 million in its capital expenditures for the relocation of the existing container storage facility at this site.

DRA opposes capitalization of this relocation cost on the basis that it is a one-time expense and SCE will not retain any assets associated with relocating

599 Exhibit DRA-73, p. 33.

600 Exhibit DRA-73, p. 34.

the container storage facility.[601] Although SCE will not retain any assets from relocating the tenant's containers, the cost is a necessary component of SCE's ability to place its micro turbines on the land. This relocation cost should be capitalized as land rights because the land being made available as a result will be used for utility purposes. We therefore deny DRA's $0.62 million micro turbine relocation adjustment.

8.3. Transmission & Distribution Capital

SCE provides testimony supporting T&D capital expenditures over the five-year period 2007-2011. For 2007-2009, SCE proposes cumulative T&D capital expenditures of $5.704 billion.

8.3.1. Customer Growth

Customer growth capital expenditures are costs incurred to construct the facilities that connect new customers to SCE's distribution system. This forecast is an arithmetic product of the meter forecast times the cost per meter forecast. In rebuttal, SCE agreed to revise its meter set forecast to match the meter forecasts of DRA and TURN.[602] This leaves the following customer growth issues to be resolved: (1) Cost Per-Meter, (2) Transformers, and (3) New Service Related Growth.

8.3.1.1. Cost Per-Meter

SCE's residential, agricultural, and commercial/industrial customers Cost Per-Meter forecasts are based on 2006 recorded amounts.[603] TURN recommends

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[601] Exhibit DRA-73, pp. 34-35.

[602] Exhibit SCE-17H1, p. 8.

[603] Exhibit SCE-17H1, p. 4.

lower Cost Per-Meter expenditures for each customer category. DRA recommends a lower Cost Per-Meter amount for the residential category only. DRA and TURN cite to declining meter sets, backbone expenditures in 2007 that will not go forward, and comparisons to overtime and increasing workforce levels to support their recommendation.[604] SCE substantially reduced its forecast in the number of meters for each customer class.[605] Even with this reduction, SCE asserts that its overall workload is increasing and SCE will need to depend on contract crews and overtime to accommodate the significant overall volume of work that needs to be accomplished.[606] Therefore, the overall mix of contract crews to SCE's labor charge will not significantly change. Overtime will occur and should be provided for whether it is in meter installation or elsewhere. However, it should not be double counted. SCE explains that even if SCE increases the number of contract crews by the same proportion as the increase in work, the contract overtime rate would remain the same. For these reasons, SCE's Cost Per-Meter forecast for residential, agricultural and commercial/industrial customers is reasonable and is adopted.

8.3.1.2. Transformers

SCE's forecast of capital expenditures for transformers related to new business is similar to Customer Growth expenditures and is based on a forecast unit price times the meter set forecast. SCE forecasts $59.4 million in capital expenditures for the period 2008-2009 based on a total of 144.8 thousand new

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[604] Exhibit SCE-17H1, pp. 4-5.

[605] For example the number of residential meters was reduced 40.6 thousand to 79.2 thousand from 109.6 thousand for the period 2008-2009.

[606] Exhibit DRA-13, p. 13; Exhibit TURN-5, pp. 60-62.

meters. TURN recommends capital additions of $42.0 million or $17.4 million less than SCE requests based on 42.4 thousand less meters during the same time period.[607] In its rebuttal testimony, SCE agreed to the lesser number of meters but increased its per-unit transformer costs to reflect actual price increases. Price increases included a 12.6% increase on August 1, 2006, 11.0% increase on January 1, 2007, 9.6% increase on October 1, 2007, and 2.9% increase effective January 1, 2008. Hence, SCE revised its initial capital expenditure forecast down to $51.2 million, an $8.2 million reduction from its initial $59.4 million forecast for the period 2008-2009.[608] We find SCE's revised $51.2 million of Transformer capital expenditures for the period 2008-2009, of which $26.9 million is for 2008 and $24.3 million for 2009, reasonable and is adopted.

8.3.1.3. Customer Growth

In some instances, DRA supports the use of recorded 2007 capital data in on the basis that recorded data eliminates an additional year of forecasting errors but in other instance DRA supports the use of forecasted 2007 capital data. Regarding New Service Related Growth, DRA recommends SCE's 2007 recorded amount of $53.574 million for New Service Related Growth be adopted over SCE's 2007 forecasted data. The forecasted data is lower than SCE's recorded costs for that year.[609] DRA uses SCE's 2007 recorded over 2007 forecasted data on the basis that the increased amount of capital expenditures spent are costs

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607 Exhibit TURN-5, p. 66.

608 Exhibit SCE-H1, pp. 13-15.

609 Exhibit DRA-13, p. 10.

that are ultimately customer financed.[610] It is reasonable and appropriate to adopt a consistent forecasting method, e.g., forecast or actual costs, for the capital expenditures associated with New Service Related Growth adopted in this proceeding. However, exceptions exists. Whether relying on forecasted or recorded data for capital expenditures is preferred often depends on an individual account analysis and the reasons why differences exist between forecast and actual expenditures. In this case, we find SCE's forecast reasonable. We adopt SCE's forecast of $294.892 million.

8.3.2. Load Growth Capital Expenditures

Load growth capital expenditures are for the expansion of SCE's system to meet increased customer load due to new customers entering the service territory, existing customers increasing their electric loads and to interconnect new generating plants to the system. Over the period 2008-2009, SCE forecasts System Load Growth capital expenditures of $721.7 million of which $283.0 million is for 2008 and $438.7 million for 2009. DRA recommends reducing SCE's forecast for Load Growth expenditures for this period[611] by $182.1 million and presents a forecast of $539.6 million of which $209.6 million is for 2008 and $330.0 million for 2009.[612] Because SCE's proposes a budget-based approach to PTYR, SCE also presents a specific forecast for 2010 and 2011.[613] We address years 2010-2011 and PTYR elsewhere in this decision.

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[610] Exhibit SCE-24A, p. 46.

[611] Because 2007 recorded data was available to DRA, DRA limited its analysis of capital project expenditures to projects with a completion date of 2008 and 2009.

[612] Exhibit DRA-13, p. 6.

[613] Joint Comparison Exhibit, p. 639.

SCE explains it overspent its authorized load growth expenditures by $56.0 million in 2006.[614] To maintain reliability of its system, SCE proposes a significant increase in capital expenditures. It uses peak load forecasts, identification of system requirements primarily through load flow studies, and an evaluation of several alternative projects that are needed to meet its reliability criteria.[615]

DRA uses a similar method to forecast load growth and determines that SCE's methodology does not capture demand reductions due to conservation and self generation. In addition, DRA claims SCE's capital expenditures forecast fails to adequately reflect the recently updated 2008 and 2009 lower sales forecast. DRA concludes that SCE's peak demand forecast should be reduced by six percent in 2008 and seven percent in 2009 because SCE did not adequately reflect updated or lower sales forecast for 2008 and 2009 resulting in a deferral of need until after 2009 for a number of projects forecasted by SCE.[616]

Both SCE and DRA employed load forecasts to support their respective proposals. Detailed descriptions of these forecasts, some of which are confidential, are contained in the record and are not repeated here. Although DRA's and SCE's forecasts are objective and employ similar methodologies, they are dependent on subjective inputs. SCE and DRA advance arguments in support of their respective subjective inputs and in criticism of the subjective inputs used by the other party. Some of these differences pertain to how the

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[614] Exhibit SCE-3G, p. 2.

[615] Exhibit SCE-17I Confidential.

[616] Joint Comparison Exhibit, p. 639.

recent changes in the overall California economy, customer growth, weather, and energy efficiency impact the results of dated 2006 forecasts.

Given these most recent changes, insufficient information exists to conclude that the result of either party's load growth study is preferred over the other. However, the results are helpful in establishing a realm of reasonableness. Therefore, the mid-range between SCE's load growth request and DRA's recommendation for the years 2008 and 2009 should be adopted. SCE should be authorized $246.3 million in 2008 ($283.0 million plus $209.6 million divided by two) and $384.4 million in 2009 ($438.7 million plus $330.0 million divided by two) for a total load growth of $630.7 million for the period 2008-2009 to be managed by SCE. This results in a $91.05 million reduction in SCE's forecast for 2008-2009. For 2007, we find the recorded expenditures reasonable and we adopt those amounts. SCE completion dates are reasonable and are adopted.

8.3.3. Distribution Infrastructure Replacement

SCE plans to spend $2.9 billion over the five-year period 2007-2011 on its infrastructure replacement program. This request is discussed below.

8.3.3.1. Deteriorated Distribution Pole Replacements

SCE requests a total of $505.2 million in capital expenditures ($80.0 million in 2007, $88.1 million in 2008, $109.7 million in 2009, $112.2 million in 2010, and $115.2 million in 2011) to replace deteriorating distribution wood poles. These capital funds will be used to replace 8,630 poles in 2007, 9,673 poles in 2008, and 11,768 poles in 2009.[617] DRA recommends that SCE's 2007 forecast be reduced by $3.4 million to $76.6 million from $80.0 million and that the subsequent years,

[617] Exhibit DRA, SCE's Response to DRA-231, Q. 1.

2008 and 2009, be adjusted to the $76.6 million actual 2007 capital expenditures.[618] SCE argues that its historical experience should not be the basis for future capital expenditures in this category because its prior experience of significant and unforeseen increases in customer and load growth required SCE to reprioritize its capital spending, which led to reductions in spending on its pole replacement program.

We disagree. We find that recorded costs, rather than a budget-based method, is a more reliable forecasting methodology in this instance as SCE has failed to provide a reasonable explanation for deferring work in this area and does not adequately explain its forecasted increase in expenditures. Unexpected load growth is not a sufficient reason to excuse maintaining distribution poles. Accordingly, we adopt DRA's proposal for years 2007-2009.

8.3.3.2. Suspected PCB Transformers

SCE requests $1.0 million each year, beginning in 2009 to proactively remove an estimated 24,000 PCB-contaminated distribution transformers at a rate of 250 each year. This request supplements its current program of removing 55 of its PCB-contaminated distribution transformers from its system each year through normal replacements. SCE's request to accelerate this project is based on its belief that the federal government may soon pass legislation requiring all utilities to remove from their system equipment containing more than 50 PPM of PCB by the year 2025 and because the Environmental Protection Agency's

[618] Exhibit DRA-15, p. 7.

proactive voluntary removal program imposes significant management and liability concerns.[619]

DRA recommends that this project not be approved because SCE is not required to accelerate its current program and SCE's belief that legislation will soon pass requiring utilities to remove equipment containing PCBs in the next few years is speculative.[620]

Although SCE is not currently required to accelerate its program of replacing PCB Transformers, PCB is a health and safety issue that impacts both its employees and customers. It is appropriate that SCE aggressively addresses this matter. The PCB Transformer capital replacement program of $1.0 million annually beginning in 2009 is reasonable and is adopted.

8.3.3.3. Street Light Replacement

SCE forecasts a constant $14.4 million level of expenditures for years 2007-2009 to replace overhead street light wire and underground cable serving street lights, deteriorated street light fixtures and street light poles. DRA recommends adjusting SCE's forecast to reflect the 2007 recorded spending level of $10.5 million for each of the years 2007-2009, adjusted for inflation.[621] DRA's forecast is based on more recent recorded data. In Rebuttal, SCE says that "…SCE's plan for replacing street light poles and fixtures in 2007 could not be performed for reasons beyond its control. Unforeseen surges in customer and load growth compelled SCE to redirect funds away from street light needs to

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619 Exhibit SCE-3H, pp. 40-41.

620 Exhibit DRA-15, p. 14.

621 Exhibit DRA-15, p. 16.

fund the more urgent need to service customers."[622] We do not find SCE explanation of unforeseen load growth a sufficient reason to defer maintenance in this area. Accordingly, we find DRA's forecast reasonable. Therefore, an annual $10.5 million of Street Light Replacement capital expenditures for the years 2007-2009 is adopted.

8.3.3.4. Capacitor Bank & Switch Replacement

SCE requests $23.1 million in capital expenditures over the period 2007-2009 to replace 1,280 capacitor banks and 1,331 capacitor switches due to aging infrastructure.[623] This equates to $7.3 million in 2007, $7.5 million in 2008, and $8.3 million in 2009**.**

DRA recommends that SCE's $23.1 million Capacitor Bank & Switch Replacement Program be reduced by $3.5 million to $19.6 million. DRA's lower forecast is based on SCE's failure to demonstrate a need to substantially increase the replacement of older capacitor banks at the 2007 rate of 404 each year, which enables SCE to replace all of its older banks within the next five years. In regards to bank and switch replacements, DRA disagrees with SCE's proposal to base these replacements based on historical number of capacitor banks and switches identified for replacement instead of the number actually replaced. For example, in 2006, SCE only replaced 200 of its 373 capacitor banks identified for replacement, and in 2007 it replaced only 404 of the 456 capacitor banks it identified for replacement.[624] As for capacitor switches, SCE only has data that

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[622] Exhibit SCE-171, p. 31.

[623] Exhibit SCE-3H, pp. 50-52.

[624] Exhibit DRA-15, pp. 17-18.

shows the number of capacitor switches replaced and not those identified for replacement.[625] For these reasons, DRA places reliance on SCE's recorded data.

We find SCE has not justified a two-year acceleration of its current five-year bank replacement program in light of the 2007 recorded replacement rate of 404 each year. Regarding the capacitor switches, reliance must be placed on the only data available, a history of recorded data. Therefore, DRA's $19.6 million capital expenditure forecast for the years 2007-2009 is reasonable and is adopted.

8.3.3.5. Deteriorated Underground Structure Replacement

SCE forecasts $7.2 million in capital expenditures for the period 2009-2011, of which $2.0 million is applicable to 2009, to replace eight deteriorated underground structures (vaults) per year.[626] This forecast is based on SCE's knowledge of a construction quality issue in vaults built between 1964 and 1983, the existence of 500 active work orders for serious problems in these vaults, and the fact that ten vaults have already been condemned and identified for replacement.[627]

DRA relies on recorded data which shows that SCE only replaced two underground vaults in 2004 and four in 2005 and recommends $0.8 million for the replacement of three of SCE's requested eight vaults in 2009. In response, SCE's explain that its failure to adhere to its 2006 GRC forecast for replacement of underground structures was due to the seriousness of the unexpected surge in load/customer growth. The decision to postpone replacement of structures was

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625 Exhibit DRA-15, pp.17-18.

626 Exhibit SCE-3H, p. 59.

627 Exhibit SCE-17H1, pp. 34-35.

not, in SCE's view, discretionary but necessary to meet the needs of our customers.[628]

SCE has not substantiated its claims that reliance of recorded data in this instance is not appropriate. Moreover, it is unclear why this serious problem took a lower priority to customer growth matters. In the absence of a proposal by SCE that incorporates historical data and further explains why SCE viewed this deferral as mandatory, we adopt DRA's recommendation.

8.3.3.6. Underground Mainline Oil Switch

SCE forecasts $32.7 million to replace Underground Mainline Oil Switches during the period 2007-2009. Of this amount $10.3 million is forecasted in 2007 to replace 232 switches, $8.4 million in 2008 to replace 185 switches, and $14.0 million in 2009 to replace 300 switches. DRA recommends $27.3 million, a $5.4 million reduction in SCE's 2009 forecast to bring down the number of switch replacements in that year to the 2008 number of 185 switch replacements.

SCE began a program to replace these older switches in 2000. SCE currently has approximately 7,000 of these switches in service, of which 1,700 are 35 years or older. These switches, used in SCE's distribution system for opening and closing electrical circuit connections, are inspected every three years and if found to be deteriorating during those inspections are replaced. However, deterioration of the electrical contact and other components internal to the switch cannot be detected. Any failure of these switches that results in arcing across electrical components under oil creates highly explosive acetylene gas. In-service

[628] Exhibit SCE-17H1, p. 34.

failures of these switches result in circuit interruptions, pose a threat to public and employee safety and affect system reliability.[629]

SCE has replaced a yearly average of 180 switches from the start of its replacement program in 2000 through 2006 and a yearly average of 188 switches through 2008. SCE seeks to further increase that replacement number to an annual replacement level of 300 switches. Although no party opposes SCE's systematic replacement of these switches, DRA finds no reason to accelerate this replacement program at this time.

Although these switches are dated, SCE has an overlapping program that enables it to replace switches found to be deteriorating during periodic inspections. In addition, to the extent SCE deemed work on this equipment unnecessary due to unexpected load growth, we find SCE's explanation inconsistent with the public safety issues that could result from such deferred maintenance. Such a deferral also fails to support SCE's request to increase its replacement rate. Accordingly, we find SCE has not adequately justified a need to almost double its replacement of switches under this program. DRA's $27.3 million forecast for the replacement of Underground Mainline Oil Switches during the period 2007-2009 is reasonable and is adopted.

8.3.3.7. Underground Cable Replacement

SCE forecasts $58.5 million for Underground Cable Replacement during the period 2007-2009. Of this amount $6.3 million is forecasted in 2007 to replace 35 miles of cable, $14.4 million in 2008 to replace 78 miles of cable, and

[629] Exhibit SCE-3H, pp. 60-66.

$37.8 million in 2009 to replace 200 miles of cable.[630] DRA recommends $10.5 million, a $48 million reduction in SCE's total forecast based on SCE's 36 mile yearly average rate of replacing underground cable over the recorded years 2005-2007.[631]

SCE has approximately 46,000 miles of underground primary cable in its distribution system. This cable is comprised of four different types of cable, a majority of which is tree retardant cross-linked polyethylene. Approximately 10% of its underground primary cable or 4,495 miles of SCE's oldest cable consists of paper insulated lead covered cable which is incompatible with modern components and cannot be used with today's removable elbow connectors for which all modern switches, transformers, and junction bars are designed. Near the end of its useful service life is its next oldest cable consisting of high molecular weight polyethylene. This cable represents approximately 3% or 1,451 miles of SCE's underground primary cable.[632]

SCE claims that failure of this cable could pose serious reliability problems to its system but at this same time SCE found it reasonable to fund the costs of new meters and install new distribution facilities to meet that growth by reprioritize its capital spending, which led to reductions in spending on preemptive cable replacement.[633] As a result, it is unclear what the level of urgency is for the proposed cable replacement. In this situation, we find reliance on historical date more reliable. Accordingly, DRA's $10.5 million forecast for

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630 Exhibit SCE-3H, p. 68.

631 Exhibit DRA-15, pp. 24-29.

632 Exhibit SCE-H, pp. 68-70.

633 Exhibit SCE-3H, p. 77.

Underground Cable Replacement during the period 2007-2009 is reasonable and is adopted.

8.3.3.8. Cable in Conduit Replacement Program

SCE forecasts $5.8 million to replace 30 miles of cable in conduit (CIC) in 2009 as a pilot program to explore and develop improved replacement methods. DRA does not recommend funding this program on the basis that SCE has not substantiated the program's need and because SCE already proactively replaces cables under two other programs, the Cable Replacement Program and the Worst Circuit Rehabilitation Program.[634]

CIC is an unjacketed cable housed in polypropylene plastic tubing making it difficult and costly to remove cable from the polypropylene tubing so that replacement cable can be reinserted, often resulting in abandoning the cable in place and digging a trench to install new cable. Among the reasons for this pilot program is to investigate new approaches to replacing CIC so that future replacement of the approximate 10,000 conductor-miles of CIC type cable currently in SCE's system can be replaced at a more affordable costs than currently.[635]

SCE's $5.8 million pilot CIC Cable Replacement Program is reasonable and is adopted.

8.3.3.9. Worst Circuit Rehabilitation

SCE forecasts $31.8 million over the period 2008-2009 to rehabilitate the worst performing circuits on its system in terms of reliability, of which

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634 Exhibit DRA-15, pp. 30-34.

635 Exhibit SCE-3H, p. 84.

$10.8 million is for 29 circuits in 2008 and $21.0 million for 40 circuits in 2009.[636] DRA recommends $10.5 million based on SCE's recorded data, a $21.3 million reduction in SCE's forecast.[637] In 2006, SCE's recorded costs associated with rehabilitating the worst performing circuits was $5.8 million and during the 2002-2006 period, SCE spent a total of approximately $13 million.

SCE is requesting a substantial increase based on recorded costs for this program. In addition, SCE explains that because it experienced significant and unforeseen increases in both customer growth and load growth, SCE funded the costs to set new meters and install new distribution facilities to meet that growth by reducing its spending in this area.[638] SCE does not quantify the impact of its decision to postpone rehabilitation of these circuits by, for example, explaining whether maintenance costs increased or the amount of work needed to rehabilitate the circuits increased as a result of this deferral. Moreover, it is unclear why rehabilitation of these circuits is urgent now but, during 2006-2007, it was not. In this situation, we find historical data more reliable than SCE's projections.

DRA's $10.5 million Worst Circuit Rehabilitation Program capital expenditure forecast is reasonable and is adopted.

8.3.4. Substation Infrastructure Replacement Program

SCE's capital substation replacement programs are designed to replace aging substation infrastructure, consisting primarily of circuit breakers and

[636] Exhibit SCE-3H, p. 90.

[637] Exhibit DRA-15, p. 34.

[638] Exhibit SCE-3H, pp. 89-90.

transformers, before that equipment fails. SCE forecasts approximately $434.6 million over the period 2007-2009 for these programs. DRA recommends $359.2 million, $75.4 million less than SCE's forecast for the same period.[639] Differences between SCE and DRA are in the following replacement programs: (1) Transformer A-Banks, (2) Transformer B-Banks, (3) Distribution Circuit Breakers, (4) Distribution Protection and Control, and (5) Routine Capital Replacements consisting of (a) On-Line Gas Monitoring for Bulk Transformers, (b) Rule 20B Circuit Breakers, (c) Overhead Lines, and (d) Circuit Electrical Infrastructure. These differences are addressed below.

8.3.4.1. Transformer A–Banks

SCE forecasts $42.0 million over the period 2007-2009 to replace 10 A-Bank transformers of which $12.2 million is for replacing three transformers in 2007, $4.2 million for replacing one transformer in 2008, and $25.6 million for replacing six transformers in 2009.[640] DRA recommends a total of $20.7 million, $21.3 million less than SCE's forecast over the same period. This $21.3 million difference results solely in the year 2009. SCE forecasts the replacement of six transformers in 2009 and DRA only recommends one replacement.

Although SCE forecasts the number of A-Bank transformers as part of its Transformer Research Management Program its selection of replacement A-Bank transformers was based on a ground-up forecast based on an average per-unit cost and does not account for historical failure rates.[641] On average the number

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[639] Exhibit SCE-17H1, pp. 58-59.

[640] Exhibit SCE-3I, p. 38.

[641] Exhibit DRA, SCE's Response to DRA-146, Q3.

of A-Bank Transformer failures is 1.1 per 12 months which equals one failure every 11 months.[642]

SCE should have taken into consideration the actual failure rate of these transformers in considering how often to replace its transformers. Based on this failure rate, SCE's forecast for replacing six transformers in 2009 appears excessive and DRA's one transformer inadequate. Given SCE's A-Banks 1.1 failure rate, we find it reasonable to authorize SCE to replace two A-Bank transformers in 2009 for a total of $8.4 million, twice the 2009 amount recommended by DRA for the replacement of one such transformer. Accordingly, we adopt SCE estimates with the exception of 2009. For 2009, we adopt a forecast of $8.4 million.

8.3.4.2. Transformer B-Banks

SCE forecasts $31.8 million over the period 2007-2009 to replace B-Bank transformers of which $7.9 million is for 2007, $11.8 million to replace 16 transformers in 2008, and $12.1 million to also replace 16 transformers in 2009.[643] DRA recommends $16.6 million, $15.2 million less than SCE during the same period.[644] This difference is attributed to DRA using 2004 and 2006 historical replacement data to determine an appropriate number of transformers that should be replaced in 2008 and 2009. Based on its review of historical data,

642 Exhibit SCE-3I, p. 36.

643 Exhibit SCE-3I, p. 42.

644 Exhibit DRA-15, pp. 56-59.

DRA recommends SCE only replace six of the 16 transformers it forecasts for replacement in both 2008 and 2009.[645]

Unlike its A-Bank replacement forecast, SCE reflected the higher B-Bank failure rate of 10 (versus one a year for A-Bank Transformers) in forecasting the number of B-Bank transformers to be replaced. [646] SCE's $31.8 million forecast over the period 2007-2009 to replace B-Bank Transformers is reasonable and is adopted.

8.3.4.3. Distribution Circuit Breakers

SCE forecasts $47.1 million over the period 2007-2009 to replace 342 aging power circuit breakers, which consists of $7.2 million to replace 54 in 2007, $20.3 million to replace 148 in 2008, and $19.6 million to replace 140 in 2009.[647] DRA recommends $25.2 million for the replacement of 184 circuit breakers based on SCE's historical experience. This is $21.9 million lower than SCE's forecast for the same period. DRA accepts SCE's 2007 forecast of replacing 54 circuit breakers in 2007. However, DRA recommends reducing SCE's 2008 forecast of replacing 148 circuit breakers in 2009 and 140 in 2009 to 65 in each of those years.

SCE's circuit breaker replacement forecast is not based on historical data. Instead, SCE bases its forecast on the age or condition of equipment needing replacement. SCE explains that historical data would show a decrease in SCE's replacement efforts due to unexpected customer load growth.[648] Historical data is relevant and SCE fails to provide an adequate explanation for deferring work

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645 Exhibit DRA-15, pp. 56-59.

646 Exhibit SCE-3I, p. 40.

647 Exhibit SCE-3I, p. 22.

on this important project. Therefore, SCE's forecast of $47.1 million over the period 2007-2009 to replace 342 aging power circuit breakers is unreasonable. Instead, we adopt DRA's forecast, which relies on historical data.

8.3.4.4. Distribution Protection & Control

SCE forecasts $18.6 million over the period 2007-2009 to replace protection and control equipment, of which $1.9 million is for 2007, $1.2 million for 2008, and $15.5 million for 2009.[649] DRA recommends $10.5 million, $8 million less than SCE for the same period. The only difference between SCE and DRA is in the number of protection and control equipment to be replaced. SCE forecasts it will replace 25 and DRA recommends 12 based on historical data. SCE explains that, due to unprecedented customer growth and load growth, it diverted funds from this program to address growth issues.[650] Now, SCE will return the program to its original scope and will increase its replacement of substations to 25 per year. SCE does not quantify its reduced spending due to customer and load growth issues.

DRA's recommended replacement of 12 protection and control substations per year will take 50 years for SCE to completely replace its antiquated electro-mechanical devices at its 600 substations.[651] It will also place some of its aging equipment well beyond their reasonable expected life. However, we remain concerned about SCE's decision to defer this important program for reasons we find insufficient, unanticipated customer and load growth. Based on

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648 Exhibit SCE-31, p. 23.

649 Exhibit SCE-3I, p. 47.

650 Exhibit SCE-3I, p. 48.

SCE's decision, the urgency of replacement is unclear. In addition, in the absence of specific amounts related to funding customer growth issues, we find it reasonable to reduce SCE's $18.6 million forecast over the period 2007-2009 by adopting DRA's position.

8.3.4.5. Routine Capital Replacements

SCE and DRA differ in the forecasts of four Routine Capital Replacement programs, each of which are discussed below. These programs are: (1) On-Line Gas Monitoring for Bulk Transformers, (2) Rule 20B Circuit Breakers, (3) Overhead Lines, and (4) Critical Electric Infrastructure.

8.3.4.5.1 On-Line Gas Monitoring For Bulk Transformers

SCE forecasts $20.1 million for the period 2008 through 2011 to install monitoring equipment that will automatically measure transformer oil on its 246 AA- and A-Bank transformers every four hours, thus allowing for remote monitoring. Of this amount, $14.4 million is under the CPUC jurisdiction, leaving a yearly California jurisdictional cost of $4.7 million for the years 2009, 2010, and 2011.[652] SCE intends to install approximately 60 units each year.

DRA recommends that this program be scaled down to $1.5 million (19 units each year rather than 60 units per year). This is because approximately one-third of the transformers that will be automatically monitored are under 30 years old and because SCE has not demonstrated a need to monitor this group as frequently as every four hours.

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651 Exhibit SCE-17H1, p. 84.

652 Exhibit DRA-15, pp. 63-65.

SCE acknowledges that age is an important factor in determining which transformers are near their technical end-of-life. However, it asserts that DRA's recommended 19 units per year would undermine the objective of this program which is to employ modern technology to assess the condition of its A- and AA-Bank transformers. Further, it would enhance reliability levels and extend the operating life of transformers by detecting the onset of transformer failures.[653]

Although SCE has a valid interest in mechanizing its monitoring of A- and AA-Bank transformers, it has not substantiated an accelerated need to mechanize the monitoring of its newer Bank transformers. DRA's recommendation for the installation of 19 automatic monitoring equipment on its A- and AA-Bank transformers at a cost of $1.5 million in 2009 is reasonable and is adopted.

8.3.4.5.2. Rule 20B Circuit Breakers

SCE forecasted $5.2 million over the period 2007-2009 to replace older 66 kV and 115kV class circuit breakers that are incapable of de-energizing underground cable beyond a certain length, of which $1.3 million is for 2007, $1.4 million for 2008, and $2.5 million for 2009. Based on recorded data, DRA recommends $3.7 million over the same time period, which equals a $1.5 million reduction to SCE's forecast.[654] However, SCE subsequently agreed with DRA's total $3.7 million recommendation for Rule 20B Circuit Breakers over the period 2007-2009.[655] Hence, DRA's $3.7 million recommendation is reasonable and is adopted.

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[653] Exhibit SCE-17H1, pp. 86-89.

[654] Exhibit DRA-15, pp. 65-67.

[655] Exhibit SCE-17H1, p. 89.

8.3.4.5.3 Overhead Lines

SCE forecasted $8.3 million over the period 2007-2009 for work activity associated with sub-transmission line additions and retirements, of which $4.4 million is for 2007, $1.95 million for 2008, and $1.99 million for 2009. DRA recommends $5.5 million over the same time period, or $2.8 million lower than SCE's forecast. This $2.8 million difference largely resulted from SCE including a one-time project in its 2007 forecast, which was not completed. SCE subsequently stated that recorded 2007 data should be used.[656] The 2007 recorded data reflects the removal of the one-time project. We agree that recorded 2007 data is more reliable and find the use 2007 recorded data appropriate in this instance.

8.3.4.5.4 Critical Electric Infrastructure

SCE forecasts $1.5 million over the period 2007-2009 on a pre-fabricated, mobile system that could be transported to any of its 50 bulk power substations to restore control and protection of the power grid in the event of a major disaster.[657] DRA recommends no funding on the basis that the project is not fully supported.[658] This project is designed to enhance system reliability. Accordingly, we find it reasonable and adopt it.

8.3.5. Reliability Investment Incentive Mechanism

SCE recommends that the Reliability Investment Incentive Mechanism, referred to as RIIM, which was authorized in the 2006 GRC by D.06-05-016 be

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[656] Exhibit SCE-17H1, p. 90.

[657] Exhibit SCE-3I, pp. 66-69.

[658] Exhibit DRA-15, p. 69.

reauthorized in this proceeding with certain modifications. SCE proposes setting a RIIM target of $2.566 million in reliability-related capital expenditures.[659] In a separate section of this decision, we reject the RIIM. Our decision to reject RIIM has no impact on SCE's requested revenue requirement. This matter is addressed in more detail in a separate section of this decision.

8.3.6. Operational Technology

SCE requests $275 million in capital expenditures for Operational Technology projects during the period 2007-2011, which include both FERC and CPUC jurisdictional projects. These projects are: (1) Phasor Measurement & Grid Stability System, (2) Distribution Control & Monitoring System, (3) Distribution Automation – Circuit Automation, (4) Critical Video Substation Surveillance, (5) Energy Management System, and (6) Centralized Remedial Action Scheme (C-RAS).

8.3.6.1. Phasor Measurement & Grid Stability System

SCE forecasts $34.0 million over the period 2009-2011, of which $13.0 million is applicable to 2009 to implement a system that will give its system operators a direct indication of transmission system stress, and how close to the margins SCE is operating from system instability and potential system failure.[660]

DRA recommends no funding for this project because, among other reasons, SCE could not identify what equipment it was basing its estimates on

659 Exhibit SCE-3H, p. 113.

660 Exhibit SCE-3K, pp. 55-63.

and was unable to explain the potential vendors' knowledge of Phasor Measurement and Grid Stability Systems.[661]

We find this system will enable SCE to better provide system reliability, to manage its electric system during times of transmission system stress, and avoid close operating margins and system instability. SCE's $13.0 million forecast for the year 2009 to implement its Phasor Measurement & Grid Stability System is reasonable and is adopted.

8.3.6.2. Distribution Control & Monitoring System

SCE forecasts $20 million over the period 2009-2011 to upgrade its Distribution Control & Monitoring System (DCMS) with new hardware and software, of which $3.0 million is applicable to 2009. DRA recommends that SCE be authorized only $0.1 million in 2009 to upgrade its software. Since installed in 1994, SCE's DCMS has undergone several upgrades, its software was upgraded in 1999 and server hardware in 2007. Problems with the existing DCMS reported by SCE include: (1) obsolete software not supported by vendors, (2) inability to mitigate known security vulnerabilities in the system, (3) lack of an operator training simulation, and (4) insufficient data management capabilities.[662] We find that, although DRA's proposal would enable SCE to upgrade its software, SCE would actually need an additional $0.9 million above DRA's recommended $0.1 million to undertake that upgrade.[663] In addition, DRA's recommendation

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[661] Exhibit DRA-15, pp. 76-80.

[662] Exhibit SCE-3L, p.12.

[663] Exhibit SCE-17H2, pp. A-48 to A-430.

would not resolve the other shortcomings of the existing DCMS. SCE's 2009 forecast of $3.0 million for upgrading its DCMS is reasonable and is adopted.

8.3.6.3. Circuit Automation

SCE forecasts $16.9 million over the period 2007-2009 to automate overhead and underground distribution switches, of which $4.8 million is for 2007, $5.5 million for 2008, and $6.6 million for 2009. DRA recommends $14.7 million over the same time period, or $2.2 million lower than SCE's forecast, based on SCE's most recent spending level for this program and lack of support for the number of overhead and underground remote control switches that SCE intends to install. DRA's $14.7 million forecast for Circuit Automation switches is reasonable and is adopted.

8.3.6.4. Critical Video Substation Surveillance

SCE forecasts $7.0 million over the period 2009-2011 to upgrade its existing security plans at 14 of its 220 kV substations by installing perimeter intrusion detection systems with remote video surveillance. Of this total, $3 million will be spent to install this equipment at six substations in 2009 and $2.0 million for four substations in each of the 2010 and 2011 years.[664]

Although DRA accepts SCE's cost estimate to install the surveillance equipment per substation it recommends only $1.0 million for 2009, $2.0 million less than SCE's forecast. In support of its recommendation, DRA cites the time line required from preparing a request for proposal, which has not yet occurred,

664 Exhibit SCE-3L, p. 39.

to the completion date for installation. DRA contends that SCE will only be able to complete installation at two substations in 2009.[665]

SCE, having previous experience with this type of security project, anticipates a rigorous vendor selection process that will be completed by the second quarter of 2009 and, as a result, it will be able to complete its forecasted six substations in 2009. SCE's $7.0 million forecast over the period 2009-2011 to upgrade its existing security plans at 14 of its 220 kV substations is reasonable and is adopted to protect the safety and security of its most critical facilities.

8.3.6.5. Energy Management System

The Energy Management System (EMS) is a computer platform that monitors and controls the flow of power throughout SCE's transmission grid. In other words, this system serves as the primary tool used by grid operators to monitor and control SCE's transmission and distribution system. SCE explains that its current EMS is obsolete.[666]

SCE requests $17.4 million to upgrade its EMS. Of this amount, $9.6 million is forecasted in 2007, $5.5 million in 2008, and $2.3 million in 2009. DRA recommends $13.5 million. This amount includes reductions of $1.7 million in 2007 to reflect SCE's actual capital expenditures, $1.1 million in 2008 because SCE has historically spent only 88.5% of its 2006 and 2007 forecast for this ongoing project, and $1.0 million in 2009 for "unknown" updates.[667] SCE

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[665] Exhibit DRA-15, pp. 89-93.

[666] Joint Comparison Exhibit, p. 637.

[667] Exhibit DRA-15, p. 75.

subsequently agreed that its 2007 forecast should be adjusted downward by $1.7 million to reflect its actual 2007 EMS capital additions.[668]

DRA's forecast, which is based on historical data, is more reliable than SCE's goals regarding EMS. DRA's $13.5 million EMS capital expenditure forecast for the period 2007 through 2009 is reasonable and is adopted.

8.3.6.6. Centralized Remedial Action Scheme

SCE requests $112.2 million over the period 2007-2011 for its Centralized Remedial Action Scheme (C-RAS) project that impacts Transmission Substations, General Buildings, and Telecommunications Equipment. Of this amount, $52 million applicable to Transmission Substations is allocated to FERC jurisdictional rates, $18.2 million of the $19.2 million applicable to General Buildings is allocated to the CPUC, and $38.9 million of the $41.0 million applicable to Telecommunications Equipment is allocated to the CPUC.[669]

DRA initially recommended that this request be denied based on its understanding that the project was entirely under FERC jurisdiction. DRA subsequently recognized in its opening brief that the C-RAS project is subject to FERC and CPUC jurisdiction and should be allowed.[670] Therefore, SCE's $58.1 million capital expenditures associated with its C-RAS project is reasonable and is adopted.

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668 SCE opening brief, p. 183.

669 SCE opening brief, p. 184.

670 DRA opening brief, p. 260.

8.3.7. Customer Requests

8.3.7.1. Purchase and Upgrade of Distribution Systems on Military Bases

SCE initially forecasted $73.1 million in capital expenditures for the purchase and upgrade of distribution systems at eight military bases, of which $53.0 million was for purchases in 2008 and $10.6 million for upgrading of facilities in 2008 and $9.5 million in 2009. SCE subsequently reduced its $73.1 million capital expenditures request by $67.2 million to $5.9 million, of which $1.7 million is for purchase and $4.2 million for upgrading one military base distribution system in 2008.[671]

DRA opposed the inclusion of any capital expenditures for the purchase and upgrade of the military base distribution systems because negotiations between SCE and the federal government for seven of the eight distribution systems were postponed until after 2009. DRA did not provide any funds for the purchase and upgrade of facilities for the remaining military base because of continued negotiations between SCE and the federal government and uncertainty that SCE will actually complete the purchase. To the extent that negotiations are successful and SCE purchases and upgrades the eight military base distribution systems, DRA recommends SCE be authorized to file an advice letter to recover its net cost.[672]

SCE has not reasonably substantiated it will acquire any of the eight military base distribution systems before the end of 2009. Therefore, SCE's

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671 Exhibit SCE-17H1, pp.18-19.

672 Exhibit DRA-13, p. 24.

$5.9 million capital expenditure forecast for the purchase and upgrade of the single military distribution system should be disallowed.

8.3.7.2. Rule 20A Conversions

SCE's Rule 20A tariff provides capital expenditures to governmental agencies within SCE's service territory for undergrounding existing overhead lines. SCE forecasts $116.1 million of Rule 20A capital expenditures for the years 2007-2009. This forecast is $28.3 million higher than DRA's $87.8 million forecast for the same period. DRA bases its forecast on 2007 recorded Rule 20A capital expenditures of $29.3 million. DRA did not rely on SCE's forecast because SCE has consistently under spent its authorized amounts. For example, SCE only spent $180.6 million of its $283.6 million authorized Rule 20A capital expenditures, or $103.1 million less than authorized, during its prior 2003–2007 period.[673] Therefore, DRA recommends SCE's 2007 recorded Rule 20A capital expenditures of $29.3 million be adopted for each of the years 2007, 2008, and 2009 for a total $87.9 million.

DRA's forecast for 2008-2009 is more in line with the current economic conditions and more realistic given SCE's consistent under-spending of its Rule 20A funds. DRA's Rule 20A capital expenditure forecast of $29.3 million is reasonable and is adopted for 2007, 2008 and 2009.

8.4. Customer Service Capital

SCE presents four categories for its customer service capital expenditures: (1) structures and improvements, (2) furniture and equipment, (3) specialized equipment, and (4) meters. SCE forecasts a total of $105.412 million for customer

[673] Exhibit DRA-13, p. 28.

service capital expenditures for the three-year period 2007, 2008, and 2009. DRA forecasts $85.719 million for the same time period, resulting in a $19.693 million difference between the two parties.[674] This difference is the result of the use of different forecasting methods.

SCE derives its customer service capital forecast from a detailed five-year construction plan which undergoes review by manager-level planning committees for approval by project and reviewed at least annually.[675] DRA uses SCE's 2007 recorded data for its 2007 forecasts for each of the four customer service categories. With the exception of adopting SCE's 2009 specialized equipment forecasts, DRA uses SCE's 2002-2006 five-year recorded average for its 2008 and 2009 forecasts of the first three customer service categories. DRA uses a different forecasting method for customer service meters, which is discussed separately.

Both SCE and DRA have a systematic method for forecasting customer service capital expenditures. However, we are unable to assess the reasonableness of DRA's forecasting method for several reasons. These reasons include DRA's failure to reflect changes in the number of service employees and customers or provide for obsolescence of the customer service capital components in its historical five-year average. SCE's structures and improvements, furniture and equipment, and specialized equipment forecasts should be adopted as follows.

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674 Exhibit DRA-7, pp. 42-51.

675 Exhibit SCE-18, p. 97.

8.4.1. Structures and Improvements

SCE's Structures and Improvements capital expenditures forecast of $2.12 million in 2007, $2.01 million in 2008, and $5.88 million in 2009 is reasonable and should be adopted.

8.4.2. Furniture and Equipment

SCE's Furniture and Equipment capital expenditures forecast of $1.95 million in 2007, $2.05 million in 2008, and $2.25 million in 2009 is reasonable and should be adopted.

8.4.3. Specialized Equipment

SCE's Specialized Equipment capital expenditures forecast of $7.13 million in 2007, $1.94 million in 2008, and $5.90 million in 2009 is reasonable and should be adopted.

8.4.4. Meters

SCE's meters forecast includes two categories, routine work and non-routine work. Routine work pertains to new metering installations for new customers, routine maintenance and rate changes. Non-routine work pertains to new meters for special programs such as radio technology meters, remotely-read meters to address safety and access problems, and meter leasing.[676]

SCE and DRA differ on forecasted capital expenditures for meters. SCE forecasts $70.295 million for the three-year period 2007, 2008, and 2009 and DRA forecasts $65.4 million for this period, $4.89 million less than SCE. SCE forecasts its capital expenditures for meters by multiplying its estimated number of meter sets and changes for 2007, 2008, and 2009 to its yearly expected cost per meter.

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676 Exhibit SCE-4B, pp. 203-205.

SCE then reduces that result by $0.113 million for anticipated productivity savings from its Enterprise Resource Planning program. This method results in capital expenditures of $22.7 million in 2007, $23.806 million in 2008, and $23.789 million in 2009.[677]

DRA's forecast differs from SCE's in that DRA uses SCE's $20.50 million 2007 recorded capital expenditures for its 2007 forecast. It also uses SCE's 2007 average recorded unit meter costs for its 2008 and 2009 forecasts. DRA multiplies that average recorded unit meter cost by its own 2008 and 2009 new meter connections forecast and to SCE's volume forecasts for routine changes and safety/access work. DRA accepts SCE's meter leasing forecasts.[678] This forecasting method results in DRA recommending $20.5 million in 2007, $22.0 million in 2008, and $22.90 million in 2009.

DRA recommends that SCE's $70.295 million capital expenditures for meters be reduced by $4.895 million, the difference between SCE's $70.295 million 2007 through 2009 capital expenditures and DRA's $65.40 million.

The cost of new meter connections varies by customer class. Residential new meter connections are the most inexpensive of the customer classes. Agricultural and non-residential new meter connections cost more than twice the average rate of residential customer class meter connections. As a result, the mix of new meter connections by customer class can vary significantly from year-to-

677 Exhibit SCE-18, p. 108.

678 Exhibit DRA-7, pp. 49-51.

year resulting in an inaccurate cost of new meter connections in subsequent years.[679]

DRA's 2007 forecast of $20.5 million, reflecting SCE's actual mix and costs of meters in that year, is reasonable and should be adopted. However, DRA's use of 2007 average cost-per-meter installation for the years 2008 and 2009 is not reasonable because the mix of new meter connections varies by year and because DRA did not include any inflation effects to its 2008 and 2009 forecasts. Therefore, SCE's 2008 and 2009 cost-per-meter and customer forecasts, adjusted to reflect the volume of new customers being adopted in this decision, should be adopted.

8.5. Information Technology & Enterprise Resource Planning Capital

SCE identifies $697.9 million of capital expenditures for IT and Enterprise Resource Planning projects for the three-year period 2007, 2008 and 2009[680] in its application.[681] IT capital expenditure projects include infrastructure, storage media, communications, operating systems, application software, and personal computing and communications hardware used by its employees. The Enterprise Resource Planning project consists of software asset management upgrades to replace SCE's aging financial information system that have been in place for over twenty years. DRA recommends $612.3 million of capital

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679 Exhibit SCE-18, p. 109.

680 DRA opening brief, p. 275.

681 SCE requests $283 million of capitalized software expenditures for the forecast period 2007-2011. Exhibit SCE-5C.

expenditures for SCE's IT and Enterprise Resource Planning projects, $85.6 million less than SCE's request.

During evidentiary hearings, SCE and DRA agreed that $25.1 million of capital expenditures for UNIX hardware over the three-year period 2007 through 2009. We find this amount is reasonable and it is adopted.[682] This amount is $7.4 million less than SCE's $32.643 million request and $4.475 million higher than DRA's $20.725 million forecast.[683] SCE also agreed to DRA's forecast of $2 million for Identity Management. As part of its rebuttal testimony, SCE accepted DRA's use of 2007 recorded cost for all IT capital forecasts except for its 2007 NERC Critical Infrastructure request.[684] SCE's acceptance of DRA's use of 2007 recorded data for IT forecasts, excluding NERC CIP which is discussed separately, is reasonable and should be adopted.

The agreed-upon capital expenditures for Identity Management, UNIX hardware, and the use of 2007 recorded data for all IT forecasts except for NERC CPI leaves three issues to resolve in this capital expenditure category: (1) Enterprise Resource Planning, (2) NERC CIP, and (3) Market Redesign and Technology Upgrade.

8.5.1. Enterprise Resource Planning Program

SCE forecasts $295.0 million in capital expenditures for the three-year period 2007, 2008, and 2009 to complete Phase 3 of its Enterprise Resource Planning Program.

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682 RT Vol. 18:1972.

683 Exhibit DRA-26, p. 16.

684 Exhibit SCE-19, p. 17.

DRA concurs with SCE's 2008 forecast of $114.5 million and 2009 forecast of $32.8 million. However, it recommends a $7.5 million downward adjustment to SCE's 2007 forecast of $147.7 million to $140.2 million.[685]

SCE testified that the $7.5 million difference between its forecast and actual capital expenditures for this project in 2007 resulted from several invoices that were expected to be received in 2007 for work performed in 2007 but that were instead received late and not paid until 2008. In addition, certain contract work that was expected to be invoiced in late 2007 was not invoiced until 2008. None of this work performed in 2007 but paid for in 2008 was included by SCE in either the 2008 or 2009 forecast.[686]

SCE has substantiated its 2007 Enterprise Resource Planning forecast, which is reasonable and is adopted.

8.5.2. NERC Critical Infrastructure Project

SCE's 2007 IT Critical Infrastructure Project forecast of $3.123 million is $3.071 million higher than the $0.052 million it actually expended in 2007. DRA recommends SCE be authorized only the actual amount it expended in 2007. However, SCE explains it did not spend its entire 2007 forecast amount in 2007 because FERC took more time than SCE expected to approve the Critical Infrastructure Project Reliability Standards. FERC merely postponed implementation to 2008. SCE must now satisfy two FERC milestone dates,

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685 DRA actually recommended a $7.7 million adjustment for the 2007 forecast year. However, subtracting SCE's $147.7 million 2007 forecast amount from the $140.2 million actual cost identified in Exhibit DRA-17, p. 276, results in a $7.5 million difference.

686 Exhibit SCE-19, p. 20.

June 2009 and June 2010.[687] SCE's 2007 IT Critical Infrastructure Project capital expenditures of $3.123 million are reasonable and are adopted.

8.5.3. Market Redesign and Technology Upgrade

SCE initially forecasted $51 million in capital expenditures for MRTU-related initiatives. Of this amount, $27.0 million is for 2007, $9.8 million for 2008, and $12.0 million for 2009. Pursuant to Resolution-4087, SCE is currently authorized to track its MRTU expenditures in a separate memorandum account and seek recovery of these costs in an ERRA proceeding outside of the GRC. SCE should use its authorized memorandum account to track and recover its MRTU capital expenditures. SCE's proposal to eliminate the memorandum account is discussed elsewhere in this decision.

8.6. Operations Support Capital – Corporate Real Estate

SCE's initial forecast for 2007-2011 for capital projects to construct or remediate non-electric facilities used by its Operations Support Business Unit was $1.243 billion. SCE later reduced its forecast to $1.197 billion.[688] SCE's capital projects fall into three categories: (1) individual projects of at least $1 million; (2) individual blanket work orders of at least $1 million; and (3) projects and blanket work orders below the $1 million threshold.[689] The third category

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[687] Exhibit SCE-19, pp. 17-18.

[688] The $46 million reduction reflects SCE's removal from its forecast of three service center projects: Bishop ($3.4 million); Ontario ($35.7 million); and Orange Coast ($6.7 million). SCE opening brief, p. 189. SCE had expected the costs for these projects to be incurred only in 2011.

[689] A "blanket work order" consists of similar types of projects throughout SCE's service territory, each component of which can be relatively small. Exhibit SCE-10B, p. 90.

cumulatively amounts to $3.7 million from 2007-2011. There is no controversy regarding the forecast for the third category of projects, and they should be approved as requested by SCE.

8.6.1. "Uncontested" Capital Projects Greater Than $1 Million

SCE identifies 25 Category 1 projects totaling $181 million as being uncontested projects that should be approved for the reasons stated in its direct testimony.[690] Uncontested is commonly defined as "not disputed". However, the record does not support SCE's uncontested assertion for the Category 1 capital projects. SCE disagrees, for example, with DRA's forecasting methodology. DRA's forecasting method is not based on a project by project review, as acknowledged by SCE.[691] DRA argues that, among other things, the most recent economic data should be used in projecting customer and load growth, infrastructure expansion needs, and so on. Current economic data and historical patterns of investment logically relate to the need and timing for these capital projects, just as they do for much of the forecasts that we consider throughout today's decision. In addition, TURN takes exception to SCE including contingencies in the range of 5% to 20% on each of its Category 1 projects.[692] SCE's labeling of these 25 projects totaling $181 million over the five-year period, 2007 through 2011, as being uncontested is simply incorrect.[693] The

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[690] SCE opening brief, p. 191.

[691] Exhibit SCE-23, pp. 19, 20.

[692] Exhibit TURN-9, p. 21.

[693] Exhibit TURN-9, p. 3. There is an even larger difference between SCE's forecast and TURN's forecast, specifically, addressing only the first category, TURN recommends $923 million less in these capital expenditures.

difference between the SCE and DRA forecasts are summarized in the table below:

	(Dollars in Millions)				
	2007	2008	2009	TOTAL 2007-2009	TOTAL 2007-2011
SCE					
Category 1	$91	$25	$333	$449	$965
Category 2	$23	$26	$54	$103	$228
TOTAL	$114	$51	$387	$552	$1,193
DRA					
Category 1	$60	$25	$93	$178	
Category 2	**N/A**[694]	$17	$19	$36	
TOTAL	$60	$42	$112	$214	$444[695]
DIFFERENCE	**$54**	**$9**	**$275**	**$338**	**$749**

DRA and TURN have made arguments in favor of a lower forecast than presented by SCE. We now examine the merits of those arguments.

8.6.2. DRA's Recommendations for Larger Capital Projects - Category 1

DRA recommends that SCE's $449 million Category 1 capital expenditures for 2007-2009 be reduced to $178 million for the same period. For 2007, DRA

694 Category 1 and 2 capital expenditures for 2007 are combined into the Category 1 total because SCE did not separate recorded 2007 capital expenditures between these categories for DRA. Exhibit DRA-7, p. 91.

695 DRA did not forecast capital expenditures for the 2010 and 2011 attrition years. It instead recommends alternative attrition methods for those years.

used SCE's actual capital expenditures of $60 million, which SCE was not able to allocate between Category 1 and Category 2 projects. DRA's 2008 forecast of $25 million is equal to SCE's forecast for that year, and DRA's 2009 forecast of $93 million is based on a two-year average of capital expenditures for 2006 and 2007, which equals $56 million. DRA then added $37 million to this $56 million base forecast to arrive at a total of $178 million Category 1 forecast for 2007-2009. The $37 million addition is for two of the larger Category 1 projects (the GO2 Data Center Upgrade and Remodel project and the GO3 and GO4 Furniture and Infrastructure project).[696]

SCE's forecast is based on detailed analysis of 38 individual projects. Such analysis does not guarantee that the individual projects will be carried out per the forecast. For example, in 2006, unanticipated levels of customer and load growth required SCE to shift funding to those needs and to scale back on authorized infrastructure replacement spending.

DRA had the advantage of using more recent economic data in its forecast than SCE. That data resulted in DRA recommending, and SCE subsequently accepting, substantially lower customer growth. The lower customer growth, in turn, reduces SCE's load growth operating requirements, electric infrastructure system expansion needs, and additional operating expense needs. DRA also relied on SCE's building survey, which concluded that its buildings are generally in good condition with few deferred maintenance issues.[697]

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[696] Exhibit DRA-7, pp. 92-97.

[697] Exhibit DRA-7, pp. 94-95.

At the same time, DRA recognizes that reduced customer and load growth do not uniformly affect SCE's proposed projects. For example, as identified by SCE, some of its capital projects, such as installation of high definition cameras in its helicopters to perform circuit patrols, respond to needs other than customer and load growth.[698]

8.6.3. TURN's Recommendations for Larger Capital Projects - Category 1

TURN recommends adjustments for the following projects out of SCE's larger Category 1 capital expenditure projects: (1) GO2 Data Center Upgrade & Remodel; (2) GO3 and GO4 Furniture and Infrastructure; (3) Energy Efficiency, (4) Satellite Service Center; (5) New Headquarters Building; and (6) the Rivergrade projects. According to TURN's analysis, SCE requests authorization to spend in 2009 ($332.8 million) approximately six times the amount actually spent in 2007 ($59.6 million). We discuss these projects in the order listed above.

The Data Center Upgrade was approved for funding in SCE's 2006 GRC at a total forecast of $31.5 million. SCE now seeks $10 million in 2009 to complete this project. DRA concurs with SCE, but TURN excludes this $10 million request from its 2009 Category 1 forecast on the basis that SCE inflated its costs. TURN instead recommends that SCE be authorized $9.34 million to renovate and repair all deficiencies associated with the GO2 Data Center in 2010.[699]

The evidence does not support TURN's contention that costs for this project have been inflated. SCE has substantiated, and DRA has affirmed, that

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[698] Exhibit SCE-23, p. 23.

[699] Exhibit TURN-9, p. 58.

renovation of the GO2 Data Center is reasonable and should continue. Category 1 capital expenditures for 2009 should include $10 million for this project.

The Furniture and Infrastructure project was also approved for funding in SCE's 2006 GRC at a total cost of $15.3 million. SCE seeks $27 million in 2009 to complete this project. DRA concurs with SCE's proposal, but TURN recommends that SCE be allowed only $11.5 million in 2009 to complete this project because the full $27 million request would result in a 77% increase over the cost estimate in the 2006 GRC.[700]

This project was initially approved for furniture and electrical and mechanical infrastructure upgrades in the 2006 GRC. However, SCE subsequently added remodeling and reconfiguration of building interior spaces to the project due to operational needs of the business units housed in the GO3 and GO4 buildings.[701] The enlarged scope of the project justifies the additional expenditure. SCE should be authorized $27 million in 2009 to complete its GO3 and GO4 Furniture and Infrastructure project.

The Energy Efficiency project implements SCE's Energy Resource Management Policy (ERMP) that addresses the shortcomings of its existing non-electric facilities and provides construction guidelines for new facilities to meet the current best practices for energy efficiency, electrical demand response, and resource consumption.[702] SCE seeks to phase in this project beginning in 2009 and continuing through 2011 at an annual $20 million in capital expenditures. TURN opposes funding for this project because SCE's estimate of

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700 Exhibit TURN-9, p. 58.

701 Exhibit SCE-23, p. 67.

energy efficiency costs for "building green" is extremely expensive and inconsistent with SCE's claims. As an alternative, TURN recommends that if this project is approved SCE be authorized no more than one-tenth ($2 million per year) of its request.[703]

Energy efficiency is important policy in California. SCE, a provider of energy, should actively promote and take the lead in energy efficiency and conservation. It should voluntarily comply with Executive Order S-20-04 of the California Governor that encourages commercial building owners to take aggressive action to reduce electricity usage and operate the most energy and resource efficient buildings. Thus, this program should be treated as a pilot program. However, SCE's $20 million yearly request for this project should be reduced to $5 million given that the funding for SCE's non-electric buildings authorized in this proceeding is lower than SCE requested. SCE shall report the results of its implementation and achieved energy efficiencies in its next GRC.

SCE requests roughly $500 million to complete the Satellite Service Center, New Headquarters Building, and Rivergrade projects. Expenditures for these projects would total $137 million, or 41%, of SCE's $333 million Category 1 forecast for TY 2009 and $347 million, or 62%, of its $562 million forecast for the 2010-2011 attrition years. The projects result from a 2005 SCE study[704] to identify

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[702] Exhibit SCE-10B, p. 21.

[703] Exhibit TURN-9, pp. 36-39.

[704] Exhibit SCE-10B, p. 76 at fn. 100 *citing to* the following study: Corporate Real Estate Strategic Facilities Plan 2005-2015 (Field Facilities).

the business drivers affecting its corporate ability to meet forecasted customer and system growth expected through 2015.[705]

- The Satellite Service Center project provides for six new service centers to be constructed in SCE's San Jacinto, San Joaquin, Victorville-High Desert, Antelope Valley, and Valencia high-growth districts.
- The New Headquarters Building project provides for a new four-story 200,000 square foot corporate office building and an employee parking structure for 1,600 vehicles.
- The Rivergrade project provides for the exercising of a lease option to acquire two buildings totaling 285,000 square feet at an estimated cost of $80 million, to spend an additional $54 million to remodel and renovate those buildings, and to construct a $30 million parking structure.

DRA and TURN oppose these projects at this time. DRA relies on the building study by Parsons-3D/I that found SCE's buildings to be generally in good condition. DRA also notes the lower 2009 customer growth forecast and DRA's own lower forecasts of Transmission and Distribution capital expenditures and operating expenses. DRA argues that each of these factors reduces SCE's need for additional office space. To the extent that SCE may need additional office space, DRA believes that some of these needs can be met with the Irwindale Business Center, a 92,000 square foot building purchased in 2006. This building can provide office space for approximately 546 employees in 2010, when SCE's Enterprise Resource planning corporate initiative team vacates the facility.[706]

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[705] Exhibit SCE-10B, p. 76.

[706] Exhibit DRA-7, p. 97.

TURN objects to these projects because SCE performed no cost effectiveness analysis, considered no alternatives, and provided inadequate justification for the projects.[707]

We agree with DRA and TURN that conditions have changed since SCE filed its application. For example, SCE significantly lowered its meter forecast for all customer growth categories during the hearing to reflect current and more recent forecasted market conditions in May 2008.[708] Real estate values have also changed, so the reasonableness of SCE's Rivergrade project, which involves an $80 million purchase of two buildings based on conditions set forth in a 2006 lease agreement, is doubtful. In addition, the current and more recent forecasted economic market conditions should require SCE to reassess these projects and to consider alternatives to these projects. All these conditions lead us to question whether SCE needs to substantially increase its office space at this time. We find that SCE has not demonstrated the need to proceed with its Satellite Service Center, New Headquarters Building, or Rivergrade projects.

8.6.4. Approved Capital Expenditures for Larger Capital Projects

Category 1 capital expenditures of $183 million is reasonable and appropriate for the 2007-2009 forecast years. Of this amount, $60 million is applicable to 2007, $25 million to 2008 and $98 million to 2009. The 2009 amount consists of DRA's $56 million base forecast for that year plus $10 million for SCE's GO2 Data Center Upgrade and Remodel Project, $27 million for the GO3 and GO4 Furniture and Infrastructure project, and $5 million for SCE's Energy

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[707] Exhibit TURN-9, p. 27.

[708] Exhibit SCE-17H1, p. 1.

Efficiency project. For 2009, the approved amount should be reduced by $5.58 million to reflect our decision to reduce SCE's contingency factor for non-electrical facilities.

8.6.5. DRA's Recommendations for Larger Blanket Work Orders - Category 2

Category 2 capital expenditures (blanket work orders of at least $1 million) are further classified into eight subcategories: (1) capital maintenance projects; (2) major structures; (3) rights-of-way acquisitions; (4) ongoing furniture modifications; (5) corporate real estate department furniture and equipment; (6) security system enhancement; (7) supply chain management department furniture and equipment; and (8) transportation services department tools and shop equipment. SCE's forecasts for projects designated above as (3), (6), (7) and (8) above are not in dispute and should be approved as requested by SCE. The table below shows the 2008 and 2009 Category 2 forecasting differences by subcategories between SCE and DRA.

(Dollars in Millions)						
	2008			2009		
Subcategory	SCE	DRA	SCE>DRA	SCE	DRA	SCE>DRA
1	$ 9.0	$ 9.0		$40.0	$ 9.5	
2	$13.0	$ 4.4		$ 7.5	$ 4.4	
4	$ 0.8	$ 0.6		$ 2.3	$ 0.6	
5	$ 0.3	$ 0.1		$ 0.3	$ 0.1	
ADJUSTMENT[709]					$ 0.5	
TOTAL	$23.1	$14.1	$9.0	$50.1	$15.1	$35.0

Regarding subcategory 1, the difference between the SCE and DRA forecasts (capital maintenance projects) pertains to how quickly SCE should correct its non-electric facilities deferred maintenance issues. As noted earlier, the 2006 Parsons-3D/I report concluded that SCE's buildings are generally in good condition with few deferred maintenance issues. SCE estimates that over $220 million is needed to immediately correct all the deficiencies found in its 162 non-electric buildings. To mitigate the immediate costs, SCE proposes to correct these deficiencies by prioritizing its maintenance work over 10 years.

DRA recommends that these deficiencies be corrected over a 15-year period.[710] DRA points to the conclusion of the Parsons-3D/I report, which found that SCE's buildings are generally in good condition with few deferred

709 Exhibit DRA-7, pp. 99-101, DRA's recommendation for each subcategory on pp. 99-104 totaling $18.2 million does not equal DRA's $18.7 million recommendation on p. 91. Therefore, a $0.5 million adjustment is made to equal the total amount of DRA's recommendation.

710 Exhibit DRA-7, p. 101.

maintenance issues. DRA also notes that SCE is already spending an average of $5.5 million for capital maintenance blanket work orders over $1 million.[711] Given these circumstances, DRA argues that SCE should spread the incremental expenditures over 15 years, not 10 years. In an effort to mitigate the immediate cost impact of addressing deferred maintenance in 162 non-electric facilities, DRA's subcategory 1 recommendation is reasonable and should be adopted.

Regarding subcategories 2, 4, and 5, the SCE and DRA forecasts differ due to the use of different forecasting methods. SCE's forecast is budget-based and anticipates future needs. DRA's forecast relies on historical experience. DRA uses a two-year 2005-2006 recorded average for subcategory 2 and a five-year 2002-2006 recorded average for subcategories 4 and 5.[712]

Subcategory 2 provides for unplanned major structural work while subcategories 4 and 5 provide for furniture modifications and replacement. These subcategories consist of blanket work orders for a wide range of conditions and requirements. DRA's forecast provides a systematic amount of funding over time. That forecast is reasonable and should be adopted.

8.6.6. Contingency Percentages Added to Cost Estimate

SCE uses a combination of internal and external sources to develop these percentages. SCE includes contingency percentages in each non-electric capital

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[711] DRA Exhibit-7, p. 102.

[712] Exhibit DRA-7, pp. 102-104, SCE was not able to provide 2002-2004 recorded expenditures for subcategory 2 or 2007 recorded expenditures for subcategories 2, 4, or 5.

project cost estimate based on the level of risk for each project.[713] TURN objects to including contingency funds in these estimates.

TURN argues that constructing, renovating, and buying furniture for buildings are not nearly as complicated as building power plants or attempting to deploy complicated multi-billion dollar information technology and advanced metering projects.[714] For less complex capital projects, TURN suggests no contingency percentage should be included. Furthermore, many of SCE's estimates are so-called "Level 1 ROM" estimates. Such estimates are Rough Order of Magnitude and are intended to facilitate budgetary decisions within the utility.[715] SCE's management does not generally rely on such estimates for purposes of approving projects but rather to determine if a project is realistic from a budgetary stand point.[716] TURN roughly calculates that SCE included $71 million of contingency funds to its non-electrical facilities, or approximately 15% of total project costs.[717]

Because SCE's cost estimates remain at a very preliminary stage, we find no value in simply increasing this number by an arbitrary contingency rate. While SCE argues that contingency percentages are standard industry practice applied to each project based on the level of risk for each project, we do not find SCE's Level 2 ROM cost estimates sufficiently reliable to make a determination that a contingency is warranted. As such, we reduce SCE's authorized capital

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713 Exhibit SCE-23, p. 45.

714 Exhibit TURN-9, p. 22.

715 TURN opening brief, p. 214.

716 TURN opening brief, p. 214.

717 Exhibit TURN-9, pp. 21-22.

expenditure amount for non-electric facilities by 15%, the approximate amount recommended by TURN.

9. Rate Base - Other than Plant in Service

9.1. Working Cash – Revenue Lag Days

SCE's determination of working cash includes the lead-lag analysis, following the Commission's policy set forth in Standard Practice (SP) U-16. The lead-lag analysis is a method used to determine the amount of funds required to pay operating expenses in advance of receiving customer revenues. It requires a comprehensive analysis of transactions to determine the net lag days between (1) the time lag between when the utility services are rendered and the receipt of the associated revenues for those services (revenue lag) and (2) the time lag between the recording of the utility costs such as purchased power, labor, materials, and so forth, and payment of those costs (expense lag).

For revenue lag, SCE originally proposed 42.03 days for 2009. SCE presents three different methodologies in support of its proposal: (1) the Accounts Receivables to Sales Ratio method yields an estimate of 42.03 revenue lag days; (2) the Aged Accounts Receivables method yields an estimate of 41.83 revenue lag days; and (3) the Analysis Individual Bills method yields an estimate of 41.97 lag days. SCE's revenue lag estimate was determined by using the Accounts Receivables to Sales Ratio method. The two remaining methods calculated by SCE were used as confirmation.[718] SCE accepts TURN's proposed adjustment for Summary Billing Lag and accordingly reduced its revenue lag day estimate by 0.28 days, resulting in a revised lag day estimate of 41.75 days.

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[718] Exhibit SCE-24A, p. 82.

As discussed below revenue lag should be reduced by an additional 0.08 day resulting in an adopted revenue lag estimate of 41.67 days.

9.1.1. DRA Adjustment for Uncollectibles and Averaging of Methods

DRA recommends removing 0.6 days of uncollectible lag adjustment from the Analysis Individual Bills method to yield a revenue lag of 41.4 days instead of 42.0 days. According to DRA, SCE is already receiving working cash treatment for uncollectibles as part of expense lag days and uncollectibles should not be included again in the derivation of revenue lag days. DRA also indicates that the Commission's Standard Practice U-16 does not include uncollectibles in the determination of revenue lag days.

DRA believes it is appropriate to take an average of the lag day estimates derived from each of the three methods that SCE used in this GRC, because all three methods appear to merit some consideration. The results of DRA's averaging methodology results in a 0.27 day reduction to SCE's revenue lag estimate.[719]

SCE disagrees with DRA's proposed uncollectible adjustment.[720] SCE states that DRA offers no evidence supporting its contention that SP U-16 does not include uncollectible bills in the revenue lag calculation. It is SCE's contention that the record is replete with evidence demonstrating that SP U-16 does include uncollectible bills in the revenue lag calculation and demonstrates how the inclusion of uncollectible bills in the revenue lag calculation is necessary

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[719] Exhibit DRA-19, pp. 8-9.

[720] Exhibit SCE-24A, pp. 84-87.

and consistent with the treatment of uncollectibles elsewhere in working cash (i.e., expense lags and the accumulated provision for uncollectibles).

Regarding DRA's argument that to include both uncollectible bills in the revenue lag calculation and uncollectible write-off expense in the expense lag calculation would double-up on the working cash, SCE states that DRA misunderstands lead-lag analyses, which represent two sides of the same coin. That is, a lead-lag analysis attempts to capture the timing difference between the payment of expenses and the receipt of the revenues for those same expenses. Therefore, the expenses included in the expense lag calculations need to mirror the amounts included in the revenues. According to SCE, this is true for all expenses, including O&M, goods and services, fuel and purchased power, depreciation, taxes, and uncollectibles or bad debt expense.

The sole method that DRA claims requires the uncollectibles adjustment (i.e., the Analysis of Individual Bills method) was not used to determine SCE's estimate. Therefore, SCE argues that DRA's prescribed averaging is neither appropriate nor necessary and the presumed basis for the proposed adjustment disappears. In light of DRA's contention regarding the uncollectibles adjustment for the Analysis of Individual Bills method, SCE states that DRA should have provided, some support for the necessity of its averaging approach since DRA's proposal assigns equal weighting to all three revenue lag methods. SCE indicates that while DRA provided no support for its position, SP U-16 indicates that reliance on the Accounts Receivables to Sales Ratio method (i.e., used by SCE) is preferable to the Analysis of Individual Bills method.

The evidence in this case supports SCE's contention that uncollectibles should be included in the revenue lag calculation and that it is included in the Accounts Receivables to Sales Ratio method.[721] SCE is also correct that SP U-16 states a preference for an "accounts receivable" method as opposed to a "statistical sampling" method.[722] It is therefore reasonable to use the Accounts Receivables to Sales Ratio method in isolation rather than as part of an average that includes a "statistical sampling" method. For these reasons, we will not adopt DRA's recommendation to reduce revenue lag by 0.27 days.

9.1.2. TURN's Adjustment for Meter to Service Billing Lag

The "metering to service billing lag" refers to the time period between the actual reading of a meter and the sending of a bill to the customer. There is no dispute concerning the facts that 99% of the bills are sent within two days of the meter read, and that only 0.026% of the accounts contribute about 8% of the lag due to their extremely long meter to billing interval that is greater than 90 days.[723]

TURN recommends that as a matter of policy the Commission should not allow SCE to profit from billing intervals that are longer than 90 days. Removing

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[721] SCE provided an analysis of how uncollectibles are include in the Accounts Receivables to Sales Ratio method in Exhibit SCE-24, pp. 82-86.

[722] Specifically, SP U-16, at p. 3-11, states "36. If appropriate accounting records are maintained and readily available from large utilities, the "accounts receivable" method should be use in preference to the "statistical sampling" method for the development of lag days in future working cash studies. The "accounts receivable" method will yield a more representative lag experienced by the utility for the entre year which will not be subjected to any sampling variability. However, if appropriate accounting records are unavailable, the "statistical sampling" method may be used."

[723] Exhibit TURN-5A, p. 136; Exhibit SCE-24, p. 89.

these accounts from the calculation decreases the revenue lag by 0.08 days. TURN states (1) SCE's Tariff Rule 17 does not even allow adjustments to bills due to meter or billing error after more than three months,[724] which means that in practice a residential bill cannot even be rendered more than 120 days after a meter read; (2) the Commission instituted the prohibition against retroactive billing in 1986;[725] and (3) the Commission just recently concluded that back billing residential customers for usage more than three months ago violates Rule 17.1 and warrants the payment of refunds.[726]

TURN reasons that even if certain problems appear after a meter is read and require additional investigation and correction, the Commission should institute all possible incentives for SCE to resolve these problems as quickly as possible. Allowing SCE to profit from excessively long billing intervals by inflating the working cash calculation is the wrong incentive.

In response, SCE states that it processes over 55 million customer statements each year on 5 million different meters and hundreds of rates, and, given this volume, it should be expected that some accounts that will fall out of the routine billing and exception processes. There will be long billing intervals and some will be unusually long depending upon the related circumstances. SCE points out that the billing intervals that TURN addresses are very rare, occurring in only about 26 out of every 100,000 bills processed, and, just as with other bills, it needs to be recognized that SCE has to finance the working cash during the time that these bills are being processed and collected. SCE

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[724] Exhibit TURN-41. The relevant provisions are in Sections C-2 and D-2 of Rule 17.

[725] D.86-06-035.

characterizes TURN's elimination of these billing lags amounts as cherry-picking and urges the Commission to dismiss it as unnecessary and unreasonable.

During cross examination, SCE witness Pierce was unable to identify specific reasons for the long delays and did not know if any of the circumstances of the long delays violated Tariff Rule 17 on the time necessary to send customer bills.[727] We are unable to determine the reasonableness of the long meter to service billing lag in question. TURN's recommendation that as a matter of ratemaking policy the Commission should limit such billing intervals to 90 days is reasonable and will be adopted. Accordingly, revenue lag will be reduced by 0.08 days.

9.2. Working Cash – Federal Income and Corporate State Taxes Lag Days

SCE determines FIT and CCFT lag days to be 46.1 and 20.5, respectively.

DRA proposes that the Commission reject SCE's determination and adopt its proposals of 147.94 days (FIT) and 143.75 days (CCFT).[728] DRA disputes the tax payment figures that SCE used in developing its FIT and CCFT lag days. DRA argues that SCE is a wholly owned subsidiary of EIX, and therefore does not make actual quarterly tax payments to the Internal Revenue Service (IRS) or California Franchise Tax Board (FTB). According to DRA, SCE derived its calculations of FIT and CCFT lag days at the utility level; the calculations are not based on actual tax payments; and SCE did not provide any correlation of its estimated utility tax lag to actual tax payments made by EIX.

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[726] *See, e.g.,* D.07-09-041, pp. 3-5.

[727] RT Vol. 15:1632-1638.

[728] Exhibit DRA-19C, pp. 9-10.

It is DRA's position that, from a working cash calculation standpoint, the tax expense lag day estimate should be based on the actual amounts and dates of payments made to the IRS and FTB. DRA used the actual EIX tax payment data to develop the FIT and CCFT lag days for SCE for TY 2009, because it is EIX that is making the actual tax payments. DRA's lag day estimate is developed on the basis that EIX pays the proportionate amounts for quarterly FIT and CCFT payments for the utility. Using the "mid-year" methodology, in conjunction with the actual EIX federal and state quarterly tax payments, DRA derived the actual FIT and CCFT lag days for year 2006. DRA used the 2006 recorded lag days to arrive at its FIT and CCFT lag days, and recommends that the Commission adopt these figures for TY 2009.

According to DRA, it used the actual 2006 tax data because it reflects the most reasonable correlation between the actual tax payment and the adopted ratemaking taxes for that year. DRA states that a review of the prior years' data shows that the actual tax payments were much lower than the adopted ratemaking taxes. DRA concludes that the 2006 is most representative year and most appropriate data to utilize for calculating the tax lag for calculation of working cash.

SCE disagrees with DRA's estimates for a number of reasons.[729] First, SCE asserts that despite the expected annual variations in tax payment patterns, DRA abandoned its previous use of a five-year average of tax payments, which would help normalize abnormal variations, and relied solely on 2006. SCE adds that the record demonstrates that 2006 estimated tax payments are anomalous, with an

[729] Exhibit SCE-24A, pp. 92-102.

extremely large Fourth Quarter payment. Consequently, the Federal Income Tax lag estimate based upon 2006 payments is about 2.3 times greater than the 2002-2006 average payments for the utility; and about 2.6 times greater than the 2002-2006 average for the holding company. SCE also notes that DRA's proposed FIT tax lags are twice as large as the current authorized and its proposed CCFT tax lags are more than three times as large as the authorized.

Second, SCE asserts that DRA was aware of the recently implemented tax regulations that significantly reduced tax payment lags,[730] and there is no reasonable justification for DRA's choice to simply disregard it. According to SCE, the record fully demonstrates that the company's compliance was required beginning this year and that the new tax regulation will change the pattern for property tax expense deductions and quarterly tax payments. SCE calculates that the IRS rule change will cause an average 50-day reduction in overall FIT payment lags.

Third, SCE argues that DRA's tax lag calculation oversimplifies the payment lag pattern by assuming a levelized incurrence of the tax liability and ignoring the underlying monthly pattern of base rate revenues. According to SCE, the annual distribution of income tax recovery in base rate revenues is not level, but is higher during the summer months, and DRA's disregard of this adjustment inflates their estimated income tax lag by eleven days.

Finally, SCE argues that DRA's proposal goes against the Commission policy as set forth in OII-24 and applies the holding company's (EIX) overall tax payments rather than the utility-specific (SCE) tax payments in its tax lag

[730] Internal Revenue Code § 6655.

calculation. SCE states that its FIT and CCFT tax payments represent actual cash payments made by the utility to EIX for its share of EIX's tax obligations, and therefore the utility tax payments utilized by SCE represent the actual working cash impact on the utility. Also, its use of the separate utility tax return method for ratemaking avoids cross subsidies with the holding company and is consistent with the Commission's OII-24 decision.

We will not adopt DRA's adjustment for two reasons. First DRA did not address or attempt to reflect the change in the recently implemented tax regulations that SCE argues significantly reduces tax payment lags. Whether or not SCE has accurately reflected the effect of the changed tax regulation has not been addressed or challenged by any party, but SCE's analysis[731] appears reasonable enough to determine that the change will have a substantial effect on the determination of income tax lag days. It is not clear why DRA has chosen to completely ignore this point, but its income tax lag recommendations are severely compromised by its choice to do so.

Second, the 2006 recorded tax payments used by DRA to calculate its FIT and CCFT lag days contains an anomaly that distorts that year's data. As described by SCE:

> The SCE fourth quarter 2006 estimated tax payment was inordinately large, primarily as a result of very sizeable ERRA balancing account over-collections (about $500 million) that occurred as a result of the extreme summer weather. Even though these over collections would eventually be refunded to customers, at that time the amounts were considered taxable as income requiring a large fourth quarter tax payment that affected the payment lag.

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731 Exhibit SCE-24A, pp. 94-97.

> This was a unique aberration that will not reoccur. Based on Revenue Ruling 2003-39 which addresses the treatment of fuel balancing accounts, SCE elected not to be taxed on over collections beginning in 2007.[732]

Because of this nonrecurring anomaly, it would not be reasonable to adopt DRA's methodology that solely uses that 2006 information as a basis for its income tax lag day calculations.

We also agree with SCE regarding the determination of the income tax recovery midpoint using actual monthly distribution of income tax recovery rather than the levelized pattern assumed by DRA. Since it is based on actual recorded information, SCE's methodology is more likely to reflect what will actually occur in the test year.

In summary, SCE's income tax lag day methodology is reasonable and the derived federal income tax lag of 46.1 days and state income tax lag of 20.5 days will be adopted.

Regarding DRA's use of EIX tax payment information, in principle we see nothing wrong with the consideration of such information in determining the income tax lag days for SCE. However, potential problems as discussed by DRA regarding the years prior to 2006 and by SCE in general would need to be considered and possibly remedied before such information could appropriately be considered. Perhaps the only real value in considering EIX tax payments might be the actual timing of the tax payments to the extent that they differ significantly from when SCE makes its payments to EIX.

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[732] Exhibit SCE-24A, p. 97, fn. 182.

9.3. Working Cash – Pensions and PBOPs Lag Days

SCE indicates that, consistent with the balancing account treatment the Commission has afforded the pensions and PBOP expenses, it has transferred the associated working cash impacts to the balancing account by applying a zero day lag. According to SCE, this approach protects both ratepayer and utility by compensating for the actual intra-year variations in the timing of pensions and PBOP payments versus revenue collections by dynamically adjusting for the actual payments dates and amounts.[733]

It is TURN's position that SCE has not justified changing the methods to use a zero lag for pensions and PBOPs. Regarding SCE's argument that using zero lag days is necessary because (1) these items are included in a balancing account, and (2) Edison will change the timing of the credits to the balancing account to reflect actual quarterly cash payments instead of monthly accruals, TURN states that SCE's first argument makes no logical sense, and its second argument evidences a desire to change accounting rules simply to benefit shareholders

While all of the utilities have some type of balancing account for pensions and PBOPs, TURN notes that SCE stands alone with its zero lag day assumption.[734] According to TURN, both PG&E and SDG&E have balancing accounts for pensions (and SDG&E for PBOPs) but do not assume zero lag days. TURN also notes that SCE itself has other expenses which have balancing

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[733] Exhibit SCE-24A, pp. 103-106.

[734] Exhibit TURN-5A, p. 138.

account treatment (most significantly, large expenses for fuel and purchased power) for which it calculates positive lag days in the lead lag study.[735]

TURN argues that in reality, Edison pays its pension and PBOPs contributions with relatively long lags. In 2006, Edison paid its pension contributions at or shortly after the end of the year. In 2007, Edison made four pension fund payments - three equal payments in June, September and December and a smaller payment in January, but only one PBOP payment.[736] TURN calculates that the pension contribution in 2007 would have 96.5 lag days. TURN indicates that for PBOPs, the payments are divided into two parts – a larger payment made near the end of the year (75.5% of the total in 2006) and a smaller portion of "pay-as-you go" payments (24.5% in 2006) that are made approximately monthly.[737] TURN calculates the lump sum end of year payment would have 179.5 lag days in 2006. Assuming the "pay as you go payments have zero lag days (i.e., made at mid- month), TURN calculates the whole PBOPs lag would be 118.20 days.

According to TURN, the balancing account is based entirely on monthly accruals, not the actual time of payment, in order to provide that actual payments for pensions and PBOPs are recovered exactly over a full rate case cycle; and the result of monthly accruals combined with quarterly payments for pensions and annual payments for 75% of PBOPs costs means that, under SCE's

[735] Exhibit SCE-11B, pp. 85-86.

[736] Exhibit SCE-24A, p. 105; RT Vol. 15:1642.

[737] Edison claims it is reasonable to pay PBOPs once a year while paying pensions quarterly because of uncertainty in the actuarial estimates and the pay-as-you-go quantities. Exhibit TURN-40.

cash working capital calculation, the lag from accrual to actual cash payment is completely ignored and therefore disappears into shareholders' pockets unless recognized in the working capital calculation.

With respect to quarterly funding of pensions and PBOPs, TURN states that in April 2008 SCE provided a data response explaining why various complicating factors made it too difficult to make quarterly PBOPs fund contributions.[738] TURN argues that SCE has not met its burden of demonstrating it has the capability to make payments on a time frame that results in lower lags, and thus TURN's estimate of lag days should be adopted, adding that even if SCE's proposal to institute quarterly funding of the PBOPs account is true, such a funding pattern would only reduce the lag and would not in any way warrant the assumption of zero lag days.

TURN's recommended adjustments to the pensions and PBOPs lags reduce rate base by $15.082 million and $18.973 million respectively. SCE's revenue requirement (return and taxes) would be reduced by $4.84 million.

SCE disagrees with TURN's argument that the use of a zero-day lag does not make sense in the context of a balancing account. According to SCE, the pensions and the PBOPs balancing account treatment should account for the actual intra-year variation in payments; the zero-day lag in the lead-lag analysis is appropriate to avoid double-counting of the working cash component included in the balancing account; and because the accrued revenue in the balancing account immediately accrues interest charges until the payment is made, then the working cash should not also be included in the lead-lag analysis.

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[738] Exhibit TURN-40, Response to TURN DR 037-04.

SCE also states that TURN's argument that SCE stands alone with its zero lag day assumption is misplaced. PG&E's and SDG&E's balancing account treatment is different than SCE's proposal in this proceeding as they do not compensate ratepayers for the actual payment timing in their respective balancing accounts at this time. SoCalGas does have a zero-day lag for its PBOPs expense. Moreover, the Commission has previously authorized SCE a zero-day lag for the pay-as-you-go PBOPs. SCE also states that TURN's comparison to the balancing account treatment for fuel and purchased power is also misplaced as the timing of these payments depends on contractual agreements. SCE indicates that the timing of pensions and PBOPs funding patterns can have a significant impact on the balancing account, and SCE's proposal would capture the actual timing of the payments.[739]

According to SCE, TURN proposes to fix the payment lags at 96.5 days for Pensions and 118.20 days for PBOPs irrespective of the actual payment timing and despite SCE's stated intent to fund on a quarterly basis. It is SCE's position that the quarterly funding pattern better aligns the timing of the ratepayers' provision of the accrued expense and the payment of those amounts and is similar to those followed by the other utilities.[740] Also, SCE witness Mr. Pierce points out that the balancing account requirement that ratepayers be compensated for the payment lag at the short-term interest rate makes the utility indifferent to making quarterly fund payments. If the utility has a need for cash, the utility can borrow from the capital markets at the short-term rate. Therefore,

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739 Exhibit SCE-24A, pp. 104-106.

740 Exhibit SCE-24A, pp. 105-106.

balancing account treatment appropriately eliminates any potential interest rate arbitrage, protecting both ratepayer and utility, and making them relatively indifferent to variations in payment timing.[741]

SCE states that it has made clear its intention to implement quarterly funding and that if the Commission decides not to account for actual payment timing in the pensions and the PBOPs balancing accounts, that it should adopt the 44.25-day lag for Pensions and the 26.66-day lag for PBOPs consistent with the quarterly funding.[742] On the other hand, SCE argues that TURN's proposed lags do not reflect the quarterly funding, are excessively long, contain calculation errors, and should be rejected.

We have major concerns with SCE's proposed lag day treatment of the pensions and PBOPs payments (excluding pay-as-you-go). First, SCE indicates that it will use actual intra-year variations in the actual payment timing in determining interest in the applicable balancing accounts. Second, SCE indicates that it intends to pay its pensions and PBOPs (excluding pay-as-you-go) on a quarterly basis. These proposals are significantly different from the current treatment, and SCE has not explained why the current treatment is defective or unworkable. Moreover, we are concerned about the effect these changes have on costs to ratepayers, and whether the changes are reasonable in that context.

Regarding intra-year variations in the payment timing, SCE states:

> "TURN misconstrues SCE's proposal as completely ignoring the lag from revenue accrual to the actual cash payments. TURN bases this on the fact that SCE's *current* balancing account uses monthly

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741 Exhibit SCE-24A, p. 106.

742 Exhibit SCE-24A, pp. 106-107.

> accruals and not actual intra-year variations in the actual payment timing. However, this current provision was necessary to accommodate the 2006 GRC decision treatment while neglecting to adjust the working cash treatment for the pensions and PBOP payment lags. The implementation of the 2006 GRC decision would have resulted in a double-counting if both the working cash and the balancing account had incorporated the payment lags impact."[743]

From this statement, we conclude that, if SCE were to maintain its current balancing account treatment that uses monthly accruals and not actual intra-year variations in the actual payment timing, it would be proper to reflect calculated lag days for pensions and PBOPs payments (excluding the Pay-As-You-Go) rather than to use a zero day lag. This treatment would apparently be consistent with that currently being provided to PG&E and SDG&E.[744] Furthermore, SCE's choice to go to quarterly payments, which decreases the lag days from that determined by historical payment patterns, has not been fully explained as to the need to go to quarterly payments or what was wrong with the previous payment patterns which provided a benefit to ratepayers in the form of a greater reduction to working cash. Therefore, we will not adopt SCE's proposal to use actual intra-year variations in the actual payment timings in determining balancing account interest. Also, we determine the lag days for pensions and PBOPs (excluding pay-as-you-go) based on the actual payments for 2006 and 2007 rather than SCE's proposed quarterly payments. This results in a pensions lag day estimate of 96.5 and a PBOPs (excluding pay-as-you-go) lag day estimate

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[743] Exhibit SCE-24A, p. 103.

[744] SCE indicates that "…PG&E's and Sempra's pensions balancing account treatment is different than SCE's proposal in this proceeding. At this time, these utilities do not compensate ratepayers for the actual payment lags in their respective balancing accounts." Exhibit SCE-24A, p. 104, fn. 191.

of 118.2, as proposed by TURN.[745] We believe our decision on this issue is optimal from the ratepayers' standpoint, and we have not been presented with any evidence that basing it on what actually happened in 2006 and 2007 will have any adverse affects on SCE's pensions and PBOPs programs.

We do not believe that our reliance on an evaluation of the ratepayer affects of SCE's proposal in deciding this issue is misplaced or unreasonable. In areas where SCE has discretion on how it handles payments, it is reasonable to impose ratemaking adjustments that will encourage the company to exercise such discretion in a manner favorable to ratepayers. We note that the lead lag analysis in SCE's 2006 GRC resulted in expense lag exceeding revenue lag by 5.9 days resulting in a reduction to rate base of $92.101 million, while SCE's lead lag analysis in its current application shows revenue lag exceeding expense lag by 12.04 days,[746] which would result in an increase to rate base in the range of $200 million. While much of this approximate $300 million swing in the lead lag analysis, which is a significant increase in costs to ratepayers, has been substantiated by SCE's showing and the evidence in this proceeding, it is important that we do what we can to ameliorate the effects on ratepayers wherever possible.

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[745] SCE has criticized TURN's use of 2006 information for PBOPs indicating that 2006 PBOPs funded amounts were unusually high. While SCE indicates that the 2006 amount was 56% higher than 2007, it did not provide any evidence that 2007 was a typical year or what a typical year would be. SCE also indicates that it would have been more appropriate if TURN had used the forecast 2009-2011 PBOP expense amounts to weight the lag days. However, SCE did not provide what those amounts would be or how the use of those amounts would affect the lag day calculation. Lacking that information, TURN's estimate will be used.

[746] Exhibit SCE-11B, p. 81.

9.4. Working Cash – Minimum Cash Balance

SCE includes $7.5 million for Cash Balances in its TY 2009 Working Cash Requirement. DRA recommends that this $7.5 million be removed from Rate Base and no funding should be included in TY 2009 for Cash Balances.

In its response to a DRA data request, SCE stated, "For 2006 and 2009 the required minimum balance that banks require SCE to deposit to maintain commercial accounts is zero."

The Commission's SP U-16 states:

> In determining the cash requirement, the only amounts which should be considered are the required minimum bank deposits that must be maintained and reasonable amounts of working funds. The determination of the amount of money required to pay expenses in advance of receipt of revenues is made by the lag study. If funds were to be allowed in the cash requirement, over and above the minimum bank deposits for payment of certain operating expenses, it would have the effect of providing for payments of the same cost twice, once as determined in the lag study and once again in determining the operational requirement.[747]

DRA argues that the $7.5 million is not a "required bank deposit" as set forth in SP U-16, and recommends it be excluded from the working capital requirement and rate base for TY 2009. This recommendation is also consistent with D.06-05-016, the Commission decision in SCE's last GRC, in which the Commission authorized no funding for Cash Balances.[748]

SCE does not disagree with the concept that only minimum required bank balances should be included in working cash. However SCE submits that the

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[747] CPUC Standard Practice U-16, pp. 3-4.

[748] D.06-05-016, Appendix C, p. C-23.

$7.5 million included in its proposed working cash is a required minimum balance. SCE reasons that although it is not an institutionally required minimum balance specifically mandated by the banks, it is a functionally required minimum balance in that the $7.5 million represents the average balance remaining at the end of the business day in which SCE is unable to invest due to the nature of banking operations and deadlines. SCE indicates that third-party remittances made after the 2:00 Pacific investment cut-off time cannot be appropriately invested until the next business day, and argues that the minimum balance in question cannot be eliminated and should be reflected in working cash.

On this issue, we agree with DRA's position. The $7.5 million cash balance should be excluded from rate base. In general, how SCE manages such day-to-day cash balances is an activity that we do not review and second guess without good cause. In this instance there are no claims of any sort of mismanagement, but only a claim that SCE's request is contrary to our stated standard practice and past decisions. While it is understandable that SCE might not be able to invest every dollar that it wants to invest at the time it would like, we feel it is reasonable for the Commission to strictly interpret its guidelines or standards, in this case that only bank required minimum deposits should be included in working cash, and to use that strictly interpreted standard or guideline in setting rates. In this case, to do otherwise would open up potential issues of not only whether the $7.5 million is functionally required but whether SCE is managing its cash in the most effective way in order to maximize the use of that cash and minimize any cash balances that the ratepayers would have to fund. In this case, we have presented with no evidence that shows whether or not SCE has maximized the use of those funds. However, the amount at issue is not large

($7.5 million to be included or excluded from a rate base of approximately $15 billion), and by imposing a strict interpretation of our standard practice, a showing of reasonableness by SCE, analyses and recommendation by other parties, and determinations of reasonableness by the Commission are obviated. By our actions, the ratemaking process is facilitated, the utility is incented to efficiently manage its cash, and any potential consequences of inefficient cash management are appropriately imposed on the company and its shareholders rather than on the ratepayers.

9.5. Working Cash – Other Operational Cash Adjustments

SCE estimated its working cash for forty Operational Cash accounts by escalating the aggregate balances to the test year. TURN analyzed SCE's Operational Cash and recommends reductions of $1.974 million for prepayments and $3.981 million for other accounts receivable.[749]

According to TURN, the June Lake and Morongo transmission prepayments are known and measurable and the 2006 recorded amounts should not be escalated as proposed by Edison. Use of the known amounts results in a reduction of $241,000 to SCE's test year 2009 estimate. For the Bechtel prepayment balance, TURN asserts two adjustments are needed. First, SCE included prepayments that are the responsibility of the plant's co-owners. Second, the Bechtel contract relates to refueling outages at SONGS, and in the base year 2006, there were two SONGS refueling outages, while on average each SONGS unit is refueled every 18 months. Since there will be four refueling

[749] Exhibit TURN-5, pp. 129-132.

outages every three years, TURN recommends that the Bechtel number in 2006 should be multiplied by 2/3 (2 refueling outages in the base year divided by 1-1/3 in the average year), thus reducing the amount by $1,459 million. The last prepayment issue relates to software. In the years 2003-2007, SCE has only had prepaid software license expenses in 2006. TURN considers this to be a non-recurring cost and recommends removing $274,000 from rate base (the 2006 average of $255,000 escalated to 2009 dollars).

Regarding other accounts receivable, TURN indicates that SCE has been successful in reducing the long lags associated with accounts receivable from its PBOPs trust. SCE reflected a lag of $38,000,000 in 2006, but recorded amounts for 2007 were reduced to $30,615,000. TURN recommends that the Commission adopt the 2007 figures for PBOPs trust receivables, and because some other costs in this account were higher in 2007 than in 2006 (even after taking inflation into account), TURN further recommends that an average of the 2006 and 2007 figures (adjusted upward to 2009) be adopted for all other costs. In total, TURN reduces other accounts receivable by $3.981 million.

SCE states that TURN's embracing of SCE's general methodology and the selective downward adjustments based upon updated balances and future expectations for five accounts is cherry picking and should not be adopted. According to SCE, some accounts will decrease and others increase, and it would be improper to selectively adjust only those that decrease. SCE also states that there are 34 other general ledger accounts included in Operational Cash that TURN chose to ignore, and updating the 2007 recorded balances for the accounts that TURN ignored actually demonstrates a decidedly increasing trend. SCE argues that if the Commission should decide to update the Operational Cash, it should consistently reflect the trend for all of the accounts, and increase SCE's working cash requirements by $1.684 million as demonstrated by the record.[750]

9.5.1. Prepayments

For prepayments, TURN identified two items where the prepayment amount is known. Rather than escalating the 2006 recorded amount to 2009, TURN used the known prepayment amounts for 2009. For prepayment costs related to SONGS, TURN reflected SCE's ownership share and normalized the costs to reflect the schedule of four refueling outages over three years. Also, TURN identified certain prepaid software to be a non-recurring cost and excluded it from the base year amount. SCE has not questioned the merits of TURN's specific adjustments, but instead accuses TURN of cherry picking. TURN's adjustments are consistent with ratemaking principles, are reasonable, and will be adopted.

In adopting test year costs, we would prefer to use known costs rather than estimated costs, for obvious reasons. The known cost is what will actually be incurred. The estimated cost may or may not be what is actually incurred in the test year. Use of known costs that are reasonable increases our confidence that the rates generated by this decision are fair. Also, normalization of costs is a well established ratemaking principle. Finally, in general, exclusion of non-recurring costs from base year amounts used to estimate test year costs is reasonable.

SCE's claim of cherry picking is unfounded. SCE bears the burden to justify its costs, and for these items chose to use a methodology that escalates

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[750] Exhibit SCE-24A, pp. 76-78.

2006 recorded costs to 2009 levels. It is reasonable for parties to question whether such costs are nonrecurring, whether such costs should be escalated, and even if the 2006 cost should be escalated whether it should be normalized over the rate case cycle. SCE's methodology for escalating base year prepayment costs to test year costs would be strengthened, if it first incorporated adjustments such as those recommended by TURN.

SCE makes the point that if 2007 recorded costs were used for the remaining prepayments and then escalated to 2009, the amount would be greater than what it estimated. We are not persuaded to reject TURN's proposal for this reason. The use of 2007 recorded data for estimating test year 2009 prepayments has not been proposed by any party, and the 2007 recorded amounts have not been examined to determine whether adjustments similar to that proposed by TURN are warranted.

9.5.2. Other Accounts Receivable

For other accounts receivable, TURN recommends the use of the 2007 recorded figures for PBOPs trust receivables to reflect the fact that lag associated with PBOPs trust receivables has been reduced from 2006 levels. The fact that lag has been reduced is not disputed by SCE. It is reasonable to assume that the reduced lag will continue into 2009 and to use the 2007 recorded amount (escalated to 2009) as recommended by TURN. Since TURN is using the 2007 recorded amount for PBOPs trust receivables, it reviewed the other items in other accounts receivable, determined that the 2007 recorded amounts were higher than the amounts determined by escalating 2006 recorded to 2007, and recommended the average of 2006 and 2007 (escalated to 2009) be used for the test year estimate of these remaining items. SCE notes this adjustment but does not indicate that it agrees or disagrees with it, indicating only that TURN did not account for 2007 recorded data in other areas of operational cash. Reflecting 2007 recorded information for all aspects of other accounts receivable is reasonable and we will adopt TURN's recommended reductions of $3.981 million for 2009. As opposed to the issue of using 2007 recorded data for prepayments, the recommendation to use 2007 recorded information for other accounts receivable has been recommended by one of the parties, and the 2007 information has been scrutinized.

9.6. Unfunded Pension Reserves

DRA recommended an adjustment to SCE's executive benefits and pension expenses in 2009.[751] SCE opposes DRA's recommendation, but both parties agree that if DRA's recommendation is adopted, there should be a related reduction to the Unfunded Pension Reserve offset to rate base of $2.782 million.

As discussed earlier in this decision, in Section 6, we have adopted DRA's recommendation to exclude 50% of SCE's forecasted executive benefits. Therefore, the Unfunded Pension Reserve offset to rate base should be reduced by 50% of $2.782 million or $1.391 million.

9.7. T&D Materials and Supplies

T&D Materials and Supplies (M&S) inventory supports current T&D project expenditures, such as infrastructure replacement and maintenance programs, as well as provides emergency inventory stock. The material flowing through this inventory consists of such items as poles, cross arms, pole hardware, conductor, insulators, lightning arrestors, switches, fuses, fuse holders, enclosures, and underground components.

[751] Joint Comparison Exhibit, p. 503.

SCE recommends using a regression analysis of the three-year rolling average trend for the T&D capital expenditures and the T&D M&S inventory. This data indicates that for each $1 million in incremental T&D construction expenditure there is a need for about $40,000 in additional T&D M&S inventory to support the project activity. SCE indicates the correlation between the expenditures and inventory is strong – the regression analysis results in an Adjusted R-square of 0.99. Applying the incremental inventory-capital expenditures relationship to the forecast capital expenditures, results in an SCE estimate of the average test year 2009 T&D M&S inventory balance of $93.096 million.[752]

DRA derived its estimated 2009 weighted-average T&D M&S balance of $88.878 million by increasing the actual 2007 figure by 1.317% in 2008 and 1.221% in 2009, which are DRA's estimates for customer growth. DRA believes that customer growth serves as a good proxy for T&D M&S growth from 2007 to 2009, since transmission and distribution capital expenditures are tied to serving the utility's customers. DRA believes that it provides a reasonable, measured increase in T&D M&S, while assuring that SCE will efficiently manage its T&D M&S inventory. By comparison, and for illustration purposes, DRA indicates that applying SCE's methodology in conjunction with DRA's T&D capital expenditure forecast yields a 2009 forecast equal to $84.084 million for weighted-average T&D M&S.[753]

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752 Exhibit SCE-11B, pp. 63-65.

753 Exhibit DRA-19, pp. 3-4.

SCE argues that customer growth is a poor proxy for T&D M&S requirements, since much of the company's capital expenditures are needed to maintain and replace older systems designed to serve existing customers, independent of the level of any new customers. In other words, T&D M&S levels do not necessarily correlate with customer growth. SCE also argues that DRA's analysis fails to include the impact of inflation on M&S procurement; and, by using a mid-year average as the basis for its recorded data, DRA's forecast overlooks the implications of the year-end 2007 recorded information.[754]

In general, SCE's methodology that correlates capital expenditures and M&S levels is reasonable and will be adopted. SCE's analysis indirectly includes the effects of customer growth, changes in activity related to maintaining and replacing older systems designed to serve existing customers, and inflation. All of which are reasonable. DRA's methodology directly reflects customer growth, and by applying such factors to the recorded 2007 balance which consists of M&S to serve new and old customers, effectively uses those customer growth rates to reflect the effects of customer growth, changes in activity related to maintaining and replacing older systems designed to serve existing customers, and inflation. DRA's explanation that transmission and distribution capital expenditures are tied to serving the utility's customers does not adequately explain how the customer growth rate adequately reflects the other factors, or why such factors should not be reflected. SCE's methodology, $40,000 M&S for each $1 million change, which assumes T&D M&S inventory is directly related to T&D construction activity appears more reasonable and will be adopted. Based on the

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[754] Exhibit SCE-24A, pp. 58-61.

T&D capital expenditures adopted in today's decision, SCE's methodology results in a test year 2009 average M&S balance of $177.8 million.[755]

9.8. Mohave Materials and Supplies

SCE recommends a flat M&S forecast of $7.145 million, based on the end-of-year 2006 balance, for the Mohave Generating Station. SCE states the Mohave forecast remains flat as the M&S inventory no longer supports continued operations.[756]

DRA recommends that the $7.145 million of Mohave M&S be removed from the TY 2009 rate base. DRA argues that SCE will have had sufficient time to dispose of the M&S at the Mohave plant by 2009 given that the plant was shut down in 2006 and will have been non-operational for approximately three years. In addition, SCE has expressed its intent to commence decommissioning of the facility in 2010. Since the Mohave facilities are no longer "used and useful" and SCE will decommission the facility, it is DRA's position that SCE should not be authorized to burden its ratepayers by earning a return on the M&S inventory for Mohave, which has not operated since late 2005. DRA also recommends that SCE be denied any rate recovery in the Mohave Balancing Account for M&S inventory beginning in 2009.[757]

SCE states that DRA's proposal to remove the Mohave M&S balance from rate base beginning at January 1, 2009, is inappropriate because this would mean

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[755] This decision reduces SCE's applicable T&D capital expenditures by $10.3 million. A reduction to SCE's T&D M&S request is calculated by applying that difference to the $40,000 per $1 million M&S inventory incremental need determined by the regression analysis.

[756] Exhibit SCE-11B, p. 67.

that SCE would have had to salvage the M&S immediately after the plant's shutdown at the end of 2005. It is SCE's position that certain levels of M&S were required to support maintenance operations in anticipation of the plant's final disposition and to enhance the asset's value for a potential sale, and certain levels will continue to be required through decommissioning, if the plant is not sold. SCE states that while it is taking steps to prepare to auction off the M&S in the event that the plant is not sold, it has prudently enhanced the plant's potential market value by not hastily salvaging the plant-specific M&S as DRA advocates.[758]

SCE and the other owners of Mohave have unsuccessfully attempted to find a buyer for the plant, and, for this GRC, SCE assumes Mohave will be decommissioned by 2010.[759] It would be prudent for the owners of Mohave to proceed expeditiously with the auctioning of the Mohave M&S to minimize ratepayer costs related to this rate base item. As indicated by SCE, steps to do this have already begun. For this GRC, we will assume the Mohave M&S balance will be reduced sooner rather than later and recognize the actual auctioning may occur in 2009 or beyond and that some M&S inventory may be needed until decommissioning is accomplished. However, we feel that over the 2009–2011 rate case timeframe DRA's recommendation of zero for Mohave M&S will likely be closer to reality than SCE's estimated balance of $7.145 million. We will therefore adopt a zero balance for test year 2009, knowing that, while the

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757 Exhibit DRA-19, pp. 4-5.

758 Exhibit SCE-24A, pp. 61-63.

759 Exhibit SCE-2J, pp. 69-73, SCE determines it is prudent to assume the plant will be decommissioned during this rate case timeframe.

actual balance may be greater than zero, it is not necessary to determine what that amount might be, due to the existence of the Mohave Balancing Account.

Since the Mohave Balancing Account will extend through at least 2011, SCE's cost recovery of Mohave related items, during this GRC cycle, will ultimately only amount to the actual costs that are determined to be reasonable by the Commission after appropriate review. Rates will be adjusted up or down accordingly. Due to this true-up, whether the M&S amounts, as part of this GRC decision, are specifically reflected in rates fully, in part, or not at all is inconsequential. Due to our reliance on the Mohave Balancing Account due resolve this issue, we will not adopt DRA's recommendation to deny SCE rate recovery for M&S inventory through the balancing account beginning in 2009.

9.9. Mountainview Emission Credits

The Mountainview Power Purchase Agreement (PPA) includes Mountainview's investment in emission credits as a part of its rate base. The PPA authorized SCE to recover the cost of the emission credits as they were consumed. If Mountainview is transferred from FERC to Commission jurisdiction, SCE recommends that the Emission Credits Inventory should be transferred to SCE's utility rate base. Based upon the scheduled amortization, the average Mountainview emission credits inventory for test year 2009 is $11.607 million.[760]

DRA recommends that the Mountainview emission credits inventory be removed from rate base. DRA argues that Emission allowances were provided to Mountainview by the South Coast Air Quality Management District

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760 Exhibit SCE-11B, p. 71.

(SCAQMD). Also, the credits were part of the overall March 2004 purchase price for Mountainview that SCE paid to the seller and were not separately priced. It is DRA's position that since SCE did not specifically expend capital dollars to pay for the emission credits and emission credits were not purchased by Mountainview, SCE should not receive a rate of return on the estimated value of the emission credits.[761]

SCE explains that the original allocation of emission credits for the San Bernardino Generating Station from SCAQMD represents only 3.1% of the total emission credits that DRA proposes be written off. The remaining 96.9% were not originally allocated to the San Bernardino (or Mountainview) Generating Station, but were later purchased on the secondary market. SCE argues there is a market for emission credits and if SCE had not purchased the credits with Mountainview, it would have had to purchase them elsewhere.[762]

SCE also explains that the Mountainview purchase price from Intergen, which amounted to $287.251 million, was not broken down by the numerous assets included in the purchase. However, for necessary accounting purposes, the assignment of the purchase price was grouped into three broad categories: (1) construction work in progress (CWIP), (2) refundable customer advances for added facilities, and (3) emission credits. Customer advances were determined to be $18.097 million. The assignment of $18.798 million for RECLAIM emission credits was made based upon estimated market values and the remainder of the purchase price, $250.356 million, was associated with CWIP. SCE argues that

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[761] Exhibit DRA-19, pp. 5-6.

[762] Exhibit SCE-24A, pp. 68-70.

even if emission credits had no value and were assigned no value, the $18.798 million estimated by SCE would have instead been assigned to CWIP, and there would be no difference in the total amount of the purchase price originally recorded to the balance sheet and recoverable in rates. SCE notes that if the costs had been assigned to CWIP, the average net book value of the amount in 2009 would be about $19.3 million (about 2.6%) greater than the original valuation.[763]

Emission credits were included in the purchase of Mountainview by SCE from Intergen, and such credits have value as evidenced by the secondary market. SCE's assignment of $18.798 million of the Mountainview purchase price to emission credits, based on the market value of emission credits, is reasonable. DRA's recommendation that the Mountainview emission credits inventory should be removed from rate base should be rejected.

9.10. Working Cash – Customer Deposits

SCE requests that the Commission approve SCE's proposal to deem customer deposit balances as a source of financing for nuclear fuel inventories.[764] According to SCE, in so doing, the Commission would be linking the funding available from customer deposits, which the Commission has identified as a permanent source of working capital, with nuclear fuel inventory, an asset with permanent characteristics. In SCE's words, this would eliminate the currently conflicting regulatory treatment of assets and liabilities on SCE's balance sheet and lower overall SCE debt. SCE states that its proposal is consistent with the

[763] Exhibit SCE-24A, pp. 66-68.

[764] Exhibit SCE-11B, p. 92.

Commission's current ratemaking policies for the treatment of customer deposits and fuel inventories, and provides additional benefits as well.

SCE provides the following background for its proposal:

- SP U-16 requires interest-bearing customer deposits be excluded from working cash adjustment calculations. Despite SP U-16, the Commission determined in SCE's 2006 GRC that customer deposits be deemed a source of permanent working capital and deducted from rate base, a decision it later described as an "aberration."[765] The result is treating a liability as an asset. Adding to the confusion is the fact that the Commission has not been consistent with the treatment of customer deposits among the utilities it regulates. Both San Diego Gas and Electric and Pacific Gas and Electric Companies continue to follow SP-U16, and neither company is required to deduct customer deposits from rate base.
- In 1986, the Commission began treating fuel inventories as a non-GRC asset. Instead, the recovery of the asset and its financing costs were moved to the energy recovery ratemaking proceeding. The Commission required that fuel inventories be financed with short-term debt with the associated interest costs recovered along with other fuel costs through the Company's Energy Cost Adjustment Clause (ECAC).[766] Although SCE has argued in subsequent GRCs that this policy violates financial principles, it remains in effect.
- In response to the Commission's 2003 policy change for SCE's customer deposits, SCE recommended in its 2006 GRC that if customer deposits constituted permanent funds and were thus deducted from rate base, then nuclear fuel inventory (also a permanent asset) should be included once again in rate base. Given that SCE's recommendation was rejected in the 2006 GRC, SCE indicates that its proposal in this 2009 GRC does not attempt to relitigate the ratemaking for fuel inventories but instead retains financing for nuclear fuel inventory at the short term debt rate and does not seek rate base treatment of it.

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765 Exhibit SCE-11B, p. 94 *quoting* D.07-03-044, p. 197.

766 Exhibit SCE-11B, p. 95 *citing to* 87-12-066, p. 56; *see also* Exhibit SCE-24A, p. 108.

Because ongoing inventory balances must be maintained for plant operations, SCE considers nuclear fuel inventory as a permanent asset like other inventories. The Commission has already determined that SCE's customer deposits should be deemed a source of permanent working capital and thus deducted from the company's authorized rate base. SCE argues that the parallels between these two items provide an opportunity for the Commission to match a permanent asset with a permanent source of funding in keeping with good financial practice.

Also, SCE states that an assessment of its financial statements shows the current regulatory approach is also inconsistent with proper accounting principles. According to SCE fuel inventory is characterized on the company's balance sheet as a long term asset, contrary to its short-term ratemaking; customer deposits are accounted for as short-term liabilities, yet the Commission treats deposits as an asset that may be used as a credit to rate base; and the result of these two ratemaking machinations is an inherent contradiction.[767]

It is SCE's position that its proposal would create consistency and simplify the current regulatory framework as it recognizes, in effect, nuclear fuel inventory as a mirror image of customer deposits due their permanent qualities; and while it will not fully resolve the inconsistency between ratemaking and accounting practices for fuel inventories, it will be a move in the right direction

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767 According to SCE, the Commission's characterization of customer deposits as "permanent" financing and fixed nuclear fuel inventories as short-term assets have caused negative consequences because: (a) rating agencies to become uncomfortable with the increased risk associated with the need to refinance a fixed asset frequently; (b) uncertainty as to the cost and availability of funds as the short-term debt needs to be continuously rolled over; and, (c) higher overall utility indebtedness.

for customer deposits. Also, using customer deposits as a means to finance fixed nuclear fuel inventories would allow SCE to minimize the cost of funding for the fuel and reduce overall debt, while at the same time the rate base shareholders depend on for their return will not be jeopardized by the volatility of customer deposits. SCE states that its proposal is a fair tradeoff that would be viewed neutrally by the rating agencies.

TURN opposes SCE's proposal, noting that (1) the Commission has included fuel inventory in the fuel adjustment account with a commercial paper return for over 20 years because the recovery of the money was virtually risk-free, and (2) individual customer deposits, which the Commission has included in rate base starting in 2004, turn over, but they are a permanent source of funding to Edison because large and rapidly increasing amounts have been outstanding over time, even while individual customers' deposits are repaid. TURN also states that its predictions of an increasing balance of customer deposits has proven correct, as the balance of customer deposits has grown 10% annually, so that in 2007 Edison held over $200 million of customer deposits.[768]

TURN considers SCE's speculation that the rating agencies will deem the current regulatory treatment of customer deposits as risky to be "hyperbole and bluff." TURN states that it does not disagree that rating agencies might consider customer deposits as a form of debt, but SCE's entire argument boils down to the fact that there is uncertainty regarding the short-term commercial paper interest rate that is paid on the customer deposit balances, and which SCE recovers as an expense. Due to interest rate fluctuations, rating agencies might look askance at

[768] Exhibit TURN-5A, p. 139, fn. 134 and p. 140, Figure 1.

using "short-term" debt to finance "long-term" assets. According to TURN, SCE's position lacks punch, because (1) a number of states in the U.S. treat customer deposits either as an offset to rate base or as part of the capital structure,[769] (2) customer deposits are less than 0.8% of SCE's assets or liabilities and equity on its balance sheet, and (3) the fluctuation in interest rates (which SCE recovers as an expense) is trivial for SCE's cash flow.

Regarding the current ratemaking treatment for customer deposits, TURN notes that SCE is actually making money in 2008 because actual short-term commercial interest rates are now less than the forecast rate. Also, the forecasted 2006 customer deposits in D.06-05-016 amounting to $159.65 million were less than the actual which was approximately $190 million. TURN calculates the amount of money retained by SCE and not used to offset rate base was about $1.6 million due to the low forecast of actual deposits.

DRA also opposes SCE's request for the Commission to deem customer deposit balances a source of financing for nuclear fuel inventories. It appears to DRA that SCE is arguing for rate base treatment of nuclear fuel inventory in this proceeding. DRA notes the significance to ratepayers in that if nuclear fuel inventories received rate base treatment, ratepayers would bear the carrying costs at the weighted cost of capital rather than the three-month commercial paper rate. Regarding the Commission's treatment of fuel inventory carrying costs, DRA provides, among other things, the following:[770]

- In a 1985 decision, the Commission first addressed the question of proper rate treatment of fuel inventory for SCE finding that:

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[769] Exhibit TURN-5A, p. 140.

[770] Exhibit DRA-19, pp. 11-15.

> Edison no longer shall be allowed to charge ratepayers the cost of carrying fuel oil in inventory at the authorized rate of return. There are several reasons for this. First, the authorized rate of return includes equity and long-term debt. The cost of using equity rather than debt is higher to the ratepayer because of the income tax that must be recovered with a return on equity. Second, the balancing account associated with the ECAC expense was not designed to reward the company with its rate of return on a non-rate base item but to shield the company from wide swings in fuel expenses. Finally, the low-risk nature of fuel oil inventories call for a different ratemaking approach.[771]

- The Commission concluded:

> Fuel oil inventory is low risk. Unlike rate base assets, fuel oil inventory is subject to balancing account treatment. In effect, Edison (SCE) has been guaranteed recovery of its rate of return on a low-risk asset. This result was never intended to occur through ECAC procedures.[772]

- In 1987, the Commission extended the above holding to SCE's coal and fuel inventories, saying:

> Although Edison (SCE) points out that the operating and life cycle characteristics of nuclear fuel are not the same as coal, gas, and oil, we believe that this is not enough to warrant a different ratemaking treatment. In fact, Edison (SCE) proposes to finance nuclear fuel with a combination of short- and intermediate-term debt. While this might indicate that there is a need to factor in the cost of intermediate debt in deriving the carrying cost associated with nuclear fuel, it does not justify rate base treatment.[773]

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[771] D.85-12-107, as modified in D.86-05-095, p. 2.

[772] D.85-12-107, p. 2.

[773] D.87-12-066.

- The Commission also said that it preferred the use of short-term debt instruments to determine carrying charges on fuel. Because fuel "is a commodity that can be used as collateral for financing and is distinguishable from fixed plant and land…fuel should not be afforded rate base treatment, regardless of its characteristics."[774] The Commission directed SCE to calculate carrying costs on its unspent nuclear fuel and coal reserves using the cost of short-term debt, and continue to include these costs in its former ECAC (now ERRA) balancing account.[775]
- In a 1993 decision, the Commission said that, "[w]e see no difference in the financing of these fuels. SCE and other utilities can use a myriad of borrowing arrangements…including intermediate-term debt …to finance carrying costs."[776] While, as noted earlier, the utility is free to finance these inventories however it pleases, the Commission has decided to limit the ratepayer's share in that expense to the short-term interest rate.[777]

DRA recommends that the carrying costs associated with fuel inventory should continue to be recovered through the ERRA consistent with the current Commission policy and the numerous past Commission decisions on the matter.

Regarding DRA's position, SCE states that the policies that DRA describes, including (1) evaluation of fuel inventories annually in ERRA proceedings; (2) fuel inventory financing cost recovery based on the three-month commercial paper rate; and (3) inclusion of these costs in the ERRA balancing account, will be maintained under SCE's recommended approach. The sole change is that funds available from customer deposits will be substituted for funds borrowed

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774 D.87-12-066.

775 D.87-12-066.

776 D.93-01-027, p. 694.

777 D.93-01-027.

from the capital markets. As a result, SCE concludes that DRA provides no real support for its rejection of SCE's proposal.

SCE states that DRA's reasons for maintaining the current cost recovery for fuel inventories does not address SCE's recommendation to change the Commission's policy of using customer deposits as an offset to rate base, which SCE asserts has not been applied to PG&E or SDG&E and is inconsistent with the Commission practices outlined in SP U-16. SCE indicates that its recommendation differs from the Commission's current policies for PG&E and SDG&E by recommending a specific use for the funds available from customer deposits. However, if Commission finds this use to be unreasonable, SCE states that the Commission should still adopt the same SP U-16 treatment applied to PG&E and SDG&E, which only includes non-interest-bearing customer deposits in rate base.

SCE states that TURN, like DRA, ignores inconsistencies in the Commission's treatment of customer deposits for SCE and for PG&E and SDG&E. Also, SCE argues that TURN presents no evidence to counter SCE's arguments regarding rating agency impacts. Regarding interest recovery risk, SCE states that its testimony makes clear, forecasting error for interest rates and deposits can work for or against either customers or investors and is only one aspect of the issue.[778]

To be clear, while SCE states that its proposal to finance nuclear fuel inventory with customer deposits is consistent with the Commission's current ratemaking policies for the treatment of customer deposits and fuel inventories,

[778] Exhibit SCE-11B, p. 103; Exhibit SCE-24A, p. 110.

SCE is in effect proposing to change a previously established Commission policy with respect to either nuclear fuel inventory or customer deposits. As discussed above, the Commission has previously determined that nuclear fuel inventory should not be included in rate base and financed through the rate of return on rate base but should instead be financed through short term debt. In D.04-07-022 the Commission instituted the policy to use customer deposits as a rate base offset[779] essentially in order to reduce ratepayer costs. By expensing the anticipated interest that SCE would have to pay in the refunding of customer deposits (assumed in that decision to be 2%), SCE was made whole and ratepayers were able to reap the benefit of the use of customer deposits to offset higher cost rate of return related rate base items. There was a net benefit to ratepayers which was obviously intended by TURN in making the proposal and intended by the Commission in adopting the proposal.

Depending on how it is viewed, SCE's proposal circumvents the Commission's intentions regarding the financing of nuclear fuel inventory through short term debt, or the use of customer deposits as an offset to rate base. Under SCE's proposal, customer deposits would instead be used to offset costs associated with nuclear fuel inventory which the Commission has determined should be financed with short term debt (the revenue requirement of which is closer to the interest that SCE pays in the refunding of customer deposits and significantly less than the rate of return on rate base.) The net effect of SCE's proposal, which increases the net cost to ratepayers, is either the same as if

[779] D.04-07-22 included customer deposits as a reduction in the calculation of the operational cash requirement which is one aspect of the working cash allowance. Working cash is included as an element of rate base.

nuclear fuel were to receive rate base treatment and customer deposits were used to offset rate base, or the same as if nuclear fuel inventory were financed by short term debt and customer deposits were excluded from offsetting rate base and instead became an interest bearing account with the interest amounting to short term debt costs. Our reasons for the current treatment of nuclear fuel inventory and customer deposits are clear in the decisions which established such treatment. By simply proposing that one be used to offset the other, SCE has not convinced us that the treatment in question for either nuclear fuel inventory or customer deposits should be changed, and we will not adopt such a proposal. In addition, we will continue the policy adopted in D.04-07-022 that provides an O&M adjustment for the estimated interest paid to customers related to these deposits. In D.04-07-022, we relied upon the three-month commercial paper rate to adopt a projected rate. We adopt a projected rate of 2% for 2009-2011. This 2% rate should not be escalated.

Regarding SCE's characterization of the Commission's actions regarding the use of customer deposits as resulting in treating a liability as an asset, we disagree, noting that SP U-16 recognizes that certain current liabilities which represent monies provided from sources other than the investors for the operation of the utility should be deducted from the amount of current assets. As SP U-16 states, the reason for allowing cash working capital in the rate base is to compensate investors for funds provided by them which are permanently committed to the business for the purpose of paying operating expenses in advance of receipt of offsetting revenues from its customers and in order to maintain minimum bank balances.[780] This is not treating a liability as an asset.

Regarding SCE's complaint regarding the Commission's treatment of its customer deposits, such treatment is consistent with the basic theory of SP U-16. By that standard practice, which recognizes that there could be interest- bearing and noninterest bearing customer deposits, noninterest-bearing customer deposits should be deducted from the operational cash requirement, which is an element of working cash and ultimately rate base. By the Commission's providing SCE with recovery of its related interest costs through additional authorized expenses, SCE's customer deposits are comparable to noninterest-bearing customer deposits for ratemaking purposes and should be used as a deduction to operational cash. In certain ways this is similar to the Commission's prior actions regarding the expensing banking fees in order to reduce required minimum bank balances. While SP U-16 recognizes bank related costs could be paid either through minimum bank balances or through the actual payment of fees, the Commission determined expensing the fees was preferable, since it reduced overall ratepayer costs. While the rate base cost to ratepayers was minimized, the utility was made whole through authorized expense recovery.[781] In both cases the working cash element of rate base is reduced, the utility is made whole through expense recovery, and there is a benefit to ratepayers.

Regarding SCE's complaint that its customer deposit treatment is different than that of PG&E and SDG&E, SCE itself recognizes both utilities' current rates

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[780] *See* SP U-16, pp.1-2.

were set based on settlements, and, while as a basis for those settlements customer deposits are treated differently than for SCE, such treatments by settlement terms are considered to be non-precedential in nature. While the last GRC decisions referenced the fact that SCE's customer deposit treatment is different than specified in SP U-16, neither specifically addresses the principal issue of whether the Commission has the latitude to deviate from the specific wording of SP U-16 under the circumstance where ratemaking adjustments, which are consistent with the theory of SP U-16, result in a ratepayer benefit while the utility is made whole through alternative cost recovery. In D.04-07-022, by granting TURN's requested customer deposit treatment, the Commission affirmed that it does have the latitude to make such adjustments.

Regarding SCE's argument that the Commission's current policies regarding fuel inventory and customer deposits increase debt and reduce equity negatively affecting its credit quality and ignores a possible limitation on debt related funds, such issues are typically addressed in the cost of capital proceedings and if adjustments to SCE's financial structure is necessary it should be addressed in that proceeding where all relevant aspects of SCE's financing needs are looked at in a total and comprehensive manner.

Regarding SCE's testimony regarding how rating agencies might view the situation, it should be understood that nothing has changed since 2004 when the Commission adopted TURN's proposal to use customer deposits as a rate base offset. The Commission's current treatment of using short term debt to finance

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[781] *See, e.g.,* D.85-12-108, pp. 135-136 (SDG&E 1986 GRC).

nuclear fuel inventory goes back to 1988.[782] Our actions today to maintain the status quo should not result in a worsening view by rating agencies.

9.11. Differences Related to Other Issues

The Joint Comparison Exhibit lists a number of differences related to other issues. For rate base, other than plant in service, this includes differences in working cash ($53.245 million), accumulated depreciation and amortization ($74.286 million), and accumulated deferred taxes ($0.176 million). Those specified differences are not caused by differences in methodologies but are caused instead by differences in the inputs used to calculate those costs. Depending on the resolution of the other issues, the differences related to the other issues are reconciled by the Results of Operations model, and are reflected in the various tables in Appendix C.

10. Market Redesign and Technology Upgrade

SCE's initial forecast included approximately $31.8 million associated with the capital expenditures for MRTU Release 1 and 1A, which were expected to be in-service in 2008 but are now delayed until 2009. SCE also initially requested that the Commission find the Release 2 capital expenditures of approximately $20 million, expected to be incurred by 2010 and beyond, reasonable and recoverable in rates. In its update testimony, SCE revised its forecast upward to a total of $58.035 million for capital expenditures.[783] SCE also increased its O&M

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[782] *See* D.87-12-066.

[783] Exhibit SCE-54, p. 19.

forecast for MRTU-related projects by approximately $1 million.[784] In this proceeding, SCE also requests the Commission eliminate the MRTU Memorandum Account, referred to as the MRTUMA and set forth in Resolution E-4087 (May 24, 2007).

SCE suggests that MRTU-related costs forecasted in this proceeding are sufficiently detailed to render unnecessary the MRTUMA. According to SCE, the Commission intended the MRTUMA to be a temporary mechanism appropriate for recording MRTU costs prior to approval of SCE's TY 2009 revenue requirement. SCE supports its request by claiming it has greater information regarding the scope of MRTU than during its 2006 GRC proceeding, and therefore, this proceeding contains a sufficiently thorough forecast for inclusion of MRTU-related costs in base rates.

SCE further explains that the 2007 and 2008 incremental MRTU-related costs could still be reviewed for reasonableness in its 2009 ERRA reasonableness proceeding, but that SCE is seeking to have the remaining MRTU costs forecasted for 2009 through 2011 to be determined reasonable in this proceeding and included in its forecast revenue requirement.

DRA recommends all MRTU costs including O&M and capital costs be removed from SCE's TY 2009 forecast pursuant to Resolution E-4087 (May 24, 2007). In Resolution E-4087, we established the MRTUMA to track and record all incremental MRTU-related costs incurred after those approved by the 2006 GRC

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[784] SCE states it will update its MRTU forecast during the update phase of this proceeding based on the most recent information available to SCE regarding MRTU. Exhibit SCE-22, pp. 2-3, 11-13, 30-31.

and required that prior to recovery in rates, costs recorded in the MRTUMA must be found reasonable in SCE's annual ERRA reasonableness proceeding.

DRA proposes to exclude all forecasted MRTU-related O&M costs from T&D, the Power Procurement Business Unit, Information Technology and for those costs to be tracked through SCE's MRTUMA. DRA states the Commission established MRTUMA for all expenses associated with implementing the CAISO's MRTU initiative.[785] DRA states that the inclusion of any MRTU forecasts in revenue requirement is unreasonable and recommends all these cost be removed.[786]

We reject both of SCE's proposals, which are contrary to Resolution E-4087. In particular, SCE is expected to continue to record all MRTU-related capital and O&M costs for Phase 2 and any subsequent phases in the MRTUMA. Since these costs are unknown at this time and the scope of the MRTU phases are changing and evolving, it is important the MRTUMA remain active to record these costs.

11. Distribution Service Request Pricing

Distribution Service Request Pricing (DSRP) is an SCE-developed software program used by SCE's planners to price distribution work orders for customers and internal SCE projects. SCE states DSRP was developed to streamline distribution work, improve initiation and management of service requests, establish a single point of entry and eliminate duplication, perform real-time

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785 Exhibit DRA-10, pp. 7, 11-12, 21-22; Exhibit DRA-17, p. 9.

786 DRA reply brief, p. 48.

pricing, improve corporate governance, and improve cost variance reporting.[787] DSRP was phased-in starting in August 2006 and was fully deployed by July 2007. In this GRC, SCE requests $10.72 million in capital expenditures (nominal dollars)[788] and $0.642 million for O&M expenses (constant 2006$).

DRA would deny all ratepayer funding for DSRP. DRA states that DSRP has been filled with pricing errors and that it decreases SCE's productivity. DRA asserts that SCE placed DSRP into service too soon, knew of the serious deficiencies in the program, and did not notify the Commission of the issues in either the NOI or application for this GRC. DRA believes that neither SCE nor SCE's customers can rely upon DSRP to price electrical work for customers in compliance with the Commission's rules or with SCE's own tariffs. DRA also believes that SCE has not demonstrated that it has addressed and satisfactorily solved the major DSRP deficiencies and problems. Finally, DRA states that since DSRP is not "used and useful", it is inappropriate to include DSRP in rates.[789]

In response, SCE states that the DSRP does not contain severe pricing errors, is functioning as intended, and provides benefits to SCE's customers.[790] SCE denies that DSRP was placed into service too soon with serious deficiencies in the program. SCE maintains that it employed industry standard methods to manage the DSRP project, and at the time of the NOI filing and the GRC

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[787] Exhibit SCE-12, pp. 37-38.

[788] SCE originally stated that the total expected capital expenditures for DSRP were $11.29 million. Exhibit SCE-12, p. 38. In a subsequent data request response, SCE informed DRA that this figure was incorrect and provided a worksheet correcting the amount to $10.717 million. Exhibit SCE-25, p. 1.

[789] Exhibit DRA-23, p. 1.

[790] Exhibit SCE-25, pp. 2-3.

application SCE was not aware of any pricing defects that were not being remedied.[791]

Although the record reveals that the DSRP project indeed experienced a substantial number of serious pricing defects since the pilot program in 2006, SCE has demonstrated that such defect levels are well within established norms for projects based upon their relative complexity.[792] Defects are a normal part of the software application development process and can exist in all phases, including deployment and post-implementation. An independent review of SCE's DSRP management practices found that SCE followed established processes and that these processes met generally-accepted best practices.[793]

DRA's assertion that DSRP cannot be relied upon to plan and price distribution work is not substantiated. SCE has demonstrated that DSRP pricing defects have been fixed, DSRP project objectives have been met, DSRP is in use throughout SCE's service area, and DSRP is the sole application used by distribution planning personnel to create and price distribution work orders, schedule jobs and order materials, and create and complete meter requests.[794] Accordingly, we approve SCE's cost recovery request for its investment and ongoing maintenance of DSRP.

12. SDG&E's Request for SONGS Cost Recovery

San Diego Gas and Electric Company (SDG&E) owns 20% of San Onofre Nuclear Generating Station (SONGS) Units 2 and 3. Under its operating

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[791] Exhibit SCE-25, pp. 4-5.

[792] Exhibit SCE-25, pp. 5-6.

[793] Exhibit SCE-25, Appendix A, pp. A-6 to A-7, Section 1.4 Accenture Report.

agreement with SCE, SCE bills SDG&E for its share of the actual costs of operating SONGS Units 2 and 3, plus contractual overheads.[795] The Commission has consistently used SCE GRCs to determine the revenue requirement for SDG&E for its share of SONGS Units 2 and 3.[796] SDG&E provided exhibits in this proceeding regarding its calculations and methodology for deriving its revenue requirements.

SDG&E states that there are some SONGS-related costs that are allocable to SDG&E that are found outside the SONGS portion of SCE's results of operations model. The three principal groups of these costs are:[797]

- Shared services costs.
- Results Sharing costs—SONGS-related incentive compensation for SCE employees.
- Contractual overheads—SCE-applied loaders for A&G, pensions and benefits, and payroll taxes.

SDG&E's requested SONGS-related revenue requirements, calculated based on SCE's request, as updated in its September 4, 2008 update testimony, are as follows:[798]

- $116.2 million 2009 revenue requirement.
- $13.19 million (2009 dollars) revenue requirement per refueling outage.
- Share of capital expenditures (nominal dollars) of $24.902 million for 2009, $35.455 million for 2010 and $44.191 million for 2011.

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[794] Exhibit SCE-25, pp. 12-15.

[795] Exhibit SDG&E-1, p. MLD-1.

[796] Exhibit SDG&E-1, pp. MLD-1 and 2.

[797] SDG&E opening brief, p. 2.

[798] SDG&E opening brief, pp. 2-3.

SDG&E's requested $116.2 million 2009 revenue requirement breaks down as follows:[799]

O&M	$99.0 million
Depreciation	$7.6 million
Taxes other than on Income	$1.6 million
Income Taxes	$4.1 million
Return	<u>$8.9 million</u>
Revenue Requirement	$116.2 million
Rate Base	$106.2 million
Rate of Return	8.40%[800]

SDG&E acknowledges its SONGS revenue requirement will differ from these numbers to the extent that the Commission adopts related costs other that those requested by SCE or a different rate of return for SDG&E.

No party has challenged SDG&E's methodology for calculating its SONGS related revenue requirement based on costs allocated by SCE.[801] It is reasonable, and will be use it to calculate SDG&E's share of SONGS-related costs in this proceeding.

Based on the costs adopted by this decision, SDG&E's shares of SONGS-related costs are as follows:

<u>2009 SONGS Revenue Requirement</u> (2009 dollars)

O&M	$94.0 million
Depreciation	$7.6 million

[799] Exhibit SDG&E-2, p. GMG-2.

[800] D.07-12-049.

Taxes other than on Income	$1.6 million
Income Taxes	$4.1 million
Return	$8.9 million
Revenue Requirement	$116.2 million
Rate Base	$106.2 million
Rate of Return	8.4%

SONGS Refueling Outage Revenue requirement (2009 dollars) as proposed by SDG&E in its September 4, 2008 update testimony are as follows.

O&M	$11.38 million
Contractual Overheads	$1.656 million
Franchise fees and uncollectibles	$0.154 million
Total	$13.190 million

SONGS Capital Expenditures (nominal dollars)

2009	$24.902 million

For post-test years 2010 and 2011, SDG&E shall use the same methodology adopted in Section 14 herein.

13. Non-Tariffed Products and Services

Within SCE's Other Operating Revenues, also referred to as OOR, is a subset of revenues derived from non-tariffed products and services (NTP&S). Generally, under the provisions that govern NTP&S, SCE uses and obtains a

[801] SDG&E opening brief, p.3.

profit from utility property for purposes other than the provision of utility services. SCE is required to share those revenues with ratepayers.

The NTP&S program is described in detail in D.99-09-070. The foundation of this program is a revenue sharing mechanism. This revenue sharing mechanism, which functions to distribute revenue from NTP&S to either shareholders or ratepayers,[802] is referred to as the Gross Revenue Sharing Mechanism. One of the mechanism's components provides for the first $16.773 million of gross revenues to flow to ratepayers. Another component requires SCE to split revenues above this threshold, based on various formulas, between shareholders and ratepayers. For example, gross revenue sharing allocation is 90:10 (shareholder: ratepayer) for so called "active" shareholder participation NTP&S and 70:30 (shareholder: ratepayer) for "passive" shareholder participation NTP&S.

SCE's NTP&S offerings are classified as "active" for revenue sharing purposes if it involves incremental shareholder investment[803] of at least $225,000 either on a one-time basis or within a twelve-month period or significant additional forms of liability or business risk by shareholders beyond the liabilities and risks associated with SCE's regulated business. Once a non-tariffed product or service is classified as "active," all revenues received from that

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[802] Exhibit SCE-26, p. 1; Exhibit SCE-13, p. 21.

[803] According to D.99-09-070, incremental shareholder investment includes capital-related costs (e.g., purchase of property or equipment) and expenses (e.g., consultants, supplies, materials, rent, marketing materials) incurred in connection with offering the NTP&S. Ratepayers remain responsible for capital-related costs, labor, and other expenses properly charged to the utility, and these amounts are not be included in calculating the $225,000 threshold.

NTP&S are from that point forward allocated on a 90:10 basis unless parties seek to change this designation. Different designations apply to other categories of NTP&S, such as "passive" services.

NTP&S include such items as Edison Carrier Solutions, the secondary use of transmission rights-of-way and other land, such as Camp Edison,[804] and bill payment options, such as QuickCheck, which offers customers the option of paying their bill over the telephone.

TURN propose the revenue sharing mechanism for NTP&S adopted in D.99-09-070 be eliminated or modified, and the Commission return all NTP&S to traditional cost-of-service ratemaking. TURN claims that if the Commission adopts the proposal, SCE's revenue requirement could be lowered by at least $40 million.[805] Alternatively, TURN proposes the threshold that must be reached before revenue sharing with shareholders is triggered be increased from the current $16.773 million. TURN would base the increase on (1) inflation from 1995 to 2009 using a 3% escalation factor (TURN calculates the TY 2009 threshold would be approximately $25.3 million)[806] (2) on the average net revenues for NTP&S from the 2004-2006 period (approximately $51.4 million per year), or (3) the average net revenues for NTP&S from 1999-2006 (approximately $40.9 million).

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804 Edison Carrier Solutions is a "business unit" of the utility that functions as a "competitive local exchange carrier" using the utility's fiber-optic network and other facilities.

805 Exhibit TURN-8, p. 2.

806 Exhibit TURN-8, p. 8.

Additionally, TURN recommends the Commission direct Edison to cease collecting the NTP&S fee presently set at $5.00 for its QuickCheck bill payment service. TURN claims the fee is collected from Edison customers paying their Edison utility bills and the QuickCheck service is used disproportionately by Edison customers who have received a service disconnection notices. TURN also recommends that any revenues derived from SCE's proposed advanced meter infrastructure (AMI) be excluded from revenue sharing.

Lastly, TURN objects to the $925,000 proposed by SCE for two new restrooms and $675,000 for the administration building at Shaver Lake Camp to expand and upgrade the facilities at this camping facility. TURN claims the camp serves no utility function in terms of providing electricity service to customers, and these costs should be borne by shareholders.[807]

SCE opposes TURN's proposals for the following reasons: (1) ratepayers are already receiving a disproportionate share of the NTP&S net benefits; (2) SCE might significantly alter the products and services SCE is willing to offer if the Commission adopts TURN's recommendations; (3) TURN's cost-of-service proposal is contrary to the intent of D.99-09-070, which SCE describes as providing incentives over the life of the contracts or NTP&S offerings; and, (4) TURN's alternate proposal (either to return to cost-of-service treatment or to increase the threshold amount) are inconsistent with Affiliate Transaction Rule VII.C.4.d.[808] SCE also points out that, of the $560.8 million in recorded NTP&S gross revenues from 2000 through 2006, $190.8 million was flowed through to

[807] Exhibit TURN-8, p. 12.

[808] SCE opening brief, pp. 222-223.

ratepayers, and that after removing costs and taxes associated with the remaining amount ($370.0 million of gross revenues) allotted to shareholders, they only received $77.8 million in net benefits from SCE's NTP&S over seven years.[809]

We agree with TURN that the Commission should revisit NTP&S, but we decline to do so here. The Gross Revenue Sharing Mechanism adopted in D.99-09-070 is now 10 years old. During these years, the regulatory framework has changed significantly. For example, in 1999 SCE operated in a largely performance-based ratemaking environment, but today the regulatory environment is more aligned with cost-of-service ratemaking. In addition, the $16.773 million threshold was calculated based on SCE's incremental costs to provide NTP&S in 1995;[810] this figure may bear little relations to TY 2009 conditions, and both TURN and SCE express concern that no provision exists for increasing or decreasing this amount.[811] We also find significant ambiguity about the circumstances under which SCE is permitted to recover its NTP&S costs from ratepayers. This issue of cost recovery has been framed in several past proceeding, including the 2004 GRC, the 2006 GRC, and this GRC. Finally, we are not convinced that SCE's comparison of the gross revenues received by ratepayers and the net revenues received by shareholders supports the existing methodology or presents an accurate picture of the benefits received under this program.

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809 Exhibit SCE-26, pp. 5-6.

810 RT Vol. 18:1821-1823.

811 Exhibit SCE-26, p. 6, SCE states "If anything, the Threshold Amount should be reduced to better align ratepayer and shareholder interests."

Accordingly, we will revisit NTP&S and the related revenue sharing provisions in a separate rulemaking on this topic in 2009. This rulemaking will not include a review of the Affiliate Transaction Rules. At the appropriate time, all the testimony submitted in this proceeding regarding NTP&S will be incorporated into the record of the rulemaking. As an interim measure, until we complete our full review of these matters in a separate rulemaking, we find it reasonable to adopt TURN's recommendation to adjust the threshold amount to account for inflation using the 3% escalation factor recommended by TURN. As a result, the threshold will increase from $16.773 million to $25.3 million. Accordingly, in TY 2009, ratepayers will be credited SCE's share of $8.527 million in the Base Revenue Requirement Balancing Account.[812].

14. Post-Test Year Ratemaking

SCE describes its proposed a post-test year ratemaking (PTYR) mechanism as "budget-based." Based on its TY 2009 forecasts, SCE estimates a 2010 revenue requirement of $5,488,152,000, an increase of $282,989,000 over its proposed TY 2009 level, and a 2011 revenue requirement of $5,819,054,000, an increase of $330,902,000 over its estimated 2010 level.[813] We adopt a 2010 revenue requirement of $4,885,082,000 and a 2011 revenue requirement of $5,031,634,000.

SCE argues its proposed mechanism is intended to provide additional revenues, as necessary, to cover costs of doing business in 2010 and 2011. SCE claims its proposal will cover cost increases caused by increased capital spending, including the need to provide facilities to meet load growth and to

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[812] Joint Comparison Exhibit, p. 703.

[813] Exhibit SCE-54, p. 5, calculations based on information therein.

replace aging infrastructure facilities, and the impact of price inflation on operating expenses. SCE's proposal for a PTYR mechanism has the following features:

- An annual advice letter providing notice of the revenue requirement change for the following year.
- O&M escalation using its proposed GRC escalation rate methodology, updated at the time of the advice letter filing.
- Capital-related cost increases using SCE's Board-approved capital budget, updated for changes in SCE's authorized cost of capital, subject to refund through a one-way balancing account if SCE's capital spending budgets are not fully implemented.
- An annual revenue adjustment to reflect the number of nuclear refueling outages at SONGS and cost per refueling outage as adopted in this proceeding and updated for escalation (applies to 2009 test year as well).
- A mechanism to address major exogenous changes in SCE's costs.

DRA recommends a PTYR mechanism to provide SCE with increases over its 2009 authorized base revenue requirement in 2010 and 2011 but does not agree with the increases contained in SCE's PTYR proposal. DRA claims the increases SCE requests, approximately 5.54% for 2010 and 6.6% for 2011, far exceed the increases granted to other utilities. DRA's PTYR proposal has the following components:

- The increases in base revenue requirement should be set at 3% annually in 2010 and 2011. This figure is based on a 1% or 100 basis point premium to the forecasted core Consumer Price Index (CPI) of 2% for those two years.
- Alternatively, if the Commission adopts a mechanism similar to SCE's proposal, DRA recommends the PTYR increases for expenses be based on using the CPI escalator

(except for pensions and medical benefits), rather than the specific utility price indices proposed by SCE. Also, as part of this alternate proposal, DRA recommends the PTYR capital-related costs be based on plant additions adopted by the Commission in this proceeding for 2009 and escalated by the CPI for 2010 and 2011.

- DRA agrees with SCE's proposed mechanism to address exogenous changes in SCE's costs ("Z factor").
- DRA does not oppose SCE's proposed annual revenue requirement adjustment to reflect the number of nuclear refueling outages at SONGS.

In support of its proposal, DRA refers to past Commission decisions finding that attrition rate changes are not an entitlement. For example, DRA points out PG&E was denied attrition increases in 2000 and 2002. Then, regarding the amount of DRA's proposed increase, DRA asserts that its proposal of a 3% annual increase to the authorized TY 2009 base revenue requirement using the 2% from a recent CPI index plus a 100 basis point premium is reasonable and will encourage SCE to operate efficiently and productively.

In addition, DRA argues that the increase is consistent with PTYR increases for PG&E (settlements approved in D.04-05-055 and D.07-03-044), SDG&E and SoCalGas (settlements approved in D.05-03-023 and settlements approved in D.08-07-046), and PacifiCorp (settlement approved in D.06-12-011).

DRA also notes the Commission rejected SCE's proposed budget-based approach for PTYR capital-related revenue requirement increases in the 2006 GRC and in the 2003 GRC. DRA also points out that in D.04-07-022, the Commission expressed concern that PTYR rate changes based on proposed budgets could allow large blocks of capital into rates without meaningful review.

If the Commission does not adopt DRA's primary proposal for PTYR revenue requirements increases, DRA recommends that plant additions for 2010 and 2011 be based on those adopted for 2009, escalated for inflation at the CPI. DRA states that it is reasonable to use either the current 2% CPI forecast, or an updated CPI published in October of the year prior to the attrition year.

SCE claims DRA's suggestion is unworkable. SCE states it needs to maintain its current financial credit rating and DRA's recommendations present an untenable dilemma for SCE: earn an inadequate return on equity or drastically scale back operations and capital programs to try to earn an adequate return. Neither alternative is acceptable as either shareholders will earn an inadequate return in the first alternative or the reliability of SCE's system is sacrificed in the second. According to SCE, even the capital investments endorsed by DRA for the 2009 test year could not be recovered in rates beginning in 2010 under DRA's PTYR proposal due to a large construction work in progress balance that would result at the end of 2009. Finally, SCE argues the method adopted in its 2006 GRC,[814] which escalates test year capital additions to estimate capital additions in attrition years, will likely result in PTYR revenue requirements that are too small. SCE claims this approach does not take into account the increase in customers or demand placed on SCE's system.

As we repeatedly observed in prior decisions, there is a fundamental problem with budget-based ratemaking that boils down to the fact that budgets are not always implemented as planned.[815] In addition, no party other than SCE provided or analyzed detailed post-TY plant addition budget forecasts in determining increases. We cannot fault other parties for not recommending

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[814] D.06-05-016, pp. 290-309.

[815] D.04-07-022, p. 276.

detailed PTYR capital budgets. As we have noted in past GRCs, analyzing such budgets for two additional years imposes a significant burden on resources.[816] For these reasons, we reject SCE's proposal for budget-based cost increases

Because we do not adopt a budget-based approach to determining post-test year revenue requirement, we reject SCE's proposal for a one-way balancing account.[817] We agree with DRA that a 3% increase in 2010 and 2011 revenue requirement is consistent with past commission decisions and provides SCE with the ability to continue its infrastructure replacement at the adopted 2009 level, which is substantial.

14.1. Major Exogenous Cost Changes

We agree, consistent with the PTYR mechanism adopted in 2006, that SCE may seek recovery of costs associated with exogenous events (Z-Factors) that result in major cost impacts for SCE.[818]

14.2. Annual Advice Letter Filing

When authorizing PTYR for 2004 and 2005 in SCE's 2003 GRC (A.02-05-004), the Commission found that if SCE's revenue requirement increase were to exceed $150 million in any year, SCE must submit an application for that year, rather than an advice letter. The Commission did not continue the procedure in SCE's 2006 GRC. In this proceeding, SCE asserts the Commission should not require SCE to file an application to implement changes in years 2010 and 2011. We agree with SCE and adopt the annual November advice letter filing

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816 D.06-05-016, p. 306.

817 Exhibit SCE-11A, p. 100.

818 Exhibit SCE-11A, p. 101; D.06-05-016, p. 8.

for implementing PTYR rate changes and as the mechanism to address major exogenous changes in SCE's costs. This procedure is consistent with the SCE's 2006 GRC.[819]

14.3. Nuclear Refueling Outages

There is no controversy regarding SCE's proposal to continue the existing "flexible outage schedule attrition mechanism."[820] We approve the continuation. In 2006 dollars, SCE's share of the total cost of each nuclear outage is projected to be $39.7 million. SCE must give notice of projected outages through its November advice letter filing.

15. Ratemaking Proposals

We address issues regarding ratemaking proposals in separate sections of this decision.

16. Kilowatt-hour Sales and Customer Forecasts

16.1. New Meters and Customer Forecasts

During the course of the proceeding, DRA and SCE agreed on the meter set and number of customers forecast through 2009. SCE and DRA revised their forecasts for new meters and customers during the proceeding to reflect the changes in the economy. As a result of these revisions, SCE accepts DRA's new meter estimates of 48,092 new meters. DRA accepts SCE's revised customer estimate of 4,910,000 customers.[821] We find these amounts reasonable and adopt these figures.

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[819] D.06-05-016, p. 308.

[820] Exhibit SCE-11A, p. 101.

[821] Joint Comparison Exhibit, p. 98.

16.2. Sales

SCE did not present revised sales forecast during this proceeding. For TY 2009, SCE forecasts sales of 90,724 GWH and DRA forecasts sales of 91,878 GWH.[822] TURN agrees with DRA's recommendation.

SCE explains that, instead of updating sales figures now, it seeks to update its sales forecast with even more current data based on the figures adopted in SCE's ERRA proceeding. In rebuttal testimony, SCE explains that, "due to the accelerated rebuttal schedule, SCE has not developed a 'current outlook' forecast of retail sales."[823] In support of its position, SCE argues DRA's recommendation regarding customer and meter set forecasts are inconsistent with its recommendation on sales because DRA has agreed to update forecasts for customers and meter sale but not for sales. SCE, however, does not present an updated forecast for sales and, instead, seeks to defer this update to the ERRA proceeding.

Regarding the forecasting methodologies, DRA's model for sales per customer differs from SCE's in that DRA does not add back to recorded kWh sales the cumulative energy efficiency kWh savings. SCE, by contrast, includes this variable in its sales forecast. SCE claims that adding back energy efficiency kWh is crucial because these kWh represents a significant policy variable that pushes sales downward. DRA also uses data obtained from SCE for February 1991 to August 2007 to develop its residential sales model parameters and data from March 1993 to August 2007 to develop its commercial sales model.[824]

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[822] Exhibit SCE-11A, p. 47; Exhibit DRA-3, p. 1; Joint Comparison Exhibit, p. 98.

[823] Exhibit SCE-24A, p. 4.

[824] Exhibit DRA-3, pp. 10-12.

SCE did not provide an updated forecast in this proceeding and will not postpone a final decision on this matter until the ERRA proceeding is concluded. Accordingly, insufficient evidence exists to support SCE's recommendation. We find DRA's recommended sales forecast reasonable and adopt it.

17. Philanthropy – Corporate Giving

Corporate giving involves philanthropic activities paid for by SCE's shareholders. The Greenlining Institute (Greenlining) argues that SCE's philanthropy is inadequate; SCE disagrees.[825] The Commission has no jurisdiction over a utility's charitable contributions.[826] Thus, no issue is before the Commission to decide regarding SCE's philanthropic activities.

18. Supplier Diversity

Greenlining also addresses supplier diversity, that is the extent to which SCE obtains goods and services from businesses owned by women, minorities, and disabled veterans. Greenlining alleges SCE has failed to improve its supplier diversity program.[827] SCE states that it remains focused on increasing its outreach efforts, providing continued access to its procurement process, and expanding its leadership role in supplier diversity.[828]

The Commission's requirements regarding this topic are set forth in General Order 156, *Rules Governing the Development of Programs to Increase Participation of Women, Minority and Disabled Veteran Business Enterprises in*

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[825] Greenlining opening brief, p. 20; SCE reply brief, p. 239.

[826] D.06-05-016, Finding of Fact 117.

[827] Greenlining opening brief, p. 27.

[828] SCE reply brief, p. 240.

Procurement of Contracts from Utilities as Required by Public Utilities Code Sections 8281-8286. Greenlining has alleged no violation of General Order 156 and the record does not indicate one.

Greenlining has, however, demonstrated that SCE's efforts to promote supplier diversity are inadequate. Not only is SCE below the supplier diversity commitment made by the company in 1989 under then CEO Howard P. Allen, equally troubling is the downward trend between 2005-2007 in the share of procurement dollars going to women, minority and disabled veteran-owned business. In sharp contrast to SCE's performance, other utilities appear to be doing substantially better, both in terms of the level of supplier diversity achieved and in terms of the goals they have set for themselves.[829] SCE can and should do better than this. We encourage SCE to develop specific goals with respect to supplier diversity and a specific plan that provides a roadmap for achieving those goals.

Accordingly, during this GRC cycle, SCE should competently staff and implement the full forecast of positions for WMDVBE related activities. Toward this end, we expect expenses included in the authorized 2009-2011 revenue requirements that support WMDVBE activities be fully and only utilized by SCE as authorized.

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[829] See Greenlining Opening Brief pp. 24-28; AT&T and PG&E have both set goals for the amount of procurement dollars going to minority-owned businesses in California at 27%, while Sempra has set a diversity goal of 30% under the Six-Year Leadership Agreement between Sempra Utilities and the Greenlining Institute. Approximately 19.3% of Verizon's contract dollars were awarded to minority owned businesses in 2007, while SoCalGas and SDG&E have attained 18.3%.

Furthermore, because the Commission's goals for enhanced supplier diversity, as well as for workforce diversity, discussed below, apply to the entire industry, the Commission commits to opening a rulemaking by July 1, 2009 to examine how to improve the performance of California's regulated energy utilities in the areas of workforce and supplier diversity, such as through the use of financial incentives and clarification of the Commission's rules under GO 156.

19. Workforce Diversity

Greenlining also raises the issue of workforce diversity, that is, representation of minorities and women in SCE's workforce. Greenlining commends SCE's progress in moving African Americans into management positions but criticizes SCE's record regarding Latinos and Asian Americans.[830] Similarly, almost three years ago in SCE's 2006 GRC, we found that "SCE has shown that it can achieve significant African American representation in its management through internal development and outside hiring" and we urged SCE to immediately implement such mechanisms to increase the representation of Latinos and Asian American managers.[831] However, the numbers of Latino and Asian Americans represented in management remain low. This is particularly troubling given the demographics of the region in which SCE operates. SCE provided the below data on workforce diversity.

[830] Greenlining opening brief, p. 30.

[831] D.06-05-016, p. 182.

SCE Management Diversity Statistics[832]

	Top 100			Top 500			Top 1000		
	2002	**2004**	**2006**	**2002**	**2004**	**2006**	**2002**	**2004**	**2006**
African American	13	10	9	26	25	22	42	40	42
Latino	4	4	5	49	52	58	96	102	119
Asian American	4	4	5	39	40	46	99	112	120

While we do not suggest the ethnic composition of a utility's high ranking employees need exactly mirror that of the region in which it operates, the disparity in SCE's case is particularly striking with respect to Asian Americans and Latinos, with Asian Americans comprising only 5% of SCE's top 100 employees despite representing 12.5% of California's population.[833] The numbers are even starker for Latinos, which represent 6% of SCE's top 100 employees despite the fact that Latinos represent 36% of the state's population.[834] SCE's efforts, in terms of African American representation, may very well place it at the forefront of utilities in the U.S. We see no reason why the company cannot achieve similar results with respect to Asian American and Latino representation. SCE and the state would be well-served if SCE were to take active steps to apply the lessons learned from its success in increasing the number of African Americans in its senior ranks to do the same for the representation of Asians and Latinos.

Moreover, we are concerned that ratepayers are funding programs at SCE that promote diversity, including certain areas of its Human Resources

832 Exhibit SCE-6A, p. 94.

833 Exhibit GLI-6, p. 32.

Department, such as Equal Opportunity, and its Leadership Programs,[835] that are not producing acceptable results. Accordingly, in SCE's next GRC, SCE is directed to provide a detailed description of funds used throughout the company to promote diversity and the results achieved by these investments. At that time, we will decide whether ratepayers should continue to fund programs that are not producing acceptable results.

During this GRC cycle, SCE should competently staff and implement the full forecast of positions for efforts in diversity. Toward this end, we expect expenses included in the authorized 2009-2011 revenue requirements that support workforce diversity be fully and only utilized by SCE as authorized.

We also urge SCE's Board of Directors to consider requiring all executive bonuses be based, in part, on achieving the goals of a fully diverse senior and middle management.

In addition, we note that the Commission's goals for enhanced workforce diversity apply to the entire energy industry regulated by the Commission. Therefore, as discussed above, the Commission commits to opening a rulemaking by July 1, 2009 to examine how to improve the performance of California's regulated energy utilities in the areas of workforce and supplier diversity, such as through the use of financial incentives and clarification of the Commission's rules under GO 156.

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[834] Exhibit GLI-6, p. 32.

[835] Exhibit SCE-6A, p. 95. These Leadership Programs include the Front-line Leadership Program, the Leadership Grant Program, the Executive Cross-Training Program, the Emerging Leaders Program, and the Future Leaders Program.

20. Escalation Rates

SCE filed its application using, in part, Global Insight's forecast for labor and non-labor escalation.[836] Pursuant to the Rate Case Plan and our scoping ruling, SCE updated its filing on September 4, 2008.[837] SCE's update relied on the Global Insight Utility Cost Information Service projections published in August 2008.[838] SCE's latter forecast indicated that the non-labor escalation rates for the test year would increase significantly when compared to the earlier forecast SCE relied on in the initial application. The changes to the labor exaction rates where minimal. Although the Rate Case Plan allows for updates of escalation forecasts,[839] we are not constrained to automatically adopt such updates without carefully considering other relevant factors. Since Global Insight published its August forecast, the financial markets and the economy as a whole has experienced significant upheaval and is clearly heading towards, or is already in, a recession which will likely continue in 2009. One graphic example of this is the current budget crisis facing the California State Budget.[840] Applying our own judgment and expertise, we believe the earlier and lower forecast set forth in SCE's application is more likely to reflect the actual rates for the test year

[836] Exhibit SCE-11A, pp. 57-67.

[837] Exhibit SCE-54. p. 7.

[838] RT Vol. 21:2228.

[839] D.89-01-040, p. 609.

[840] November 6, 2008 Governor's Office Press Release explains that economic conditions have deteriorated radically since the Governor signed the 2008 Budget Act on September 23, 2008.

21. Taxes

SCE provides estimates of income taxes, payroll taxes, and other miscellaneous taxes for the years 2007 through 2011. With the exception of one issue raised by DRA concerning income taxes, no party disputes SCE's proposed methodologies for computing estimated taxes. Any difference in parties' tax recommendations is attributed to underlying pre-tax income amounts or rate base amounts caused by differences in recommendations on matters such as operations and maintenance costs, administrative and general costs, depreciation, and capitalization.

DRA's income tax-related issue concerns the treatment of business meals/travel expenses and entertainment costs. DRA recommends that SCE modify its accounting system to separate business-related activities from entertainment activities. Unless and until this is done, DRA recommends that approximately $1.6 million for all business meals and travel expenses be eliminated from the Income Tax Schedule M deductions and that approximately $3.1 million for these expenses be removed from FERC Account 930.2.[841]

SCE asserts DRA's recommended disallowance goes beyond the statutory tax requirements of Internal Revenue Code § 274(n) which allows SCE to take a tax deduction of 50% of all the meal and entertainment expenses. SCE claims its income tax expense computation for non-deductible expenses is in full compliance with Internal Revenue Code § 274(n) and is the same as SCE has used in prior GRC proceedings without challenge. SCE asserts DRA's issue is not about taxes but rather about the proper recovery of employee expenses, such

[841] Exhibit DRA-12, pp. 12-1 and 12-2.

as the costs of business meals while employees travel, the recovery of overtime meal expenses, and other similar costs. SCE states that the recovery of ratepayer (vs. shareholder) expenses was addressed in its Compliance testimony[842] included as Exhibit SCE-13 in this proceeding, and that SCE already incorporated any necessary adjustments related to employee expense records.[843]

We adopt DRA's recommendation to disallow all meals and travel expenses because SCE lacks a tracking system to show that these expenses are not primarily for entertainment purposes and are justified as a business function for rate recovery. The Commission has consistently rejected rate recovery of entertainment, political, and social expenses of utilities because such expenses are an unfair economic burden on ratepayers.[844] Since SCE did not provide records to demonstrate the meals and travel expenses are legitimate business expenses and not for entertainment-related activities, it is reasonable to exclude such costs from rates. Accordingly, we adopt DRA's recommendation to eliminate $1.559 million for meals and business expenses from the Income Tax Schedule M deductions and to remove the associated expenses of $3.118 million from FERC Account 930.2.

22. Audit

DRA performed an audit of SCE's books and records for 2002 through 2006. Based on this review, DRA made a number of recommendations regarding SCE's recorded balances. Forecasts for the test year are often based on recorded

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[842] In GRC proceedings, the applicant is required to submit a list of all studies and information required by prior rate cases.

[843] Exhibit SCE-24A, p. 51.

[844] D.82-12-054, pp. 140-141.

data. Thus, changes to recorded 2006 data may influence test year forecasts. The DRA audit recommendations are discussed below.

22.1. Privileged Audit Reports

DRA reviewed internal audits conducted from 2003 through August 2007 by SCE's Audit Services Department (ASD).[845] In the course of this review, SCE asserted attorney-client privilege and on that basis refused to allow DRA to review 36 audits.[846] DRA does not challenge SCE's assertion of attorney-client privilege.[847] However, DRA could not determine the reasonableness of these audits for ratemaking purposes. For this reason, DRA concludes that SCE's showing is deficient and recommends disallowance of $1.996 million (25%) of 2006 recorded audit costs.[848] In 2006, SCE completed 160 audits and DRA requested to review 12 reports designated as privileged. SCE later determined that only 11 privileged audit reports existed for 2006.[849]

SCE asserts it has provided DRA with access to over 90% of the audit reports.[850] SCE argues it has "satisfied its burden of proof by making all of its non-privileged audit reports, representing more than 90% of its audits, available for review by DRA."[851]

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[845] Exhibit SCE-27, p. 9.

[846] Exhibit SCE-27, p. 9.

[847] DRA opening brief, p. 320.

[848] Exhibit DRA-22, p. 4-4.

[849] Exhibit SCE-27, p. 15.

[850] Exhibit SCE-27, p. 16.

[851] SCE reply brief, p. 244.

Since DRA does not challenge SCE's assertion of attorney-client privilege, the Commission need not address the reasonableness of the assertion. Thus, the issue is whether SCE has met its burden of proof. Since SCE chose to assert its claim of attorney-client privilege, it must meet its burden of proof in some other way. SCE argues that it met its burden of proof by giving DRA access to over 90% of the audits.

If, out of all the audits, 90% were randomly picked and reviewed, and if the review found that the randomly picked audits were reasonable, one could reasonably infer that the remaining 10% of the audits were reasonable. However, since the audits SCE chose to withhold from review were not randomly picked, the results of the review of the non-privileged audits can not reasonably be applied to the withheld audits. Thus, SCE's provision of over 90% of the audits to DRA does not mean that the costs of the remaining privileged audits are reasonable.[852] Therefore, SCE has not demonstrated that its privileged audits are reasonable for ratemaking purposes. For this reason, the costs of the privileged audits will be disallowed for 2006.

DRA proposes a reduction of 25% of the 2006 audit costs. However, 159 audits were conducted in 2006, of which 11 (6.9%) were privileged.[853] Therefore, a reasonable disallowance for 2006 would be 6.9% of such costs. SCE's 2009 forecast for its ASD FERC Account 920/921 is based on 2006 data. DRA's 2009 forecast did not reflect this disallowance.[854] Likewise, SCE's forecast

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[852] Our use of the term "privileged" herein means that SCE asserted the privilege. It does not indicate our agreement with the assertion.

[853] Exhibit SCE-27, p. 15.

[854] Exhibit SCE-27, p. 13.

did not do so. Therefore, the adopted amount for ASD audits for 2009 in ASD FERC Accounts 920/921 should be reduced by 6.9%.

22.2. Pre-Payments for Tax Consultants

In its audit of 2006, DRA found two prepayments to tax consultants that it recommends be removed for ratemaking purposes from Account 923 because both were for contingent refunds arising in prior tax years.[855] The first prepayment ($813,959) is for filing refund claims for casualty loss for tax years 1997-1999. The second prepayment ($513,448) relates to a contingent tax refund claim.

As to the first prepayment, SCE argues that it was to its external vendor, pursuant to contract, for filing tax refund claims. SCE further argues that, if the claims are successful, ratepayers will receive the benefits resulting from applying the claims to new vintages of property.[856]

The record does not indicate anything unusual about SCE filing for tax refunds or using an outside vendor to do so. Additionally, there will be uncertainty as to whether the claim will be successful and when the claim will be resolved. Thus, no apparent reason exists to disallow such expenses.

Regarding the second prepayment, SCE states that it made two journal entries for this item in 2006. The first, in January, was a negative amount. The second, in December, was a positive amount. Since the net effect was zero, SCE

[855] Exhibit DRA-22, p. 4-5.

[856] SCE reply brief, p. 244-245.

argues DRA's recommendation should not be adopted.[857] Based on SCE's explanation, DRA's recommendation is not adopted.

22.3. Allowance for Funds Used During Construction

DRA recommends adoption of the 2006 AFUDC rate of 6.9521% for 2009 because, according to DRA, SCE's proposal is based on unrealistically low forecasts of short-term debt available for construction.[858]

DRA explains that the FERC formula for calculating AFUDC provides that construction work in progress (CWIP) is to be financed first by short term debt. The remainder is to be covered by an average of prior year long-term debt, preferred stock, and common equity weighted by their respective balances.[859] DRA argues that SCE's increased AFUDC rate is due primarily to SCE's forecasted decrease in the amount of short-term debt used to finance CWIP. DRA points out that SCE filed A.08-06-013 in which it seeks authority to increase its short-term borrowing authorization to $2 billion.[860]

SCE estimates a 2009 AFUDC rate of 8.2196%.[861] SCE represents that it made its estimate based on FERC principles.[862] SCE also argues that if the

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857 SCE reply brief, pp. 244.

858 DRA opening brief, p. 315.

859 Exhibit DRA-22, p. 3-5

860 DRA reply brief, p. 53.

861 Exhibit DRA-22, p. 3-7.

862 SCE reply brief, p. 245.

Commission takes the position that previous rates should be used, the 2007 rate of 7.7670% would be more appropriate.[863]

As pointed out by DRA, SCE has filed A.08-06-013, which indicates that it seeks the ability to incur additional short-term debt.[864] The record does not indicate that SCE considered this request in its forecast of its AFUDC rate. Although the Commission has reached no decision in A.08-06-013, the filing of the application tends to support DRA's contention that the portion of CWIP to be financed by short-term debt will be higher than forecasted by SCE. This, in turn, means that the AFUDC rate will be less than forecasted by SCE.

Using the 2006 AFUDC rate as recommended by DRA is not reasonable if more recent data is available. Use of SCE's forecast is not reasonable for the reasons discussed above. SCE's suggested alternative is the 2007 AFUDC rate of 7.7670%. However, SCE states the actual 2007 rate was 7.7204%.[865] Therefore, the actual 2007 rate of 7.7204% is reasonable because this figure is the most recent available in the record, and is adopted for 2007-2011.

23. Proposed Settlements

23.1. Reliability Investment Incentive Mechanism Proposal

SCE and the Coalition of California Utility Employees (CCUE) proposed bilateral settlement to adopt a revised version of the RIIM[866] originally adopted

[863] SCE reply brief, p. 245.

[864] The Commission takes official notice of A.08-06-013 for the limited purpose of establishing that SCE made the request contained therein.

[865] Exhibit SCE-27, p. 3.

[866] Joint Motion by SCE and CCUE filed May 23, 2008.

in D.06-05-016[867] for SCE's 2006 GRC. As discussed below, we reject the proposed RIIM settlement for TY 2009 and beyond. We find it fails to satisfy our settlement rules because it is not in the public interest.[868]

The revisions to the RIIM would provide for refunds to ratepayers of certain "shortfalls." First, if SCE spends less than the adopted forecast for certain reliability-related capital, then that difference is a "shortfall" and is refunded to ratepayers at the end of the 3-year GRC cycle, 2011. (Settlement, § 3.6.2.) Second, the RIIM would identify specific TDBU O&M expenses, with specific employee hiring and total employee targets. SCE would refund any GRC cycle "shortfall" if SCE fails to achieve the target number of employees. The refund is per-employee but varies depending on the magnitude of the employee shortfall. Specifically, the refund would be $16,500 for each of the first 30 positions of the shortfall and $77,500 for each position thereafter. (Settlement, § 3.6.4.) The settlement also has two optional targets based on whether TDBU O&M funding adopted in this decision is greater or less than $500 million in the test year. (Settlement, § 3.5.3.)

CCUE and SCE devised the RIIM revisions without knowledge of the final adopted allowances for capital expenditures. Therefore, for specificity in the adopted test year's and two post-test years' revenue requirements, the settlement relies on the 2009-2011 cumulative total of $2,556,000,000[869] proposed in SCE's

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[867] D.06-05-016, pp. 329 – 337.

[868] (Rule 12.1) ***Proposal of Settlements*** part (e): "The Commission will not approve settlements, whether contested or uncontested, unless the settlement is reasonable in light of the whole record, consistent with law, and in the public interest."

[869] Exhibit SCE-3H *citing to* Attachment A to the proposed settlement agreement.

application. These allowances would have to be adjusted to adopted test year forecasts.

Also, within the category of reliability-related capital expenditures, the proposed settlement identified as the "highest priority" those that affect long-term service reliability. Based on the testimony served by SCE, the proposed settlement identified $1,195,000,000.[870] This amount, too, would have been subject to the final amount adopted in this decision.

23.1.1. Responses to the RIIM Settlement

DRA opposed the RIIM in SCE's 2006 GRC and continues to question how RIIM will be effective in improving or maintaining reliability.[871] DRA argues the "Commission [adopted in D.06-05-016] the RIIM because it felt that related expenditures adopted in the Decision were necessary." If the Commission does approve the revised RIIM, DRA recommends that the capital expenditures tied to the mechanism must be specifically adopted by the Commission. DRA points out our own reservations in D.06-05-016, pp. 331-332:

> We approve the Settling Parties' stipulation regarding the RIIM, although we are somewhat concerned about the actual incentive. The incentive is not to maintain or improve distribution reliability, but rather to spend money on projects or activities that will likely maintain or improve distribution reliability. Whether spending the money actually accomplishes anything is not tied to the RIIM.

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[870] Exhibit SCE-3H, p. 119 *citing to* Attachment B to the proposed settlement agreement.

[871] DRA opening brief, pp. 259 – 260.

DRA cautions that there is no assurance in the RIIM that reliability actually improves.[872] In the last GRC proceeding, we rejected a DRA proposal which DRA argued would hold reliability constant, and we instead adopted the RIIM with the expectation that reliability would improve.

TURN recommends that we reject the "headcount" component of the RIIM and that "the incentive should be [changed] to encourage the utility to spend up to, but not beyond, the authorized amounts for the spending categories the settlement identifies as particularly related to preserving long-term electric service reliability."[873]

23.1.2. Discussion of Provisions for Capital Expenditures

We find the record does not show that SCE's system reliability would be improved by earmarking capital expenditures, or by limiting SCE's obligation to invest to meet the needs of new customers, maintenance, and repairs, by the adoption of refundable targets. Ear-marking funding for specific expenditures would have the effect of reducing SCE's managerial responsibility and absolving SCE from responding to the specific needs of the system to serve customers.

SCE has an unavoidable obligation to serve its customers safely and reliably. To do so, SCE is obliged to exercise competent managerial discretion and make the necessary capital expenditures and capital repairs and maintenance without limitation by test year forecasts. This settlement would obscure that obligation and would imply that SCE need only spend the amount included in the forecast. Test year ratemaking is not a guarantee of full recovery

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[872] "There is no evidence that the RIIM is effective in improving or maintaining reliability for ratepayers." DRA opening brief, p. 323.

[873] TURN opening brief, p. 263.

or of fully expending the amounts as forecast. The "regulatory compact," is that in exchange for a reasonable opportunity of earning a fair return, ratepayers pay the adopted rates and the utility does what is necessary to provide safe and reliable service. A utility cannot be excused from making needed expenditures merely because the expenditures are more than the forecast.

23.1.3. Discussion of Provisions for Employee Targets

We reject this portion of the settlement with CCUE as not in the public interest and unsupported by the record. The settlement would almost guarantee a net increase of employees without regard to any justification of the need for these specific additional positions not otherwise included in the application. The refund for employee shortfalls would be far less per employee-shortfall than any actual employee would be paid in wages and benefits. Thus, SCE might well have no incentive to actually fill the position. Moreover, although we approved a similar settlement in the last proceeding, we have no persuasive evidence before us that this mechanism was at all effective in increasing reliability.

The proposed settlement also would in part grant preferential treatment to certain employees. Specifically, the proposed settlement would grant the unions represented by CCUE preferential treatment by funding new positions not requested in SCE's application. We recently rejected a settlement between SoCalGas and one of its unions where we found the proposed settlement there assured a union of more members and existing members an opportunity for up-grades, finding that these matters were more rightly a matter for collective bargaining.[874] We find, as we did in the SoCalGas GRC, that specific employee

[874] D.08-07-046, pp. 76-77.

targets are a matter best left to collective bargaining and to the operating discretion of SCE in safely and reliably operating the system.

23.1.4. Conclusions Regarding RIIM Revision Proposal

This settlement would revise the RIIM in ways that would not be in the public interest. The goal in approving the original RIIM was to give SCE an incentive to give appropriate weight to distribution reliability improvements in managing the utility. But even when we approved the original RIIM, we expressed unease that the incentive was only indirectly linked to actual reliability improvements. Unfortunately, instead of refining the incentive, both the spending target and the hiring target under this settlement would focus management on exactly hitting the targets, irrespective of the appropriateness of those targets under actual conditions during the GRC cycle and irrespective of the success or failure of the programs SCE undertakes. The rigidity of the targets constitutes an inappropriate use of GRC forecasts and undesirable dilution of managerial responsibility.

Finally, we believe part of this settlement would have us address matters that are properly within the scope of collective bargaining. SCE and CCUE are "negotiating" a labor agreement as part of a GRC – for example, CCUE "agreed" to a lesser outcome (in the form of fewer new positions) if the adopted rates are lower than an amount in the proposed settlement.

To summarize, the bilateral settlement between SCE and CCUE is not supported by the record taken as a whole, and is not in the public interest. We therefore reject the settlement.

23.2. Public Access Proposal

This proposed bilateral settlement between SCE and Disability Rights Advocates[875] addresses issues such as public access and right of way access to streets and sidewalks, etc., affected by permanently installed utility property or during construction, internet access, and emergency communications with customers. The proposed settlement provides for SCE to engage a consultant to review the remaining branch offices and all payment locations to address the adequacy of these locations' accessibility.

Disability Rights Advocates was an active participant. It filed a protest and demonstrated that in recent GRCs other utilities made comparable efforts to more carefully and thoughtfully ensure anyone could reasonably interact with the companies' web sites or offices, and that facilities would be accessible. Specifically, Disability Rights Advocates entered into a similar agreement with PG&E and with both San Diego Gas & Electric Company and Southern California Gas Company.[876]

The proposed settlement is unopposed; however, TURN raises the issue of payday lenders as Authorized Payment Agents (APAs). In its opening brief TURN summarizes its concerns:

> "The Commission should adopt a moratorium on new "payday lenders" in SCE's Authorized Payment Agent (APA) network, as well as a transition plan for SCE to replace existing payday lender APAs with suitable alternatives. The Commission should direct SCE to work with community-based organizations to locate suitable replacements for existing payday lenders in its APA network, and to

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[875] Joint Motion by SCE and Disability Rights Advocates dated May 23, 2008.

[876] PG&E in D.07-03-044, pp. 247–249; and SDG&E and SoCalGas in D.08-07-046.

> require its existing payday lender APAs to provide customers with information about Edison's financial assistance programs. Funds to assess APA compliance with the Americans with Disabilities Act should first be spent on APAs that are not payday loan centers, until Edison ascertains if alternatives to payday loan establishments can be found."

We adopted a moratorium on "payday lenders" as APAs for SDG&E and SoCalGas.[877] The applicants there were allowed to reexamine the issue of more suitable APA locations. TURN argues persuasively in this proceeding that payday lenders are highly problematic:

> "According to the June 2007 report published by the National Consumer Law Center, Utilities and Payday Lenders: Convenient Payments, Killer Loans, '"When utilities send their customers to pay bills in the storefronts of ultra-high-cost payday lenders, those customers – typically the most financially vulnerable – become targets for predatory loans.'"[878]

We find the terms of the settlement are clearly in the public interest and should be adopted. Although there are no specific performance metrics in the settlement, we direct SCE to document and demonstrate in the next GRC that there were significant and useful changes made to utility operations and facilities. However, we also find that TURN raises a significant concern regarding payday lenders. Consistent with our decision for SDG&E and SoCalGas only a few months ago, will impose a moratorium on any new payday lender APAs.

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[877] D.08-07-046, p. 21.

[878] TURN opening brief, p. 81 *citing to* Exhibit TURN-4, Attachment 5 (NCLC Study on Payday Loan Centers), p. 1.

24. Purchase of Receivables

A purchase of receivables program is a regulatory program coupled with a utility's consolidated billing under which a utility (1) reimburses non-utility suppliers of energy service for customer charges and (2) assumes responsibility for the collection of the charges for energy service from the non-utility suppliers' customers. Customers of non-utility suppliers receive a single bill from their local utility that includes charges for both delivery services provided by the local utility and energy service provided by their non-utility supplier. Alliance for Retail Energy Markets (AReM) argues generally: that the Commission should direct energy utilities such as SCE, SDG&E, and PG&E to implement a purchase of receivables program applicable to residential, small commercial customers, and customers of community choice aggregation and direct access programs because such a program will facilitate customer choice of renewable and other energy products.[879]

AReM's proposal is not relevant here. The scope of this proceeding includes issues related to determining SCE's revenue requirement for TY 2009. Investigation (I.) 08-01-026 includes any issue we find relevant to our inquiry into revenue requirement. We find AReM's proposal falls outside the scope of this proceeding.

25. Comments on Proposed Decision

The proposed decision of the ALJ and the alternate proposed decision in this matter were mailed to the parties on November 18, 2008 in accordance with Section 311 of the Public Utilities Code and comments were allowed under

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[879] Exhibit AReM-1, p. 4.

Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed on December 8, 2008, and reply comments were filed on December 15, 2008 by the following parties: SCE, DRA, TURN, CFBF, AReM, Disability Rights Advocates, CCUE, WPTF, Alliance for Nuclear Responsibility, and Greenlining. To the extent that comments merely reargued the parties' positions taken in briefs, those comments have not been given any weight. The comments which focused on factual, legal or technical errors have been considered and the appropriate changes have been made.

26. Assignment of Proceeding

Michael R. Peevey is the assigned Commissioner and Regina DeAngelis is the assigned Administrative Law Judge in this proceeding.

Findings of Fact

<u>Section 2</u>

1. Initiating a feasibility study of a SONGS 2 & 3 license renewal in 2009 and filing an application with the NRC in late 2012 will likely result in a decision from the NRC around 2015, which would be about 7 years before the current operating licenses expire in 2022.

2. SCE has not demonstrated that all the benefits of its NEI membership go to its customers as distinct from furthering the interests of the nuclear industry.

3. The Commission previously adopted SCE's proposed post-test year ratemaking flexible outage schedule mechanism in prior GRCs as the means to most accurately predict PTYR refueling and maintenance outage costs. No party opposes SCE's request to continue the mechanism for years 2009-2011.

4. SCE's TY 2009 refueling and maintenance outage O&M forecast of $39.7 million (SCE share) excludes the cost of steam generator inspections in 2009 and 2010 because it expects to replace the steam generators in those years.

5. SCE's forecast of Palo Verde O&M costs reflects significant O&M increases in recent years and additional staffing increases proposed by APS to reduce backlogs in areas of engineering and elective maintenance.

6. Palo Verde's engineering workload increased by 42% in 2007 as a result of initiatives undertaken in response to NRC oversight.

7. SCE has historically under-recovered its Palo Verde O&M expenses by an average of $9.9 million per year due to APS consistently underestimating its O&M expenses.

8. SCE's forecast of Four Corners TY 2009 O&M expenses (SCE's share) includes the costs of hiring 50 additional employees now to address retirements that may happen in 5 to 10 years.

9. SCE's forecast of Mohave O&M for TY 2009 to manage the Mohave site during and after decommissioning includes a 15% contingency.

10. SCE's Mohave O&M costs are subject to balancing account treatment.

11. Unlike cost forecasting for capital construction projects, an overall contingency is not normally included in O&M cost forecasts.

12. SCE's Hydro O&M forecast is based on its 2002-2006 recorded expenses adjusted to remove one-time charges and to correct accounting errors and is referred to as "base estimate," to which SCE adds $13.504 million for future adjustments.

13. SCE's forecast of TY 2009 expenses for the subaccount "Operations of Reservoirs, Dams and Waterways" is based on SCE's expenses from the last recorded year, 2006, for non-labor costs.

14. SCE's non-labor costs associated with subaccount "Operations of Reservoirs, Dams and Waterways" have fluctuated significantly, mainly due to weather-related events, with no discernable trend over the past five years.

15. SCE proposes to adjust its "base estimate" of Hydro O&M to add $250,000 for cloud seeding efficiency improvements.

16. The efficacy of cloud seeding is unknown.

17. SCE plans to decommission the San Gorgonio Hydro Project in 2009, but will incur O&M costs until it transfers ownership to Banning Heights Mutual Water Company in 2010 or beyond.

18. SCE's recorded 2006 O&M expenses for San Gorgonio were the highest in recorded years 2002 through 2006.

19. SCE's forecast of staffing costs for its hydro facilities includes funding for 23 additional positions (22 apprentices and one training instructor) to prepare for retirements, but has not adequately explained how retirements will impact these requested additions to workforce.

20. SCE's forecast bases the wages of the proposed new hydro positions on the average of all hydro staff rather than on the wages of the proposed new positions.

21. SCE includes expenses related to training staff in its wage calculation.

22. SCE seeks to include in future adjustments to FERC Account 542 (Housing & Asbestos Abatement Project) $371,000 to rehabilitate and remove asbestos from certain housing units at Poole and Rush Creek.

23. SCE sought, and the Commission approved, $386,000 in its 2006 GRC to demolish the housing units that are the subject of its proposed housing rehabilitation and asbestos removal activity.

24. SCE's expenses related to housing & asbestos removal are more appropriately capitalized.

25. IAG requests the Commission order SCE to file an explanation of certain alleged discrepancies in amounts requested for various hydro projects. SCE explained these discrepancies in its rebuttal testimony.

26. IAG asserts SCE mislead the Commission regarding whether the Lundy Powerhouse Project had been approved by FERC and requests the Commission find SCE in violation of Rule 1.1.

27. SCE's requested $253,333 for Big Creek Vegetation Management and Rush Creek Heliport Brush Clearing includes, in addition to costs associated with brush clearing, costs associated with moving the helicopter landing site and construction of a new helicopter site.

28. In D.03-12-059 and subsequent decisions, we approved the Mountainview PPA, finding it to be cost-effective and the megawatts represented by the PPA to be needed.

29. D.06-05-016 approved depreciation cost of $553,000 for Mountainview and SCE's request to include its deprecation in the 2006 test year forecast.

30. SCE's requested O&M expenses for Mountainview include the costs of seven additional staff hired in 2008 to address increased workload, and funding for "Additional Future Projects (Unforeseen)" in order to address areas of concern that have arisen.

31. The permit process for the non-operational peaker is not moving forward on a sufficiently reliable timeline to assume its operation by August 2009.

32. The O&M costs associated with the fifth, currently non-operational peaker, is at most less than 20%, and possibly even less than 10%, of SCE's forecast total for peaker O&M costs.

33. The record does not demonstrate that integrating the operating systems of Mountainview and the peakers would be efficient.

34. SCE's forecast of IT costs for TY 2009 for the new peakers includes a one-time $400,000 O&M project for additional plant instrumentation and data collection hardware and software.

35. SCE has not identified additional specific one-time O&M projects beyond 2009.

36. SCE requests recovery of $4.6 million for its one-third share of the Solar Two decommissioning project. This forecast is based on SCE's decommissioning cost estimate provided to the Department of Energy in seeking project approval in 1999, escalated to 2009 dollars.

37. SCE's requested O&M costs for its Project Development Division includes $21.572 million for generation-related research, development and demonstration.

38. D.06-05-016 rejected SCE's request to include in rates costs associated with the Project Development Division's activities with respect to Generation Business Unit project development in order to assure a level playing field for competitors who cannot recover the development costs of unsuccessful projects.

39. D.06-05-016 adopted the PDDMA to allow rate recovery of the costs of certain functions of the Project Development Division after review in an ERRA proceeding.

40. SCE developed its TY 2009 forecast for Pebbly Beach Generation Station O&M expense by considering the activities contained in each FERC Account and applying a forecast methodology for each account based upon its unique circumstances.

Section 3

41. SCE requests an increase in funding over 2006 base year for Engineering Advancement of $2.094 million for subaccount 560.100 (transmission) and $2.140 million for subaccount 580.100 (distribution) to support its efforts to

develop and deploy "smart" technologies on the electric grid, but cannot provide further specificity in estimating these costs until it has received actual bids for the work.

42. SCE requires three additional civil engineers to handle apparatus design review and substation automation, whether or not SCE experiences customer growth in the test year, to address recently emerging issues not addressed in historical costs.

43. SCE proposes to rely partially on the three additional civil engineers in lieu of contract resources from its Standards and Publications Contract group.

44. Analysis of cost recording practices for clearing accounts shows the need to record $1,145,000, previously recorded as O&M in subaccount 560.100 (Overhead), as capital.

45. There are no desktop software upgrade costs embedded in SCE's 2006 recorded expenses.

46. Desktop software upgrades are needed in 2009, 2010 and 2011; the upgrade costs are not one-time expenses.

47. SCE requests a $333,000 (constant 2006$) increase for write-offs of work orders in its Project Management Organization, based on an increase in the level of Project Management Organization-related capital expenditures.

48. The evidence shows that the amount of Project Management Organization-related write-offs varies with the amount of capital expenditures.

49. SCE proposes reductions to O&M be applied to associated clearing accounts as a ratio but fails to explain the relationship between its requested increases in the clearing account to the related total forecasted amount in a corresponding O&M account.

50. In the absence of an acceptable proposal by SCE to account for adjustments in clearing account activity when related O&M costs are adjusted, a 40% reduction in each .980 account reflects an approximation of the reduction to these clearing accounts.

51. SCE currently has a shortage of grid operators on staff.

52. Approximately 56% of the increased Vehicle Cost forecasted by SCE represents replacement of vehicles that have exceeded their useful lives and no longer comply with state and federal emission requirements.

53. SCE has not explained its proposed increased rate for replacing vehicles.

54. SCE proposes additional funding of $10.623 million for a Transmission Line Clearance Study for study, evaluation and mitigation planning to address potential clearance issues on SCE's transmission and sub-transmission lines.

55. SCE is adding circuit miles to its transmission system.

56. SCE is recording excess overtime with its current staffing for Transmission Line Patrols.

57. Analysis of cost recording practices for clearing accounts shows the need to record $811,000, previously recorded as O&M in subaccount 563.100 (Inspect and Patrol Lines Overhead Line Expense), as capital.

58. SCE is adding new employees who must participate in safety meetings pursuant to, e.g., CAL-OSHA and other environmental regulations.

59. SCE has increased corporate real estate and information technology costs over those authorized in the 2006 GRC, driven by increased office and field personnel who require additional computers, communication devices and photocopiers.

60. Analysis of cost recording practices for clearing accounts shows the need to record $323,000, previously recorded as capital, in subaccount 563.100 (Field Accounting) as O&M.

61. SCE's workload with respect to regulatory, planning and business development has increased; for example, SCE's workload increased from performing 72 Grid Interconnection studies in 2005, to 140 studies in 2006

62. SCE forecasts a $4.673 million increase for Transmission Training, and a $10.385 million increase for Distribution Training, which represent an approximate 50% increase over 2006 recorded expenses.

63. SCE requests an increase of $633,000 or 40% over 2006 recorded expenses of $1.555 million for maintenance and repair of transmission circuit breakers, based on the need to perform maintenance and repair that it deferred in 2006.

64. Using the five-year average of historical costs to forecast them, SCE's requested increase for circuit breaker maintenance costs would be reduced by $346,000.

65. SCE requests an increase of $584,000 to perform approximately 500 preventative maintenance assessments, as compared to its historical average of 70 preventative maintenance assessments per year.

66. SCE requests $400,000 over 2006 recorded costs to replace lighting, much of which is over 50 years old, at many of its substations.

67. SCE's embedded costs include the cost of replacing lighting at substations.

68. SCE's embedded costs include the cost of replacing cable trench covers.

69. SCE's embedded costs include the cost of rack inspections.

70. The underlying cost drivers for work order expenses are capital projects.

71. This decision reduces SCE's forecasted capital expenditures by 13.7%.

72. SCE has not shown that its 2006 expense levels for the Transmission Life Extension Program are insufficient.

73. The majority of SCE's requested additional expenses for Intrusive Inspections stem from an increase in a competitively-bid contract.

74. SCE's recorded costs do not include costs for insulator washing in the San Joaquin Valley as that program did not begin until 2007. However, SCE requested funds to address this "severe" problem in its 2006 GRC.

75. SCE has not demonstrated that its insulator replacement program is a Life Extension Program activity or that the proposed costs of this program are not in its embedded costs.

76. SCE has not demonstrated that grading activity in Angeles National Forest is a Life Extension Program activity.

77. SCE's 2009 estimate of Project Management Organization work order write-offs is based on the historical average ratio of write-offs to capital spending, multiplied by the forecasted level of capital spending in Project Management Organization-related areas.

78. The costs associated with SCE's requested $174,000 for additional staff in the Customer Service Business Unit Safety Organization are not embedded in recorded 2006 costs, but are to provide training beyond the type offered in the past and to handle an increase in ergonomic assessments.

79. Of the $2.82 million of additional expenses SCE requests for subaccount 580.200 (Internal Market Mechanism), $156,000 is for new ongoing annual costs in response to guidelines from the U.S. Fish and Wildlife Service, and $1.6 million is for facility operation and maintenance costs for new facilities. SCE does not provide any evidence supporting the remainder of this request.

80. SCE's forecast of expenses related to the management and supervision of the Meter Service Organization is $2.485 million, as compared to 2006 recorded expenses of $2.751 million, based on its projection of slowed customer growth and increased productivity.

81. SCE's forecasted increase of $3.601 million over 2006 recorded levels for subaccount 580.500 (research development and demonstration) is not supported by historical data.

82. SCE's Distribution Inspection & Maintenance Program was created in consultation with the Commission's Consumer Protection and Safety Division to ensure compliance with Commission regulations.

83. SCE's Distribution Inspection & Maintenance Program is a new program that assesses safety and reliability from a much broader perspective, and imposes greater responsibilities and burdens on inspectors, than before, resulting in an overall increase in workload.

84. SCE did not prepare a cost benefit analysis to determine whether additional pre-construction site readiness checks are needed to support load growth and customer growth projects.

85. SCE intends to replace some contract construction/materials coordinators with additional employees but still anticipates relying on contract hiring.

86. SCE demonstrated that $3.628 million incurred during emergency responses to non-storm outages should have been charged to O&M rather than capital, and proposes to include this amount in subaccount 583.400.

87. SCE's distribution wood pole inspection costs will be higher than historical costs due to a mandatory contract renegotiation in 2007 that resulted from a competitive bid solicitation process.

88. SCE's forecast of the number of intrusive inspections related to distribution wood poles is excessive based on historical data.

89. SCE's productivity has increased in the area of map sketching, and a significant backlog of map sketches still exists.

90. SCE's 2006 recorded amounts for distribution construction and maintenance stand-by time mistakenly does not reflect any stand-by time for two of its eight distribution regions; SCE's forecast corrects this oversight by adding $78,000.

91. SCE's request for funding for an additional Mapping supervisor is attributable to its need for new hires in reference to Account 588.000.

92. SCE's request for funding for two additional Joint Pole supervisors is attributable to its need for six additional positions to address a 300% increase in workload.

93. SCE's request for a $438,000 increase in labor expenses for the Joint Pole Organization to fund six additional positions is based on an increase in Joint Pole Agreements from 2006-2007 of 25% and a 333% increase in Requests for Pole Attachments in that same time period.

94. SCE forecasts the need for an additional $4.424 million for its Business Process and Technology Improvement projects for TY 2009, as compared to its 2006 recorded expenses of $12.378 million, using a bottoms-up approach of developing the forecast on a project-by-project basis.

95. Analysis of cost recording practices for clearing accounts shows the need for an additional $1.509 million to subaccount 588.300 to reflect an accounting adjustment of shifting certain amounts recorded as capital to O&M.

96. SCE proposes an additional $514,000 for service guarantee credits and proposes a baseline level of credits for recovery in rates. SCE's determination of

a baseline level of credits addresses two of the four elements of SCE's Service Guarantee program, the Notification of Planned Outage Standard and the Restoration of Service within 24 Hours Standard.

97. The Service Guarantee Program should be expanded to include erroneous disconnect credits that SCE currently provides under a company policy.

98. SCE forecasts $3.619 million in expenses for subaccount 592.200 (maintenance of distribution circuit breakers), a $908,000 increase over the 2006 base year. SCE bases $511,000 of the total increase on the need to support maintenance postponed due to resource constraints.

99. DRA estimates $2.857 million in expenses for subaccount 592.200 (maintenance of distribution circuit breakers) based on a five-year average.

100. SCE bases its request for an additional $1.078 million in labor expense for disconnect repairs on the existing backlog and on the amount of repairs SCE has historically performed.

101. SCE's requested additional $1.078 million in labor expense for disconnect repairs is not supported by historical costs.

102. SCE requests an additional $600,000 in subaccount 592.400 (maintenance of station equipment) for repairing and upgrading switchrack lighting in its substations, which is in addition to the increase of $400,000 SCE seeks in subaccount 570.400 to repair and upgrade its switchrack lighting in substations.

103. SCE's embedded costs include the costs of repairing and upgrading switchrack lighting in its substations.

104. There is a need to repair and upgrade switchrack lighting in SCE's substations.

105. SCE requests an additional $716,000 for replacing Trench Covers located in its substations.

106. There is a need to replace trench covers in SCE's substations.

107. Normalizing SCE's request of $716,000 to replace trench covers over a three year period results in a forecast of an additional $239,000 for the test year.

108. SCE's current level of funding for inspecting and repairing steel structures is consistent with historical costs.

109. SCE forecasts an increase of $3.971 million for Vegetation Management and $582,000 for Line Clearing over 2006 recorded expenses based on its forecasted increase in labor and non-labor costs.

110. TURN provides evidence of reduced costs to support a 2-year trim cycle.

111. SCE raised concerns based on growth patterns regarding viability of 2-year trim cycle.

112. It is not possible to determine on this record the relationship between SCE's deferred preventative maintenance and its requested increases in subaccount 593.300 (overhead line maintenance).

113. SCE's recorded 2006 expenses for subaccount 593.300 (overhead line maintenance) are $37.168 million.

114. SCE forecasts an increase of $3.965 million, or about 28%, over 2006 recorded expenses of $14.438 million, for subaccount 594.300 (maintenance of underground lines), $2.670 million of which SCE seeks in order to address planned maintenance related to its new Distribution Inspection & Maintenance Program.

115. SCE has experienced declining expenditures related to subaccount 594.300 since 2006.

116. SCE's requested additional funding for subaccount 596.400 (maintenance of streetlight and signal system) includes $184,000 for increased O&M repairs and $593,000 for increased lamp replacements.

117. SCE experienced less streetlight repairs in 2006 than in previous years because, in that same year, it performed its highest number of capital fixture replacements for its streetlights.

118. SCE is experiencing a slower rate of customer growth than in previous years, 2006-2008.

Section 4

119. SCE uses a 2-year average ratio of late payment charges multiplied by non-CARE electric revenues to determine the residential late payment charge.

120. A three-year average ratio of late payment charges and a more recent revenue forecast, as used by TURN, provides a reasonable forecast of the residential late payment charge.

121. The current FAC service fee is $13.75 which is about 30% less than the current $19.74 cost of service for this fee.

122. We find that a $17.00 FAC service fee reasonably balances the actual cost of service, the potential for increasing service disconnections, and the ability of late paying customers to pay their bills.

123. Until the ongoing negotiations with telecommunications providers on joint pole attachment fees are concluded, SCE will maintain the amount of revenue at current rates.

124. SCE has indicated in this proceeding that, while it views changes to Tariff Rule 17-D as unnecessary, SCE will make such changes if directed by the Commission.

125. Recorded customer service expenses from 2002 through 2006 were offset by productivity initiatives that produced cost savings.

126. Productivity initiatives helped to offset additional costs related to increased customer growth.

127. Additional customers require additional services which increase costs.

128. SCE's forecasting of those costs affected by growth in customers is reasonable.

129. Forecasts of future expenses should consider historical recorded data and new programs where justified.

130. Forecasts of vehicle expenses in customer service accounts should use consistent methodology with forecasts of vehicle expenses in other areas, including transmission and distribution accounts.

131. San Joaquin Valley Power Authority is the only currently identified CCA which may operate in 2009.

132. It is uncertain whether other CCAs will begin operation during the 2009 TY GRC cycle.

133. Recorded staffing levels in SCE's Ledger Organization have remained stable during the past five years.

134. DRA's forecast of expenses which does not include new employees in the Leger Organization is reasonable.

135. Additional new customer payment options could create increased opportunities for fraud.

136. Additional employees in the credit department will reduce the opportunities for fraud.

137. Reduced costs from SCE's GPS project will benefit ratepayers and should be included in expense forecasts.

138. Shareholders should continue to pay for Service Guarantee Credits.

139. SCE's internal policy to address erroneous disconnects fails to provide sufficient notice to customers. SCE does not have a tariff provision within its Service Guarantee Program related to erroneous disconnects.

140. Forecasts of ESP services should include consideration of reduced 2005 recorded costs due to vacant positions.

141. The average call volume increase during the past 5 years exceeds the growth in customers.

142. Even with past productivity measures that reduce phone call costs, future phone call costs are expected to increase.

143. The uncollectible factor has been declining for the past 7 years.

144. No party has sufficiently explained the reasons for the decline in the uncollectible factor.

145. In D.07-03-044, Pacific Gas and Electric Company's last GRC, the Commission used a five-year average of most recent recorded uncollectible factors to forecast PG&E's test year uncollectible factor.

146. It is reasonable to take into consideration the average of SCE's most recent five-year recorded uncollectible factors to forecast the 2009 uncollectible factor.

147. The recorded 2006 expenses in subaccount 905.900, Market Research and Communication, were the greatest of the past five years.

148. Costs for customer communications exist in other FERC Accounts, including the Public Goods Charges and Demand Response Funding.

149. A reasonable estimate for subaccount 905.900 is the amount recorded in 2006.

150. Recorded expenses in subaccount 905.300 indicate a wide variance during the past 5 years.

151. A 5-year average of past expenses associated with customer bill adjustments recorded in subaccount 905.300 contains a one-time cost of $882,684 and therefore does not present a reliable forecast of future costs.

152. DRA's forecast methodology for costs associated with customer bill adjustments recorded in subaccount 905.300 is more reliable than SCE's forecast which contains a substantial one-time cost.

153. SCE requests a 157% increase over recorded 2006 Electric Transportation expenses.

154. Adoption of the PREP is expected to reduce use of petroleum products and reduce costs of operation.

155. The number of compliance employees has remained constant during the past years.

156. Non-GRC proceedings, including those addressing energy efficiency and demand response, include load management activities.

157. Advantages for converting forklifts from carbon-based fuels to electric power include avoiding petroleum consumption, decreased fuel costs, have fewer moving parts, and no oil changes or smog checks.

158. DRA recommends adopting SCE's request for $500,000 to test and evaluate truckstop and seaport electrification.

159. Although PHEVs are not yet commercially available, it is reasonable to provide SCE funds for Electric Transportation safety studies, planning, and consumer and employee safety education.

160. Research on PHEVs is conducted by the United States Department of Energy and through the Commission's PIER program.

161. PHEV studies should be conducted on a state-wide basis.

162. Adopted expenses for Account 912.100 are almost 90% above recorded 2006 expenses.

163. SCE has not yet concluded its negotiations with telecommunication providers regarding new rates for pole attachments.

164. SCE's tariff does not include a rule to address adjustments of customer bills for billing errors that is consistent with existing Commission decisions.

Section 5

165. SCE's estimated 2009 expenses for Information Technology Expenses-Computing Services FERC Account 923 (Outside Services) of $18.996 million, based on 2006 recorded costs with adjustments for supplemental labor, software maintenance, etc., is more reasonable than DRA's forecast based on a linear trend.

166. Inclusion of a contingency in project cost estimates for budgeting purposes is generally reasonable.

167. Since there is uncertainty whether all of the contingency included for data center relocation in SCE's estimate of 2009 expenses for Information Technology Expenses-Computing Services will be needed, it is reasonable to reduce SCE's estimate by half of the contingency amount ($0.025 million labor and $0.020 million non-labor).

168. Although SCE transferred 13 positions from Computer Services to another part of its organization in 2007, they still perform the same functions.

169. SCE planned to start its NERC CIP effort in 2007 by hiring 14 Full-Time Equivalent employees. However, only six Full-Time Equivalent employees were actually filled, and it hired 11 contract employees whose costs were recorded in (Account 923 Outside Services).

170. Because SCE's request for six senior technology analysts to evaluate relevant emerging technologies involves new technologies whose potential benefits are unknown, a cautious approach of allowing half of SCE's request is reasonable.

171. Because SCE's request for contractor and consultant services to evaluate relevant emerging technologies - Information Technology Expenses-New Technology (Account 923 Outside Services) - involves technologies that are unknown and whose potential benefits are unknown, a cautious approach of allowing half of SCE's request is reasonable.

Section 6

172. SCE's Total Compensation Study addresses the narrow issue of whether SCE's compensation (the amount presented for analysis) is consistent with other similar companies. It does not determine who, e.g., shareholders or ratepayers, bears the cost of employee compensation.

173. SCE forecasts Results Sharing expenses of $106.413 million, a $15.1 million increase from its 2006 recorded expenses due to the significant increase in anticipated labor costs.

174. The Commission determined in D.08-09-038 that SCE's Results Sharing Program had been based on fraudulent data for a period of seven years.

175. The 2006 GRC decision ordered SCE to rely on a one-way balancing account for the Results Sharing Program.

176. SCE extensively redesigned the Results Sharing Program in 2006.

177. There is no data upon which to determine whether SCE's redesigned Results Sharing Program successfully addresses the known deficiencies identified in the 2006 GRC decision and in D.08-09-038.

178. SCE asserts in testimony that it forecasted a Spot Bonus program cost of approximately $4.5 million, but does not provide any evidence in support of its asserted Spot Bonus program cost.

179. SCE does not provide any evidence of the total exact cost of its Awards to Celebrate Excellence program.

180. SCE requests $23.304 million for related expenses, annual bonuses, and long-term incentives, which are closely tied to the stock performance of the parent company, Edison International, and, therefore, in part, to non-utility activities. These incentive costs have not previously been included in SCE's revenue requirement.

181. SCE's forecast of $24.588 million for executive base salaries, related expenses, and short-term bonuses assumes 37 officers, which includes an additional officer to implement the SmartConnect program.

182. The record does not contain information regarding individual officer salaries.

183. SCE has not shown that SmartConnect, and to a lesser degree some other large capital projects, will occur in TY 2009.

184. SCE's 2006 recorded expenses for executive base salaries, related expenses, and short-term bonuses are $21.208 million.

185. SCE does not provide any evidence in support of its requested amount for executive short-term incentives for TY 2009.

186. SCE requests an additional $644,000 for Account 930.2 expenses for corporate governance, based on its unsubstantiated assertion of an increasing frequency of corporate reporting required of Corporate Governance and oversight by the Board of Directors in response to increased corporate compliance requirements, public scrutiny, and frequent adoption of new and revised laws, regulations, and rules.

187. SCE requests $884,000 in Account 930.2 for stock-based compensation for its directors.

188. SCE has not shown that corporate reporting and stock-based compensation for its directors are tied to ratepayer benefits.

189. SCE forecasts $17.668 million in expenses, an increase of approximately $4.8 million over 2006 recorded costs of $12.862 million, for Talent Management, on the basis that its increased costs are the result of increased hiring and additional funding required for SCE's Leadership Programs.

190. SCE has increased its spending for Talent Management by 81% from 2002 to 2006.

191. SCE's Talent Management activities experienced declining productivity (new hires per SCE staff have declined) and there is no discernable relationship between SCE's TY 2009 forecast and the trending forecast for 2006-2008, which is stable.

192. In the 2006 GRC, the Commission determined that the costs of SCE's Leadership Programs should be shared 50/50 between shareholders and ratepayers.

193. SCE's forecast of Outside Services expenses is based on a three-year average, which includes consultant expenses related to the Fair Labor Standards Act 2004 amendment.

194. SCE expects to continue to incur expenses during 2009-2011 related to implementation of the Fair Labor Standards Act 2004 amendment.

195. SCE's forecast of Client Services expenses is based on a five-year average of historical costs which includes the one-time cost of responding to union organizing in 2004.

196. SCE forecasts $52.947 million for 2009 pension costs, although it is legally required to contribute the minimum of zero.

197. Historical evidence indicates that SCE's estimates of pension contributions exceed actual contributions.

198. SCE's pension costs are subject to a two-way balancing account pursuant to the 2006 GRC decision.

199. SCE forecasts medical program costs of $115.921 million based on the application of a 10% escalation factor to 2006 recorded costs and for 2007 and 2009. The 10% escalation factor is supported by analysis of numerous factors influencing medical costs for SCE's covered population, multiple surveys forecasting medical cost trend rates, and underwriting projections from its medical plans.

200. SCE's Comprehensive Disability Program is more cost effective, provides greater protections to employees, and returns employees back to work more rapidly than the State Disability Program.

201. Some functions associated with the Miscellaneous Benefits Program provide benefits to ratepayers in the form of reduced medical costs or are appropriate costs for SCE's Commuter Programs.

202. Executive Benefits are largely tied to the amount of compensation awarded to the executives.

203. SCE provided additional information regarding the valuation of its executive retirement severance benefits, satisfactorily responding to our directive in D.06-05-016.

204. The parties who participated on the issue are in agreement that that the Commission should adopt TURN's proposal to assign Pension and Benefit costs to the labor costs that SCE records below-the-line by using a rate of .54% applied to the ultimately adopted Accounts 925 and 926.

205. The costs of the incremental work identified by SCE to justify the additional amounts for Law Department salaries and related expenses beyond 2006 base year are included in embedded costs.

206. SCE argues that, at a minimum, the incremental expenses attributed to filling vacant positions as of year-end 2006 or to meet the Law Department's technology demands should not be removed from SCE's forecast.

207. SCE provides no evidence on the incremental costs associated with filling its vacant positions as of year-end 2006 or to meet the Law Department's technology demands.

208. Based on historical trends, no further increase in the Law Department salaries and related expenses is warranted beyond the 2006 base year amount of $22.676 million.

209. The implementation and operation of an attorney timekeeping system would incur substantial expenses and divert resources.

210. The difference between SCE's adjustment of $1.188 million to Account 923 (Outside Counsel) is likely attributable to SCE's proper accounting of the related Business Unit adjustment of $424,000.

211. Between 2002 and 2006, SCE experienced an average increase in claims filed against SCE of approximately 11.8% while keeping its claims division labor expenses flat. SCE expects this trend to continue.

212. Between 2006 and 2007 the claims division workload increased approximately only 1.35%. The transfer of 316 claims investigations from Environmental and Safety to the claims division results in an additional increase of only 3.89%.

213. The record shows that costs related to Account 925 (Additional Claims Reserves) fluctuated over the 2002-2006 period. However, SCE fails to account for this fluctuation.

214. SCE requests funding associated with 12 additional Full-Time Equivalent employees to its workers' compensation division, based on its expectation that workload will increase as the new employee population increases.

215. Based on industry standards, funding for 6 Full-Time Equivalent employees is sufficient to address SCE's increased workload in its workers' compensation division.

216. The 2006 GRC adopted a forecast of Workers' Compensation Reserve (Account 925) based on a four-year average of past reserve expenses.

217. The vast majority of SCE's requested costs for Ethics and Compliance (Accounts 920, 921 and 923) support SCE's response to behavior highlighted in I.06-06-014, and which the Commission found to be fraudulent in D.08-09-038.

218. SCE fails to demonstrate that its compliance with the Sarbanes Oxley Act of 2002 and the Federal Sentencing Guidelines revised in 2002 contributes to its requested costs for Ethics and Compliance (Accounts 920, 921 and 923).

219. SCE's request for costs for Regulatory Policy & Affairs includes incremental costs of $1.471 million over 2006 recorded levels, based on its forecast of increased labor costs.

220. Recorded labor costs for SCE's Regulatory Policy & Affairs have been relatively stable during 2002-2008.

221. SCE's request for costs for Regulatory Policy & Affairs includes a one-time 2002 severance payment of $38,000.

222. The Commission reversed policy in the 2006 GRC to disallow the recovery of expenses for compliance with the Affiliate Transaction Rules from ratepayers.

223. DRA proposes removal of $1,000 from SCE's forecasted expenses for its Central Services and Corporate Accounting groups (Accounts 920/921) based on an error in SCE's workpapers that understated SCE's forecast.

224. Expenses in years 2002-2006 related to Audit Services (Accounts 920/921) have been relatively stable.

225. SCE has not provided sufficient support for its expectation of an increase of approximately 16% over 2006 base year expenses related to Audit Services.

226. SCE's forecast of expenses related to Audit Services includes one-time, non-recurring severance costs of $24,000.

227. SCE seeks costs for five additional employees based on its projected capital investment program for 2007 through 2011.

228. SCE does not quantify the extent to which its capital investment program will rely on additional staff.

229. To the extent that SCE's Tax Department performs work for any unregulated entities, the costs are subject to the affiliate credit mechanism, which ensures that ratepayers are only charged for costs related to the regulated utility.

230. SCE bases its forecast of costs for four additional tax specialists, including a salary premium, on increased work related to new tax forms, new electronic filing requirements, new California audit requirements, and implementation of a new financial accounting standard for computing income taxes for publicly traded companies.

231. SCE bases its forecast of an additional $2.354 million in corporate property insurance costs (Account 924) on an increase of $500,000 for Mountainview, an increase of $200,000 for SONGS, and the remaining incremental amount based on its assertion that it has justified an intense growth program throughout this application in order to serve its customers.

232. SCE does not support the additional amounts requested for corporate property insurance costs (Account 924) beyond its requested additional amounts for Mountainview and SONGS.

233. SCE forecasts a \$4.722 million increase from recorded 2006 costs of \$3.855 million for claims reserves (Account 925), based on the five-year average of 2002-2006 recorded expenses, which includes two years with unusually high costs.

234. SCE identifies the need for an additional \$78,000 for Mountainview's liability insurance and approximately \$329,000 for hull insurance to cover loss or damage to the three additional helicopters.

235. SCE does not support the additional amounts above 2006 base year requested for corporate liability insurance beyond its requested additional amounts for Mountainview and SONGS.

236. SCE forecasts a \$657,579 increase from recorded 2006 costs for Corporate Communications labor expenses (Accounts 920/921) to add the cost of eight additional Full-Time Equivalent employees that were authorized in the 2006 GRC decision but never filled.

237. SCE's 2006 recorded costs of Corporate Communications labor expense do not include severance payments.

238. Recorded costs of Corporate Communications labor expense for 2006 are representative of future costs.

239. Recorded costs of Corporate Communications design expenses (Account 930) for 2006 are representative of future costs.

240. SCE's forecasts additional MRTU-related O&M costs for Accounts 920/921 and 923.

241. Pursuant to Resolution E-4087, all costs related to MRTU are recorded in a memorandum account.

242. The record does not support SCE's claim that additional employees are needed to meet increasing workload in the Power Procurement Business Unit (Accounts 920/921 and 923).

243. TURN's productivity analysis demonstrates declining productivity associated with SCE's requested staffing levels above 25 Full-Time Equivalent employees and certain consulting expenses for its Risk Control Group (Accounts 920/921 and 923).

244. SCE forecasts $600,000 in expenses for Outside Services (Account 923) related to its Risk Control Group activities, as compared to its 2006 recorded expenses of $285,000.

245. Of the $600,000 in expenses for Outside Services related to Risk Control Group activities forecasted by SCE, $150,000 is attributable to consulting costs related to the Enterprise Risk Management program that will be complete before 2009 and $176,000 is attributable to recruitment consulting related to SCE's forecasted staffing above 25 Full-Time Equivalent employees.

246. SCE requests $78.095 million in expenses for its Operations Support Business Unit, which is an increase over 2006 recorded expenses of $48.008 million.

247. SCE's forecast of expenses for its Operations Support Business Unit relies on a budget-based approach, based on its unprecedented growth in both new customers and system load, which SCE states has caused it to exceed its authorized spending levels, resulting in corporate-wide reallocation or deferral of funding from other projects and a strain on workforce capacities.

248. Operations Support's employees do not generally interact directly with SCE's customers but, instead, work "behind the scenes" to support other SCE business units.

249. It is not possible, based on the record, to identify the impact of SCE's budget-based forecasting on its specific recommendations.

Section 7

250. TURN's proposed net present value net salvage methodology would defer costs to future ratepayers.

251. The record does not demonstrate that TURN's net present value net salvage methodology is superior the Commission's longstanding depreciation rate calculation methodology.

252. DRA's proposal, to retain current net salvage estimates, is a deferral of the recovery of future net salvage costs and based on the policy that deferral will mitigate the rate impact of this decision.

253. SCE performed a comprehensive depreciation study and its proposed depreciation rates were derived following the Commission's longstanding methodology.

254. DRA has not explained the purpose of the information requested in its proposed reporting requirements regarding net salvage or how the requested information would be used to achieve that purpose.

Sections 8.1 and 8.2

255. The weighting percentage of plant is a function of the plant additions and retirements.

256. Atypical projects distort the plant weighting factor.

257. SCE's SONGS 2 & 3 and Palo Verde forecasts are uncontested.

258. SCE's annual level of unanticipated reliability-related capital projects was $0 in 2007 and $553,000 in 2008.

259. SCE applies a 10% contingency factor on its Four Corners reliability projects' total project estimates. This contingency factor is on top of an 8.7% contingency factor that SCE includes in its capital expenditures forecast on all specifically-identified projects.

260. SCE has increased its efforts with the Arizona Public Service Company to better identify future Four Corners reliability projects.

261. In R.06-04-009, the issue of whether SCE's capital expenditures for 2007-2011 associated with its ownership share in Four Corners is recoverable in rates under Pub. Util. Code § 8341(d)(1) is pending.

262. SCE's Mohave decommissioning TY 2009 estimate includes $12.8 million or 30% in contingency reserves.

263. Mohave expenditures are subject to a two-way balancing account as approved in SCE's 2006 GRC.

264. SCE has company housing for only 83 of its 155 employees located at its remote Big Creek site. Other employees unable to find near-by affordable housing must now travel long distances.

265. SCE accepts TURN's 40% recommended reduction in housing capital projects.

266. TURN's recommendation of a $1.773 million increase in SCE's housing capital projects (contingent upon SCE capitalizing the Big Creek housing repairs that SCE seeks to expense in Account 542) is reasonable and consistent with the finding in today's decision regarding Big Creek O&M.

267. DRA recommends SCE be required to evaluate the cost-effectiveness of continued investments in small hydro projects in its next GRC.

268. In light of the agreement between SCE and TURN, it is reasonable to reduce the cost of its CAISO/WECC projects by $1.397 million or 50% for the years 2008 through 2011.

269. SCE's benefit-cost assessment of small hydro refurbishment projects uses different assumptions from TURN's. The differences are reasonable, based on engineers' and technicians' assessment of equipment.

270. SCE has not yet completed a formal project design for its Lundy Powerhouse project or submitted its design to various agencies for review.

271. The $0.1 million Poole Housing Project encompasses replacement of the existing roof containing asbestos.

272. SCE's decision to include $19.134 million in its capital expenditures to construct new back-up gas and service air compressors was based on its analyses of alternatives and a benefit-cost analysis.

273. SCE requests funds for new back-up gas and service air compressors at a yet-to-be constructed peaker site.

274. SCE used a benefit-cost analysis based on the manufacturer's specifications to include a spare combustion turbine in its 2010 capital additions.

275. Funds for a new Pebbly Beach administration building were authorized funds the SCE 2006 GRC decision to address employee safety concerns.

276. SCE must design and improve a new site to which a present tenant's containers will be moved before SCE may use the leased parcel for its micro turbines adjacent to Pebbly Beach.

Section 8.4

277. SCE derived its customer service capital forecast from a detailed five-year construction plan which undergoes review by manager-level planning committees for approval by project and reviewed at least annually.

278. The cost of new meter connections varies by customer class. Residential new meter connections are the most inexpensive of the customer classes. Agricultural and non-residential new meter connections cost more than twice the average rate of residential customer class.

Section 8.5

279. SCE did not make any IT Identity Management capital improvements in 2007 and has spent less that $1.0 million on an annual average between the years 2003 and 2006.

280. SCE did not include in either its 2008 or 2009 IT Enterprise Resource Planning capital expenditure forecast any such work performed in 2007 that was not paid until 2008 or that was not billed until 2008.

281. SCE must satisfy two FERC milestone dates (June 2009 and June 2010) in implementing its IT Critical Infrastructure Project.

282. SCE is authorized to track all its MRTU capital expenditures in a separate memorandum account and to seek recovery of these costs in a separate ERRA proceeding outside of the GRC.

Section 8.6

283. SCE's non-electric real estate projects and blanket work orders with accumulated costs of less than $1 million are not in dispute.

284. SCE seeks to correct building maintenance issues identified in a 2006 Parsons-3D/I report over a ten-year period.

285. SCE uses a combination of internal and external sources to develop its industry-standard best practices for forecasting capital remodel and construction projects which includes contingency percentages.

286. SCE incorrectly identifies 25 individual real estate non-electric capital expenditure projects totaling $181 million as being uncontested.

Section 9

287. The evidence supports SCE's contention that uncollectibles should be included in the revenue lag calculation and, in particular, that uncollectibles are included in the Accounts Receivables to Sales Ratio method.

288. Standard Practice U-16 states a preference for an "accounts receivable" method as opposed to a "statistical sampling" method.

289. It is reasonable to use the Accounts Receivables to Sales Ratio method in isolation rather than as part of an average that includes a "statistical sampling" method.

290. SCE was unable to identify specific reasons for meter to service billing lag in excess of 90 days.

291. SCE's income tax lag day methodology reflects the changed IRS regulation regarding how property tax payments are reflected.

292. DRA's income tax lag day methodology does not reflect the changed IRS regulation regarding how property tax payments are reflected.

293. The 2006 recorded tax payments used by DRA to calculate its FIT and CCFT lag days contains an anomaly that distorts that year's data.

294. The determination of the income tax recovery midpoint using actual monthly distribution of income tax recovery as proposed by SCE, rather than the levelized pattern assumed by DRA, is more likely to reflect what will actually occur in the test year.

295. SCE's proposal to use actual intra-year variations in the actual payment timing in determining interest in the applicable pensions and PBOPs balancing accounts is different from the current treatment.

296. SCE's proposal to pay its pensions and PBOPs (excluding pay-as-you-go) on a quarterly basis is different from what was included in its 2006 GRC and different from actually transpired in 2006 and 2007.

297. SCE has not explained why the 2006 GRC treatment of pensions and PBOPs (excluding pay-as-you-go) lag days is defective or unworkable.

298. Compared to what was adopted in the 2006 GRC, SCE's proposed treatment of pensions and PBOPs (excluding pay-as-you-go) lag days will increase costs to ratepayers.

299. As part of working cash, SCE has included a $7.5 million balance in bank deposits as a functional minimum bank deposit level not required by the banks.

300. There is no evidence that shows whether or not SCE is managing its cash in the most effective way in order to maximize the use of that cash and minimize any cash balances that the ratepayers would have to fund.

301. By Standard Practice U-16, only bank required minimum deposits are to be included as minimum deposits and reflected as such in working cash.

302. By excluding from working cash $7.5 million in a minimum bank deposit balance determined by SCE to be functionally required, any need to determine the reasonableness of SCE's management in maximizing the use of such funds is obviated.

303. Regarding operational cash requirements, TURN's assertion that prepayment costs related to June Lake Transmission and Morongo Transmission are known for 2009 is uncontested.

304. TURN's assertion that 2006 recorded prepayments reflect two SONGS refueling outages and the schedule is to do four refueling outages over three years is uncontested.

305. TURN's assertion that certain prepaid software costs are non-recurring is uncontested.

306. TURN's assertion that lag associated with PBOPs trust receivables has been reduced from 2006 levels is uncontested.

307. SCE and DRA agree that, if DRA's recommendation to adjust executive benefits and pension expense is adopted, there should be a related reduction to the Unfunded Pension Reserve offset to rate base of $2.782 million.

308. SCE's regression analysis, of the three-year rolling average trend for the T&D capital expenditures and the T&D M&S inventory, results in an Adjusted R-square of 0.99.

309. DRA's explanation that transmission and distribution capital expenditures are tied to serving the utility's customers does not adequately explain how the effects of changes in activity related to maintaining and replacing older systems designed to serve existing customers and inflation are adequately reflected in its estimate, or why such factors should not be reflected in its estimate.

310. Application of SCE's methodology for estimating T&D M&S to the applicable T&D capital expenditures adopted in today's decision results in an adopted T&D M&S estimate of $182 million for TY 2009.

311. SCE and the other owners of Mohave have unsuccessfully attempted to find a buyer for the plant, and, for this GRC, it is reasonable to assume Mohave will be decommissioned by 2010.

312. It would be prudent for the owners of Mohave to proceed expeditiously with the auctioning of the Mohave M&S inventory to minimize ratepayer costs related to this rate base item.

313. Over the 2009–2011 rate case timeframe, DRA's recommendation of zero for Mohave M&S will likely be closer to reality than SCE's estimated balance of $7.145 million and will be adopted.

314. Due to the continuation of the Mohave Balancing Account and the resultant true-up to the actual costs determined to be reasonable after appropriate review, whether the forecasted M&S amounts, as part of this GRC decision, are specifically reflected in rates fully, in part, or not at all is inconsequential.

315. Emission credits were included in the purchase of Mountainview by SCE from Intergen, and such credits have value as evidenced by the secondary market.

316. SCE's assignment of $18.798 million of the Mountainview purchase price to emission credits, based on the market value of emission credits, is reasonable.

Section 9.10

317. SCE's proposal to finance nuclear fuel inventory with customer deposits is a proposal to change a previously established Commission policy with respect to either nuclear fuel inventory or customer deposits.

318. The Commission has previously determined that nuclear fuel inventory should not be included in rate base and financed through the rate of return on rate base but should instead be financed through short-term debt.

319. The Commission has previously determined that SCE's customer deposits should be used to offset rate base.

320. By the Commission's providing SCE with recovery of its related interest costs through additional authorized expenses, SCE's customer deposits are comparable to noninterest-bearing customer deposits for ratemaking purposes

321. The current treatment of customer deposits for PG&E and SDG&E is a result of settlements in their last GRCs, and as such are non-precedential in nature.

322. For SCE, the status quo is for nuclear fuel inventory to be financed through short-term debt and customer deposits to be used to offset rate base.

Section 10

323. Resolution E-4087 requires that prior to SCE's recovery in rates of the incremental capital additions, O&M costs, and all other costs associated with the CAISO's MRTU initiative, SCE must record such costs in the MRTUMA and the Commission must find such costs reasonable in SCE's annual ERRA reasonableness proceeding.

324. Because the costs associated with the CAISO's MRTU initiative are unknown at this time and the scope of the MRTU phases are changing and evolving, it is important the MRTUMA remain active to record these costs.

Section 11

325. SCE has demonstrated that defect levels for the DSRP project are within established norms for projects based upon their relative complexity, and that SCE followed processes that met generally-accepted best practices.

326. SCE has demonstrated that DSRP pricing defects have been fixed, DSRP project objectives have been met, DSRP is in use throughout SCE's service area, and DSRP is the sole application used by distribution planning personnel to create and price distribution work orders, schedule jobs and order materials, and create and complete meter requests.

Section 12

327. SDG&E's methodology for calculating its SONGS related revenue requirement is reasonable.

Section 13

328. The Gross Revenue Sharing Mechanism for NTP&S adopted in D.99-09-070 is now 10 years old. During these years, the regulatory framework has changed significantly.

329. In 1999, SCE operated in a largely performance-based ratemaking environment but today the regulatory environment is more aligned with cost-of-service ratemaking.

330. The $16.773 million threshold for NTP&S was calculated based on SCE's incremental costs to provide NTP&S in 1995. This figure may bear little relation to TY 2009 conditions and both TURN and SCE express concern that no provision exists for increasing or decreasing this amount.

331. We find significant ambiguity about the circumstances under which SCE is permitted to recover its NTP&S costs from ratepayers.

332. SCE's comparison of the gross revenues received by ratepayers and the net revenues received by shareholders does not fully support the existing methodology or present an accurate picture of the shareholder benefits received under this program.

Section 14

333. SCE's budget-based PTYR mechanism to calculate a 2010 and 2011 revenue requirement doe not take into account that budgets are estimates that are not always implemented.

334. The existing annual November Advice Letter process provides a method of implementing the revenue requirement for years 2010 and 2011.

335. A PTYR forecast based upon 3% increase provides for reasonable spending needs for the PTYR period of this GRC cycle.

336. DRA proposes that PTYR capital-related cost increases be determined using the plant addition level reviewed and adopted for TY 2009, escalated by 2% for 2010 and 2011 levels.

337. SCE's proposal for O&M escalation is to use its proposed GRC escalation rate methodology, updated at the time of the advice letter filing.

Section 17

338. The Commission has no jurisdiction over SCE's philanthropic activities.

Section 18 and Section 19

339. The Commission's requirements regarding supplier diversity are set forth in General Order 156.

340. The record does not indicate that SCE has violated General Order 156.

341. The record does not indicate SCE has violated any Commission decision, rules, or order regarding workforce diversity.

342. Diversity is good public policy and, therefore, SCE should competently staff and implement the full forecast of positions for WMDVBE activities and efforts in diversity.

343. Diversity is good public policy and, therefore, the Commission should examine ways to improve the performance of California's regulated energy utilities in the areas of workforce and supplier diversity, such as through the use of financial incentives and clarification of the Commission's rules under GO 156.

Section 20

344. SCE's labor and non-labor cost escalation methodology and forecasts are unopposed and are reasonable.

Section 21

345. SCE does not demonstrate that meals and travel expenses are legitimate business expenses and not for entertainment-related activities.

346. The Commission must be able to indentify categories of entertainment-related expenditures that are not allowed for ratemaking purposes.

347. In the absence of an accounting system that enables the Commission to make regulatory distinctions between business and entertainment expenses, it is reasonable to exclude meals and business expenses from SCE's revenue requirement calculations.

Section 22

348. SCE asserted attorney-client privilege and on that basis refused to allow DRA to review 36 of the ASD audits completed by SCE from 2003 through August 2007.

349. Since SCE chose to assert its claim of attorney-client privilege regarding 36 ASD audits, it must meet its burden of proof in this proceeding in some other way.

350. SCE's provision of over 90% of the ASD audits to DRA does not mean that the costs of the remaining 36 privileged audits are reasonable.

351. Of the 159 audits conducted in 2006, 11 (6.9%) were privileged.

352. SCE's forecast for ASD Account 920/921 is based on 2006 data.

353. DRA's 2009 forecast for ASD Account 920/921 did not reflect a disallowance based on the 36 asserted privileged ASD audits.

354. If SCE's tax refund claims are successful, ratepayers will receive the resulting benefits.

355. The record does not indicate that there is anything unusual about SCE filing for tax refunds or using an outside vendor to do so (Account 923). Since

there will be uncertainty as to whether a tax refund claim will be successful and when the claim will be resolved, prepayment to the consultant filing the claim seems reasonable.

356. Regarding DRA's recommended disallowance in Account 923 of a $513,448 prepayment for 2006, SCE made two journal entries for this item in 2006 whose net effect was zero.

357. The FERC formula for calculating AFUDC provides that is to be financed first by short-term debt. The remainder is to be covered by an average of prior year long-term debt, preferred stock, and common equity weighted by their respective balances.

358. The Commission takes official notice of A.08-06-013 for the limited purpose of establishing that SCE made the request contained therein. In that application, SCE seeks authority to increase its short-term borrowing authorization to $2 billion.

359. The record does not indicate that SCE considered its A.08-06-013 request in its forecast of its AFUDC rate.

360. The existence of A.08-06-013 tends to support DRA's contention that the portion of CWIP to be financed by short-term debt will be higher than forecasted by SCE, which means that the AFUDC rate will be less than forecasted by SCE.

361. SCE's actual 2007 AFUDC rate of 7.7204% is the most recent in the record, and it is reasonable to adopt that rate for 2009.

Section 23

362. The record does not support the proposed settlement between SCE and CCUE.

363. The proposed earmarking of capital expenditures has not been shown to increase reliability.

364. Earmarking capital expenditures unreasonably constrains SCE's obligation to exercise managerial discretion and make all necessary capital expenditures to serve customers and maintain the system.

365. The issues addressed in the proposed settlement with CCUE embody specific employment terms and conditions, which belong in collective bargaining and not in the GRC decision.

366. The proposed settlement with Disability Rights Advocates provides reasonable and useful improvements to SCE's facilities, web sites and customer practices. These improvements are within the scope of this proceeding.

Section 24

367. AReM's proposal regarding purchase of receivables is not within the scope of this GRC.

Conclusions of Law

Section 2

1. Initiating a feasibility study of a SONGS 2 & 3 license renewal after 2011, after the steam generator replacements, will allow SCE a reasonable amount of time to identify replacement generation in the event the NRC refuses to renew the license and provide SCE will important information.

2. SCE's proposed PTYR flexible outage schedule mechanism reasonably predicts PTYR refueling and maintenance outage costs.

3. It is reasonable to continue using the post-test year ratemaking flexible outage schedule mechanism.

4. SCE's forecast of Palo Verde O&M costs is reasonable.

5. Adopting a two-way balancing account for Palo Verde O&M costs will reasonably allow SCE to recover actual costs while protecting against over-recovery.

6. It is premature to include the costs of hiring additional staff to account for retirements that may happen in 5 to 10 years.

7. The Mohave balancing account provides SCE with sufficient protection against unknown costs, making it unnecessary and unreasonable to include a contingency in the adopted Mohave TY 2009 O&M cost forecast.

8. SCE's base estimate of Hydro O&M is reasonable.

9. Costs that fluctuate based on weather are better forecasted on an historical average basis rather than last recorded year. Accordingly, it is more reasonable to forecast SCE's non-labor costs associated "Operations of Reservoirs, Dams and Waterways" based on a five-year average rather than on last recorded year.

10. SCE's proposed adjustment to its "base estimate" of Hydro O&M to add $250,000 for cloud seeding efficiency improvements is reasonable.

11. SCE should provide the Commission with additional information regarding the process of cloud seeding, including the CEC's policy position on it.

12. Because it is possible that SCE will incur O&M costs into the foreseeable future, it is reasonable to adopt a forecast of O&M costs that contemplates that event through 2011. However, because it is possible that ownership of San Gorgonio will be transferred from SCE before 2011, it is reasonable adopt a conservative forecast of O&M costs based on the average of recorded costs for 2002 through 2006 rather than on the high recorded costs in 2006.

13. In the absence of an adequate showing relating to SCE's requested staffing additions to the impact of retirements at Four Corners, is reasonable to reduce the number of forecasted additional apprentice positions by 50%.

14. It is reasonable, for purposes of forecasting SCE's hydro staffing costs, to base the wages of the proposed new hydro positions on the actual wages of each proposed new position rather than on the average wages of all hydro staff.

15. Because training expenses are included in SCE's hydro wage calculation, it is reasonable to disallow costs associated with a training instructor for additional apprentices.

16. It is reasonable to disallow from SCE's future adjustments in FERC Account 542 $374,000 associated with rehabilitation and asbestos removal from houses which Edison obtained $387,000 to demolish in its 2006 GRC.

17. It is reasonable to capitalize, rather than expense, SCE's O&M costs for hydro housing and building rehabilitation.

18. SCE's requested $253,333 for the Rush Creek Heliport Brush Clearing and Big Creek Vegetation Management is reasonable.

19. SCE's conduct with respect to IAG's allegation of misrepresentation does not warrant further action under I.08-01-029.

20. We find IAG's requests fails to establish a *prima facie* case of a Rule 1.1. violation. Based on the existing evidence, no further action will be taken with respect to this matter.

21. It is reasonable to allow SCE to include its capital costs in rate base and recover its operating costs for Mountainview through the TY 2009 revenue requirement. However, this ratemaking change cannot occur until FERC issues a decision approving termination of the existing power purchase contract.

22. SCE's requested Mountainview O&M expenses are reasonable.

23. It is not reasonable to track all peaker O&M in a one-way balancing account on the basis of uncertainty regarding the operational date the fifth peaker when the O&M of the fifth peaker constitutes such a small percentage of total peaker O&M costs.

24. It is reasonable to reduce SCE's requested peaker O&M expenses by 10%, the amount equal to SCE's best estimate of the costs associated with the operation of the fifth peaker.

25. SCE should continue to explore ways to increase cross-support on information technology between the staffs of the peakers and Mountainview.

26. It is unreasonable to collect $400,000 for unknown "one-time" O&M projects in each year of the rate case cycle on the basis of the costs of an identified one-time O&M project in 2009.

27. It is reasonable to limit SCE's cost recovery for the Solar Two decommissioning project to its share of its 1999 decommissioning cost estimate, escalated to 2009.

28. For the same reasons we stated in D.06-05-016, SCE's request to recover generation RD&D costs in rates should be denied.

29. For the same reasons we stated in D.06-05-016, SCE's of RD&D PDD costs associated with support costs should be tracked in the PDDMA and subject to review in the ERRA proceeding. Costs related to proposed project development are excluded from the PDDMA.

30. SCE's methodology for forecasting Pebbly Beach Generation Station O&M expense is reasonable.

Section 3

31. In the absence of further detail supporting its request, it is reasonable to allow only 50% of SCE's requested increase for Engineering Advancement.

32. SCE's request for $285,000 to add three civil engineers (subaccount 560.100) is reasonable.

33. SCE's proposed credit adjustment to reflect the elimination of certain contract resources from its Standards and Publications Contract group is reasonable.

34. SCE's request to modify its accounting practices and decrease subaccount 560.100 (overhead) accordingly by $1,145,000 is reasonable.

35. SCE's request for $500,000 to upgrade desktop software is reasonable.

36. Based on the relationship between capital spending and Project Management Organization write-offs, it is reasonable to reduce SCE's requested increase in Project Management work order write-offs by 14.56%.

37. It is reasonable to reduce SCE's requested increase in each clearing account by 40%.

38. SCE's request for an increase of $396,000 in Account 562.100 (Transmission Station Expenses) and an increase of $517,000 in Account 582.100 (Distribution Substations) for additional grid operators is reasonable.

39. A portion of SCE's requested increase to its Vehicle Costs should be rejected, consistent with DRA's recommendation.

40. Based on the magnitude and complexity of SCE's transmission and sub-transmission line, SCE's proposed additional funding for the Transmission Line Clearance Study is reasonable.

41. SCE's proposed increase of $781,000 in labor and non-labor expenses for additional Transmission Line Patrols is reasonable.

42. SCE's request to modify its accounting practices and decrease subaccount 563.100 (Inspect and Patrol Lines Overhead Line Expense) accordingly by $811,000 is reasonable.

43. Based on the fact that it is adding new employees, SCE's forecast of an increase of $721,000 over 2006 recorded expenses in labor and non-labor expenses for safety meetings is reasonable.

44. Based on the fact that SCE will be adding additional miles of transmission line, SCE's forecast of an increase of $1.136 million in increased transmission line maintenance is reasonable.

45. SCE's requested increase for corporate real estate and information technology costs is reasonable.

46. SCE's request to modify its accounting practices and increase subaccount 566.300 (Field Accounting Overhead) accordingly by $323,000 is reasonable.

47. SCE's forecast of labor and non-labor expenses for regulatory, planning and business development is reasonable.

48. SCE's forecast of incremental costs for Transmission and Distribution Training is unreasonably excessive. In the interest of allowing SCE incremental funding for these activities, it is reasonable to allow only 50% of SCE's incremental request, which is approximately 25% over its historical expenditures.

49. It is reasonable to base the forecasting of circuit breaker maintenance expenses on a five-year average of historical costs, rather than on the need for increased maintenance due to the previous deferral of such maintenance. Accordingly, it is reasonable to reduce SCE's forecast of circuit breaker maintenance by $346,000 and to also remove $287,000 to reflect recorded costs for vehicles.

50. It is reasonable to base the forecasting of disconnect repairs costs on historical data, rather than on SCE's stated intention to perform approximately six times as many preventative maintenance assessments in 2009 as it has

historically performed on an annual basis. Accordingly, it is reasonable to adopt DRA's forecast of disconnect repair costs.

51. Balancing the need to replace lighting at many of SCE's substations with the fact that SCE's embedded costs include the cost of this activity, it is reasonable to reduce SCE's requested incremental expenses related to switchrack lighting by 50%.

52. Balancing the need to replace cable trench covers with the fact that SCE's embedded costs include the cost of this activity, it is reasonable to reduce SCE's requested incremental expenses related to cable trench covers by 50%.

53. SCE's request for additional expenses for rack inspections is unreasonable.

54. It is reasonable to reduce SCE's forecasted work order expenses related to miscellaneous station equipment by 14.56%, consistent with this decision's reduction to SCE's forecasted capital expenditures.

55. SCE's request for additional expenses for the Transmission Life Extension Program is unreasonable.

56. SCE's request for additional expenses for Transmission Intrusive Inspections is reasonable.

57. SCE's request for incremental funding for insulator washing in the San Joaquin Valley is unreasonable.

58. It is reasonable to reduce SCE's forecasted work order expenses related to insulators and conductors by 14.56%, consistent with this decision's reduction to SCE's forecasted capital expenditures.

59. SCE's request for additional expenses to increase its insulator replacement as part of its Life Extension Program should be denied.

60. SCE's request for expenses for grading in Angeles National Forest as part of its Life Extension Program should be denied.

61. It is reasonable to reduce SCE's estimate of Project Management Organization work order write-offs by 14.56%, to reflect this decision's reduction to SCE's forecasted capital expenditures.

62. SCE's request for additional expenses for Customer Service Business Unit Safety Activities is reasonable.

63. SCE's request for additional expenses for subaccount 580.200 (Internal Market Mechanism) related to new ongoing annual costs in response to guidelines from the U.S. Fish and Wildlife Service and facility operation and maintenance costs for new facilities is reasonable, except that the amount of expenses related to new facilities should be reduced by 14.56%, to reflect this decision's reduction to SCE's forecasted capital expenditures.

64. SCE's requested expenses related to the management and supervision of the Meter Services Organization are reasonable.

65. SCE's request for increased expenditures over 2006 recorded levels for research development and demonstration is unreasonable.

66. SCE's proposal to continue the one-way RD&D balancing account for transmission is reasonable, provided that SCE's funding under this balancing account is restricted to endeavors that meet the criteria for permissible RD&D projects as stated in Pub. Util. Code § 740.1.

67. SCE's requested expenses related to the Distribution Inspection and Maintenance Program, in subaccount 583.400 (overhead detail inspections) and Account 584 (underground line expenses) are reasonable.

68. Balancing the fact that SCE did not prepare a cost benefit analysis to determine whether additional site readiness checks are needed to support load growth and customer growth projects with the facts that SCE intends to replace some contract construction/materials coordinators with additional employees

and that load growth is expected, it is reasonable to reduce SCE's requested incremental expenses related to pre-construction site readiness checks (subaccount 583.400) by 50%.

69. SCE's request to include $3.628 million in subaccount 583.400 to account for costs incurred during emergency responses to non-storm outages that were charged to capital rather than O&M is reasonable.

70. SCE's forecast for subaccount 583.400 (distribution inspections) should be reduced by 17% or $855,000 because it is based on an excess cost per inspection and an excess forecast of the number of inspections.

71. SCE's request for an additional $1.170 million for Underground Cable/Conduit Inspections should be denied.

72. SCE's forecast of customer growth reasonably reflects changing economic circumstances.

73. SCE's request for an increase in subaccount 586.100 (meter turn on and off services) of $316,000 over 2006 recorded expenses of $15.613 million to account for customer growth is reasonable.

74. SCE's forecasting methodology for subaccount 586.400 (test/inspect meters) of using last recorded year plus customer growth and forecast is reasonable.

75. SCE does not provide adequate support for its proposed underground cable testing program.

76. SCE's request for an additional $1.170 million for underground cable/conduit inspections should be denied.

77. SCE does not adequately explain the relationship between its forecasted increase in expenses for training and to hire new employees and the expected decreased costs associated with retirements of meter technicians.

78. SCE's request for an additional $207,000 in subaccount 586.400 (test or inspect meters) for new hires to replace meter technician retirees should be denied.

79. SCE's request for an additional $78,000 over 2006 recorded amounts for distribution construction and maintenance stand-by time mistakenly is reasonable.

80. SCE's request for funding for an additional Mapping supervisor is reasonable.

81. SCE's request for funding for two additional Joint Pole supervisors is reasonable.

82. SCE has not adequately explained why its requested increase of $511,000 for recurring costs related to Safety Activities is not already included in the recorded 2006 base year.

83. SCE's requested increase of $511,000 for recurring costs related to Safety Activities should be denied.

84. SCE's request for a $438,000 million increase in labor expenses for the Joint Pole Organization to fund six additional positions is reasonable.

85. SCE has not established the reasonableness of its bottom-up methodology for forecasting its Business Process and Technology Improvement project expenses.

86. SCE's request for additional funding for its Business Process and Technology Improvement project expenses beyond the 2006 base year should be denied.

87. SCE's requests, in connection with the to reallocation of Field Accounting & Grid Operations costs as a result of the division overhead analysis, a reduction of $1.509 million in TY 2009 in Account 588.300.

88. There is not sufficient evidence in the record to support SCE's request for an additional $89,000 for non-capital Furniture and Equipment.

89. Regarding the Service Guarantee Program, there is insufficient basis on this record to deviate from our previously adopted policy and adopt a baseline level of credits for SCE's Service Guarantee Program that would result in assigning liability to ratepayers.

90. SCE's policy regarding crediting customers when SCE incorrectly disconnects service should be formalized in a tariff rule so that customers are properly noticed of such credits.

91. Cost associated with credits provided to customers as a result of SCE's erroneous disconnects should be a shareholder cost.

92. It is appropriate to forecast TY 2009 expenses related to subaccount 592.200 (maintenance of distribution circuit breakers) based on historical expenses.

93. DRA's estimate of $2.857 million for subaccount 592.200 is reasonable.

94. SCE's requested increase of $1.078 million in labor expense for disconnect repairs should be denied.

95. Balancing the need to replace lighting at many of SCE's substations with the fact that SCE's embedded costs include the cost of this activity, it is reasonable to reduce SCE's requested incremental expenses related to repairing and upgrading switchrack lighting by 50%, to $300,000.

96. SCE's requested incremental expenses of $716,000 are excessive based on DRA's argument regarding historical costs and it is reasonable to reduce SCE's requested incremental expenses related to repairing and upgrading trench covers by 50%, to $358,000.

97. SCE's request for an additional $300,000 for inspecting and repairing steel structures should be denied.

98. Given the conflicting evidence regarding the reasonableness of a 2-year trim cycle, it is reasonable to direct SCE to research the benefits of the trim cycle (or similar concept) and provide the Commission with the results of its research in its next GRC.

99. It is reasonable to adopt DRA's forecast of $37.168 million for subaccount 593.300 (overhead line maintenance).

100. SCE's requested additional funding of $2.670 million related to planned maintenance in subaccount 594.300 (overhead line maintenance) should be denied.

101. SCE's requested additional funding of $184,000 for increased O&M repairs of streetlights, in subaccount 596.400 (maintenance of streetlight and signal system) is reasonable.

102. SCE's requested additional funding for lamp replacements should be limited consistent with its slower rate of customer growth, historical trends, and 2006 recorded costs.

Section 4

103. It is reasonable to adopt the Customer Service expenses addressed in this decision.

104. Ratepayers should not bear the costs of erroneous disconnects.

105. It is reasonable to continue the CCAICBA a memorandum account for CCA revenue, expenses, and any capital-related costs.

106. The proposal to maintain the amount of revenues from joint pole attachment fees at current rates is reasonable. SCE will update fees when negotiations with telecommunications carriers conclude.

107. It is reasonable for SCE to conform its tariff to Resolution G-3372 and D.05-09-046 regarding adjustments of customer bills to reflect billing errors.

108. It is reasonable to adopt DRA's forecast of $660,000 for the costs associated with customer bill adjustments recorded in subaccount 905.300.

109. It is reasonable to direct SCE to modify Tariff Rule 17-D, the rule regarding adjustments as a result of billing errors.

110. It is reasonable for SCE to maintain the amount of revenues from pole attachments at current rates pending finalization of negotiation.

Section 5

111. SCE's estimated 2009 expenses for Information Technology Expenses-Computing Services FERC Account 923 (Outside Services) of $18.996 million should be adopted.

112. SCE's estimated 2009 expenses for Information Technology Expenses-Computing Services Account 920/21 (Salaries, Office Supplies and Expenses) of $23.383 million ($12.045 million labor and $11.338 million non-labor) should be reduced by $0.045 million ($0.025 million labor and $0.020 million non-labor) to $23.338 million ($12.020 million labor and $11.318 million non-labor).

113. SCE's NERC CIP estimate of $1.978 million ($1.404 million labor and $0.574 million non-labor) in expenses in Account 920/921 (Salaries, Office Supplies and Expenses) is reasonable and should be adopted.

114. SCE's request for six senior technology analysts to evaluate relevant emerging technologies (Information Technology Expenses-New Technology Account 920/921 Salaries, Office Supplies and Expenses) at a cost of $1.200 million should be reduced by half to $0.600 million ($0.390 million labor and $0.210 million non-labor).

115. SCE request for contractor and consultant services to evaluate relevant emerging technologies (Information Technology Expenses-New Technology FERC Account 923 Outside Services) at a cost of $0.5 million should be reduced by half to $0.25 million (non-labor).

Section 6

116. SCE's total compensation study is not determinative of the reasonableness of SCE's requested per-employee compensation or who, e.g., shareholders or ratepayers, should bear the cost of employee compensation.

117. In the absence of data upon which to evaluate whether SCE's redesigned Results Sharing Program successfully addresses the known deficiencies identified in the 2006 GRC decision and in D.08-09-038, it is reasonable to share SCE's forecasted costs 50/50 between ratepayers and shareholders and to continue the one-way balancing account for the Results Sharing Program.

118. SCE's request to include amounts associated with Spot Bonus or Awards to Celebrate Excellence programs in its TY 2009 revenue requirement should be denied.

119. It is reasonable to continue the Commission's existing policy of excluding from revenue requirement incentive costs for related expenses, annual bonuses, and long-term incentives, which are closely tied to the stock performance of the parent company, Edison International, and thus in part to non-utility activities.

120. It is reasonable to reduce SCE's forecast of executive base salaries, related expenses, and short-term bonuses by one officer. In the absence of information regarding individual officer salaries, it is reasonable to accomplish this by reducing SCE's estimate by $1/37^{th}$.

121. It is reasonable to reduce SCE's forecast of executive base salaries, related expenses, and short-term bonuses (adjusted to remove costs associated with an additional officer) by 50%.

122. It is reasonable to remove SCE's forecasted amounts of $644,000 for increased corporate reporting and board of directors' oversight, and $884,000 for stock-based compensation for its directors, from SCE's total forecasted amount of $4.752 million.

123. There is no record basis for deviating from the Commission's policy in the 2006 GRC of sharing Talent Management program expenses 50/50 between ratepayers and shareholders.

124. SCE's 2006 base level of $12.862 million, plus 50% of its forecasted additional funding for its Leadership programs ($1.644 million), is sufficient to cover SCE's projected expenses for Talent Management.

125. SCE's forecast of outside services expenses for Account 923 is reasonable.

126. SCE's forecast of client services expenses for Account 923 should be reduced by $99,000 to reflect the removal of its one-time cost of responding to union organizing from its five-year average forecast.

127. Adopting SCE's forecast of pension contributions provides SCE with an incentive to overestimate its contribution.

128. It is reasonable to adopt the mid-point between the legally required minimum contribution to pensions (zero) and SCE's forecast, and to continue balancing account treatment of this amount.

129. SCE's forecast of medical program costs, adjusted to account for labor changes adopted in other sections of this decision, is reasonable.

130. Because SCE's forecasted medical expenses are such a significant amount, it is reasonable to adopt a two-way balancing account to protect ratepayers from any overestimating of this amount.

131. It is reasonable to adopt SCE's forecast of expenses for disability programs for TY 2009, adjusted to account for labor changes adopted in this decision.

132. It is reasonable to adopt, SCE's requested costs for Miscellaneous Benefit Programs, apart from SCE's requested costs for Awards to Celebrate Excellence adjusted to account for labor changes adopted in this decision.

133. It is reasonable to reduce SCE's forecast of executive benefits by 50%, consistent with our treatment of executive base salaries, related expenses, and short-term bonuses and consistent with the 2006 GRC decision.

134. It is reasonable to reduce SCE's Four Corners' Pension and Benefits forecast by the appropriate amounts associated with 50 additional employees, consistent with our decision to reject SCE's request for those 50 additional employees at Four Corners.

135. It is reasonable to adopt TURN's proposal to assign Pension and Benefit costs to the labor costs that SCE records below-the-line by using a rate of .54% applied to the ultimately adopted Accounts 925 and 926.

136. SCE's request for additional amounts beyond the 2006 base year for its Law Department should be denied.

137. SCE should not be required to implement the attorney timekeeping system discussed in this proceeding.

138. SCE's adjustment of $1.188 million to Account 923 (Outside Services) is reasonable.

139. SCE's request for an increase in costs above for additional claims personnel (Account 920/921) should be denied.

140. SCE's request for an increase in costs above 2006 base year for additional claims reserves costs and corporate liability insurance, with the exception of Mountainview and the three helicopters (Account 925), should be denied.

141. It is reasonable to reduce SCE's requested costs for Account 925 (additional workers' compensation personnel) to reflect approval of 6 rather than 12 additional employees.

142. It is reasonable to continue to use the methodology used in the 2006 GRC for forecasting workers' compensation reserve expenses. Accordingly, it is reasonable to adopt TURN's forecast of $20.535 million.

143. It is reasonable to require shareholders, rather than ratepayers, to bear the costs of addressing the problem of fraud. Because the requested costs are associated with the problem of fraud related to I.06-06-014, it is reasonable to deny SCE's request in its entirety.

144. It is reasonable to base the forecast of labor and non-labor costs on a five-year average of the recorded data.

145. It is reasonable to remove the one-time 2002 severance payment of $38,000 from the calculation of the forecast of costs of the Regulatory Policy & Affairs department.

146. It is reasonable to remove SCE's requested costs of compliance with the Affiliate Transaction Rules from revenue requirement.

147. It is reasonable to continue the policy set forth in the 2006 GRC and to disallow the recovery of costs of compliance with the Affiliate Transaction Rules from ratepayers.

148. SCE's forecast of expenses for its Central Services and Corporate Accounting groups (Accounts 920/921) is reasonable.

149. It is reasonable to adopt the five-year average of Audit Services expenses (Accounts 920/921), adjusted to remove $24,000 in one-time, non-recurring severance costs.

150. Consistent with our adjustments to SCE's request for authorization for capital projects in this decision, and in the absence of a quantification of the correlation between SCE's capital investment program and its request for additional staff, SCE's requested increase in labor and non-labor costs for its Treasurer's Organization (Accounts 920/021 and 930) should be denied.

151. SCE's forecast of expenses for its Tax Department, including four additional tax specialists and their associated salary premium, is reasonable.

152. SCE's request for additional amounts over 2006 recorded costs for corporate property insurance costs (Account 924), beyond its requested additional amounts for Mountainview and SONGS, should be denied.

153. SCE's request for additional amounts over 2006 recorded costs for reserve accruals for injuries and damages claims (Account 925) should be denied.

154. SCE's forecast of corporate communications labor costs (Accounts 920/921), adjusted to reflect our treatment of Spot Bonuses, is reasonable and should be adopted.

155. SCE's forecast of corporate communications design costs (Account 930) is reasonable.

156. SCE's forecast of MRTU incremental O&M for Accounts 920/921 and 923 should be reduced to reflect reliance on a memorandum account.

157. SCE's forecast of expenses for the Power Procurement Business Unit (FERC Accounts 920/921 and 923), adjusted for the removal of MRTU-related costs, should be reduced by 50% to reflect historical trends (2002-2006).

158. SCE's forecast of risk control-related expenses should be reduced by $2.383 million to maintain staff at 25 full-time equivalent employees (Account 920), by $651,000 in non-labor expenses associated with the eliminated 15 additional staff positions (Account 921), and by $326,000 for consulting related to the Enterprise Risk Management program and for recruitment consulting associated with the eliminated 15 additional staff positions (Account 923).

159. It is reasonable to adopt SCE's 2006 recorded expenses for the Operations Support Business Unit for TY 2009, rather than SCE's budget-based forecast.

Section 7

160. TURN's proposed net present value net salvage methodology should not be adopted.

161. DRA's proposal to retain current net salvage estimates is adopted to mitigate the rate impact of this decision.

162. DRA's proposed reporting requirements regarding net salvage should not be adopted.

Sections 8.1 and 8.2

163. DRA's 42.554% plant weighting factor, which excludes atypical projects, is reasonable and is adopted.

164. SCE's request for $6 million in contingency reserves for TY 2009 is excessive and will be addressed in R.06-04-009 together with all capital expenditures pertaining to 2007-2011.

165. SCE's TY 2009 $12.8 million Mojave decommissioning capital cost should be disallowed because the Mojave balancing account eliminates the need to include a 30% contingency reserve in this GRC.

166. SCE's proposed $0.44 million new apartments at Big Creek is adopted because it will mitigate SCE's difficulty in recruiting and retaining employees in that remote hydro location and the need for its employees to travel long distances in the absence of local affordable local housing.

167. SCE's hydro housing capital budget is reduced by $0.462 million in 2009, $0.176 million in 2010, and $0.4 million in 2011.

168. Consistent with our findings to capitalize rather than expense certain Hydro O&M for SCE's Big Creek repairs related to Account 542, SCE should increase its housing capital projects by $1.773 million.

169. SCE will provide information on the cost-effectiveness of continued investments in small hydro projects in its next GRC application.

170. SCE's forecast for CAISO/WECC projects is reduced by $0.412 million in 2008, $0.266 million in 2009, $0.438 million in 2010, and $0.282 million in 2011.

171. TURN's recommended removal of 12 hydro refurbishment projects totaling $2.768 million from SCE's TY 2009 small hydro refurbishment projects capital forecast is not adopted.

172. The Lundy Powerhouse Project totaling $2.4 million is disallowed because SCE has not substantiated that the project will be undertaken during the test or attrition years.

173. The $0.1 million Poole Housing Project involving the removal of asbestos is reasonable and is allowed.

174. SCE's request for capital expenditures to construct new back-up gas and service air compressors at four peaker sites during 2008 through 2010 for system

reliability at an estimated cost of $15.708 million is reasonable. SCE's request related to the fifth peaker, which has not yet been constructed, is not reasonable.

175. The $7.103 million spare combustion turbine project for the 2010 attrition year is reasonable and is adopted.

176. SCE's $4.92 million Pebbly Beach administration building project is not reasonable and is not adopted.

177. The $0.62 million micro turbine project is reasonably capitalized because it represents the cost to use a Catalina Island parcel of land via a land right and should remain capitalized as long as SCE uses that land parcel for utility use.

Section 8.3

178. The results of our transmission and distribution capital expenditures discussion in the body of this decision are reasonable and should be adopted.

Section 8.4

179. SCE's Structures and Improvements capital expenditures forecasts of $2.120 million in 2007, $2.010 million in 2008, and $5.880 million in 2009 are reasonable and should be adopted.

180. SCE's Furniture and Equipment capital expenditures forecasts of $1.950 million in 2007, $2.050 million in 2008, and $2.250 million in 2009 is reasonable and should be adopted.

181. SCE's Specialized Equipment capital expenditures forecast of $7.130 million in 2007, $1.940 million in 2008, and $5.900 million in 2009 is reasonable and should be adopted.

182. DRA's 2007 forecast of $20.5 million capital expenditures for Meters should be adopted. For the years 2008 and 2009, SCE's cost-per-meter and customer forecasts, adjusted to reflect the volume of new customers being adopted in this decision should be adopted for the years 2008 and 2009.

183. It is reasonable to reduce SCE's forecast for non-electric capital expenditures by reducing the contingency factor.

Section 8.5

184. SCE's 2009 IT Identity Management Project capital forecast of $5.5 million is reduced to $2.0 million.

185. SCE's 2007 IT Enterprise Resource Project capital forecast of $147.7 million is reasonable and is adopted.

186. SCE's 2007 IT Critical Infrastructure Project capital expenditures of $3.123 million are reasonable and are adopted.

187. SCE's capital expenditures including, but not limited to, of $27.0 million in 2007, $9.8 million in 2008, and $12.0 million in 2009 should be recovered in its MRTU memorandum account as provided for in its Advice Letter 2091-E, not this GRC.

Section 8.6

188. SCE's 2007-2009 forecast of non-electric real estate projects and blanket work orders with accumulated costs of less than $1 million that total $2 million are not in dispute and should be adopted. This amount includes $0.3 million in 2007, $0.7 million in 2008, and $1.0 million in 2009.

189. Individual real estate capital expenditure projects of at least $1 million totaling $183 million for the 2007-2009 period is reasonable and should be adopted. Of this amount $60 million is applicable to 2007, $25 million to 2008, and $98 million to 2009.

190. The building maintenance issues identified in a 2006 Parsons-3D/I report should be corrected by SCE over a fifteen year period.

191. DRA's forecast of real estate blanket work orders over $1.0 million is reasonable and should be adopted.

192. SCE's Satellite Service Center, New Headquarters Building and Rivergrade Real Estate capital expenditure projects should not be approved at this time.

193. SCE has not substantiated its contingency percentages applied to its capital expenditure projects.

194. DRA's forecasting method for real estate capital expenditures and TURN's contingency exception does impact the reasonableness of each capital project and, therefore, does result in each of SCE's individual project being contested.

Section 9

195. DRA's recommended 0.27 day adjustment to remove uncollectibles from the revenue lag calculation should not be adopted.

196. TURN's recommendation that meter to service billing lag should be limited to 90 days for ratemaking purposes is reasonable and should be adopted.

197. A revenue lag of 41.59 days should be used for the lead lag analysis.

198. SCE's estimates of income tax lag days are reasonable and should be adopted.

199. TURN's estimate of a pensions lag day estimate of 96.5 and a PBOPs (excluding pay-as-you-go) lag day estimate of 118.2 are reasonable and should be adopted.

200. $7.5 million in deposit balances that are in excess of bank determined minimum balances should be excluded from working cash.

201. Regarding operational cash requirements, TURN's adjustments to use known prepayments costs related to June Lake Transmission and Morongo Transmission, to normalize SONGS related prepayment costs, and to exclude

non-recurring prepaid software costs are consistent with ratemaking principles, are reasonable, and should be adopted.

202. TURN's recommendation to use 2007 recorded information for other accounts receivable, produces reasonable results regarding PBOPs trust receivables, fairly accounts for increasing amounts for other items in other accounts receivables, and should be adopted.

203. Since the Commission has adopted DRA's recommendation to exclude executive benefits, the Unfunded Pension Reserve offset to rate base should be reduced by $2.782 million.

204. Application of SCE's T&D M&S regression analysis to estimated T&D capital expenditures to estimate the average 2007 T&D M&S balance is reasonable and should be adopted.

205. Since the Mohave Balancing Account is key in the resolution of the appropriate Mohave M&S balance to use for 2009, DRA's recommendation to deny SCE rate recovery for M&S inventory through the balancing account beginning in 2009 should be rejected.

206. DRA's recommendation that the Mountainview emission credits inventory should be removed from rate base should be rejected.

207. SCE's proposal to use customer deposits to finance nuclear fuel inventory should be rejected.

208. Issues regarding the proper amounts of debt and equity and SCE's credit quality are best addressed in SCE's cost of capital proceeding.

209. The decision to reject SCE's proposal to use customer deposits to finance nuclear fuel inventory maintains the status quo and should not result in a worsening view by rating agencies.

210. We will continue our policy, adopted in D.04-07-022 of providing an O&M adjustment for the estimated interest paid to customer related to deposits.

211. We adopt a projected interest rate on customer deposits of 2% based on the methodology adopted in D.04-07-022.

Section 10

212. We deny SCE's request to find the MRTU capital expenditure forecast of $58.035 million and all related O&M expenses recoverable in rates through this proceeding and that the MRTUMA unnecessary.

213. SCE should record all MRTU-related costs in the MRTUMA.

Section 11

214. SCE's request of $10.72 million in capital expenditures (nominal dollars) and $0.642 million for O&M expenses (constant 2006$) for the DSRP project should be adopted.

Section 12

215. SDG&E is authorized a 2009 SONGS revenue requirement of $116.2 million based on its 2008 rate of return adopted in D.07-12-049.

216. SDG&E's SONGS per refueling outage revenue requirement of $13.19 million (2009 dollars) should be adopted.

217. SDG&E's 2009 revenue requirement for SONGS should be treated consistent with section 14 herein for 2010 and 2011.

Section 13

218. We agree with TURN that the Commission should revisit NTP&S but we decline to do so here.

219. As an interim measure, until we complete our review of NTP&S in a rulemaking proceeding, we adopt TURN's recommendation to increase the threshold by 3% to reflect inflation. The threshold is adjusted from

$16.773 million to $25.3 million. SCE's TY 2009 forecast is reduced by $8.527 million.

Section 14

220. We should adopt an annual November Advice Letter filing to implement the revenue requirement change for 2010 and 2011.

221. In connection with post-test year ratemaking, we should adopt SCE's proposed annual revenue requirement adjustment to reflect the number of nuclear refueling outages at SONGS.

222. DRA's recommendation for determining authorized revenue requirements for 2010 and 2011 by applying a 3% increase to 2009 adopted level should be adopted.

223. We should adopt SCE's proposed mechanism to address exogenous changes in SCE's costs ("Z factor").

224. We find it reasonable for SCE to remove all one-time costs from 2009 plant additions when determining 2010 and 2011 levels.

Section 17

225. There is no issue for the Commission to decide regarding SCE's philanthropic activities.

Section 18 and Section 19

226. The Commission has the discretion and authority to require that expenses included in the authorized 2009-2011 revenue requirements that either support WMDVBE activities or are associated with workforce diversity, must be fully and only utilized by SCE as authorized.

227. The Commission has the discretion and authority to examine ways to improve the performance of California's regulated energy utilities in the areas of

workforce and supplier diversity and to ensure that ratepayers obtain value for related expenses.

Section 20

228. SCE's labor and non-labor cost escalation methodology and forecasts should be adopted.

Section 21

229. DRA's recommendation to eliminate $1.559 million for meals and business expenses from the Income Tax Schedule M deductions and to remove the associated expenses of $3.118 million from FERC Account 930.2 is adopted.

Section 22

230. Since SCE has not demonstrated that its 36 privileged ASD audits are reasonable for ratemaking purposes, the costs of the privileged audits should be disallowed for 2006.

231. SCE's 2009 forecast for its ASD FERC Account 920/921 should be reduced by 6.9%.

232. DRA's recommended disallowance in Account 923 of an $813,959 2006 prepayment for filing refund claims for casualty loss for tax years 1997-1999 should not adopted.

233. DRA's recommended disallowance in Account 923 of a $513,448 2006 prepayment should not be adopted.

234. DRA's recommended use of the 6.9521% 2006 AFUDC rate for 2009 is not reasonable.

235. Use of SCE's forecast AFUDC rate is not reasonable because the portion of CWIP to be financed by short-term debt will be higher than forecasted by SCE.

236. SCE's actual 2007 AFUDC rate of 7.7204% is reasonable and should be adopted for 2009.

Section 23

237. The settlement with CCUE is not reasonable when examined in the light of the whole record.

238. The settlement with CCUE is not supported by the evidentiary record.

239. The settlement with CCUE is not in the public interest.

240. The settlement with Disability Rights Advocates is consistent with the law, and does not contravene or compromise any statutory provision or Commission decision.

241. The settlement with Disability Rights Advocates is reasonable when examined in the light of the whole record.

242. The settlement with Disability Rights Advocates is supported by the evidentiary record.

Section 24

243. AReM's proposal falls outside the scope of this proceeding.

O R D E R

IT IS ORDERED that:

1. Application (A.) 07-11-011 is granted to the extent set forth in this decision. Southern California Edison Company (SCE) is authorized to collect, through rates and through authorized ratemaking accounting mechanisms, the 2009 test year base revenue requirement set forth in Appendix C, effective January 1, 2009.

2. SCE shall file its next General Rate Case (GRC) for test year 2012 pursuant to the applicable Rate Case Plan adopted in Decision (D.) 89-01-040, as modified.

3. Within ten days of the effective date of this decision, SCE shall file revised tariff sheets to implement the revenue requirement, accounting procedures, and

charges authorized in this decision and to incorporate the relevant finds and conclusions of this decision. The revised tariff sheets shall become effective on filing, subject to a finding of compliance by the Energy Division, and shall comply with General Order 96-B. The revised tariff sheets shall apply to service rendered on or after their effect date.

4. SCE shall transfer the General Rate Case Revenue Requirement Memorandum Account balance, as of the effective date of this decision, to its Authorized Base Revenue Requirement Balancing Account.

5. SCE is authorized to implement its proposed Authorized Base Revenue Requirement Balancing Account (ABRRBA) to adjust for sales variations and its proposed Post-Test Year Ratemaking (PTYR) mechanism for both 2010 and 2011 to the extent consistent with the foregoing discussion, findings of fact, and conclusions of law.

6. SCE shall file an advice letter to eliminate the Reduced Cost Recovery Amount (RCRA).

Section 2

7. SCE shall file an advice letter to establish the Palo Verde Balancing Account (PVBA) to record the difference between: (1) O&M expenses authorized by the Commission in this proceeding; (2) actual O&M expenses billed to SCE by APS under the Palo Verde Operating Agreement for SCE's share of expenses, including refueling outage O&M expense, and contractual overheads; and, (3) actual SCE oversight expenses. The balance in the PVBA will be carried forward from month-to-month throughout the year. SCE will transfer the balance recorded in the PVBA annually to the Generation Subaccount in the Base Revenue Requirement Balancing Account, commonly referred to as the BRRBA, to be recovered from or returned to customers on an annual basis. The

Commission will review the operation of the PVBA in SCE's annual Energy Resource Recovery Account (ERRA) reasonableness proceedings.

8. Because the overall efficacy of cloud seeding is unknown, SCE shall provide the Commission additional information regarding this process, including the policy position of the California Energy Commission, in the next GRC.

9. SCE shall continue the use of the Project Development Division (PDD) Memorandum Account (PDDMA) for RD&D and, consistent with D.06-05-016, may seek recovery of certain costs in the ERRA proceeding.

10. SCE shall continue the two-way balancing account to record the ongoing costs associated with Mohave Generating Station.

Section 3

11. We direct SCE to research the benefits of The Utility Reform Network's (TURN) proposal to rely on a two-year tree trimming cycle (or similar proposal) and provide the Commission with the results of its inquiry in SCE's next GRC.

Section 4

12. SCE shall update the joint pole attachment Other Operating Revenues and the resulting GRC revenue requirement. This update shall be submitted with the compliance filing in this GRC proceeding or, if the new rates are not yet finalized, in the annual PTYR advice letter filing.

13. SCE shall continue the existing memorandum account to record all Community Choice Aggregation (CCA) expenses and any capital related costs, and all CCA revenues. The memorandum account is known as the Community Choice Aggregation Implementation Costs Balancing Account (CCAICBA). The amounts recorded in this account shall be reviewed and the appropriate ratemaking shall be determined in SCE's first annual ERRA reasonableness

proceeding after SCE begins recording costs and revenues in the account. SCE shall serve all parties in Rulemaking (R.) 03-10-003 with that ERRA reasonableness application to ensure that parties interested in CCA matters are aware of SCE's request for disposition of the amounts recorded in the account.

14. SCE shall file revised tariffs to implement the service fees adopted herein.

15. SCE shall file an advice letter within 90 days of the issuance of this decision to conform Tariff Rule 17-D to Resolution G-3372 and D.05-09-046 in a manner similar to other electric and gas utilities.

16. Similar to the procedure adopted in D.07-03-044, we direct SCE to arrive at a consensus with all stakeholders regarding the language of a new tariff rule within SCE's Service Guarantee Program to address erroneous disconnects. SCE is directed to make this tariff filing within 90 days of the issuance of this decision.

Section 6

17. SCE shall continue to track the authorized and recorded Results Sharing costs in a memorandum account. When the actual Results Sharing payouts for 2009-2011 are determined, any shortfall in the payment to employees when compared to the authorized amount for that particular year shall then be credited to the Authorized Base Revenue Requirement Balancing Account.

18. SCE shall continue the two-way balancing account for pension costs and for Post-Retirement Benefits Other than Pension (PBOPs) consistent with the terms authorized in D.06-05-016.

19. SCE shall file a Tier 2 Advice Letter implementing a two-way balancing account for medical, vision, and dental expenses within 30 days of the issuance of this decision.

20. SCE shall explain in its next GRC why it records amounts for Awards to Celebrate Excellence under Miscellaneous Benefit Programs in FERC Account 926.

Section 8

21. We will address SCE's requested capital expenditures related to Four Corners in R.06-04-009 and, at that time, also address the issue of whether the revenue requirement authorized by this decision should to adjusted to reflect capital expenditures associated with its ownership share in Four Corners Generation Station Units 4 and 5.

Section 12

22. San Diego Gas & Electric Company (SDG&E) is authorized a 2009 San Onofre Nuclear Generating Station Units 2 and 3 (SONGS) revenue requirement of $116.2 million based on its 2008 rate of return adopted in D.07-12-049. This revenue requirement shall be revised to reflect SDG&E's 2009 adopted rate of return.

23. SDG&E is authorized a SONGS per refueling outage revenue requirement of $13.19 million (2009 dollars).

24. SDG&E is authorized to increase this revenue requirement consistent with the methodology adopted for SCE in Section 14 herein.

25. SDG& E shall transfer the San Onofre Nuclear Generation Station Revenue Requirement Memorandum Account balance, as of the effective date of this decision, to its non-fuel Generation Balancing Account.

Section 13

26. We intend to issue a rulemaking in 2009 for the purpose of reviewing Non-Tariffed Products & Services (NTP&S). This rulemaking will not include a review of the Affiliate Transaction Rules. At the appropriate time, all the

testimony submitted in this proceeding regarding NTP&S will be incorporated into the record in the rulemaking.

Section 14

27. SCE must file an annual November advice letter to implement changes to its revenue requirement for post-test years 2010 and 2011 consistent with the requirements set forth in this decision.

Section 18 and Section 19

28. In SCE's next GRC, SCE is directed to provide a detailed description of funds used throughout the company to promote diversity and the results achieved by these investments. At that time, we will decide whether ratepayers should continue to fund programs that are not producing acceptable results.

29. By July 1, 2009, the Commission will open a rulemaking to examine how to improve the performance of California's regulated energy utilities in the areas of workforce and supplier diversity, such as through the use of financial incentives and clarification of the Commission's rules under GO 156.

30. Expenses included in authorized 2009-2011 revenue requirements that either support WMDVBE activities or are associated with workforce diversity must be fully and only utilized as authorized. Such allocation is not subject to diversion or reallocation as might reasonably happen with other funding to meet the actual operational needs of SCE to provide safe and reliable service to ratepayers. Any such diversion will be investigated in the companies' next GRC.

Section 23

31. The Coalition of California Utility Employees' settlement with SCE, creating the Reliability Investment Incentive Mechanism (RIIM) is not adopted.

32. The Disability Rights Advocates' Settlement with SCE is adopted without modification.

33. SCE shall perform the studies as identified in the settlement with Disability Rights Advocates. SCE shall include this information on this study in testimony and work papers in the next GRC.

34. There is a moratorium imposed on SCE precluding any further new authorized payment locations within "payday lenders." SCE may file a separate application on these issues after meeting and conferring with interested parties.

35. Application 07-11-011 and Investigation 08-01-026 are closed.

This order is effective today.

Dated ____________________________, at San Francisco, California.

DeAngelis Agenda Dec. Revision 3 Appendices A-D