Decision 12-11-051 November 29, 2012

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 2012, And to Reflect That Increase In Rates.	Application 10-11-015 (Filed November 23, 2010)

(See Appendix A for Service List)

DECISION ON TEST YEAR 2012 GENERAL RATE CASE FOR SOUTHERN CALIFORNIA EDISON COMPANY

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DECISION ON TEST YEAR 2012 GENERAL RATE CASE FOR SOUTHERN CALIFORNIA EDISON COMPANY

1. Summary

In this decision, we authorize Southern California Edison Company (SCE) to recover from ratepayers an increase of $271.9 million 5.04% over present rates, representing the reasonable costs of providing safe and reliable electrical service to its customers in 2012.

The decision is the result of the Commission's detailed review of the future operations and service requirements claimed by one of the largest utilities in the country. The Commission holds safety, reliability, and just and reasonable rates for customers as the basis of our review. SCE, like other electric utilities, is in a period of transition—with dual responsibilities to inspect, maintain and replace vast existing infrastructure, and also to respond to national, state, and Commission policies requiring additional renewable energy sources and new technologies for tomorrow's more efficient energy service. The technological changes are expected to result in efficiencies, better service, and lower costs to ratepayers over time.

On the other hand, southern California has severely felt the effects of the recent economic recession, and most ratepayers have reduced resources to support rate increases. In order to keep rates just and reasonable, our decision imposes some belt tightening on SCE, including more efforts at cost effectiveness, slower implementation of some activities, and disallowance of non-essential costs and projects. The decision reduces SCE's Test Year 2012 company-wide request for Operations and Maintenance (O&M) expenses by approximately $258 million and reduces SCE's 2010-2012 capital spending request by approximately $756 million.

SCE serves 4.9 million customers in a 50,000 square mile area of central, coastal, and southern California. SCE's service territory includes hundreds of cities and communities with a collective population of more than 13 million people. To provide electrical service, SCE employs over 19,000 people, and works with thousands of contractors to operate and maintain its infrastructure, including 88,207 miles of overhead and underground distribution lines, as well as its nuclear, hydroelectric, and gas- and diesel-fired plants.

This decision authorizes $5.671 billion base revenue requirement for Test Year (TY) 2012 for 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 17.44% increase over the 2009 authorized revenue requirement of $4.829 billion, a 18.57% increase over SCE's 2009 recorded base revenue requirement of $4.783 billion, and 5.04% increase over the projected revenue requirement at present rate levels of $5.399 billion, and a 9.9% reduction from the updated 2012 revenue requirement requested by SCE of $6.294 billion.[1]

The adopted methodology for calculating post-test year revenue requirement results in a revenue requirement for 2013 of $6.078 billion and for 2014 of $6.426 billion. This decision also authorizes a 20.73% increase in SCE's total company rate base between 2009 and 2012. In 2009, the authorized rate base

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[1] When SCE filed its request for a 2012 TY revenue requirement with the Commission on November 23, 2010, it requested a revenue requirement of $6.285 billion. In July 2011, SCE reduced parts of its request by approximately $71.4 million to reflect agreed-upon changes with Division of Ratepayer Advocates and intervenors, corrections to the Results of Operations model, and updated numbers. Exhibit SCE-25, Vol. 01 at 1. Later, in SCE's update testimony filed on October 24, 2011 SCE presented an updated revenue requirement of $6.294 billion.

was $14.77 billion. Today, we increase the authorized rate base to $17.814 billion. However, when SCE's sale of the Four Corners Generating Station is completed, all associated assets will be removed from rate base.

As a result of this decision, SCE total projected company revenue requirement for 2012 is approximately $6.126 billion.

It is an enormous challenge for the Commission and the public to review SCE's proposal within the time available, particularly when few issues were resolved by settlement. Several parties asked the Commission to improve the transparency of SCE's testimony and data responses. The decision includes initiatives and orders to SCE to improve the consistency and clarity of crucial information SCE will provide in future general rate cases.

Safe operations continue to be a top priority, and we recognize the importance of SCE knowing the condition of its assets, particularly poles and wires which can cause great damage if downed. In this decision, we authorize enhanced equipment inspections and new technology to better track the condition and service record of SCE's assets. We also order an independent assessment of SCE's system utility poles to determine whether current loads meet legal standards.

SCE has faced two significant challenges to operations in the preceding 12 months: the December 2011 windstorms and extended shut down of the two nuclear power plants at San Onofre (SONGS). In this decision, we find it is in the best interest of ratepayers for Test Year O&M and post-2011 capital expenditures related to SONGS to be tracked in a memorandum account for separate review and be subject to refund. Regarding SCE's much-criticized response to the windstorm, in 2013, SCE is required to provide the Commission with a progress report on various initiatives SCE stated it would take to improve its emergency communications and responses to service communities and customers.

We remain committed to authorizing recovery only for those expenses necessary to provide safe and reliable electric service. Going forward, SCE proposes to invest billions of dollars in Information Technology (IT) solutions. These capitalized costs are substantial, the assets are short-lived, project costs are difficult to estimate and benefits can be tough to quantify. Therefore, to assist the Commission with reviewing these expenses in SCE's next GRC, the decision requires SCE to provide specific testimony in its next GRC about SCE's capitalized software cost estimation methodology, approach to cost-effectiveness, and whether reasonable metrics exist to measure benefits.

Another significant change in this rate cycle, is the full deployment of Edison SmartConnect, or smart meters, scheduled for the end of 2012. The decision integrates SmartConnect into regular operations in 2013 with separate forecasts, and shifts funding into general rates from a dedicated balancing account. We have also reduced rate recovery for the replaced electromechanical meters.

In addition, SCE has reached three settlements on specified issues with intervening parties: Disability Rights Advocates, Vote Solar Initiative, and California Coalition of Utility Employees (CCUE). This decision finds that the proposed settlements are a reasonable resolution of the specified issues in light of the record that are consistent with the law and in the public interest. Consequently, the decision approves these settlements. However, in relation to the settlement with CCUE, we order SCE to obtain an independent audit of SCE's Reliability Investment Incentive Mechanism.

1.1. Procedural History

On November 23, 2010, SCE filed its TY2012 GRC application. In support of its application, SCE provided thousands of pages of testimony and supporting work papers, and sponsored more than 88 witnesses. The prehearing conference in this proceeding was held on January 31, 2011.

SCE proposed a procedural schedule based on the Commission's 1989 Rate Case Plan, as modified by numerous subsequent decisions. 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 GRCs for the last ten years. Both parties were concerned about use of their limited resources given the fact that San Diego Gas & Electric Company and Southern California Gas Company also had just filed applications for their consolidated GRCs. Other parties sought delayed schedules for a number of different reasons.

On December 29, 2010, TURN filed a motion asking the Commission to authorize a GRC Revenue Requirement Memorandum Account (RRMA) to track the change in revenue requirement ultimately adopted in this proceeding during the period between January 1, 2012 and the date a final decision is adopted.

The assigned Commissioner adopted a schedule with the goals of providing sufficient time for DRA to competently produce Results of Operation and for other parties to review SCE's extensive application and testimony. In the Scoping Memorandum and Ruling, issued March 2, 2011, the Commissioner found that the public interest was best served by adopting a realistic procedural schedule and authorizing the RRMA in case the final decision was not adopted prior to December 31, 2011.

Parties were encouraged to engage in alternative dispute resolution and settlement discussions. Three parties reached a settlement with SCE on discrete issues within the GRC. On August 22, 2011, SCE and DisabRA filed a joint motion for approval of settlement agreement. On September 19, 2011, SCE and VSI filed a joint motion for approval of settlement agreement. On October 20, 2011, SCE and CCUE also filed a joint motion for approval of a settlement.

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 PPHs between June 8, 2011 and June 23, 2011 in San Bernardino, Garden Grove, Oxnard, Visalia, Long Beach, Palm Springs, and San Clemente. Evidentiary hearings were held in Los Angeles on July 25 and July 26, 2011 and continued in San Francisco on August 8 through 26, 2011. Parties submitted concurrent opening and reply briefs on September 26, 2011 and October 17, 2011, respectively.

Pursuant to the Rate Case Plan, SCE, Pacific Gas and Electric Company, and DRA submitted Update Testimony on October 24, 2011 to reflect changes in cost of labor, non-labor escalation factors, and governmental action. A hearing was held regarding the Update Testimony on November 3, 2011. Some parties submitted opening and reply briefs related to the Update Testimony on November 15, 2011 and November 22, 2011, respectively.

Beginning on November 30, 2011, electric utility customers across Southern California experienced power outages as heavy winds ripped through the region. The severe wind conditions resulted in downed trees and power lines, road debris, and other safety-related problems across SCE's service territory. Some SCE customers were still without service one week later. The Administrative Law Judge scheduled a January 26, 2012 PPH in Temple City, the heart of the damaged area, to hear firsthand from the public about the sufficiency of SCE's emergency response. Four Commissioners participated in the well-attended hearing. At the request of the Commission, SCE submitted information on February 8, 2012 about its damage claims outreach to low-income and minority communities affected by the power outages.

Lists of all parties, their acronyms, and other acronyms used in the GRC are attached as Appendices A and B to this decision.

1.2. Burden of Proof

Pub. Util. Code § 451[2] provides, in part, that "all charges demanded or received by any public utility … shall be just and reasonable."

Section 454 provides:

> Except as provided in § 455, no public utility shall change any rate or so alter any classification, contract, practice, or rule as to result in any new rate, except upon a showing before the commission and a finding by the commission that the new rate is justified.

Where a utility fails to demonstrate that its proposed revenue requirements are just and reasonable, the Commission has the authority to protect ratepayers by disallowing expenditures that the Commission finds unreasonable. As the applicant, SCE has the burden of affirmatively establishing the reasonableness of all aspects of its application, including that it is entitled to the relief it is seeking in this proceeding. Other parties do not have the burden of proving the unreasonableness of SCE's showing.

[2] Unless otherwise indicated, all other references to "Code" or "Section" means the California Public Utilities Code.

As a general matter, with respect to individual uncontested issues in this proceeding, we find that SCE has made a prima facie just and reasonable showing, unless otherwise stated in this opinion.[3]

1.3. 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.[4] Evidence Code § 190 defines "proof" as the establishment by evidence of "a requisite degree of belief."[5] We have analyzed the record in this proceeding within these parameters.

2. Policy Matters

We confirm that the Commission's mandate is specific and requires a balancing of interests to authorize rate recovery only for those just and reasonable costs necessary for safe and reliable service. This requires a hard look at each proposed expense, including whether it is necessary during the coming rate cycle and is appropriately calculated. Given the Commission's forward-looking charge to move the utilities toward more diverse and renewable sources of energy, and a substantial emphasis on operational and public safety, we must look beyond mere maintenance of the status quo.

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[3] In this context, "uncontested" means there was never opposition to the issue. It does not include issues resolved by settlement or stipulation.

[4] The Commission has, at times, incorrectly referred to this standard as "clear and convincing" evidence; *see*, In the Matter of the Application of California Water Company, Decision (D.) 03-09-021 at 17.

[5] Application of Pacific Gas and Electric Company, D.00-02-046 at 38, quoting Application of PT&T Co. for A General Rate Increase (1970) 2CPUC2d 89, 98-99.

Under cost-of-service ratemaking principles, the utility is generally entitled to its reasonable costs and expenses, as well as the opportunity, but no guarantee, to earn a rate of return on the utility's rate base. Generally, requests for additional funds have to be justified or established as reasonable by comparison to other alternatives. For example, it is not enough for the utility to merely assert that equipment failures would occur or safety would be compromised absent approval of a certain expense.

Ratepayers are entitled to the Commission's sharp eye and consideration of other options before committing their hard-earned cash. Therefore, we have neither accepted all requests nor adopted across-the-board percentage reductions. Instead, the decision is the result of scrutinizing each request according to the standards and policy articulated here.

2.1. Southern California Edison Company's (SCE) Capital Requests

SCE's capital spending requests are forecast to grow substantially during the five year period (2010-2014) covered in SCE's testimony. In this General Rate Case (GRC), we are primarily focused on California Public Utilities Commission (CPUC or Commission) jurisdictional expenditures which increase from 2010 recorded spending of $2.23 billion to almost $3 billion in 2012, and much more in the following years.

The main drivers of SCE's application are the capital expenditures SCE claims it must make to replace an aging infrastructure and to expand the system to accommodate the increased loads and new power sources that have developed since the system was built.[6] SCE relies on various projections of its

[6] SCE-01 at 1.

aging assets and equipment failures to support much of its capital request. Another significant component is SCE's estimates of capital spending necessary to quickly implement a variety of advanced technologies and programs related to state and Commission policies associated with smart grid implementation, including smart meters, demand side management, and dynamic pricing.

A portion of SCE's revenue request is for capital investments for which SCE received authorized funding in the 2009 GRC, but did not actually fund. Another reason for the size of SCE's revenue request is that it spent more than authorized in the 2009 GRC, which SCE claims caused deferred maintenance and undermined its ability to earn the authorized return for its shareholders. SCE contends that ratepayers are not disadvantaged as long as the utility is investing capital at authorized levels, and does not over-earn.

Contrary to SCE's claim it was underfunded in the 2009 GRC and had to spend more than authorized, The Utility Reform Network (TURN) points out that if one excludes one-time costs, amounts the Commission expressly excluded from rates, and amounts subject to balancing account treatment, SCE's spending was below authorized levels. According to TURN, instead of resulting in a low return for shareholders, the actual 2009 rate of return was 9.55%, 80 basis points higher than authorized.

TURN, Division of Ratepayer Advocates (DRA), Aglet Consumer Alliance (Aglet), and Joint Parties[7] reject the proposition that all $2.259 billion in capital additions are essential and protest that SCE often failed to adequately justify, or

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[7] Joint Parties is comprised of three organizations which participated jointly: Black Economic Council, National Asian American Coalition, and Hispanic Business Chamber of Greater Los Angeles.

quantify the benefits of, a project. TURN also criticizes SCE for failing to prioritize any of its spending requests, essentially taking the position that all are equally necessary.

SCE and Coalition of California Utility Employees (CCUE) vigorously attack nearly all proposals to cut SCE's capital spending as leading to many negative consequences, including layoffs and compromised reliability. In addition, SCE contends that basic principles of cost-of-service ratemaking provide SCE with flexibility to shift funding from categories that formed the basis of a prior GRC forecast to other, more pressing needs if intervening facts require it.

However, the Commission has found that this management flexibility is not absolute. For example, in the 2009 GRC, we rejected SCE's additional funding for deferred activities purportedly made to accommodate unanticipated customer and load growth, because the growth was not "unique circumstances."[8] In D.09-03-025, the Commission said:

> 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 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.[9]

Thus, we have rejected some requests in this GRC for projects which were authorized in a previous GRC, but not completed due to managerial discretion.

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[8] D.09-03-025 at 4-5.

[9] *Ibid*.

Finally, we adopt 2010 unadjusted, recorded capital expenditures for all business units where these recorded costs were made available during the course of the proceeding. According to the Rate Case Plan, SCE is required to prepare its application based on 2009, not 2010, recorded expenses. However, there is nothing in the Rate Case Plan which limits discovery of 2010 actual recorded expenditures and the Commission finds them informative.

Therefore, the Commission examined each requested capital expenditure for necessity, duplication, and cost, and further adopts the unadjusted, recorded expenditures for 2010 capital spending unless otherwise stated in this decision.

2.2. Forecasting Methodologies

Forecasting costs is central to the art of determining the revenue requirement. The Commission has said that selecting the most appropriate method to forecast test year expenses "is ultimately a matter of informed judgment."[10] Forecasting methods were the basis of a large number of disagreements in this GRC.

Several different methods can be used to calculate test year estimates of expenses, e.g., linear trending, averaging (e.g., five year average (5YA) recorded expenses), last recorded year (LRY), and budget based estimates. We recognize that the forecasting principles discussed in prior decisions are generally appropriate and applicable here.[11]

SCE primarily relied on "budget-based" forecasting where it used a variety of methods to establish a "base year" forecast and then made incremental

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[10] D.04-07-022 at 19.

[11] *See*, D.00-02-046, D.89-12-057, and D.89-04-060.

additions by tying each forecast to identified drivers of future work. SCE asserts that, for many items, use of recorded data is inappropriate because of changed circumstances. The Commission has previously observed that because utility spending plans may not always be implemented as intended, budget-based forecasts generally are given less weight than forecasts based on recorded spending absent a showing supporting the contrary approach.[12]

DRA disputes the accuracy of SCE's varied approach and instead contends that SCE tended to use whatever method yielded the highest result. In contrast, DRA relied heavily on historical costs and the concept of "embedded costs" which it explained were costs previously approved and already in existing rates. For example, embedded costs include: (1) historical costs for routine activities that are similar to those forecast; (2) costs for closed or completed projects but for which SCE is still collecting rate recovery; (3) previously authorized funds spent elsewhere; and (4) expenses forecast by SCE to be reduced due to efficiency gains.

Forecasting is educated estimation, is imprecise by nature, and more than one method may be reasonable. We generally accept that use of the best information available is preferred, and total reliance on historical costs will be flawed in at least some areas. For example, reliance on historical costs alone does not capture growth in the number of pieces of equipment to be purchased or maintained, expanded programs of inspection, maintenance, repair or replacement, new programs and technologies, or new failure information.

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[12] D.09-03-025 at 17.

Basic forecasting principles are also subject to interpretation and application on a case-by-case basis. For example, one party's "trend" is not so to another party. Whether costs are non-recurring or whether to use a three-year or five-year average of recorded costs can be a question.

The forecasting principles articulated in other decisions are important guidelines for the Commission, but are not dogma to be rigidly imposed. Circumstances and perceptions vary, and we agree that there are instances when SCE's forecasts do not reflect embedded costs. In other instances, SCE provides sufficient explanation for why funds should be re-authorized.

In this decision, the Commission examined each forecast method individually to ensure an appropriate method was used to reflect the specifics of each expense item.

2.3. Safety

SCE identifies safety as a core value and points to several measures of employee safety that improved between 2008 and 2009. The company also invokes safety in various program areas to support increased funding, largely for infrastructure inspection, repair, and replacement.

When the Commission considers safe and reliable service, our commitment is to ensure that the utility has accurate records about all of its facilities, has a trained professional workforce, and takes appropriate actions to keep its system facilities safely operational in conformity with applicable laws, regulations, and policies.

The Commission carefully reviewed each funding request to determine the potential impacts to public and employee safety at the competing funding levels requested by the parties. In our view, the adopted Operations and Maintenance (O&M) costs and capital expenditures enhance the safe and reliable operation of

SCE's electrical system. Moreover, we have adopted more explicit reporting by SCE of actual expenditures for key safety and reliability categories.

In this decision, we also acknowledge that the Nuclear Regulatory Commission (NRC) has required certain safety-related actions be taken to ensure a "safety culture" exists at San Onofre Nuclear Generating Station (SONGS). The Commission has determined in this decision that we should review these expenses, activities, and results in the future. Therefore, we direct SCE to provide in its next GRC, a summary of its SONGS-Safety Culture programs, achievements, and three years of recorded expenses to assist the Commission in its oversight of this critical activity.

2.4. Cost-Benefit Analysis

Both TURN and DRA raised questions about whether SCE conducted a cost-benefit analysis of, or examined other alternatives to, various expenditures proposed in the GRC application. SCE's responses included that many activities are not suited to cost-benefit analysis because they are required by law, are a necessary prerequisite to achieving public policy goals, or involve new technology where there is insufficient data to measure benefits. Also, some benefits (e.g., improved safety and reliability) are not easily measureable.

The burden is on SCE to not only establish that the proposed work activities are necessary, but also that SCE has prudently examined alternatives before coming to ratepayers to fund the chosen action. The Commission reviews SCE's showing to ensure that SCE is addressing the work in a cost-effective manner. For some items, we were persuaded that SCE did not provide the necessary support for requested funding and we made reductions. In other areas, where there is a new program or technology, we recognize that reasonableness may be otherwise demonstrated.

The parties' requests for more cost-benefit analysis for capital spending are discussed in each section as applicable to the pertinent capital requests.

2.5. Transparency

SCE's Vice President, Ms. L. Ziegler, testified, "When we get our GRC decision, which gives us an authorized capital amount and O&M for the company, [SCE], we then go…back [and] put our budgets together."[13] Another SCE witness testified that some capital projects arise and are completed between GRCs and are not identified to the Commission in the subsequent GRC. SCE views this discretion as appropriate and authorized, and finds no authority which requires SCE to track prior forecasts, authorized spending, and actual spending for individual program categories. Moreover, SCE claims it is difficult to gather such information because the data is not computerized.

We find that when SCE redirects funds authorized for one purpose to a different purpose, it is relevant to our oversight role and consideration of future revenue requests. SCE states it was transparent, provided all necessary information in its work papers, and went to great lengths to do so given a one-time change in its accounting system. However, the changed account numbers led to confusion and extra work by parties. We do not dispute SCE's intentions in this regard; however, the information could be, and should be, presented in a more useful way to the Commission and the public.

SCE's direct testimony was not consistently presented between and within business units about historical and forecast costs, and whether an explanation was included about expense categories that exceeded or were below authorized

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[13] Transcript (TR) at 930.

amounts. Proposed labor increases were generally supported by broad narrative, rather than a workload analysis. In the next GRC, we direct SCE to clearly explain in testimony the workload analysis used to develop estimated labor increases, and an explanation of why new employees must be hired during the test year.

SCE's use of budget-based forecasting, often with multiple cost increments forecast for each 2012 cost, frequently resulted in numerous data requests and several rate case issues for each funding request. This approach unnecessarily increases review time by the Commission and the parties.

DRA complained that because SCE did not provide data responses in a manner consistent with how it was presented in its testimony, DRA was unable to match historical data and forecast data on some items. Other parties, like Eastern Sierra Ratepayer Association (ESRA), complained that SCE's application was presented in a form which made it difficult to track costs and expenditures from year to year, including what was previously authorized, recorded expenses, and how those expenses were adjusted. TURN and ESRA observed that SCE may make inconsistent forecasts of load growth, demand, and customer growth, in other proceedings which should be considered when determining revenue requirement in a GRC.

SCE stated it received a record number of data requests in this GRC, and parties made various complaints about the adequacy of SCE's responses. These facts or perceptions drive up the cost of the proceeding for everyone, and result in delays to the development and resolution of the proceeding. We believe that if SCE were to routinely present essential data in a manner that allows parties and the Commission to more expeditiously evaluate it, the result would be fewer and more focused data requests, more illuminating testimony, more concise evidentiary hearings, and a quicker resolution.

Going forward, this decision requires SCE to include summary data with its direct testimony, and to provide particular evidence, regarding some programs in the next GRC. The purpose is to assure that SCE's spending is sufficiently transparent to permit the Commission and the public to assess where spending occurred and if ratepayers benefited by SCE's spending choices.

The Commission and the public should be able to track the progress of previously authorized large capital projects. For Generation and TDBU capital expenditures in excess of $1 million, SCE shall submit with its direct testimony in the next GRC, tables which provide historical and forecast CPUC jurisdictional amounts by sub-categories. The table for each business unit shall provide five years (2008-2012) of recorded costs, 2012 authorized capital spending, and SCE's 2013, 2014, and 2015 capital requests by organization within these business units.

For the Generation table, the data shall be presented by generation source categories (i.e., nuclear, coal, gas-fired, hydroelectric, and renewable power). For the TDBU table, the data should be presented by organization (e.g., Infrastructure Replacement, Load Growth, Transmission Interconnection, Capital Maintenance, Distribution Construction and Maintenance, Substation Construction and Maintenance, and Customer-Driven programs). This is a modest expansion of information already provided by the utility facilitated by authorized software projects.

In order to assure the Commission has current information for determining SCE's forecast Load Growth, SCE must include in its next GRC, an estimate of unused distribution capacity for the test year, and address it in connection with SCE's forecast Load Growth during the rate cycle at issue.

In the next GRC, we also direct SCE to provide specific information about follow-through on certain required critical infrastructure replacements (e.g., distribution circuit breakers, transformers) and asset-based preventative maintenance. These are described by activity in the decision text. We also direct SCE to provide in its next GRC, information about anti-discrimination and harassment complaints received, and in-house training efforts.

2.6. Environmental Responsibility

Many of the environmental-associated programs SCE participates in are considered in proceedings other than the GRC. These programs include the SmartConnect meter program, Energy Efficiency, the Solar Photovoltaic program (SPVP), and nuclear decommissioning. Within this GRC, SCE makes requests for several environmental-associated programs, including hazardous waste disposal, smart grid-related projects, emission-reducing electric vehicle infrastructure, and to integrate SmartConnect costs into the rate case going forward. Some of these requests are disputed by other parties on the grounds of overforecast need, excessive costs, or as inappropriate for the GRC.

In addition, we also reviewed O&M costs and capital spending in 2012 for the two coal plants in which SCE has an ownership interest. One plant has been decommissioned and SCE has received approval from the Commission to complete the sale of the other in 2012. These projects are discussed in the Generation section.

2.7. Economic Factors

There was a great deal of discussion by parties about the proper role of economic data in the GRC, particularly as to the recession and high unemployment in SCE's service territory, especially in minority and low-income areas. SCE provided an external study to support its claim that its large capital spending program has the economic benefit of creating 13,000 additional jobs, calculated through the use of multipliers, assuming that every dollar spent has direct and indirect effects as the money spreads through the economy.

Aglet and Joint Parties contend that the economic recession is not the right time for a record revenue requirement by SCE. Instead of seeking increases in excess of the inflation rate, Aglet argues that SCE should respond "by tightening its belt and acting to keep high rates under control."[14]

In addition, several parties agree that SCE's study is flawed and should be given no weight. Aglet asserts that the alleged benefits are temporary increases in regional economy that decline once construction ends, and the study fails to account for ratepayer costs over the entire financial life of the capital expenditures. Moreover, DRA notes the claimed benefits are speculative since SCE failed to assess the impacts estimated by a similar study SCE provided in the 2009 GRC. California Black Chamber of Commerce (CBCC) found the report flawed because it could be used to justify any spending without measuring negative impacts on ratepayers. DRA added that capital spending primarily benefits shareholders who earn a high return. CBCC and other parties contended that lower rates would have a more significant impact on local economies.

The potential for economic benefits of capital spending is not an appropriate factor in determining whether to authorize capital expenditures

[14] Aglet Opening Brief (OB) at 2.

which provide the underpinning of the electrical system. Instead we review capital spending to determine whether the investment is necessary for the delivery of safe and reliable electric service. However, the timing of the expenditure may be affected by economic considerations as discussed below.

2.8. Just and Reasonable Rates

When reviewing whether the revenue requirement is just and reasonable, we consider many factors including the economic tolerance of the ratepayer. Ratepayers are struggling through an extended recession, so it may be reasonable to delay some work activities, or extend some programs over an additional time period, in order to mitigate the economic impact to ratepayers. We took this view in the 2009 GRC as well, after determining that such timing modifications would not compromise safety or reliability.

CCUE joined SCE in claiming that if the Commission were to adopt spending reductions proposed by DRA or TURN, it would substantially compromise SCE's system and result in large layoffs of SCE's workforce. Historically, the Commission has made significant reductions to SCE's GRC requests, and historical evidence does not support the hypothetical results suggested by SCE and CCUE.

We note that the use of implied motives and ad hominem attacks on DRA and TURN witnesses does not advance SCE's position. In general, we found the parties presented their positions, albeit different than SCE's, in a professional manner. DRA and TURN represent ratepayer interests which may well be at odds with employee or management or shareholder interests during a GRC. That does not mean that recommended cuts equate with a "pathology of indifference" or blatant disregard of safe operations, or a failure to see linkage between maintenance and reliability, for example. It means that these parties view SCE's methods and activities through a different lense of reasonableness.

Additionally, the use of the Results of Operations (RO) model to assess the impacts of proposed reductions is not a reliable indicator of eventual results. SCE adamantly voices its perceived authority to re-allocate authorized funds on an "as needed" basis and will redesign spending after the GRC is complete. TURN describes other problems with the model, including how real time managers will implement cuts. For example, SCE's estimated headcount reductions have not been borne out in the past or, as DRA comments, "SCE has made all these threats before."[15] Although the Commission reduced SCE's 2009 GRC request, SCE did not lay off employees in 2009, 2010, or 2011. In fact, SCE added employees.

Additionally, SCE supports its record revenue request by asserting that SCE's residential customer bills, as of 2008, were below the national average. Since bills are a function of usage and rates, SCE contends it is a fair comparison. DRA rejects any national comparison because it thinks SCE failed to take into account the moderate climate and lower energy consumption in SCE's territory, including financial benefits SCE receives in other proceedings.

The Commission finds that SCE's comparison is not sufficiently supported to be given weight. The comparison is from 2008, before the full impacts of the economic recession were felt in SCE's territory and nationally. The fact that the comparison only refers to residential service and does not include commercial, agricultural or other rate categories further erodes SCE's comparison.

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[15] TURN OB at 7.

2.9. Joint Comparison Exhibit

Between SCE and the other participating parties, there are numerous conflicting estimates and recommendations, due in part to use of different dollar models (e.g., $2009, $nominal, etc.) and jurisdictional amounts. This is complicated by errata and updates that have occurred at different times during this proceeding. The Joint Comparison Exhibit (JCE) reconciles SCE's corrections, revisions and agreements since the filing of its application. Similarly, it reconciles changes to the estimates and recommendations of the interested parties since their initial submittal of testimony.

The parties' final positions, prior to update testimony, are reflected in the JCE, and the numerous resulting issues that are identified and summarized form the basis for determining what must be addressed and resolved in this decision. Revisions to SCE's request due to its agreement with the positions of other interested parties, as reflected in the JCE, are reasonable. Those revisions, as well the adopted numbers related to the resolution of issues in this decision, are reflected in the RO model used to calculate the adopted summary of earnings table and related tables for this proceeding. These are attached as Appendices C and D.

Identified issues related to SCE's agreement with other parties' proposals are explained in the JCE and may not be addressed further in this decision.

2.10. Differences in Parties' Capital Forecasts

A major difference between SCE's capital forecasts and the forecasts of other parties is that for most categories, the parties did not examine 2013-2014 capital expenditures. In this decision, we examine SCE's forecast 2010-2012 capital expenditures, even if a project includes proposed spending in subsequent years. This is consistent with prior GRCs, due to both the limited resources of the parties, but also to the greater degree of speculation present the farther the estimated costs are projected from 2009 (when developed by SCE).

Unless otherwise indicated, O&M costs are discussed in 2009 constant dollars, and capital expenditures are in nominal dollars.

The adopted forecasts are incorporated in the development of the adopted expenses by FERC account, as detailed in Appendix C. Appendix C also details the escalation from base year 2009 dollars to Test Year 2012 (TY2012) nominal dollars.

3. SCE's Request

SCE filed its application on November 23, 2010 asking for authority for a base revenue requirement of $6.285 billion to become effective January 1, 2012, and "attrition year" increases in 2013 and 2014. As revised during the proceeding, SCE's TY2012 requested revenue requirement is $6.294 billion.[16] When SCE's expected sales revenues are combined with the currently-authorized revenue requirement, the revenue requirement increases are approximately $946 million in 2012, $488 million in 2013, and $617 million in 2014.

In addition, SCE estimates other operating revenues in 2012 totaling $5.9 billion, excluded from the GRC and received through other proceedings.[17]

SCE offers six basic reasons supporting the revenue requirements sought in this GRC:

- Connect new customers to the system, respond to customer requests;
- Reinforce system to accommodate load growth;

[16] SCE-84 at 2.

[17] SCE-15 at Appendix A, Table II-3.

- Substantial capital investments to replace aging distribution infrastructure and business systems;
- Significantly increased expenses to meet regulatory requirements in generation and electricity procurement;
- A substantial contribution to SCE's defined benefit pension fund to compensate for poor performance of markets in last few years; and
- Increase depreciation rates to account for increased costs of removal after Commission left old rates in place in 2009 GRC.

The expenses and capital expenditures presented in SCE's Opening Testimony include some that are subject to the ratemaking authority of FERC. Each GRC-cycle, SCE splits the costs to be recovered through rates authorized by the Commission from those authorized by FERC, although most FERC-only costs have been removed from this application. SCE followed the same method accepted by the Commission in three previous GRCs.

As in prior GRCs, SCE, and DRA jointly selected an independent expert, Hewitt Associates, to perform a total compensation study (TCS) to benchmark and compare total compensation--salaries, benefits, and long- and short-term incentives--to other companies in the relevant labor markets. SCE offers the results of that study in support of the reasonableness of its labor costs, including executive compensation.

SCE also made other requests of the Commission, including the following:

- Adopt a post-test-year ratemaking (PTYR) mechanism for 2013 and 2014;
- For the SPVP, approve 2008-2009 capital expenditures as reasonable and approve forecast of 2012 O&M;
- For Fuel Cell program costs, approve termination of current balancing account treatment and transfer recovery to base rates;

- Approve recovery of revenue requirement for Four Corners power plant;
- Terminate the Project Development Division (PDD) memorandum account and transfer recovery of costs into base rates;
- Authorize recovery of SmartConnect revenue requirement;
- Authorize recovery of Market Redesign and Technology Upgrade (MRTU) revenue requirement; and
- Continue Reliability Investment Incentive Mechanism (RIIM).

This application did not address Rate Design issues. On June 6, 2011, SCE filed an application to Establish Marginal Costs, Allocate Revenues, Design Rates, and Implement Additional Dynamic Pricing Rates.[18]

4. Generation

Across all types of generation, SCE forecasts $568.860 million in TY2012 O&M and $1.054 billion in 2011-2012 capital expenditures. SCE recorded $431.917 million in 2010 capital spending. These amounts include SCE's original forecasts related to SONGS. In this decision we reduce total TY2012 Generation O&M by $18.512 million and 2011-2012 capital expenditures by $253.506 million and adopt 2010 recorded expenditures.

As discussed in Section 2.1, the Commission adopts recorded 2010 generation capital expenditures, which results in a net $101.5 million reduction to SCE's forecasts.[19] To the extent SCE requested modifications of 2010 recorded expenditures in certain categories, these may be discussed below.

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[18] Application (A.) 11-06-007.

[19] TURN-3 at 24.

Both of SCE's nuclear reactors at SONGS have been shut down since January 2012 due to premature wear found on tubes in large steam generators installed in 2010 and 2011. The prolonged shutdown of the two nuclear power plants at SONGS has caused us to reconsider our treatment of SCE's request for associated O&M and capital spending. In the GRC, SCE forecast SONGS-related O&M and capital expenditures based on the expectation of normal operating conditions in 2012-2014. Certain expenses are clearly no longer reasonable or justified because the particular activities cannot occur during 2012 due to the shutdown. These expenses are disallowed as discussed in more detail below.

4.1. Nuclear Generation

The GRC record does not contain evidence regarding SCE's operating response to the shutdown of the SONGS units. Based on evidence in the record, we undertook a preliminary review of SCE's SONGS-related requests. We believe that SCE has some on-going operational expenses at SONGS, even if the nuclear units are not operating. If no expenses are authorized for preliminary rate recovery, it is highly probable that some expenses will be later approved as reasonable and result in a substantial rate increase.

In order to avoid future rate shock, we have determined it is in the best interests of ratepayers for 2012 O&M and capital expenditures related to SONGS, which would have been authorized under normal operating conditions, be allowed for preliminary rate recovery but subject to review and refund in 2013. These expenses will be tracked in a memorandum account for future reasonableness review when more information is available.

4.1.1. SONGS

SCE is the operating agent and 78.21% co-owner[20] of SONGS Units 2 and 3. SONGS Units 2 and 3 began commercial operation on August 8, 1983 and April 1, 1984, respectively, and provide approximately 1170 megawatts electric (MW) for each unit serving 1.4 million customers. SONGS Units 2 and 3 are licensed to operate until 2022.[21]

The NRC regulates commercial nuclear power plants through licensing, inspections, and enforcement of its requirements. Although the NRC has found that SCE has operated SONGS "in a manner that preserved public health and safety," beginning in 2008, the NRC issued a number of orders and requirements arising from safety-related concerns (e.g., training, maintenance), the most significant associated with developing a better culture of safety. This latter item remains open with the NRC.

4.1.1.1. SONGS Memorandum Account (SONGSMA)

SCE has not obtained NRC approval to repair and restart the units. Pursuant to Section 455.5, the Commission may remove from rate base the value of any portion of a major electric generation facility which remains out of service for nine months, and may disallow any expenses related to that facility. These issues will be addressed in a separate proceeding.

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[20] SCE's ownership portion includes a 3.16% share of SONGS 2 and 3 acquired from the City of Anaheim on December 29, 2006, as approved in D.06-11-025. The remaining 1.79% of SONGS 2 and 3 is owned by the City of Riverside.

[21] SONGS units 2 and 3 were shut down in early 2012 as a result of damage to steam generator tubes. The original steam generator replacement costs, and consequential expenses of the outages, are not part of this GRC. Instead, SCE will submit a separate application to the CPUC for approval of these costs.

Nevertheless, the changed circumstances have undoubtedly impacted SCE's Test Year operating expenses and capital spending at issue in this GRC, and would influence our determination of whether the requested 2012 expenses are just and reasonable. However, the outages occurred after the close of evidentiary hearings and final briefing, so there is no evidence in the record regarding SCE's activities or the reasonableness thereof, in light of the non-operation of Units 2 and 3 since January 2012.

Therefore, we authorize SCE to establish a SONGS Memorandum Account (SONGSMA), effective January 1, 2012, to track for post-2011:

- 100% of O&M;
- 100% of cost savings from scheduled personnel reductions;
- 100% of maintenance and refueling outage expenses, if any; and
- 100% of capital expenditures.

No later than January 30, 2013, SCE should file an application for a reasonableness review of the expenses tracked in the SONGSMA. All expenses disallowed by the reasonableness review will be refunded to ratepayers. The SONGSMA application will be consolidated with the SONGS Order Instituting an Investigation (SONGS OII), Investigation (I.) 12-10-013, which, *inter alia*, will examine the facts and circumstances of the Unit 2 and 3 shutdowns and SCE's operational response.

4.1.1.2. SONGS Safety

In its application, SCE provided evidence that resolution of the NRC concerns and improvement in industry standard performance metrics require extraordinary expenses during this rate cycle, even after one-time costs are removed from the calculation.[22] The effect of the current non-operation of SONGS 2 and 3 on SCE's forecast safety expenses is unknown.

The Commission considers the safe operation of the SONGS facilities, and all nuclear facilities, a primary concern and finds that SCE has a responsibility to maintain a safe nuclear facility, regardless of whether the units are producing power, to conform with industry standards, and to have performance metrics to measure its activities. SCE shall identify all safety-related costs separately in the SONGSMA to ease the Commission's review of this category of expense.

4.1.1.3. SONGS 2 & 3 Operation and Maintenance (O&M) Expenses: FERC 517, 524, 525, 528, 530

According to SCE, it spent $275.4 million in 2009 for SONGS O&M, $45.2 million more than authorized in the 2009 GRC.[23] SCE claims the additional costs were paid by shareholders in order to resolve the NRC concerns. SCE also claims its 2012 O&M includes achieving resolution of all current NRC concerns and establishing industry-standard performance metrics. There are no categorical objections to SCE's forecast of basic 2012 O&M expenses.

SCE's TY2012 forecast for SONGS O&M expenses is $345.9 million (100% level) or $270.5 million (SCE's share). SCE's request represents an increase of 31% over 2009 authorized funds. The forecasts by FERC account are primarily based on 2009 recorded expenses, i.e., LRY. SCE's refueling and maintenance outage (RFO) expenses are additional and discussed in Section 4.1.1.4. below.

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[22] SCE-02-Vol. 01 at 10 (e.g., bring facilities, programs, and equipment up to industry standards, increase training, etc.).

[23] SCE-02, Vol. 01 at 5.

SCE also provided evidence that resolution of the NRC concerns and improvement in industry standard performance metrics require extraordinary expenses during this rate cycle, even after one-time costs are removed from the calculation.[24] Management driven efforts to improve efficiency and productivity also drive 2012 costs, according to SCE.

In addition, SCE proposes personnel reductions, including 100 contractors expected at the end of 2011, and a reduction of 500 SCE personnel in 2012, which SCE thinks will yield about $150 million in savings over the rate cycle. During TY2012, SCE seeks to allocate its $19.3 million share of net cost savings 50/50 between ratepayers and shareholders.[25]

DRA recommends the Commission reduce SCE's forecast O&M by about $35.0 million, primarily due to crediting 100% of cost savings to ratepayers. Both DRA and TURN reject any allocation of savings to shareholders because they view the allocation as a reward for belatedly correcting mismanagement going back to 2008.[26] Moreover, the workforce reductions were recommended by an outside consultant in 2009 and delayed by SCE due to the NRC matters.[27]

SCE assumes that sharing savings with shareholders is reasonable because there have been other occasions where the Commission, and DRA, have supported a 50/50 split of savings arising from cost containment projects. SCE is correct that this allocation has sometimes occurred rather than simply applying

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[24] SCE-02-Vol. 01 at 10 (e.g., bring facilities, programs, and equipment up to industry standards, increase training, etc.).

[25] SCE-17, Vol. 01 at 5-6.

[26] D.08-09-038 at 93 (The Commission found numerous safety violations at SONGS with complicity of SCE management).

[27] SCE-02, Vol. 01 at 12.

savings to offset revenue requirement within a cost category. However, such an allocation is not automatic and must be reviewed by the Commission.

Under the circumstances, we decline to adopt a 50/50 allocation of the net savings from workforce reductions delayed since 2009. The ratepayers have funded these excess positions for two years, and have done so to rectify management problems at SONGS which required a resetting of the safety culture through various activities. SCE seeks record high O&M in 2012 in order to maintain the corrective measures taken by SCE.

The Commission considers the safe operation of the SONGS facilities, and all nuclear facilities, a primary concern and finds that the operating utility, here SCE, has a responsibility to operate according to industry standards and to have performance metrics to measure its activities.

Therefore, the Commission finds SCE's TY2012 O&M forecast of $270.5 million to be reasonable and adopts it, subject to offset from recorded savings associated with implementation of the identified workforce reductions. In addition, with its next GRC application, SCE shall report on the actions taken and total expenses incurred to address NRC concerns beginning in 2009, any shareholder costs, and identify whether the expenses are recurring in the next forecast for SONGS O&M.

4.1.1.4. SONGS 2 & 3 Refueling and Maintenance Outage Expenses

Over the course of the proceeding, SCE revised its forecast of 2012 refueling outages from one to two, although its estimated cost per outage remains $46.0 million (100% level) or $36.0 million (SCE's share) per outage per unit.[28] Although SCE states a refueling was performed at SONGS Unit 2 in the First Quarter of 2012, the unit was not restarted. These costs may be tracked in the SONGSMA for future reasonableness review.

SCE asks the Commission to continue the flexible outage schedule mechanism adopted by the Commission in previous GRCs due to the difficulty in predicting exactly the number of outages that will occur in any year. No party opposes this mechanism and it will be applicable if either of the units come back online during the rate cycle.

Therefore, the Commission agrees to continue the flexible outage schedule mechanism for the three-year (2012–2014) GRC cycle, but declines to adopt SCE's forecast of $72.0 million (SCE's share) for RFO expenses associated with two outages in 2012.

4.1.1.5. SONGS 2 & 3 Capital Expenditures

SCE forecasts capital spending of $131.1 million in 2012 that will be placed in service that year, and $277.1 million between 2012 and 2014 that will be placed in service by 2014. For purposes of this GRC, SCE's share of requested total capital expenditures, including those scheduled to close after 2014, are as follows: $115.983 million in 2010, $125.713 million in 2011, and $151.114 million in 2012.

SCE identified major projects under three capital work categories: Special Projects, Plant Modifications, and its Department Annual Program (DAP). For each project in excess of $1 million, SCE provided a specific description and a

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[28] SCE-84 at 1; (SCE's OB at 14 refers to one outage in 2012, but this appears to be a reference to SCE's initial position in testimony).

safety, reliability, cost-effective, or regulatory justification for the 2010-2014 expenditures.

Summary of SONGS 2 & 3 Recorded and 2010-2014 Forecast Capital Expenditures $nominal (000's)[29]					
Description	**Prior years**	**2010**	**2011**	**2012**	**Total 2010-2014**
Special Projects	$ 63,849	$ 80,475	$109,560	$ 94,080	358,545
>$1 million Plant Modifications	38,829	40,740	15,640	15,120	92.446
Small Plant Modifications	1,949	3,020	1,645	495	14,495
DAP	23,485	20,790	21,035	21,370	104,540
Projects Closing to Plant post-2014 but incurred during year	4,320	3,920	13,515	62,850	325,250
Total	**$132.432**	**$148,945**	**$161,396**	**$193,915**	**$895,276**
SCE Share	**$103,517**	**$115,983**	**$125,713**	**$151,114**	**$697,600**

DRA objected to capital spending requests for four projects, discussed below: 1) high pressure turbine (HPT) retrofit; 2) service air piping; 3) site parking and pedestrian lighting; and 4) cafeteria remodeling.

4.1.1.5.1. High Pressure Turbine Project

This project will be suspended in 2012 due to the non-operation of both SONGS units and the 2012 expenses are disallowed. However, 2010 and 2011 capital spending is reviewed below.

The objective of this project is to replace the existing HPTs at Units 2 and 3 with new HPTs including a modern steam path, new rotor and moving blades, diaphragms, etc. SCE claims the retrofit will provide a number of ratepayer benefits, including (1) less reliance on replacement power by a natural gas

[29] SCE-02, Vol. 02 at 9, Table III-1.

resource, (2) reduction in system wide greenhouse gas (GHG) emissions, (3) efficiency gains that reduce the amount of heat discharged to the Pacific Ocean, and (4) an increase in energy output at SONGS. SCE also points out that new HPTs should reduce future O&M costs associated with required inspections.

As part of Special Projects, SCE's capital forecast to complete retrofit of the HPT at SONGS Unit 2 in 2012 is $36.6 million and an additional $36.6 million for Unit 3 in 2013, for a total of $73.2 million (100% level) in capital expenditures 2010-2014. The total project cost is $82.8 million, including costs from prior years allowed in SCE's 2009 GRC.

DRA agrees with most of the projected benefits of the HPT project, but challenges the cost effectiveness of the project and objects to the costs including a 40% contingency. DRA argues that a $9.2 million ($2004) cost cap associated with turbine work that had been removed from the Steam Generator Replacement Project (SGRP) approved in D.05-12-040 should carry forward to this HPT project.

We disagree. The HPT project is a separate and distinct project from the turbine work removed from the SGRP. Furthermore, in the 2009 GRC, the Commission already found reasonable about $41 million estimated for the SONGS Unit 2 portion of the HPT project.[30] Additionally, SCE provided evidence, based on vendor contract information, that the expected 48 MW output gain can be achieved with the new HPTs. (SCE did not perform any sensitivity analyses, and there could be a broad range in any actual gains.) We are also

[30] D.09-03-025.

persuaded that the contingency factor is reasonable because it is based on the Association for the Advancement of Cost Engineering (AACE) guidelines.

We finds that the pre-2012 HTP project costs as proposed by SCE are reasonable based on the facts and circumstances known to SCE at the time. However, as of January 2012, the HPT project cannot go forward due to the non-operation of both SONGS units, and it would be unreasonable to authorize additional spending unless there is another change in circumstances.

Accordingly, the Commission finds reasonable and adopts SCE's share of the total 2010-2011 capital expenditures: $10.209 million in 2010 and $22.466 million in 2011. If any post-2011 expenditures are made for the HPT project, SCE may record them in the SONGSMA or seek rate recovery in the next GRC.[31]

4.1.1.5.2. Service Air Piping Project

According to SCE, the service air piping project is necessary to prevent maintenance equipment fouling and failures, as well as breathing apparatus filter failures, by limiting deterioration and improving distribution to accommodate increased demand during outages.

SCE's forecast for the project is $1.1 million (100% share), including a 20% contingency cost, and assumes completion in 2013. DRA does not oppose the project, but recommends removing these costs because the project was included in the 2009 GRC. SCE states that it deferred the project from its in-service year of 2009 to provide funding for higher priority projects.

[31] JCE at 580.

The Commission already approved funding for the service air piping project in the 2009 GRC. Given the claimed benefits to worker safety and tool and equipment life, we are not persuaded the project should have been deferred by SCE. Therefore, the Commission rejects additional funding in this GRC and expects the project to be completed.[32]

4.1.1.5.3. Site Parking and Pedestrian Lighting Project

According to SCE, the site parking and pedestrian lighting project, to install battery-powered, solar-cell charged light emitting diode (LED) overhear lighting in three parking lots, will improve lighting in three SONGS parking lots. For this project, SCE's capital forecast is $1.2 million (100% level), scheduled for completion in 2013.

DRA recommends removal of these costs from the SONGS capital forecast because it questions any realization of benefits of safety from this project and the use of the 42% percent contingency factor, which SCE based on AACE guidelines.

The Commission concurs with SCE that improved lighting in the parking lots is essential for maintaining employee, contractor, and visitor safety, as well as for non-SCE employees and the public who might be using the SONGS parking lot adjacent to San Onofre State Beach. However, we find that SCE has not justified a 42% contingency which seems excessive for this type of project, particularly in comparison to the more complex air piping project above which carries a 20% contingency.

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[32] JCE at 582.

Therefore, the Commission finds this project reasonable and adopts $1.014 million (100% level) to reflect substitution of a 20% contingency.

4.1.1.5.4. Cafeteria Remodeling Project

The cafeteria has not been upgraded since it was first built in the 1980s. According to SCE, upgrading the cafeteria facilities is necessary to maintain the safety of SCE employees, contractors using the facilities, as well as the cafeteria workers.

SCE's capital forecast for SONGS Units 2 and 3 includes $1.5 million (100% level) for the cafeteria remodeling project, scheduled for completion in 2011. SCE has moved forward with a portion of the remodel, including replacement of the ventilation and fire suppression systems at the larger cafeteria, for a cost of $320,000, resolving some or all cafeteria worker safety issues.

DRA recommends removing these costs from the capital forecast because it questions whether the project will enhance safety and it also objects to the 40% contingency included in the project. According to SCE, the contingency included in the project is based on the level of the project definition at the time the estimate was prepared, when detailed project plans and schedules had not been developed, which necessitates the 40% contingency in accordance with AACE guidelines.

After about 30 years of use, we agree that a cafeteria remodeling project is warranted to improve the working conditions and wellbeing for SONGS employees, contractors, and cafeteria workers who use the cafeteria facilities. SCE expected the cafeteria to be in use for an additional 11 years through the current operating licenses, and potentially an additional 20 years should SCE seek license extensions for SONGS Units 2 and 3.

Even under shutdown conditions, SCE has numerous employees and workers on-site and will continue to do so whether the units are restarted or decommissioned.

For example, there will be spent fuel stored on site in the spent fuel pools and in the Independent Spent Fuel Storage Installations (ISFSI) for decades to come, which would require the cafeteria to continue to provide food and beverage service to SCE workers and contractors.

The Commission expects SCE to perform and complete the cafeteria remodeling project with the $1.5 million (100% level), and not delay or divert these funds to other projects.[33]

4.1.1.6. San Diego Gas & Electric Company

SDG&E is a 20% co-owner of SONGS, and its request for SONGS cost recovery, which includes a request to continue its balancing accounts for SONGS, is reasonable.

As a co-owner of SONGS, SDG&E has an obligation to oversee and monitor SCE's performance and to protect its ratepayers. We expect SDG&E to ensure that funds authorized for SONGS operation and maintenance expenses, RFO expenses, and capital projects are appropriately used and not delayed nor diverted to other projects by SCE.

Under usual conditions, SCE bills SDG&E for its proportional share of expenses at SONGS. We do not anticipate any change at this time, but SDG&E is subject to the same conditional allowance of SONGS-related O&M and capital spending adopted for SCE. To the extent that SDG&E recovers post-2011

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[33] JCE at 583.

SONGS-related expenses in rates, the amounts are subject to refund in the proceeding opened to review the SONGSMA.

4.1.2. Palo Verde Nuclear Generation Station (Palo Verde)

SCE is a 15.8% co-owner of Palo Verde, for which Arizona Public Service (APS) is the operating agent and 29.1% owner.[34] Palo Verde, which is located approximately 50 miles west of Phoenix, Arizona, consists of three nuclear units, each with an electrical output of approximately 1170 MW. As a co-owner, SCE is obligated to pay its share of Palo Verde costs pursuant to the Palo Verde participation agreement.

4.1.2.1. O&M Expenses: FERC accounts 517, 519, 520, 523, 524, 528, 529, 530, 531, 532, and 556

SCE forecasts Palo Verde O&M expenses of $ 525.9 million (100% level) or $83.1 million (SCE's share). This amount is similar to the $82.5 million forecast by SCE for its share of Palo Verde O&M in the prior 2009 GRC. No party in this 2012 GRC proceeding objected to SCE's O&M forecast for Palo Verde.

SCE's forecast is an increase of 3% over 2009 recorded costs and includes future year adjustments for increases to NRC fees and water fees. Since this amount is needed to continue to provide safe and reliable performance and regulatory compliance at the nuclear facility, the forecast amount of $83.1 million (SCE's share) is deemed reasonable.

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[34] The other five participant owners of Palo Verde are: Salt River Project (17.5%), El Paso Electric (15.8%), Public Service New Mexico (10.2%), Los Angeles Department of Water and Power (LADWP) (5.7%), and Southern California Public Power Authority (5.9%).

4.1.2.2. Capital Expenditures

SCE provided a forecast of $117.236 million ($2009) for 2010-2012 Palo Verde capital expenditures, of which $105.172 million is allocated to projects scheduled to be in service by 2014. SCE identified and provided support for dozens of capital projects it deems necessary to ensure safe and reliable operations. SCE requests $40.605 million for 2010 capital expenditures, $40.290 million for 2011, and $36.340 million for 2012.[35]

DRA recommends a reduction of $9.5 million based on objections to SCE ratepayers funding two Palo Verde capital projects DRA views as the product of mismanagement by APS: 1) component design basis review documentation project; and 2) nuclear administrative and technical manual replacement (NATM) project.

4.1.2.2.1. Component Design Basis Review Documentation Project

This project is in response to an NRC inspection at Palo Verde which found deficiencies in vendor design documentation. According to SCE, the project will include documenting the design of certain high risk equipment designated by the NRC, and developing and updating Design Basis Manuals consistent with NRC regulatory guidelines.

SCE's capital forecast includes $5.7 million (SCE share) for the component design basis review project, scheduled for completion in 2011. This project has been underway for over five years. SCE already has prior capital expenditures of $3.7 million, and requests $1.3 million in 2010, and $0.7 million in 2011, for a total of $5.7 million.

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[35] SCE-02, Vol. 04 at Appendix B.

DRA recommends removing these costs because the project was first developed in the 1990s, and DRA contends that APS did not adequately complete the job pursuant to NRC requirements. DRA argues that APS erred by neither completing the development of the Design Basis Manuals nor kept them up-to-date as they should have. DRA reasons that responsibility belongs to APS as the operating agent, and SCE ratepayers should not be responsible to pay for this project.

We agree with SCE that the Design Basis Manuals are safety-related, and need to be reviewed, completed, and updated over time due to maintenance activities at the plant, plant component upgrades, design changes, and equipment alterations. Although APS is responsible for the daily operation and maintenance of the plant, SCE's obligations as a co-owner include paying of its share of Palo Verde costs to ensure the safety and reliability of the plant.

Therefore, the Commission finds reasonable and authorizes a total of $5.7 million (SCE's share) for this project. As a partial owner of Palo Verde, SCE has an obligation to oversee and monitor APS's performance and to protect its own ratepayers from unnecessary costs. We expect SCE to ensure that these authorized funds are used for completion of this project, and not delayed nor diverted to some other activity or project at Palo Verde.

4.1.2.2.2. NATM Project

This project will replace the existing Palo Verde NATM with a new set of administrative and technical procedures. According to SCE, performance and human behavior issues involving ineffective program administration were identified in an internal APS audit and by the NRC. To address these concerns, APS is replacing the NATM to improve the technical specifications and reduce the likelihood of inoperable equipment.

SCE's capital forecast is $3.8 million (SCE share) for the project scheduled for completion in 2012. SCE has prior capital expenditures of $0.8 million, a 2010 forecast of $0.9 million, a 2011 forecast of $1.0 million, and a 2012 forecast of $1.1 million, for a total of $3.8 million.

While DRA does not oppose replacement of the NATM, these costs are removed from DRA's forecast on the grounds that APS should be solely responsible for what APS and the NRC identified during audits as ineffective program administration and human performance issues at Palo Verde.

We disagree. SCE, as a co-owner, is responsible for its share of expenses related to the continued safe operation and maintenance of the plant, including costs required by the NRC to comply with certain corrective actions such as replacing the NATM with updated technical specifications.

Therefore, the Commission finds reasonable and authorizes $3.8 million for SCE's share of the NATM expenditures. However, as a co-owner of Palo Verde, SCE has an obligation to oversee and monitor APS's performance and maintenance of Palo Verde manuals that are safety-related. SCE shall ensure that the NATM replacement project is completed in a timely manner, and that the authorized funds are not diverted to some other project at Palo Verde.

4.2. Coal Generation

SCE has a partial ownership interest in two coal generation resources: Mohave Generation Station (Mohave) and Four Corners Generation Station (Four Corners).

4.2.1. Mohave Generating Station: 506.013 and 514.013

Mohave includes two coal-fired generating units and is jointly-owned by four entities.[36] SCE, as 56% co-owner, is the Operating Agent. Mohave ceased operations on December 31, 2005 and is undergoing decommissioning which is forecast to be completed during this GRC cycle. However, not all environmental and other requirements necessary for site closure have been fully defined.

SCE's share of decommissioning capital expenditures is currently forecast at $31.9 million, including $11.6 million recorded through 2009 and $20.3 million forecast for 2010 and 2011.[37] Although decommissioning was forecast to be completed in late-2011, SCE states there is a "significant potential" that the work could take longer due to its complexity.

Because SCE continues to incur O&M expense until all decommissioning and site closure and disposition activities are completed, the company forecast 2012-2014 annual O&M Expense for Mohave of $0.5 million (SCE share).[38] The forecast assumes SCE will remain a partial owner of the site through 2014 or beyond, and co-owners will continue to co-fund necessary activities (e.g., site security, groundwater testing). SCE proposes to continue the Mohave Balancing Account (MBA) approved in its 2006 GRC[39] until 2014 or final disposition of the plant site is complete.

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[36] Other co-owners are LADWP (10%), Salt River Project Agricultural Improvement and Power District (20%), and NV Energy, Inc. (14%). SCE-02 Vol.6, Pt. 1 at 59-60.

[37] SCE-02 Vol. 06, Pt. 2 at 50.

[38] *Id.*, Pt. 1 at 67 identifies the O&M work scope.

[39] D.06-05-016, Ordering Paragraph (OP) 8.

No party recommended reductions to these forecasts, although TURN proposed that the Commission adopt a zero rate of return on the remaining investment and decommissioning costs. This issue is discussed below in Section 20.7.

The Commission finds that SCE's forecast O&M and capital expenditures are reasonable pursuant to its course of decommissioning Mohave, and we adopt the 2012 O&M forecast of $0.5 million and 2009-2011 capital expenditures of $31.9 million as proposed by SCE. In addition, continuation of the MBA is reasonable so that costs will be subject to a reasonableness review, and to provide ratepayers protection against unknown costs.

4.2.2. Four Corners Generating Station: FERC 500-502, 505-507, and 510-514[40]

Four Corners is a coal-fired base load plant with five units located in New Mexico. SCE owns 48% of Units 4 and 5, each rated at 750 MW, and a portion of the common systems at the site. APS, one of five other co-owners, is the Operating Agent. The rights and responsibilities of the co-owners are set forth in several agreements and leases (co-tenancy agreements), most of which are scheduled to expire in 2016.[41]

In this GRC, SCE forecast $44.343 million for TY2012 O&M expense, assuming it will sell its interest in Four Corners in 2012 or thereafter. Based on the potential sale, SCE revised its capital request to $45.616 million for 2007-2011 capital expenditures, including $8.548 million for projects completed in 2007-2009 but not requested in the 2009 GRC, and an additional $67.067 million

[40] SCE uses ".015" as a suffix to designate an internal subaccount for Four Corners.

[41] SCE-02 Vol. 06, Pt. 1 at 3.

for 2012-2014 expenditures, assuming the sale is delayed or denied.[42] DRA, TURN, and the Sierra Club each contest parts of SCE's requests.

On March 30, 2012, the Commission approved the sale of Four Corners and found it reasonable to allow SCE to make minimal necessary capital expenditures in 2012 totaling $1.88 million for its estimated share of projects necessary for routine operation of the plant and environmental compliance.[43] Approval of the sale impacts 2012 capital spending.[44]

4.2.2.1. Background

The extent of SCE's capital expenditures, and rate recovery, is at issue in this proceeding due to the Commission's Emissions Performance Standard (EPS) set forth in D.07-01-039. That decision implemented an interim GHG EPS which prohibits Commission approval of a "long-term financial commitment"[45] that extends the life or increases the capacity of a coal-fired plant, unless it meets EPS. The concept of "life-extension" was not defined.

In SCE's 2009 GRC, the Commission approved the utility's 2007-2008 capital expenditures of $50.866 million, but deferred action on 2009-2011 forecast expenditures pending a decision on SCE's application for a broad exemption from EPS for Four Corners. The Commission granted SCE only a partial exemption, limited to pre-2012 costs authorized under the co-tenancy

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[42] SCE-02, Vol. 06, Pt. 3 at 1, Table XIV-1.

[43] D.12-03-034 at 13.

[44] D.12-03-034.

[45] D.07-01-039 at 7 ("long-term financial commitment" is defined as either a "new ownership investment" in base load generation or a new or renewed contract with a term of five years or more.)

agreements, mostly due to the "importance of Four Corners to SCE's generation portfolio."[46]

The Commission also established the applicable legal standard for rate recovery of capital expenses at Four Corners for pre-2012 projects. SCE was required to make a showing in the 2012 GRC that projects costing SCE less than $1 million are "reasonable," and for those costing more than $1 million that they are both reasonable and "necessary." In evaluating "necessity" for the larger projects, SCE was directed to review several criteria.[47] The Commission capped recoverable expenditures for 2007-2011 at $178.6 million as requested by SCE in the 2009 GRC.

Regarding 2012-2016 capital projects, the Commission ordered SCE to submit a report in the 2012 GRC regarding the viability of continued SCE ownership in Four Corners and denied cost recovery of any more expenditures pending the report.[48] In this GRC, SCE submitted what it claimed was the required information regarding pre- and post-2012 capital expenditures and a study of the feasibility of continuing to maintain its ownership interest in Four Corners after 2011.[49] The study concluded that the non-sale options were economically infeasible.

On November 15, 2010, SCE filed an application to sell its ownership share in Four Corners Units 4 and 5 to APS, effective October 1, 2012.[50] SCE also

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[46] D.10-10-016 at 2.

[47] *Id*. at 17-18.

[48] SCE-02, Vol. 06, Pt. 3 at 26-31.

[49] *Ibid*.

[50] A.10-11-010.

sought Commission approval of its proposed ratemaking treatment with respect to the transaction and its proceeds, and authority to make limited, non-life-extending 2012 capital expenditures at Four Corners to operate the plant safely through closing of the Sale Agreement.

In D.12-03-034, the Commission approved the Sale Agreement and found reasonable SCE's 2012 proposed capital spending of $1.88 million.[51] The Sale Agreement also provides for excess 2010-2011 and 2012 capital expenditures by SCE to be returned to SCE in the sale price, and the net sale proceeds to be credited to SCE's ratepayers.

4.2.2.2. SCE's Position

SCE estimates 2012 O&M expenses will be $44.343 million, and assuming the sale proceeds, seeks Commission approval of the following revised capital request:

SCE Revised Sale Capital Request $nominal (000s)

2007-2009	2010	2011 Sale	2012	Total
$8,548	$21,513 ($29,846 –$8,333)	$9,619 ($7,222 +$2,397)	$4,856	$44,536

According to SCE, all capital projects address reliability, safety, or compliance with environmental regulations. In direct testimony, SCE provided supporting documentation for each project addressing the criteria set forth in D.10-10-016.[52]

In its application, SCE proposed both a "Sale Case" and a "Decommissioning Case" for Four Corners costs which include forecasted O&M

[51] D.12-03-034 at 13.

[52] SCE-02, Vol. 06, Pt. 3 at 10-11.

and 2012-2014 capital expenditures. The Sale Case assumes the plant will continue to be operated and maintained consistent with historical practice until the sale is completed, and SCE is obligated to pay its share of those expenses, including regularly scheduled major overhauls. The Decommissioning Case assumes that maintenance and capital spending can be reduced as the plant shut down date approaches, with some degradation of reliability as an acceptable trade-off.

Prior to seeking approval of the Sale Agreement, SCE asked the Commission to adopt the Sale Case forecasts, resulting in TY2012 O&M of $44.343 million, compared to $41.5 million under the Decommissioning Case. SCE's forecast share of estimated 2010-2014 capital expenditures is $104.1 million, compared to $71.4 million for the Decommissioning Case. If all requested capital spending is approved, then total authorized 2007-2014 capital expenditures would total about $163 million, below the $178.59 million cap adopted by the Commission in D.10-10-016.

4.2.2.3. Other Parties' Positions

DRA assumes that the sale will close as planned by October 1, 2012, ending SCE's duty to fund Four Corners expenses. DRA recommends a reduction of $4.418 million to SCE's 2012 O&M forecast to remove $4.257 million, one-third of the annualized costs for the 2014 scheduled overhaul of Unit 5.[53] The remaining $0.161 million adjustment is based on DRA's forecast method for certain discrete labor and non-labor costs.[54] DRA does not contest SCE's proposed capital

[53] JCE at 138.

[54] *Id*. at 144.

spending, but recommends that SCE only recover nine months of the revenue requirement associated with the O&M expenses.

TURN recommends adjusting SCE's forecast 2010 capital expenditures by $8.333 million to conform with actual recorded 2010 expenditures of $21.513 million. SCE agreed to accept 2010 recorded capital spending, but move $2.397 million of the forecast for a key delayed project for ash disposal to 2011 capital spending.[55]

Sierra Club opposes all of SCE's post-2011 forecast capital expenditures because it believes approval of any capital project violates the EPS. Sierra Club also contends that SCE failed to establish that its pre-2012 investments are not "life-extending" and disputes the benchmark of 2016 as the basis for measuring "life-extending."[56] Instead, Sierra Club asserts that "life span" refers to the particular replacement component or the unit as a whole.

Furthermore, Sierra Club argues that SCE has failed to meet the criteria of the reasonableness review for capital projects, and the cumulative effect of SCE's capital spending is a massive and illegal "repowering" of Four Corners that will extend life, increase actual capacity (regardless of the nameplate capacity), and increase GHG for years to come.

4.2.2.4. Discussion of Pre-2012 Expenditures

In D.10-10-016, the Commission declined to grant a broad exemption to SCE for all capital projects at Four Corners until the factual record about the nature and necessity of each project was reviewed in this GRC. Sierra Club and

55 SCE-17, Vol. 06, Pt. 2 at 1.

56 Sierra Club (SC)-1 at 5-7.

SCE have differing views about what was authorized in that partial exemption, what constitutes "life-extension," and what SCE needs to show for approval and rate recovery of 2007-2011 expenditures in this GRC. However, the Commission clearly stated that SCE could recover in rates pre-2012 capital expenditures for Four Corners, subject to a reasonableness review of SCE's share of the projects in this GRC.[57]

Even under the EPS, some capital expenditures are still permitted in GHG emitting coal plants. In D.07-01-039, the Commission distinguished between major refurbishments, such as repowerings, which it defines as new ownership investment, and much more limited replacements, which it excludes. The Commission also found that it may be more economical to replace instead of repair equipment or a part, especially during scheduled maintenance.[58]

For 2007-2014 projects costing less than $1 million, SCE submitted a "Reliability Capital Project Document" which included an explanation of the purpose of each project, the basis for cost estimates, and the justification and benefits of reliability, safety or regulatory compliance. For projects costing more than $1 million, SCE provided a worksheet describing each project, including damage or deterioration to the equipment to establish need, and responding to the other necessity review questions: (1) whether or not the project will extend the life of Units 4 or 5; (2) is the investment necessary for safety or environmental reasons; (3) is the investment is necessary to continue basic operations; (4) the

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[57] D.10-10-016 at 17.

[58] *Id*. at 16 (citing to D.07-01-039 at 35).

cost-benefit of the investment; and (5) the cumulative impact of all capital investments at issue in this GRC.[59]

Sierra Club's primary criticisms are that SCE (1) declared all projects to be not life extensions, (2) failed to examine other low cost alternatives in its cost-benefits analysis or in discussing necessity, and (3) did not actually perform a cumulative analysis of all Four Corners capital expenditures. Sierra Club focused on four types of capital projects, totaling $45.076 million, or 12 of 13 reliability projects costing more than $1 million, to illustrate SCE's omissions. We find that Sierra Club's analysis was generalized, with assumptions that alternatives "likely" or "almost certainly" exist for enhanced maintenance, extended repairs, or use of new or old equipment for spare parts. This is insufficient to show the projects do not meet the review criteria.

It is true that SCE employed similar, generalized language for asserting (1) the projects are not life extensions and (2) the cumulative impact was positive and cost-effective because the projects are necessary to continue basic operation of the plant. However, we do not agree with Sierra Club that SCE's submissions as a whole lack substance.

We find that SCE established the nature, purpose, and necessity of the expenditures as required for its pre-2012 Four Corners capital projects. The fact that SCE's ownership until 2016 was an integral part of the Commission's decision to grant the partial exemption from EPS for expenditures, otherwise shown to be reasonable and necessary, indicates acceptance of 2016 as the measure of Four Corners plant life for SCE. To the extent that replacement

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[59] *Id*. at 17-18.

equipment might last beyond 2016, it does not equate with plant life extension because the ownership agreements, fuel supply contract, and land lease expire that year. Without new agreements, the plant cannot continue to operate.

We find that SCE may recover in rates $8.548 million for 2007-2009 capital expenditures and $31.132 million for 2010-2011 expenditures: $21.513 million recorded expenditures for 2010 and $9.619 million for 2011 to reflect addition of $2.397 million to complete the ash pond project.

4.2.2.5. Discussion of Post-2011 Expenditures

We have previously found that SCE has obligations to fund basic operations at Four Corners based on its co-tenancy agreements and duty of assuring reliability of its energy supply. However, the changes in California law regarding GHG and the approved sale cast a new light on that duty. Based on the record provided, we find that SCE shall make all reasonable efforts to complete the sale of its interest in Four Corners as soon as possible pursuant to the authority in D.12-03-034.

The decision authorizing the sale of Four Corners establishes 2012 capital expenditures of $1.888 million representing SCE's share of 2012 capital projects necessary for the routine operation of the plant, including environmental compliance.[60] The decision is silent as to O&M expenses. We agree with DRA that the 2012 O&M expenses should be reduced to exclude the pro rata costs of the Unit 5 overhaul scheduled for 2014 and to reflect the intended sale as of October 2012. SCE's argument that the overhaul could occur in 2012, before the sale, is unlikely and unpersuasive. We also decline to authorize rate recovery for

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[60] D.12-03-034 at 13.

twelve months of forecast O&M expenses which SCE will not be obligated to pay after the sale. It is more reasonable to authorize $30.065 million for nine months of 2012 O&M expenses ($44.343 - $4.257 x .75 = $30.065 million) and no costs for 2013 or 2014.

SCE shall limit funding of post-2011 capital projects to the Decommissioning Case. If SCE does not complete the sale of Four Corners as authorized, SCE shall include in its 2015 GRC a showing that each post-2011 expenditure is reasonable, necessary, and in service of Decommissioning. The showing of necessity shall include an analysis of expected failure and available less costly alternatives. Although we agree that the sale might not close in 2012, we find that the policy objectives of EPS require that, going forward, SCE only be eligible for rate recovery for O&M and capital expenditures identified in the Decommissioning Case that it reached in consultation with its co-owners.

For 2012, the Commission finds reasonable and adopts O&M of $30.065 million and capital expenditures of $1.888 million. If completion of the sale is delayed, SCE may establish a memorandum account to track expenses between October 1, 2012 and the sale date and to apply to the Commission for cost recovery subject to the established standards of reasonableness review for Four Corners.

4.3. Hydroelectric Generation

SCE's Hydroelectric (Hydro) generating facilities are forecast to provide an aggregate of 1,176 MW of power in TY2012. SCE operates and maintains 33 Hydro generating plants consisting of 76 generating units, 33 dams, 46 stream diversions, and 143 miles of tunnels, conduits, flumes, and flow lines. All but five of the Hydro plants operate under FERC licenses. About 86% of the generation comes from the Northern, or Big Creek, region. The Eastern region encompasses facilities in the Bishop and Mono basin areas of the eastern Sierra Nevada Mountains. SCE states that the majority of the facilities, and some equipment, are more than 70 years old.

4.3.1. SCE's Position

SCE's O&M request of $57.6 million ($2009) is $11.2 million higher than 2009 recorded expense and includes 28 additional employees. To reach the TY forecast, SCE used a mix of methods by FERC account and by labor and non-labor to arrive at a 2009 total Hydro base year O&M recorded/adjusted expense of $46.4 million, and adjusted to $48 million for "account estimating."[61] SCE then added $9.6 million, the average of anticipated future year adjustments, to result in a TY forecast of $57.610 million.

SCE estimates spending $457.6 million on Hydro Capital projects during 2010-2014 in seven project categories.[62] Dams and Waterways ($140.7 million), Electrical Equipment ($101.3 million), and Prime Movers ($79.6 million) account for 70% of SCE's forecast.[63] The Hydro capital expenditure forecasts for years 2010, 2011, and 2012 are $104.5 million, $93.1 million, and $95.5 million, respectively. The forecast includes over 300 individual projects combined into a five-year forecast, although many are still in early planning stages.

4.3.2. Positions of Other Parties

DRA recommends a $6.196 million reduction to O&M by rejecting SCE's methodology, and primarily used 2009, the highest recorded year of costs, as a

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[61] The adjustment reflects that SCE used estimating methodology for various FERC accounts that was not equal to LRY. SCE-02, Vol. 7, Pt. 1 at 9, fn. 2.

[62] SCE-02, Vol. 07, Pt. 2 at 2, Table V-2.

[63] *Id*. at 4, Figure V-1.

base year.[64] The 2009 recorded costs are 11% higher than average recorded expense from 2005-2009. DRA also questions the adjustments SCE made to its recorded cost data. In addition, DRA comments on the 28 new hires, a majority added in TY2012, because it is a 10% increase to Hydro Division doing the same work as existing personnel. But, DRA did not remove them from the forecast.

DRA urges the Commission to adjust SCE's base year forecast back to the five-year historical average O&M, plus SCE's proposed future adjustments, for a total TY O&M of $51.413 million.[65] DRA does not oppose SCE's proposed capital expenditures. TURN recommends adopting SCE's 2010 recorded capital expenditures of $77.930 million, reducing the 2010 forecast by $26.587 million.

ESRA recommends more than $49 million in capital adjustments for 2010-2014. The following discussion will focus on 2011-2012 capital spending. ESRA's biggest cut is a $21.126 million reduction to SCE's forecast of $27.926 million for 2011-2012 FERC relicensing projects.[66] ESRA also would eliminate $7.575 million to be spent in 2011-2012 for eight Eastern Sierra projects that it contends will not be in service by 2014.[67] Finally, ESRA asked the Commission in future GRCs to require: (1) SCE to include an exhibit that provides a status update for all capital projects approved in prior GRCs, (2) SCE to use a consistent format of presentation, and (3) SCE to identify all safety related projects.

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[64] JCE at 174-184.

[65] SCE made two corrections to DRA's calculation with which we agree (SCE-17, Vol. 7, Pt. 1 at 3).

[66] JCE at 960.

[67] *Id*. at 958.

4.3.3. O&M Expenses: FERC 535-545

The 2012 forecast of $57.6 million is 24.2% higher than 2009 recorded costs. According to SCE, the increase, particularly the 28 new employees, is necessary due to higher fees and costs and because work requirements will rise above current levels from improved maintenance practice, and compliance with new standards and regulations by regulatory agencies. SCE criticizes DRA's forecast method as "one-size fits all" without regard for actual changed circumstances.

We agree with DRA that SCE's total recorded O&M fluctuated between 2005 and 2009. However, costs within individual FERC accounts, and labor and non-labor within the FERC accounts, did not all vary similarly. SCE's method of choosing a separate forecasting method for labor and non-labor in each FERC account, while possibly more nuanced, maximized the base year forecast, including adding $1.6 million due to the chosen method.

We also observe that SCE's forecast, including future adjustments, appears weighted to the test year. For example, SCE intends to add 18 employees for North American Electric Reliability Corporation (NERC) compliance which results in a $1.5 million 2012 requirement, or 75% of the 2010-2012 total increase in this area. Although the new employees' proposed duties are explained, it is unclear why these employees must be added mostly in 2012, thus driving up the TY O&M. Similarly, we observe that SCE proposes to hire 10 more employees to "Optimize System Operations" with more than 60% of the 2010-2012 costs scheduled for the test year. In future GRCs, SCE must clearly explain why new employees must be hired during a test year and the relationship of the timing of new hires to SCE's provision of safe and reliable delivery of service.

The Commission finds it reasonable to eliminate the $1.6 million "account estimating" adjustment to the base year arising from SCE's choice of forecasting method and adopts a total TY2012 O&M forecast of $56.0 million.

4.3.4. Capital Expenditures

4.3.4.1. 2010 Recorded Capital Expenditures

SCE's opposes TURN's request to authorize recorded 2010 capital expenditures of $77.930 million which reflects substantial underspending. SCE argues that it needs $15.321 million of the underspend in 2011 for Hydro capital work that was unavoidably delayed, and the balance will be utilized for Hydro projects during 2012-2014.

In general, we prefer to use actual costs when available. In this instance, we are persuaded that some of the unspent 2010 funds are due to delays that are surmountable during this rate cycle. For example, nearly all of the funds reallocated to 2011 by SCE are for the Tule Fire Damage Flume Replacement where a 2009 fire destroyed approximately 2,000 feet of flowline and support structures. The project is underway and scheduled to be in service in 2011.

The Commission finds it more reasonable to adopt the 2010 recorded expenditures for all Hydro categories and projects, and add $15.321 million to the 2011 forecast. The Commission also finds reasonable and adopts SCE's 2011 and 2012 forecasts for Hydro capital expenditures other than the substations, relicensing, and Lundy flowline projects discussed below. As stated previously, we decline to review reallocations to 2013 and 2014 at this time.

4.3.4.2. Eastern Hydro Substation Projects

SCE's forecast includes eleven Eastern Hydro substation infrastructure projects.[68] The primary dispute is whether the Hydro projects will be constructed during this rate case cycle. SCE contends it has made reasonable projections of in-service dates based on the best available evidence.

ESRA recommends removal of all 2010-2014 funding ($17.8 million) for eleven substation projects: $0.475 million in 2011 and $7.1 million in 2012. No reasonable basis exists to conclude the projects will be completed by December 2014, states ESRA, because SCE has not done sufficient planning, including a preliminary California Environmental Quality Act assessment pursuant to General Order (GO) 131-D. ESRA asks the Commission to eliminate all spending for (1) the construction of six substations: Bridgeport, Control, Inyo, June Lake, White Mountain, and Zack; (2) preliminary engineering work in 2013 and 2014 for Magmagen, Mt. Tom, and Skiland; and (3) the Lee Vining substation relocation project. Lee Vining and the $5.050 million Lundy Reconveyance project (Lundy) are discussed separately below.

SCE argues that it has shown the projects are likely to be completed by 2014 and the determination of whether the work requires a Permit to Construct (PTC) is made shortly before construction. SCE believes that the projects, other than Lundy and Lee Vining, will not be subject to GO 131-D because the scope of work will be within the existing substation and not increase voltage. Therefore, construction can be completed by 2014.

We find that SCE made a reasonable showing of necessity for most of its proposed substation expenditures, including construction of five substations:

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[68] SCE-02, Vol. 07, Pt. 2 at 41, Table VII-13.

Control, Inyo, June Lake, White Mountain, and Zack. On the other hand, SCE did not adequately justify the need for the Bridgeport project where the equipment is relatively young compared to the other substations at issue, and no history was provided of outages, repairs, or reliability or safety problems. The substation projects at Magmagen, Mt. Tom, and Skiland will not be in service during this rate cycle and no costs were forecast between 2010 and 2012 for these projects.

Therefore, the Commission finds it reasonable to reduce SCE's 2012 capital forecast by $0.050 million to reflect elimination of the Bridgeport substation project.[69]

4.3.4.2.1. Lee Vining Substation

The $7.35 million "infrastructure replacement" project at the Lee Vining substation is actually a relocation plan that involves construction of a completely new facility West of Highway 395. SCE says the relocation is necessary (1) to replace equipment, (2) to move away from Lee Vining Creek, and (3) because the current location is unsuitable for expansion or modification. The Lee Vining project has been recently re-assessed by SCE but is still forecast to be completed by 2013. In July 2011, SCE agreed that it would have to seek a PTC for the project.[70]

ESRA recommends the Commission exclude funding because the project needs to be redesigned and will not be in service by 2014. ESRA contends the project is still in the early planning stages, the location is unresolved due to

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[69] SCE-02, Vol. 07, Pt. 2 at 8, Table VI-3; Appendix B; JCE at 958.

[70] SCE-17, Vol. 07, Pt. 2 at 17:11-13.

avalanche risk, aesthetic concerns, and other factors, and SCE has not yet initiated the PTC process. Although an avalanche assessment was done in December 2010, the results were not complete.[71] ESRA recommends further study and that any final plan incorporate avalanche protection engineering. This would require additional costs not included in the forecast.

Another problem identified by ESRA is that the new substation would not be compatible with the town of Lee Vining until the town is upgraded from a 2.4 kilovolts (kV) system to a 16 kV system, scheduled after 2014. If the substation is improved prior to the upgrade to the town's system, SCE would have to temporarily acquire a 2.4 kV transformer to provide distribution until the town upgrade occurs. SCE states that this is not an obstacle.

We agree with ESRA that this project is not sufficiently developed for this rate cycle. SCE has not made its final decision on the new location, there is community opposition to the relocation, the local planning and PTC process have not yet begun, it is premature ahead of the upgrade to the town's system, and the avalanche risk may lead to additional construction costs, reliability issues, and rethinking of the project. Therefore, the Commission finds it reasonable to reduce the capital forecast to eliminate funding at this time. The result for 2011-2012 is a reduction of $0.050 million in 2011 and $6.0 million in 2012.[72] We do not address 2013-2014 costs.

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[71] TR at 2779-2780.

[72] SCE-02, Vol. 07, Pt. 2 at Appendix B (B-2); JCE at 958.

4.3.4.3. Lundy Reline Conveyance System (Lundy) – FERC 537

Lundy has been under discussion for about 15 years, and was included in SCE's hydro capital request in its 2006 GRC, its 2009 GRC, and again in the 2012 GRC. In 2012, the estimated cost had increased to $5 million to replace an existing earthen-lined ditch that has a capacity of moving water at approximately 12 cubic feet per second (cfs). The replacement is described as cement-lined conduit and plastic pipeline with a capacity for 40 cfs or 52 cfs.[73] SCE states it is a FERC-approved conveyance system that SCE is required to construct pursuant to a settlement agreement reached with various parties in connection with SCE's FERC relicensing for Lundy.[74] This assertion is somewhat misleading.

The new pipeline would replace an earthen ditch that historically could provide a limited amount of irrigation water from the "tailrace"[75] of the Lundy Powerhouse to Mill Creek to satisfy senior water rights.[76] Because this ditch has been the same size for 100 years, no water in excess of the 12 cfs capacity has been transported to Mill Creek since the Powerhouse was built in approximately 1911. Most of the water has gone through Wilson Creek to Mono Lake. No water has been sent to Mill Creek since 2007.[77] SCE makes an unsupported claim

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73 *Id*. at 89.

74 E.g., U.S. Department of Agriculture, U.S. Department of the Interior, California Department of Fish & Game, et al.

75 Tailrace water refers to the water that exits the Powerhouse.

76 SCE-17, Vol. 07, Pt. 2 at 9.

77 ESRA-01 at 13.

that the ditch needs to be replaced because "the existing ditch is very unreliable."[78] SCE has no rights to any of the tailrace water.

When SCE renewed its FERC license for the Lundy Powerhouse in 1999, it reached a settlement agreement with numerous objecting parties whereby SCE committed to putting in a pipeline to replace the ditch. None of the parties are water rights holders. The settlement included a provision that SCE would pay the cost of a 40 cfs capacity conveyance system and that signatory parties would pay the incremental cost to increase the capacity to 52 cfs. It also provided that if the Commission approves rate recovery for the incremental costs, SCE would place the approved funds into an escrow account established by the funding parties and subject to their control.[79] However, FERC expressly declined to require the conveyance be constructed and has admitted a lack of jurisdiction over water flows. SCE admitted it did no work on the project between August 2009 and March 2011, despite this Commission's authorized funding.

SCE's total capital request for the pipeline has grown from $1.1 million in 2006 to $5.05 million in this GRC. ESRA recommends elimination of this project because it has nothing to do with electrical generation, is not required by the FERC license, is unnecessary, would transport water pursuant to rights held by LADWP, and is of no benefit to ratepayers. There is no evidence LADWP wants to move the water, and the State Water Resources Control Board (SWRCB) has both denied a similar project (proposed by LADWP) and said any such project would require an Environmental Impact Report (EIR).

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[78] SCE-02, Vol. 07, Pt. 2 at 90.

[79] SCE-17, Vol. 7, Pt. 3, Appendix B (Settlement Agreement) at ¶ 3.6.8.

Although SCE has maintained in prior GRCs that FERC required the project be built, ESRA demonstrated that FERC specifically did not order it to be built. SCE did not disclose in its application that the settlement agreement also provided for the ratepayer funds to be deposited in an escrow account, along with funds from other signatories. It appears that neither the Commission nor SCE would have control over the escrowed ratepayer funds which would be managed by the "funding parties."

SCE was not fully forthright with the Commission, and its actions indicate a lack of concern and priority about undertaking the groundwater monitoring or environmental permitting necessary to commence the project. This project does not appear to be necessary for the safe and reliable delivery of electrical service to SCE's ratepayers. Instead, the proposal is locally controversial and apparently will require an EIR and other local permits, such that it is unlikely the conveyance would be in service by 2014. SCE presented the Commission with no information about the potential scope and estimated cost of future environmental and legal work. Moreover, the hazy funding controls are troubling, even if it were a suitable project.

Therefore, based on the evidence, and a number of unanswered questions about the project, the Commission eliminates funding for this project from SCE's forecast as follows: $0.025 million in 2011, and $4.5 million in 2012.[80]

4.3.5. FERC Relicensing

Thirty of SCE's 35 Hydro powerhouses require FERC licenses to operate and account for 1,171 MW. SCE is pursuing relicensing of six of its FERC

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[80] *Id*. at Appendix B (B-5); JCE at 962.

licenses which are likely to result in costly mitigation or other requirements. Five other recently awarded licenses require SCE to make continued capital expenditures for studies or mitigation costs as a license condition. For these combined activities, SCE requests $56.446 million for 2010-2014 capital expenditures related to FERC relicensing projects: $15.626 million in 2011; and $12.3 million in 2012.[81]

ESRA recommends a reduction of $42.8 million 2010-2014 because it is concerned about the accuracy of SCE's forecast and disputes whether most of the projects will be completed by 2014. ESRA argues that SCE has repeatedly overestimated FERC relicensing costs in prior GRCs, e.g., in its 2009 GRC, SCE forecast $58.5 million for such relicensing activities in 2007-2011, but only spent a total of $13.5 million through 2010.[82] The reduction proposed by ESRA is an approximate of the amount SCE was authorized to spend in the 2009 GRC, but did not spend on relicensing projects as of 2011.

SCE explained that the underspending resulted from permitting delays beyond its control and claimed that the work would be performed during 2012-2014. The primary delay is that the SWRCB cannot issue a Water Quality Certification for each project until it evaluates how to apply new GHG rules to hydroelectric projects. FERC has completed its evaluation process for the re-licensing and SCE described the various resource plans and mitigation projects to be required by the new licenses.

Furthermore, SCE asserts that its capital underspending for relicensing work was largely offset by larger-than-forecast spending for other Hydro capital

[81] SCE-02, Vol. 07, Pt. 2 at 15, Table VI-4.

[82] ESRA OB at 25.

work. If ESRA's reduction is adopted, SCE states it will not have enough funds available after the license is issued to undertake required work.

We acknowledge ESRA's concern that it is unknown when the SWRCB will issue its new GHG rules, but we agree with SCE that it is more likely than not that the rules will issue within the rate case cycle. Since the license applications have been pending many years, FERC has completed its review and license conditions are generally known, we are persuaded that the relicensing projects are likely to be completed by 2014.

However, we are also concerned that the funds approved in prior GRCs for FERC relicensing were redirected to over-budget non-relicensing projects at SCE's discretion. While some diversion is expected due to unforeseen circumstances, SCE is on track to spend less than 30% of the funds authorized for relicensing activities 2009-2011. Accordingly, since this Commission already approved funding for most of the proposed relicensing projects, we expect SCE to advance the FERC relicensing projects in this rate cycle.

Therefore, based on the record, the Commission declines to adopt SCE's request in full, and instead finds it reasonable to reduce both the 2011 and 2012 capital forecasts by $4.2 million, approximately 10% of the underspend, to reflect gross overestimating by SCE in its prior forecasts. Accordingly, the Commission adopts $11.426 million for 2011 and $8.1 million for 2012.[83]

4.3.6. Additional Capital Information

ESRA expressed substantial concerns about SCE's failure to spend previously authorized funds on identified projects and the difficulty in tracking

[83] SCE-02, Vol. 07, Pt. 2 at Appendix B (B-1); JCE at 960.

projects from GRC to GRC, sometimes due to merging or renaming of projects. ESRA demonstrated that some capital projects for which funding was authorized in prior GRCs were delayed, actual expenditures were significantly lower than authorized, or the projects may not even be re-scheduled during this rate case cycle.[84] SCE's witness also admitted that some projects receiving re-directed funds may open and close between GRCs and are not identified in the GRC application.[85]

ESRA recommended that SCE be required in future rate cases to include an exhibit that provides a status update for all capital projects for which funding was authorized in the prior GRC, and to specifically identify safety-related projects. To be effective, the format of SCE's tables and project descriptions should also remain the same in each GRC.

SCE opposes this recommendation as burdensome and unnecessary.

SCE believes that it has met its burden of proof as to capital projects by submission of detailed testimony and responses to numerous data requests. SCE also disputes that it has retained previously authorized funds for the proposed projects. Instead, SCE states that since 2009, previously authorized funds for these projects were re-directed to higher priority projects, as allowed by the Commission. For capital expenditures, SCE said it can track cost accounting data, even if the projects merge or are renamed. However, SCE said it cannot provide the "type of data" ESRA requested which is not computerized.[86]

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[84] E.g., TR at 2487, 2490-2503.

[85] TR at 2496-2497, 2504.

[86] The "type" is not specified but may include the project descriptions, reference numbers, and in-service dates for each project from the prior GRC.

We agree that the Commission and the public should be able to track the progress of previously authorized large capital projects. Therefore, we have directed in Section 2.5 that SCE include an exhibit in future rate cases that facilitates public tracking of large generation, transmission, and distribution projects authorized in a prior GRC.

4.4. Generation – Gas-Fired Generation

4.4.1. Mountainview

Mountainview Power Plant (Mountainview), located in Redlands California, has a nominal electrical output of 1,054 MW. Mountainview began full commercial service in January 2006. It consists of two retired units[87] and two modern combined-cycle operating units (Units 3 and 4) that contain both natural gas and steam turbines intended for load-following operation.

4.4.1.1. O&M Expenses: FERC 546, 548-554

SCE forecasts TY2012 O&M expenses of $49.042 million for Mountainview, slightly less than 2009 recorded expenses of $49.211 million. The forecast includes the annualized costs for NERC reliability standards compliance and prepayment of expenses for a major overhaul planned for 2015.

DRA recommends a reduction of $0.307 million in FERC account 546 for the 2012 increase in NERC-related Labor expenses which it concludes are unnecessary. Work activities recorded in this account include general supervision and operations of Mountainview, and some expenses related to environmental health and safety.

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[87] Units 1 and 2 were demolished in 2010.

For FERC 546, SCE asked for a total of $2.772 million ($1.863 million in Labor, $0.909 million Non-labor), a 27.4% increase over 2009 expenses, based on increased labor needs to support compliance with NERC reliability standards. SCE plans to hire two Program Managers and one Engineer just for Mountainview. SCE argues that recorded costs do not reflect the full cost of compliance in the future because NERC standards cover many different operations and tasks, some of which are performed on cycles greater than one year.[88] DRA contends the work should be absorbed by the remaining $2.4 million request.

We are not persuaded that SCE needs these three positions, at a cost of $307,000, in order to maintain NERC compliance. These are new plants and SCE should be able to enjoy some economies and utility from the significant increases allowed for NERC compliance throughout this decision. SCE also agreed with DRA to remove a confidential amount forecast for a Hot Gas Path Inspection prepayment and tax related to a 2015 overhaul.[89]

Accordingly, the Commission finds it reasonable to reduce the FERC 546 account by $0.307 million of Labor expense and the normalized portion of the Hot Path Gas Inspection Fee.

4.4.1.2. Capital Expenditures

Recorded expenditures in 2010 were $14.076 million, $2.7 million less than forecast. SCE requested capital spending for Mountainview of $4.6 million for

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[88] SCE-02, Vol. 08 at 30.

[89] SCE-17, Vol. 08 at 1.

2011 and $18.9 million for 2012.[90] The largest project is a $16.7 million preventive gas turbine compressor section upgrade in response to a significant failure rate with this model. DRA does not dispute SCE's capital budget forecast.

TURN recommends a total 2011-2012 reduction of $1.346 million in the sub-category Blanket Work Orders based on three-year average (2007-2009) of recorded costs.[91] SCE initially forecast $2.580 million for 2011-2012 based on SCE's own "known work forecast" and its prior experience. TURN argues that costs have historically varied and a three-year average of recorded expenditures (2007–2009) is more reliable.

Blanket Work Orders expenditures include: 1) Furniture and Equipment, 2) Tools, 3) Buildings and Grounds, and 4) Capital Spare Parts.

Mountainview Units 3 and 4 will undergo their first round of major inspection overhauls during the GRC rate cycle and SCE believes it must have an adequate supply of capital spare parts as it inspects major equipment. SCE argues that spare parts costs are increasing, some items have long procurement lead-times, and it is not always possible to predict failure sufficiently far in advance to secure the replacement in time.

In rebuttal, SCE offered to adjust three of the four categories to a TYA of historical costs but only if TURN would accept SCE's updated 2011-2012 Spare Parts forecast which accounts for the majority of expenses.[92] Based on additional purchasing information, SCE increased its 2011-2012 Spare Parts forecast by

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90 SCE-02, Vol. 08 at 49, Table VI-9.

91 SCE-17, Vol. 08 at 8, Table IV-1.

92 *Id*. at 10, Table IV-2.

$278,000 (18.5%), at the same time it offered to reduce the Blanket subcategories by $450,000, for a net reduction of $172,000 to SCE's initial forecast.

TURN does not agree. However, we are persuaded that SCE's capital parts forecast is reasonable. For example, during 2011 and 2012, SCE is adding first-time inventory of capital spare parts related to the Unit 3 and Unit 4 steam turbines which will be disassembled and inspected during the upcoming major overhauls in this rate cycle.

Therefore, the Commission finds reasonable and adopts TURN's proposed forecasts for Blanket Work orders using a three-year average of historical costs, escalated to $0.310 million ($nominal) in 2011 and $0.320 million in 2012. For Capital Spare Parts, the Commission finds reasonable and adopts SCE's revised forecast totals of $0.79 million ($nominal) in 2011 and $0.988 million total in 2012.[93] The result would be an overall decrease of $0.160 million in 2011 and $0.012 million in 2012 to SCE's original forecasts in this category.[94]

In summary, the Commission finds reasonable and adopts SCE's 2010 forecasts for capital expenditures, and reduces SCE's 2011 and 2012 forecasts to reflect the above-discussed modifications to Blanket Work Orders.

4.4.2. Peakers

SCE currently owns and operates four peaking power plants each providing 49 MW. The peaking units, which came online in 2007, are simple-cycle, quick start units, and are intended for peak load operation to support system reliability. SCE is constructing a fifth peaker, McGrath, which

[93] *Ibid*.

[94] JCE at 849.

SCE expects to be operational in 2012. The delayed operation date led SCE to reduce its McGrath-related O&M and capital expenditures forecasts.

4.4.2.1. O&M: 546.700, 548.700, 549.700, 550.700, 551.700, 553.700, and 554.700

SCE's revised forecast for TY2012 O&M for all five peakers is $11.299 million, $2.376 million more than 2009 recorded costs based on three additions: increased dispatch, NERC compliance, and McGrath.[95] SCE estimates an additional $0.801 million[96] related to increased dispatch and $0.683 million for NERC reliability standards compliance, for a total of $1.484 million, which impacts all peakers. The forecast includes three new employees, although a larger portion of the increase is Non-labor.

DRA recommends the Commission adopt 2009 recorded costs without any increase. TURN opposes the $0.801 million for dispatch costs which it contends are not adequately supported. Peaker dispatch grew to 21,326 Megawatt hour (MWh) in 2010, but SCE estimates an increase to record highs of 51,131 MWh/year in 2012-2014. TURN observes that SCE's loads are not growing rapidly and SCE's own forecast shows 2012 demand below 2007 levels.[97]

We are persuaded by SCE that it is reasonable to expect increases in Peaker dispatch for several reasons, including recent SONGS outages and management of the additional 1,200 MW of renewable generation resources expected to be

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95 SCE-17, Vol. 09 at 15.

96 JCE at 760.

97 TURN-5 at 27.

added to the grid during 2011 which requires other generation sources to ramp up and down.

Therefore, the Commission adopts SCE's revised forecasts for peaker dispatch costs and NERC reliability standards compliance.[98] Combined with the McGrath O&M adopted below, the Commission finds reasonable and adopts total Peaker O&M of $11.299 million for TY2012.

4.4.2.2. Capital Expenditures

Excluding construction of the McGrath peaker, SCE's revised 2010-2012 forecast for peaker-related capital expenses is $14.8 million: $11.8 million in 2010, $1.7 million in 2011, and $1.3 million in 2012.[99] The revisions were made by SCE to remove forecast costs for a spare compressor and a new building at McGrath which will not be completed until 2015. DRA recommended removal of all McGrath-related expenditures because the plant would not likely be built in this rate cycle.

SCE's forecast capital projects are in six categories, including $11.2 million to install spare gas compressors at each peaker, and $2.84 million to complete construction of a maintenance building at the four existing peaker sites, before revising the forecast. These projects were previously approved in the 2009 GRC, and some expenditures have been made, but the gas compressor purchases were delayed in contract negotiations.

TURN sought removal of the McGrath expenditures now excluded by SCE, and also recommended removal of the cost of a potential overhaul of one

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[98] SCE-02, Vol. 09 at 32-44.

[99] SCE-17, Vol. 09 at 1, 4.

combustion engine, which SCE estimates could occur in 2014 at one of the existing four peakers. TURN rejects the forecast expenditure as discretionary and unsupported, but SCE contends there is deferred capital work and improvements would benefit ratepayers. In any event, the estimated $2.6 million cost is forecast for 2014, and we have not addressed the reasonableness of 2014 capital spending in this GRC.[100]

The Commission finds reasonable and adopts SCE's forecast of $14.8 million for peaker capital expenditures

4.4.2.3. McGrath Peaker Construction

SCE's 2012 capital and O&M forecasts include $20 million in capital expenditures to complete construction and $0.841 million in O&M for the McGrath peaker. The capital project also includes associated facilities (e.g., additional electrical transmission lines and poles, a natural gas pipeline, transformers, an electrical substation, etc.). A total of $42.5 million, previously forecast and spent towards construction of McGrath, has been recorded by SCE.

Since 2007, local opposition and litigation with the City of Oxnard have delayed the approval and construction of McGrath. DRA and TURN initially opposed all of the forecast expenses in the 2012 forecasts because the plant was neither permitted by the City of Oxnard nor had construction begun. DRA and TURN argued that McGrath was not likely to be in operation in the 2012 GRC test year, and therefore associated costs should be removed. TURN and DRA also question the need for a fifth peaker, its location, local reliability needs, and alternative options, which they contend should all be addressed prior to the start

[100] JCE at 848.

of any construction. Two recent events inform the Commission's review of the McGrath forecast expenses. On August 17, 2011, the California Court of Appeal issued a decision (Appellate Decision) that affirmed the McGrath Peaker's Coastal Development Permit, the key approval SCE needs to build the project.[101] In addition, on October 24, 2011, the City of Oxnard entered into a settlement agreement with SCE to resolve all remaining permit issues, and granted SCE approval for the permits needed to begin construction of McGrath.[102]

According to SCE's Update Testimony, it promptly began construction and estimates that McGrath will be on-line in the Summer of 2012.[103] Based on the foregoing, construction of McGrath can now move forward according to SCE's forecast schedule. Consideration of the $20 million in capital expenditures and $1.108 million in O&M for McGrath is now justified in TY2012.

After the construction obstacles were removed, TURN supported by DRA, filed a motion on October 27, 2011 for an Assigned Commissioner's Ruling Regarding SCE's Construction Plans for McGrath. TURN asked the Commission to halt construction of McGrath until the Commission can review the need for the plant. The motion is denied in this decision.

We do not revisit the need to construct the McGrath peaker here because it is outside the scope of the GRC. However, SCE has purchased most of the major equipment and now begun construction. The primary purpose of the peakers is to provide reliable rapid start capability which will become more important as

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[101] City of Oxnard, et al. v. California Coastal Commission, et al. (CA2/4)(B227835).

[102] SCE-84 at Appendix A to Chapter III (Settlement Agreement).

[103] *Id*. at 7.

renewable energy sources are added to the grid. The record supports that the peaker will become operational in 2012.

Therefore, we find reasonable and adopt SCE's O&M request related to McGrath, and the forecast of $20 million in 2012 capital spending to complete the construction of McGrath.[104] All funds that SCE spends on the McGrath construction shall be recorded in the referenced memorandum account and shall be reviewed for reasonableness in a subsequent proceeding and subject to refund if not found to be reasonable. SCE shall file an application for the review of all recorded construction-related expenditures no later than December 31, 2012, approximately 60 days after SCE anticipates completing the peaker plant.

4.5. Generation – Project Development Division: FERC 549

In the 2006 GRC, the Commission authorized SCE's PDD to conduct certain generation support activities to analyze generation technologies and costs, locate sites for generation development, monitor generation-related regulatory and legislative activity, and to develop Best Option Outside Negotiation (BOON) for future generation needs.

SCE's PDD forecast for TY2012 O&M is $5.80 million ($1.577 million Labor, $4.223 million Non-labor) to fund authorized generation-related PDD activities.[105] The labor portion funds salaries for ten existing approved PDD employees. The non-labor request covers the cost of performing studies, analysis, and preliminary development work and necessary training, travel, and

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[104] JCE at 588.

[105] SCE corrected its forecast due to a calculation error and states it is only asking for the escalated amount of its original authorized funding, SCE-17, Vol. 10 at 1.

industry participation expenses. SCE also wants to discontinue use of the PDD Memorandum Account (PDDMA) and allow these costs to be recovered through traditional ratemaking.

The Western Power Trading Forum (WPTF) is concerned about a possible expansion of PDD activities and opposes elimination of the PDDMA. WPTF reminds the Commission of prior concerns about the scope of PDD activities within the competitive market. In 2006, the Commission agreed and limited PDD activities and established the PDDMA to ensure review of PDD expenses and limited rate recovery to costs that support new generation, are justified, and do not exceed forecasts.[106]

SCE argues that WPTF's concerns are unwarranted because SCE does not intend to exceed the scope of the program. SCE states that PDD is the tool it uses for consideration of new utility-owned generation projects, such as studying the feasibility of Clean Hydrogen Power Generation and the feasibility of various solar photovoltaic installations.[107] "Whenever SCE has sought to develop a utility-owned generation project, SCE filed an application at the Commission for recovery of the project costs ensuring that the Commission has full oversight over SCE's new generation proposal."[108]

The Commission finds that SCE's PDD continues to operate within the scope of its primary support functions and has not presented costs associated with research, development, and demonstration (RD&D) functions. Therefore, the Commission finds reasonable and adopts SCE's forecast of $5.80 million for

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[106] WPTF OB at 3.

[107] SCE-02, Vol. 10 at 2.

[108] SCE-17, Vol. 10 at 3.

TY2012 O&M. We also decline to eliminate the PDDMA at this time. SCE should continue to demonstrate that tracked expenses are associated only with authorized support functions.

4.6. Generation - Other

4.6.1. Solar PV – FERC 549, 550

4.6.1.1. Background of the Solar Photovoltaic Program

In 2009, the Commission authorized a five-year SPVP for SCE to develop 500 MW of solar photovoltaic (PV) on existing commercial rooftops within SCE's service territory. SCE was authorized to own, install, operate and maintain 250 MW of distributed solar PV projects primarily in the one to two MW range, and to seek competitive bids for power purchase agreement for electricity from independently produced (IPP) 250 MW of rooftop solar PV.[109]

The Commission found that SCE's estimated costs over the 2008 through 2014 program period of approximately $41.31 million ($2008) in O&M and $875.0 million ($2008) in direct capital expenditures, adjusted to $962.5 million for a 10% contingency, were reasonable.[110]

To protect ratepayer interests, the Commission required review of SPVP performance and SCE's operation of the facilities in SCE's annual Energy Resource Recovery Account (ERRA) proceeding. The Commission also determined that in addition to the ERRA review, all SPVP program costs, and capital costs in excess of $3.85/W, should be subject to a reasonableness review

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[109] D.09-06-049 at 39-40.

[110] *Id.* at 44-45.

conducted in SCE's GRC proceeding.[111] SCE was authorized to establish a balancing account (SPVPBA) to record the difference between the SPVP's actual revenue requirement and SPVP program-related revenue.[112]

SCE filed a Petition for Modification (PFM) of D.09-06-049 in which it requested, inter alia, that its 250 MW portion of the program be reduced to 125 MW, purportedly resulting in potential $300 million in savings to the revenue requirement.[113] On February 23, 2012, the Commission partially approved SCE's petition, primarily to reduce both the 250 MW Utility-owned Generation (UOG) portion and the 250 MW IPP portion to no more than 125 MW each.[114] Due to changed circumstances in the solar PV market, the Commission reassigned the remaining 250 MW to a separate competitive solicitation.

For SCE's 125 MW SPVP, we reduced the reasonable cost estimates over the 2008 through 2014 program period by half, to approximately $20.655 million ($2008) in O&M expenses, and $481.25 million ($2008) in direct capital expenditures ($427.5 million plus a 10% contingency). These total costs remain based on $3.50/W ($3.85 per Watt including contingency), with costs in excess of $3.85/W subject to a reasonableness review. The decision informs our review here.

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111 *Id.* at 57 (Finding of Fact 10).

112 *Id.* at 57 (Conclusion of Law 7).

113 TURN OB at 36, citing to SCE'S Petition for Modification of D.09-06-049, (A.08-03-015) at 3.

114 D.12-02-035.

4.6.1.2. SCE's Request in the GRC

SCE did not ask for any additional funds beyond the forecasts approved when the program was created. The 2012 O&M forecast of $4.239 million, plus confidential lease costs, is based on a per MW installed basis using a three-year average of MWs to be constructed between years 2012-2014.[115] SCE also claims that its recorded 2009 SPVP capital costs of $18.108 million ($2009) should be deemed reasonable because they are lower than the reasonableness threshold of $5.50/W approved in D.09-06-049 for the first year.

SCE's estimated capital expenditures of $191.0 million, $197.0 million, and $203.0 million for 2010, 2011, and 2012, respectively, are based on its original forecast 50 MW/year build out schedule.[116] This spending is subject to review in future ERRA proceedings and in the next GRC if the costs exceed the $3.85/W threshold.

In addition, SCE argues that the Commission meant to consider in this GRC the elimination of the balancing account for SPVP expenses.[117] As a result of keeping its overall costs below the 2009 forecast, SCE contends there is sufficient basis to eliminate the balancing account in line with Commission treatment of other UOG.

4.6.1.3. Other Parties' Positions

TURN asserts that SCE's capital forecasts are unrealistic given the current status of the SPVP projects. Actual capital spending in 2010 was $68.009 million less than forecast, and SCE had only 38.7 MW online at the end of June 2011. In

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115 SCE-02, Vol. 10 at 10.

116 *Id*. at 11.

117 *Id*. at 48.

its most recent estimate, SCE has reduced its forecast capital spending for 2010-2011 by $127 million.[118]

TURN recommends that the 2010 capital forecast be reduced to reflect actual 2010 expenditures of $121.525 million.[119] TURN also seeks reduction of 2012 O&M expenses in Account 549 by $229,000 and solar lease expenses in Account 550 by a confidential amount on the grounds that SCE will operate 16 MW fewer solar projects due to previous delays and the substantial underspending in 2010.[120] TURN rejects SCE's view that D.09-06-049 requires elimination of the SPVPBA, which could result in unwarranted profits even if spending and build out are slower than forecast.

DRA does not oppose the O&M or capital forecasts for 2010-2012 but strongly opposes replacing the one-way balancing account authorized in D.09-06-049 with traditional test-year GRC base rate revenue requirement treatment. The Commission authorized the balancing account, argues DRA, to ensure that SCE would recover only the actual program expenditures. SCE's recorded costs are well below the pace of spending forecast in D.09-06-049. If low spending continues, and the balancing account is eliminated, SCE could receive a revenue requirement well above program needs.

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118 TURN OB at 30.

119 TURN-92.

120 JCE at 765-766.

4.6.1.4. Discussion

Recently, the Commission approved modifications to the SPVP and permitted SCE to cut its commitment to UOG and IPP rooftop projects by 50%. We also adopted 50% reductions to forecast costs previously found reasonable.[121]

Based on the Commission's decision on the SPVP, SCE's forecast O&M costs should be reduced by 50% because SCE has not, and will not, install 50 MW per year which served as the basis for the 2012 estimate. Instead, the Commission finds reasonable and adopts $2.120 million, plus half of forecast confidential lease expenses, for TY2012 O&M. This result obviates the need for TURN's requested O&M reduction.

We disagree with TURN's view that the Commission intended SPVP capital expenditures to be "trued up" to actual expenditures in the GRC. In 2009, the Commission clearly considered variables which could impact the pace of spending and capped the total for the period of 2009 to 2014. SCE is required to present the operational aspects of its SPVP program in the ERRA to be reviewed for reasonableness. In addition, if SCE can establish that its annual capital spending equates to below the $3.85/W threshold for 2010-2014 (and below $5.50/W in 2009), the capital expenses will be deemed reasonable in the GRC.

However, as a result of our recent modifications to the SPVP, total authorized capital spending from 2009-2014 is reduced to $481.25 million, including 10% contingency. Through 2010, SCE has cumulatively spent below the revised spending cap by spending $141.099 million ($2009): $18.108 million in 2009 and $122.991 million in 2010. However, if SCE were to fully spend its forecasts for 2011 and 2012, it would exceed the modified cap on expenditures

[121] D.12-02-035.

through 2014. SCE's forecasts for these years must be reduced to reflect the Commission's recent decision to lower the limit on SPVP capital expenditures. The remaining authorized expenditures are $340.151 million, or $85.037 million annually through 2014.

Accordingly, based on the Commission's recent decision modifying the SPVP, we find reasonable SCE's recorded 2009 and 2010 capital expenditures of $18.108 million and $122.991 million, respectively, and $85.037 million annually for 2011 and 2012.

The Commission declines to adopt SCE's request to eliminate the SPVP balancing account because it serves as an appropriate protection for ratepayers, particularly in light of uncertainties arising from a revised and reduced program. The SPVPBA was designed to protect ratepayers from overruns and underspending due to the reasonableness review of operations in the ERRA proceeding and the reasonableness review of costs in the GRC.

We expect SCE to perform its commitments to the SPVP program, including completion of development and operation of its 125 MW of solar PV projects by 2014 within the revised O&M and capital spending limits adopted by the Commission, unless later modified by Commission action.

4.6.2. Catalina Diesel

SCE provides electric service to about 5,000 permanent residents and 750,000 annual visitors at Santa Catalina Island (Catalina), located about 27 miles off the California coast. Currently, six diesel engine generators at Pebbly Beach Generating Station (PBGS) provide 9.4 MW of power generation, in addition to a 50 kW propane gas turbine. Exhaust emissions are regulated by the South Coast Air Quality Management District (SCAQMD).

Between 2004 and 2006 the diesel electricity generators on Catalina Island violated SCAQMD regulations on several occasions, resulting in a large fine imposed by SCAQMD on SCE. In July 2008, SCE entered into a settlement agreement with the SCAQMD, and avoided the fine by agreeing to install 23 micro turbines provided by SCAQMD, and a 1 MW storage battery. SCE and SCAQMD finalized the agreement in March 2009.

4.6.2.1. O&M: 548.140, 549.140, and 553.140

The O&M subaccounts for Catalina's PBGS are: 1) Account 548.140—Operation of Prime Mover (Internal Combustion Engine); 2) Account 549.140—Miscellaneous Expenses; and 3) Account 553.140—Maintenance of Generation Prime Movers.

SCE's TY2012 original forecast for Catalina is $4.729 million ($1.594 Labor and $3.135 million Non-labor), a 9% increase over 2009 recorded costs. SCE applied different forecasting methods for Labor and Non-labor within each subaccount. SCE reduced its TY2012 O&M forecast by $198,000 in response to a savings issue identified by TURN.[122]

After review of SCE's explanation, DRA dropped its request to disallow $87,000 for power packs in subaccount 553.140.[123] For subaccounts 548.140 and 549.140, DRA recommends a $54,000 reduction, and a $1,000 increase, respectively, based on a five-year averaging method instead of SCE's method of LRY plus incremental costs.[124]

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122 SCE-17, Vol. 05 at 4 (The change to 553.140 will be reflected in the updated RO Model, all Non-labor).

123 JCE at 192.

124 *Id.* at 193.

We are not persuaded by DRA's forecasting changes to the other subaccounts. For example, SCE forecast an increase of $0.164 million for two additional staff to support a recently implemented safety-related policy which limits an employee's maximum work shift to 24 hours. The cost related to the two workers is defined by the union contract.[125]

Accordingly, the Commission finds reasonable and adopts a TY2012 forecast for Catalina's O&M expense of $4.532 million to reflect the savings adjustment.

Catalina Diesel O&M Expense Forecast				
Account	**Description**	**Requested ($000)**	**Adopted**	**Disallowed**
548.130	Operation of Prime Mover (Internal Combustion Engine)	$914	$914	
549.130	Miscellaneous Expense	2,282	2,282	
553.140	Maintenance of Generation Prime Movers	1,534	1,336	198
	Catalina Diesel O&M Expense Total	**$4,730**	**$4,532**	**$198**

4.6.2.2. Capital Expenditures

SCE forecasts $26.529 million in capital expenditures for a variety of projects in the 2010-2014 rate case cycle, including $7.213 million in 2010, $12.110 million in 2011, and $6.146 million in 2012. SCE recorded expenditures of $7.980 million in 2010, $767,000 more than its forecast.[126]

In this GRC, SCE requests funds for a number of projects related to diesel engine and air-quality compliance infrastructure. The projects include: 1) a sodium sulphur battery installation; 2) a micro turbine project; 3) a 2.4 kV switchgear replacement; 4) a PBGS office "betterment"; 5) supervisory control

[125] SCE-17, Vol. 05 at 3.

[126] TURN-3 at 24.

and data acquisition (SCADA) generation automation; 6) main and garage building betterment; 7) control room betterment; and 8) other Projects totaling less than $1 million. This last category accounts for a number of small projects that total less than $1 million in forecasted capital expenditure for any one year.

SCE asserts that this investment is vital to providing continuous, safe, and reliable service to customers on Santa Catalina Island. In addition, the micro turbines provided by SCAQMD as part of the settlement require capital-related to land and installation cost. We find they are a useful addition to the island's generation infrastructure due to lower emissions, and by their ability to meet fluctuating system demand while contributing to improved system reliability.

DRA recommends a disallowance of $5.77 million for the years 2010 and 2011, by removing expenditures for two projects previously approved in the 2009 GRC. TURN recommends disallowance of $5.182 million for one project,[127] and would delay another. Specifically, TURN would disallow the estimated total cost of $11.875 million and delay the "switchrack" project, because it does not view this project as necessary for this rate case cycle. Since SCE only requested funding in 2014, we do not address the request in this GRC.

Control Room Betterment and Main & Garage Building Betterment

SCE requests approval of $1.147 million in 2010-2011 to complete the Control Room project which involves improvements to the Control Room to allow operators to monitor and control the system "more efficiently and safely." DRA contends SCE spent $1.406 million through June 2011, more than authorized in 2009, and needs no more ratepayer funds.[128]

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[127] TURN-5 at 39.

[128] DRA OB at 38.

Similarly, SCE requested $4.623 million in 2010 and 2011 to complete the Main & Garage Building project. The 2009 GRC decision approved $2.29 million for the Main & Garage Buildings project, and as of June 2011, SCE had spent $2.43 million.[129]

Although SCE received authorization for these projects in the 2009 GRC, it deferred most spending due to required expenditures arising from its settlement with SCAQMD. SCE also claims the deferrals were prudent until the design of other major capital projects were completed due to efficiencies of designing interconnections.[130]

We find it reasonable that the projects were deferred for efficiency reasons. DRA concedes that SCE has spent the requested funds for the Control Room project through 2011 and we decline to remove them from the forecast. SCE explained that the scope of the Main Building project expanded and increased the cost as a result of the Commission's rejection of the new Administration Building in the 2009 GRC and its replacement with the cheaper Station Office project.[131] SCE appears to be on track to complete this project.

Station Building Betterment Project

SCE estimates the project to be completed in 2012 at a total cost of $5.182 million, which SCE plans to spread across the ratepayers of the Electric (60%), Water (25%), and Gas (15%) utilities which SCE provides on Catalina. As of 2009, SCE had already spent $0.361 million.[132] SCE's 2011-2012 rate request for

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129 *Ibid.*

130 SCE-02, Vol. 11 at 24-26.

131 *Id*. at 27.

132 SCE-02, Vol. 11 at 21.

the Station Office Betterment Project is currently $2.893 million, the equivalent of 60% of the remaining costs.[133] However, should the sale of the water and gas utilities be completed and approved by the Commission, SCE seeks authority to allocate the entire cost (an additional $1.928 million) to electric rate base and obtain rate recovery.

SCE was authorized $3.9 million in its 2006 GRC to fund a new administration building, but said it diverted these funds to meet unforeseen load growth during that time period. In 2009, SCE's request for $4.92 million for the administration building project was denied because of the previously approved funding. SCE points out that, on the merits of the project, TURN admits that the current offices are not sufficient to house even what TURN deems electric-only employees.[134]

When the Commission rejected the predecessor project in 2009, it was because it viewed deferred funds for unexpected load growth and customer growth as routine, within SCE's discretion, and not subject to re-funding in the next GRC. The facts are essentially the same, despite SCE's repackaging of the project. Moreover, approximately $2.3 million was added to the Main Building project as a result of the rejection of the Administration building in the 2009 GRC. Thus, the overall request by SCE for its re-configured Administration construction is almost $7.8 million.

We agree with TURN that these costs appear to be excessive and growing as a result of SCE's management making discretionary choices to not use authorized funds for the identified projects and to keep coming back to

[133] JCE at 851.

[134] SCE-17, Vol. 11 at 9.

ratepayers for more. Accordingly, the Commission finds it reasonable to exclude the entire capital request.

To meet air quality standards and to continue maintaining infrastructure needed to support the Catalina generating plant, certain capital investments may be necessary or prudent.

The Commission finds reasonable and adopts SCE's recorded 2010 capital expenditures of $7.980 million. Other than the Station Betterment project discussed above, we find SCE's forecast capital expenditures for 2011-2012 to be reasonable and adopt the $23.344 million remainder of SCE's 2010-2012 forecast.[135]

4.6.2.3. Undersea Cable Write-off: 588.281

In the 2006 GRC, SCE requested funding for terminal substations and an undersea cable to deliver electricity to Catalina Island. At that time, SCE saw an undersea cable as the least cost solution and best technical alternative to address the need for additional capacity. In 2004, new air quality regulations from the SCAQMD imposed operational limitations which required SCE to install catalytic reduction systems. SCE undertook the study, but eventually abandoned this alternative, determining that the undersea cable was not cost effective when compared to retaining existing generation, notwithstanding the additional capital costs required to upgrade generation facilities to support new customer additions and load growth, and remain in compliance with air quality standards. After the project was cancelled, SCE wrote-off to expense in subaccount 588.281 the $1.276 in work orders related to the project.

135 JCE at 851.

DRA takes no position on this issue. TURN states that the $1.276 milion undersea cable write-off should be excluded because SCE canceled the project imprudently and recommends complete disallowance of SCE's write-off of this cost for subaccount 588.281. TURN also recommends a further reduction of $20 million in SCE's rate base for what TURN asserts is "imprudent" management of the undersea cable project.

For its part, SCE cites the substantial avoided capital investment required to place the cable—which would have added rate base and return on that rate base to SCE's revenue requirement—and which is substantially more than the capital funds requested at this time. SCE also cites the necessity of facing near-term emission compliance obligations from the SCAQMD, requiring immediate action to meet compliance, and the necessity of retaining existing generation capacity.

We find that SCE took a reasonable course in evaluating alternatives for delivering electricity to Catalina's customers, including undergoing the cost of evaluating the feasibility of an undersea cable. SCE's write-off to expense of the cost of the study is more appropriate than capitalizing it. It was also prudent because SCE found that the project could not be completed at a reasonable cost.

We do not adopt TURN's recommendation to disallow $20 million in capital costs. In its testimony, TURN admits the figure is "judgmental" and is based on their argument that the undersea cable could have been cost effective even at a capital cost of $100 million. This is speculative. SCE said that, in 2005, it determined that the cable was not cost effective at $64 million.[136] SCE also said

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136 SCE-17, Vol. 05 at 11.

that its study indicated a benefit-to-cost ration of 0.94 compared to different generation options and concluded that the proposed project was not cost effective.

SCE's and TURN's respective analyses disagree on almost every aspect of SCE's decision to discard the undersea cable option. TURN spends considerable time trying to aggregate consequential expenses related to SCE's settlement with SCAQMD which it claims could have been avoided if the undersea cable had been built. We reject TURN's argument which is speculative and the recommended penalty to shareholders which is unjustified.

4.6.3. Fuel Cells

In 2010, the Commission approved SCE's application for a Fuel Cell Project (FCP) to install, own, and operate three fuel cell units with a combined capacity of up to 3.0 MW on three separate California state university campuses.[137] The Commission also approved SCE's recovery of up to $19.1l million in capital costs and $8.9 million in non-fuel O&M for the 10-year life of its fuel cells. Construction was initially scheduled to be complete by December 31, 2011 and the units are expected to have 10-year lives.

SCE requests approval of its TY2012 O&M forecast of $0.89 million, however, it has reduced its 2010-2012 capital forecast to $10.608 million.[138] SCE reduced its original capital forecast by 44.4% because actual 2010 recorded costs are only $208,119 and one of three projects has been canceled. SCE made the appropriate rate base reduction during the Update hearing phase of the GRC.

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137 D.10-04-028.

138 SCE-84 at 10.

TURN recommended a $6.3 million reduction to the 2010 capital forecast because it understood no expenditures at all occurred. We find that SCE's updated capital forecast, including 2010 recorded expenditures, makes the appropriate adjustments for the reduced program scope.

SCE also wants to terminate the Fuel Cell Program Memorandum Account (FCPMA) where actual capital and O&M costs are recorded for rate recovery. DRA does not oppose the request, but would replace it with a one-way balancing account to assure that authorized ratepayer funds are not redirected to other activities or shareholder accounts. SCE objects to a one-way balancing account because it would not be able to recover any cost overruns. Given the choice of rate recovery in the GRC with a one-way balancing account, or the status quo, SCE would prefer to retain the FCPMA.

The Commission finds reasonable and adopts SCE's TY2012 O&M forecast of $0.89 million and the revised 2010-2012 capital forecast of $10.608 million: $0.208 million in 2010, $6.6 million in 2011, and $3.8 million in 2012. We decline to terminate the FCPMA at this time, just a year after it was authorized by the Commission. Although we agree that costs may be moved to the GRC at some point in the ten-year life of the projects, it is too soon. The FCP has been delayed and modified, including the loss of one of three projects. The FCPMA is an appropriate mechanism for the Commission to review the FCP costs prior to rate recovery.

In total, the Commission adopts $514.348 of SCE's $532.860 million O&M expense request (excluding SONGS refueling costs), disallowing 3.5%.

Generation Business Unit O&M Expense Request			
Expense Description	**Requested ($000)**	**Adopted**	**Disallowed**
SONGS (exclusive of refueling)	$270,466	$270,466	-
Palo Verde	83,100	83,100	-
Mohave	500	500	-
Four Corners	44,343	30,065	14,279
Hydro	57,610	56,000	1,610
Gas-Fired (Mountainview)	49,042	48,735	307
Peakers	11,299	11,299	-
McGrath Peaker Construction	841	841	-
Project Development Division	5,800	5,800	-
Solar PV	4,239	2,120	2,119
Catalina Diesel	4,730	4,532	198
Fuel Cells	890	890	-
Generation O&M Expense Total	**$532,860**	**$514,348**	**$18,512**

For capital expenditures, the Commission adopts $1.198 billion of SCE's $1.450 billion capital expense request for 2010-2012 (excluding the $36.6 million for a high-pressure turbine in the 2012 capital request for SONGS), disallowing 24.0% of SCE's 2011-2012 request.

Generation Business Unit Capital Expenditure Request						
	Capital Request by Year ($000)					
Project Description	**2010 Recorded**	**2011 Forecast**	**2012 Forecast**	**Total 2010-2012**	**Adopted**	**Disallowed**
SONGS (SCE Share)*	$115,983	$125,713	*$114,514	*$356,210	$355,350	$860
Palo Verde (SCE share)	40,605	40,290	36,340	117,235	117,235	-
Coal (Mohave)	10,283	10,150	0	20,433	20,433	-

Four Corners	30,061	9,619	1,888	41,568	41,568	-
Hydro	77,930	108,421	95,500	281,851	262,826	19,025
Gas-Fired (Mountainview)	14,076	4,600	18,900	37,576	37,404	172
Peakers	11,800	1,700	1,300	14,800	14,800	-
McGrath Peaker Construction	0	0	20,000	20,000	20,000	-
Solar PV	122,991	197,000	203,000	522,991	293,065	229,926
Catalina Diesel	7,980	12,110	6,146	26,236	23,343	2,893
Fuel Cells	208	6,600	3,800	10,608	10,608	-
Total Capital Expense	**$431,917**	**$516,203**	**$501,388**	**$1,449,508**	**$1,196,632**	**$252,876**

*2012 capital expense forecast referred to SONGSMA in Section 4.1.1.1.

5. TDBU

The TDBU is responsible for planning, engineering, constructing, operating and maintaining transmission and distribution facilities in SCE's electric system. According to SCE, TDBU assets total about $12 billion in distribution, $5 billion in substations, and $2 billion in transmission.[139] Most of the transmission-related costs are recovered through rates set by FERC. As of 2009, SCE reports it had 7,682 TDBU employees and expects to grow to 8,834 by 2012.[140]

5.1. SCE's TDBU Request

SCE initially forecast $607.916 million ($2009) for total TDBU O&M expenses for TY2012: $191.590 million for Transmission; and $416.326 million for

[139] SCE-03, Vol. 01 at 1.

[140] SCE-18, Vol. 01 at 6, Figure I-5.

Distribution.[141] This amount represents an increase of approximately $77 million over 2009 recorded expenses, an annualized increase of 4.83%. The change is to cover increases in inspection and maintenance, capital-related expenses, training, breakdown costs, storm-related costs, and new NERC Critical Infrastructure Protection (CIP) regulations.[142] In 2009, SCE spent $47 million less than authorized on TDBU O&M, the large majority in distribution.[143] During the proceeding, SCE revised its 2012 O&M forecast down to $598.045 million.

SCE's annual TDBU capital spending grew from $1.1 billion in 2005 to $1.3 billion in 2009, a 5.2% average annual growth rate. In 2009, the Commission authorized $1.433 billion in TDBU capital spending, but SCE recorded $1.334 billion, 6.9% less. In this GRC, SCE's revised forecast total TDBU 2012 capital expenditures are $1.831 billion, a 13.9% average annual increase over 2009 expenditures. After transmission interconnection projects (30%), the largest drivers for 2010-2014 capital spending are load growth (18%), infrastructure replacement (11%), and distribution construction and maintenance (11%). SCE expects to undertake significant capital work related to developing smart grid and other advanced technologies, and electric vehicle readiness.

As discussed below, the Commission has adopted $562.247 million in TY2012 O&M and $4.507 billion in 2010-2012 TDBU capital expenditures across all project categories, incorporating 2010 recorded expenditures.

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141 DRA-5 at 14.

142 SCE-03, Vol. 01 at 20.

143 The 2009 underspending is largely the result of SCE spending $8.0 million less on storm-related expenses, $8.7 million less on distribution inspection and maintenance, $8.2 million less on customer-related and streetlight maintenance, and $7.7 million less on a transmission line rating study.

5.1.1. Other Parties' Positions

DRA's combined estimate for TDBU O&M is $476.7 million, a 21.6% reduction to SCE's request.[144] This is comprised of a $40.6 million reduction for Transmission expenses and a $90.5 million reduction for Distribution expenses. For capital spending, DRA proposes reductions of $648 million ($628 million of which is CPUC jurisdictional) for 2011-2012, a 20% reduction on a CPUC jurisdictional basis.

DRA identified several concerns about SCE's forecasts, most of which were discussed in Section 2. However, specific to TDBU, DRA criticizes SCE for providing no clear employee headcount, including actual headcount and labor expenses in specific TDBU subaccounts. DRA considers this a matter of concern to the Commission and urges careful scrutiny of labor expense forecasts. In addition, DRA asks the Commission to direct SCE in its next GRC application to clearly show the historical employee headcounts included in the TDBU O&M expense forecast by subaccount. DRA also thinks SCE should provide more detail about its TY2009 underspending, and should discuss how that $47 million of "embedded funding" is incorporated into its request for additional TY2012 funding in the same areas.

TURN proposes reductions in several categories. TURN agrees with some of DRA's capital proposals, and recommends no additional expenditures for Plug-in Electric Vehicle (PEV) readiness related activities and significant reductions to Smart grid and other programs based on its own (lower) forecasts of new meter sets. TURN also proposes reductions in TDBU's requested O&M

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144 DRA-5 at 5-6. Tables 5-1 and 5-2.

expenses, primarily in breakdown maintenance, capital related expense, write-offs, vegetation management, and PEV readiness programs.

The CCUE urges the Commission to reject the spending levels proposed by DRA, TURN, and others on the grounds that the reductions are excessive. The proposed cuts would not only create system maintenance and operational challenges, states CCUE, they would also make it difficult to comply with ever-expanding federal and state policies, regulations and requirements. Furthermore, CCUE argues that DRA did not present evidence to rebut SCE's position that as infrastructure ages the failure rates increase. Instead, CCUE recommends we adopt SCE's forecasts for capital maintenance programs and fully fund the projects.

5.1.2. RIIM

SCE recommends that RIIM, which was authorized, with "concerns," in the 2006 GRC,[145] and modified in the 2009 GRC,[146] be reauthorized in this proceeding with minor modifications pursuant to a contested settlement. The RIIM is intended to require SCE to make certain long-term reliability capital additions, and includes specific employee hiring and total employee targets.

During 2009-2011, SCE exceeded total authorized RIIM capital expenditures by $355 million. In this GRC, SCE proposes setting the 2012-2014 RIIM capital reliability target at $3.127 billion, and $1.259 billion for other "High Priority" categories, a 21.9% increase over actual spending in the prior rate cycle.

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[145] D.06-05-016 at 385, OP 26.

[146] D.09-03-025 at 396, OP 25.

SCE and CCUE have proposed a settlement of the RIIM, contested by TURN, which we consider in Section 23.4.

5.1.3. Port of Long Beach: Added Facilities and Private Lines

The City of Long Beach, on behalf of the Port of Long Beach (POLB or Port), submitted direct testimony which described the Port's operations, competitive challenges, and plans to develop more shore power capabilities at new terminals and when retrofitting existing terminals. Although SCE and POLB notified the Administrative Law Judge (ALJ) that they anticipated settlement of their differences with the result that POLB would withdraw its testimony, no motion has been filed. Therefore, we proceed with our review.

The Port asserts that, with co-located enterprises, it is SCE's largest customer; it also has a load growth rate that exceeds the rest of SCE's system. The growth is driven largely by the Port's programs to improve air quality, including substituting electricity for diesel fuel for ships in port and cargo handling. According to POLB, meeting this growth will require significant new electricity infrastructure. The POLB asked the Commission "to adopt, maintain, and implement programs which encourage use of the Port."[147]

After more than six months of available discovery time, during the evidentiary hearings, the Port sought evidence regarding SCE's historic activities and policies regarding "Added Facilities" and "Private Lines." Over objections, the ALJ permitted some development of these inquiries in order to assess the relevance to the GRC's purpose of establishing SCE's revenue requirement for

[147] POLB-1 at 9.

TY2012. Some of the Port's inquiries and document requests were excluded by the ALJ, primarily on the grounds of relevance.

In its post-hearing brief, the POLB made two new recommendations:

- Revise Rules 15 and 16 to permit use of Private Lines subject to objective criteria; and
- Revise Rule 2.H to provide articulated and transparent criteria for characterizing facilities as Added Facilities, with a timely dispute mechanism.
- The lengthy SCE tariff rules at issue are briefly described below:
- Rule 2 - provides general descriptions of SCE's service and addresses SCE's discretion to install "added facilities" which are in addition to, or in substitution for standard facilities.[148] Specifically, SCE is not required to install, operate and maintain added facilities, but may do so, may determine costs to be charged to the customer, and may choose to either finance the facilities or require the customer to finance them.[149]
- Rule 15 - addresses extension of electric Distribution Lines of SCE's standard voltages (less than 50 kV) necessary to furnish permanent electric service, including design, construction, costs, and operation. The distribution facilities installed under the provisions of this rule, are owned, operated, and maintained by SCE (i.e, no privately-owned lines).[150]
- Rule 16 - addresses both (1) SCE Service Facilities that extend from SCE's Distribution Line facilities to the Service Delivery Point, and (2) service related equipment required

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148 SCE Tariff Rule 2.H.1.

149 *Id*. and SCE Tariff Rule 2.H.2.

150 SCE Tariff Rule 15.A.1.c.

> of Applicant on Applicant's Premises to receive electric service. As to Private Lines, SCE is not required to connect Service Facilities to or serve any Applicant from electric facilities that are not owned, operated, and maintained by SCE.[151]

The thrust of POLB's post-hearing position is that the identified tariffs (Rule 2H, 15, and 16) award SCE too much discretion in permitting Private Lines and characterizing "Added Facilities" subject to user fees. Additionally, the Port asserts that SCE's misapplication of the tariffs results in "unreasonable infrastructure costs" which inhibit POLB's ability to achieve environmental goals and to continue to serve as an economic engine in the area. As a result, POLB recommends the Commission reform SCE's tariff provisions governing Private Lines and Added Facilities.

SCE contends that these arguments are untimely and outside the scope of the GRC proceeding. In particular, the Port did not set forth its arguments and recommendations until the Opening Brief, thus denying SCE an opportunity to rebut the arguments in testimony. In addition, SCE contends that any revision of these tariffs should be undertaken in a rulemaking proceeding because changes would impact similarly worded tariffs applicable to other utilities. Lastly, SCE observes that if POLB believes that SCE has violated a tariff or arbitrarily applied a tariff, the proper remedy is to file a complaint with the Commission.

As background, the Port's tenants take electric service at 66 kV, a cheaper subtransmission voltage than electricity delivered at 12 kV. However, that choice results in a need for Added Facilities (e.g., transformers, conductors) the cost of which SCE recovers through Added Facilities tariffs rather than through

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151 SCE Tariff Rule 15.1.A.4.

rate base. The POLB wants the Added Facilities to be re-characterized as either Private Lines or Standard Facilities, each of which would be adverse to end customer/ratepayer interests according to SCE. The Port also seeks expansion of Private Lines to include 66 kV lines.

The POLB asserts that SCE has vested financial and strategic interests in preventing the use of Private Lines, which are excluded from rate base, to the detriment of customers and the public interest. SCE denies this is accurate, particularly when the Port retains ownership of the facilities. Rules 15 and 16 are not currently applicable to the Port's facilities because they do not apply to electricity delivered at greater than 50 kV, nor do the rules require SCE to provide Private Lines.

Without further analysis of the identified tariffs, the Commission finds that this matter is outside the scope of the GRC because it does not result in a change to SCE's proposed revenue requirement. We do not know whether SCE (or another utility) has abused its discretion in matters of Private Lines or Added Facilities. Such a question is better raised in a specific complaint proceeding, or a petition requesting a rulemaking to reconsider the current language of the tariffs.

5.2. Advanced Technology

SCE created the Advanced Technology Organization (ATO) in 2009 by combining employees' knowledge and experience from various business groups within SCE.[152] SCE claims the centralization of its smart grid efforts into one organization was necessary to efficiently meet near-term smart grid objectives and it has already yielded management benefits.

[152] SCE-03, Vol. 02 at 5.

For advanced technology activities, SCE submitted an O&M request of $23.790 million for 2012[153] and a capital request of approximately $170 million for 2010 through 2012. SCE's capital expense request for TY2012 is $71.8 million.[154]

As discussed below, the Commission adopts $18.673 million for TY2012 O&M and 2011-2012 total capital expenditures of $120.597 million.

5.2.1. O&M Request: 560.260, 580.260, 580.261, 588.260

SCE states that ATO's primary mission is to "identify, develop, demonstrate, and evaluate an evolving portfolio of new technologies to create a smarter, more robust, resilient and efficient power grid."[155]

SCE's 2012 O&M request of $23.790 million covers subaccounts 560.260—Operation Supervision and Engineering ($4.507 million); 580.260—Distribution Engineering and Planning ($11.955 million); 588.260—PEV Readiness ($4.514 million); and 580.261—RD&D ($2.814 million).[156]

DRA disagrees with SCE's methodology for developing their TY2012 O&M forecast, and provides a test-year forecast of $15.254 million, an $8.536 million reduction. TURN recommends a smaller $5.619 million reduction resulting in a test-year forecast of $18.171 million.[157]

SCE's respective O&M request amounts by FERC subaccount are addressed in these following sections:

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153 *Id.*, Vol. 01 at 24.

154 SCE-18, Vol. 02 at 36.

155 *Id*. at 5.

156 *Id*. at 16.

157 *Ibid*.

5.2.1.1. Transmission Operation Supervision and Engineering: 560.260

This subaccount records the costs for work performed relating to the integration of technology solutions for the transmission system. Recorded costs varied between 2005 and 2009, with 2009 costs ten times more than in 2005.

SCE requests $4.507 million ($2.539 million Labor, $1.968 Non-labor), anticipating that it will continue the level and types of activities associated with this subaccount during 2012. SCE relies on its highest level of expenditures, recorded in 2009, a $3.201 million increase over 2008. SCE justifies use of LRY on the grounds it commenced three important initiatives between 2008 and 2009 which will continue.

Based on different forecasting assumptions, DRA recommends the Commission adopt a $1.889 reduction to SCE's request. DRA utilizes a three-year historical cost average from 2007-2009 to arrive at its $2.618 million recommendation. However, nearly 80% of the total $2.485 million non-labor increase from 2008-2009 is attributable to a one-time study.[158] SCE supports its estimate by referring to deferred projects and forecasting the need for six new positions.

We agree with DRA's conclusion that the 2009 costs should be averaged over the historical period. The Commission is mindful of SCE's regulatory policy goals and that it may engage in follow-up activities related to the 2009

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158 These initiatives were: 1) SCE's Smart Grid Strategy and Road Map, 2) Large Scale Integration of Renewable Energy Resources and 3) Department of Energy Stimulus Proposals. SCE spent $1.948 million on the large Scale Integration study. (SCE-03, Vol. 02 at 25.)

initiatives.[159] However, the costs for follow-up activities, including refining and running the models, should be largely covered by existing funding from the completed projects, especially given the forecast decreased costs in 2010 and 2011.

Accordingly we approve an increase for 2012 O&M expenses in Subaccount 560.260 equal to $3.861 million, a three-year average of recorded costs, plus an increase of one-half of the study-related ($2.485 million, Non-labor) increase in Non-labor between 2008 and 2009 ($2.618 + 1.243 = $3.861), which likely reflects the actual on-going activities unsupported by prior funding.

5.2.1.2. Distribution Operation Supervision and Engineering: 580.260

This Subaccount records costs for work performed related to integration of technology solutions on SCE's distribution system. SCE requests $11.955 million in 2012 O&M expenses ($6.836 million Labor, $5.119 million Non-labor) which is equivalent to escalated 2009 recorded costs, plus $701,000 to evaluate Home Area Network (HAN) technologies.

Total recorded costs in this subaccount jumped 70.6% in 2009 from 2008, after a 9% drop from 2007. Based on fluctuating historical costs, DRA utilizes a three-year cost average from 2007-2009 to arrive at its $8.376 million forecast. DRA argues the reduction is reasonable because of the steady addition of new and transferred full time positions to this unit beginning in 2007 and studies financed in 2009 are one-time, non-recurring expenses.

TURN recommends a disallowance of $1.486 million for all HAN activities, and opposes any funding for HAN activities through general rates on the

[159] SCE-18, Vol. 02 at 19-20.

grounds that vetting HAN technology is the role of private industry—who will profit from implementing HAN technology. To the extent HAN costs are funded at all, TURN asserts they should be recovered from the SCE SmartConnect Balancing Account (ESCBA). SCE's Labor costs increased in 2009 mostly due to adding 18 full-time positions, and Non-labor costs increased by $3.713 million driven by projects and studies related to integration of smart grid technologies and renewable energy sources. In 2012, Labor expense is forecast to grow by $2.485 million due to adding 24 more full time positions, many of whom will take over contract positions resulting in offsetting reductions to Non-labor costs. Non-labor expenses are forecast to decrease by $1.784 million.

According to SCE, the ATO HAN team is working to prepare SCE for the influx of new devices and communication technologies (487,000 customer HAN devices are expected through 2014.)[160] During the 2012 GRC cycle, the ATO will test the compatibility of HAN appliances and devices with the Edison SmartConnect metering system to ensure that SCE customers will be able to choose from a wide spectrum of devices.[161] We agree with TURN that these activities are within the SmartConnect deployment plan scope (i.e., ability to pair HAN enabled devices with Edison SmartConnect meter) and within the deployment period (2012). Therefore, we agree with TURN that the 2012 HAN-related costs should be recorded in the ESCBA for review. For a more complete discussion of the ESCBA and HAN-related activities, see Section 6.2.1, Integration of SmartConnect Costs and Benefits and Section 6.2.5, Home Area Network Costs.

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[160] SCE-03, Vol. 02 at 14.

[161] *Ibid.*

The Commission also finds that DRA's use of a three-year average of costs to mitigate steeply increasing O&M costs is reasonable. Accordingly, we approve $8.376 million in O&M expenses for subaccount 580.260.

5.2.1.3. Research, Development and Demonstration (RD&D): 580.261

Subaccount 580.261 records the costs incurred for SCE's authorized RD&D expenses, which are tracked in a one-way balancing account.[162] SCE proposes test-year funding of $2.814 million (all Non-labor), the equivalent of the escalated 2009 authorized amount.[163] Recorded costs have varied over the previous five years, including a 45.5% drop in 2007 followed by a 57.5% increase in 2008 and a 22.3% decrease again in 2009 to $1.651 million.[164]

Based on fluctuating historical costs and other variables, DRA uses a five-year average (2005-2009) as a basis for forecasting $1.977 million for RD&D expenses. DRA also claims that SCE did not justify ratepayer funding for its various RD&D projects. TURN has dropped its recommendation for a three-year historic average to forecast costs, and SCE has agreed to make a correction in the JCE to avoid double escalation in the RO model.[165]

The Commission finds that the role RD&D plays in facilitating the ATO's mission justifies an expanded role, and adopts SCE's request for $2.814 million for RD&D expenses. SCE's funding under the balancing account is restricted to

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[162] In a one-way balancing account, any year-end balance in the subaccount will carry over to the following year and will be trued-up at the end of the current GRC cycle, with any remaining balance returned to customers.

[163] SCE-03, Vol. 02 at 111.

[164] DRA OB at 49.

[165] TURN-98.

endeavors that meet the criteria for permissible RD&D projects as set forth in § 740.1.

5.2.1.4. Plug-in Electric Vehicle (PEV) Readiness

In the 2009 GRC, the Commission acknowledged that an evolving PEV market will translate into operational impacts on utilities.[166] In accordance with legislative direction[167] the Commission is evaluating policies to develop infrastructure to overcome barriers for the widespread deployment and use of plug-in hybrid and electric vehicles in California, and directed PG&E, SCE, and SDG&E to implement a series of measures that would help effect that result.[168]

In this GRC, SCE makes several requests for O&M and capital spending related to PEV Readiness in other business units, primarily CSBU and IT&BI. TURN recommends that the Commission deny any funding related to PEV-Readiness for this GRC, while DRA proposes funding capped at the 2009 recorded level.

5.2.1.4.1. SCE's Forecast of PEV Additions

SCE concedes there is a significant amount of uncertainty about the pace of PEV adoption by its customers.[169] Edison forecasts that its service territory will be serving 146,000 new PEVs by 2014: cumulatively adding 10,000 PEVs by 2011, 21,000 by 2012, 42,000 by 2013, and 73,000 by 2014. These numbers are based on a "medium" scenario of a weighted average from external studies of production and expected sales scaled to SCE's service territory. SCE also provided "low"

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[166] D.09-03-025 at 118.

[167] E.g. § 740.2.

[168] D.11-07-029 (R.09-08-009) at 2.

[169] SCE-03, Vol. 02, Pts. 1 & 2 at 17.

and "high" scenario forecasts ranging from a 2011-2014 total of 83,000 to 221,000 vehicles in its service territory.[170]

DRA's evidence showed that there were about 100 PEV's in SCE's territory as of February 2011.[171] TURN and DRA contend SCE's forecast is inflated due to various uncertainties and instead urge adoption of the "low" case forecast. The "low" forecast for PEVs being served in SCE's territory is 16,000, 25,000, and 33,000 respectively for the years 2012-2014.

The Commission appreciates the length to which SCE gathered data to provide an analysis in developing a PEV forecast. Still, we find a more compelling argument in the numerous near-future market uncertainties affecting the likely momentum for increasing PEV sales. For the purpose of considering SCE's costs and capital expenditure levels in this GRC, the Commission finds reasonable and adopts SCE's "low" weighted average forecast of 83,000 PEVs being served in SCE's territory by the end of the rate case cycle. The four-year aggregate "low" forecast is approximately 40% less than the four-year "medium" forecast used by SCE.

5.2.1.5. PEV Readiness: 588.260

This subaccount records the costs for work performed by the ATO to conduct operational planning and strategic activities to achieve PEV readiness, primarily provisioning associated PEV battery charging infrastructure.[172] SCE requests $4.514 million in TY expenses ($2.789 million in Labor; $1.725 in

[170] *Id.* at 16-17, Figure III-2.

[171] DRA-10 at 12, fn. 32.

[172] PEV-related capital expenditures are discussed in Section 5.4 as part of Load Growth-related capital spending.

Non-labor).[173] SCE states that the increase in labor expense forecast in this subaccount is due to the hiring of 21 incremental full-time equivalent positions needed to staff the PEV-Readiness core team and to manage activities. A corresponding decrease in non-labor expense forecast is due to the 21 full-time employees replacing contract workers.[174]

DRA recommends SCE's recorded 2009 expenses of $2.284 million be adopted. SCE's request is excessive when compared to 2009 recorded expenses, DRA argues, and SCE has not adequately justified an increase of 97.64% in the test year.[175] SCE concedes that "significant uncertainty about the pace of vehicle adoption by SCE's customer exists, and the number of PEVs on the road will likely remain small in the early years."[176] Based on this "significant uncertainty," DRA concludes that increasing ratepayer funding for these projects would be inappropriate.[177]

TURN recommends that SCE's entire request be denied for numerous reasons: 1) The 2012 PEV sales forecast is based on unsupported assumptions; 2) projected costs per vehicle is unreasonable; the forecast contains too much overhead and expands the utility's role beyond its reasonable scope; 3) the Commission has already authorized sufficient funds for SCE's PEV activities in the 2009 GRC; 4) SCE has not coordinated any of its PEV study efforts with the two other electric utilities as it was directed by the Commission; 5) SCE is

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173 JCE at 775.

174 *Ibid*.

175 DRA OB at 52.

176 SCE-03, Vol. 02 at 17.

177 DRA OB at 53.

requesting PEV funding in another Commission application; 6) SCE capital request is duplicative, can be avoided, and should not be funded by ratepayers; and 7) SCE's request to charge ratepayers for additional meters for separate PEV charging contradicts the Commission's rationale for requiring PEV owners to pay for the cost of a second meter.[178]

On the other hand, SCE responds that the PEV-Readiness program is a new initiative, different from SCE's traditional Electric Transportation program, and 2009 recorded expenses are not useful. The PEV-Readiness program began in late 2009, so only four months of expense is recorded. "On an annualized basis, this rate of spend would have exceeded $6 million if SCE utilized DRA's test year methodology."[179]

The Commission finds some merit in DRA's and TURN's arguments. At the same time, we recognize the obligations undertaken by utilities in response to mandated initiatives. The Commission finds it reasonable to adopt a portion of the requested increase for subaccount 588.260, equal to an increase of 60% between the 2009 recorded expenses of $2,284 and the TY request of $4.514 million, and accordingly adopt an expense of $3.622 million. This should result in sufficient funding for the program based on the "low estimate" for PEV growth.

The Commission adopts $18.673 million of SCE's request, allocated to Labor/Non-Labor per SCE's ratio, and disallows $5.117, as illustrated in the table below:

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[178] TURN-05 at 12-17.

[179] SCE-18, Vol. 02 at 29.

Advanced Technology O&M Expense Request				
Account	**Description**	**Requested 2009 ($000)**	**Adopted**	**Disallowed**
560.260	Transmission Operation Supervision and Engineering	$4,507	$3,861	$646
580.260	Distribution Operation Supervision and Engineering	11,955	8,376	3,579
580.261	Research, Development and Demonstration	2,814	2,814	-
588.260	Plug-in Electric Vehicle Readiness	4,514	3,622	0,892
	Advanced Technology O&M Expense Total	**$23,790**	**$18,673**	**$5,117**

5.2.2. Summary of Advanced Technology's Capital Expenditures Request

From 2005 through 2009, SCE recorded $71.302 million for capital projects related to Advanced Technology. Capital expenditures fluctuated between 2005 and 2008, before more than doubling in 2009 to $25.3 million when the ATO was established, and to $37.5 million in 2010.[180]

SCE forecasts $64.4 million for 2011 and $71.8 million for 2012 for 14 programs.[181] Based on adoption of 2010 recorded spending, SCE's total capital expenditure request is $173.6 million for 2010-2012 for the continuation of previously authorized projects, as well as new projects to further implementation of a comprehensive smart grid. Contested programs are discussed below and use nominal dollars.

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[180] DRA-7 at 7, Table 7-2.

[181] SCE-18, Vol. 02 at 36, Table IV-6.

5.2.2.1. Parties' Positions

TURN recommends broad project disallowances, as described below, on the grounds that SCE failed to comply with the requirements of D.10-06-047 to perform cost-benefit or least-cost analyses. DRA recommends several reductions based on SCE's failure to spend much of what the Commission authorized for 2009 and 2010[182] and also rejects some projects altogether claiming that SCE did not adequately justify them as legally required or by cost-benefit analysis.

SCE admits that it did not do any cost-benefit analyses for ATO capital spending projects.[183] SCE also disputes that D.10-06-047 requires a cost-benefit analysis, or that a project is unnecessary simply because it is not required by statute or no cost-benefit analysis is provided.

As a general matter, we agree that a project might be necessary to achieve the Commission's policy goals, even if not specifically statutorily required. Nonetheless, the Commission did not dismiss the requirement for exploration of cost effectiveness of Smart Grid deployment projects in D.10-06-047:

> IOUs shall also explain how their cost-effectiveness projection was made. The analysis of costs should also indicate any specific legislated or Commission ordered goal that requires a particular investment. Further, the analysis should identify which cost and performance data offer the best approach, and the reliability of both cost and performance estimates. Additionally, to facilitate Commission review, the cost per customer (or participating customer) for each project should also be estimated in the plans. If an IOU cannot provide this information, it should explain why

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182 DRA OB at 55 (in 2009 SCE was authorized to recover $53.4 million but only capitalized $25.3 million, and in 2010 was authorized to recover $40.3 million but only spent about $22.9 million).

183 TR at 1261.

> this information cannot be provided.[184] In those cases, where the investment in a Smart Grid is necessary to achieve a policy requirement, then a least-cost analysis may be appropriate. However, in cases where the Smart Grid investment will produce benefits beyond simple compliance with a regulatory requirement, we believe a cost-benefit analysis is appropriate.[185]

5.2.3. Distribution System Projects and Expenditures

5.2.3.1. Circuit Automation

This five-year old program adds automatic switching equipment to circuits to facilitate quicker restoration of power and fault isolation after an outage. SCE initially forecast $14.3 million for the Circuit Automation program 2010 -2012: 2010 ($3.8 million), 2011 ($3.8 million), and 2012 ($6.7 million)[186] SCE later increased its 2010-2012 request to $22.6 million to reflect higher recorded expenditures in 2010 of $11.680 million, and forecasts of $3.9 and $7.0 million for 2011 and 2012.

DRA recommends a total $14.2 million be adopted for Circuit Automation: $11.5 million in 2010, $1.350 in 2011, and $1.350 million for 2012.[187] According to DRA, SCE does not explain the large increase in 2010, nor offer evidence that ratepayers would receive added benefit for the added cost. Instead, SCE wants to automate 134 circuits per year 2010-2014 and rejects DRA's 2011 and 2012

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[184] D.10-06-047 at 69.

[185] *Id*. at 74.

[186] SCE-03, Vol. 02 at 35, Table IV-1.

[187] JCE at 590 footer: Note that for all the following capital expense related items, DRA states that it recommends a Consumer Price Index-related Post Test Year (2012) proposal; therefore, it does not recommend a forecast of capital expenditures for the years 2013 and 2014 for capital expense items, and uses 2010 recorded figures for the 2010 forecast in making recommendations for 2010-2012 capital expenditures.

estimates as permitting only 31 circuits per year. DRA's position is that if SCE seeks additional funding, it should provide the Commission with a cost-benefit analysis of the program including the basis in safety or reliability for deploying the program at a specific rate.

SCE has not adequately explained why the nearly 75% jump in expenditures in 2010 did not sufficiently advance the program so that it should be able to perform the same work planned for 2011 and 2012 with the original estimated amounts.[188] Therefore, the Commission allows recovery of SCE's $11.680 million recorded expenditures in 2010 and $3.922 million forecast for 2011, but agrees with DRA's $1.434 million recommendation for TY2012, thereby adopting $17.036 million of SCE's $22.620 million request, and disallowing $5.584 million.[189]

5.2.3.2. Smart Distribution Transformers

This is a pilot program whereby SCE will replace a limited number of failed standard transformers with Smart Distribution Transformers to determine whether and how to deploy them system wide.[190] SCE based its $0.3 million forecast for 2012 on the work currently underway.[191] SCE states that a Smart Transformer will provide information that would enable SCE to replace distribution transformers before they fail and provide current and voltage data

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[188] TR at 1252.

[189] JCE at 590-591.

[190] SCE-03, Vol. 02 at 40-41.

[191] JCE at 592.

that will allow SCE to better manage increased loads.[192] SCE did not spend $4.9 million authorized in 2009 for this project.

Both TURN and DRA recommend the program not be funded. TURN's recommendation is based on SCE's alleged failure to quantify claimed benefits, either as stand-alone items or as compared to the potential cost of the program.[193] DRA agrees that SCE should have provided a cost-benefit analysis and the program is not required by statute or regulation. SCE cites the impact of failed transformers on "reliability, safety, and operational efficiency, yet was unable to quantify the frequency or cost of transformer failures."[194]

The Commission sees a potential value in Smart Distribution Transformers contributing to future system reliability. Despite SCE's lack of the most elementary cost/benefit analysis, we have recognized that costs may be difficult to estimate with new and experimental technology.[195] Because this is a pilot program, the Commission authorizes the $0.3 million request for TY2012 capital expenditures for the Smart Distribution Transformers pilot program.[196] However, if SCE seeks additional funding, it should provide the Commission with a cost-benefit analysis of the program using the data it intends to acquire.

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192 SCE-18, Vol. 02 at 40.

193 TURN OB at 76.

194 SCE-18, Vol. 02 at 41-42.

195 D.10-06-047 at 69.

196 JCE at 592, 854.

5.2.3.3. Distribution System Efficiency Enhancement Project (DSEEP)

The DSEEP project consists of servicing and expanding the NETCOMM[197] wireless communication system, which provides the infrastructure necessary to remotely monitor and control SCE's distribution automation devices.[198] SCE wants to install 2900 radios annually from 2012 to 2014 in its automated devices.

SCE requests $14.871 million ($nominal) during the years 2010-2012 ($4.526 recorded in 2010; $5.096 and $5.249 forecasted for 2011 and 2012 respectively), arguing these amounts are generally consistent with historical DSEEP spending levels, and reflect the growth in the number of automated devices it is monitoring and controlling.[199]

DRA recommends limiting SCE's request in 2011 and 2012 to the 2005-2009 five-year escalated average of $4.475 and $4.582 million, respectively.[200] DRA asserts that SCE's actual DSEEP costs have been decreasing, noting that SCE's highest capital expenditure of $4.274 million ($nominal) occurred in 2006.

Historical expenditures for this program have varied between 2005 and 2010. SCE's proposal to spend approximately $5.096 million in 2011 and $5.249 million in 2012 is consistent with 2009 spending. We agree that capital expenditures have fluctuated historically, supporting DRA's use of a five-year average. Furthermore, SCE did not adequately explain how it arrived at its intended number of radio installations per year. Therefore, we find 2010

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[197] NETCOMM refers to SCE's analog-based mobile radio network.

[198] SCE-03, Vol. 02 at 47.

[199] JCE, Vol. 2 at 593.

[200] *Ibid.*

recorded expenditures reasonable and adopt DRA's recommendation to cap 2011 and 2012 expenditures at the five-year average, resulting in authorized expenditures in nominal dollars of $4.475 and $4.582 million, respectively.

5.2.3.4. Integrated Smart Distribution

The purpose of the new Integrated Smart Distribution project is to deploy an integrated group of Smart grid field devices to help SCE address operational challenges associated with increasing amounts of interconnected energy resources and improving its response to customer outages. The pilot project includes three sub-projects (self-healing circuit, advanced relays, and distribution support devices) which SCE claims are essential to evaluate the viability of the technology.

SCE forecasts $16.043 million in capital funding in 2012 when the project is scheduled to be deployed. The forecast is based on vendor quotes, SCE's experience, and estimates developed for its Irvine Smart Grid Demonstration project. SCE argues the projects are a necessary prerequisite to achieve Smart grid policy goals to integrate distributed energy resources.

DRA recommends disallowance of all funding because it is not required, and SCE has not demonstrated that its benefits will outweigh its costs. TURN would remove $10.721 million proposed for the Self-Healing Circuit pilot project pending the completion of the Irvine SmartGrid™ Demonstration and a preliminary cost-benefit analysis.

The Commission understands that the emergence of distributed generation puts increasing demands on distribution systems that were not designed for two-way flows of electricity. The industry needs to know more about the effect that this customer-generated load has on aging distribution systems. However, we agree with TURN that the Self-Healing Circuit portion of this project can wait for the completion of the Irvine SmartGrid™ Demonstration and a preliminary cost-benefit analysis. This would provide a basis for determining whether it is prudent to authorize future funding for a Self-Healing Circuit component for the Integrated Smart Distribution project.

Therefore, the Commission adopts $5.322 million for this project for TY2012, and disallows $10.721 million of this request.[201]

5.2.3.5. Substation Automation 3 (SA3)

In 2012, SCE intends to begin implementation of an advanced substation automation program, SA3,[202] to replace and upgrade substation networking and communication equipment. SA3 is intended to comply with a new international standard, International Electrotechnical Commission (IEC) 61850, and to meet the NERC/CIP standards for substation automation. SCE claims the program is essential to manage a range of field devices scheduled to be installed in substations, and to bridge the distribution and substation automation systems.

SCE requests $3.0 million in capital funding for this project during 2012. SCE estimates the cost of implementing SA3 at "AA" and "A" substations at approximately $2 million per station and "B" substations at $0.6 million each. These estimates were developed by SCE engineers, utilizing historical costs of existing substation automation programs and ongoing design work.

DRA recommends no ratepayer funding for the program at this time because it is not required, no cost-benefit analysis was provided, and SCE did not establish that the program is compatible with SCE's existing infrastructure.

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201 JCE at 594, 855.

202 SCE's current substation automation system is SA2 which replaced its first substation automation system.

DRA rejects as insufficient, SCE's claim that its "Engineering/Procurement/Design allocations are based on engineering judgment," and the "quantity based on project management estimates."

Given SCE's prior experience with substation automation, the Commission shares DRA's concern that a more specific cost/benefit analysis has not been provided before adopting another one. Furthermore, SCE claims the program will support IEC and NERC/CIP standards which have not yet been adopted. Therefore, the Commission finds that funding in 2012 is premature, and disallows all of SCE's request.[203]

5.2.3.6. Distribution Management System (DMS)

SCE's existing Distribution Control and Monitoring System (DCMS) is the centralized computing system that 1) allows SCE to gather data from SCE's various distribution automation programs, and 2) facilitates automated operation and control of the distribution system as a whole. SCE states that the system is essential to the safe and reliable operation of its distribution system, but the DCMS is now obsolete. SCE proposes to replace DCMS with the DMS which meets the requirements of SCE's smart grid vision.

SCE recorded $7.735 million in DMS capital expenditures in 2010, and forecasts $19 million for the DMS upgrade in 2011 and 2012 ($11 million and $8 million, respectively) for a total request of $26.735 million.[204] In its initial testimony, SCE forecast only $4 million in 2010 expenditures, and a total of

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[203] JCE at 596.

[204] This figure includes approximately $16 million in services provided by General Electric, and approximately $11 million for SCE's implementation costs including labor, information technology, and equipment installation; *see*, JCE, Vol. 2 at 597.

$23 million for 2010-2012.[205] However, SCE now states the higher recorded expenditures were primarily for licensing fees for software still in development.[206] DRA recommends no ratepayer funding because SCE did not spend $3 million authorized for 2009, the program is not required, and SCE has not shown that its benefits outweigh its costs.

The Commission views this program as necessary to maintain operational safety and reliability using current technology in view of impending DCMS obsolescence. Still, the Commission is concerned about escalating expenditures and SCE's failure to complete the project with the $20 million authorized in 2009.

Accordingly, the Commission approves the 2010 recorded capital expenditures for this program, but limits approval for 2011 and 2012 to an equivalent amount of $7.735 million for each year, allowing $23.205 million and disallowing $3.530 million of the $26.735 million request.[207]

5.2.4. Advanced Technology Transmission System Projects

5.2.4.1. Online Transformer Monitoring

SCE plans to install monitoring and communications devices on SCE's bulk transformers to enable it to better manage transformer failure risks by early and more accurate detection of some of the most common problems that can lead to catastrophic failure.[208] SCE recorded $1.217 million in capital expense for this project in 2010, and requests $4.911 and $5.029 in funding for 2011 and 2012,

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[205] Exhibit SCE-03, Vol. 02 at 71.

[206] TR at 1271.

[207] JCE at 597.

[208] JCE at 883.

totaling $11.157 million for 2010-2012. SCE recorded costs of $7.044 million in 2009.

TURN recommends that as of 2011, spending be halted on this program because SCE's own cost-benefit study indicates that most of the benefits can be captured by increasing manual monitoring at a fraction of the cost.[209] TURN agrees that online monitoring of dissolved gases can provide valuable information on transformer status, potentially leading to timely decisions to test and/or replace transformers. However, TURN concludes that it would be far more cost-effective for SCE to first spend an extra $60,000 to $100,000 yearly[210] to increase manual transformer sampling than to invest millions of dollars to install equipment for continuous monitoring of dissolved gases in its bulk transformers. Furthermore, SCE concedes that since 1990, only one large transformer failure has actually led to a service interruption, and that was when two transformers failed back to back.[211]

SCE disputes TURN's cost analysis, arguing the reasonableness of the project is risk mitigation, not the "financial model" conclusions relied upon by

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[209] TURN OB at 87.

[210] *Id*. at 89 (Edison has approximately 260 bulk transformers. Presently, as part of its routine preventive maintenance program SCE takes DGA (dissolved gas analysis) samples manually just once a year at a cost of $250 per sample. The total loaded cost of sampling and analyzing dissolved gases in the entire fleet of transformers once a year is approximately $65,000.)

[211] TR at 1292.

TURN.[212] Moreover, the Commission explicitly stated that risk mitigation was one reason that it approved this project in SCE's 2009 GRC.[213]

The Commission views transformer monitoring as a key factor in ensuring system reliability. We approve a gradual transition from the manual sampling method to a more technical online method of performing DGA analyses. Therefore, in order to balance the impact on ratepayers with a normalized approach to the costs of transition, the Commission finds reasonable and allows expenditures of $3.5 million in each of the years 2011 and 2012, and disallows $2.940 million.

5.2.4.2. Phasor Measurement & Wide-Area Situational Awareness (WASAS)

SCE's request is to begin deployment of phasor measurement devices at its substations, upgrade WASAS, and develop reports that analyze the data gathered.[214] SCE states that system operators and engineers need to accurately measure transmission system stress due to "continual erosion of capacity margins" that have resulted in increased congestion leading to a greater risk of wide-scale outages.[215]

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[212] SCE-18, Vol. 02 at 61.

[213] D.09-03-025 at 218-219 ("Edison has provided ample evidence to support its request as in the interest of ratepayers by enabling Edison to take proactive steps to prevent transformer failure through early detection of gas build-up, a precursor to transformer failure. This offers a variety of benefits including prevention of catastrophic failure, and the attendant costs as well as offering substantial value in terms of extending the life of Edison's transformers.").

[214] JCE at 598.

[215] SCE-03, Vol. 02 at 82.

SCE recorded $0.281 million in 2010 capital expense, and requests $19.1 million and $10.9 million respectively for 2011 and 2012. DRA recommends no funding on the grounds that SCE has failed to justify the program, spent only a fraction of 2009 authorized funds, did not explain the basis for cost estimates or vendor knowledge, or provide a ratepayer cost-benefit analysis.[216]

During the previous GRC, the Commission authorized spending $13 million for the program in 2009 to provide better system reliability, to manage transmission system stress, and to avoid close operating margins and system instability.[217] SCE explained its spending delay was due to a decision to deploy a device that meets pending NERC standards.

We accept SCE's assurance that previously spent funds support the advancement of the expanded scope of the project.[218]

The Commission finds reasonable and adopts the $0.281 million recorded capital expenditures for 2010 and the forecasted capital expenditures for 2011 and 2012 ($19.1 and $10.9, respectively) for total authorized capital expenditures of $30.281 million for 2010-2012.

5.2.4.3. Centralized Remedial Action Scheme (C-RAS)

According to SCE, Remedial Action Schemes (RAS) use automated programs that respond to transmission system disturbances by disconnecting generation, and/or customer load. SCE has 17 separate RAS deployed and

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216 TR at 1281-82. (SCE spent only $2.5 million of $13 million authorized in 2009.)

217 D.09-03-025 at 222.

218 TR at 1282.

expects the number to increase as more generation is interconnected. SCE claims future interconnections will push the limits of its current RAS technology. C-RAS was developed by SCE to improve coordination, and to overcome technology and management problems.[219]

SCE requests approval of $6.756 million for 2010 capital expenses, and an additional $16.541 million in 2011 to engineer, design, develop, and install equipment, and complete related transmission studies. No funding is requested for 2012; recorded 2010 expenditures were $0.364 million. However, SCE estimates spending $111 million between 2010 and 2014. SCE developed the estimates using internal engineering estimates in conjunction with vendor hardware budgetary quotes.[220] In the 2009 GRC, SCE received authorization to spend $58.1 million (CPUC jurisdictional portion) during 2007 to 2011, yet capitalized only $0.6 million as of 2009.

DRA recommends that the Commission discontinue ratepayer funding of CRAS because it is not required by statute or regulation, nor has SCE performed a cost/benefit study. Additionally, SCE spent only a tiny fraction of funds authorized by the Commission in its 2009 GRC after SCE argued the urgency of the program.[221] TURN also recommends no funding in either 2010 or 2011. TURN argues that SCE mistakenly justified the need by assuming that all projects in the California Independent System Operator Corporation (CAISO) queue would be interconnected and has not otherwise made any showing that

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[219] SCE-03, Vol. 02 at 90-92.

[220] JCE at 857.

[221] SCE capitalized $0.6 million in 2009 for C-RAS; JCE at 600.

the operational benefits that may be realized will outweigh the costs of the capital project.[222]

SCE explains it "temporarily held off on this project because it determined that near-term advancements in communications and computing technology would add substantial value."[223] We agree that the interconnection queue is an indicator of increasing need for improved technology to integrate new generation, particularly renewables driven by California's Renewable Portfolio Standard (RPS) and GHG goals, and that SCE has taken significant steps to implement the C-RAS project.[224]

However, SCE's costs have not tracked forecasts and are not well documented, nor has SCE fully examined the costs and benefits to ratepayers for implementing C-RAS versus other alternatives. Since 2006 SCE has been able to install five new, advanced RAS systems which have been able to handle more interconnections. SCE's interconnection estimates are excessive. We are not persuaded of the C-RAS project's urgency where SCE has not followed up on its opportunity to implement the project. C-RAS now needs a reassessment and more development by SCE as to actual need and a cost-benefit analysis before approval of additional ratepayer funding.

Given the Commission's prior approval of the project in the 2009 GRC, SCE likely spent the remainder of its 2010 $6.756 million C-RAS forecast ($6.392) in 2011 on project design and development. Almost all of the $16 million it forecast for 2011 was for software licensing. However, given SCE's choice to

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[222] TURN OB at 96.

[223] SCE OB at 80.

[224] SCE-18, Vol. 02 at 69.

delay the project, we are not convinced that SCE has adequately examined the current necessity of its own proposal in light of revised interconnection estimates and SCE's recent utilization of new, advanced RAS systems with more capability.

The Commission authorizes SCE to recover only its recorded 2010 capital expenditures of $0.364 million for C-RAS and finds reasonable and adopts the balance of its 2010 forecast, $6.392 million, in 2011to account for preliminary work. However, we do not authorize any additional funding, until SCE re-evaluates the project, and the viability of using existing, advanced RAS going forward.[225]

5.2.5. Smart Grid Cyber Security

Beginning in 2012, SCE wants to implement a centralized, comprehensive cyber security system to manage risks associated with deploying an increased amount of smart grid equipment over the next ten to twenty years. Cyber security elements are already being built into the devices and systems from various vendors as they are deployed.[226] This project addresses centrally managing the disparate security elements.

SCE's $8 million request for 2012, part of a $25.58 million ($2009) forecast for 2012-2014, covers the information technology equipment and software that will be used to ensure the security of communications, to, from, and between SCE's smart grid systems.[227] This forecast was developed by SCE engineers, and is based on SCE's experience implementing cyber security solutions for its

[225] JCE at 600-601, 857-858.

[226] SCE-03, Vol. 02 at 99.

[227] *Id*. at 35, 102.

Edison SmartConnect.[228] However, SCE provided no engineering study to ensure ratepayer benefits.[229]

DRA recommends no funding for the program at this time because SCE has failed to justify either the necessity or the cost. SCE has not previously asked for funds or made capital expenditures for this program. In addition, DRA urges the Commission to reject SCE's cost analysis as insufficient where the basis of unit costs for proposed capital expenditures relied on "engineering judgment" for design and specification, as well as estimated quantities.[230]

The Commission recognizes the need to plan for cyber security related to the future deployment of smart grid equipment in order to protect customer privacy and system reliability. However, SCE's "solution" seems premature. If the goal is to secure equipment and systems, some of which are yet to be developed, and to communicate with systems, some not yet deployed by other utilities (particularly in the Western Electric Coordinating Council),[231] then how can SCE assure that the project specifications developed in 2012 will be capable of broad integration in the next decades? This raises the prospect of obsolescence and a request for more ratepayer funding of another new system in a few years.

In addition, we agree with DRA that given the initial cost of the project, and SCE's recognition that the project is meant to be compatible with some equipment likely not yet invented, SCE should perform a cost/benefit study, or

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[228] JCE at 602.

[229] TR at 1286.

[230] DRA-7 at 21.

[231] SCE-03, Vol. 02 at 98-99.

initiate a test program to find out the actual costs and benefits to justify ratepayer funding.

The Commission approves $1 million of SCE's $8 million request for 2012 and directs SCE to provide a cost and benefits analysis of the Smart Grid Cyber Security solution in its next GRC, including the optimal timing for deployment in an evolving technological environment.[232]

5.2.6. Advanced Technology Laboratory Projects

SCE is expanding its technology evaluation facilities for its Advanced Technology engineers to determine how to integrate new smart grid technologies with existing transmission and distribution equipment and systems. This includes the 1) Distribution Grid Support System (DGSS) and Advanced Energy Storage Technology Evaluation Center (AES-TEC) Testing Centers; the 2) Real-Time Digital Simulator (RTDS) Lab Expansion; and the 3) Electric Vehicle Testing Center.

SCE's revised request for 2010-2012 Advanced Technology Laboratory capital expenditures, using 2010 recorded expenditures, is $13.717 million ($4.680 million in 2010, $2.703 million in 2011 and $6.334 million in 2012). SCE's forecast is based on internal cost estimates to expand and enhance these facilities.

DRA recommends the Commission allow recovery of the $4.680 million recorded for 2010, followed by $3.276 and $3.354 million in 2011 and 2012 respectively, allowing a total $11.310 million and disallowing $2.407 million. DRA contends this amount will allow SCE to accomplish what it describes as the mission of the Advance Technology division, and levelizes the capitalized

[232] JCE at 602.

expenditures over the period. DRA also argued that its proposal will allow SCE's ratepayers to benefit from "the new 2010 tax law that will be able to deduct 100% of 2011 investments from SCE's taxes via the bonus depreciation provision of the new tax law."[233]

TURN asks the Commission to disallow all spending for the projects included in this category on the grounds that the planned work duplicates research work being already conducted by other agencies and organizations in existing facilities.[234] In addition, TURN contends some of the projects are actually to construct buildings to conduct RD&D and subject to the requirements and "unnecessary duplication" prohibition found in § 740.1(d).

We are persuaded by SCE's detailed rebuttal to TURN's arguments and agree that SCE cannot solely rely on other entities to lead integration of new technologies with existing SCE equipment and systems. We do not make any determination in this section as to whether SCE should apply bonus depreciation to provide ratepayers with benefits in 2011.

The Commission finds reasonable and adopts $11.310 million of SCE's capital expenditure request for 2010-2012 and disallows $2.407million.[235] In the next GRC, SCE should provide a least cost analysis to support new construction versus leasing the required laboratory space.

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233 DRA-7 at 22.

234 TURN OB at 99.

235 JCE at 603-604, 859-860.

Although SCE did not rebut TURN's recommendation to disallow SCE's capital spending for capacitor automation as unsupported,[236] we find the forecasts for this category and Grid Operations to be reasonable and adopt them.

SCE's requests for capital spending for capacitor automation and grid Disptach are reasonable and we adopt them. In total, the Commission adopts $120.597 million of SCE's $173.608 million capital investment request for Transmission and Distribution Advanced Technology Projects for 2010 through 2012, and disallows $53.011 million, as indicated in the following table:

Advanced Technology Capital Expenditure Request						
	Capital Request by Year ($000)					
Project Description	**2010 Recorded**	**2011 Forecast**	**2012 Forecast**	**Total 2010-2012**	**Adopted**	**Disallowed**
Circuit Automation	$11,680	$3,922	$7,018	$22,620	$17,036	$5,584
Smart Distribution Transformers	-	-	300	300	300	-
DSEEP	4,526	5,096	5,249	14,871	13,583	1,288
Integrated Smart Distribution	-	-	16,043	16,043	5,322	10,721
SA3	-	-	3,000	3,000	0	3,000
Distribution Management System	7,735	11,000	8,000	26,735	23,205	3,530
Online Transformer Monitoring	1,217	4,911	5,029	11,157	8,217	2,940
Phasor Measurement and WASAS	281	19,100	10,900	30,281	30,281	-

[236] TR at 1340.

C-RAS	394* (6,756)	16,541	-	23,297*	6,756	16,541
Smart Grid Cyber Security	-	-	8,000	8,000	1,000	7,000
Advanced Technology Labs	4,680	2,703	6,334	13,717	11,310	2,407
Other (Capacitor Automation and Grid Dispatch, combined)	588	1,120	1,879	3,587	3,587	-
Total Capital Expense	**$37,463**	**$64,393**	**$71,752**	**$173,608**	**$120,597**	**$53,011**

*The 2010 recorded expense for C-RAS was $0.364 million, underspending original 2010 forecast of $6.756 million by $6.392 million; resulting 2010 and 2011 sum forecast equals $23.297 million.

5.3. Transmission and Distribution (T&D) Electric System Planning: 561.210, 587.210

Electric System Planning (ESP) is an organization within TDBU that performs engineering activities to analyze SCE's transmission and distribution capabilities. Much of the work is capitalized, but there are two major areas of O&M expenses each in its own subaccount: Transmission Interconnection Planning and Power Quality Inspection and Resolution.

For 2012, SCE estimated a total of $6.632 million: $5.305 million in the first category and $1.327 in the latter. DRA's estimates are $3.92 million and $0.964 million, respectively, a 30% recommended reduction.[237] The varied estimates arise from different forecasting methods. Non-labor expenses are largely driven by consulting/contractor agreements.

[237] SCE-18, Vol. 03, Pts. 1 & 2 at 1, Table I-1.

As discussed below, the Commission finds reasonable and adopts $5.327 million for TY2012 O&M.

5.3.1. Transmission Interconnection Planning: 561.210

Transmission Interconnection Planning includes activities regarding strategy and policy related to developing grid performance criteria and assessing system integrity.

For TY2012, SCE forecasts $5.305 million, a 20.7% increase over 2009 recorded costs. Labor expenses were estimated using 2009 recorded costs, the year SCE added 10 new employees. The forecast for Non-labor expenses was based on a three-year average of recorded expenses because the focus of work changed in 2007 to NERC compliance and RPS.

DRA considered the total expenses to have fluctuated "slightly" between 2005 and 2008, and used a five-year average as a basis for its forecast of $3.692 million in 2012, a reduction of $1.613 million.[238] DRA argues that SCE has "embedded funds from completed projects" to apply to requested incremental funding for additional work. SCE rejects use of a five-year average because Labor expenses were essentially flat 2005-2008, then increased 30% in 2009 based on substantial growth in both regulatory activities and interconnection requests.[239]

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238 DRA-5 at 115, Table 5-55.

239 Interconnection requests grew 160% between 2009 and 2010; SCE-18, Vol. 03, Pts. 1 & 2 at 8.

We agree with DRA that both labor and non-labor fluctuated between 2005 and 2009.[240] SCE's 2012 forecast is 20.8% more than 2009 recorded expenses, and its use of 2009 LRY results in the largest increase in historical data, one that mirrors large increases in expenses recorded in test years 2006 and 2009.[241]

Nonetheless, SCE has incurred additional NERC regulatory activities beginning in 2007 and received a significant increase in generation interconnection requests in 2010 (although there was only one additional interconnection request between 2008 and 2009). SCE already hired 10 people in 2009 to handle the increased work activities. Thus, SCE was prepared for the significant one year increase in interconnection requests in 2010.

Therefore, the Commission finds reasonable and adopts a three-year average of both labor and non-labor costs, with labor costs adjusted for 10.4% growth, half of the growth sought by SCE, to reflect additional regulatory and other activities. The result for Subaccount 561.210 is $3.197 million ($2.896 x 1.104) for labor costs and $0.984 for non-labor, for a total $4.181 million, or a reduction to SCE's forecast of $1.124 million.

5.3.2. Load Side Support for Power Quality, Radio & TV Interference: 587.210

This subaccount covers expenses for inspecting, monitoring, and mitigating power quality issues such as voltage dips and electromagnetic interference that can affect customers' service.

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240 (2006 = +10.5%, 2007 = <2.7%>, 2008= + 8.1%, 2009 = +16.8%, 2012 (estimated) = +20.8%, over prior year spending); DRA-5 at 115, Table 5-55.

241 DRA-5 at 115, Table 5-55.

For TY2012, SCE forecasts $1.327 million for this Subaccount 587.210, consisting of $0.919 million for labor and $0.408 million for non-Labor. This is a combined 37.66% over its 2009 recorded adjusted expenses of $0.964 million.[242] SCE's labor forecast is up 53.9% to fill four vacancies, bringing the total number of inspectors to 10.

DRA recommends use of 2009 recorded adjusted expenses for TY2012. DRA argues that SCE's proposed overall increase is not justified, particularly increased Labor costs. SCE relies on "management judgment" for its claim for additional inspectors. However, Labor expenses have consistently declined since 2005, no cost benefit analysis was performed, and SCE did not quantify the increased workload. SCE objects to use of LRY when the number of inspectors was at its lowest.

We agree that SCE's justification for the additional labor costs is insufficient. SCE did not clearly establish it needs to add four more inspectors. Additionally, the cost of the replacement inspectors should have been embedded in the program costs. On the other hand, it is reasonable to assume that the demand for Power Quality services is rising along with increased use of microprocessors and the shifts from electric to electronic loads.

Therefore, the Commission finds it reasonable to adopt 50% of the requested increase in Labor costs, or $0.758 million for 2012, with a similar reduction to the forecast Non-labor increase, primarily to exclude vehicle purchases for two inspector positions removed from the Labor forecast. The

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[242] SCE-18, Vol. 03, Pts. 1 & 2 at 9.

resulting combined amount approved for this Subaccount is $1.146 million, a reduction of $0.181 million from SCE's request.

5.4. T&D Load Growth

SCE's forecasts of load growth, which reflects customer growth and other factors, impact several expense categories including some O&M, capital expenditures on new construction, and buildings and related expenses for projected new employees. Retail sales are forecast by SCE to grow by 1.5% annually between 2010 and 2012.[243] Over the test year period, SCE assumes total customer growth will average about 1 % per year, which is somewhat lower than the 1.2% average annual growth recorded between 2001 and 2008. In addition, SCE expects new meter sets to decrease in 2010, then increase in 2011 and 2012.

Both Agricultural Energy Consumers Association (AECA) and TURN criticize SCE's load growth forecast as based on pre-recession growth, as well as other now-outdated factors present during 2005-2008. TURN argues that SCE's forecast of customer growth, a component of load growth, was too high and unsupported. The issue of customer growth, and particularly our adoption of an approximate 20% reduction to forecast new meter sets for 2010-2012, is discussed in Section 5.7.

AECA demonstrated that SCE's load forecasts from the 2009 GRC turned out to be too high.[244] For example, the record established that on a weather-normalized basis, the 2009 peak load on the SCE system was 7% below

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[243] SCE-10, Vol. 01 at 49.

[244] AECA OB at 6.

the forecast, and in 2010 it was 11% below the forecast.[245] SCE attributes this "departed load" primarily to the unexpected economic downturn in southern California.[246]

When considering proposed spending related to load growth categories, we bear in mind that we have adopted a lower new meter set than used by SCE.

5.4.1. 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 generation to the system. There are 10 project categories that make up the Load Growth area and primarily relate to system reliability.

In 2009, SCE requested, and the Commission authorized, $440.8 million in Load Growth capital expenditures, but SCE recorded only $367.047 million.[247] SCE decided to reschedule some projects and shift some of the funds into areas it determined to be of more immediate need (e.g. Infrastructure Replacement.)[248] Consequently, some of the projects SCE is requesting in this GRC were previously funded in the 2009 GRC.

For 2010-2014, SCE estimates $2.3 billion in capital expenditures for projects based on SCE's "likely case" peak load forecast for 2010-2019.[249]

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[245] TURN OB at 103, Figure 1.

[246] SCE-03, Vol. 03 at 29 (i.e., vacant, foreclosed homes, lower commercial demand, and lower individual use).

[247] SCE-03, Vol. 03, Pts. 1 & 2 at 27, Figure II-8.

[248] *Id*. at 26-27.

[249] SCE developed "high," "low," and "likely" ten-year load forecasts for all its distribution circuits, B-stations, and A-stations to account for inherent uncertainty in the

Footnote continued on next page

Assuming 2010 recorded expenses of $370.06 million, SCE's initial 2010-2012 forecast is $1.329 billion ($467.77 million in 2011 and $491.019 million in 2012).[250] CCUE supports SCE's load growth-related capital spending as necessary for reliable service.

DRA and TURN recommend reductions affecting four categories discussed below. AECA recommends that the Commission completely reject SCE's proposed 2010-2014 distribution investment on the grounds that the load growth SCE forecast in the 2009 GRC failed to materialize, and SCE continued to build anyway resulting in excess capacity. AECA also argues that customer-side energy technologies (e.g., energy efficiency, distributed generation, etc.) will offset any load growth. However, AECA's testimony lacks sufficient supporting documentation of either excess capacity or an evaluation of potential offsets to load growth. AECA also suggests that SCE investment in additional distribution infrastructure should be based on various reconciled demand forecasts SCE has presented in all regulatory proceedings (e.g., the Long-Term Procurement Plan (LTPP) proceeding), an accounting of unused distribution system components, and agreed-upon expectations about growth in residential and commercial development.

SCE provided sufficient justification to establish that some load growth will occur and that even if it does not use all of its current capacity by 2014, SCE will need to initiate some new projects to be in place as growth continues into the next rate cycle period. However, we agree that SCE's projected demand as

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load forecasting process, including how quickly California will recover from the recent economic recession.

[250] *Id*. at 28, Table II-4.

established in other Commission proceedings should be considered in the GRC. Therefore, SCE should include in its next GRC application a discussion in the Load Growth testimony that includes: (i) an estimate of unused distribution capacity for the test year, and (ii) other Commission Findings of Fact, particularly from Resource Planning and Long-Term Procurement proceedings, regarding forecast Load Growth during the rate cycle at issue.

No evidence was offered to rebut SCE's requests in six categories: A-Bank Plan, subtransmission VAR[251] Plan, Distribution Substation Plan (DSP) Circuits, Distribution Plant betterment, Distribution VAR Plan, and Generator Interconnection program. The Commission finds SCE's forecasts reasonable and we adopt them. Disputed program forecasts are discussed below.

5.4.2. Subtransmission Lines Plan

The capital expenditures in this plan involve upgrading, expanding, or reinforcing 66 kV and 115 kV subtransmission networks to adequately serve forecast load growth. SCE forecasts $53.221 million in 2011, and $33.419 million in 2012, a 2010-2012 total of $139.295 million for 27 capital projects, including four previously approved by the Commission but deferred due to permit delays.[252] SCE's forecast was based on planning studies and where SCE determined that a subtransmission line would become overloaded, it proposed a project to expand, upgrade, or reinforce the subtransmission system.

Although the total difference between SCE's forecast and recorded 2010 load growth expenditures is nominal, for this category the difference

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[251] "VAR" is an acronym for Voltage Ampere Reactive, SCE-03, Vol. 03, Pts. 1 & 2 at 63, fn. 101.

[252] SCE-03, Vol. 03, Pts. 1 & 2 at 48, Table II-6.

is about $27.1 million less was recorded.[253] DRA proposes adoption of 2010 recorded expenditures and reductions of $2.607 million in 2011 and $3.829 million in 2012 based on SCE's failure to identify construction authority for five of the projects in response to DRA's Data Request.[254] Given previous project delays due to permitting, DRA questions whether the five projects are likely to be completed during the rate cycle period since all construction must be authorized, pursuant to GO 131-D.[255] In rebuttal testimony, SCE provided new information about the five projects, including that the projects would likely qualify for an exemption.[256] However, the data was struck in an ALJ Ruling pursuant to DRA's motion which argued SCE developed and used information in its rebuttal testimony that had previously been requested by DRA, but not provided.[257]

SCE has an obligation to be forthcoming about the construction status of its projects. Requests for exemptions can be challenged and protested, which would have the potential to delay a project. In this situation, without

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[253] DRA-06 at 12, Table 6-1.

[254] JCE at 605.

[255] GO 131-D states that before a utility begins construction of certain power line facilities or certain types of substations it must have a PTC or Certificate of Public Convenience and Necessity (CPCN), or an exemption from these requirements.

[256] SCE-18, Vol. 03, Pts. 1 & 2 at 13-14.

[257] ALJ Ruling (September 29, 2011) at 15-16 ("It is simply unfair for a utility, or any party, to respond to discovery by stating information is unavailable, then to develop the information and use it in rebuttal without notice to the requesting party. If evidence is not timely brought forward for analysis, then the Commission and the public may be impaired in accurately evaluating the utility's application. One appropriate remedy is to exclude the untimely information in order to discourage future holdback of relevant data.").

authorization or an exemption, the Commission cannot evaluate the viability of a project. Because the record is insufficient to establish that the five projects are likely to come into service during the rate cycle period, the Commission finds it reasonable to adopt DRA's recommendation to exclude them and reduce the capital expenditure requests in 2011 and 2012 accordingly.

Accordingly, the Commission finds DRA's recommendation reasonable and adopts $50.614 million for 2011 and $29.590 million for 2012.[258]

5.4.3. Distribution Substation Plan

The objective of the DSP is to provide adequate B-bank[259] capacity and distribution circuit capacity to serve forecast peak loads under a one-in-ten-year heat storm condition. If load transfers are not sufficient to relieve a projected overload, then SCE develops a capital project to expand peak capacity. Seventy-five projects have been identified with a cost of $1 million or more, accounting for 94% of the overall DSP cost.[260]

SCE's revised forecasted capital spending is $117.328 million in 2011 and $119.761 million in 2012, and a total of $548.221 for more than 176 projects[261] through 2014. Expenditures for several projects were previously approved by the Commission in the 2009 GRC, but deferred due to permitting delays.

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[258] JCE at 605.

[259] B-banks are step-down transformers located at B-stations that reduce voltage from the subtransmission level to the distribution level (typically 4 kV, 12 kV, or 16 kV).

[260] SCE-03, Vol. 03, Pts. 1 & 2 at 70-71, Table II-8.

[261] JCE at 608; SCE-03, Vol. 03, Pts. 1 & 2 at 70 (Seventy-five of the projects, or 94% of the overall DSP cost, cost $1 million or more, the remainder, or $32.717 million cost less than $1 million each).

Similar to its position on the Subtransmission Lines Plan, DRA initially recommended reductions of $25.155 million in 2011 and $55.583 million in 2012.[262] SCE has since agreed to remove $0.140 million in 2011 and $12.601 million in 2012 for two projects it has deferred or cancelled, but contends the other projects are sufficiently justified.

At this time, DRA does not dispute any of the exemptions SCE initially claimed are applicable to proposed projects. However, given previous project delays due to permitting, DRA questions whether 35 projects for which SCE initially provided no authority to construct, are likely to be completed during this rate cycle. On rebuttal, SCE provided new information about the 35 projects, including that the projects would likely qualify for an exemption.[263] However, the data was struck in the same ALJ Ruling discussed above.

TURN recommends elimination of one project, Presidential Substation, which SCE justified based on load growth in Simi Valley and Thousand Oaks. TURN argues that SCE has significantly reduced its original forecast of load growth and SCE admits it does not expect to construct the substation in 2012 due to a heavily protested application for a PTC.[264] SCE forecast $22.971 for 2011-2012, and argues that no reductions should be made because it can apply the funds to other projects.

We agree that the Presidential Substation project will not be constructed during 2012, will likely be modified, and may not be constructed during the rate case cycle. Thus, all forecast expenditures for this project 2011-2012 should be

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[262] *Ibid.*

[263] SCE-18, Vol. 03, Pts. 1 & 2 at Attachment 6, A-15.

[264] A.08-12-023.

removed. We also agree, in part, with DRA's recommendation to exclude the 33 remaining projects for which construction authority was not initially identified because there was insufficient data to timely evaluate whether the projects were likely to come into service during this rate case cycle. Based on the record, some projects appear on their face to likely qualify for an exemption, others do not. We find it reasonable to adopt 50% of this recommendation as an incentive for SCE to timely provide complete information to parties in the next GRC, and to seek capital funding only for DSP projects truly in a position to begin construction or come online during the rate cycle.

Therefore, in addition to 2010 recorded expenses of $101.749 million, the Commission finds reasonable and adopts reductions to SCE's forecasts as follows: $20.763 million in 2011, and $36.341 million in 2012. The result is total authorized funds of $281.734 million for 2010-2012. This is a reduction of $57.104 million, the equivalent of a 16.9% reduction to SCE's updated request.

5.4.4. Substation Equipment Replacement Program (SERP)

SCE forecasts total expenditures of $44.4 million between 2010 and 2014 for the SERP program which evaluates the adequacy of substation terminal equipment and system protection equipment.

Based on the revised forecast, SCE's capital spending would grow from $6.882 million ($nominal) in 2010 to $9 million in 2012, and to $12 million in 2014. This contrasts sharply with 2005-2008 when SCE's SERP expenditures averaged $0.766 million ($2009) per year.[265] Recorded 2010 expenditures were $3.683 million. Based on its 2009 short-circuit studies, SCE replaced 26 circuit

[265] SCE-03, Vol. 03, Pts. 1 & 2 at 116-117, Figure II-13.

breakers in 2011 and launched a plan to replace 211 circuit breakers at 22 substations by 2014. SCE also forecasts replacing 60 more due to forecast load growth.

DRA agrees that SCE will need to replace the circuit breakers but recommends the Commission find it reasonable to extend SCE's replacement schedule over a longer period, i.e., replace 26 of the 66 kV circuit breakers per year instead of increasing the number to 36 per year from 2012 to 2014. SCE criticizes DRA's recommendation as arbitrary, unaware of the operational and safety-related implications of delay, and solely intended to reduce rates.

The timing of SCE's forecast is speculative.[266] We agree with DRA that SCE is not required or mandated to complete these replacements within four years, nor has it demonstrated an operational or safety imperative to do so. SCE's forecast expenditures for replacements increased by 50% from 2011 to 2012, but decreased 14.7% from 2010 to 2011. We find it reasonable to instead spread the replacements over six years and normalize the costs to $8.143 million per year for 2011 and 2012. As elsewhere, the commission adopts SCE's 2010 recorded capital expenditures of $3.683 million.

5.4.5. PEV Readiness

SCE asserts that PEVs will incrementally increase the need for infrastructure maintenance and upgrades, as charging of the PEVs can have substantial impact on SCE's distribution system. SCE plans capital spending it contends is necessary to support PEVs in the future: capacity upgrades, new

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[266] SCE-18, Vol. 03, Pts. 1 & 2 at 16 (forecast includes an allowance for some replacements to keep pace with anticipated future increases in short-circuit duty levels throughout SCE's system).

circuits, 4 kV circuit cutovers, shunt capacitor banks, main and radial line segments, and transformers, secondaries, and service drops.[267]

No PEV expenditures were made in 2010. SCE estimates capital expenditures of $2.089 million in 2011 and $8.523 million in 2012, for a total of $10.612 million. SCE's expects to spend $70.714 million by 2014. SCE based its forecast on an analysis to identify infrastructure equipment upgrade requirements needed to accommodate the emerging PEV market while maintaining grid stability.[268]

DRA and TURN oppose any capital funding for PEV readiness at this time on several grounds, including that SCE's forecast is excessive, existing rates are sufficient, the funding request is not adequately supported, and the request may be duplicative of other capital requests throughout SCE's application.

SCE argues that the Commission has directed it to pursue the development of the necessary infrastructure for PEVs. For example, in the 2009 GRC, the Commission recognized that over time, PEVs will have an impact on the electric system.[269] In D.11-07-029, the Commission directed the utilities to complete certain tasks related to electric vehicles, including development of a data clearinghouse to track PEVs and preparation of rate design schedules in 2013.[270] SCE also provided detailed responses to DRA and TURN's objections.

We generally agree with DRA and TURN that SCE's timetable for rolling out the PEV readiness program is based on an excessive forecast. The record

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[267] SCE-03, Vol. 03, Pts. 1 & 2 at 128.

[268] *Id*. at 129.

[269] D.09-03-025 at 118.

[270] SCE-18, Vol. 02 at 4.

indicates that consumer purchases have been slow. We adopt SCE's "low" case estimate for the number of PEVs in SCE's territory during the rate cycle, approximately 43% lower than SCE's 2011-2014 "medium" case.[271]

Accordingly, the Commission finds it reasonable to apply a 40% reduction to SCE's forecast and adopt PEV readiness capital expenditures of $1.253 million in 2011 and $5.114 million in 2012.[272]

5.5. T&D Infrastructure Replacement (IR)

SCE operates and maintains a vast infrastructure of transmission and distribution equipment throughout its system that must eventually be replaced as the equipment approaches its end of service life rather than waiting for in-service failure. According to SCE, not all of this equipment can be identified through inspections. The Commission recognizes that safety, system reliability, cost, and customer satisfaction are key considerations in determining reasonable funding for equipment replacement programs.

SCE originally forecast IR capital expenditures of more than $1.3 billion for 2010–2014 in 14 separate expense categories, estimating growth of 155% during that period. SCE's actual recorded 2010 expenditures are $184.846 million, almost one-third higher than previously forecast by SCE.[273] SCE also increased its 2011 and 2012 near-term capital forecasts in its rebuttal testimony to $180.64 million in 2011, and $350.249 million in 2012, a

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[271] SCE-03, Vol. 02 at 17, Table III-2; (SCE's medium case estimates 21,000 PEVs in 2012 and 73,000 by 2014, the low case estimates 16,000 PEVs by 2012 and 33,000 by 2014).

[272] JCE at 615.

[273] SCE-18, Vol. 03, Pt. 3 at 2, Table I-1; SCE-03 Vol. 03, Pt. 3 at 12, Table I-1.

2010-2012 total of $715.734 million[274] In this decision, the Commission adopts a total of $653.148 million for 2010-2012 IR capital spending, including SCE's 2010 recorded expenditures.

SCE provided data showing the average age of several categories of equipment trending upward during 2000-2009, and argued for increased funding due to the growing volume of infrastructure wearing out and needing to be replaced each year.[275]

DRA replaced SCE's 2010 IR forecasts with 2010 recorded data and accepted SCE's 2011-2012 estimates in eight of the 14 categories, and challenged the remaining six. SCE does not dispute approval of recorded 2010 expenditures. The Commission finds reasonable and adopts SCE's forecast for the eight uncontested IR expenditures for 2011-2012.

The discussion below addresses the remaining contested issues.

5.5.1. Cable Replacement Program and Worst Circuit Rehabilitation

SCE's distribution system includes approximately 49,000 circuit miles of underground primary cable, some installed as far back as the mid-1950s. According to SCE, the Cable Replacement Program (CRP) identifies the poorest performing circuits, in terms of cable reliability, and implements improvements in those circuits where needed most. Related underground CRPs included in the discussion are Worst Circuit Rehabilitation (WCR) and Oil Switch Replacement (OSR).

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[274] *Ibid*.

[275] SCE-03, Vol. 03 at 6-8.

In the 2009 GRC, the Commission reduced SCE's CRP request for $37.8 million to $10.5 million to allow replacement of 36 miles of cable annually, based on SCE's historic average replacement rate. In 2009, SCE recorded actual expenditures of $27.7 million in CRP and replacement of 116 miles of cable. SCE's costs for the CRP have grown from $3.4 million in 2007 to $27.7 million in 2009, and $35.9 million in 2010.[276]

SCE recorded costs of $35.947 million 2010[277], and estimates spending $38.874 million in 2011, and $74.514 million in 2012 for CRP capital expenditures. In 2011, SCE plans to replace 267 circuit miles of cable, using all three replacement programs, including 154 miles under CRP.[278] In 2012 and beyond, SCE plans to replace 415 conductor-miles of cable in its worst performing circuits: 300 miles under the CRP and 115 miles under the WCR. SCE also plans to replace 74 miles in the OSR program, resulting in 489 total annual replacement miles. CCUE supports SCE's projected cable replacements as necessary for reliability. DRA agrees only that the OSR forecast is reasonable.

SCE supports its forecast with data showing the average age, time to wear out, and current inventory for each of the four types of cable.[279] SCE also provided an analysis of cable failures and a relationship between the probability of failure and cable age, with failures rising significantly in the 35-40-year old

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276 *Id*. at 17, Table II-2.

277 DRA-6 at 5, Table 6-1.

278 154 miles under CRP, 46 miles under OSR, and 67 miles under WCR; SCE-03, Vol. 03 at 17.

279 SCE-03, Vol. 03 at 20, Table II-3.

period.[280] To establish its 2012 cable replacement goal, SCE relied on an outside consultant[281] to evaluate how system reliability in 2030 will be impacted under different annual cable replacement scenarios, excluding OSR. The Quanta report measured the reliability impact of different annual replacement rates (i.e., zero miles, 150 miles, 415 miles, and 700 miles) by calculating to what degree System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) levels would change.[282]

DRA recommends the Commission authorize SCE's recorded expenditures for CRP in 2010, and expenditures of $38.874 million in 2011 and $46.820 million in 2012.[283] The 2010-2012 result is $121.641 million, an approximately 15% reduction to SCE's 2010-2012 request of $143.024 million. TURN agrees with DRA's forecast and both parties accept SCE's estimated unit cost estimates.

After rejecting what it described as "complexities" in SCE's analysis, DRA arrived at its forecast by determining a "reasonable" quantity (in circuit miles) of underground cable to be replaced each year, allocated the result between the three programs, and then calculated reasonable expenditure levels.[284] DRA agrees with SCE's 2011 forecast of 270 miles for CRP and WCR, but in

[280] *Id*. at 21.

[281] The Quanta Technology study also included two other programs: WCR and the Underground OSR.

[282] SCE-03, Vol. 03, Pt. 3 at 15-16.

[283] JCE at 616.

[284] DRA OB at 85.

2012 recommends replacement of 276 miles, with 161 miles allocated to CPR, assuming adoption of SCE's forecasts for WCR and OSR.[285]

According to SCE, the issue is how much reliability degradation is acceptable. The Commission's review is primarily driven by a balance of system reliability and ratepayer costs. Prior to 2009, SCE had not replaced more than 100 miles in all three programs combined. In the 2009 GRC, the Commission was not persuaded that a substantial increase in cable replacement was necessary, yet SCE performed three to five times (if WCR is included) the replacements authorized.

In this rate cycle, we are persuaded that SCE should perform more cable replacements than its five-year historical average of 47.6 miles per year because its existing cable is aging. We are also persuaded that SCE should perform the forecast replacements for OSR and WCR. However, we agree with DRA and TURN that the CRP may be deployed at a slower pace given the probable remaining life of existing cable. The small improvement to reliability projected in 2030 between replacing 415 miles, instead of 276 miles annually (CRP and WCR), does not warrant the additional cost of expedited replacements now. Moreover, it is unclear whether SCE is capable of replacing the record number of miles it estimates, more than six times the previous five-year average in CRP.

Regardless of the replacement scenario, SAIDI and SAIFI are projected to increase through 2030. Increasing the replacement miles from 150 annually to 415 will result in the average customer experiencing one less outage every 7.14 years, or 686,000 customers experiencing one more outage every 7+ years.

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[285] DRA-6 at 27, Table 6-4.

DRA's replacement forecast is higher than 150 miles annually and the Quanta report excluded 74 miles per year of OSR replacement which will also improve reliability. Before 2030, there will be other opportunities in more robust economic times, for ratepayers to ramp up replacement spending in this category should the Commission find it necessary.

Therefore, we find SCE's 2012 forecast for replacing 415 circuit miles overly ambitious, and DRA's recommendation to scale back to 276 circuit miles (161 miles for CRP and 115 miles for WCR), to be more reasonable. The Commission adopts DRA's recommendation which results in a $27.694 million reduction to SCE's 2012 forecast. SCE's updated forecast is accepted for 2011.

5.5.2. Cable-In-Conduit Replacement

Of the approximately 49,000 circuit miles of underground cable, roughly 10,000 conductor miles are of a type known as cable-in-conduit (CIC), which is essentially unjacketed wires inside a plastic pipe. SCE states the system has increasing failures, and based on the current age profile of the CIC and the probability of failure versus age curves,[286] SCE estimates that 3,000 conductor-miles of CIC will fail in service in the next twenty years.

SCE requests approval of $13.357 million in 2011 and $30.560 million in 2012. SCE began recording replacement costs in 2009 ($0.932 million), which grew to $4.030 million in 2010, $0.750 million more than forecast. CCUE supports SCE's plan to replace 36 conductor miles annually in 2011 and 2012 as necessary for system safety, reliability, and cost.[287] According to SCE, the

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[286] SCE-03, Vol. 03, Pt. 3 at 21.

[287] CCUE OB at 11-12.

forecast 2012-2014 capital expenditures will be used to fund 15 projects as a "pilot program" to investigate better, more cost-efficient approaches for replacing this cable.

DRA recommends the Commission eliminate $35.614 million ($9.255 million in 2011 and $26.359 million in 2012) from SCE's proposed amount, which would still leave $4.102 million in 2011 and $4.201 million in 2012 for CIC replacement. DRA agrees with SCE that failures will increase over time and that ratepayers want the replacement costs to be economical. However, DRA believes the pilot program is too large and should be scaled back. DRA contends that the substantial spending increases in 2011-2012 will lock-in a replacement methodology before SCE has determined the most cost-effective means to make replacements. DRA proposes that SCE replace approximately five miles of CIC in 2012.

We recognize that the aging CIC needs to be replaced and the best methodology for CIC replacement has not been established. A large amount of CIC cable was installed up to 40 years ago and SCE claims that many circuits have had multiple failures.[288] We review this program primarily for its impact on system reliability. SCE argued that the possibility of "stray voltages" from excessive wire corrosion could pose a safety hazard, but provided no evidence such incidents have occurred or are likely to occur. Even so, the risk of failure is real and we agree that SCE needs to collect data to develop the most cost-efficient method of replacement.

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[288] SCE-18, Vol. 03, Pts. 3 & 5 at 9.

We are persuaded that SCE's proposed replacement of 36 conductor miles per year, 0.3 % of the total CIC population, is not excessive. DRA's recommended replacement of five miles of CIC, apparently equates to two CIC projects per year which is unlikely to yield significant information by the next GRC. We expect SCE to carefully document the data collection from this program, as well as other efforts it undertakes to develop a best practice, and most cost-effective method, for performing the balance of CIC replacements in the years to come. This information shall be submitted in support of future GRC requests in this category to assist the Commission and to illustrate that ratepayers achieved value from SCE's "lessons learned."

The Commission finds reasonable and adopts SCE's forecasts totaling $43.917 million in capital expenditures for 2011-2012.[289]

5.5.3. Substation Transformers

SCE's Infrastructure Replacement program includes replacing A-bank and B-bank substation transformers. A-bank transformers, which reduce high electrical voltage down to 66 kV levels, are located in major substations. B-bank transformers, which reduce this voltage from 66 kV down to a level usable to SCE's customers via the distribution circuits, are typically located in neighborhood substations.

No party takes issue with SCE's proposed A-bank transformer replacement expenditures. Replacement of aging high voltage transformers is both a safety and reliability issue. SCE's forecast is consistent with replacement

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[289] JCE at 618.

history. Therefore, the Commission finds SCE's proposed expenditures for replacement of the A-bank transformers to be reasonable.

For B-bank transformers, SCE forecast $16,582 million ($nominal) in capital expenditures for 2011 and $42.512 million in 2012.[290] The forecast for 2010 was $28.467 million, but SCE only recorded $20.358 million. SCE has historically replaced between four and 14 B-bank transformers per year. After replacing 14 in 2010, SCE estimated it would replace 16 in 2011 and plans to replace 40 per year beginning in 2012. SCE derived a theoretical replacement level of 45 transformers per year based on a failure probability curve.

DRA has no objections to SCE's proposed replacement of 16 B-bank transformers in 2011. DRA also does not dispute the unit cost of replacement and agrees with SCE that failures will increase over time. However, DRA proposes to reduce the number of 2012 replacements from 40 to 30 (an 87.5% increase over 2011) on the grounds that SCE's request is not supported by either historical replacements, or data on the failures of these types of transformers or identification of which would be replaced.

The Commission authorizes funding to replace 30 transformers in 2012 because we recognize that an increase in the number of replacements is warranted for reliability reasons due to the increasing age of the inventory of B-bank transformers. The fact that SCE has not yet accomplished half of that amount of replacements in one year gives us pause about approving an even larger program.

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[290] *Id*. at 619.

Accordingly, the Commission finds reasonable and adopts DRA's recommendation of $31.890 million for 2012 and reduce SCE's forecast by $10.622 million. We also find SCE's 2010 recorded expenditures and 2011 forecast to be reasonable. We expect that SCE will continue to make 30 replacements annually through 2014. To assist the Commission, SCE shall document the replacements performed and submit the names, locations, and ages of the replaced transformers in support of future GRC requests in this category.

5.5.4. Distribution Circuit Breakers

SCE has about 10,411 distribution circuit breakers in its system. According to SCE, 20% are older than their 48-year mean-time-to-failure and 40% were manufactured by companies no longer making breakers or replacement parts. SCE plans to replace the oldest circuit breakers first.

In nominal dollars, SCE forecasts $ 215.296 million in 2011 to replace 147 circuit breakers and $22 million in 2012 to replace 215. In 2010, SCE recorded costs of $12.023 million.[291] The company's expenditures in this category fluctuated between 2005 and 2009, when SCE recorded $23.147 million.

DRA does not challenge SCE's circuit breaker expenditure estimates for 2011, which it deems reasonable. However, DRA recommends reducing 2012 replacements from 215 to 175, higher than any other recorded year, resulting in a $3.564 million reduction. SCE has never replaced more than 159 distribution circuit breakers, which it did in 2009. In 2010, SCE replaced

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[291] SCE-18, Vol. 03, Pt. 3 at 2, Table I-1.

only 62 and in 2011, SCE proposes to replace 147. DRA points out that SCE's own failure analysis predicts that 75 circuit breakers will fail each year.

We agree with SCE's targeting of the oldest circuit breakers, and their replacement on a planned basis is far more prudent than incurring the risks associated with running them to failure. However, given SCE's historical replacement record and its own failure analysis, DRA's forecast of replacing 175 circuit breakers in 2012 seems reasonable. DRA anticipates that SCE may reduce the number of replaced circuit breakers to 153 in the 12 kV category, seven in the 115 kV category, and 15 in the 66 kV category for a total of 175.

Therefore, the Commission finds it reasonable to reduce SCE's 2012 forecast amount by $3.564 million, from $22 million to $18.436 million. We expect SCE to replace 175 distribution circuit breakers within the authorized funding in 2012 and report on this activity in the next GRC.

5.5.5. 4 kV Circuit Replacement Cutovers

Approximately 1,100 of SCE's 4,800 distribution circuits operate at a voltage of 4 kV or lower which SCE deems inadequate and inefficient for today's power needs, mostly due to obsolete and unreliable equipment. According to SCE, there are currently 142 4 kV (or lower voltage) circuits which are incapable of carrying the expected load during a significant (i.e., one-in-ten-year) heat storm. SCE's approach is to offload 16,330 amps from the most heavily loaded circuits onto neighboring 12 kV or 16 kV circuits which typically have excess capacity.[292]

[292] SCE-03, Vol. 03 at 89.

SCE forecasts capital expenditures for 4 kV circuit replacement cutovers of $17.214 million ($nominal) in 2011 and $30.167 million in 2012. The recorded expenses for this program more than doubled from 2008 to 2009, and grew another 120% from 2009 to 2010 ($11.080 million to $24.376 million). SCE states it used best estimates of future load increases as the basis of its forecast of when circuits would be overloaded.

DRA accepts SCE's 2011 estimate for 4 kV circuit cutovers, which is 3,019 amperes, slightly higher than the 2010 estimate. DRA also accepts SCE's cost per amp. For 2012, DRA recommends $20.433 million, a $9.734 million reduction achieved by evening out the pace of the cutovers.

Instead of SCE's increase to 5,168 amps in 2012, DRA recommends that 3,500 amps be used as the annual level of amps to be transferred. SCE is proposing to use cutovers in the distribution circuits to transfer 16,330 amps by 2014, and an additional 11,194 amps for a total of 27,524 amps by 2020. DRA states that if 3,500 amps were transferred annually beginning in 2012, both goals set by SCE for 2014 and 2020 could be achieved. SCE responds that it has a project backlog and needs the 2012 funding.

Transferring the 4 kV circuits to higher voltage lines presents issues of ratepayer cost and reliability benefits. The Commission concurs with DRA's recommendation to transfer at least 3,500 amps in 2012 as part of a levelized approach which will exceed SCE's stated 2014 (and 2020) goals.

Therefore, the Commission finds reasonable and adopts a $9.734 million reduction to SCE's 2012 forecast of $30.167 million. SCE's recorded 2010 costs of $24.376 million are reasonable.

5.5.6. 4 kV Substation Elimination

SCE is seeking funding to eliminate its old and obsolete 4 kV substations after transferring the load to adjacent 12 kV and 16 kV circuits. There are 34 substations with transformers 80 years old or older, most with circuit breakers over 50 years old.[293] According to SCE, this option prevents in-service failure of equipment, obviates the need for emergency repairs, solves future problems with inadequate 4 kV circuit capacity, and enhances reliability by increasing the number of circuit interconnections available to restore power following outages.

For 2012, SCE forecast a capital expenditure of $34.286 million to eliminate seven substations. Prior to this GRC, SCE has not had a formal program to systematically eliminate 4 kV substations, therefore no prior expenses have been recorded under this account. SCE based its unit cost for eliminating a 4 kV substation on "detailed studies" of the cost of eliminating six other substations which SCE is planning to complete in 2012.[294]

DRA recommends no funding in 2012 for this program. Although DRA does not dispute that the 4 kV substations should eventually be eliminated, in its view SCE has not adequately justified commencing and funding the program in 2012. Given that SCE will be transferring its 4 kV circuits to higher voltage circuits at least through 2020, DRA concludes it is reasonable to keep the existing 4 kV substations running, and replaced at a future date.

We agree that the old 4 kV substations will need to be eliminated over the next decade in order to maintain system reliability. Although it would seem there would be some correlation between SCE's 4 kV cutover projects and

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[293] SCE-03, Vol. 03 at 94.

[294] SCE-03, Vol. 03 at 97.

its 4 kV substation elimination projects, this is not apparent from the listing of identified projects in either program. Moreover, we are not persuaded that SCE's unit costs are reliable given they were developed two years before the subject projects were scheduled to be completed.

In the previous section, we approved a more evenly paced cutover program which resulted in a 32% reduction to SCE's 2012 forecast. We mirror that reduction here, and expect SCE to coordinate its cutover program and its substation elimination programs to best ratepayer advantage, including prompt removal of unutilized property from rate base.

The Commission finds reasonable and authorizes $23.314 million to begin the program in 2012, a $10.972 million reduction and the equivalent of 68% of SCE's request.

A summary of the SCE forecasts for the Infrastructure Replacement Program and the Commission authorized amounts is set forth below.

Infrastructure Replacement Capital Expenditure Request						
	Capital Request by Year ($000s)					
Project Description	**2010 Recorded**	**2011 Forecast**	**2012 Forecast**	**Total 2010-2012**	**Adopted**	**Disallowed**
Cable Replacement Program	$35,947	$38,874	$74,514	$149,335	$121,641	$27,694
Worst Circuit Rehabilitation	24,607	18,660	33,119	76,386	76,386	-
CIC Replacement	4,030	13,357	30,560	47,947	47,947	-
Cable Testing Pilot	-	-	2,123	2,123	2,123	-
Underground Oil Switch Replacement	21,556	6,479	10,615	38,650	38,650	-
PMH-4 Switch Replacement	-	2,281	2,335	4,616	4,616	-
Capacitor Bank Replacement	7,667	5,667	10,482	23,816	23,816	-
Automatic Recloser Replacement	1,536	1,596	2,229	5,361	5,361	-

PCB Transformer Replacement	1,783	624	2,282	4,689	4,689	-
Substation Transformers	38,077	48,524	80,581	167,182	156,560	10,622
Circuit Breakers	12,023	15,296	22,000	49,319	45,755	3,564
Protection and Control	13,244	12,068	14,955	40,267	40,267	-
4 kV Cutovers	24,376	17,214	30,167	71,757	62,023	9,734
4 kV Substation Elimination	-	-	34,286	34,286	23.314	10,972
Total Capital Expense	**$184,846**	**$180,640**	**$350,249**	**$715,734**	**$653,148**	**$62,586**

5.6. T&D Engineering

Engineering Design & Project Management is responsible for performing engineering design for medium to large substation and transmission projects; analysis of in-service equipment failure; assessment of new technology prior to installation; and development of engineering standards. No party contested SCE's annual forecast of $1.473 million ($2009) to support capital expenditures for lab, test, and shop equipment for the Shop Services and Instrumentation Division (SSID). The Commission finds reasonable and adopts $4.591 million ($nominal) for SSID 2010-2012 capital spending.

SCE forecasts $13.557 million of updated O&M expenses for Engineering Design and Project management in 2012 by utilizing its 2009 recorded adjusted expenses for subaccounts 560.220, 580.220, 588.220, and 595.220, plus incremental expenses for proposed projects and work activities.

DRA forecasts $11.894 million in O&M expenses, $2.586 million less than SCE's forecast for the four subaccounts. DRA proposes reductions in SCE's expense forecasts for: 1) Transmission/Substation Operations Supervision and Engineering (FERC 560.220), and 2) Engineering Planning and Protection Studies (FERC 580.220), discussed below.

The Commission finds SCE's uncontested O&M forecasts in subaccounts 588.220 and 595.220 to be reasonable and adopts them.

5.6.1. Transmission/Substation Operations Supervision, and Engineering: 560.220

Subaccount 560.220 records costs for three separate activities: 1) engineering activities that contribute to the operation of the transmission system; 2) Shop Services and Instrumentation Division (SSID) instrument repair and tool calibration; and 3) miscellaneous employee expenses.

For 2012 O&M, SCE's forecast is $8.899 million ($2009) in this Subaccount ($2.527 million Labor and $6.372 million Non-labor).[295] SCE's forecast is based on 2009 recorded costs, adjusted for incremental new work, in categories other than miscellaneous employee expenses where it used a three-year average due to an upward trend in spending. SCE asserts the forecast amount is necessary to comply with new NERC standards.[296]

DRA's 2012 forecast is $7.563 million, $1.336 million less than SCE's request.[297] The total forecast is based on a five-year average (2005-2009) of recorded O&M costs for this Subaccount, and removal of $0.369 million for discretionary costs associated with employee recognition programs.[298] DRA removed the funding on the grounds the recognition programs do not provide a clear or identifiable benefit to ratepayers and are not necessary to operate the utility business.

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[295] JCE at 309.

[296] SCE-18, Vol. 03, Pts. 3 & 5 at 23.

[297] DRA-5 at 122.

[298] *I.e.*, Spot Bonuses and Awards to Celebrate Excellence Recognition Points.

SCE argues DRA's use of a total five-year average is inappropriate because it does not take into account the different factors that drive the activities and costs in this Subaccount, and recorded expenses did not significantly fluctuate from year to year, nor were they influenced by weather or other external forces beyond the control of SCE.[299]

It is a matter of opinion whether recorded Engineering costs, the largest portion of the Subaccount, have "trended" upward in the prior three years. Furthermore, use of 2009 recorded expenses is problematic. In its 2009 GRC, SCE requested $16.795 million, a 206% increase over 2006 recorded, adjusted expenses, due to a $10.623 million request for a Transmission Line Clearance Study (TLCS) on its bulk transmission and sub-transmission lines. However, SCE only spent $3.360 million to address the Study, and an additional $2.733 million to perform other transmission work in 2009. Therefore, LRY is an inflated basis for the 2012 forecast.

The Commission is persuaded that SCE's low spend of the funds authorized for the TLCS was related to changed circumstances which reduced the number of affected transmission lines. However, SCE did not adequately explain why it needs additional funding for the preliminary mitigation phase of the study.[300]

We are also persuaded that DRA made a calculation error when calculating employee recognition expenses. The correct amount estimated for 2012 is $0.251 million. We exclude this amount from the approved forecast and discuss employee bonus/recognition programs in Section 8.5 of the decision.

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299 SCE-18, Vol. 03, Pts. 3 & 5 at 24.

300 *Id*. at 26.

The Commission reduces SCE's non-labor forecast for 2012 by $0.676 million (50% of DRA's recommendation) to reflect exclusion of the employee bonus funds and a portion of the previously authorized, but unused, funds for the TLCS which could have been retained, and SCE should have anticipated were needed, for the second phase of the Study. The Commission finds reasonable and adopts the result: $8.223 million ($2.527 million Labor, $5.696 million Non-labor), a 7.5% reduction.

5.6.2. Engineering, Planning and Protection Studies: 580.220

Subaccount 580.220 records the costs for engineering, operations, and maintenance activities related to operation of the distribution system. The primary project in this rate cycle is compliance with new NERC CIP standards expected in 2012.

SCE forecasts $1.125 million in TY2012, an increase of $327,000 over its 2009 recorded costs of $798,000.[301] According to SCE, the increase is to cover an additional analyst ($77,000) hired in 2010 to develop requirements for new procedures related to the revised 2012 NERC/CIP standards and $250,000 annually to hire two contract engineers during 2012 to 2014 to review and classify drawings from 106 substations potentially impacted by NERC/CIP compliance.

Based on declining historical expenses through 2009, DRA recommends using 2009 recorded expenses of $0.798 million as the basis for expenditures in TY2012, claiming no cost increase is needed or justified.[302] DRA also claims that

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[301] SCE-03, Vol. 03, Pts. 4 & 5 at 49.

[302] DRA-5 at 125.

SCE has not specifically tracked all the related costs embedded in its TDBU historical expenses, and therefore cannot accurately calculate expense increases to justify additional funding.[303]

We agree with SCE if new NERC/CIP standards are implemented it could lead to new, additional substation assessments. Thus, we agree with the addition of an analyst to determine what compliance steps might be necessary. On the other hand, SCE's evidence to support the contract engineering costs is insufficient. SCE said it would need to review up to 50 drawings per impacted substation which would total about 5000 drawings. However, the new NERC/CIP standards have not yet been adopted and the contract engineering estimate is for review of 3,500 drawings per year for three years.[304] Therefore, the Commission finds it reasonable to reduce SCE's proposed engineering contract expenses by 50% ($125,000 per year).

5.7. T&D Customer-Driven Programs

A large portion of SCE's TDBU is generated by requests from SCE's customers. These include installing new service connections to connect new customers, converting overhead lines to underground lines, and relocating facilities at the request of customers. In this section, we adopt TURN's "base" case for new meter sets resulting in an overall five-year weighted average reduction of 17% to SCE's forecasts based on customer growth, e.g., estimated new meter costs.

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[303] *Id*. at 127.

[304] SCE-18, Vol. 03 at Attachment 4.

Of the customer-driven capital projects, DRA is recommending adjustments to three of them, all related to undergrounding. SCE converts overhead lines to underground lines pursuant to CPUC Tariff Rules 20A, 20B, and 20C. Under Rule 20A, SCE pays 100% of the costs for undergrounding primarily from requests from cities, counties, and government agencies. Under Rule 20B, the costs for undergrounding are shared between SCE and the applicant. Typically SCE pays about 20% of the cost, while the applicant pays the remaining 80%. Rule 20B undergrounding projects generally occur when a developer of a new project needs to remove existing overhead lines, usually for aesthetic reasons. Under Rule 20C, the costs are paid entirely by the applicant. Rule 20C projects are typically requested by individual property owners wish to remove existing overhead lines.

5.7.1. Rule 20A Conversions

SCE forecasts that conditions will generally remain similar for requests for Rule 20A conversions from 2010 through 2014 at the same funding level as authorized by the Commission in the 2009 GRC at $29.507 million, plus escalation. For 2010, SCE forecast $30.050 million for Rule 20A expenditures, but actual recorded costs were $21.942 million.[305]

DRA claims that SCE continually overestimates the amount of Rule 20A funding it forecasts as necessary each year, and that Rule 20A expenditures are generally trending downward. DRA recommends using the 2010 actual amount of $21.942 million plus escalation for the 2011 and 2012 forecasts, which it calculates as $22.335 million and $22.871 million

305 JCE at 629.

respectively.[306] Using DRA's lower estimate would result in reductions of $8.259 million in 2011 and $8.461 million in 2012 to SCE's forecasts.

Based on annual underground conversion reports submitted to the Commission, SCE has consistently spent less than its allocations for Rule 20A undergrounding.[307] According to DRA, SCE had cumulatively spent $181 million less than its allocation from 1968 through 2007, and the underspend increased to $204 million through 2010.

The Commission is aware that SCE has committed to spend $161 million to complete Rule 20A undergrounding projects that it already started and which could take up to five years to complete. However, we are concerned that SCE consistently continues to spend less than authorized by the Commission for Rule 20A undergrounding conversions.

Undergrounding electrical systems have both safety-related and reliability advantages, besides aesthetical value. In order to encourage more underground conversions, we will grant SCE's request for funding for 2011 and 2012 at the 2009 level of $29.507 million plus escalation, which SCE calculates as $30.594 million in 2011 and $31.332 million in 2012. However, going forward we expect SCE to fully support conversion projects within the authorized funding for undergrounding conversions.

5.7.2. Rule 20B and 20C Conversions

Unlike Rule 20A where SCE pays for the entire undergrounding conversion project, under Rule 20B SCE only pays for an equivalent overhead

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306 DRA-6 at 45.

307 *Id*. at 46.

electrical system, which is roughly only 20% of the cost to underground. The applicant pays the remaining 80% of the cost to underground an electrical system. Typically, most entities that undertake Rule 20B projects are large developers who are required to underground their electrical lines because of local rules, laws, or requirements.

SCE forecast Rule 20B capital expenditures of $27.047 million for 2011 and $34.418 million for 2012.[308] SCE assumes that the cost per mile of installing underground cable would equal the 2009 recorded cost. To develop separate forecasts for Rule 20B and Rule 20C, SCE evaluated how costs had been split between the two categories in previous years. All of the amounts cited below for both Rule B and Rule C are combined to include SCE's share and the applicant's share of the costs for the undergrounding project.

SCE originally estimated Rule 20B expenditures for 2010 to be $25.830 million, but actual recorded expenditures were $15.078 million. DRA notes that SCE's recorded expenditure data shows a decline since 2008, with 2010 expenditures being particularly reduced. DRA recommends using the 2010 recorded level of $15.078 million, plus yearly escalation, as the forecast for 2011 and 2012, which would be $15.348 million in 2011 and $15.716 million in 2012.[309] This would result in decreases of $11.699 million in 2011 and $18.702 million in 2012 from SCE's forecasts for Rule 20B undergrounding projects.

For Rule 20C, the requesting applicant pays the entire cost of the project. Rule 20C projects generally occur when an individual property owner wishes to

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[308] SCE-18, Vol. 4, Pts. 1 & 2 at 1, Table I-1.

[309] DRA-5 at 45.

remove existing overhead lines, for aesthetical reasons, but also to improve safety and reliability concerns.

For 2010, SCE forecast $8.610 million, but actual recorded expenditures were only $5.259 million. SCE forecasts $9.016 million for 2011 and $11.473 million for 2012. DRA recommends using the 2010 recorded level of $5.259 million plus yearly escalation as the forecast of $5.353 million for 2011 and $5.482 million for 2012.

The total 2010-2012 SCE forecast for Rules 20B/C expenditures is $116.394 million including SCE's share and the applicant's share. DRA's corresponding 2010-2012 total recommendation is $62.236 million, with reductions of $14.103 million in 2010, $15.362 million in 2011, and $24.693 million in 2012.

For 2010, SCE lists 18 projects, of which 16 are distribution lines throughout its service territory and two small projects for about $203,000 related to telecommunications. DRA excluded these small telecommunication projects and made other reductions.

We find that underground conversion projects are likely in a downward trend due in part to the economy, but SCE has a pattern of forecasting more than it spends for Rule 20B and Rule 20C projects. Most recently, in 2010, SCE spent only about 60% of what it forecast. However, we find DRA's proposed reduction to be excessive. SCE has long-term projects underway and the demand for undergrounding remains, even if the pace of new projects continues to slow.

Accordingly, the Commission finds it reasonable to reduce SCE's forecast for Rule 20B and Rule 20C expenditures in 2011 and 2012 by 40%. This outcome reflects both the shortcomings of its most recent forecasts, and also that SCE has projects in progress that it needs to complete.

The result for Rule 20B projects is $16.228 million in 2011 and $20.651 million in 2012. For Rule 20C projects, the approved forecast is $5.410 million for 2011 and $6.884 million for 2012. The Commission accepts as reasonable SCE's 2010 recorded costs of $15.078 million and $5.259 million for Rule 20B and Rule 20C projects, respectively.

We find that authorizing a portion of DRA's recommended reductions to Rule 20B and Rule 20C undergrounding should in no way discourage applicants from pursuing undergrounding projects. We encourage the growth in undergrounding utility lines and the conversion to underground of utility lines where appropriate.

5.7.3. Distribution Relocations

Each year, local governmental agencies require SCE to relocate portions of its distribution facilities located along public rights-of-way. Sometimes the requests follow the capital budgeting process of local cities and other times it is the result of local agencies requiring developers to widen frontage streets as a condition of future property development. Individual customers also make relocation requests associated with remodeling or expansion.[310]

SCE forecasts $31.994, $32.567, and $33.348 million ($nominal) in capital spending each year from 2010 to 2012 based on escalated 2009 authorized expenditures.[311] Historic expenditures in this category have generally fluctuated between $30 million and $40 million, and SCE asserts that it expects requests for relocations to continue at about the same rate (excluding the anomalous

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310 SCE-03, Vol. 4, Pts. 1 & 2 at 52.

311 *Id*. at 53.

2008 spending level). We agree that historic capital spending for this activity has been somewhat stable. Therefore, the Commission finds reasonable and adopts SCE's 2010 recorded and the 2011 and 2012 forecast capital spending of $32.567 and $33.348 million for 2011 and 2012.

5.7.4. Distribution Added Facilities

Pursuant to tariff Rule 2.H, at the customer's request, SCE provides added facilities materials and equipment for additional reliability enhancements, beyond-the-meter services, requests for service at higher voltage levels and to interconnect customer-owned generation to our distribution system. We briefly discussed this matter above in connection with comments from the POLB.[312]

Typical added facilities projects for the distribution system include:

- Subtransmission metered service
- Primary metered service – Distribution
- Automatic Preferred Emergency services

Added Facilities can be financed by the customer or by the Company. SCE charges a monthly fee for Added Facilities based on the total installed cost of the equipment multiplied by the applicable monthly rate. If the project is customer financed, the equipment is deeded to SCE, and the customer pays the applicable federal and state taxes for the contributions in aid of construction. For both financing options, the impact to the capital budget is identical. Revenues from these projects are treated as "Other Operating Revenue" and recorded in subaccounts 454.300 and 456.700.

[312] *See*, Section 5.1.3.

SCE forecasts capital spending of $8.264, $8.567, and $8.773 million ($2009 constant) annually for 2010 through 2012 for Distribution Added Facilities. The forecast is equivalent to 2009 recorded spending. According to SCE, capital spending in the last three years, 2007– 2009, has been very close to $8.3 million in constant dollar terms. SCE expects that spending during the forecast period will be similar to these recent recorded years. No party recommended any changes to SCE's forecast.

The Commission finds reasonable and adopts 2010 recorded spending, and the 2011 and 2012 forecast of $8.567 million and $8.773 million, respectively for 2011 and 2012.

5.7.5. Customer Growth and Meter Sets

According to SCE, new residential, commercial, and agricultural customers will be added to SCE's electrical network system. SCE bases its forecast of customer growth on the meter forecast, which is an indicator of customer growth as well as the associated facilities. SCE states it had 4.99 million residential and non-residential customers as of 2009 and expects to grow by 4.5% through 2014 to 5.2 million. Approximately 82% of the growth is estimated to occur in residential customers.[313] The historical data shows that the rate of SCE's customer growth has generally been declining since 2005, with the exception of a slight bump in 2009 of 17,463 new customers (+0.36%).

For its forecasts, SCE primarily relies on a ratio to forecast building permits. In this GRC, SCE has modified its forecasting methodology for 2010-2014 to take into account operational factors such as the lead times when

313 DRA-10 at 11, Table 10-6.

facilities need to be constructed to support the new meters in addition to the forecast number of meters to be installed. DRA accepts SCE's forecast for sales and customer growth, and not proposed any changes to SCE's capital forecasts. TURN accepts SCE's revised methodology for forecasting expenditures to include the lead times between different work categories, but has proposed adjustments based on its own revised forecasts for building permits and new meter sets.[314] TURN asserts that SCE's forecast does not reflect the economic realities of lower growth arising from lingering economic effects of the recession in SCE's territory.

According to TURN, the actual number of meter sets for 2010 and the first half of 2011 were lower than SCE's forecast: SCE forecast 22,324 meter sets in 2010, but the actual number was 19,146; SCE forecast 12,143 meter sets in the first six months of 2011, and the actual meter sets were 6,475. TURN recommends using its calculated average of the TURN base and low cases rather than SCE's higher forecasts. Both are based on actual meter sets in 2010, but the "low" case assumes a six-month lag due to continuing economic weakness.[315] Depending on use of the "base" case or "low" case, from 2010-2012, TURN is forecasting about 25-28% fewer residential meters than SCE forecasts, and 20% fewer non-residential meters than forecast by SCE.

SCE criticizes TURN's calculations as based on erroneous methodology, however, we are not persuaded that TURN's results are flawed.[316] In rebuttal, SCE explained its forecast of meter counts is unaffected by the lower number of

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[314] SCE-18, Vol. 4, Pts. 1 & 2 at 8, Table I-5.

[315] TURN-3 at 46.

[316] SCE-25 at 16-18.

building permits because an additional source of meter connections is from the "resale of foreclosed homes."[317] Meter counts may also include conversion of single family dwellings to multi-family units and connections to a remodeled dwelling, claims SCE.

SCE is not able to adequately explain its new meter forecast and provided inconsistent testimony at hearing. After claiming that foreclosures comprised a significant part of its new meter forecast, later testimony confirmed that not only did SCE not identify foreclosure work orders, SCE did not use foreclosures as a factor in its model.[318]

The Commission finds that SCE did not sufficiently estimate the longer term effects of the economy on growth within its territory. We agree there will likely be customer growth during the rate cycle. TURN's base case forecast appears the most reasonable and we adopt it.[319]

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317 TR at 1442.

318 TR at 1490-1496.

319 SCE and TURN appear to agree on SCE's forecast of 360 new Agricultural meters per year.

Residential and Non-Residential Meter Set Forecast TURN Base Case Comparison						
Year	SCE Residential	TURN Residential	% Difference	SCE Non-Residential	TURN Non-Residential	% Difference
2010	22,324	19,146	14.2	7,115	6,109	14.1
2011	28,215	19,863	29.6	6,953	5,639	18.9
2012	38,591	28,063	27.3	7,443	5,494	26.2
2013	46,853	41,056	12.4	8,627	6,336	26.6
2014	49,732	47,746	9.6	9,869	8,053	18.4
Total	**185,715**	**155,874**	**16.1%**	**40,087**	**31,631**	**21.1%**

5.7.6. Customer Growth Expenditure Summary in 2011 and 2012

SCE forecasts customer growth-related expenditures in 10 work categories, excluding new legacy meter costs, totaling $114.337 million in 2011 and $153.300 million in 2012.[320] Total meter-related recorded expenditures for 2010 are $101.208 million, but SCE seeks approval of $108.293 million and TURN recommends $93.595 million.[321] The categories include four related to residential services, three to commercial services, two for agricultural services, and one related to street lighting.[322] For 2011-2012, both Street Lighting and Agricultural customer growth expenditures are not disputed.

TURN provided recommendations for line connection capital spending related to the number of new meter sets for each category which generally substitute TURN's new meter forecasts into SCE's calculations. TURN

[320] SCE-18, Vol. 04, Pts. 1 & 2 at 7, Table I-4.

[321] JCE at 871-872 (Excludes new meter costs identified at 872.)

[322] SCE-18, Vol. 04, Pts. 1 & 2 at 7, Table I-4.

recommends $95.847million in expenditures for all ten categories in 2011 and $106.448 million in 2012 as a result of utilizing its "base case" revised forecast for new meter sets.[323] For all categories combined (excluding new legacy meter costs), TURN proposes a reduction of $72.06 million (19.3%) to SCE's 2010-2012 request.

The Commission finds reasonable and adopts SCE's recorded 2010 expenditures of $101.208 for these work categories. The Commission also finds reasonable and adopts SCE's uncontested 2011-2012 forecasts for Street Lighting ($5.287 million in 2011 and $5.414 million in 2012) and Agricultural customers ($2.233 million in 2011 and $2.287 million in 2012). For all other work categories, the Commission finds reasonable and adopts TURN's "base case" recommendations, resulting in an aggregate total of $95.847 million and $106.855 million, respectively.[324] These latter recommendations reflect the lower number of new meter sets in TURN's "base case" adopted in Section 5.7.3 and exclude new meter costs.

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[323] *Id*. at 8, Table I-5.

[324] JCE at 870-878.

Summary of Contested Capital Expenditures Related to New Meter Sets and Service Connections* ($nominal 000's)					
	SCE 2011	**SCE 2012**	**TURN 2011 (base case)**	**TURN 2012 (base case)**	**Difference**
All Residential	$55,442	$89,603	$45,868	$56,855	$42,322
All Commercial	51,175	55,998	44,691	44,587	17,895
Street Lighting*	5,287	5,414	5,287	5,414	----
Total	$111,904	$151,015	$95,846	$106,856	$60,217

* Street Lighting costs are included because TURN's base case would affect totals in later years. These amounts are from the JCE at 871, less actual meter costs, because meter costs are included in CSBU capital spending in Section 6.5.4 (JCE at 872). The undisputed Agricultural connection costs are also omitted.

5.8. T&D Inspection and Maintenance

This organization is responsible for all inspection and maintenance work on SCE's electric distribution system, much of which is capitalized. Most of the work is performed according to the Distribution Inspection and Maintenance Program (DIMP) which SCE developed with the Commission's Consumer Protection and Safety Division (CPSD) pursuant to D.04-04-065.[325] In that decision, the Commission directed SCE, among other things, to refine its maintenance priority system in order to concentrate resources on appropriately prioritized conditions.

Pursuant to DIMP, SCE undertakes a company-wide program to inspect and maintain its distribution system in accord with GO 165, which sets maximum inspection frequency for all electric distribution facilities.[326] The basic

[325] Issued in Order Instituting Investigation 01-08-029 (Maintenance OII).

[326] GO 165 at Appendix A.

premise of GO 165 is that all distribution assets must be patrolled frequently for safety and reliability risks. Other than wood poles, which are subject to a twenty-year inspection interval after an intrusive inspection, assets must have a detailed inspection every three or five years, depending on the asset and whether it is in an urban or rural location.

SCE's program was deployed in 2008 with a backlog of 62,852 maintenance items, according to SCE's 2010 Annual Report on Distribution Inspection required by GO 165 (2010 Annual Report).[327] SCE's Inspection and Maintenance costs increased from 2007 due to implementation of DIMP, where identified items are prioritized for repair generally within 24 months or less. Beginning in 2008, SCE also converted its previous inspection data to a new three-priority system based on the criteria of safety/reliability and violations of GO 95[328] (overhead lines) and GO 128[329] (underground facilities). Wood pole inspection data was not converted to the three-priority system until 2011.[330]

Beginning in 2009, SCE modified its inspection routine. It started completing all identified maintenance items at a structure whenever a qualified worker is performing scheduled work on that structure, irrespective of the item's due date. In the 2010 Annual Report, SCE also reported that in the last GRC, it had substantially underestimated corrective actions to be taken in 2010 by 263%, and still had not completed all of the scheduled corrective actions.

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327 SCE's 2010 Annual Report on Distribution Inspection Required by GO 165 (2010 Annual Report), filed in R.96-11-004 on July 1, 2011 at 4.

328 GO 95 establishes requirements for construction of overhead lines.

329 GO 128 establishes construction requirements for underground electric supply and communication facilities.

330 2010 Annual Report at 8.

However, SCE reported that it would clear the backlog of corrective actions by the end of 2011.[331]

The Commission considers the following expense categories to have substantial safety implications if adequate inspection and maintenance is not appropriately funded. Therefore, where evidence suggested a close judgment call, we have generally leaned towards the utility's evidence in establishing the reasonable amount of funding. However, we have also directed SCE to provide follow-up information in the next GRC to assist the Commission and the pubic in better evaluating the scope and effectiveness of these programs.

5.8.1. O&M Expenses: 583.120, 584.120, 593.120, 594.120

SCE forecasts $108.289 million for additional inspection and maintenance O&M expenses in TY2012 based on 2009 recorded adjusted expenses in four subaccounts, plus incremental expenses for proposed projects and work activities. Based solely on average recorded costs, DRA forecasts $98.281 million, a $10.008 million reduction affecting four programs and subaccounts. DRA accepts as reasonable SCE's forecasts for overhead detail inspections and annual patrols. TURN proposes reductions to SCE's vegetation management forecast as discussed below.

5.8.1.1. Wood Pole Intrusive Inspections: Portions of 583.120

The objective of this program is to identify and measure the extent of internal decay within wood poles that could jeopardize structural integrity. Pursuant to GO 165 inspection standards set in 1997, intrusive inspections must

[331] *Id*. at 10.

occur every 10 years for poles 15 years old or older, and every 20 years for all poles previously inspected. SCE completed its first cycle of inspections in 2007. Few inspections were done in 2007 and 2008 before SCE launched its second inspection cycle. In SCE's 2009 GRC, the Commission found SCE's forecast of 130,000 intrusive inspections per year to be excessive, and reduced forecast expenditures 17% to $4.175 million for TY2009.[332] Also in 2009, SCE transitioned to what it claims is a less costly grid-based inspection method and states it performed 152,000 inspections.

Going forward, SCE again forecasts 130,000 inspections per year, based on a levelized approach to performing the inspections consistent with a ten-year inspection cycle for 1.34 million distribution poles. SCE seeks to conform with other utilities which follow a 10-year inspection cycle for their poles. CCUE supports SCE's inspection plan and test year forecast of $5.533 million for the inspections, which are primarily done by contractors. To develop its forecast, SCE used 2009 recorded cost-per-inspection adjusted for pre-test year contract negotiations.

DRA recommends $3.939 million for 2012, based on a five-year average (2005-2009) of fluctuating expenses for this activity, which translates into about 77,327 inspections per year. DRA argues that SCE's proposed inspection count is unrealistic and asserts that SCE combined its inspections with corrections to give the appearance of more inspections than actually performed. DRA objects that SCE's projections do not follow the intrusive inspection schedule set forth in

[332] D.09-03-025 at 84.

GO 165, which requires only about 65,650 per year, nor do they match what SCE has been doing over the last five years.[333]

SCE criticizes DRA's approach as flawed because it does not reflect the actual number of inspections performed nor SCE's transition to grid-based inspections on a ten-year cycle. SCE established why its costs varied widely during 2005-2009, showing that DRA's reliance on a five-year historical average is not reasonable here. We agree that SCE should move toward a ten-year inspection cycle for all poles and that SCE's method of cost-per-pole multiplied by the number of inspections produces a more accurate forecast.

However, SCE's claim that the grid-approach is less costly is not clearly established where the projected cost per inspection in 2012 is higher than in four of the last seven years, including 2010 and 2011.[334] SCE's evidence also did not clearly demonstrate that its projected increase in the annual number of intrusive inspections is realistic. Although SCE claims it performed well over 130,000 intrusive inspections in 2009 and 2010, these figures do not all represent intrusive inspections. For example, in 2009 the total includes "record corrections"[335] and in 2010 the total is a combination of visual and intrusive inspections. SCE reported that it actually intrusively inspected only 86.4% of the total 140,755 inspections it reported in 2010.[336] The cost of a visual inspection is much less than an intrusive inspection which involves a trained inspector

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[333] *Ibid*.

[334] SCE-03, Vol. 04, Pts. 1 & 2 at 79, Figure II-38.

[335] SCE's 2009 Annual Report on Distribution Inspection Required by GO 165 filed in R.96-11-004 on July 1, 2010 at 7.

[336] 2010 Annual Report at 6, and Attachment A.

drilling a hole into the pole. SCE did not distinguish between these inspections in its GRC testimony. Furthermore, SCE's accelerated inspections in 2010 resulted in only tiny fraction of poles needing prompt corrective action.[337]

SCE did not establish its ability to undertake intrusive inspections of 130,000 wood poles per year during this rate cycle. However, we are concerned to the degree that some poles in SCE's service territory, particularly jointly-owned poles, may, unknown to SCE, be overloaded. Overloaded poles may break and thereby contribute to increased fire and other hazards. In R.08-11-005, the Commission addressed fire safety hazards relative to pole loading, and set new safety requirements for any utility planning a material increase in load in high fire areas. Several of SCE's poles also toppled in heavy windstorms late 2011, although the cause is still unknown.

Absent the pole loading matter, we would reduce SCE's 2012 forecast to $4.780 million, equivalent to 86.4% of SCE's forecast, which is comparable to the inspections performed in 2010, and reflects a total of 112,320 intrusive inspections per year. Instead, we adopt SCE's forecast but direct SCE to initiate an assessment of pole loads in its territory, as set forth below.

SCE shall use up to $0.753 million, the remainder of its request, to perform full inspections of a statistically valid random sample of loaded poles, utility-owned and jointly-owned, to determine whether the loads meet current legal standards. To the extent that the Commission orders, through any other proceeding, an examination of pole loads within SCE's territory, the study ordered here shall be coordinated to avoid duplication. Any unspent funds must

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[337] *Id.*

be used for intrusive pole inspections unless the Commission is notified to the contrary by a Tier 2 Advice Letter.

SCE shall serve the summary results of the study on the service lists of the GRC and R.08-11-005, and provide the pole-by-pole results to the Director of CPSD, no later than July 31, 2013. The results should also be included in SCE's next DIMP annual report. Following receipt of the study results, CPSD shall make recommendations to the Commission about what steps, if any, are necessary to assure that SCE's poles are not overloaded going forward.

Therefore, the Commission finds reasonable and adopts a TY2012 forecast of $5.533 million for intrusive wood pole inspections, inclusive of performing the study as described. In addition, we direct SCE to provide in the next GRC information about how many priority 1, 2, and 3 conditions were identified by the actual number of intrusive inspections performed in 2012 and 2013 so that the Commission may evaluate the utility of an accelerated inspection program.

5.8.1.2. Underground Detail Inspections: 584.120

An underground detail inspection is done by specially trained employees who remove water from structures, monitor oxygen levels, and perform infrared heat testing and corrosion evaluation. SCE forecasts a cost of $1.687 million to perform 152,886 underground detail inspections in 2012 in order to conform to DIMP and GO 165,[338] a 14.45% increase over 2009 recorded adjusted expenses of $1.474 million. The estimated 2012 O&M expense is based on the 2009 unit cost per inspection and the average number of inspections SCE claims are due between 2012 and 2014.

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[338] GO 165 requires detail inspections of underground equipment and facilities every three or five years.

DRA recommends the Commission adopt $1.474 million, 2009 recorded expenses, because SCE's expenses have declined every year from 2005 to 2009. DRA reasons that SCE's costs should continue to decline or remain at 2009 levels and argues that SCE's claim it will perform more inspections is not supported by the record. Therefore, DRA concludes that costs for the same "major activities" performed before are already embedded in 2009 recorded expenses.[339]

SCE argues that DRA ignores the increased number of detail inspections that must occur from 2009 to 2012 and calculates that if the DRA forecast is adopted, SCE will perform 20,000 fewer inspections than required by GO 165.[340] SCE explained its declining labor costs before 2009 as resulting from fewer inspections and an accounting change where certain costs are no longer recorded in this subaccount. SCE has also captured in 2009 recorded costs, its significantly lower cost per inspection (although it is not clear how much of that is a result of re-allocated labor costs). Therefore, we find SCE's reliance on 2009 a reasonable basis to estimate future costs. On the other hand, SCE has not sufficiently justified its forecast of a nearly 15% increase in inspections per year.

SCE cites to testimony and workpapers to support the increase from 2009 to 2012.[341] However, a review of the cited authorities does not reveal the basis for any actual total number of inspections required during the various cycles, nor provide any distinction between vaults and pieces of equipment, nor between visual and detail inspections. Therefore, we are unable to evaluate how or why the number of "detail" inspections is forecast to grow by 15%. For

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339 DRA-05 at 21-22.

340 SCE-18, Vol. 04, Pts. 1 & 2 at 16.

341 *Id*. at fn. 25.

example, SCE reported 426,963 detail inspections 2007-2009 and proposes 471,312 between 2010 and 2012, yet it is unknown how it quantified the number of estimated inspections as a derivative of total items to be inspected over the one, two, three, and five-year cycles of patrol and detail inspections.

Accordingly, SCE's request for an additional $213,000 for 2012 is not justified. Instead we adopt the average number of inspections performed between 2007 and 2009 (142,321 per year), multiplied by $11 per inspection, to arrive at an estimated expense of $1.566 million for 2012, a reduction to SCE's forecast of $121,000.

5.8.1.3. Vegetation Management: Portion of 593.120

As part of its fire-prevention rulemaking, the Commission declared, "The failure to keep power lines clear of vegetation poses a serious threat to service reliability and public safety."[342] Vegetation management includes all expenses associated with tree trimming, tree removal, and weed abatement in proximity to high voltage distribution lines in order to comply with GO 95 and Public Resources Code Sections 4292-4293. Most of the costs are from a fixed price contract with a contractor responsible for 1.4 million trees throughout SCE's service territory.

SCE forecasts $52.934 million for 2012, $10.10 million of which is for high fire area costs. The total is an increase of $9.108 million over 2009 recorded expenses due to new requirements adopted by the Commission that require more clearance in Very High Fire (VHF)[343] areas. SCE has been recording VHF

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[342] D.09-08-029 at 166, Finding of Fact (FoF) 9.

[343] D.09-08-029 (Fire Safety Order Instituting Rulemaking 08-11-005) at 24.

area costs in a memorandum account (FHPMA) but is now asking to have these costs included in base rates as on-going cost of service.

DRA recommends $47.274 million, a reduction of $5.660 million, based on 2009 recorded expenses and an assessment of partial 2010 expenses for VHF area work. Furthermore, DRA recommends that SCE record all of its vegetation management costs, including VHF area costs, in a one-way balancing account in the test year. DRA points out that SCE's costs have fluctuated in prior years, averaging $37.626 million per year during 2005-2008, but increasing to $43.826 million in 2009. That increase supports DRA's view that 2009 recorded costs include embedded costs associated with VHF areas. DRA also expressed concern that SCE did not provide a detailed breakdown of specific expenses it incurred in 2009 to permit the Commission to evaluate whether VHF area costs were properly recorded in the FHPMA.

TURN recommends a $5.1 million reduction for high fire area tree trimming based on its estimate that 84,000 trees will need a second trim annually. Despite SCE's use of several different numbers of trees located in high fire zones, only 11% of total trees in SCE's service territory are in VHF areas and subject to the new clearance requirements.[344] TURN concurs with DRA that costs for routine clearing of the vast majority of trees in the high fire zones are included in existing costs. TURN contends that SCE has created an unnecessarily expensive plan where VHF crews engage in duplicate work after regular crews have passed through the territory. Moreover, TURN concludes it is implausible that trimming 11% more trees requires 25% more funding.

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[344] The areas affected by increased clearances from the Fire Safety OIR, R.08-11-005.

We agree with SCE that it has additional work in high fire areas, particularly VHF areas, that was not included in 2009 expenses. SCE has supported its funding forecast for vegetation management, established error in DRA's analysis of excluded costs from its forecast, and rebutted DRA's suggestions that SCE seeks double recovery of 2012 expenses and should establish a one-way balancing account for these expenses. In support of its forecast, SCE provided evidence that cost per trim in high fire areas is higher due to more tree removals and overhang removals in high fire areas, along with mid-cycle trims. SCE also had to add trained personnel to comply with the Commission's new requirements.

We decline to eliminate the FHPMA as requested. In D.09-08-029, the Commission ordered each electric utility to record authorized costs in its FHPMA which would be subject to a reasonableness review in a subsequent application. In Phase 2 of the rulemaking, the Commission directed SCE to seek approval of 2012 expenses in its 2012 GRC, and declared that the FHPMA would remain open until the first GRC after the rulemaking proceeding is closed.[345]

Accordingly, the Commission adopts and finds reasonable SCE's forecast of $52.934 million for TY2012 O&M expenses.

5.8.1.3.1. Preventive Maintenance: Portion of 593.120

SCE forecasts $39.712 million for preventive maintenance recorded in subaccount 593.120 in TY2012. Funded activities include repair and replacement of equipment, primarily arising from DIMP inspection programs, but also from items identified during the normal course of business. SCE developed its

[345] D.12-01-032 at 153-154. (The rulemaking is still open for Phase 3.)

forecast using 2009 recorded adjusted expenses, increased to reflect an average of additional preventive maintenance items it expects to complete from 2012 to 2014, a total of 16,500 more repairs than in 2009.[346]

DRA forecasts $37.710 million, using SCE's 2009 recorded adjusted expenses, based on DRA's view that 2009 reflects the first full year under the DIMP program and includes costs for all major activities to be performed in 2012. DRA assumes that adequate funds are embedded for future preventive repairs.

We disagree with DRA that sole reliance on 2009 recorded adjusted costs is reasonable to forecast 2012 costs for this program because 2009 was only the first full year of inspections. Not only did SCE modify its repair program to identify repair items early if otherwise inspecting or repairing an asset, DIMP and GO 165 require some assets to have detailed inspections every five years. Thus, it is not unreasonable for SCE to forecast a modest increase in preventive maintenance in 2012 arising from more inspections and more repairs. However, we expect that these expenses will level out or may begin to decline during this rate cycle as a result of the robust preventive efforts of SCE.

Therefore, the Commission finds reasonable and adopts SCE's forecast of $39.712 million for 2012.

5.8.1.4. Distribution Apparatus: 594.120

Distribution apparatus expenses are recorded for inspecting, testing, and maintenance of overhead and underground distribution apparatus which control power and determine when to switch power. SCE forecast $4.031 million for these activities, a 15% increase over 2009, based on a five-year average unit repair

[346] SCE-03, Vol. 04, Pts. 1 & 2 at 84.

cost and estimated 2012 inspections, adjusted to account for forecast new equipment.

DRA recommends adopting SCE's 2009 recorded adjusted level of $3.492 million, a $0.539 million reduction to SCE's estimate. DRA points to SCE's statement that the program which "remained the same from 2005-2009" will continue to require no additional funding.[347] SCE was persuasive that DRA had misunderstood its testimony, and the scope of the program would expand to include more inspections as required to comply with DIMP. Yet, SCE does little more than say it has calculated a number of estimated inspections and then points to the number as evidence.

We agree that the requirements of DIMP and GO 165 require inspections at regular intervals. The result is that the full expenses of an inspection cycle may not be fully seen until a five-year cycle has been completed. Given that the DIMP was initiated during 2008, it is reasonable to assume that there will be some additional costs in 2012 as the first five-year cycle is continued. SCE's proposed 15% increase is less than the 17% increase from 2008 to 2009, and the test year amount requested is less than 2006 recorded costs. We find SCE's forecast reasonable and adopt it. However, we note that SCE's completion of its first inspection cycle and grid approach to inspections should result in a leveling off of inspection costs after 2014.

5.8.2. Inspection and Maintenance – Capital Request

These capital expenditures are the inspection driven replacement of major pieces of equipment, such as poles, transformers, switches, and underground

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[347] DRA-05 at 32 (citing SCE-03. Vol. 04, Pts. 1 & 2 at 77).

structures, for which the replacement qualifies for capitalization and incorporation into rate base.

SCE forecasts approximately $1.2 billion for capital expenditures 2010-2014 which it estimates will be necessary pursuant to the results of DIMP and GO 165-required inspections. Some of the capital expenditure categories identified in this section may have safety implications should the equipment fail-in-service. Therefore, the Commission strives to determine a reasonable amount of funding, supported by the record, to enable SCE to execute its preventive replacement program at an appropriate pace.

For all such activities, SCE forecasts capital expenditures of $220.703 million in 2011 and $246.613 million in 2012.[348] SCE's total recorded costs for capital expenditures have previously fluctuated annually including a high of $236.504 million in 2006 and a low of $176.040 million in 2007.[349] Total recorded, adjusted expenditures in 2009 were $203.185 million.[350]

DRA recommends a total of $155.096 million ($nominal) in 2011, and $159.021 million in 2012, resulting in a $153.199 million decrease to SCE's 2011-2012 forecasts. TURN supports DRA's recommended reduction for one program described below.

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348 SCE-18, Vol. 04, Pts. 1 & 2 at 27, Table II-13.

349 *Ibid*. (DRA used slightly different figures in DRA-7 at 23, Table 7-4 using $2009 rather than $nominal).

350 *Ibid*.

5.8.2.1. Capital Preventive Maintenance Forecast

Capital Preventive Maintenance program consists of asset based preventive maintenance, transformer bank replacement, and underground structure replacement sub-programs.

SCE forecast zero additional funding for transformer bank replacement in 2011-2012. For the other two areas combined, SCE forecast $120.448 million ($nominal) in 2011 and $134.485 million for 2012. SCE generally projected out the number of replacement units for the years 2010-2014 and multiplied the replacement units by the five-year average price to install each replacement unit.

DRA recommends $97.777 million in 2011 and $100.120 million in 2012, a total reduction of $57.036 million. TURN agrees with DRA's $43.860 million reduction for 2011-2012 Asset Based Preventive Maintenance.

5.8.2.1.1. Asset Based Preventive Maintenance

SCE forecasts capital expenditures of $110.361 million ($nominal) in 2011 and $119.730 million in 2012 for asset based preventive maintenance in four categories, driven mostly by regulatory requirements. SCE developed its forecast based on historical analysis and estimated work volume derived from increasing system size and increasing system age. The replacement forecasts are calculated based on the number of units in the asset base by the "inspection-driven replacement rate."[351] Unit replacement costs are a five-year average. SCE's actual recorded adjusted costs for 2010 were $90.387 million.

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[351] SCE-03, Vol. 04, Pts. 1 & 2 at 91.

TURN agrees with DRA's proposed total reduction of $43.860 million for 2011-2012 ($92.013 million in 2011 and $94.218 million in 2012).[352] DRA developed its own estimate of replacement units and applied unit costs from 2009 recorded data. DRA found that SCE's replacement costs decreased in 2008 and 2009, making LRY more reliable as a basis for unit replacement cost, and consistent with SCE's use of LRY for breakdown maintenance replacement costs. DRA shows that underground cable replacement miles have been decreasing since 2006, yet SCE forecasts growth during 2010-2012.[353] TURN agrees with DRA's cable replacement forecast.

SCE persuasively explained its statistical forecast methods, including for cable replacement volumes. SCE also identified changes to charging practices to support its use of average unit costs. SCE's overriding argument is that capital replacement expenditures will increase as SCE continues to replace its growing and aging infrastructure. The biggest difference between SCE and DRA forecasts is for replacement of overhead transformers ($30.142 million 2010-2012). SCE replaced eight overhead transformers in 2010, so it is reasonable to assume that it will likely replace eight in 2011 and 2012, rather than the seven DRA estimates.

We agree there will likely be increases in inspection-driven repairs through 2012. When combined with SCE's claims it has integrated inspections with routine maintenance, it is reasonable to assume that during 2008-2012, the utility may experience an increase in required replacements. By its sole reliance on historical recorded costs, DRA fails to factor in changes to SCE's inspections program likely to yield an increase in identified replacement items during the

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352 SCE-18, Vol. 04, Pts. 1 & 2 at 29, Tables II-14 and II-15.

353 DRA-07 at 27, Graph 7-2.

current inspection cycle. We expect these costs to begin to level out as SCE experiences a complete five-year cycle with the new routine of integrated inspections.

Accordingly, the Commission adopts as reasonable SCE's 2010 recorded adjusted expenditures of $100.084 million ($nominal), and SCE's forecast 2011 and 2012 expenditures. In the next GRC, SCE shall include with any request for additional funding of this program, a description of how many replacements were performed annually after 2010, the number of new replacements identified, and the number, priority, and estimated cost of backlog replacement projects, if any.

5.8.2.1.2. Underground Structure Replacement

Beginning in 2009, SCE began using a new process to identify, track and evaluate underground structures and now projects large increases in its "ramped up" underground structure replacement program.[354] SCE's historic expenditures range in amount from $82,000 in 2007 to $2.8 million in 2009. In 2010, SCE projected capital expense for underground structure replacement of $8.9 million but actually spent $5.6 million.[355] For 2012, SCE forecasts about $14.8 million in additional replacement costs.

SCE forecasts replacement of 217 underground structures from 2010 to 2014 based on identified vaults not yet replaced, new inspections in 2010-2011, expected inspection failure rates, and a 2009 recorded replacement cost of $2.78 million. SCE expects a reduced failure rate by 2012 at the same time it

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[354] *Id*. at 92.

[355] DRA-7 at 30.

expects the number of structures replaced in a year to grow to 50; 10 were replaced in 2009.[356]

DRA recommends $5.764 million ($nominal) for 2011 and $5.902 million 2012, based on 2010 recorded costs and SCE's estimate that it will identify 20 vaults that need replacement in 2012.[357] For the period 2010-2012, DRA points out that SCE is asking for a number that is six and a half times greater than the previous five years' capital expense, too much for a brand new program without sufficient justification. SCE presented evidence that DRA's forecast does not account for previously identified vaults needing replacement. On the other hand, we note that SCE has not supported the estimated large increase in the number of replacements, nor explained a doubling of the inspection failure rate during 2010.

We accept that SCE's replacement backlog exists but do not find adequate support for SCE's bold replacement schedule, particularly given its lack of spending in 2009 and 2010. Instead, we find 2010 recorded costs of $5.521 million to be reasonable, and a forecast of $9.730 million for each year 2011 and 2012, which is sufficient for SCE to replace 37 vaults per year and resolve the backlog by 2015.

In the next GRC, SCE shall include with any request for additional funding of this program, a description of how many replacements were performed annually after 2010, the number of new replacements identified, and the number, priority, and estimated cost of backlog replacement projects, if any.

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[356] SCE-18, Vol. 4, Pts. 1 & 2 at 33.

[357] *Id*. at 31, fn. 58.

5.8.2.2. Wood Pole Replacements

Pole repairs and replacements are prioritized for repair or replacement based on safety significance and to meet the strength requirements of GO 95. Poles are identified for replacement from inspections and a variety of other sources.

Based on recorded 2010 costs of $91.404 million, SCE seeks to spend a total of $309.213 million over the 2010-2012 period for replacement of deteriorated distribution wood poles.[358] SCE forecasts expenditures of $101.345 million in 2011 and $116.464 million in 2012 to replace 7,857 and 8,818 wood poles per year, respectively. SCE expects the replacement cost to remain constant at $12,440 per pole, adjusted for inflation.[359] For this second ten-year inspection cycle, SCE based its replacement forecast on lower pole rejection rates than it applied in the last GRC.[360] CCUE supports SCE's forecast and accelerated replacement schedule.

DRA forecasts $59.202 million in replacement costs for 2011 and $60.621 million in 2012, approximately $98 million (45%) less than SCE's 2011-2012 forecast. DRA based its estimate on a five-year historical average number of annual intrusive inspections (77,327), multiplied by SCE's 3.3% second cycle failure rate (2,552), plus SCE's expected replacements from

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[358] SCE-03, Vol. 4, Pts. 1 & 2 at 95; SCE-18, Vol. 4, Pts. 1 & 2 at 37 (SCE forecast replacement of 5,082 poles in 2010, but actually replaced 6,768.)

[359] *Id.*, Table II-28.

[360] DRA-7 at 33. (During the first cycle (1998-2007), SCE experienced a failure rate of 7.7% (for every 1,000 poles inspected, SCE needed to replace 77 poles). SCE's experience during the second cycle (2008-2017) is that it is failing only 3.3% of the poles).

2010 inspections and other replacement requests (2,148), and multiplied the total by SCE's 2009 average cost of $12,150 for installing a pole. DRA continues its objections to SCE' accelerated inspection program and instead forecasts SCE replacing 4,700 poles per year. This is less than half of SCE's yearly average of 10,884 replacements between 2005 and 2009, and less than half of SCE's forecast for 2011 and 2012.

DRA's recommendation is too low. It is not reasonable to use a five-year average of intrusive inspections that spans two inspection cycles, nor to develop a forecast that does not account for SCE's backlog of poles already pending replacement in a three-year cycle. SCE also presented evidence that DRA's use of the 3.3% failure rate is inapplicable to previously repaired poles, which have a 28% failure rate, although SCE did not separately quantify this portion of the forecast.

Although SCE did not clearly demonstrate it could conduct all forecast inspections, wood pole replacements are also identified from other sources. In addition, the Commission directed SCE, elsewhere in this decision, to undertake a survey to determine what portion of its poles may be overloaded and in need of replacement.

Accordingly, the Commission finds reasonable and adopts SCE's forecasts for 2011 and 2012 wood pole replacements.

5.8.2.3. Joint Pole Credits and Wood Pole Disposal

SCE sometimes receives Joint Pole Credits when installing a new or replacement wood pole where SCE receives payments from other utilities that use the poles. SCE also pays the cost to dispose of the removed wood poles. This category offsets disposal costs with the joint pole credits.

SCE recorded Joint Pole Credits of $9.285 million in 2010, and forecasts $11.835 million in 2011, and $15.501 million in 2012. The forecast is driven by the expected number of pole replacements. Based on its estimate of far fewer wood pole inspections, DRA recommends Joint Pole Credits of $8.557 million in 2011 and $8.555 million in 2012.

SCE also seeks $1.945 million in 2010, $1.7 million in 2011, and $1.904 million in 2012 for wood pole disposal costs. Based on its own estimate of a reasonable number of pole inspections, DRA recommends $0.521 million in 2011 and $0.534 million in 2012.

In order to reflect the previous reduction to actual intrusive pole inspections, which are a primary driver of total pole replacements, we find it reasonable to reduce SCE's forecast Joint Pole Credits by 5% (to $11,243 and $14,726, respectively) for 2011 and 2012, and reduce SCE's proposed pole disposal costs by 5% (to $1.615 and $1,809 million, respectively) for 2011 and 2012.

5.8.2.4. Removal of Idle Facilities

When SCE facilities become idle or unused, they should be removed from rate base. SCE forecasts $4.489 million ($nominal) in 2011 and $4.596 million[361] in 2012 to remove facilities from rate base that are no longer used and useful. SCE based its forecast on a four-year average (2005-2008) which excludes a large, one-time increase in 2009 for a transformer bank replacement program that concluded in 2010.

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361 SCE-18, Vol. 04, Pts. 1 & 2 at 40; cf. SCE OB at 114 ($4.596 million).

DRA recommends the Commission adopt recorded expenses of $9.185 million in 2010, and a forecast of $1.597 million for 2011 and $1.635 million for 2012. DRA based its forecast on SCE's total 2010-2012 forecast, less 2010 actual expenditures, and dividing the remainder between 2011 and 2012. SCE rejects DRA's method because expenditures in this category are not fixed over three years.

SCE did not adequately support its forecasts of about $4.5 million per year in 2011-2012. SCE spent more than $9 million in 2010 to remove idle facilities, and did not explain why its 2010 costs exceeded both 2009 (an atypical year excluded from historical average) and are more than twice the original forecast amount of $4.41 million. Instead, SCE merely states its forecast was "conservative" and claims "the drivers of this work are largely outside the utility's control."[362]

We do not find SCE's explanation sufficient to support an additional $5.853 million in 2011-2012 and instead find DRA's proposal is more reasonable. Furthermore, we find SCE's claim troubling that it "will defer the removal of idle facilities from rate base" if it does not receive its requested funding for this activity.[363] It is our expectation that SCE exercise its operational judgment for the benefit of ratepayers. That judgment includes the expeditious removal of assets not used and useful from rate base.

The Commission finds SCE's recorded 2010 expenditures of $9.185 million to be reasonable, and adopts DRA's recommendation to apportion the balance of SCE's original forecast between 2011 and 2012.

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362 SCE-18, Vol. 04, Pts. 1 & 2 at 41.

363 SCE OB at 115.

5.9. T&D—Distribution Planning and Field Accounting

The Distribution Planning and Field Accounting (DP&FA) organization administers activities including Field Accounting, Facility Inventory Mapping, Join Pole Activities, Distribution Line Rents, and Miscellaneous Expenses related to the DP&FA organization.[364]

SCE's TY2012 forecast for O&M expenses is $5.699 million for the DP&FA group.[365] This consists of a $5.095 million request for subaccount 588.130—Field Accounting, Facility Inventory Mapping, Joint Pole Expense and Miscellaneous Expenses; and $0.604 million for subaccount 589.130—Distribution Line Rents. The corresponding DRA estimate for the O&M expenses is $4.080 million, with a recommended disallowance of $1.619 million, all in Subaccount 588.130.[366] DRA takes no issue with SCE's subaccount 589.130 request of $0.604 million and the Commission finds SCE's forecast is reasonable.

5.9.1. Field Accounting, Joint Pole Expenses and Miscellaneous Expenses: 588.130

Costs are recorded to this Subaccount from four work areas. DRA recommends reductions to three of them.

5.9.1.1. Field Accounting

The Field Accounting Organization (FAO) provides accounting related governance and support to transmission, substation, and distribution field

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364 SCE-18, Vol. 04, Pts. 3 & 5 at 1.

365 *Id*. at 9.

366 DRA-5 at 33.

operations. Its primary activity is work order closing, but also includes material management activities, and processing time and expenses for field employees.

SCE requests $0.953 million ($2009) for O&M expenses ($0.931 million labor, $0.022 non-labor) in TY2012 in this sub-category of FAO. SCE's forecast is based on 2009 recorded O&M expenses, with an adjustment to the portion of expenses allocated to O&M. In 2009, SCE allocated 7.8% of total capital expenses to FAO. Based on a more recent analysis of capital versus O&M activities performed by FAO personnel, SCE reduced the allocation to 4.5%.[367]

DRA forecasts approximately $73,000 ($2009) for TY2012 based on SCE's allocation of 4.8%[368] and applying that to SCE's two-year average (2008 and 2009) of recorded adjusted expenses. DRA's estimate is $880,472 less than SCE's estimate.[369] DRA utilized a two-year average because "2008 was the first full year of the accounting change to an allocated cost O&M split for Field Accounting expenses."[370]

We are persuaded that DRA did not correctly re-calculate its forecast by applying the revised 4.5% allocation to the 2008 and 2009 recorded amounts (already reduced to 7.8% of total) instead of total 2008 and 2009 expenses. However, we have elsewhere in the decision adopted somewhat lower forecasts

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367 SCE-18, Vol. 04, Pts. 3 & 5 at 1 (dividing 4.5% by 7.8% equals approximately 57.7%. SCE's $0.953 million request for the Field Accounting component for TY2012 is approximately 57.7 of the $1.651 recorded expense for 2009).

368 DRA-5 at 35. DRA may have inadvertently used a 4.8% rather than 4.5% multiplier.

369 DRA OB at 138 (DRA used the reduced allocation percentages SCE calculated as a ratio equal to Field Accounting expenses divided by total expenses for 2008 and 2009 (7.8% and 4.5%, respectively)).

370 DRA-5 at 36.

for system growth and related work activities. Thus, the Commission adopts a 5% reduction to SCE's request to account for slightly lower spending on capital projects through 2012, resulting in $0.905 million for TY2012 Field Accounting O&M expenses.

5.9.1.2. Joint Pole Organization

The Joint Pole organization is responsible for the execution and administration of all joint pole agreements where SCE shares in the ownership of distribution poles with other utilities and/or may lease space to renters. Joint Pole sees that billings are generated and payments are received from joint pole users for all capital investments, maintenance-related expenses, and for the recovery of other operating revenue (OOR) for non-owner transactions.

SCE requests a total $3.175 million ($2009 --$3.1 million labor, $0.075 million non-labor) for TY2012 Joint Pole expenses. SCE based its forecast on 2009 recorded O&M expenses of $2.675 million and added $0.500 million to hire five additional joint pole employees to manage the increase joint pole activities.[371] SCE's labor expenses increased slightly between 2005 and 2009 averaging $2.325 million while its non-labor expenses decreased annually during the same period.[372]

DRA forecasts $2.675 million ($2009) based on SCE's 2009 recorded expenses. DRA removes the $0.500 million because it concludes that SCE already has adequate staffing. SCE added eight employees between 2005 and 2009 to

[371] SCE-18, Vol. 04, Pts. 3 & 5 at 3.

[372] SCE-03, Vol. 04, Pts. 3 & 4 at 44.

address its increased work activities due to joint pole requests.[373] DRA states the Commission authorized an additional $0.438 million in the 2009 GRC to fund six additional positions in the Joint Pole Organization, however, this did not occur in 2009.[374]

SCE explains that it filled five out of six of the positions authorized in 2009 during 2010. Therefore, most of the costs and incremental expenses for the authorized new hires are not included (or embedded) in SCE's 2009 recorded O&M expenses.[375] According to SCE, DRA's forecast would essentially disallow funding for needed employees that have already been approved by the Commission and already hired by SCE.[376]

SCE provided testimony that the number of pole attachment requests processed by the Joint Pole Organization increased from 998 in 2008 to 1,827 in 2009—an 83% increase—to demonstrate that the workload is increasing.[377] We are persuaded that the costs of the additional employees were not reflected in 2009 recorded costs and it is reasonable to include them here.

The Commission adopts SCE's forecast $3.175 million O&M expenses for TY2012.

5.9.1.3. Miscellaneous Expenses

Miscellaneous expense primarily includes employee recognition and minor furniture and equipment expenses.

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373 DRA OB at 139 (SCE's response to DRA-SCE-086-TLG question 6-d).

374 D.09-03-025 at 91.

375 SCE-18, Vol. 04, Pts. 3 & 5 at 4.

376 *Id*. at 4-5.

377 SCE-03, Vol. 04, Pts. 3 & 4 at 45.

SCE forecasted $0.302 million ($2009 --$0.082 Labor and $0.220 Non-labor) for TY2012, utilizing a five-year average in recorded expenses from 2005 through 2009.[378] Recorded costs fluctuated significantly during this period. SCE contends the employee recognition program benefits ratepayers because employees are asked to take on tasks beyond their job duties, e.g., leadership focused on improving crew safety.[379]

DRA forecasts $0.063 million for SCE's Miscellaneous O&M expenses, based on the same five-year average but excluding $0.220 million forecast for employee recognition expenses that DRA argues are not necessary to operate the utility business. As it has elsewhere, DRA recommends the Commission exclude $0.220 million forecast in this subaccount for employee recognition expenses that DRA argues are not necessary to operate the utility business.[380] We reject an additional $19,000 reduction for equipment recommended by DRA due to insufficient justification.

Employee recognition awards are addressed in a separate section of this decision. The Commission approves $0.082 million in Miscellaneous O&M expenses for 2012.

The total amount SCE requested for DP&FA subaccounts 588.130—Field Accounting, Joint Pole Expense and Miscellaneous Expenses, and 589.130—Distribution Planning and Field Account O&M expense was $5.699 million; the Commission adopts $5.431 million of this request and disallows $0.268 million, as illustrated in the table below:

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378 SCE-18, Vol. 04, Pts. 3 & 5 at 5.

379 SCE-03, Vol. 04, Pts. 3 & 5 at 45.

380 DRA-5 at 37.

Distribution Planning and Field Accounting O&M Expense			
Description	**Requested ($000)**	**Adopted**	**Disallowed**
Field Accounting	$953	$905	$48
Facility Inventory Mapping	665	665	-
Joint Pole Expenses	3,175	3,175	-
Miscellaneous Expenses	302	082	220
O&M Expense Subtotal	**$5,095**	**$4,827**	**$268**
Distribution Line Rents	604	604	-
DP&FA O&M Expense Total	**$5,699**	**$5,431**	**$268**

5.10. T&D—Grid Operations

SCE's Grid Operations organization, in partnership with federal and state regulatory agencies, is responsible for monitoring and operating SCE's transmission and distribution system. Grid Operations plays a critical role in ensuring that SCE complies with the reliability standards developed and enforced by NERC, FERC, and Western Electricity Coordinating Council (WECC).

Grid Operations performs four major activities: 1) Operates and monitors the bulk power system consisting of electric facilities from 115 kV to 500 kV;[381] 2) Operates and monitors the sub-transmission and distribution system which consists of electric facilities from 66 kV to 120 kV;[382] 3) Restores service after an unplanned outage, whether during storm or non-storm conditions; and 4) Inspects and maintains the street lighting system.[383]

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381 The bulk power system includes 1,229 miles of 500 kV and 3,532 miles of 220 kV transmission lines.

382 The bulk power system supplies power to 360 sub-transmission substations, feeding 1,866 miles of 115 kV lines and 5,140 miles of 66 kV lines. The distribution system has 4,435 circuits originating from 217 distribution substations.

383 SCE-03, Vol. 04 at 1 (SCE owns and maintains over 640,000 street light fixtures).

For Grid Operations, SCE requests approximately $87 million in capital expenditures and approximately $90 million in O&M expenses for the 2012 Test Year. DRA and TURN both recommend reductions as discussed below.

5.10.1. O&M Expenses: 561.170, 562.170, 573.170, 582.170, 583.170, 588.170, 593.170, & 598.170

To manage the activities described above, the Grid Operations organization consists of the following groups: 1) Grid Control Management; 2) Northwest and Southeast Grid Operations; 3) Street and Outdoor Lighting Organization (SOLO); and 4) Grid Operations Business Support.[384] There are 12 subaccounts associated with Grid Operations O&M expenses: 1) Transmission Substation Supervision Costs; 2) Grid Control Center Costs; 3) Transmission Substation Costs; 4) Transmission Related Storm Costs; 5) Distribution Substation Costs; 6) Overhead Line Operations; 7) Street Light Patrol Costs; 8) Customer Generated Troubleman Work Costs; 9) Other Grid Operations Costs; 10) Breakdown Maintenance of Overhead Lines; 11) Street Light Maintenance; and 12) Distribution Related Storm Costs.

SCE requests $89.706 ($2009) million for its Grid Operations Expenses in TY2012, 15% of the total TDBU request for TY2012 O&M expenses. SCE developed its forecast by utilizing its 2009 recorded adjusted expenses for these accounts, plus incremental expenses for proposed projects and work activities.[385] SCE cautions that if DRA's "flawed" recommendations are adopted, the cuts will

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[384] *Id*. at 7-9.

[385] DRA-5 at 93.

"lead to shifting of funds from other programs to pay for mandatory spending in areas like breakdown maintenance and storm restoration."[386]

DRA's estimate for 2012 Grid Operations expenses is $71.972 million ($2009), $17.734 million less than SCE's forecast, as the result of reductions in eight of the subaccounts.[387] TURN recommends similar reductions in two of the subaccounts for a 2012 forecast of $88.840 million ($2009).

No party, including DRA, takes issue with the Transmission Substation Supervision, Customer Generated Troubleman Work, Street Light Patrols, and Street Light Maintenance Costs (subaccounts 560.170, 587.170, 585.170, and 596.170, respectively) forecast O&M expenses.[388] The Commission finds SCE's forecast 2012 O&M expenses for these subaccounts to be reasonable.

5.10.1.1. Grid Control Center Costs: 561.170

The costs in this subaccount are for 1) monitoring and dispatching the bulk power system, and 2) coordinating planned outages. The work activities provide a critical reliability function.

SCE requests $6.057 million ($2009—$4.860 million for Labor, $1.197 million for Non-labor) for its Grid Control Center (GCC) O&M expenses in TY2012.[389] The increase of $1.585 million over 2009 recorded expenses is for ten new employees to begin staffing SCE's alternate Grid Control Center (AGCC) during high risk times, to implement new NERC reliability and CIP cyber

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386 TR at 1045-1049.

387 DRA-5 at 93.

388 *Id*. at 95.

389 SCE-18, Vol.04, Pts. 3 & 5 at 13.

security standards, and to provide for workforce continuity in view of future retirements.[390]

DRA forecasts $4.472 million for this subaccount based on SCE's 2009 recorded adjusted expenses, the highest level of expenditures for the five-year period 2005-2009.[391] DRA rejects SCE's proposed staffing increases and states the requested increase of 35.44% over 2009 recorded adjusted expenses is not justified when compared to historical cost levels which averaged $3.990 million over the five-year period.[392]

SCE explained its plan to begin staffing the AGCC during normal business hours to comply with a new NERC reliability standard effective August 2010—stating that SCE must maintain a backup control center and be able to transfer control from the primary to the backup in less than two hours.[393] SCE also provided a detailed explanation of its need for more staff to implement new and more complex NERC and CIP standards, and to mitigate the risk from expected future employee retirements.[394]

We are concerned that SCE's request for ten new employees is twice what was added in the previous five years combined and that some of the added compliance activities may be handled by existing staff as prior regulatory projects close. In addition, what began in testimony as a request to address

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390 DRA-5 at 95.

391 *Ibid.*

392 JCE at 266.

393 SCE OB at 119 (The GCC is in Alhambra and the AGCC is located in Irvine—more than 40 miles apart).

394 SCE-03, Vol. 04, Pts. 5 & 6 at 17-18; SCE-18, Vol. 4, Pts. 3 & 5 at 14.

three workforce concerns, has now changed into a need for ten employees just to staff the AGCC.[395] We find it reasonable that six additional employees should be sufficient to address the future staffing concerns of AGCC, new regulatory standards, and a training pipeline in face of an aging workforce.

Therefore, the Commission approves 60% of SCE's proposed increase, or $0.951 million, for a total TY2012 O&M expense of $5.423 million.

5.10.1.2. Transmission and Distribution Substation Operations Expenses: 560.170, 562.170 & 582.170

Transmission related activities are recorded in subaccounts 560.170 and 562.170, while distribution related activities are recorded in subaccount 582.170. The expenses in these three subaccounts are associated with operating substations, including monitoring the system from 13 manned switching centers, controlling the system from those locations, and writing switching programs to isolate or energize equipment. Costs incurred for routine and emergency switching of electrical equipment and substation inspections are also included.[396]

SCE requests a total of $26.306 million ($2009) in TY2012 O&M costs for the three subaccounts,[397] as follows:

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395 *Ibid.*; SCE-18, Vol. 04, Pts. 5 & 6 at 14; SCE OB at 119.

396 SCE-18, Vol. 04, at 3 & 5, at 16.

397 *Id*. at 13.

Subaccount	SCE Labor	SCE Non-Labor	SCE Total 2012
560.170 Transmission Substation Supervision	$581	$176	$757
562.170 Transmission Substation	8,731	1,909	10,640
582.170 Distribution Substation	12,750	2,159	14,909
TOTAL	**$22,062**	**$4,244**	**$26,306**

The total forecast represents an increase of $0.391 (1.5%) over 2009 recorded O&M costs. SCE based its forecast on the number of substations it expects to have in its system in 2012, the five-year average cost per substation, and allocation of the total among the three subaccounts using historical ratios. No party takes issue with the forecast 2012 costs for subaccount 560.170 Transmission Substation Supervision.

DRA recommends $10.293 million in 2012 O&M for Transmission Substation Costs (subaccount 562.170), a reduction of $0.347 million, and $14.425 million in 2012 O&M for Distribution Substation (subaccount 582.170), a reduction of $0.484 million. DRA considered the historical costs to have fluctuated during 2005-2009 and calculated its forecasts separately for each subaccount based on the five-year average of O&M costs.[398]

The Commission finds that SCE's formula is reasonable because the number of substations is the key driver for these costs. Therefore, the Commission authorizes SCE's $10.640 million requests for subaccount 562.170, $14.909 million for subaccount 582.170, and $0.757 million for subaccount (560.170).

[398] *Id.* at 103.

5.10.1.3. Transmission and Distribution Storm Expenses: 573.170 & 598.170

The costs associated with restoration of service during storm conditions are recorded in subaccount 573.170 and 598.170. Subaccount 573.170 includes costs associated with work during storm conditions on transmission facilities, including repair of transmission assets. Subaccount 598.170 records costs associated with repairing storm damage to distribution assets.

SCE's combined request for TY2012 O&M costs related to T&D storm damage is $22.463 million ($2009). This is a 121% increase over 2009 recorded costs, however, 2009 costs were less than half of the five-year historical combined average, which is also equal to $22.463 million.[399] DRA recommends a reduction of $12.146 million ($2009), a 54% decrease, based on different forecast methodologies for each subaccount. By subaccount, SCE's forecasts are $3.731 million ($1.036 million Labor, $2.695 million Non-labor) for Transmission and $18.372 million ($7.029 million Labor, $11.703 million Non-labor) for Distribution storm expenses. Both forecasts are based on a five-year average of historical costs.[400] SCE claims its methodology is "consistent with Commission precedent and the nature of the costs in the category, which depends on the weather from year to year."[401]

DRA's forecast for Transmission storm damage 2012 O&M is $1.312 million, $2.419 million less than SCE's forecast, utilizing a three-year

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399 SCE-18, Vol. 04, Pts. 3 & 5 at 13 (2009 combined $10.186 million).

400 *Id*. at 19.

401 D.09-03-025 at 23 ("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….").

average (2007-2009) of recorded costs. DRA chose 2007-2009 because these years "appear to be more normal and routine years" compared to the recorded costs for the years 2005 and 2006.[402] SCE may recover certain costs incurred for major emergencies and catastrophic events through the Catastrophic Event Memorandum Account (CEMA). DRA also claims it is concerned that SCE did not remove all its CEMA related costs from its recorded expenses and that such costs were mistakenly included in SCE's test year forecast.[403]

DRA's forecast for Distribution storm damage 2012 O&M is $9.005 million, $9.727 million less than SCE forecast. DRA utilized 2009 recorded costs because "that year appears to be a more normal and routine year" compared to recorded costs for 2005-2008. DRA notes that SCE's expenses declined each year between 2006 and 2009 making LRY a reasonable method to forecast SCE's test year expenses.[404]

CCUE disagrees with DRA's recommended reductions because it views the storm-related expenses to be "critical components of reliability."[405] CCUE's argument links various overhead and underground maintenance and storm-related subaccount disallowances proposed by DRA, which CCUE sharply criticizes as significantly below historical levels of expenditures.[406]

The basis for DRA's use of different methodologies is not well supported. The primary driver of the storm-related O&M costs is the weather. Given the

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402 DRA-5 at 103.

403 *Id*. at 102.

404 *Id*. at 149.

405 CCUE OB at 14.

406 *Id*. at 15.

unpredictability of the weather, recently illustrated by the December 2010 windstorm in SCE's territory, use of a five-year average seems more reasonable to develop a test year forecast for these subaccounts. The Commission utilized a five-year average for these categories in SCE's 2009 GRC.[407] DRA's designation of some years' costs being "more normal" resulted in the lowest forecasts, but lacked any supporting evidence. Furthermore, DRA's concern that SCE did not remove all its CEMA related costs from its recorded expenses is not supported by any facts. We are persuaded by SCE's evidence that it has properly excluded CEMA costs.[408]

The Commission adopts SCE's five-year average methodology to establish TY2012 Transmission Related Storm Costs (subaccount 573.170) and Distribution Related Storm Costs (subaccount 598.170) of $3.731 million and $18.732 million, respectively.

5.10.1.4. Overhead Line Operations: 583.170

The Overhead Distribution Line Operations activities recorded in this subaccount are associated with the inspection, testing, and switching of distribution equipment to identify, isolate, or prevent problems. This work is primarily driven by outages or abnormal conditions, and is dependent on the size and age of the system. The work has both reliability and safety implications.

SCE requests $4.722 million ($2009--$3.744 labor, $0.978 non-labor) for its O&M expenses in TY2012, an increase of $0.593 million or 14.36%, over

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407 D.09-03-025 at 23.

408 SCE-18, Vol. 04, Pts. 3 & 5 at 20.

2009 recorded adjusted expenses of $4.129 million.[409] SCE's forecast is based on an historical ratio to projected expenditures for capital reactive maintenance.[410] SCE applied the 2009 ratio (3.4%) to SCE's forecast of 2012 capital reactive maintenance ($140.762 million) to develop the 2012 forecast.[411] The ratio to projected capital reactive maintenance has risen steadily from 2.1% in 2005 to 3.4% in 2009.

DRA utilized SCE's 2009 recorded expenses, the highest level of expenditures for the five-year (2005-2009) period, as the basis for its forecast of $4.129 million. Recorded costs have trended upward and nearly doubled since 2005 yet SCE does not explain why its current workforce funding is insufficient. DRA argues that SCE's forecast for this subaccount is too high because DRA recommended lower levels of funding for proposed capital projects in the test year.[412] TURN agrees with DRA's recommendation, also on the basis of its recommended reduced funding for capital reactive maintenance projects.

The Commission takes note of the escalating recorded costs from 2005 to 2009 for Distribution Line Operations, and the similarly trending reactive capital maintenance ratio. These trends support use of the LRY as a basis for the forecast more than they support SCE's methodology. If the ratio continues its erratic rise, then it may have little value as a forecast tool. We understand SCE's attempt to improve its forecast by identifying a correlation between these O&M expenses and related capital projects. However, SCE's calculation is the result of

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409 *Id*. at 13.

410 *Id*. at 22.

411 JCE at 270, 769.

412 DRA-05 at 104-106.

assumptions of a specific level of capital projects, some of which may not be approved. Accordingly, not making an adjustment would result in overfunding the subaccount.

At this time, the Commission finds DRA's and TURN's approach somewhat more reasonable. We adopt $4.129 million for Overhead Line Operations subaccount 583.170, and disallow $0.593 million ($0.468 million Labor and $0.125 million Non-Labor).

5.10.1.5. Breakdown Maintenance of Distribution Lines: 593.170

This account captures costs for performing reactive breakdown work on the distribution system during non-storm conditions. As with Overhead Line Operations (subaccount 583.170 addressed in the previous section), SCE states this work is driven by outages or abnormal conditions and is dependent on the size and age of the system.

SCE requests $10.307 million ($7.880 labor, $2.427 non-labor) for its Breakdown Maintenance of Overhead Distribution Lines O&M expenses in TY2012.[413] This represents an increase of $1.311 million or 14.57% over 2009 recorded adjusted expenses of $8.996 million.[414]

DRA utilized SCE's LRY as a basis for its forecast of $8.996 million for subaccount 593.170, and takes issue with SCE's forecast because the forecast is based on significant increases in SCE's proposed, but not authorized, capital in the test year.

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413 SCE-18, Vol. 04, Pts. 3 & 5 at 13.

414 DRA-5 at 110.

Based on a review and analysis of SCE's recorded adjusted expenses in subaccount 593.170 for 2005-2009, there appears to be no correlation between the fluctuations in this account, which SCE claims are out of its control, and SCE's capital project expenditures. DRA's test year estimate of $8.996 million based on SCE's 2009 recorded expenses, which is more than the five-year average of $8.201 million and the three-year average of $8.357 million, is a reasonable test year estimate.[415]

For the same reasons expressed in the previous section, the Commission finds that DRA's approach of using SCE's LRY ($2009) as a basis for its $8.996 million for subaccount 593.170 is reasonable. We disallow $1.311 million of the total $10.307 million request.

5.10.1.6. Other Grid Operations Costs: 588.170

This subaccount records miscellaneous expenses associated with Grid Operations. Other Grid Operations Costs included in this subaccount are: 1) Circuit Mapping; 2) Outage Data Management; 3) Street Light Mapping and Inventory; and 4) Other Expenses. SCE requests a total $6.317 million ($4.745 labor, $1.572 non-labor) for the four components of Other Grid Operations O&M costs for TY2012.[416] DRA proposes disallowances in all four areas; TURN proposes a disallowance for Streetlight Mapping and Inventory. Our discussion for each item within subaccount 588.170 for Other Grid Operations Costs follows:

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[415] *Id*. at 111.

[416] SCE-18, Vol. 04, Pts. 3 & 5 at 13.

5.10.1.6.1. Circuit Mapping

This activity involves updating circuit maps as new equipment is installed, old equipment is replaced, or system configuration is changed. These maps are relied upon by engineers and field personnel for work planning, trouble isolation, and service restoration.[417] SCE has chosen 2009 recorded expenses as its forecast for 2012 expenses, and therefore requests $1.906 million for Circuit Mapping O&M costs during TY2012.

DRA forecasts $1.446 million for Circuit Mapping expenses by utilizing a five-year average (2004-2009), recommending a disallowance of $0.460 million, and notes the 40.77% increase between 2008 and 2009 for Circuit Mapping expenses.[418] The Commission has concerns about such steep expense increases in administrative areas that are not subject to the unpredictable qualities of areas subject to weather, the possibility of catastrophic events, or an immediate need for increased staffing due to compliance issues.

The Commission finds it reasonable to use the recorded 2009 expenses as the basis for adopting a TY2012 O&M expense of $1.446 million for the Circuit Mapping component of subaccount 588.170, disallowing $0.460 million.

5.10.1.6.2. Outage Data Management

This activity involves verifying unplanned outage data, correcting data as needed, and recording the data in a central repository for outage reporting and analysis. This data is also a compliance requirement (D.96-09-045) and is used by SCE for infrastructure replacement and circuit automation. Costs associated

[417] *Id*. at 25-26.

[418] DRA-5 at 108.

with this activity have only been recorded as an expense since 2007.[419] SCE used 2009 recorded expenses as its 2012 O&M forecast, and requests $1.936 million for Outage Data Management O&M costs during TY2012.

DRA used a three-year average (2007-2009) to forecast a $1.668 million O&M budget for the Outage Data Management subaccount component, and recommends disallowance of $0.268 million. DRA states:

> Expenses increased between 2007and 2009 but there are no specific line items details, for review and analysis on the cause of the increases…DRA's use of a three-year average is reasonable and addresses concerns for the lack of verifiable and recorded adjusted data.[420]

The Commission finds DRA's argument persuasive and adopts SCE's TY 2009 O&M expense of $1.668 for the basis of its 2012 O&M expense for the Outage Data Management component of subaccount 588.170, disallowing $0.268 million of this request.

5.10.1.6.3. Street Light Mapping and Inventory (Energy Efficient Street Light Evaluation)

This activity is associated with updating the street light maps, street light inventory database, and work management systems with installation, replacement, and repair information from the field. This account also includes miscellaneous streetlight expenses that might be incurred.[421]

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[419] SCE-18, Vol. 04, Pts. 3 & 5 at 27.

[420] DRA-05 at 108.

[421] SCE-18, Vol. 04, Pts. 3 & 5 at 28.

SCE requests $1.453 million in TY O&M expenses for the streetlight Mapping & Inventory component of subaccount 588.170. The forecast was developed using two factors:[422]

- The number of streetlights expected in the system, the labor cost per unit, and the ratio of labor costs to total costs. The number of units was estimated using the 2009 street light count and the number of street lights SCE expects to install as part of new development work.[423] SCE requests $1.453 million for Street Light Mapping and Inventory O&M costs during 2012.
- $.0250 million for expenses related to energy efficient street light evaluation.

DRA forecasts $1.185 million based on SCE's 2009 recorded adjusted expenses, recommending a $0.268 million disallowance. DRA states that "SCE's Street Light Mapping and Inventory expenses fluctuated between 2005 and 2009 averaging $1.148 million for the five-year period (2005-2009) which is comparable to SCE's 2009 recorded adjusted expenses."[424]

TURN rejects ratepayer funding for the street light study on the grounds the research is already funded elsewhere or conducted by other entities.[425] TURN reminds the Commission that SCE's ratepayers paid approximately $25,000 in each of 2009 and 2010 for a project called "LED Street Light Demonstration," conducted by SCE's CSBU and funded through the RD&D

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[422] *Ibid*.

[423] SCE-03, Vol. 04, Pt. 1 at 45, Table I-15.

[424] DRA-5 at 108.

[425] TURN OB at 114.

balancing account.[426] TURN's position is that regardless of whether the CSBU research continues, "it is entirely unclear how the research related to LEDs that SCE proposes to fund in 2012 through Account 588.170 is distinct from the prior work or warrants 10 times the funding (from $25,000 to $250,000) per years for three years of the rate case cycle."[427] Additionally, TURN opposes SCE's request for an additional $18,000 for projected growth in the number of streetlights, recommending an accounting change to collect these costs from streetlight customers rather than the general body of ratepayers.[428]

The Commission recognizes the support role that the Street Light Mapping and Inventory function provides, but again proceeds with caution in considering costs that continually trend upward. We agree with TURN that the proposed study appears to be duplicative and a cost more appropriate to allocate to street lighting customers. Given the adoption of TURN's base case for customer growth, we also reduce the number of forecast new streetlights by 20%, the approximate difference from SCE's forecast growth.

Accordingly, the Commission adopts a $1.199 million authorization for this component of subaccount 588.170 and disallows $0.254 million.

5.10.1.6.4. Other Expenses

Other Expenses in Grid Operations include those incurred for field employee informational meetings and employee recognition. SCE requests $1.022 million for Other Expenses O&M costs during TY2012. SCE notes that in 2008 and 2009, informational meetings were approximately 90% of these costs.

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426 *Id*. at 115.

427 *Id*. at 116.

428 TURN Brief at 114.

SCE states that it "forecast these costs based on the number of employees and cost-per-employee. The number of employees is forecast based on the volume of work that needs to be performed in 2012."[429] The expenses in this account have increased significantly in 2008 and 2009 due to change in accounting practices that require employees to charge their time to meetings to this account. SCE used the 2009 cost-per-employee to develop its forecast.[430]

DRA forecasts $0.750 million for Other Expenses by utilizing a two-year average (2008 and 2009), minus an adjustment to remove discretionary costs associated with SCE's employee recognition program, which DRA states are inappropriate to charge to ratepayers. The Commission finds persuasive the argument that SCE's Other Costs component has increased due to accounting considerations. However, employee recognition award costs as a part of this component will be excluded here as these awards are addressed in a separate section of this decision. Instead, the Commission adopts SCE's 2009 recorded adjusted expenses, equal to its 2012 TY O&M request minus award costs. We adopt a $0.917 million authorization for the Other Costs component, and disallow $0.105 million.

Of SCE's requested $6.317 million requested for Other Grid Operations O&M costs, the Commission adopts $5.230 million for TY2012, and disallows $1.087 million.

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[429] SCE-18, Vol. 04, Pts. 3 & 5 at 31 (This includes Troublemen, Power System Operators, System Operators, Substation Operators, Dispatchers, Streetlight Repairmen, and Utilitymen).

[430] SCE-03, Vol. 04, Pt. 5 at 54-55; SCE-18, Vol. 4, Pts. 3 & 5 at 32.

The total amount SCE requested for Grid Operations subaccount O&M expenses was $89.706 million; the Commission adopts $86.081 million of this request and disallows $3.625 million, as illustrated in the table below:

Grid Operations O&M Expense Request				
Account	**Description**	**Requested ($000)**	**Adopted**	**Disallowed**
560.170	Transmission Substation Supervision Costs	$757	$757	-
561.170	Grid Control Center Costs	6,057	5,423	$634
562.170	Transmission Substation Costs	10,640	10,640	-
573.170	Transmission Related Storm Costs	3,731	3,731	-
582.170	Distribution Substation Costs	14,909	14,909	-
583.170	Overhead Line Operations	4,722	4,129	593
585.170	Street Light Patrols	585	585	-
587.170	Customer Generated Troubleman Work Costs	7,608	7,608	-
588.170	Other Grid Operations Costs	6,317	5,230	1,087
593.170	Breakdown Maintenance of Overhead Lines	10,307	8,996	1,311
596.170	Street Light Maintenance	5,341	5,341	-
598.170	Distribution Related Storm	18,732	18,732	-
	Grid Operations O&M Expense Total	**$89,706**	**$86,081**	**$3,625**

5.10.2. Grid Operations: Capital Request

SCE recorded $17.342 million in capital expenditures during 2010, and forecasts $14.888 and $18.345 million, respectively, in 2011 and TY2012 for the repair and replacement of streetlights, for routine operation expenditures to maintain substations, and an expansion of the Valley Substation to accommodate additional operators.[431] This total request for 2010-2012 is $50.575 million.

[431] SCE-18, Vol. 04, Pts. 3 & 5 at 8.

Within the Grid Operations capital expenditures, there are three line item activities: 1) Street Light Replacement Program; 2) Facilities Operational; and 3) Valley Substation Capital Expenditure. DRA accepts SCE's recorded 2010 and 2011-2012 forecasts for Facilities Operational and the Valley Substation Project.[432] However, DRA recommends a significant reduction for street light maintenance, including the replacement of steel street light poles.

5.10.2.1. Street Light Replacement Program

SCE has more than 640,000 street lights in its system and incurs capital expenditures to replace failing equipment. SCE forecasts this activity in four categories: steel pole replacements, street light fixtures, overhead conductor and underground conductor.[433] For each of the four category repair types requiring capital expenditure, SCE provides documentation used in forecasting its capital expense request.

SCE forecasts replacing 4,000 street light poles and associated components as part of its street light replacement program in 2012.[434] For the Street Light Replacement Program, SCE recorded $11.337 million in 2010, and forecasts $13.922 and $17.356 million in capital expense for 2011 and TY2012 respectively, for a total of $42.615 million in capital expenditures.[435]

DRA proposes allowing $11.341 million for 2011 and $11.613 million for 2012. DRA uses a three-year average of SCE's street light replacement

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432 *Ibid*.

433 *Id*. at 8-9.

434 SCE-03, Vol. 04, Pts. 5 & 6 at 56, Table I-6 and Figure I-9.

435 SCE-18, Vol. 04, Pts. 3 & 5 at 8.

expenditures in support of its forecast[436] and recommends that SCE annually replace 2,021 steel street poles and light poles plus components.

SCE points out DRA's proposal results in less than SCE spent in any year during the historical period except 2008 on a constant dollar basis.[437] SCE also takes issue with DRA's rejection of replacing all of SCE's corroding steel street light poles within 20 years.[438]

The largest component of SCE's Street Light Replacement Program is its request for funding for steel street light pole replacements which DRA claims has not been established as an "urgent" need.[439] SCE's highest year of steel street light pole replacements was six years ago when SCE replaced 3,135 steel poles.[440] DRA forecasts the annual replacement of 2021 steel street light poles based on historical averages for all four categories used by SCE, and SCE's 2009 unit cost.[441]

The three-year (2007-2009) average for SCE's pole replacement is skewed by a very low pole replacement number for 2008. Table 7-17 in DRA's Exhibit 07 shows that pole replacements for these years were 2,473, 742, and 2,849, respectively. SCE is persuasive that additional pole replacements will be necessary during this rate cycle. We observe that SCE estimated a 20-year cycle

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436 DRA-7 at 43, Table 7-17.

437 SCE-18, Vol. 04, Pts. 3 & 5 at 8, Table II-5 (nominal dollars); DRA-7 at 43, Table 7-17 ($10.940 million in 2009 constant dollars).

438 DRA-7 at 43.

439 DRA OB at 149.

440 *Ibid*.

441 DRA-7 at 43, Table 7-17.

of replacement is 3,115 per year, approximately 50% between DRA's recommended three-year average for pole replacement at 2,021 and SCE's stated need to replace 4,000 poles per year.[442] We find that SCE has not established the likelihood of an accelerated need for this program in 2010-2012 as requested.

The Commission finds it reasonable to reduce SCE's 2011 and 2012 forecasts by 50% of the difference from DRA's estimate to reflect a steady replacement program. For 2011, the result is $12.632 million and $14.485 million for 2012. We also find SCE's recorded 2010 expenditures of $11.337 million to be reasonable. For 2010-2012, the Commission adopts $38.454 million of a $42.615 capital request for the Streetlight Replacement Program, and disallows $4.162 million.

Including the Facilities Operational and Valley Substation Programs projects within the Grid Operations organization, the Commission adopts capital expenditures of $46.414 million out of a total $50.575 million request for 2010-2012, disallowing $4.161 million, as illustrated in the table below:

Grid Operations Capital Expenditure Request						
	Capital Request by Year ($000)					
Project Description	**2010 Recorded**	**2011 Forecast**	**2012 Forecast**	**Total 2010-2012**	**Adopted**	**Disallowed**
Street Light Replacement Program	$11,337	$13,922	$17,356	$42,615	$38,454	$4,161
Facilities Operational	1,693	966	989	3,648	3,648	--
Valley Substation	4,312	--	--	4,312	4,312	--
Total	**$17,342**	**$14,888**	**$18,345**	**$50,575**	**$46,414**	**$4,161**

[442] SCE-18, Vol. 04, Pts. 3 & 5 at 10.

5.11. T&D Distribution Construction and Maintenance

Distribution Construction and Maintenance (DCM) is SCE's internal construction organization for all facilities on the distribution system outside of substations. It manages and performs projects related to voltages below 66 kV, and performs maintenance items which are either inspection-driven or unplanned (breakdown). SCE applies a forecast methodology which models increasing failure rates and system growth to determine how many assets will be replaced each year. The result is multiplied by SCE's historic unit replacement cost for each asset.[443]

5.11.1. Distribution Construction and Maintenance: O&M Expenses

SCE forecasts a total of $56.125 million for DCM TY2012 O&M expenses to support construction and maintenance of the distribution system, installation, removal, and replacement of customer meters, service guarantee payments, and emergency repairs. CCUE supports SCE's forecast expenses and replacement schedules for DCM O&M, and generally criticizes DRA's proposed cuts as too severe and likely to compromise reliability.

DRA recommends a corresponding total of $29.497 million ($2009) for DCM O&M, a reduction of $26.628 million (47.4%) to SCE's total forecast, affecting six Subaccounts. However, 92% of DRA's reductions are for two Subaccounts: overhead and underground breakdown expenses. DRA solely relied on historical costs for each Subaccount to develop its forecasts, and

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443 SCE-03, Vol. 04, Pts. 5 & 6 at 101.

assumed existing funding levels were adequate to fund necessary future activities. TURN recommends more than $22 million in reductions to SCE's forecast in three subaccounts.

There is no dispute about SCE's forecast for Subaccount 580.140, Operations Supervision and Engineering. We find SCE's 2012 forecast of $2.653 million reasonable and adopt it.

5.11.1.1. Construction Related Expenses: 583.140

SCE forecasts $735,000 ($2009) in 2012 ($0.614 million Labor, $0.121 million Non-labor) to support civil inspections of underground structures, warranty inspections and switching. Recorded adjusted expenses in this subaccount declined significantly between 2007 and 2009, so SCE relied on 2009 as a basis for its forecast. However, SCE forecast an additional $123,000 in labor and $30,000 in non-labor expenses for an increase in civil inspections due to forecast increased underground capital work in 2012.[444]

DRA recommends $582,000, based on 2009 recorded costs, and states SCE's proposed 26.29% increase is not supported. DRA asserts (1) SCE has embedded funding for eliminated activities, and (2) proportionate reductions should occur if SCE's forecast for underground capital work is reduced.

SCE presented evidence that 2009 recorded expenses were so low because site readiness checks were terminated and no costs were recorded. Thus, there is no "embedded funding" for ceased activities in SCE's 2012 forecast.[445] However,

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444 *Id*. at 111.

445 SCE-18, Vol. 4, Pt. 6 at 15.

the Commission adopts a slightly lower forecast than SCE for TDBU capital work and we adjust the civil inspection forecast accordingly.

Elsewhere in this decision we have reduced SCE's forecasted 2011-2012 total TDBU capital expenditures by 9.4%. Therefore, the Commission finds it reasonable to adopt a similar reduction to all TDBU capital-related O&M expenses, including to the $0.153 million incremental increase to subaccount 583.140 Construction Related Expenses. The decrease is approximately $0.015 million, resulting in a $0.138 million TY2012 increase from $0.582 million to $0.720 million for this O&M category.

5.11.1.2. Meter Related Expenses: 586.140

SCE originally forecast $6.7 million ($2.675 million Labor, $4.025 million Non-labor) in 2012 to install (set), remove and replace meters on SCE's system based on projected meter sets, removals and replacements. SCE forecasts a steady increase in all three sub-categories from 2009-2012.[446] Its TY forecast is an increase of $1.117 million (20%) over 2009 recorded adjusted expenses of $5.583 million. SCE explains the trends are based on contractor expenses that vary according to demand for meter work linked to fluctuations in the housing market which it forecasts will improve during the next rate cycle.

DRA recommends $5.583 million, the equivalent of 2009 recorded costs, for this activity because total expenses declined from 2006 to 2009, the total number of meter sets and removals in 2009 was the lowest in five years, and a 2009 increase in meter replacements may be related to installation of

[446] SCE-03, Vol. 4, Pts. 5 & 6 at 113, Figure II-37.

SmartMeters.[447] We agree with SCE that DRA's position lacks supporting evidence and contradicts other positions DRA has taken in the GRC.[448]

TURN proposes a 2012 forecast of $5.796 million based on a different forecast methodology, including a lower new meter set forecast, a three-year average to calculate meter replacements, and lower contractor costs. SCE accepts TURN's proposed modifications in the forecast methodology, but rejects TURN's proposed reduction in the new meter set forecast. As a result, SCE reduces its request by $290,000 to $6.41 million.[449]

We find TURN's forecast methodology reasonable given the 2006-2009 increases in meter replacements and historical variations in contractor costs. In addition, we adopted TURN's "base" case new meter forecast elsewhere in this decision.

Accordingly, the Commission adopts TURN's 2012 forecast of $5.796 million for this subaccount, resulting in a $614,000 reduction to SCE's revised request (all Non-labor).

5.11.1.3. Service Guarantees: 587.140

SCE proposes to continue its Customer Service Guarantee program that was adopted in D.04-07-022 and asks the Commission to shift the funding of a baseline of $670,000 in service guarantee credits from shareholders to ratepayers. This amount is equivalent to the lowest recorded year of payments.

In 2009 GRC, the Commission declined SCE's similar request stating, "The record in this proceeding is insufficient to establish a baseline or to change our

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[447] DRA-5 at 42.

[448] SCE-18, Vol. 04, Pt. 6 at 17-18.

[449] *Id*. at 18.

previously adopted policy" that SCE's shareholders should pay this amount.[450] SCE asserts that, in the current proceeding, it provides five years of recorded payouts and other evidence to support the baseline amount, and that some payouts will occur despite a utility's good practices.

DRA argues that "shareholders and not ratepayers should be responsible for reimbursing the inconvenienced customer" and recommends no funding for SCE's Service Guarantees recorded to subaccount 587.140.[451]

We agree with DRA that SCE's proposal to have ratepayers fund baseline service guarantee credits should be denied. The Commission has adopted this view in the two previous Edison GRCs and the utility has not articulated persuasive arguments for reversing this longstanding policy decision.[452]

5.11.1.4. Miscellaneous Distribution Expenses: 588.140

SCE forecasts $3.779 million ($2009) for TY2012 O&M expenses related to field supervision, electrical worker informational meetings and stand-by time, and DCM employee recognition. SCE used its 2009 recorded adjusted expenses to forecast 2012 O&M for Field Service Representatives Supervision, Informational Meetings, and Stand-By Time, and used a five-year average to forecast its Recognition expenses.[453] The four-year average (2005-2008) for this category was $3.075 million before increasing in 2009 by almost 27% for

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[450] D.09-03-025 at 94.

[451] DRA OB at 152-153.

[452] D.06-05-016 at 122 ("If the company is unable to meet its commitments, the shareholders and not ratepayers should be responsible for reimbursing the inconvenienced customer.").

[453] SCE-03, Vol. 04, Pts. 5 & 6 at 119, Figure II-39.

employee recognition Non-labor expenses.[454] Employee recognition/bonus expenses were excluded from the 2009 GRC revenue requirement.

DRA accepts use of LRY to forecast O&M for this subaccount, since it is comparable to the four-year (2005-2008) historical average. However, DRA removed $773,000 in costs associated with SCE's employee recognition program from SCE's forecast. The result is a forecast of $3.006 million.

We adopt DRA's forecast which is comparable to SCE's recent expense history and is a reasonable test year forecast. Employee recognition and bonus programs have been excluded from rate recovery here and are discussed in Section 8.5.

5.11.1.5. Overhead and Underground Work Order and Breakdown Maintenance Expenses: 593.140 and 594.140

Breakdown and work order maintenance, usually capital related expenses, are recorded in subaccount 593.140 for the overhead portion and in subaccount 594.140 for the underground portion. SCE's overhead and underground maintenance expenses each nearly doubled from 2005 to 2009, largely driven by significant increases to Non-labor costs in both subaccounts. In 2009, there were $5.0+ million increases to both underground and overhead maintenance costs due to an accounting adjustment for related capital work and to hiring more contractors to handle increases in breakdown maintenance.

SCE's total TY2012 revised forecast for both subaccounts for breakdown and work order expenses is $41.587 million. SCE presented its evidence both by

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454 *Id*. at 120, Table II-11 (In 2009, employee recognition awards equaled 30.5% of the total expense for this category.).

subaccount as it did in the 2009 GRC, and by category of expense (i.e., breakdown maintenance and work order-related expense) combined for this GRC.

Breakdown Maintenance

Breakdown maintenance occurs when in-service equipment fails and requires repair or replacement (except for those items driven by storms or claims). SCE forecasts a total of $17.412 million for overhead and underground breakdown maintenance expenses. To develop its forecasts, SCE calculated the historical percentage of capital (work order) breakdown to expense breakdown and applied the percentage to SCE's forecast capital breakdown expenditures.[455] Combined overhead and underground breakdown expenses for 2012 are forecast by SCE to grow by 14.6% over 2009 recorded expenses.

DRA recommends a reduction of $7.165 million (41.1%) based on a five-year average of both overhead and underground breakdown maintenance expenses and assumes there are embedded costs for routine work. TURN accepts SCE's linkage to capital breakdown expenditures, but recommends the Commission instead adopt SCE's 2009 combined recorded breakdown expenses of $15.192 million, $2.220 million less than SCE's forecast. Both DRA and TURN criticize SCE's forecasts as unreasonable in method and result.

Generally, breakdown maintenance on in-service failures must be performed in order to assure system reliability. DRA's reliance solely on five-year historical averages does not adequately recognize that SCE is expected

[455] *Id*. at 122, 125 (SCE says it calculated the historical percentage of capital breakdown to expense breakdown and applied this percentage to the forecast capital breakdown expenditures).

to perform more work in this rate cycle than last. SCE provided evidence that as its system ages, the company has increased its inspections and repairs in many areas, often in response to Commission direction, e.g., DIMP, GO 165, etc. It is reasonable to assume some increases in breakdown expenses, but we are not persuaded that SCE's new correlation ratio of overhead breakdown capital to expense breakdown is valid.

For example, SCE's evidence does not explain why, in 2009, the previously steady 4% ratio of expense to breakdown capital grew to 5% for underground and 7% for overhead breakdown expense.[456] It is also unknown if SCE was able to achieve truly comparable ratios with its backcasts for this GRC, given SCE's recent reorganization of these O&M expenses and other accounting changes.

Work Order-Related Maintenance

For combined overhead and underground work order-related expenses, SCE's revised forecast is $24.176 million for TY2012. SCE developed its forecasts by subtracting historic materials costs from 2012-2014 forecast distribution capital expenditures, and then "apply[ing] the related expense percentage used in our SAP[457] accounting system to calculate related expense."[458]

DRA uses a five-year average of both overhead and underground work order related expenses to develop its total TY2012 recommendation of $7.426 million. DRA's view is that costs fluctuated between 2005 and

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[456] SCE-18, Vol.0 4, Pt. 6 at Attachment 13.

[457] System Applications and Products (SAP) provides business software, including inventory management software which works with Enterprise Resource Planning (ERP).

[458] SCE-03, Vol. 04, Pts. 5 & 6 at 122, 125 and Attachment 13.

2009, historical expenses capture routine and on-going expenses, and SCE's capital request may be reduced. SCE's 144% projected increase over 2009 recorded costs is at odds, argues DRA, with expenditures that varied between $4.4 million and $10.5 million during the period of 2005 to 2009.

TURN recommends the Commission adopt LRY, $9.925 million, for TY2012. TURN criticizes SCE's methodology which is driven primarily by 4 kV cutovers and PEV readiness which account for 2/3 of SCE's proposed increase. TURN tested SCE's methodology with 2009 actual capital spending using a backcast and found the model would have yielded a 49% over forecast.[459] Also problematic is SCE's assumption that its forecast of 2012-2014 capital expenditures will occur, although 2013-2014 are not under review in this proceeding.

SCE claims that in the 2009 GRC, the Commission rejected use of LRY as a forecast basis in favor of an historical ratio of capital related expense to capital expenditures.[460] However, SCE's claim of prior Commission approval of its methodology is misleading. The citation provided was to a discussion of transmission substation expenses, a different category of work. In fact, in the 2009 GRC, SCE used LRY (2006), plus incremental expenses for new work, to forecast test year O&M for all sub-categories of underground and overhead maintenance.[461] The Commission accepted DRA's removal of all increases over LRY for breakdown and work order-related expenses for overhead maintenance,

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[459] TURN OB at 126-127.

[460] SCE-18, Vol. 04, Pts. 5 & 6 at 27.

[461] D.09-03-025 at 98-102.

despite finding that SCE would be performing additional work to implement the new DIMP.[462]

Breakdown and Capital Related O&M Expense – Subaccounts 593.140 (Overhead) and 594.140 (Underground) Combined (Constant 2009 $000)					
	2012 Forecast				
	SCE	DRA		TURN	
Description	**2012**	**2012**	**Variance**	**2012**	**Variance**
Breakdown Expense	17,412	10,247	(7,165)	15,192	(2,220)
Capital Related Expense	24,176	7,426	(16,750)	9,925	(14,251)
Total	**$41,588**	**$17,673**	**($23,915)**	**$25,117**	**($16,471)**

5.11.1.5.1. Overhead Maintenance Expenses: 593.140

In subaccount 593.140, SCE's revised forecast is $29.877 million in TY2012 for combined breakdown and work order expenses, an increase of $15.499 million (108%) over 2009 recorded adjusted expenses of $14.378 million. Work order-related expenses are estimated to be $20.094 million, and breakdown expenses to be $9.783 million.

SCE's total overhead expenses, and work order expenses separately, fluctuated significantly during the five-year historic period (2005-2009) with an average annual total of $10.172 million. Overhead work order expenses nearly tripled between 2008 and 2009 and would more than triple again in SCE's 2012 forecast of $20.094 million. SCE defends its forecasts as solidly linked to estimated system needs going forward which are sure to increase due to aging and system growth.

462 *Ibid.*

DRA recommends adopting the five-year average for overhead expenses of $10.172 million, resulting in a $19.705 reduction to SCE's forecast, mostly for work-order expenses. These forecasts are below 2009 recorded expenses in both categories. TURN's forecasts totaling $14.386 million are the equivalent of 2009 recorded adjusted expense.[463] TURN argues that LRY is the most reasonable basis to forecast these costs.

Overhead Breakdown and Capital Related O&M Expense – Subaccount 593.140 (Constant 2009 $000); 2012 Forecast					
	SCE	**DRA**		**TURN**	
Description	**2012**	**2012**	**Variance**	**2012**	**Variance**
Overhead Breakdown Expense	$9,783	$5,465	($4,318)	$8,535	($1,248)
Overhead Capital Related Expense	20,094	4,707	(15,387)	5,843	(14,251)
Total	**$29,877**	**$10,172**	**($19,705)**	**$14,378**	**($15,499)**

Both DRA and TURN contend that SCE's forecasts are unreasonable because total TY2012 expenses would be twice that of 2009 and far exceed historical expense levels. Moreover the forecasts erroneously assume that Distribution capital expenditures and work order maintenance costs are increasing proportionally, and SCE utilizes a single year with the highest breakdown maintenance O&M to capital ratio.

We are persuaded that SCE's forecasts have overestimated work order related expenses and are inflated by proposed capital spending. Even if we accepted SCE's new forecast approach as reasonable, assumed capital spending requests will have to be adjusted to reflect actual authorized expenditures.

[463] JCE at 782; SCE-18, Vol. 04, Pt. 6 at 21, Table I-11.

Further, SCE did not establish that its correlation ratios for breakdown expense to capital are valid.

For the breakdown maintenance expense, the Commission finds it reasonable and adopts TURN's recommendation of $8.535 million. For work order-related expenses, we incorporate our decision to reduce SCE's forecast TY2012 capital-related O&M expenditures by 9.4% of the $14.251 million incremental increase between 2012 and 2009 recorded expenses. Therefore, the Commission finds it reasonable to adjust SCE's TY forecast for Overhead Work Order Expenses to $18.755 million.

5.11.1.5.2. Underground Maintenance Expenses: 594.140

In subaccount 594.140, SCE forecasts $11.710 million in 2012 for combined breakdown and work order expenses, an increase of $0.971 million over 2009 recorded adjusted expenses of $10.739 million. The forecast for work order expenses is $4.082 million and for breakdown maintenance is $7.629 million.[464]

SCE's total underground maintenance varied during the five-year period (2005-2009) with an average annual total of $7.5 million.[465] On the other hand, one could view underground maintenance expenses as growing from 2007 to 2009 separately, and on the other hand, one could view underground maintenance expenses, separately and combined, as growing from 2007 to 2009. SCE defends its forecasts as solidly linked to estimated system needs going forward which are sure to increase due to aging and system growth.

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[464] *Id*. at 22, Table I-12.

[465] *Ibid*.

DRA recommends adopting the five-year average of $7.501 million total for underground maintenance in 2012, a $4.209 million reduction to SCE's revised estimate. TURN's forecasts totaling $10.739 million,[466] the equivalent of SCE's 2009 recorded adjusted expenses. As discussed above, TURN and DRA offer similar criticisms of SCE's methodology and results as described for SCE's overhead maintenance expense forecasts.

We are persuaded that SCE's forecasts have overestimated work order related expenses and are inflated by proposed capital spending. Even if we accepted SCE's new forecast approach as reasonable, assumed capital spending requests will have to be adjusted to reflect actual authorized expenditures. Further, SCE did not establish that its correlation ratios for breakdown expense to capital are valid.

For the underground breakdown maintenance expense, the Commission finds it reasonable and adopts TURN's recommendation of $6.657 million. For capital-related expense, SCE reduced its $10.994 million forecast by $6.912 million to $4.082 million (equal to 2009 recorded expenses), based on its association with capital expenditures.[467] Therefore, the Commission finds it reasonable to adopt SCE's adjustment to the TY forecast for Underground Work Order Expenses in this subaccount.

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[466] JCE at 784 identifies TURN's recommendation to be $13.628 million, but this appears to be in error because TURN's testimony and OB refer to reliance on LYR ($10.739).

[467] *Ibid.*

Underground Breakdown and Capital Related O&M Expense – Subaccount 594.140 (Constant 2009 $000)					
	2012 Forecast				
	SCE	DRA		TURN	
Description	**2012**	**2012**	**Variance**	**2012**	**Variance**
Underground Breakdown Expense	$7,629	$4,782	($2,847)	$6,657	$972
Underground Capital Related Expense	4,082	2,719	(1,363)	4,082	0
Total	**$11,710**	**$7,501**	**($4,210)**	**$10,739**	**($972)**

5.11.2. Distribution Construction and Maintenance: Capital Expenditures

SCE forecasts $265.379 million for DCM capital expenditures in 2012, primarily for inspection-driven capital maintenance or in-service failures. DRA accepts SCE's 2010 recorded adjusted expenditures but recommends reductions totaling $21.007 million in 2011-2012 for capital breakdown maintenance and tools and work equipment. TURN proposes adjustments to the sub-categories of storms and claims, transformers, and breakdown maintenance.

5.11.2.1. Distribution Storm Capital Expenditures

Storm Damage capital expenditures are required to repair damage to distribution assets as the result of acts of nature. SCE modified its original forecasts for 2011-2012 in response to TURN's identification of a calculation error. The result is a reduction to its 2011 and 2012 forecasts by a total of $0.718 million. TURN and SCE agree that SCE's revised forecasts are reasonable. TURN and SCE also agree to accept DRA's true-up of 2010 recorded costs.

We find reasonable SCE's revised forecast for Storm Damage capital expenditures of $38.166 million, $38.497 million, and $ 39.418 million for 2010, 2011, and 2012, respectively.

5.11.2.2. Distribution Claims Damage Capital Expenditures

Claims Damage capital expenditures include capital costs incurred to make repairs to the distribution system resulting from the acts of others. SCE modified its original forecasts for 2011-2012 as suggested by TURN, based on 2006-2010 data that reduced the net claims percentage paid by ratepayers from 50% to 45.67% of gross claims.[468] The result is a reduction to forecasts on a net basis of $5.084 million over 2010 to 2012 period. TURN and SCE also agree to accept DRA's true-up of 2010 recorded costs.

We find reasonable SCE's recorded Claim Damage capital expenditures for 2010 of $17.028 million, and adopt SCE and TURN's forecast of $20.577 million, and $21.071 million for 2011 and 2012, respectively.

5.11.2.3. Distribution Breakdown Maintenance Capital Expenditures

This category accounts for $338.5 million dollars of SCE's proposed 2010-2012 capital expenditures.

SCE calculates breakdown capital costs based on the need to replace a percentage of the growing asset base each year. During this rate cycle, SCE assumes economic growth will spur customer growth and lead to significant asset growth. DRA and TURN seek to exclude growth estimates as unreliable and continue reliance on historical replacements. SCE views any reductions in this account as leading to earlier preventive infrastructure replacement costs, thereby increasing overall costs to the ratepayers.

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[468] TURN OB at 12 (TURN used 2006-2010 recorded expenditures to calculate a five-year average for Claims Damage and the net claims percentage paid by ratepayers).

SCE forecasts breakdown maintenance expenditures of $108.434 million ($nominal) for 2011 and $118.293 million for 2012. For forecasting purposes, SCE used four major types of equipment that account for most of the work and unit costs in this category.[469] The forecast is an estimate of the increased number of units that will fail and the 2009 unit cost per category for: Overhead conductors, underground cable, overhead transformers, and underground transformers. SCE's estimates of failure rates are based on average failure rates or historical trends. SCE's 2010 recorded costs of $111.775 million are accepted by DRA and TURN.

DRA recommends the Commission adopt an 8.4% reduction of $18.947 million ($102.660 million for 2011, $105.120 million for 2012), based on a three-year average of replacement unit counts that have historically fluctuated. TURN also rejects SCE's asset based forecasting in favor of historic replacements. TURN agrees with a three-year average for underground transformers and overhead conductors "where there is little variation and limited trends over time."[470] For overhead transformers and underground cable, TURN used two-year averages to estimate slightly more replacements at slightly less cost than DRA.[471] TURN's recommendation for 2011 is $101.5 million and $103.9 million for 2012, a $21.319 million (9.4%) reduction to SCE's request.

We expect short-term continued increases for breakdown maintenance capital expenditures largely due to old infrastructure. Breakdown capital expenditures grew 55% between 2005 and 2009, and another 13% in 2010 after

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469 SCE-18, Vol. 04, Pt. 6 at 6.

470 TURN-3 at 62.

471 TURN OB at 119 (citing TURN-3C at 62).

a 6% drop in 2009. DRA and TURN raised reasonable questions about SCE's forecast methodology, including optimistic growth forecasts, low correlation coefficients, and slimly supported linkage to failure rates.[472]

SCE criticizes use of historic replacement rates by reference to the Commission's decision in the 2009 GRC.[473] However, the citation was to a discussion of preventive maintenance (where we have authorized increases), instead of estimating breakdowns. Contrary to SCE's view, we find that historical replacement units capture (with lag) increasing breakdowns as the median age of an asset category increases. On the other hand, sole reliance on historical averages does not account for the lag or increasing failures going forward.

Prior breakdown maintenance provides a reasonable basis to develop a forecast of growth in this category. We are not persuaded to apply different averages to some equipment categories. Therefore, we begin with DRA's forecasts based on three-year historical averages of replacement units for all four equipment categories.[474] We adjust the estimates by 5%, the average annual growth in this category between 2005 and 2009, in order to adjust for increasing age-related failures and a small amount of new asset failures.

The Commission finds reasonable the 2010 recorded expenditures of $111.775 million ($nominal), and forecasts of $107.793 for 2011 and $113.182 million for 2012. This is a total 2011-2012 reduction to SCE's forecast of $5.752 million.

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[472] TURN-3 at 62; DRA OB at 159-160.

[473] SCE OB at 138.

[474] SCE-18, Vol. 04, Pts. 5 & 6 at 12.

5.11.2.4. Distribution Transformers

SCE forecasts $57.127 million ($nominal) in 2011 and $64.068 million in 2012 for capital expenditures to purchase replacement distribution transformers. SCE's forecast is based on forecast system growth in this rate case period as a function of forecast customer growth. TURN forecasts $53.936 million in 2011 and $57.742 million in 2012, a reduction of $9.517 million over both years. The difference is that TURN's forecast is based on its own, lower recommended forecast of customer growth, rather than SCE's.

Elsewhere in this decision, we adopted TURN's forecast of customer growth. Accordingly, the Commission finds it reasonable to reflect it here and adopt TURN's forecasts of distribution transformer capital expenditures. The Commission allows $53.936 million in 2011 and $57.742 million in 2012, resulting in a total reduction to SCE's 2011-2012 forecast of $9.5 million, or 7.9%.

5.11.2.5. Tools and Work Equipment

This category includes costs for acquisition and retirement of typically complex portable tools and work equipment that cost more than $1,000.[475]

SCE's costs fluctuated between 2005 and 2009, including an 84% increase in 2009 over 2008, and an additional 40.2% more spent in 2010. SCE explained the 2009 spike as due to increasing wear and tear from more work, and SCE's commitment to replace worn tools with one that has improved safety features. SCE's forecasts assume this trend will continue, and relied on escalated 2009 recorded capitalized expenditures for estimates of $3.188 million in 2011 and $3.264 million in 2012.

[475] SCE-03, Vol. 04, Pts. 5 & 6 at 102.

DRA relied on a five-year average of historical costs to arrive at its forecasts of $2.170 million for 2011 and $2.222 million for 2012. DRA argued this methodology was appropriate due to the historical fluctuations in costs and the lack of SCE documentation to support its safety claims.

SCE states that it increased its tool purchases in 2009, and presumably 2010, because it undertook an evaluation of the tools it was using and replaced them with a new, safer version.[476] Therefore we find that the large increases in 2009 and 2010 are largely anomalous. To the extent that increasing work leads to wear and tear, historical costs should account for additional expenditures.

The Commission finds reasonable and adopts DRA's forecasts of $2.170 million for 2011 and $2.222 million for 2012.

5.12. T&D – Substation Construction and Maintenance

SCE's substation facilities step up voltage from generators to transmission lines and then step the voltage down for distribution. Substations also contain automated protection equipment, which prevent a fault in one part of the system from affecting other parts of the system. The Substation Construction and Maintenance (SC&M) organization is responsible for all aspects of field work associated with the routine inspection, testing, maintenance, replacement, and construction of SCE's substation equipment and structures in compliance with regulatory requirements, and to address safety and reliability.[477]

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[476] *Id*. at 103.

[477] SCE-03, Vol. 4, Pts. 7 & 8 at 2.

5.12.1. O&M Expenses: 570.150, 588.150, 592.150

For TY2012, SCE forecasts $32.143 million for SC&M O&M expenses covering nine subaccounts. DRA accepts as reasonable SCE's forecasts for T&D substation expenses incurred in non-TDBU business units, T&D substation maintenance crew supervision, and maintenance of T&D grounds and facilities. SCE developed its forecast by using its 2009 recorded adjusted expenses plus incremental expenses for proposed projects and work activities.

DRA forecasts $26.184 million, an 18.5% reduction to SCE's forecast. DRA's proposed reductions are in several areas including T&D substation inspection and maintenance, capital-related expenses, additional equipment, and miscellaneous expenses. Generally, DRA used SCE's LRY and a five-year average (2005-2009) as its basis to forecast future expenditures.

Unless discussed below, we find SCE's forecast O&M expenses for the uncontested SC&M Subaccounts to be reasonable and we adopt them as set forth in SCE's testimony.[478]

5.12.1.1. Transmission Substation Inspection and Maintenance: 570.150

Subaccount 570.150 includes expenses associated with inspection and maintenance of circuit breakers, transformers, relays, miscellaneous equipment in transmission substations, and capital related expenses associated with substations.

SCE forecasts $12.881 million (Labor of $6.352 million and Non-labor of $6.529 million) for TY2012 expenses in subaccount 570.150, covering five line items and capital-related expenses. SCE uses a forecast asset count, including

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[478] *Id*. at 12, Table I-2.

estimated growth, to yield the 18.25% increase over 2009 recorded costs of $10.893 million. For each sub-category, DRA uses SCE's LRY or a five-year average recorded costs to forecast a total of $9.360 million, $3.521 million less than SCE's forecast.

Transmission Substation Inspection and Maintenance Differences ($2009) (000s)			
Sub-category of 570.150	**SCE 2009 recorded O&M expenses**	**SCE's TY2012 forecast**	**DRA's TY2012 forecast**
Circuit breakers	$1,655	$1,883	$1,655
Relay inspection & maintenance	2,237	2,830	2,237
Miscellaneous equipment	2,790	3,235	2,790
Transformer Maintenance	1,076	687	687
Capital-related	3,135	4,246	1,991
Total	**$10,893**	**$12,881**	**$9,360**

SCE's forecasts are all developed utilizing its own forecasts of capital additions in each the sub-category for TY2012 and unit costs that are either five-year averages or 2009 (LRY). For relay inspection and maintenance, SCE increased unit cost to reflect additional costs arising from new NERC/CIP regulations, resulting in a 26.5% increase over 2009. For capital-related expenses, SCE's test year forecast was based not only on expected substation capital expenditure but also the expected ratio of expense to capital.[479] SCE argues that DRA has not opposed its capital increases in these equipment areas and should not oppose the necessary additional O&M expense.

[479] SCE-18, Vol. 04, Pt. 7 at 15.

DRA rejects use of SCE's proposed, but not authorized, capital expenditures as a reasonable basis for SCE's forecasts, and relies instead on LRY for all sub-categories except capital-related expenses. For relay inspection and maintenance, DRA argues that SCE's past replacement decisions should be yielding efficiencies and cost decreases in the test year. DRA based its forecast for capital-related expenses on a five-year average because these costs fluctuated significantly over the prior five years, with the highest costs recorded in the two prior test years: 2006 and 2009.

We have concerns about SCE's reliance on requested capital expenditures in the test year to develop its forecasts for all of these substation activities. In all sub-categories, recorded expenses have fluctuated between 2005 and 2009.

For all but capital–related expenses, the Commission adopts DRA's forecasts as reasonable, including use of the highest recorded year (2009) for relay inspections and maintenance to account for new NERC requirements. We note that SCE's "weighted" average ratio of expenses to capital lacks support, but the result is sufficiently close to the five-year average to be reasonable.[480] As we did in SCE's 2009 GRC, we find the underlying cost drivers for capital-related (work order) expenses are capital projects.[481]

In this decision, we reduce SCE's forecasted TDBU capital-related expenditures by 9.4%. Therefore, the Commission finds it reasonable to similarly reduce SCE's TY forecast for capital-related O&M expenses in subaccount 570.150 by 9.4% of the incremental increase over 2009 recorded expenses of $3.135 million. The result is $4.142 million for capital–related expenses. We

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480 The five-year average ratio of expenses to capital is 1.08%.

481 D.09-03-025 at 68.

adopt the aggregate total of $11.511 million for all subcategories of this subaccount, a combined reduction of $1.370 million to SCE's forecast.

5.12.1.2. Substation Miscellaneous Expenses: 588.150

This subaccount includes expenses incurred as part of maintaining substations not directly related to inspection and maintenance programs, primarily for IT&BI business unit services and employee recognition.

SCE forecasts $674,000 ($0.233 million Labor, $0.441 million Non-labor) for these miscellaneous expenses in 2012. DRA recommends $0.249 million based on a five-year average of expenses after removing employee recognition expenses calculated as non-IT&BI expenses. SCE disputes both the removal of employee recognition programs and DRA's calculations thereof.

We are persuaded that SCE's recorded five-year average for miscellaneous expenses, other than employee recognition, is $561,000. Accordingly, the Commission finds reasonable and adopts $561,000 as the forecast for O&M expenses for miscellaneous Substation Expenses in subaccount 588.150 for TY2012, a reduction to SCE's forecast of $113,000.

We take up the issue of employee recognition and bonus programs in Section 8.5.

5.12.1.3. Distribution Substation Inspection and Maintenance: 592.150

Subaccount 592.150 includes expenses associated with inspection and maintenance of circuit breakers, relays, and miscellaneous equipment in distribution substations. Four new distribution substations were added by SCE in 2010, and the utility plans to add eight more by 2012.

SCE developed its forecast of $11.760 million ($2009) based on asset count, including estimated growth, and unit cost per asset. This is a 17.2% increase over

2009 expenses of $10.038 million. DRA used SCE's LRY as a basis for its forecast of $9.748 million for the test year. DRA accepts SCE's forecast for transformer maintenance,[482] but challenges the remaining categories of circuit breakers, relay, and miscellaneous equipment inspection and maintenance costs.

We have concerns about SCE's reliance on requested capital expenditures in the test year to develop its forecasts for all of these substation activities. For inspection and maintenance of distribution substation circuit breakers, and miscellaneous equipment, recorded costs and units replaced varied considerably between 2005 and 2009. For 2012, SCE estimates the number of circuit breakers in asset base will increase more than twice as fast as in any historical year. Also, despite additions of 17 substations between 2007 and 2009, recorded costs for miscellaneous equipment decreased significantly.

Use of a five-year average of historical costs is a more reasonable approach for these sub-categories, although DRA's forecast of $3.541 for miscellaneous equipment is sufficiently similar to the five-year average to be reasonable. For the relay inspection and maintenance portion of the subaccount, SCE's forecast seems reasonable in light of upward trends to both units and costs, as well as additional NERC-related activities.

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[482] SCE's forecast is very similar to a five-year average of historical costs for this sub-category.

Distribution Substation Maintenance O&M Expense Request, subaccount 592.150 (Constant 2009 $, 000)			
Sub-category of 592.150	**Requested**	**Adopted**	**Disallowed**
Circuit breakers	$3,460	$3,258	$202
Relays (including incremental NERC/CIP)	1,944	1,944	0
Miscellaneous equipment	4,868	3,541	1,327
Transformer maintenance	1,488	1,488	-
Total	**$11,760**	**$10,231**	**$1,529**

Therefore, the Commission allows a total of $10.231 million ($2009) for O&M expenditures in Subaccount 592.150 as set forth above.

5.12.2. Capital Expenditures

For SC&M capital expenditures, SCE forecasts spending $218.0 million from 2010-2012 and $392.297 million from 2010-2014. According to SCE, the majority of these expenses include the removal, replacement, and retirement of substation equipment and structures where imminent equipment failures or safety issues are detected or after in-service failures. Additional categories of capital include storms, claims, Rule 20 circuit breakers in conversions to underground projects, and added facilities.

For 2010, DRA recommends using SCE's actual 2010 capital expenditures of $59.722 million. For 2011 and 2012, DRA does not dispute SCE's forecast for substation storm capital and substation claims. However, DRA recommends reductions totaling $64.540 million from SCE's forecast for 2011 and 2012 related to substation capital maintenance, Rule 20, and substation added facilities.

Substation Capital Maintenance Capital Expenditure Request						
	Capital Request by Year ($000)					
Project Description	**2010 Recorded**	**2011 Forecast**	**2012 Forecast**	**Total 2010-2012**	**Adopted**	**Disallowed**
Capital Maintenance	$33,449	$41,933	$42,952	$118,334	$103,173	$15,161
Storm Capital	546	784	802	2,132	2,132	-
Claims	120	475	486	1,081	1,081	-
Rule 20 B, C Circuit Breakers	2	500	512	1,014	376	638
Added Facilities SCE Funded	8,768	14,406	14,369	37,543	37,543	-
Added Facilities Customer Funded	16,837	22,346	18,715	57,898	57,898	-
Total	**$59,722**	**$80,444**	**$77,836**	**$218,002**	**$202,203**	**$15,799**

5.12.2.1. Substation Capital Maintenance

These expenditures are associated with removal, replacement, and retirement of assets on a reactive basis. They are driven by SCE's Substation Preventive Maintenance program which is charged with detecting imminent equipment failures and safety issues.

SCE forecasts capital spending of $41.933 million ($nominal) in 2011 and $42.952 million in 2012, for a 2011-2012 total of $84.885 million. SCE separately calculated both historic and forecast "planned" maintenance and "reactive" maintenance costs, choosing as a base point the highest historical recorded year for each (2007 and 2009, respectively).[483] After a 2007 spike, capital expenses in this sub-category have been declining due to design and other delays, according to SCE. DRA accepts SCE's 2010 recorded expenditures of $33.449 million.

[483] SCE-18, Vol. 04, Pt. 7 at 3, Table II-2.

DRA recommends $34.424 million ($nominal) for 2011 and $35.300 million for 2012, a total reduction of $15.161 million (17.9%), based on a five-year average of historical costs. DRA argues that the record does not support SCE's proposed 26.6% increase from its 2009and 2010 recorded expenditures. On the other hand, SCE contends that using a five-year average to forecast the work in these categories is inappropriate because planned and reactive capital maintenance costs are not random.

We are not persuaded that SCE's methodology is reasonable. SCE states it chose 2007 recorded expenditures for planned maintenance because it was a "desirable and achievable goal."[484] It chose 2009 recorded costs for reactive maintenance because SCE "deemed [it] to be most representative of the system and operational needs."[485] SCE has little choice about spending on reactive maintenance, but routinely re-sets priorities for planned maintenance. SCE's spending declined in 2008-2009. Notwithstanding spending over $33 million in 2010, it has not established the necessity nor the capability to accelerate its planned maintenance to unprecedented levels in 2011 and 2012.

The Commission finds reasonable and adopts SCE's recorded 2010 expenditures and DRA's forecast capital expenditures for 2011 and 2012 based on a five-year average of historic costs.

5.12.2.2. Rule 20B and C

Rule 20B and Rule 20C are tariffs that provide for the replacement of overhead facilities with underground equipment when requested by customers.

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[484] *Id*. at 4.

[485] *Ibid*.

This work category includes replacement and installation of circuit breakers to accommodate overhead to underground conversion for distribution customers. Since 2007, SCE's Substation Rule 20B and 20C capitalized expenditures have been declining; SCE's 2010 actual expenditures ($2,000) are substantially lower than in 2009.

SCE forecasts $500,000 in 2011 and $512,000 in 2012 for replacement and installation of circuit breakers to accommodate overhead to underground conversions for distribution customers. SCE uses a five-year average to develop its forecast.

DRA recommends $185,000 for this activity in 2011 and $189,000 in 2012, for a total 2011-2012 reduction of $638,000, based on SCE's 2009 recorded level of expenditures. According to DRA, Substation Rule 20 B and C capitalized expenditures have been declining since 2007 due to the economy and 2009 recorded reflects current conditions.

The Commission finds reasonable and adopts DRA's forecasts for 2011 and 2012 and we expect SCE to fully spend these amounts on undergrounding conversion projects.

5.12.2.3. Added Facilities

Substation Added Facilities are facilities requested by an applicant which are in addition to or in substitution for standard facilities which would normally be provided by SCE.[486] As for other Added Facilities, at the customer's request, SCE may provide additional facilities materials and equipment for various distribution substation enhancements. Regardless of whether it is customer- or

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[486] SCE's Tariff Rule 2(h), and Rule 21.

SCE-financed, customers pay a monthly fee to SCE based on the total installed cost of the equipment. Revenues from these projects are treated as "Other Operating Revenue."[487]

For substation added facilities funded by SCE, SCE forecasts expenditures of approximately $14.4 million ($nominal) in each of 2011 and 2012. SCE's forecast is based on estimates for known and upcoming work load. DRA recommends approximately $5.1 million in 2011 and $5.3 million in 2012 based on a five-year average.

For substation added facilities funded by the customer, SCE forecasts $22.3 million in 2011 and $18.7million in 2012. DRA recommends $5.1 million in 2011 and $5.3 million in 2012, based on a five-year average. According to SCE, the capital expenditures in the customer-funded substation added facilities are paid by the customer upfront.

SCE states, "[A]fter accounting for the funding for these projects, the forecast in this account is revenue neutral to ratepayers. Since these expenditures do not impact revenue requirements, as stated in rebuttal testimony, SCE is willing to accept DRA's forecast if a reduction is made in SCE's OOR forecast corresponding to the reduction adopted in the added facilities capital expenditures."[488]

We are persuaded that DRA's use of a five-year average is not as reliable for this category of expense as SCEs approach. SCE's forecast is more reasonable because it is based on actual planned work following pending and approved

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[487] *Ibid*.

[488] SCE OB at 146-147.

applications for added facilities. Therefore, the Commission adopts SCE's forecasts for 2011 and 2012 for added facilities.

5.13. T&D – Transmission

SCE's Transmission system consists of transmission lines and substation facilities that operate at voltage levels of 500 kV, 220 kV, 115 kV, 66 kV, and 33 kV. Generally, the higher voltage assets (220-500 kV) are under the jurisdiction of FERC, while the lower voltage transmission assets (33-115 kV) are under the jurisdiction of the CPUC. The costs of this work are shown in total and are split between FERC and CPUC jurisdictional costs in the RO model. At the end of 2009, SCE's transmission system included 1,125 circuits comprised of 11,942 miles of overhead lines, 336 miles of underground lines, 127,244 poles, and 25,669 towers.

5.13.1. Operations and Maintenance Expenses: 563.160, 564.160, 566.160, 567.160, 571.160

SCE's Transmission-related O&M expenses cover ten sub-categories of work activity that are recorded in five subaccounts.[489] SCE forecasts approximately $56 million ($2009) in O&M expenses for TY2012. SCE based its forecasts on 2009 recorded expenses, plus incremental costs based on new asset additions. Capital-related expense is the largest category with a test year forecast of $14.235 million.

The corresponding DRA estimate for Transmission O&M expenses is $45.360 million, $11.004 million (19.6%) less than SCE's forecast. DRA's forecasts

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[489] Expenses for new transmission interconnection projects and substation projects are separately discussed in testimony and are discussed elsewhere in this decision.

were nearly all 2009 actual recorded costs, and include reductions to SCE's forecasts in every sub-category except Transmission Maintenance.

5.13.1.1. Overhead Transmission Line Inspections: 563.160

Overhead Transmission Line Inspections expenses include the costs of patrolling SCE's overhead transmission lines, and all the poles and towers supporting them. Subaccount 563.160 includes two expense line items: Overhead Transmission Line Inspection and Intrusive Pole Inspections.

SCE forecasts $3.851 million total for subaccount 563.160 (Labor of $2.336 million and Non-labor of $1.515 million) for TY2012, an increase of $1.181 million (44.23%) over 2009 recorded adjusted expenses of $2.670 million. DRA based its forecast of $2.683 million for this subaccount on 2009 recorded costs because SCE's costs have declined since 2007.

Overhead Line Inspections

These activities are performed to comply with the Commission's GO 95. SCE's overhead inspection expense forecast of $3.171 million is derived from a five-year average of annual inspection expenses-per-transmission line miles for 2005-2009 and estimated line miles it expects to add in 2010-2012.[490] DRA concluded that 2009 recorded costs of $2.609 million is sufficient because the amount of transmission line miles appears to have no historic relation to the recorded costs and SCE has embedded funding to handle routine activities.

Reliance on LRY may not be the most reasonable forecast method because the total expenses and unit costs in this category fluctuate according to a number of variables, primarily fires and weather. In addition, SCE has not established

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490 JCE at 255.

that it is able to add the proposed 188 miles/year 2010-2012 upon which it bases its forecast, given that the most SCE has added to its inventory since 2005 is 14 miles in 2008. Moreover, the record does not establish that SCE's installation of additional overhead line miles bears a direct correlation to actual inspection costs in that year.[491]

Therefore the Commission finds it reasonable to utilize 2009 recorded costs as recommended by DRA for a TY2012 amount of $2.609 million ($2.183 million Labor, $0.426 million Non-labor).

Intrusive Pole Inspections

SCE's pole inspection costs of $0.680 million are estimated based on the number of intrusive pole inspections it expects to perform in 2012, which is more than ten times the number of inspections it performed in 2008 or 2009, but less than in 2007. These costs have varied widely since 2005. SCE states it is moving to levelize intrusive inspections at 15,000/year based on a 10-year cycle in common with PG&E and SDG&E.[492] SCE performed 1,290 intrusive pole inspections in 2008 and 1,312 in 2009.

DRA recommends a reduction to SCE's forecast to $74,000. DRA concludes that LRY is the most reasonable basis to forecast test year expenses due to a lack of historic data, and because embedded funding exists from unspent, but authorized, funds from the 2009 GRC and is available for any routine growth. SCE provided five years of data in rebuttal testimony.[493]

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[491] SCE-03, Vol. 05, Pts. 7 & 8 at 83.

[492] *Id*. at 85.

[493] SCE-18, Vol. 4, Pt. 8 at 7.

We are cognizant of the reliability consequences of in-service failure of transmission poles. SCE's commitment to perform pole inspections on a 10-year cycle under its new grid-based inspection program is in the ratepayer's interest and conforms with SCE's prior commitments to CAISO. On the other hand, SCE has not established that it is capable of performing such an abrupt and extraordinary increase to the number of pole inspections. This is especially so, given the forecast decline in inspections to 5,307 in 2011, and SCE's point of the specialized training required by the work force.

Giving SCE the benefit of the doubt, it is reasonable to believe that SCE will ramp up its inspections, as it says, and may double its 2011 inspections to 10,614 in 2012. Therefore, the Commission finds it reasonable to reduce SCE's forecast to provide for 10,614 inspections at SCE's unit cost of $46,000 per inspection, for a total TY2012 amount of $0.488 million. However, in order to assess whether the ramped up inspection schedule results in enhanced reliability and safety, SCE should include with the next GRC, a summary of the inspection results by category of identified repair (i.e., 1, 2, or 3).

5.13.1.2. Underground Transmission Line Inspections: 564.160

SCE conducts annual patrols of its 336 miles of underground transmission lines and the structures patrolling them to comply with GO 128 and SCE's CAISO-approved inspection program. Additional inspections are conducted after unplanned events, primarily fire and weather conditions. SCE explains that recorded expenses and unit costs peaked in 2007 then declined in 2008 and 2009 due to a decline in requests to locate and mark underground facilities (prior to digging activities by anyone).

In $2009, SCE forecasts $0.991 million ($0.742 million Labor, $0.249 million Non-labor) based on a five-year average of cost per line mile, and an estimated addition of 25 line miles between 2010 and 2012.

DRA recommends the Commission approve $0.720 million, the equivalent of 2009 recorded expenses. In DRA's view, costs have declined to historic levels since 2007 and it finds no apparent relationship between SCE's total line miles and recorded costs.

We find that the number of line miles SCE estimates it will add by 2012 is reasonable and within the range of prior work; however, it is not as dominant a factor as external variables such as weather and the economy (i.e., more locate activities).

Therefore, the Commission finds it reasonable to reduce SCE's forecast for additional expenses by 10%, pro rata Labor and Non-labor, for a TY2012 amount of $0.892 million.

5.13.1.3. Miscellaneous Transmission and Other Transmission Expenses: 566.160

The costs recorded in this subaccount include encroachment (unauthorized use of SCE property) work and activities related to right of way usage, as part of SCE's Compliance and Enforcement Program.[494] There are two line item expenses in the subaccount: Miscellaneous and Other transmission expenses.

SCE's total TY2012 forecast for Miscellaneous and Other transmission expenses is $7.230 million ($4.702 million Labor, $2.528 million Non-labor).

[494] SCE-03, Vol. 04, Pts. 7 & 8 at 100.

Miscellaneous Transmission Expenses

To develop its TY2012 forecast of $5.140 million ($2009) for the Miscellaneous Transmission portion of subaccount 560.160, SCE utilized 2009 recorded adjusted expenses per transmission line mile times the number of transmission line miles forecast to be on its system in 2012. Recorded costs varied between 2005 and 2009. SCE explains that expenses were highest in 2007 due to encroachment work arising from an increase in residential and commercial development, which declined along with costs in 2008 and 2009.[495]

DRA's forecast is $4.904 million, equal to SCE's 2009 recorded expenses. DRA states that SCE did "not explain the relationship between the decreases in recorded expenses for this line item during the historical period, and the increases in line miles, nor do they demonstrate that SCE's current funding level is insufficient."[496]

The correlation between line miles and recorded expenses is not well established. SCE explained its varying historical costs as primarily a function of the level of encroachment work related to new development. Elsewhere in this decision, we adopted a lower forecast than SCE for customer growth. On the other hand, we expect addition of new transmission lines on SCE's system during this rate cycle, and agree that adding line miles will have some impact on encroachment work.

Therefore, the Commission finds it reasonable to adopt SCE's forecast of $5.140 million for TY2012 Miscellaneous Transmission Expenses in subaccount 566.160.

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495 *Id*. at 102.

496 DRA-05 at 82.

Other Transmission Expenses

This line item reflects other expenses, including those for employee information meetings, communication line expenses, employee recognition and bonus awards, and the Transmission program (a workforce pipeline program that provides specialized training for transmission line work).

SCE's TY2012 forecast is $2.090 million, a 201.15% increase over 2009 almost entirely due to the first-time addition of $1.630 million for the Transmission Program. The union-backed program provides specialized training to attract and retain a stabilized workforce as part of the six-year training of transmission linemen. Employees who commit to the three-year program receive a bonus recorded in this account.[497]

DRA recommends removal of all employee bonus and recognition programs: the $1.630 million for the Transmission Program and $0.68 million for other employee awards.

SCE has provided evidence that its retention rate for transmission linemen has significantly improved, to 97%, since the Transmission Program went into effect. Additionally, retaining Transmission linemen reduces costs that would otherwise be incurred for recruitment, and experienced Transmission linemen results in both increased work efficiency and safety.[498]

Therefore, we find that the costs of the Transmission Program result in a benefit to ratepayers because the program leads to a more stable workforce in a key area that impacts reliability and safety, in addition to providing reductions

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497 SCE-18, Vol. 04, Pt. 8 at 11-12.

498 *Id*. at 12-13.

to other costs, e.g., apprentice classes. This employee bonus program stands out among the others by evidence of direct cost benefits to ratepayers.

The Commission adopts a TY2012 forecast of $2.090 million for expenses for this line item in subaccount 566.160. In order to better evaluate the benefits going forward, SCE shall provide a cost-benefit analysis in the next GRC related to the Transmission program expenses and the consequential benefits to ratepayers.

5.13.1.4. Transmission Line Rents: 567.160

Transmission line rents are expenses to rent non-SCE property that SCE must use, occupy, or operate in connection with its transmission system, primarily for transmission line rights of way on public and private land. Historical cost increases are linked to rent increases imposed by the U.S. Forest Service (USFS), Bureau of Land Management (BLM), and Union Pacific, Burlington Northern, and the Santa Fe Railroads.

SCE forecasts $8.224 million ($7.408 million Non-labor and $0.816 million Other) for TY2012 O&M in this subaccount, an addition of $2.686 million (48.5%) over SCE's 2009 recorded expenses of $5.538 million. SCE explains that the increase is due to increasing rents, some of which are part of a negotiated delay until 2010 of a portion of the rent increases implemented by BLM and USFS in 2009.

DRA recommends the Commission adopt 2009 recorded expenses of $5.538 million as the TY2012 forecast for expenses in this subaccount. In its view, SCE has not justified the requested increase because it did not provide "specific documentation and reference material" or specific contracts to determine the reasonableness of SCE's claims. DRA concludes that SCE has embedded funds to address rent increases given that SCE spent $48 million less than authorized for total TDBU O&M in the 2009 GRC.

We do not adopt DRA's position. First, the expenses in this subaccount are directly related to rent payments to government entities or third parties. Therefore, reliance on historical costs is misplaced in light of evidence that the rent charges will increase during the rate cycle. SCE also supported its claims of increased rents, and provided DRA with information that its 2009 expenses for this category were more than the $4.611 authorized by the Commission.[499]

Therefore, the Commission finds SCE's forecast of $8.224 million to be reasonable and adopts it for TY2012 O&M expenses for subaccount 567.160.

5.13.1.5. Transmission Maintenance Expenses: 571.160

The costs recorded in this subaccount for Transmission Maintenance Expenses can be for proactive work identified during regular inspections, or reactive maintenance due to storms or other unplanned events. SCE's proactive maintenance on its transmission system is performed in accordance to its Programmatic Maintenance program.

DRA does not contest SCE's forecast of $8.861 million for TY2012, a decrease of $0.949 million compared to 2009 recorded expenses due to a correction for erroneously recorded expenses during 2005-2007. We find SCE's forecast reasonable and adopt it for TY2012 O&M expenses for this line item.

[499] *Id*. at 14-15, Attachment 7.

5.13.1.6. Insulator Washing Expenses: 571.160

SCE washes insulators by various means to remove contaminants that could compromise reliability of service and public and worker safety.[500] Major sources of contamination are coastal weather patterns, low rainfall, and industrial activity near transmission lines. Recorded costs for this activity peaked in 2008, then declined in 2009 which SCE explains as due to several vehicle retirements.

SCE utilized a five-year average of cost per overhead transmission line mile times the number of overhead line miles forecast to be on its system in 2012 to develop its TY2012 forecast of $3.929 million for Insulator Washing expenses. DRA's forecast of $3.709 million is the equivalent of 2009 recorded expenses, a 5.6% reduction to SCE's forecast.

SCE did not establish that TY2012 cost increases will primarily be driven by newly added line miles. On the other hand, we find LRY is not the most reasonable forecast method because the total expenses and unit costs in this category fluctuate according to a number of variables, including weather, equipment and vehicle costs, and location of line miles.

Therefore, the Commission finds reasonable and adopts SCE's TY2012 forecast of $3.929 million, a modest increase to account for a generally upward trend of costs since 2005 and to reflect our expectation of additional line miles in remote areas to link new renewable generation.

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[500] SCE-03., Vol. 04, Pts. 7 & 8 at 93.

5.13.1.7. Road and Right of Way (ROW) Maintenance: 571.160

The ROW Maintenance program expenses include the costs related to performing road grading, brushing, and weed abatement activities on or near SCE's roads and rights of way. Historic costs have fluctuated since 2005, including a 2008 low of $6.7 million and a 2009 high of $10.794 million. SCE ascribes the variations to compliance schedules, access issues driven by external agencies, and weather conditions (e.g., rain, fire).[501]

SCE forecasts $9.043 million for the TY2012 ROW Maintenance program expenses recorded in subaccount 571.160, a decrease of 16.2% from 2009. The forecast was developed by SCE using a five-year average of expenses per overhead line mile times the number of overhead line miles forecast to be on its system in 2012. SCE's estimate also increased the Labor to Non-labor ratio to 40% from a five-year average of 12%.

As a result of the historic fluctuations of Road and ROW Maintenance expenses, DRA utilized a five-year average of recorded Road and ROW Maintenance expenses to develop its forecast of $8.624 million. DRA's view is that "the amount of line miles in SCE's system does not appear to have caused major increases in historical expenses."[502]

We agree with SCE that right-of-way maintenance activities impact safety and reliability, and are a matter of compliance with state and local regulation. However, SCE did not adequately support its forecast. For example, SCE did not specifically explain the 2009 spike in recorded expenses, or establish a direct

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[501] *Id*. at 97.

[502] DRA-5 at 89-90.

relationship between SCE's total inventory of transmission line miles and ROW maintenance costs. These expenses appear to be driven more by external factors than line miles, and not every new line mile is to a formerly inaccessible location requiring the same allocation of ROW cost.

Therefore, the Commission finds reasonable and adopts DRA's estimate of $8.624 million for TY2012 ROW Maintenance program expenses in subaccount 571.160, modified to accept SCE's Labor to Non-labor ratio of 40%.

5.13.1.8. Capital-Related O&M Expenses: 571.160

Examples of capital-related expenses include: paving the ground for new equipment, repairing or strengthening structures, relocation of equipment to accommodate new additions to an existing facility, switch-rack reconfiguration, and secondary wiring.

SCE requests $14.235 million, a $4.306 million (43.4%) increase over 2009 recorded expenses. SCE utilized a five-year average ratio of capital-related expense to Transmission capital expenditures, times the forecast transmission-related capital expenditures for 2012-2014, which was then normalized.

DRA recommends the Commission adopt 2009 recorded expenses as for TY2012 capital-related O&M. DRA points out that capital-related costs fluctuated between 2005 and 2009, historical expenses capture routine and on-going expenses, and SCE's capital request may be reduced.[503]

As we did in the 2009 GRC, we find the underlying cost drivers for work order expenses are capital projects. In this decision, we reduce SCE's forecasted

[503] DRA-5 at 93.

TDBU capital expenditures by 9.4%. Accordingly, we find it reasonable to reduce SCE's forecasted capital-related work order expenses in subaccount 571.160 by 9.4% of the forecasted $4.3 million TY increase over 2009 recorded expenses of $9.929 million, a decrease of $0.405 million.

Therefore, the Commission allows a total of $54.687 million ($2009) for Transmission O&M expenditures in subaccounts 563.160, 564.160, 566.160, and 571.160 as set forth below.

T&D--Transmission O&M Expense Request (2009 $000s)				
Account	**Description**	**Requested ($000)**	**Adopted**	**Disallowed**
563.160	OH Trans Line Inspections	$3,171	$2,609	$562
"	Intrusive Pole Inspections	680	488	192
564.160	UG Trans Line Inspections	991	892	99
566,160	Miscellaneous	5,140	5,140	-
"	Other	2,090	2,090	-
567.160	Transmission Line Rents	8,224	8,224	-
571.160	Transmission Maintenance	8,861	8,861	-
"	Insulator Washing	3,929	3,929	-
"	Road and ROW Maint	9,043	8,624	419
"	Capital-Related	14,235	13,830	405
Transmission O&M Expense Total		**$56,364**	**$54,687**	**$1,677**

5.13.2. Capital Expenditures

For 2011-2012 Transmission capital expenditures, SCE requests $66.016 million, and estimates $202 million in expenditures for 2010-2014, of which $180 million are CPUC-jurisdictional.

DRA recommends $58.323 million making one adjustment described below.

5.13.2.1. Transmission Deteriorated Poles

At the end of 2009, SCE had 127,244 wood poles in its transmission system. SCE replaces transmission poles for a variety of reasons, including being unsuitable for climbing, not strong enough to support new equipment, or have reached the end of their service life.[504] Nearly all of the work is performed by outside contractors and prices are set through the competitive bidding process.

SCE plans to make capital expenditures of $14.595 million ($nominal) in 2011 and $14.966 in 2012 based on replacing 800 poles each year times the 2009 recorded cost-per-pole replacement of $17,600. DRA accepts SCE's 2010 recorded costs of $9.923 million ($nominal).

DRA recommends $5.338 million in 2011 and $5.474 in 2012 based on its own calculations using the 20-year inspection cycle of GO 165, SCE's second cycle inspection failure rate, new 2010 requests, and SCE's 2009 average replacement cost. DRA continues its objections to SCE' 10-year inspection program and contends replacement of 293 poles in both 2011 and 2012 is adequate.

The main difference between the parties is the number of poles that have already been identified as requiring replacement. According to SCE, at the end of 2010 it carried over 604 poles that required replacement, and the utility has an additional 249 poles that have already been identified as requiring replacement in 2011.[505] DRA acknowledged that it did not consider this backlog in its forecast capital expenditures.[506]

DRA is incorrect that transmission intrusive pole inspections should be performed in accordance with GO 165 which sets inspection cycles for electric distribution facilities. We find that SCE's new 10-year inspection cycle for wood

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504 SCE-03, Vol. 04, Pts. 7 & 8 at 110 (The mean average age of these poles is 40.3 years.).

505 SCE-18, Vol. 04, Pt. 8 at 22.

506 *Id*. at Attachment 9.

poles has ratepayer benefits at this time due to the age of SCE's wood transmission poles. However, the accelerated pace is likely to lead to higher replacement rates than DRA estimates in this rate cycle.[507]

Over the past five years (2005-2009), SCE has replaced an average of 700 poles per year. We find that SCE's forecast to replace 800 wood transmission poles annually is reasonable given its prior pace and the back log of poles awaiting replacement.

Therefore, we find reasonable and adopt SCE's recorded 2010 expenditures, and SCE's forecast for 2011 and 2012 capital expenditures for deteriorated transmission wood pole replacements.

5.13.2.2. Transmission Maintenance Capital

Transmission Maintenance expenditures include the cost of replacing transmission equipment that fails in service. SCE's revised forecast, after correcting an error identified by DRA, is $5.807 million in 2011 ($nominal) and $5.955 million in 2012. The forecast is no longer disputed by DRA.

5.14. T&D – Business Process and Technology Integration (BP&TI)

The BP&TI group makes routine assessments of current work processes and information technology in the field, reviews changing requirements, and develops and implements process improvements and technology solutions that sustain safe and reliable service. BP&TI's request in this proceeding includes capital expenditures for technology solutions and O&M expenses for various technology integration activities.

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507 SCE-03, Vol. 04, Pts. 7 & 8 at 111, Figure II-51.

5.14.1. O&M expenses: FERC subaccounts 566.270 and 588.270

For TY2012, SCE forecasts O&M expenses of $20.217 million, including those expenses needed to support capital expenditures, and forecasts $1.456 million in productivity benefits that reduce SCE's O&M forecast to $18.761 million.[508] The O&M forecasts for BP&TI are included in two subaccounts driven by three primary activities – expenses associated with development and implementation of capital projects, on-going maintenance of field tools and software currently in use, and IT support for TDBU in general.

5.14.1.1. Technology Solution Implementation: 588.270

Subaccount 588.270 includes three categories of expenses: capital project-specific expenses, non-capital project expenses, and miscellaneous expenses. SCE's forecasting methodology varies for each expense category.[509] SCE's TY2012 estimate for this subaccount is $12.373 million ($2.684 million Labor, $9.689 million Non-Labor), a $1.695 million decrease from 2009 recorded expenses. DRA recommends a TY2012 reduction of $5.041 million to SCE's forecast without distinction as to category of expense.

<u>**Capital project related expenses**</u>

The largest portion of this subaccount, $7.734 million ($2009), is for capital-project expenses, which in 2012 involves three projects: Geographic Information System (GIS), Consolidated Mobile Systems (CMS), and Distribution Management System (DMS). DRA rejects SCE's forecast methodology for this

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[508] DRA-5 at 156.

[509] SCE-18, Vol. 05, Pt. 1 at 2.

sub-category which was developed using a budget-based approach. Although DRA views these costs as fluctuating historically, SCE views them as a reflection of the unique nature of the capital projects underway as opposed to those in prior years.[510]

DRA relied on a five-year historical average of combined expenses for this subaccount, after removing from 2009 recorded expenses, $7.523 million of GIS and Wires Investment Strategy Efficiency Review (WISER) related costs on the grounds the expenses were non-recurring. (DRA also removed $1.4 million for employee recognition expenses discussed below.)

Both recorded capital-related and recorded total expenses for this subaccount declined between 2005 and 2008; the 2008 low costs of $2.07 million grew in 2009 to $9.941 million driven by costs related to implementation of GIS and WISER. We find that capital project costs are linked to the specific projects undertaken during the rate cycle, such that SCE's forecast method is more appropriate than a look back at historical activity.

Therefore, the Commission finds reasonable and adopts SCE's forecast of $7.734 million for capital project costs given the Commission's approval of capital funding for the GIS, CMS and DMS programs elsewhere in the decision. Given SCE's self-described urgent need to complete the integrated IT effort represented by GIS and WISER here, we expect the company will timely complete implementation of both GIS and WISER without returning for additional costs in the next GRC.

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510 *Ibid.*

Non-Capital Project expenses

Non-Capital Project expenses, which include costs necessary to implement new minor software projects and perform enhancements on existing systems, are forecast to be $3.5 million, based on a ratio of enhancement to original capital spending for new capital software projects.[511] Recorded costs have fluctuated since 2005 and the five-year average is similar to 2009 recorded expenses of $2.291 million.

SCE explained that it has delayed some enhancement while implementing its new integrated technology plan. The test year O&M forecast assumes that the current backlog of projects will have been cleared and all anticipated enhancements for the new TDBU capital software projects discussed below will be authorized and occur. SCE forecasts $2 million in TY2012 costs, but a total of $10.5 million from 2012-2014 which it normalizes to $3.5 million per year for the test year forecast.

We find that SCE did not adequately explain the basis for its 2012-2014 cost forecast which it relied upon to adjust its TY forecast of $2 million to $3.5 million for this sub-category. SCE's assumption that a prior ratio of upgrade costs to capital software expense is applicable to different, not yet purchased software is not persuasive. Therefore, we adopt 2009 recorded expenses of $2.291 million, just slightly higher than the five-year average for this activity.

Miscellaneous expenses

Miscellaneous expenses include costs related to software licenses, Power Delivery consultant costs, employee recognition programs, and BP&TI meeting

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[511] *Ibid.*

expenses. SCE's TY forecast is $1.139 million based on five-year historical average of recorded costs.

DRA recommends removal of employee recognition expenses of $0.282 million, based on a five-year average of recorded costs.[512] Similar to other sections of this decision, we exclude $0.282 million in estimated costs for employee bonus programs from this test year forecast and discuss the matter in Section 8.5.

Therefore, the Commission finds reasonable and adopts $0.857 million for TY2012 O&M costs for this sub-category.

In total, for subaccount 588.270, the Commission authorizes a total of $10.882 and disallows $1.491 million as illustrated in the table below:

Business Process and Technology Integration O&M Expense Request (Distribution)				
Technology Solution Implementation Expenses				
Account	**Description**	**Requested (2009 $000)**	**Adopted**	**Disallowed**
588.270	Capital Project Specific	$7,734	$7,734	-
"	Non-Capital Projects	3,500	2,291	1,209
"	Miscellaneous	1,139	857	282
Total 588.270	**BP&TI O&M Expense Total**	**$12,373**	**$10,882**	**$1,491**
Total 588.271	**CMS and WISER O&M benefits (50%)**	**($1,456)**	**($1,456)**	**-**

The Commission also recognizes SCE's TY2012 forecast of $1.456 million in new initiative benefits in subaccount 588.271 as the result of the CMS and WISER programs. No party had issues with the CMS program and those O&M expenses are approved herein. We accept SCE's proposal to evenly allocate the benefits

512 JCE at 422.

between shareholders and ratepayers. The adopted benefits result in an offset to forecast total test year BP&TI O&M expenses.

5.14.1.2. Transmission Substation Information Technology (IT) Interdepartmental Market Mechanism (IMM): 566.270

This subaccount records two types of expenses: IT IMM costs and capital-related expenses to support two contested capital projects, C-RAS[513] and Phasor Measurement,[514] discussed in Section 5.2.6 of this decision. IMM costs include support of employee computers, cellular voice and data services, and multi-function copiers.

SCE's TY2012 estimate for O&M is $7.844 million, comprised of $6.013 million for IMM and $1.831 million for capital-related expenses. To prepare the forecast, SCE used the 2009 recorded expense of $6.013 million, plus the three-year 2012-2014 forecast average for the C-RAS and Phasor Measurement projects.

DRA recommends $6.013 million because it concludes that SCE disregards embedded funding associated with closed or completed projects which could be re-directed to test year projects.[515] DRA utilized SCE's LRY, the highest level of expenditures for the five-year period through 2009, as a basis for its forecast.

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513 SCE-03, Vol. 5, Pt. 1 at 46 (SCE states the Centralized Remedial Action Scheme is a project is intended to centralize coordination of various new transmission system protection schemes).

514 *Id*. at 47 (SCE states that continued installation of higher-capability phasor measurement equipment and monitoring and control applications will help SCE system operators *leverage the data to increase* grid reliability).

515 DRA-5 at 158-159.

We agree that 2009 recorded expenses are an appropriate basis to forecast IMM costs due to the upward trend in spending. We also find that capital-related costs are related to the specific capital projects forecast to be underway during the test year. However, SCE's use of requested 2012-2014 capital expenditures to support test year O&M is speculative. Elsewhere in this decision, we authorized SCE's request for funding the Phasor Management program, but disallowed 2011 and 2012 spending on C-RAS, as recommended by TURN and DRA.[516]

Therefore, the Commission finds reasonable and approves $6.013 million for IMM costs in 2012, and excludes support costs for C-RAS to conform with our disallowed capital funding. The result is a total of $6.920 million ($0.048 million Labor, $6.872 Non-labor) for TY2012 O&M costs for this subaccount.

For total BP&TI O&M expenses combined with New Initiatives Benefits, the Commission approves a total $16.346 million of the $18.761 million request, as indicated in the table below:

Total BP&TI O&M Expense (2009 $000's)				
Account	**Description**	**Requested**	**Adopted**	**Disallowed**
Total 588.270	Technology Solution Implementation	$**12,373**	**$10,882**	**$1,491**
Total 566.270	Transmission Substation IT IMM	7,844	6,920	924
Total 588.271	CMS and WISER Benefits	(1,456)	(1,456)	-
	BP&TI O&M Expense Total	**$18,761**	**$16,346**	**$2,415**

516 *See* Sections 5.2.6.2 and 5.2.6.3.

5.14.2. BP&TI Capital Expenditures

SCE forecasts 2010-2012 capital expenditures of $56.353 million for two projects: GIS and CMS. As discussed above, GIS is intended to provide a map based view of all work, workers, and assets from a single source. SCE claims various reliability, employee safety and public safety benefits from the project.[517] CMS includes: (1) a collection of field computing devices; (2) a mobile software application; and, (3) required infrastructure that will "enable field personnel, system operators, and office workers to share real-time information that will enhance SCE's safety, improve outage responsiveness, and contribute to SCE meeting its compliance obligations."[518] Neither DRA nor any party takes issue with SCE's BP&TI capital forecast.[519]

The Commission adopts BP&TI capital expenditures of $56.353 million for 2010-2012, as illustrated in the table below:

BP&TI Capital Expenditure Request ($nominal 000s)						
	Capital Request by Year					
Project Description	**2010 Recorded**	**2011 Forecast**	**2012 Forecast**	**Total 2010-2012**	**Adopted**	**Disallowed**
Geographical Information System	$8,095	$15,250	$15,000	$38,345	$38,345	$0
Consolidated Mobile Solutions	9,257	6,750	2,001	18,008	18,008	0
Total Capital Expense	**$17,352**	**$22,000**	**$17,001**	**$56,353**	**$56,353**	**$0**

[517] SCE-03, Vol. 05, Pt. 1 at 12-13.

[518] *Id*. at 21.

[519] SCE OB at 156.

5.15. T&D—Technical Services

This organization is comprised of three groups: TDBU Safety and Environmental Services (S&ES), TDBU Training, and Oversight and Quality Assurance. The vast majority of expenses are related to safety and other training costs for Transmission and Distribution employees.[520] The organization also handles environmental services and toxic wasted disposal for TDBU.

5.15.1. O&M Expenses: 566.250, 588.250, 582.250, 573.250, 598.250

SCE forecasts $68.311 million ($2009) in TY2012 O&M expenses to support the Technical Services Organization.[521] SCE's forecasts utilize 2009 recorded adjusted expenses, plus incremental expenses for proposed projects and activities. The corresponding DRA estimate is $57.379 million, a $10.932 million (16%) reduction.

O&M Expenses consist of five subaccounts: 566.250—Safety and Training—Transmission; 573.250—Transmission Toxic Waste Disposal; 582.250—Environmental Services; 588.250—Safety and Training, Distribution; 598.250—Distribution Toxic Waste Disposal.

SCE's testimony discussed these expenses by broad categories of safety, training, and environmental services. DRA approached the discussion by Subaccount. This decision has primarily reviewed O&M expenses by Subaccount and we follow that model here.

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520 SCE-03, Vol. 05, Pt. 2 at 1.

521 *Ibid*.

5.15.2. TDBU Safety and Training: 566.250, 588.250

For subaccount 566.250, SCE's forecast for TY2012 is $20.712 million and includes the transmission portion of safety expenses, training delivery, and training seat time. SCE forecasts $38.918 million for TY2012 expenses in subaccount 588.250, for distribution portions of safety expenses, training delivery, and training seat time. SCE allocated total safety expenses between transmission and distribution based on the 2009 ratio of recorded expenses (25%/75%) and allocated the forecast expenses between Labor and Non-labor based on the five-year average of Labor to total expenses for each account.

The table below illustrates SCE's and DRA's respective 2012 O&M forecasts for the Transmission and Distribution Safety, Training Delivery, and Training Seat-Time work activities, and the Commission's action:

Safety and Training Expenses (2009 $000s)					
Account	**Description**	**SCE**	**DRA**	**Adopted**	**Disallowed**
566.250	Transmission Safety	$3,065	$2,494	$2,869	$ 196
"	Transmission Training Seat Time	11,557	8,891	10,401	1,156
"	Transmission Training Delivery	6,090	5,653	6,090	0
566.250	**Transmission Training Total**	**$20,712**	**$17,038**	**$19,360**	**$1,352**
588..250	Distribution Safety	$9,107	$7,750	$8,947	$160
"	Distribution Training Seat Time	19,752	15,439	17,777	1,975
"	Distribution Training Delivery	10,059	9,346	10,059	0
588.250	**Distribution Training Total**	**$38,918**	**$32,535**	**$36,783**	**$2,135**

The only reductions are based on a lower forecast of new hires in 2012. Our discussion of the respective subaccount work activities follows.

5.15.2.1. Safety Programs

TDBU Safety expenses include the costs incurred for safety team meetings, training, programs, and safety program development primarily directed at improving employee and workplace safety. SCE forecasts a total $12.172 million for safety programs within Subaccounts 566.250 and 588.250. SCE developed its forecast by multiplying its recorded 2009 expense per employee ($1,705) by the 7,139 employees TDBU expects to have in place in 2012.[522] DRA recommends a total $10.244 million based on SCE's LRY of expenditures, after removing an employee recognition/bonus costs.

Transmission and Distribution Safety recorded expenses have fluctuated since 2005. SCE explains that the increases through 2009 are associated with new programs targeted at reducing employee injuries, and are sufficient only for its 6,115 employees as of 2009, not the 7,139 employees forecast for 2012. SCE provided evidence of declining injury rates for SCE employees since 2005 and enhanced program efficiencies.

SCE criticizes DRA's proposal as assuming no new employees and argues that if DRA's forecast is adopted, SCE would be forced to significantly reduce annual safety funding per employee, a result it finds "unreasonable and dangerous" and may result in putting public safety at risk.[523]

We decline to accept the issue as framed by SCE which ignores the question of whether 7,139 is the necessary number of employees to provide safe and reliable service. It also conveniently lumps all "safety" funds together including an exercise program and employee bonuses it asks ratepayers to fund. Finally, SCE describes the thrust of the program to be employee and workplace safety, rather than public safety.

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522 SCE OB at 160.

523 *Ibid.*

We accept that there is a cost per employee for attending safety training, and that ratepayers benefit from employees, particularly field personnel, trained to perform their work safely and to spot safety concerns on the job. However, simply because SCE has hired its forecasted TDBU employees already, and criticizes any proposed reductions, does not bootstrap the reasonableness of actually funding the new hires it relies upon to develop its forecast here.

The Commission finds it reasonable to reduce the estimated increase in the number of TDBU employees by 10% to account for various reductions to SCE's forecasts for O&M and capital expenditures in TDBU. Therefore, we re-calculate the Safety Training forecast based on 922 new employees (an increase from 6,115 to 7,037), allocate the results between Transmission and Distribution, and Labor and Non-labor as did SCE, then remove costs associated with SCE's employee recognition awards in each subaccount (because they are addressed in a separate section of this decision.)

The Commission adopts a TY2012 forecast for Transmission and Distribution Safety programs of $2.869 million for subaccount 566.250 and $8.947 for subaccount 588.250.

5.15.2.2. Training Seat-Time

Training seat-time expenses include the labor and associated expenses incurred by employees attending company-sponsored training programs.[524] According to SCE, it has increasing training needs in 2012 due, in part, to "the introduction of new work systems and advanced technology, increased hiring

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[524] SCE OB at 161.

projections, and rapidly evolving regulatory standards that impact safety and reliability."[525]

SCE forecasts a total $31.309 million for Training Seat-Time for subaccounts 566.250 and 588.250: $11.557 million and $19.752 million, respectively. This is nearly 29% more than combined 2009 recorded expense; by subaccount it represents growth of 30% for Transmission and 27.9% for Distribution training costs. These increases are not specifically explained by SCE. SCE developed its forecast by identifying each training program it plans to offer in 2012, the number of employees expected to attend, and the total hours of training required. SCE calculated TDBU training will require over 200,000 hours more than in 2009.[526]

DRA uses 2009 recorded expenses to recommend $8.891 million for Transmission subaccount 566.250 and $15.439 million for Distribution subaccount 588.250. DRA concludes that SCE has embedded costs in its historical expenses that can be utilized to address training activities in TY2012.

SCE's recorded expenses for both Transmission and Distribution Training have fluctuated since 2005, but neither three- nor five-year averages would fully reflect the employee growth, and technological and regulatory changes SCE has identified as drivers of increased training during 2012. We find that SCE's approach to forecasting training expenses is more appropriate than assuming existing programs will be sufficient to handle both new employees and other new activities for which some training must occur.

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[525] SCE-03, Vol. 05, Pt. 2 at 31.

[526] *Id.* at 161.

SCE concedes the bulk of the training is for new employees and is contingent on hiring.[527] Therefore, the most reasonable adjustment to SCE's forecasts is a reduction based on our lower forecast of new hires.

The Commission finds it reasonable to reduce SCE's forecasted amounts by 10% in each subaccount to reflect fewer new hires as a result of our reductions to SCE's forecasts for O&M and capital expenditures in TDBU. Therefore, the Commission adopts a TY2012 forecast for Transmission and Distribution Training Seat Time of $10.401 million for subaccount 566.250 and $17.777 for subaccount 588.250.

5.15.2.3. Training Delivery

Training Delivery expenses are the costs incurred to analyze, design, develop, implement, evaluate, and track training.[528]

SCE forecasts a total $16.149 million for Training Delivery Programs within subaccounts 566.250 and 588.250 for Transmission and Distribution Training Delivery. This is both a separate and combined 7.7% increase over 2009 recorded expenses. SCE's forecasts are based on 2009 recorded expenses, with specific incremental additions to account for new compliance, technology integration, and supervisory training requirements.

DRA recommends $5.653 million and $9.346 million, respectively, for Transmission and Distribution Training Delivery, using the LRY as the basis in each subaccount. A key premise is DRA's view that SCE has embedded costs in its historical expenses to re-direct to 2012 activities.

[527] SCE-18, Vol. 05, Pt. 2 at 10.

[528] SCE OB at 162.

We find that SCE will incur some additional training program development and evaluation costs even if it hires fewer employees than forecast, especially regarding NERC compliance and Smartgrid technologies. Therefore, the Commission finds reasonable and adopts SCE's TY2012 forecasts of $6.090 million for Transmission Training Delivery and $10.059 million for Distribution Training Delivery.

In its next GRC, SCE shall identify for 2012, the portion of recorded costs related to terminated, superseded, and completed activities, and a review of steps considered or taken to minimize training costs, including low or no cost vendor support of new technologies.

5.15.3. TDBU Environmental Services: 582.250

Environmental Services includes expenses related to service programs such as Biological and Archaeological, Air Quality, Environmental Engineering, Water Quality, and Hazardous Waste. The Corporate Environmental Health & Safety organization charges expenses for these services back to TDBU. Recorded expenses have trended upward since 2007, growing about 41% in 2008 and 38% in 2009.

SCE forecasts $2.926 million for TY2012 O&M expenses, the equivalent of 2009 recorded expenses. DRA uses a four-year average (2006-2009) of $2.051 million; a five-year average (2005-2009) would have been even lower. DRA contends that SCE's recorded costs include one-time, non-recurring costs including consultations, implementation of drinking water quality programs, increased water sampling, and archeological and biological activities.[529]

[529] SCE-18, Vol. 05, Pt. 2 at 9, Attachment 1.

DRA has not supported its claim that SCE has embedded historical costs sufficient to absorb new environmental activities. SCE explained the 2007-2009 increased costs are mostly related to increased solid/hazardous waste management activities, e.g., the deteriorated pole project and the infrastructure replacement program, as well as associated salvage of electrical equipment, cable, soil, and debris waste management.[530] Given SCE's commitment in this GRC to an enhanced inspection and maintenance program for its TDBU infrastructure, we do not expect short-term reductions in this category of expenses.

Therefore, the Commission finds it reasonable to adopt SCE's.

SCE's requested increase of $2.926 million for TY2012 Environmental Safety expenses recorded in this subaccount.

5.15.4. Transmission and Distribution Toxic Waste Disposal: 573.250 598.250

No party takes issue with the test year forecasts for the Toxic Waste Disposal subaccounts 573.250 and 598.250. The Commission finds the SCE TY2012 forecasts for subaccounts 573.250 and 598.250, for transmission and distribution toxic waste disposal, reasonable and we adopt them ($0.517 million and $5.238 million, respectively).

SCE requested a total $68.311 million in Technical Services O&M expenses; the Commission adopts $64.824 million of this request and disallows $3.487 million, as illustrated in the table below:

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530 SCE-03, Vol. 05, Pt. 2 at 24-25.

Technical Services Expenses (2009 $000s)				
Account	**Description**	**Requested**	**Adopted**	**Disallowed**
566.250	Safety and Training-Transmission	$20,712	$19,360	$1,352
573.250	Transmission Toxic Waste Disposal	517	517	0
582.250	Environmental Safety	2,926	2,926	0
588.250	Safety and Training-Distribution	38,918	36,783	2,135
598.250	Distribution Toxic Waste Disposal	5,238	5,238	0
	Technical Services O&M Expense Total	**$68,311**	**$64,824**	**$3,487**

5.16. T&D—Business, Regulatory and Financial Planning

Business, Regulatory, & Financial Planning consists of the Business Planning and Financial Management (BP&FM) and the FERC Compliance, Policy and Contracts (FCPC) organizations. Together, these groups manage financial, regulatory, contract, standards, and compliance matters for TDBU.

SCE forecasts $13.271 million ($2009) for TY2012 O&M, and capital expenditures of $7.586 million.[531] DRA recommends reductions in two O&M subaccounts totaling $6.205 million, as discussed below, and no adjustments to SCE's proposed capital expenditures.

5.16.1. O&M Expenses: 566.280, 580.280, 588.280

SCE's total O&M forecast covers expenses recorded to three subaccounts, although nearly 88% is associated with subaccount 566.280. No party recommended adjustment to the $0.222 million forecast for subaccount 580.280, TDBU Charge backs for Services from Internal Support Providers. We find SCE's forecast for this expense category to be reasonable and adopt it.

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[531] SCE-03, Vol. 05, Pts. 3 & 4 at 4.

5.16.1.1. Compliance, Policy, Contracts, and Billing: 566.280

FCPC works with regulatory agencies, independent system operators, and industry groups to develop policies and tariffs to support the development and construction of transmission facilities, and manages generation interconnection requests and compliance with NERC/CIP reliability standards.[532] Between 2009 and 2012, SCE plans to increase the number of employees in FCPC from 49 to 82, which accounts for most of the growth in this subaccount.

For 566.280, SCE forecasts $11.626 million for TY2012, nearly twice recorded 2009 expenses of $5.882 million. The forecast has two parts: $9.074 million for more employees to negotiate and manage contracts for interconnection of renewable generators, and $2.552 million to implement new NERC/CIP mandates and provide ongoing support of NERC/CIP cyber security standards.[533]

DRA recommends use of 2009 recorded expenses for TY2012 because it views SCE's requests as excessive in historical context and lacking documentation as to why increased staffing from 2005-2009 is insufficient to handle test year activities. DRA rejects any more funding for incremental NERC/CIP activities, and criticizes SCE for failure to provide a cost-benefit analysis to support addition of new employees.[534] We agree that cost-benefit analysis may be applicable to some regulatory activities because there may be more or less efficient ways to implement requirements.

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[532] *Id*. at 1.

[533] JCE at 465.

[534] *Id*. at 310.

SCE provided descriptions of the type of work performed within each line item recorded in this subaccount, the ups and downs of historical costs, and its need for new employees. However, for non-NERC activities, it did not provide calculations to support its workforce estimates, or analysis in light of recent employee growth. However, an important driver is the number of active interconnection requests which have grown from 200 in early 2009 to 400 in April 2010 and 850 in May 2011.[535] Although DRA argues embedded costs exist from routine and ongoing activities, SCE claims that as requests are negotiated and contracts signed, new requests have entered the queue at a faster rate.

SCE provided a more complete analysis of the workforce estimate to add eight employees between 2009 and 2012 to comply with new NERC/CIP standards. However, SCE did not clearly explain why existing staff are unable to incorporate the new standards into their current work scope. In addition, we have concerns about SCE's estimated Non-labor costs of $1.640 million which include 1/3 of the $1.724 million cost ($0.575 million) for a 2012-2014 outside contract to identify assets subject to the new CIP standards, to develop and implement controls, and enforce compliance. SCE does not explain why it needs to hire contractors to identify which of its own assets are subject to NERC/CIP standards, especially in light of the fact SCE has experienced compliance professionals, has been actively implementing NERC throughout its organization since before 2009, and has been closely following the development of these standards.

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[535] *Ibid.*

We recognize that SCE will have more interconnection contracts to process during this rate cycle than last, will need to support California's Renewables Portfolio Standard goals, and to comply with NERC/CIP standards. However, we agree with DRA that SCE's testimony, while providing some support for additional staffing, did not quite justify the specific number of new employees it requests.

Therefore, the Commission finds it reasonable to reduce SCE's non-NERC Labor requests by 50% of the differential between SCE and DRA ($1.596 million),[536] and to reduce SCE's NERC/CIP Labor request by 25% of the differential ($0.228 million), to account for performing additional activities but maximizing integration within existing staff levels. The Commission also finds it reasonable to reduce SCE's NERC/CIP related request to exclude $0.575 million in Non-labor costs associated with contractors performing an asset study which is not fully justified in the record.[537]

The result is a $2.399 million reduction to SCE's $11.626 test year forecast ($1.824 million Labor, and $0.575 million Non-labor), for an authorized TY2012 forecast of $9.227 million.

5.16.1.2. Distribution Construction Contract Management: 588.280

Subaccount 588.280 records the activities for this group which manages CPUC Tariff Rules 15 and 16 contracts, including refunds, billings, and collections.[538] SCE forecasts $1.423 million for TY2012 O&M expenses using

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536 *Ibid*.

537 JCE at 465.

538 SCE-18, Vol. 05, Pts. 3 & 4 at 6.

2009 recorded expenses, plus additional funding for two new employees and software upgrades.

DRA also used SCE's 2009 recorded expenses as a basis for its forecast of $0.962 million for subaccount 588.280, but argues that the additional expenses are not justified because SCE should have embedded costs for software upgrades from programs that are no longer in use or are no longer incurring maintenance costs incurred for purchases of software programs during the last five recorded years (2005-2009).[539]

We find that SCE supported its need for additional staffing and that the funding requested is for necessary new software programs.[540] The Commission agrees. However, the Commission disallows $0.168 million to remove employee bonus/recognition awards which are addressed in a separate section of this decision. The Commission finds $1.255 million reasonable for subaccount 588.280.

For total Business, Regulatory, and Financial Planning Organization expenses, the Commission approves a total $10.704 million of the $13.271 million TY2012 request, while disallowing $2.567 million, as indicated in the table below:

Business, Regulatory and Financial Planning Organization O&M Expenses $2009 (000s)			
Description	**Requested**	**Adopted**	**Disallowed**
Compliance, Policy, Contracts	$11,626	$9,227	$2,399
TDBU Chargebacks for Services	222	222	0
Distribution Construction Contract Management	1,423	1,255	168
Transmission Training Subtotal	**$13,271**	**$10,704**	**$2,567**

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539 JCE at 311.

540 SCE OB at 165.

No party recommended adjustments to SCE's capital expense forecast in the Business, Regulatory and Financial Planning Organization.[541] The Commission finds SCE's capital expense forecast for 2012 to be reasonable and adopts capital expenditures of $8.895 million for 2012:

Business, Regulatory, and Financial Planning Organizations Capital Request						
	Capital Request by Year					
Project Description	**2010 Recorded**	**2011 Forecast**	**2012 Forecast**	**Total 2010-2012**	**Adopted**	**Disallowed**
Furniture and Equipment	$181	$1,128	$1,155	$2,464	$2,464	-
Secure Control System Access Project	0	0	6,431	6,431	6,431	-
Total Capital Expense	**$0**	**$0**	**$7,586**	**$8,895**	**$8,895**	**$0**

5.17. T&D Other Costs and Other Operating Revenue

This section discusses SCE's O&M estimates for write-offs, services, credits, and O&M resulting from allocations; distribution and transmission allocated costs; and OOR from transactions not associated with the sale of electric energy.

For TY2012, SCE forecasts $107.314 million ($2009) for the identified activities in twelve subaccounts that comprise Other Costs, and $111.801 million of OOR. DRA recommends a $15.305 million reduction to O&M and an increase of $1.130 million to OOR. TURN recommends smaller adjustments in many of the same O&M subaccounts totaling $7.723 million. DRA found SCE's forecasts

541 *Id*. at 163.

for the following subaccounts to be reasonable: 566.282 – Transmission Facility Maintenance ($4.602 million); 584.281 – Transformer Credits (<$2.455> million); and 586.281 – Meter Credits (<$6.437> million).

The Commission finds these forecasts reasonable and adopts them. For the other subaccounts, SCE's forecasts and both TURN's and DRA's recommended cuts in TY2012 are summarized below.

5.17.1. Transmission Work-Order Write-Offs: 560.281

Write-offs include the expense for cancelled capital projects, unpaid claims for damaged facilities, and uncollected costs for billable work orders.[542] The key issue is the more reasonable forecast methodology. Recorded costs in this subaccount have fluctuated historically, but jumped in 2009 from a four-year average (2005-2008) of $700,500 to $4.889 million, primarily due to cancellation of the Ultra Small Antenna Terminal Satellite System (USAT).[543]

For TY2012, SCE's revised forecast is $2.676 million ($0.190 Labor, $2.486 Non-labor).[544] The forecast is based on the average 2005-2009 percentage of write-offs to recorded transmission capital expenditures, multiplied by 1/3 of the 2012-2014 forecast capital expenditures ($1.27 billion/year) for transmission interconnection projects and transmission substation planning projects.[545] In

[542] SCE-03, Vol. 05, Pts. 3 & 4 at 28.

[543] *Id*. at 28-29.

[544] JCE at 313, 785.

[545] SCE-018, Vol. 05, Pts. 3 & 4 at 11, and Table II-8 at 16.

SCE's 2009 GRC, we approved SCE's forecast linking transmission write-off costs to total TDBU forecast capital expenditures.[546]

DRA utilized a five-year historical average of $1.538 million and criticizes SCE's forecast methodology as unnecessarily complicated and based on significant forecasted capital increases in the test year. TURN relied upon an adjusted five-year average of historical costs to forecast $0.739 million, after excluding two write-offs as non-recurring or inappropriate. The USAT write-off of $3.906 million makes up more than half of all write-offs in 2005-2009, and SCE's witness confirmed the write-off was an unusual occurrence.[547]

Both TURN and DRA reject SCE's forecast approach and its constant linkage to capital projects, particularly unexamined and unauthorized capital projects SCE forecasts for 2013-2014. SCE's write-off ratios also varied between 2005 and 2009. As a result of TURN's analysis, SCE revised its forecast to exclude historic large capital projects subject to incentive ratemaking treatment from its calculations. However, TURN argues that allowing SCE to base its write-offs on untested capital budgets gives the utility an unfair opportunity to drive up expense in the test year without adequate review.

TURN and DRA raise important concerns about SCE's methodology. Work-order write-offs may be a common business occurrence, but SCE's use of an unusually large, one-time, abandoned project to bootstrap additional write-off expenses in following years is troubling. Much of the forecast 2012-2014 transmission work is for large reliability and renewable transmission projects

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[546] D.09-03-025 at 49.

[547] TR at 1194-1195.

where work-order write-offs have been rare.[548] SCE did not clearly explain why the ratios did not historically track changes in capital expenditures or why large write-offs in one year from a cancelled project did not skew the average ratio, as it did the average costs.

In this decision, we reconsider SCE's speculative forecast method in light of additional evidence in the record which points out flaws likely to lead to excessive rate recovery in the test year. If SCE chooses to use this forecast method in another GRC, SCE shall provide an analysis of the historical ratios of transmission and distribution work-order write-offs to test year authorized and recorded transmission or distribution capital expenditures, respectively, and establish that the ratio is actually reliable as a forecast tool.

Accordingly, the Commission finds it reasonable to use the five-year average of historical costs, after removing 50% of the extraordinary $3.906 million USAT write-off. It is insufficient for SCE to argue that abandonment of USAT was in the ratepayer interest, but not respond to TURN's questions, e.g., whether such write-off would likely recur and whether SCE applied contract holdback funds to offset the write-off. We do not make any other adjustments.

The Commission adopts a five-year historical average of recorded costs, (adjusted 2009 costs are $2.973 million) and adopts $1.198 million ($0.103 million Labor, $1.095 million Non-labor) for Transmission work-order write-offs, a reduction of $1.478 million to SCE's request.

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[548] TURN OB at 138-139.

5.17.2. Distribution Work-Order Write-Offs and Underground Utility Locating Services: 588.281

5.17.2.1. Individual Work-Order Write-Offs

The parties follow the positions taken for Transmission work-order write-offs. SCE's revised forecast for TY2012 Distribution Work-Order Write-Offs costs is $10.001 million, after re-classifying certain expenses identified by TURN.[549]

SCE's forecast is derived from the average historical percentage of write-offs to distribution capital expenditures, multiplied by average 2012-2014 forecast distribution capital expenditures. SCE justifies its forecast method by reference to the Commission's decision in the 2009 GRC.[550]

DRA used a five-year adjusted historical average for this line item to forecast $ $8.214 million, after removing $3.4 million associated with the Catalina fire as unusual and non-recurring. Similarly, TURN made adjustments to recorded historical expenses before developing its five-year average for a TY2012 forecast of $7.971 million. DRA and TURN reiterated the arguments each put forth regarding Transmission work-order write-offs above.

Historical recorded expenses for this line item have fluctuated between 2005 and 2009, ranging from a low in 2008 of $5.081 million to a high of $18.444 million in 2009, a 263% increase in one year "due primarily to an increase in cancelled capital projects, uncollectible costs for billable work orders, and delayed write-offs from 2008."[551] This is an inadequate explanation.

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[549] JCE at 314; SCE-18, Vol. 05, Pts. 3 & 4 at 20-23.

[550] D.09-03-025 at 75.

[551] SCE-03, Vol. 05, Pts. 3 & 4 at 31.

Based on the same reasoning as set forth above, we find it reasonable to adopt a five-year average of adjusted recorded costs. SCE claims it wrote-off $44.554 million between 2005 and 2009.[552] From its original list of excluded write-offs, TURN now accepts two items and SCE accepts exclusion of three, leaving the following write-offs in dispute as to whether they should be removed from the forecast:

- $648,646 written off before but paid after 2009;
- $101,780 associated with the USAT write-off;
- $600,000 associated with defects in a software project ($437,000 per SCE); and
- $1.276 million for Catalina undersea cable.

We agree with TURN that the write-offs associated with the Catalina undersea cable should be excluded from calculations of average historical costs. Although we approved the write-off in Section 4.6.2 as reasonable, that does not mean that it is a type of recurring expense. Catalina has a uniquely isolated service population and the undersea cable project was abandoned in favor of a more cost effective delivery system. It is unlikely that similar costs would be incurred by SCE in the next rate cycle. We also exclude 50% of the extraordinary USAT expenses, but decline to exclude the other expenses which appear to be the ordinary types of write-offs to be expected in this subaccount.

The five-year average of adjusted recorded costs for Distribution Work-Order Write-Offs is $8.230 million and the Commission adopts this amount for TY2012. Furthermore we apply SCE's Labor to Non-labor ration of 6% ($0.494 million Labor, $7.736 million Non-labor).

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[552] SCE-18, Vol. 05, Pts. 3 & 4 at 18, Table II-10.

5.17.2.2. Underground Utility Locating Services

State law requires SCE to respond to external requests for underground locating services, and SCE employs an outside contractor to do so. SCE records costs in this subaccount to mark the location of its underground facilities and for its share of the costs of a regional notification call center.[553] SCE forecasts $10.187 million for TY2012, based on 2009 recorded costs.

DRA utilized a three-year average of recorded costs (2007-2009) to develop its forecast of $8.981 million because it reflects the increase in expenses in 2009 after stable expenses in 2007-2008. TURN recommends the Commission adopt $9.755 million, a $0.432 million reduction to reflect declining units of work and decreasing costs through 2010.[554]

The Commission finds that TURN's forecast is a more reasonable basis to estimate test year expenses because its average of 2009 and 2010 costs reflect declining work, and reduce SCE's Non-labor forecast accordingly.

5.17.3. Claims Write-Offs: 583.281

When a third party damages SCE's facilities, SCE repairs the facilities and invoices the responsible party and pursues collection. After collection efforts have been exhausted, SCE writes off the unpaid invoices in subaccount 583.281 as a normal cost of service. SCE forecasts $6.046 million based on a five-year average of fluctuating recorded expenses.

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[553] The Underground Service Agency call center is also known as "811—call before you dig."

[554] TURN OB at 150.

DRA and TURN also use a five-year average of recorded costs but recommend removing the write-off associated with the Catalina fire[555] from recorded costs for the purpose of calculating historical averages. Both parties view the damages as unusual, non-recurring, infrequent, and unusual.[556] DRA's TY2012 forecast for Claims Write-Offs is $5.846 million and TURN's is $5.386 million.

SCE defends its forecast by arguing that the five-year average appropriately accounts for an unusual uncollectible claim, and that fires are common within its service territory. TURN responds that the claim is unusual both for its circumstance and size.[557] According to TURN, the cost of the Catalina fire was $11.962 million and SCE made a $3.298 million write off; the average cost for third party fires since 2000 was approximately $174,271, and the average annual write-off was $50,800. Moreover, the third party was convicted of a criminal offense.

Although the Catalina fire was an extraordinary write-off, it nonetheless reflects the type of costs SCE is entitled to write-off in this subaccount. However, for purposes of developing an appropriate and reasonable test year forecast of third party claims write-offs, this expense is so far outside SCE's historical costs that it unfairly skews the forecast going forward.

Therefore, the Commission finds it reasonable to exclude 50% of the Catalina write-off as calculated by TURN from the historical average and reduce

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555 They each remove a slightly different amount: DRA excludes $2.298 million and TURN excludes $3.98 million from the five-year total.

556 SCE OB at 170.

557 TURN OB at 152.

SCE's forecast by $0.330 million to $5.716 million. This amount is in line with the historical pattern, exclusive of the fire costs.

5.17.4. Facility Maintenance Distribution: 580.282

Examples of expenses recorded in this subaccount are plumbing repairs, painting, janitorial services and supplies, and landscape care.

SCE forecasts $9.066 million, based on 2009 recorded expenses. These costs varied between 2005 and 2009, including a $4.7 million increase (118%) in 2008. SCE explained the 2008 jump was due to a change from recording only TDBU's portion of facility maintenance to all facility maintenance (TDBU plus other business units).[558]

DRA recommends the Commission adopt a TY2012 forecast of $5.918 million based on a five-year average (2005-2009) of recorded costs, a reduction of $3.148 million to SCE's forecast. DRA expressed concern that SCE may be requesting duplicate ratepayer funding in various business units for distribution facility maintenance expenses. However, DRA presented no supporting evidence for this concern.

We are persuaded that SCE has materially changed the costs recorded in this subaccount as of 2008, thus a five-year average is not reliable. Instead, the Commission finds reasonable and adopts SCE's forecast of $9.066 million based on 2009 recorded costs.

5.17.5. Transmission Allocated Costs: 568.281

This subaccount includes the transmission expense portion of the costs for TDBU general support and vehicles. Recorded costs have generally trended

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[558] SCE-03, Vol. 05, Pts. 3 & 4 at 37.

upward since 2005. Prior to 2008, all expenses were recorded as Non-labor. With the implementation of the SAP accounting system, SCE could allocate expenses to Labor, resulting in a first appearance in 2008 and an almost 20% increase from 2009 to 2012.[559]

For TY2012, SCE forecast $4.618 million of Labor and $9.752 million of Non-labor, totaling $14.370 million, a $2.393 million increase over 2009 recorded costs based on anticipated transmission work activities. SCE developed its forecast by taking all projected capital, O&M, and allocated costs throughout TDBU, and using a spreadsheet simulation of SAP cost allocations to calculate the amount to allocate to expense, and then the amount of expense to allocate to transmission and to distribution.[560]

DRA used LRY, the highest recorded amount for the five-year period (2005-2009), as a basis for its forecast of $11.977 million for TY2012. DRA contends that SCE is basing its forecast on proposed capital projects that are not authorized by the Commission and recommends the Commission reduce the forecast in proportion to reductions to TDBU capital spending adopted in this decision.

We think DRA is on the right track, although the allocation is ultimately based on an allocation of expense. Elsewhere in this decision, we have expressed concerns about SCE's forecasts which rely on other forecasts, particularly when the forecast locks in rate recovery. Since we have made reductions to TDBU forecasts of O&M expenses, and not all O&M expenses result in the same

[559] *Id*. at 44.

[560] *Id*. at 46-48.

percentage allocations, it is appropriate to make a modest adjustment to SCE's forecast to reflect O&M reductions adopted herein.

Therefore, the Commission finds it reasonable to reduce SCE's forecast by 10% to account for reductions made to SCE's Transmission-related forecast TY2012 O&M, and adopts $12.933 million for this subaccount.

5.17.6. Distribution Allocated Costs: 590.281

This subaccount includes the distribution expense portion of the costs for TDBU general support and vehicles. Recorded costs have fluctuated significantly, peaking at $41.507 million in 2009. SCE and DRA have the same forecast methods and positions asserted for the transmission allocated costs above.

SCE forecasts $45.453 million for TY2012, an increase of $3.946 million over 2009. DRA recommends $41.507 million, SCE's 2009 recorded expenses.

For the same reasons outlined for Transmission allocated costs, the Commission finds it reasonable to reduce SCE's forecast by 5% to account for reductions made to SCE's Distribution-related forecast TY2012 O&M, and adopts $43.180 million for this subaccount.

TDBU Other Costs O&M Expense Request				
Account	**Description**	**Requested 2010 ($000)**	**Adopted**	**Disallowed**
560.281	Transmission Work Order Write-offs	$2,676	$1,198	$1,478
588.281	Distribution Work Order Write-offs	10,001	8,230	1,771
"	Underground Utility Locating Service	10,187	9,755	432
583.281	Claims Write-offs	6,046	5,716	330
566.282	Transmission Facility Maintenance	4,602	4,602	-
580.282	Distribution Facility Maintenance	9,066	9,066	-
584.281	Transformer Credits	(2,455)	(2,455)	-
586.281	Meter Credits	(6,437)	(6,437)	-
568.281	Transmission O&M Allocated Costs	14,370	12,933	1,437
590.281	Distribution O&M Allocated Costs	45,453	43,180	2,273
566.281	FERC-Jurisdictional	(3,049)	(3,049)	-

569.281	FERC-Jurisdictional	3,090	3,090	-
570.281	FERC-Jurisdictional	13,764	13,764	-
	Other Costs O&M Expense Total	**$107,314**	**$99,593**	**$7,721**

5.17.7. TDBU's Other Operating Revenues

TDBU receives OOR from transactions that do not involve the sale of electric energy and is supposed to apply it to offset the revenue requirement.

SCE forecasts $111.801 million for its OOR in TY2012 covering 15 subaccounts.[561] The tariffed OOR is based on the CPUC or FERC approved rates. DRA's corresponding estimate for 2012 is $112.931 million, an increase of $1.130 million, based proposed adjustments discussed below.

5.17.7.1. Meter Damage and Temporary Services: 451.100

This subaccount records payments for repairs to damaged meters and lock-rings. SCE calculated its forecast of $26,000 by escalating 2009 recorded revenue to years 2012-2014 and averaging the result for TY2012. Recorded revenue peaked in 2007 at $1.938 million, then dropped off to $0.517 million in 2008 and to $24,000 in 2009. SCE explains the reduced revenue as a result of the SAP accounting system which no longer recorded customer payments for temporary services in this subaccount; instead they are recorded where the expenses reside."[562] Thus, the offset is recorded when the order is closed.

DRA used as five-year average of recorded costs to develop its estimated revenue of $1.134 million because "SCE has provided insufficient documentation to determine that this change in accounting…has no effect on revenue

[561] SCE-18, Vol. 05, Pts. 3 & 4 at 41, Table III-24.

[562] SCE OB at 172.

requirement."[563] DRA's concern is that SAP records expenses used to forecast future costs before the expenses are offset to zero. SCE does not address this implication of its accounting change.

We are persuaded that SCE has made this accounting change as shown by the substantial drop in revenue beginning in 2008. Therefore, a five-year average of recorded costs is not appropriate. However, we share some of DRA's concern that not only does this approach remove revenues from sight, if the offset has not occurred, the expenses may well be used as part of a forecast of test year expenses.

The Commission finds that SCE's forecast of $26,000 for this subaccount is reasonable. However, in the next GRC, SCE shall provide a breakdown of how much OOR was recorded in other subaccounts with the offsetting expense, and how much had not been offset by the end of the calendar year in which it was recorded, set forth by subaccount.

5.17.7.2. Transmission Services for Generation: 456.308 & Non-CAISO Services: 456.340

The revenue recorded in subaccount 456.308 represents Firm Transmission Service provided to non-Public Power Utility customers using facilities not controlled by CAISO. The revenue is subject to FERC-approved rates. Revenue recorded to subaccount 456.340 is for load dispatching services allocated to the operation of the El Dorado System in accordance with the El Dorado System Operation Agreement.[564]

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[563] DRA OB at 209.

[564] SCE OB at 173.

SCE estimates $1.150 million in combined revenue for these subaccounts in TY2012 by escalating 2009 recorded revenue to years 2012-2014 and averaging the result for TY2012. DRA used a five-year average as a basis to forecast $1.172 million in 2012, a difference of $22,000.

Revenues recorded in these subaccounts declined slightly from 2005-2008 and increased in 2009. We find that SCE's forecast method is more appropriate than an historical average.

Therefore, the Commission finds reasonable and adopts SCE's estimated TY2012 revenue of $1.150 million for subaccounts 456.308 and 456.340.

5.17.7.3. Other SCE Concerns

SCE expressed concern that its estimated revenue in two areas could be impacted adversely by any reductions made by the Commission to capital that drives added facilities.

Revenue from SCE-Financed Added Facilities is recorded in subaccount 454.300. The incremental increase over 2009 of $3.751 million is based on new facilities expected to be constructed between 2012 and 2014. Revenue from Customer-Financed added facilities and interconnection facilities installed and treated as added facilities, are recorded in subaccount 456.700. SCE forecasts $11.938 million in revenue for this subaccount in TY2012 based on "existing facilities, plus new projects, and minus termination of projects."[565]

SCE requests that if the Commission adopts any reductions to the capital expenditures that drive the revenue for either of these types of added facilities,

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[565] *Id*. at 174.

the Commission should make a corresponding reduction to the estimated revenue based on new facilities.

Elsewhere in this decision, the Commission has adjusted the incremental increase (the difference between recorded and 2012 forecasted) in capital-related O&M expenses by 9.4%, therefore we adjust the increase for these subaccounts at $0.146 million and $0.380 million, respectively.

6. Customer Service Business Unit

The CSBU is SCE's primary point of contact with its customers. CSBU is comprised of two divisions: Customer Services Operations Division (CSOD) and Customer Services and Information Division (CSID). According to SCE, 3,682 CSBU employees and 647 contingent workers provided customer service to 4.9 million customers in 2009.[566] SCE estimates it will require 254 fewer total workers in 2012.

SCE contends that current energy policies and evolving customer needs and expectations require a new technology-enabled customer service model, involving wireless communications and internet-based services for customer interactions, while still maintaining tradition customer care services.

A one-time wrinkle in forecasting for 2013 arises due to the deployment of SCE's advanced metering infrastructure program (SmartConnect, AMI or smart meters) to residential and small commercial customers by the end of 2012. Edison's SmartConnect deployment consists of metering and communications infrastructure as well as the related computerized systems and software. Pursuant to D.08-09-039, costs through 2012 related to the deployment of

[566] SCE-04, Vol. 01 at 1, 19.

SmartConnect are to be recovered through the ESCBA, and moved into general rates in 2013. SCE and DRA developed separate 2013 O&M forecasts which they recommend, only if the Commission were to adopt the other party's Post Test year ratemaking mechanism (PTYR). We did not wholly adopt either party's PTYR, and adopt separate 2013 forecasts below.

SCE has asked to retain the ESCBA for certain delayed and adjusted deployment costs from 2012 and for recording authorized costs which are expected to be incurred in 2013 and 2014 (i.e., programmable communicating thermostats (PCTs) and in-home displays (IHDs). There is a dispute about whether certain expenses are to be recovered in the ESCBA or in the GRC, and these are discussed below.

6.1. SCE's and Parties' Positions

For total CSBU, SCE submitted an O&M request of $300.4 million ($2009) for TY2012, an increase of $29 million over 2009.[567] In addition, SCE forecasts 2012 capital expenditures of $75 million, including approximately $43 million for capitalized software to implement smart energy policies and practices, and to engage customers in "active energy management."[568] SCE's 2010-2014 capital request, just for capitalized software, totals more than $200 million.[569]

SCE's 2012 O&M forecast reflects "business as usual" operational costs without SmartConnect, plus what it calls "incremental costs" to support new commission-mandated programs and services, including PEV, dynamic pricing

[567] SCE-04, Vol. 01 at 18.

[568] DRA-10 at 79, Table 10-53.

[569] *Id.* at 80, Table 10-54.

(DP) and HAN.[570] For 2013, SCE's forecast of $275 million includes estimated ongoing operational costs and benefits of deployed smart meters.

DRA's 2012 "business as usual" forecast is $274.154 million after removing most of SCE's incremental costs.[571] For 2013, DRA forecasts $226 million ($2009), nearly 20% lower than SCE's estimate, based on similar disallowances of incremental costs.

TURN raises several issues with the SmartConnect program and SCE's forecast of costs and benefits as they impact CSBU revenue requirements. TURN contends that SCE has booked some expenses and capital costs associated with the SmartConnect project into 2010-2012 general rates which should be moved to the ESCBA. TURN also views SCE's requests related to PEVs and HAN to be excessive and unjustified. In addition, TURN requests that the deployment period benefits calculation be continued and recorded in ESCBA through 2014.

SCE responds that the lower funding levels recommended by DRA and TURN overlook long-term impacts on achievement of the Energy Action Plan (EAP) goals, such as implementation of DP and demand response (DR) programs, as well as reductions in GHG emissions. SCE claims that its proposals recognize that customer education and outreach, and enabling technologies, empower customers to manage their electricity usage.[572]

6.2. Policy Considerations

The Commission is committed to the deployment of advanced metering infrastructure and achieving EAP goals. At the same time, we closely examine

[570] SCE-04, Vol. 01 at 1.

[571] DRA-10 at 3.

[572] SCE-19 at 1-2.

each SCE request in the GRC to determine whether it is necessary, justified, and reasonable to implement during this rate cycle. Furthermore, we previously adopted TURN's base case projections of new meter sets which impacts SCE's estimates of customer growth used as a basis to adjust O&M costs in this section.[573] We discuss these issues in the context of the FERC accounts and subaccounts below.

6.2.1. Integration of Smart-Connect Costs and Benefits

The Commission is presented with unique issues in this GRC surrounding SmartConnect deployment and post-deployment costs, whether to continue the ESCBA beyond 2012, how to measure post-deployment benefits and where to record them. Moreover, SCE asked to retain the ESCBA for certain delayed deployment costs.

The deployment of SmartConnect is intended to result in the installation of smart meters in all households and businesses with demand of less than 200 kW in SCE's service area. Anticipated benefits include advanced metering and telecommunication capability to measure interval electricity usage; improved customer services through access to energy usage information and remote service activation and deactivation; support for an open standard communication interface with in-home devices, load control devices, and other smart appliances and energy management devices; and to enable improved electric distribution management through outage detection at the customer premise.

[573] Section 5.7.1 Customer Growth.

In D.08-09-039, SCE was authorized to fully deploy the SmartConnect program, pursuant to a settlement agreement with DRA. The decision authorized SCE to recover costs up to $1.63 billion for deployment activities during the 2008 to 2012 period. These costs, and related ratepayer operational benefits, were to be recorded in the ESCBA. During the meter deployment period, operational benefits of meter installation were determined to be $1.42 per meter per month, beginning eight months after installation. However, some aspects of the deployment have been delayed and actual realized benefits are lower than original estimates.

Costs appropriate to the ESCBA were described in the Settlement Agreement as "Phase III costs and capital-related costs" related to one of the following:

- Acquisition of meters and communications network equipment;
- Installation of meters and communications network equipment;
- Implementation and operation of new back office systems;
- Customer tariffs, programs, and services;
- Customer Service Operations;
- Overall program management;
- Contingencies for mass meter deployment; and
- And any other activities as related to Phase II and authorized by the Commission.[574]

In addition, the Settlement identified certain deployment costs for Billing Services, Meter Panels, and Program Management.[575] The

[574] D.08-09-038 at Appendix A, Attachment C.

[575] D.08-09-038, Appendix A at 6.

Commission-approved description of anticipated "deployment costs" to be recorded in the ESCBA informs our review of SCE's requested incremental adjustments for SmartConnect related activities.

The overlapping periods between the SmartConnect project deployment period (i.e., 2008 to 2012) and the GRC application (i.e., 2012 to 2014) require the development of GRC forecasts that delineate between SmartConnect and GRC funded costs to avoid double recovery. SCE asserts its 2012 forecast assumes no SmartConnect meter deployments. SCE's separate 2013 O&M forecast assumes full SmartConnect deployment and includes net SmartConnect operating costs and benefits of $33.7 million. This amount includes benefits of $58.2 million and costs of $23.0 million. SCE also identified $1.4 million in revised incremental costs.[576]

In addition to recommending cuts for PEV and HAN-related activities, TURN disputes SCE's benefits analysis. TURN claims that, given the number of meters SCE will have installed by the end of 2012 and 2013, SCE should have provided $87.206 million in 2013 operational benefits instead of the $58.22 million figure proposed by SCE. TURN argues that SCE's calculation deprives ratepayers of over $30 million in SmartConnect operational benefits, if based on a $1.42 meter/month benefit calculation. TURN would allocate this larger amount to the ESCBA rather than offset the GRC revenue requirement to make it easier for the Commission and public to track benefits.[577]

SCE views it as unreasonable to recommend cuts to post deployment costs and still expect projected post deployment benefits. Further, the $1.42 per meter

576 SCE-04, Vol. 01 at 23-25.

577 TURN-05 at 7-12.

per month is not relevant to the post-deployment benefits of $58 million, states SCE, because that amount was accepted by the Commission when it authorized deployment.[578]

Nonetheless, TURN is troubled that SCE's proposed 2013 benefits are about one-third less than in 2012, and many meter benefits are stranded due to the eight month lag. Actual costs and benefits are hard to track, notes TURN, because not all SmartConnect costs are booked to the ESCBA due to internal accounting methodologies.[579]

In D.08-09-039, the Commission established a $1.42/meter/month benefit through 2012 for meters installed during the deployment period, but did not specifically address calculation of post-deployment operational benefits. In this GRC, SCE presented a table of estimated 2013 benefits which total $58.223 million, the amount set forth in its original SmartConnect application.[580] Although the largest source of post-deployment benefits continues to be from lower meter reading costs, SCE provided eight categories of benefits contributing to its 2013 calculation.

The Commission expected post-deployment costs and benefits would be integrated into the 2012 GRC. Therefore, we find that a separate 2013 forecast to include SmartConnect costs and benefits is reasonable and appropriate. In addition, SCE's itemized benefits by subaccount are a reasonable method of estimating 2013 benefits because they more closely follow the business case review in the deployment proceeding. Lastly, we find SCE's request to retain the

578 SCE-19 at 16-17.

579 TURN-5 at 3. Attachment C.

580 SCE-04, Vol. 01 at 26, Table V-3.

ESCBA for limited purposes to be reasonable, modified to include certain HAN-related functionality costs which have been delayed. This is discussed below.

We share TURN's concern about capturing all SmartConnect costs and the correct calculation of post-deployment ratepayer benefits for ongoing Commission review.[581] In the next GRC, SCE shall provide a spreadsheet of 2008-2015 costs and benefits credited by FERC account/subaccount and capital program. Moreover, SCE shall provide documentary support for its calculations of ratepayer benefits forecast for the next rate cycle.

Accordingly, the Commission will adopt a separate SmartConnect-related forecast for 2013, with SCE's estimated benefits providing an offset to authorized 2013 costs. The authorized costs will be discussed by subaccount and aggregated at the end of the O&M and Capital sections below.

6.2.2. Customer Growth

SCE forecast total 4.5% growth in customers between 2009 and 2014.[582] As discussed in Section 5.7.5, we instead adopted TURN's lower estimate of customer growth to forecast costs for new meter sets. For forecasting purposes, we consider that the approximate weighted difference between SCE's forecast and the adopted rates of customer growth from 2010 to 2014 is a 17% reduction.

In its CSBU forecasts, SCE has generally made additions to reflect planned program effects of customer growth at a rate of 1.83% for 2012 and 2.73% for 2013. Average annual customer growth between 2007 and 2009 was 0.49%. DRA

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[581] The costs and benefits of ESCBA are now reviewed by Advice Letter rather than in the ERRA proceeding.

[560] SCE-10 at 49.

rejects every customer growth adjustment on the ground that SCE has not demonstrated that the expenses in each account or subaccount are directly proportionate to the customer growth rate, and points to historic declines in costs at times of customer growth. TURN did not directly address these adjustments.

On the other hand, SCE asserts that DRA has selectively chosen data, ignored the relationship between more customers and customer service costs, some of which is masked by several productivity initiatives.

We find that SCE's proposed adjustments for customer growth in 2012 and 2013 are excessive. To the extent we approve of such adjustments, account by account, we will reduce them by 17% to reflect lower adopted growth forecasts. Thus, if adjustments are allowed, it will be at a rate of 1.52% in 2012 and 2.27% in 2013.

6.2.3. Dynamic Pricing

The Commission has encouraged California's investor-owned energy utilities to increase DR and implement DP tariffs as a means of reducing electricity demand during peak periods. In order to implement DP, customers must have advanced meters that can measure energy usage on a time-differentiated basis.[583] As part of its SmartConnect deployment decision, the Commission authorized SCE to record in the ESCBA, costs to conduct outreach, marketing, and education on DP and DR program offerings for customers receiving the new meters.[584]

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[583] D.08-09-039 at 2-3.

[584] *Id*. at 6.

In D.09-08-028, the Commission directed SCE to develop and implement DP rates by January 1, 2012, to provide customers with pricing signals to encourage the reduction of energy consumption during peak usage periods. Customers are expected to benefit through bill credits or lower non-peak energy periods.[585] However, SCE's DP program has been delayed.[586]

For CSBU, SCE forecast incremental DP costs totaling $3.839 million in 2012 and $3.057 million in 2013, in three subaccounts 905.900, 908.600, and 908.640. SCE also seeks $36.73 million for capitalized DP-related software costs.

DRA accepts SCE's forecast adjustments for DP-related O&M expenses in two of the subaccounts but rejects it in a third. DRA also recommends no funding for 2011-2012 related to DP capitalized software because the DP project is delayed and unlikely to generate expenditures.

TURN rejects any funding for DP activities or capital expenditures because TURN contends the Commission intended SCE to record the implementation costs of DP in the ESCBA.

At the time the Commission adopted the SmartConnect deployment decision, we anticipated that DP would be implemented in January 2012 and costs of DP and DR outreach, marketing, and education would be recorded in the ESCBA through 2012. This is underscored by the Settlement which states that incremental O&M and capital costs related to "new back office systems" and "customer tariffs, programs, and services" would be recorded in the ESCBA. Thus, we anticipated the initial functionality of the DP program to be part of deployment, and the costs incurred in 2012 should be recorded in the ESCBA.

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585 SCE-04, Vol. 04 at 75.

586 TR at 2022.

We expect some future incremental costs related to the DP program which may be recovered in general rates. However, since the program is behind schedule and DP tariffs have not yet been adopted, we find it reasonable to authorize only 60% of SCE's forecast 2013 DP-related costs, excluding customer education and outreach.

6.2.4. Plug-In Electric Vehicle Costs

SCE requests $9.044 million for TY2012 CSBU O&M expenses related to its PEV readiness program. These expenses are found in FERC accounts 901, 586.400, 902.300, 907.600, 908.600, 908.640, 903.500 and 580.260. SCE also seeks $12.572 million as its capital forecast for PEV-related infrastructure, meter installations and software for TY2012.

We incorporate our discussion of SCE's PEV forecast in Section in 5.2.1.4. DRA and TURN recommend the Commission reject all requests for increased funding for PEV Readiness on various grounds. As it relates to CSBU, in 2009 SCE recorded $2.3 million in O&M for PEV readiness, and another $11.2 million in its Low Emission Vehicle (LEV) program which includes an education and customer outreach component. DRA contends that SCE can use some of these recorded funds for PEV costs (e.g., an 800 number for LEV questions, a PEV microsite on its website).[587]

SCE disagrees that additional funding, especially for PEV education and outreach efforts, is unnecessary or unjustified. We are persuaded that SCE reasonably expects to incur more work as the number of PEVs in its service

[587] DRA-10 at 11-12.

territory increases.[588] SCE's proposed PEV activities are consistent with Commission policy as articulated in the Alternative-Fueled Vehicle Rulemaking.[589]

However, SCE's proposed adjustments for PEV readiness activities in 2012 and 2013 are based on an overly optimistic forecast of PEV penetration of its service territory. As previously discussed, we find reasonable and adopt SCE's "low" weighted average forecast of PEVs for this rate cycle which is approximately 40% lower than the "medium" forecast utilized by SCE in its forecasts. Therefore, to the extent we approve of such adjustments, account by account, we will reduce them by 40% to reflect the lower adopted growth forecast. To the extent there may be embedded funding or excess costs for some PEV activities, we will examine these matters on an account by account basis.

6.2.5. Home Area Network Costs

In this GRC, SCE requests O&M costs and capital spending on HAN-related activities in three business units: TDBU, CSBU, and IT&BI.

As part of the SmartConnect deployment, the Commission set forth certain functionality requirements applicable to HAN, including; (1) collection of detailed usage data to support customer understanding of the relationship of usage to cost; (2) flexible customer access to personal usage data; and (3) compatibility with applications that utilize collected data to provide customer

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588 SCE-19 at 21.

589 R.09-08-009.

education and energy management information.[590] By the end of 2010, SCE recorded about $1.5 million for such HAN-related activities in the ESCBA.[591]

More recently, the Commission adopted rules concerning privacy and security of electric usage data in D.11-07-056. The Commission acknowledged delays in the HAN program, noted that HAN-enabled devices are "in their infancy," and ordered all three IOUs to develop a HAN smart meter implementation plan.[592] The Commission only required the plan to provide an initial rollout of 5,000 devices, "which would allow for HAN activation for early adopters upon request, even if full functionality and rollout to all customers awaits resolution of technology and standards issues."[593] SCE's plan, filed November 29, 2011, includes a timetable for making HAN functionality and benefits generally accessible to customers, and an initial phased rollout of up to 10,000 HAN devices by 2012, much less than SCE's original GRC forecast of 116,000 customers.[594]

SCE makes 2012 and 2013 O&M requests for HAN-related activities in the form of incremental adjustments to 2009 recorded costs. Specifically, SCE forecasts $1.157 million for 2012 O&M expenses related to HAN, and $2.908 million for 2013.[595] These expenses are found in FERC accounts 901, 586.400, 902.300, and 908.640 and are intended to support development, testing,

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590 D.08-09-039 at 41-42.

591 TURN-05 at Attachment L.

592 D.11-07-056 at 122.

593 *Id*. at OP 11.

594 Advice Letter (AL) 2662-E.

595 TURN-5 at 18, Table 3.

and analysis of home network devices. In 2012, SCE also seeks $8.3 million ($2009) for CSBU capitalized software related to HAN.

DRA recommends removing HAN program costs for 2012 and 2013 because it concludes it unlikely that SCE will have any HAN customers in this rate cycle. DRA views SCE's forecast of 116,000 HAN customers by 2012, and 487,000 as of 2014, to be unrealistic due to several problems with the technologies.

SCE concedes that original HAN designs are being reformed to address privacy concerns, and that implementation of its related PCT and IHD programs, have been delayed.[596] We previously adopted SCE's request to retain the ESCBA to record PCT and IHD costs through 2014.

DRA and TURN claim that wide availability of HAN devices is dependent on pending ratification of HAN interoperability standards, Smart Energy Profile (SEP) 2.0.[597] SCE does not expect the delay to materially impact its HAN-related forecast because its plans allow for flexibility to integrate SEP 2.0 standards. Since product development and testing will likely begin in earnest after adoption, we are not persuaded that SCE customers will flock to HAN devices during 2012 or perhaps even 2013.[598] Some uncertainty about this technology persists.

TURN calculates that SCE's projected HAN spending reaches $20 million by 2014, and argues these costs should not be recovered through general rates.

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596 SCE-19 at 12.

597 The National Institute of Standards and Technology is preparing to issue SEP 2.0.

598 DRA-10 at 13.

TURN believes that SCE's costs are the result of exceeding its role to monitor providers of HAN systems to assure the technology is compatible with the SmartConnect system. Instead, SCE is stepping into the private sector's role by trying to develop and implement HAN. If the Commission authorizes any HAN-related spending, TURN argues that such costs are deployment costs, should be treated like PCTs and IHDs, be recovered through the ESCBA through 2014, and count against the ESCBA cost cap.[599]

SCE criticizes the recommended cuts which it asserts are inconsistent with national, state and Commission policy directives. SCE maintains the HAN expenses for 2012 are incremental and not included in SmartConnect deployment funding.[600] However, the pace of deployment is behind SCE's original forecast.

The Commission stated just last year that it expected at most a few early users of HAN until resolution of technology and standards issues. Apparently in agreement, SCE's expectations were also lowered in its SmartConnect implementation plan.

We share the skepticism of TURN and DRA about SCE's forecasts and timing for HAN-related activities. Moreover, the Commission anticipated that deployment costs would include basic HAN functionality (i.e., costs related to "compatibility with applications that utilize collected data to provide customer education and energy management information"). Due to market changes, basic HAN functionality will include unanticipated work with new devices to ensure compatibility with SCE's system. On the other hand, we do not expect SCE 's ratepayers have a role in HAN product development.

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[599] TURN-05 at 17-20.

[600] SCE-19 at 6-15, 116.

Therefore, given the delays in development and use of HAN devices, including PCTs and IHDs, the Commission finds it reasonable, logical, and transparent for SCE to record HAN costs in the ESCBA through 2014.

6.2.6. November 30, 2011 Windstorm Response

On January 26, 2012, all five Commissioners attended an overflow public participation hearing (PPH) in Temple City about SCE's response to a severe windstorm in early December 2011 where substantial system damage occurred and hundreds of thousands of customers lost power, some for up to a week. Among other issues, members of the public criticized SCE's call centers and a lack of accurate outage information. Local government representatives also complained about a lack of access to SCE representatives and to accurate information about SCE's response to the windstorm damage.

At the close of the PPH, SCE agreed to provide additional public information to the Commission to respond to concerns raised. Through *ex parte* filing served on the service list of this proceeding, SCE provided two responses:

- February 7, 2012 – addressed (1) customer outreach activities for customer claims processing after the windstorm, particularly for minority communities, (2) long-term outreach plans for processing windstorm-related claims, and (3) the status of previously submitted customer claims and the estimated processing time.
- February 27, 2012 – addressed additional questions regarding, (1) a separate dedicated telephone number for local government officials to improve access to outage information affecting their communities, (2) customer service training at call centers, (3) methods to communicate with medical baseline customers, and status of technology improvements, (4) integration of SCE's corporate emergency response plan and storm response plan, and (5) mobilization of tree-trimming crews in advance of anticipated wind event.

SCE states that due to the unique nature and severity of the wind event, the utility did not meet its service restoration targets nor its predicted restoration times, and public communications did not meet expectations. SCE conducted an internal and external review of its emergency preparedness and response. The Commission's CPSD is still reviewing operational aspects of SCE's response. Following the PPH, SCE's Local Public Affairs (LPA) staff met with city managers in the San Gabriel Valley to discuss more effective communication during emergencies. Promising initiatives reported by SCE include:

- Use of Reverse 911 systems to provide general messages to customers;
- Regular conference calls with local officials during an event;
- Development of a mechanism to inform city managers of outages inside their cities and restoration estimates for critical city services;
- More training for customer service representatives to improve interaction skills; new call monitoring and scoring tool to measure skills;
- Improved communication protocols for medical baseline customers, including notice of any unplanned outage that will exceed 12 hours, plus field visits for such customers SCE cannot reach by telephone;
- Integration of SCE's corporate emergency response system with other emergency response protocols;
- Revision of post-windstorm customer outreach efforts regarding damage claim information to include a "multi-cultural, multi-channel approach that incorporates grass-roots and community outreach activity" in English, Spanish, Cantonese, Mandarin, Korean, and Vietnamese; and
- A commitment to acknowledge a filed claim within five days and to respond to the claim within 30 days.

Although SCE has identified several positive steps to improve communications and customer satisfaction in times of emergency, we are concerned that so many customer communications deficiencies were identified. It raises the question of whether to provide additional funding for customer services and training when SCE failed to deliver basic elements of emergency communications, particularly with local officials who can enhance the flow of accurate information and emergency services to the public.

Rapid emergency response and accurate customer communications during a prolonged outage are an integral part of system accountability sought by a utility's customers. We are deeply disappointed by SCE's failures in these areas during December 2011. Although SCE appears to have identified several key areas for improvement, we note that these areas should have been considered by routine advance planning fully funded by prior rates.

Therefore, we require SCE to provide a report to the Commission via a Tier 2 Advice Letter by January 30, 2013, which describes the progress made by the utility in each of the internal and external initiatives SCE documented in its two February 2012 ex parte filings. In addition to the service list of this proceeding, the Advice Letter shall be served on the Directors of the Commission's Energy Division, Consumer Service & Information Division, and Consumer Protection and Safety Division.

6.3. Customer Service Operations Division (CSOD) O&M: FERC 901-905, 580, 586, 587, 597

The activities of CSOD include the Meter Services Organization (MSO), Revenue Services Organization (RSO), and Customer Communication Organization (CCO). MSO is heavily impacted by the SmartConnect systems which are expected to automate approximately 98% of field meter reading and

66% of the field services activities.[601] However, SCE forecasts MSO and RSO will incur additional costs due to an initiative that would use SmartConnect data to identify potential energy theft. By 2013, MSO operations will include the SmartConnect Operations Center (SOC) which will be responsible for the SmartConnect metering and communications systems.

SCE assumes that the CCO customer service programs will have significantly more activity associated with helping customers to understand and use new tools, programs, services and rate options enabled by SmartConnect.

For all CSOD categories (excluding Uncollectibles), SCE forecasts a total 2012 Test Year O&M funding level of $237.096 million and a 2013 forecast funding level of $209.040 million.[602] The 2012 estimate is an increase of $18.953 million (8.7%) over 2009 recorded costs, which SCE claims is more than offset by ESCBA net O&M savings of $26.078 million.

6.3.1. Business Units Management and Support: FERC 901

This account includes costs incurred in the general management and support of customer service operations, such as finance and administration, business planning, regulatory and tariff programs support, training and program management organization support of customer service. Recorded costs in 2009 were $12.06 million.

SCE requests $14.63 million for 2012 ($10.5 million Labor and $4.1 million Non-labor), and $14.772 million for 2013.[603] The forecast includes six

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601 SCE-04, Vol. 02 at 1.

602 *Id*. at 15, Table II-4.

603 JCE at 295, 346, 351 and 363.

adjustments to 2009 recorded costs, totaling $2.568 million: five employees to support major technology initiatives, nine employees (plus consultants) for training in the new technologies, the HAN program, customer growth, PEV-related training, and support for Finance and Administration activities. The 2013 adjustments are similar except to add three more employees.

DRA concludes these costs have historically varied, generally declining except for 2008. DRA used the five-year average (2005-2009) of recorded labor and non-labor expenses as the basis of its 2012 and 2013 forecasts of $13.332 million each year.[604] If the Commission were to adopt SCE's approach, DRA opposes SCE's adjustments for customer growth, PEV Readiness, and HAN program activities.[605] TURN opposes funding for PEV Readiness and the HAN program, a total of $379,000 for this account.[606]

Based on a review of historic costs for this account, we agree with DRA that $13.332 million is a reasonable forecast for TY2012. The 10.5% increase over 2009 recorded expenses provides an additional $1.270 million in 2012 to account for customer and program growth over current levels.

Therefore, the Commission finds reasonable and adopts $13.332 million as the 2012 forecast for O&M in this account.

For 2013, the Commission finds it reasonable to allow an additional $0.142 million to account for additional employees SCE seeks in relation to the rollout of major technology initiatives. Accordingly, the Commission adopts $13.474 million for 2013 ($10.267 million Labor and $3.207 million Non-Labor).

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[604] DRA-10 at 10.

[605] DRA-10, at 9-10; JCE at 295, 346, 351, 363.

[606] TURN-5 at 13-14, 18; JCE at 776, 797.

6.3.2. Meter Reading Expenses: FERC 902

This account captures all expenses related to the reading of customer meters. Between 2005 and 2008, historical costs remained relatively stable, followed by a 5.6% decline in 2009 due to productivity from the 2008 replacement of 45,000 hard to read and safe access meters.

SCE seeks $45.113 million ($35.460 million Labor and $9.653 million Non-labor) for TY2012, an increase of $812,000 (1.8%) over 2009 recorded expenses to account for expected customer growth.[607] For 2013, SCE estimates that substantial SmartConnect benefits, including far fewer physical meter reads, will result in a nearly $32 million reduction to costs. However, SCE adds $328,000 for customer growth to arrive at its 2013 estimate of $12.34 million.[608]

DRA recommends the Commission adopt the 2009 recorded costs of $44.3 million as the 2012 forecast for this Account, rejecting the 1.83% customer growth adjustment.[609] For 2013, DRA concurs with SCE's benefit calculation and rejects the customer growth adjustment, resulting in a forecast of $12.012 million. TURN made no specific recommendation for this category of expense.

Utilizing 2009 recorded expenses is a reasonable basis to forecast 2012 O&M expense. Although in past years there may have been some correlation of meter read costs to customer growth, in this period of transition to remote electronic reading of advanced metering devices, SCE has not shown such a correlation will exist in 2012. In view of SCE's recent productivity

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[607] SCE-19 at 37.

[608] SCE-4, Vol. 02 at 130.

[609] DRA-10 at 18-19.

accomplishments, including non-SmartConnect initiatives, meter read costs should not materially increase during 2012, regardless of any customer growth.

Accordingly, the Commission finds it reasonable and adopts $44.3 million for 2012 O&M in this account, recognizing that related operational benefits from SmartConnect deployment will still be recorded in the ESCBA.[610] For 2013, we find DRA's forecast of $12.012 million, 2.6% less than SCE's forecast, to be reasonable and we adopt it.

6.3.3. SmartConnect Operations Center (SOC): 902.300

This subaccount is a new activity with very different costs forecast for 2012 than for 2013. In 2012, SCE forecasts spending $1.089 million for what the utility characterizes as non-SmartConnect deployment costs: (1) Information Technology applications and communications systems for PEV readiness ($760,000), and (2) troubleshooting and diagnostics for HAN-enabled customer devices ($329,000).[611]

As discussed above, DRA and TURN both reject inclusion of any PEV and HAN-related costs in 2012 O&M.

To the extent SCE incurs costs for 2012 HAN activities, the activities are related to initial functionality and appropriate to record in the ESCBA. We find it reasonable to reduce SCE's PEV request by 40% to conform to the lower PEV forecast. Therefore, the Commission finds it reasonable and adopts $457,000 (all Non-labor) for this subaccount in TY2012.[612]

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610 JCE at 347.

611 SCE-19, at 39-40; DRA-10 at 20.

612 JCE at 777.

With completion of the SmartConnect deployment, in 2013, the SOC will become part of MSO operations. According to SCE, in 2013 the SOC will "plan, monitor, operate and maintain the SmartConnect meter and communication system including: 1) Over the air operations, 2) system optimization, triage and trouble analysis, and 3) planning and service support. The SOC will operate 24 hours-a-day, seven days-a-week, and dynamically integrate the SmartConnect meter and meter communication systems relating to outages and energy usage."[613]

For 2013, SCE forecast $13.115 million for this subaccount. Approximately $11.9 million is to add post-deployment costs for the installation and ongoing operation and maintenance of the SmartConnect telecommunication data management system. Of that amount, $3.3 million is for 29 new employees. The balance of SCE's request is for increased funding for PEV readiness ($770,000) and HAN-related ($422,000) costs for troubleshooting and diagnostics of customer devices.[614]

DRA recommends only $4.098 million ($1.55 million Labor and $2.54 million Non-labor) based on deployment period costs recorded in the ESCBA for SOC functions.[615] DRA annualized two months of (unadjusted) recorded labor and non-labor costs in January and February of 2011 to forecast SCE's 2013 costs of about $4 million for the SOC. DRA's method would result in an almost 20% reduction from actual 2010 recorded costs of $5.08 million.

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613 SCE-04, Vol. 02 at 34.

614 SCE-04, Vol. 02 at 133-134.

615 DRA 10 at 22, Table 10-12.

TURN recommends removal of $1.192 million from SCE's forecast, representing SCE's proposed adjustments for PEV readiness and HAN functionality.[616]

We are persuaded by SCE's argument that the meter and communications system that SCE will operate in 2013 much differently than in 2012. In particular, SCE will assume all operation and maintenance functions. In addition, the SOC will change from a business-hours operation to 24-hours, seven-days a week resulting in a substantial increase in labor costs. Around-the-clock operational support is necessary to operate and maintain the new SmartConnect system and to assure integration with other SCE systems.

However, we agree with TURN that the delayed HAN roll out costs should continue to be recorded in the ESCBA. As before, we also reduce the PEV request by 40% to $456,000.

Therefore, the Commission finds reasonable and adopts $12.385 million for this subaccount in 2013.

6.3.4. Customer Records and Collections: - 903.100-903.300, 903.500, 903.700 - 903.800

FERC account 903 includes all activities involved with processing customer applications for service, receiving payments, conducting customer credit activities, producing and delivering bills, and receiving and resolving customer inquiries. For estimating purposes, SCE disaggregated the historical data for account 903 into six functional subaccounts.

For 2012, SCE seeks a total of $115.102 million for account 903, an increase of $9.085 million (8.57%) over 2009 recorded expenses.[617] SCE's forecast is the

[616] JCE at 821, 830.

sum of each separately estimated subaccount, including adjustments for customer growth and other estimated program changes and benefits.[618] For 2013, SCE forecasts $115.963 million including adjustments for customer growth, program changes, SmartConnect post-deployment operations, and PEV-related costs, as well as benefits from productivity initiatives and SmartConnect deployment.

In reaching its 2012 forecast of $106.015 million, DRA rejects all of SCE's adjustments in three subaccounts, Credit, Billing, and CCO, and instead adopts 2009 recorded costs. The forecasts are summarized in the Table below. We discuss disputed forecasts by subaccount.

FERC subaccount	SCE 2009 recorded	SCE 2012	DRA 2012	SCE 2013	DRA 2013
903.100 Postage	$21,798	$21,341	$21,341	$21,518	$21,518
903.200 Credit	16,995	17,815	16,995	11,662	10,292
903.300 Payment service	9,603	9,836	9,836	9,673	9,673
903.500 Billing	17,170	17,902	17,170	21,364	15,668
903.700 ESP service	966	1,188	1,188	1,188	1,188
903.800 CCO	39,485	47,020	39,845	50,558	38,095
TOTAL	$106,017	$115,102	$106,015	$115,963	$96,434

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617 SCE-04, Vol. 02 at 134.

618 *Id*. at 135, Table IV-38.

6.3.4.1. Credit: 903.200

Costs related to credit and collection activities are recorded in this subaccount. SCE states that about 18% of its customers require follow-up for failure to pay their bills on time (although no support was provided for this percentage).[619]

For 2012, SCE requests $17.815 million ($14.180 million Labor and $3.635 million Non-labor), an increase of $820,000 (+4. 8%) over 2009 recorded costs. SCE's adjustments for incremental costs are, in declining value order: Field Service Representative (FSR) after hours reconnections, customer growth, final call notices to special needs customers, mandated fraud alerts, and review of deposit guarantors.[620]

For 2013, SCE's forecast is $11.662 million, including most of the 2012 adjustments, an extra $580,000 for alerts and notifications, a slight decrease to the customer growth adjustment, and $6.7 million in productivity savings from the SmartConnect Remote Service Switch (RSS).

DRA recommends $16.995 million for 2012, equivalent to 2009Y, a $820,000 (4.6%) reduction to SCE's forecast due to rejection of all SCE's proposed adjustments.[621] For 2013, DRA's forecast is $10.29 million, a $1.37 million decrease, or 11.7% less than SCE's request. TURN's only stated position is its objection to the calculation of 2013 operating benefits which was discussed and rejected above.

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[619] TR at 2130.

[620] SCE-04, Vol. 02 at 149-151.

[621] JCE at 352.

Specifically, DRA argues that SCE failed to establish a correlation of these costs to customer growth, as evidenced by the highest recorded costs in 2005 and lowest in 2009, despite customer growth during those years.[622] Similarly, the number of FSR after hour service reconnections declined in 2010 to the lowest number in six years.[623] DRA also views SCE's other incremental costs as unjustified because SCE is already performing the functions and has embedded funding.

SCE argues that the lower number of disconnections and costs is a direct response to Commission directed policies that disrupted the normal correlation to customer growth.[624] SCE further claims its adjustments for after-hours reconnection expenses, hand delivery of final call notices to special needs customers, credit fraud exceptions and its deposit guarantor program are necessary to account for costs that did not exist in 2009. SCE contends these new services will support the after-hours and weekend functionality of the SmartConnect RSS and provide in-person services to an increasing number of special needs customers.[625]

We are persuaded that customer growth will likely impact these costs. However, as before, we reduce the adjustment to 1.52% in 2012 ($258,000). Additionally, SCE reduced customer disconnections by 17% from 2009 to 2010.[626]

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[622] JCE at 349, 527.

[623] DRA-10 at 26-27.

[624] In R.10-02-005, the Commission found excessive service disconnections with a disproportionate impact on low income California Alternate Rates for Energy customers and ordered PG&E and SCE to implement certain disconnection practices.

[625] SCE-19 at 44-47.

[626] DRA-10 at 27.

The utility's estimated 2012 incremental need for after-hours reconnections is overstated and we reduce it by 17% from $321,000 to $266,430. Additionally, SCE did not adequately support its request for $57,000 for an additional employee to handle SCE's estimated 26% increase in deposit guarantors. The remaining adjustments, totaling $131,000, are reasonable in light of increased activities, particularly after hours reconnections and personal disconnection notices to medical baseline customers.

Accordingly, the Commission finds reasonable and adopts $17.650 million for this subaccount in TY2012. For 2013, we note that SCE's customer growth calculation is $281,000, less than the revised 2.27% we have allowed, so we adopt SCE's calculation. We also accept SCE's estimated SmartConnect benefits of $6.703 million as an offset. However, SCE did not adequately support its request for an additional $580,000 for electronic notices for 25% of its customer base in 2013. Instead, we reduce this request by 50% to reflect a more modest increase in requests for electronic notices. Following a similar analysis as for 2012, for 2013 the Commission finds reasonable and adopts $11.260 million for this subaccount.

6.3.4.2. Billing: 903.500

Expenses recorded to this account are for routine billing, special billing, rebilling and customer account analysis. Recorded costs have been relatively stable since 2007, with a three-year average (2007-2009) of $17.566 million. SCE estimates that new customers and rate structures will increase costs in this rate cycle.

For 2012, SCE forecasts $17.902 million ($15.9 million Labor and $2.002 million Non-labor), a 4.3% increase for this subaccount. The forecast is based on 2009 recorded costs and three adjustments: customer growth ($314,000), special needs billing formats ($365,000), and one FTE to handle rate and bill analysis for PEV customers ($53,000). SCE assumes that 1000 customers will ask for enlarged bill format and another 1000 will request a Braille bill in 2012.

DRA recommends $17.170 million for 2012, equivalent to 2009, and rejection of SCE's proposed $732,000 in adjustments as unjustified.[627] DRA argues billing costs do not correlate to customer growth, noting that the highest recorded costs for this subaccount are in 2006 and the lowest in 2009, despite more customers.[628] Similarly, the number of billing exceptions, a primary task, is at odds from customer growth. DRA supports SCE's enlarged format and Braille billing options, but disputes SCE's 2012 customer estimates and points out the large billing program began in 2008 and only serviced 146 customers in 2010. Lastly, DRA argues that inquiries from the few PEV customers in 2012 can be handled by existing staff. TURN seeks removal of all PEV-related expenses.

SCE responds that there is a cyclical spike in costs after a GRC due to implementation of new rate structures which mask the impact of customer growth. Similarly, SCE expects its costs to increase in 2012-2013 due to many new billing options. The special needs billing costs are due to wider public awareness, a move away from manual creation, and hiring an outside vendor to develop the Braille bill.

We are persuaded that customer growth may impact these costs but reduce the 2012 adjustment, as before, to 1.52%, or an increment of $261,000.[629] SCE's estimates of 1,000 customers asking for enlarged print bills and 1,000

[627] JCE at 353.

[628] JCE at 349.

[629] JCE at 349, 528.

seeking a new Braille bill by 2012 are optimistic. Between 2008 and 2010, the number of customers of large print bills grew from 6 to 146. Although SCE does not separately track these costs, it provided DRA with a cost estimate of $7,300 in 2010. We find it reasonable to assume 500 customers (50%) may seek enlarged bills and 500 seek Braille bills in 2012, based on coordinated customer outreach activities between SCE and Disability Rights Advocates (DisabRA).[630] On the other hand, we are not convinced that SCE needs another full-time equivalent (FTE) to respond to the few PEV billing inquiries likely in 2012.

Therefore, the Commission finds reasonable and adopts $17.613 million for 2012, a 1.6% decrease from SCE's forecast.

For 2013, SCE forecasts costs of $21.364 million, adjusted for $1.502 million in SmartConnect operational benefits, nearly a 25% increase over 2009 costs. The forecast reflects SmartConnect benefits of $1.5 million due to more accurate billing data, 77 new FTEs to support new rates using the interval metering data ($4.938 million), customer growth ($428,000), support for special needs billing ($277,000), and $53,000 for one FTE for PEV inquiries.

DRA recommends $15.668 million for 2013, $5.696 million (27%) less than SCE. While accepting the estimated benefits of $1.5 million, DRA opposes funds for customer growth and all 77 new FTEs proposed by SCE to assist with new rates using interval metering. SCE claimed its Meter Data Management System (MDMS) can provide all of the necessary analysis to generate accurate bills. SCE's other 2013 adjustments-- for special needs bills and PEV bill inquiries-- are also disputed by DRA.

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[630] SCE-19 at 51.

For 2013, we reduce SCE's customer growth calculation to $389,000, utilizing 2.27 % growth over 2009. We also include SCE's estimated SmartConnect benefits of $1.5 million, but reduce the request related to special needs billing by one-third, to $185,000, assuming higher demand in 2013 from targeted customer outreach. However, SCE did not adequately support its new request for 77 new employees for rate inquiries and billing analysis stimulated by SmartConnect and DP. We have noted above that HAN and DP are on a slower rollout than SCE expected when it prepared its GRC application. On the other hand, we recognize that some additional staff are necessary to implement new GRC and DP rates, and particularly to support the new SmartConnect system beyond what the MDMS can provide.

Therefore, we find it reasonable to allow 50% of the FTE request, or $2.469 million in 2013. Following a similar analysis as for 2012, the Commission finds reasonable and adopts $18.711 million for this subaccount in 2013, a 12.4% decrease from SCE's forecast.

6.3.4.3. Customer Communication Organization: 903.800

Costs recorded in this subaccount relate to customer contact centers providing 24-hour access to an SCE representative. In 2009, the largest portion of Account 903 was spent on the CCO.[631] SCE intends to continue the CCO spending trend into 2012, growing from $39.5 million to $47 million, or 83% of the total 2009-2012 increase for account 903. Total recorded costs increased between 2005 and 2009 by 10.5%. In this rate cycle, SCE assumes more calls and more complex problems that take longer to resolve.

[631] CCO is recorded in subaccount 903.800.

SCE forecasts $47.020 million ($37.355 million Labor and $9.665 million Non-labor) for 2012, a $7.535 million (19%) increase over 2009. The forecast is based on 2009 recorded costs, plus adjustments, including a decrease of $651,000 due to expected call deflection and productivity savings. SCE's biggest proposed change is $3.0 million to support longer call handle times, which went down (278 to 270 seconds) from 2008 to 2009 but grew to 273 seconds from 2009 to 2010.[632] An increase of $2.67 million for higher call volume over estimated customer growth, and $1.797 million for scheduled wage increases account for almost all of the increase from 2009.

For 2013, SCE forecasts $50.559 million ($40.627 million Labor and $9.932 million Non-labor), a 28% increase over 2009. The adjustments include a $2.55 million reduction for SmartConnect and productivity benefits, and increases similar to its 2012 forecast.

DRA recommends the Commission adopt $39.485 million for 2012, the equivalent of 2009, a 16% reduction.[633] DRA objects to all of SCE's proposed incremental cost increases. DRA cites a lack of correlating data to customer growth, declining costs despite more calls, small changes to call handle times, its labor escalation approach to wage increases, and a rejection of estimated benefits. DRA rejects a $651,000 productivity offset in 2012, instead using the estimate as a mechanism to fund any increases for call volumes and handle times. For 2013, DRA has a similar position and again recommends $38.095 million.[634] DRA

[632] DRA-10 at 40.

[633] JCE at 354.

[634] JCE at 534.

rejects $1.160 million in productivity benefits to cover possible increases, but accepts $1.4 million in SmartConnect benefits.

The rising number of customer calls since 2005 supports a correlation to customer growth.[635] However, we reduce the 2012 customer growth adjustment to $600,000, and in 2013 to $896,000, to reflect our adoption of lower growth estimates.[636]

SCE did not adequately support its adjustments for call volumes in excess of customer growth in 2012 and 2013. SCE estimates its overall call volume will grow by 2% in 2012 and 1.9% in 2013, compared to adopted customer growth of about 0.5% annually through 2012 and another 0.77% by 2013.[637] Although it is reasonable to expect more calls and longer handling times as the SmartConnect program is implemented, historic costs did not move commensurately as the number of calls increased, some calls will be handled by CSBU's Interactive Voice Response system (IVR), and not all assumed new rates and programs will roll out in 2012, or even 2013.

Therefore we reduce SCE's adjustments by 50% to reflect some increased number of calls, lower per call costs, and the utility of automated response systems. The result is a 2012 adjustment of $1.333 million and in 2013 of $1.496 million.

In 2013, SCE seeks an additional $2.116 million adjustment for call volume growth due to SmartConnect inquiries and remote service disconnections. We

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635 DRA-10 at 40, Table 10-23.

636 JCE at 350, 529.

637 SCE-19 at 58, Table III-8.

find it reasonable to reduce this amount by 10%, to $1.904 million, to reflect fewer than estimated service disconnections as a result of Commission policies.

SCE also claims the adjustment for call handle times utilizes a 2.1% growth rate, based on historic annual growth rates of 1.7% and new programs and pricing options (e.g., HAN, DP, DR). SCE's 2012 adjustment of $3 million is the equivalent of 7.6%, or 2.5% annually from 2009 to 2012. We reduce the adjustment in 2012 to reflect a 2.1% annual growth rate, or $2.488 million. For 2013, SCE states it used average annual growth of 1.8% between 2009-2013, yet the proposed $3.282 million increase is the equivalent of a 2.1% average. We reduce the adjustment to $2.843 million to reflect annual growth of 1.8%.

SCE seeks $1.8 million in 2012, and $4.2 million in 2013, to increase wages by $3.50 an hour because it claims its Customer Service Representatives are paid 30% less than comparable utility employees and it needs them to have better skills to handle more complex calls. DRA contends that all wage increases should be handled by the labor escalation rate, which SCE dismisses as only keeping the status quo.[638]

We are not persuaded that SCE needs $6 million over two years to attract and retain qualified employees, especially in times of high unemployment. Indeed, SCE claims to pay its managers and executives competitive wages yet admits to skimping on wages for customer service representatives. This is troubling. At the PPH, the public repeatedly criticized the customer service representatives for their limited responsiveness, attitude, lack of information, wait time, and other problems. SCE should be able to address this claimed

[638] SCE-19 at 60.

deficiency through redirection of existing funds, new and embedded training funds, and $1 million in each of 2012 and 2013.

In addition to adopting estimated operational and SmartConnect benefits, the Commission finds reasonable and adopts $44.255 million for 2012, a 5.9% decrease from SCE's request, and $45.074 million, a 10.8% decrease, for 2013.

6.3.5. Uncollectible Expense: FERC 904

This account records SCE's expenses for all revenue components of uncollectible customer accounts. Historically, recorded expenses are authorized based on an estimate of uncollectible expense factor expressed as a percent of gross SCE revenue. This "uncollectible factor" is applied to various components of SCE's revenue as each is reviewed in proceedings other than the GRC.

For TY2012, SCE forecasts an uncollectible factor of 0.229%, slightly below the current factor of 0.240% and slightly above an eight-year adjusted average from 2000-2009 (excluding 2005-2006) of 0.227%.[639] The resulting 2012 expenses are $15.7 million.[640] SCE contends the two years, where the factor was 0.112% and 0.108%, respectively, were "abnormally low" due to the housing and subprime credit boom and should be excluded from the calculation.[641] When credit is easy, more customers pay their bills, states SCE.

On the other hand, Aglet recommends using the 10-year average of recorded uncollectible factors, 0.203%, because it finds no justification for excluding 2005-2006.[642] Aglet argues that use of a ten-year average is more

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[639] SCE-04, Vol. 02 at 177-178.

[640] JCE at 956.

[641] SCE-04, Vol. 02 at 175.

[642] Aglet 1 at 16.

reliable because it will smooth varied economic effects, as evidenced by its adoption in the 2009 GRC.[643] Aglet also argues that SCE did not show causality between credit excesses and the uncollectible factor.[644]

We agree with Aglet that a 10-year average to determine the uncollectible factor is reasonable, and the exclusion of two years from SCE's calculation is not adequately supported. In addition, we adjust the factor to 0.205% to reflect four untested adjustments. Therefore, the Commission adopts 0.205% as the uncollectible factor resulting in a $1.649 decrease to SCE's estimate.

6.3.6. Miscellaneous Expense: FERC 905

This account captures all of the customer account expenses not reflected in or specific to the activities identified within FERC Accounts 901-904. This includes telephone expenses recorded by call centers, customer billing policy adjustments, website upgrades, consumer affairs expenses and market research expenses.

For 2012, SCE seeks $14.534 million for four subaccounts, a $2.304 million increase from 2009 recorded costs.[645] SCE contends that recorded expenses have increased significantly in each of the last three years, and more funding is necessary to conduct increased consumer outreach and education for SCE's growing special needs population.[646] SCE's forecast grows to $15.936 million for 2013 to address integration of SmartConnect.

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643 *Ibid*.

644 I*bid*.

645 SCE-04, Vol. 02 at 180.

646 SCE-19 at 69-72.

DRA recommends $12.325 million, 15% less than SCE's 2012 request affecting four subaccounts. The forecast is based on a five-year average of recorded expenses (2005-2009) because the functions (such as outreach to special needs customers and the handling of complaint volumes) are routine activities.[647] DRA's 2013 forecast is $12.281 million, affecting the same four subaccounts.

We agree with DRA's removal, in both 2012 and 2013, of $200,000 from subaccount 905.300 (Policy Adjustments) because we decline to alter our policy of shareholders funding payments to customers in SCE's Service Guarantee program.[648] Otherwise, we agree with SCE that costs for this account have been rising and can be expected to continue.

The Commission finds reasonable and adopts SCE's forecasts, less $200,000 in 2012 and 2013.

6.3.7. CSBU Safety: FERC 580

SCE presents these costs in two subaccounts. All expenses related to the management and supervision of the organization within SCE which develops and implements safety programs related to the field, technical and office environments of the CSBU are recorded in 580.100.[649] Subaccount 580.300 captures all expenses related to the management and supervision of meter services operations and management.[650] There is no dispute regarding these subaccounts.

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[647] DRA-10 at 44.

[648] JCE at 305, 522.

[649] SCE-04, Vol. 02 at 202.

[650] *Id*. at 205.

Therefore, the Commission finds SCE's 2012 and 2013 forecasts reasonable and adopts them for both subaccounts.

6.3.8. Meter Expenses: FERC 586

6.3.8.1. Turn Off and Turn On Services: 586.100

Subaccount 586.100 captures all expenses related to turning on and turning off meters at the request of the customer. SCE requests $18.474 million for this account for 2012, an increase of $811,000 from 2009 recorded costs due to incremental costs forecast for customer growth ($323,000) and after hours support ($488,000). As the result of $11.6 million in estimated SmartConnect benefits, and $1.5 million in costs, SCE's 2013 forecast is $8.223 million. DRA did not object to the adjustments.

The Commission finds SCE's forecasts for this subaccount to be reasonable and we adopt them.

6.3.8.2. Test and Inspect Meters: 586.400

This account captures all expenses related to the operation, inspection and testing of meters and associated metering equipment. Also captured are costs for meter testing, maintenance of bundled and direct access customers, and accuracy and regulatory compliance for existing meter installations.

SCE forecasts costs of $11.196 million for 2012, an increase of $1.340 million from 2009 recorded expenses, and adds 11 FTEs.[651] The forecast is based on adjustments for customer growth ($180,000), and meter activities related to PEVs ($564,000) and HAN ($596,000). For 2013, SCE's forecast of $11.334 million

[651] SCE-04, Vol. 02 at 219.

includes SmartConnect benefits of $1.8 million and $1.35 million in costs, in addition to the 2012 categories, and adds a net twenty more FTEs.[652]

For 2012, DRA recommends the Commission adopt 2009 recorded expenses of $9.856 million with no adjustments. We are persuaded that customer growth will have some effect on these expenses, but reduce the adjustment to $150,000 in 2012 and to $176,250 in 2013 to conform to the adopted growth forecast.[653] As before, DRA disputes that SCE will have significant costs related to PEVs or HAN in 2012.[654] For 2013, DRA recommends $9.375 million, which is $1.959 million (17%) less than SCE's forecast. DRA accepts SmartConnect costs and benefits, but objects to the same adjustments as in 2012.[655] TURN recommends that all HAN costs be recorded in the ESCBA and PEV costs be removed.[656]

Based on our adoption of the lower PEV forecast, we reduce SCE's PEV adjustments by 40% to $338,400 in 2012 and $492,600 in 2013. Widespread deployment of HAN devices is delayed. Since meter compatibility with HAN applications is part of the original SmartConnect deployment functionality requirements, we conclude that the 2012 and 2013 HAN-related meter testing costs should be recorded in the ESCBA.

Accordingly, the Commission finds reasonable and adopts a 2012 forecast of $10.344 million and a 2013 forecast of $10.044 million.

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652 *Id*. at 220-221.

653 JCE at 345, 524.

654 *Id*. at 293, 362.

655 *Id*. at 503, 543.

656 *Id*. at 774, 796, 819, 828.

6.3.9. Energy Theft, Customer Installation, and Management and Supervision: FERC 587

SCE presents these CSBU costs in three subaccounts. Subaccount 587.500 captures expenses for customer problems regarding billing or electrical service, including noisy meters, remodeling, rewiring and flickering lights. SCE's forecasts for 587.500 Customer Installation Expense are $3.118 million in 2012 and $375,000 in 2013. The 2012 forecast reflects a12.5% increase mostly for a higher number of billing inquiries due to SmartConnect. In 2013, the forecast includes a $2.7 million reduction for SmartConnect benefits.[657]

For subaccount 587.800 Management and Supervision, SCE's forecasts are $2.34 million in 2012, and $2.36 million in 2013.[658] These costs, related to employee safety, training, and information meetings, were nominally adjusted from 2009 recorded costs of $2.3 million.

The Commission finds SCE's forecasts for the two subaccounts to be reasonable and adopts them.

6.3.9.1. Energy Theft: 587.200

This subaccount captures all costs for activities required to collect revenues that would otherwise be lost as a result of energy theft and billing exceptions.

SCE forecasts $2.905 million for 2012, the same as 2009 recorded costs. For 2013, the forecast grows by $1.908 million (66%) for SmartConnect revenue protection requirements, including 22 new FTEs for three new energy theft programs.

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[657] SCE-04, Vol. 02 at 229-231.

[658] *Id*. at 232-235.

Both DRA and TURN recommend the Commission reject SCE's incremental costs on the grounds that, (1) SCE's projected theft cases are speculative, (2) fewer meter readers will cause a decline in theft investigations, and (3) adequate staff exists to address future theft cases.

SCE presented its theft assumptions to the Commission as part of the SmartConnect deployment proceeding.[659] In D.08-09-039, the Commission acknowledged that energy theft losses would likely increase once meter readers were gone, unless replaced with Advanced Metering Infrastructure (AMI) assisted energy theft programs.[660] We are persuaded that SCE's proposals involving meter tamper flags, analysis of consumption data, and meter inspections are likely to identify potential theft. However, the addition of 22 employees, to a total of 56, is excessive when the number of investigations formerly triggered by meter readers is expected to drop, leaving some personnel available to address the new programs. Even though SCE claims the preliminary investigation work done by meter readers was not charged to this subaccount, the AMI is supposed to provide data that serves a similar function.

Therefore, the Commission finds reasonable and adopts SCE's 2012 forecast, and reduces SCE's 2013 request by $638,000, which could still result in an additional 15 FTE's, a 44% increase over 2009.

6.3.10. Repair Billing Meters: 597.400

This account captures all expenses related to the maintenance and repair of electric billing meters and ancillary metering equipment. This account also

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[659] SCE-04, Vol. 02 at 222-225.

[660] D.08-09-039 at 34.

includes the costs incurred by the SSID Standards Lab for the repair of meter testing equipment and related devices.

SCE forecasts $1.689 million for 2012, an increase of $30,000 from 2009 recorded expenses to account for customer growth. For 2013, SCE adds $252,000 in incremental costs to 2009 recorded, for a total forecast of $1.911 million. An adjustment of $207,000 is to support more complex metering installations and includes three new FTEs. The remainder is for customer growth.

No party disputes SCE's forecasts which the Commission finds reasonable and adopts here.

Customer Service Operations Division (CSOD) O&M Expense Request ($000s)							
FERC Acct #	**Activity**	**2012 Request**	**2013 Request**	**2012 Adopted**	**2013 Adopted**	**2012 Disallowed**	**2013 Disallowed**
901	Business Units Mgmt & Support	$14,630	$14,772	$13,332	$13,474	$1,298	$1,298
902	Meter Reading & Operating Center	46,202	25,455	44,757	24,397	1,445	1,058
903	Customer Records & Collections	115,102	115,963	111,848	107,424	3,254	8,539
905	Miscellaneous	14,534	15,936	14,334	15,736	200	200
580	Ops Supervision and Engineering	6,906	7,882	6,906	7,882	0	0
586	Meter Expense	29,670	19,572	28,818	18,282	852	1,290
587	Customer Install Expense	8,363	7,549	8,363	6,911	0	638
597	Maintenance of Meters	1,689	1,911	1,689	1,911	0	0
Total		**$237,096**	**$209,040**	**$230,047**	**$196,017**	**$7,049**	**$13,023**

6.4. Customer Service and Information Delivery

Customer Service and Information Delivery (CS&ID) addresses the service needs faced by non-residential customers including government, commercial, industrial, and agricultural customers. SCE states these customers account for approximately 66% of all electricity consumed on the SCE distribution system and 60% of SCE's retail revenues.[661] In addition, CS&ID develops and delivers service offerings and programs for both residential and non-residential customers. Its functions include Customer Care, Economic Development Services, and LPA.

SCE anticipates higher costs for these activities due to its technology-enabled customer service models, new customer service and outreach initiatives, new and flexible rates, infrastructure for emerging technologies (e.g., PEVs, HAN), local community support and transmission licensing.

In 2009, SCE incurred O&M expenses for CS&ID of $53.543 million. SCE's 2012 forecast of $63.316 million is calculated in eight subaccounts. Each subaccount forecast utilizes 2009 recorded costs as the Base Year, with various adjustments totaling $9.773 million. The adjustments include $5.6 million for expanded communications on new, more complex rate options, on-line energy information, and program support; $1.728 million to support increased transmission and substation licensing activities; $1.197 million to assist new technology initiatives; $1.059 million to support mandatory Time-of-Use (TOU) and default Critical Peak Pricing (CPP) rates; and $141,000 for Business License Tax fees.

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[661] SCE-04, Vol. 03 at 1.

6.4.1. Customer Assistance: FERC Account 908

There are five subaccounts associated with account 908. No party protested 2009 as Base Year, or SCE's 2012-2013 forecasts in subaccounts 908.620 Technical Services ($7.4 million total) and 908.630 Economic Development ($5 million total). Either DRA or TURN protested some of SCE's adjustments in the remaining three subaccounts.

The Commission finds reasonable and adopts SCE's 2012 and 2013 forecasts for subaccounts 908.620 and 908.630.

6.4.1.1. Account Management: 908.600

The Account Management function provides basic customer services to 689,000 non-residential service accounts that have more complex issues than can be practically resolved by simple phone communication or mail.

SCE forecasts expenses of $15.534 million for 2012, an increase of $894,000 from 2009 recorded expenses of $14.640 million. The increase anticipates 15 new positions in three program areas: PEVs, Dynamic Pricing, and Outage Communications. For 2013, SCE's forecast increases to $15.610 million including one more FTE for PEV support.

DRA rejects incremental increases for PEVs ($308,000)[662] and Outage Communications ($146,000)[663] for a reduction of $455,000 from SCE's 2012 forecast. DRA points out that Outage Communications are a routine activity and have shown historical stability.[664] SCE defends the increase by stating this began as a pilot program in 2007 with increased staffing in 2009-2010, and describes

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662 JCE at 298, 507.

663 *Id*. at 357, 537.

664 DRA-10 at 63.

past efforts related to planned outages. Future increases are also supported by reference to increased equipment failures due to aging infrastructure.[665]

TURN opposes SCE's 2012 request for ten FTEs ($439,000) to support increased inquiries from small, non-residential customers as DP is implemented.[666] TURN contends these costs are clearly caused by SmartConnect deployment and should be recorded in the ESCBA.[667] SCE responds that its DP account management activities are necessary to implement the directives of D.08-09-039, including support of CPP and mandatory TOU, and are incremental to the SmartConnect deployment.[668] TURN also rejects SCE's adjustment for PEV support.[669]

We have previously addressed DP requests in the GRC and found that due to delays in adoption of DP rates, the program is behind schedule. Contrary to SCE's view, costs to respond to customer inquiries about DP fall within O&M costs related to DP customer education and "customer tariffs, programs, and services" which are to be recorded through 2012 in the ESCBA. As we discussed above, it is reasonable to reduce the PEV forecast by 40% to $185,000 to reflect lower levels of PEV use.

We are also persuaded by DRA that SCE's Outage Communications unit has been growing, adding staff, and the recorded costs have shown little fluctuation in recent years. SCE's generalized expectation of equipment failure is

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[665] SCE-19 at 20, 86-87.

[666] JCE at 794.

[667] TURN-05 at 6.

[668] SCE-19 at 22-24, 84.

[669] JCE at 779, 824.

insufficient to support additional staff. However, at the PPH on the 2011 windstorm, SCE received criticism about poor communications from some local governments despite SCE's favorable review of its own efforts. We expect SCE to review and modify its practices, where appropriate, to better achieve its communications goals with local governments in an emergency situation.

Therefore, the Commission finds reasonable and adopts $14.825 million for 2012 in this subaccount.

For 2013, we agree with SCE that after DP prices are adopted, there will likely be more inquiries from these business customers about how to better manage energy costs. Therefore, the Commission finds it reasonable to adopt SCE's forecast of $439,000 for additional staff, and 60% of the 2013 PEV forecast (.6 x $385.000 = $231,000). The resulting 2013 forecast is $15.456 million.

6.4.1.2. Energy Centers: 908.610

O&M costs recorded in this subaccount include support for two Energy Centers dedicated to providing residential, commercial, industrial and agricultural customers with information regarding safe energy usage, utility programs, demand side management, environmental solutions and other energy issues. One center is located in Irwindale[670] and the other, focused on agricultural customers, is located in Tulare.[671]

The centers are jointly funded through Public Goods Charges and O&M funding. In 2009, the centers together conducted 1,891 events attended by a total

[670] SCE-04, Vol. 03 at 43 (Customer Technology Application Center).

[671] *Ibid.* (Agricultural Technology Application Center).

of 31,787 customers.[672] SCE claims growing demand and wait lists for these programs, so SCE forecasts additional staff and a third energy center.

SCE forecasts expenses of $2.110 million for TY2012, an increase of $165,000 from 2009 recorded expenses of $1.945 million. The increase is mostly for three new FTEs to provide more training and programs for customers. In 2013, SCE seeks an additional $202,000 for three employees to staff a new Energy Center.

DRA takes issue with SCE's 2012 adjustment to add three FTEs because it views existing funds as adequate for current needs.[673] However, we are persuaded that the incremental expense is necessary to support growth in demand at the existing Energy Centers and off-site locations beyond the current resource capacity. SCE states that Energy Center seminar attendance grew by a total of 111% from 2006 through 2009, an average of 28% annually.[674]

Accordingly, the Commission finds reasonable and adopts SCE's forecast of $2.11 million for 2012.

For 2013, we refer to our discussion of the third energy center is the CSBU capital spending section. We do not authorize the construction of a new center in 2013 for several reasons, including the availability of other, less costly, means to address demand. However, we recognize the need for SCE to expand its customer programs, especially in light of evolving standards and technologies. The addition of three FTE's will allow for creative and less costly solutions.

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[672] *Id*. at 47.

[673] JCE at 358, 538.

[674] SCE-19 at 89-92.

Therefore, the Commission finds reasonable and adopts SCE's forecast for 2013.

6.4.1.3. Program Management: 908.640

Program Management consists of Market Research, Programs and Services, and Market Management and Communications activities. Costs recorded in this subaccount relate to research, development, management, communication, and measurement of customer care programs.

SCE forecasts expenses of $14.262 million for 2012, an increase of $5.648 million (66%) over 2009 recorded expenses of $ 8.614. The increase consists of five incremental adjustments for: PEV support including two new employees ($2.698 million); DP program support ($2.160 million); web accessibility ($343,000); program administration including four new employees ($292,000); and SCE EnergyManager support ($155,000).[675]

DRA recommends use of 2009 recorded expenses as the forecast for 2012, rejecting all five proposed adjustments. DRA rejects all DP costs in this subaccount due to program delays and a belief the costs are duplicative.[676] In addition to its objections to PEV funding, DRA opposes the other adjustments as unnecessary due to existing embedded costs.[677]

TURN recommends $9.249 million for 2012, based on removal of the adjustments for PEV and DP support, and the increased EnergyManager staffing as unjustified due to disappointing participation levels.[678] TURN's objections to

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[675] SCE-04, Vol. 03 at 113-114.

[676] *See*, subaccounts 905.900 and 908.600.

[677] DRA-10 at 70-71; JCE at 299, 359.

[678] TURN-9 at 44-45; JCE at 780, 792-793.

funding for DP and PEV support have been stated.[679] As above, we reduce the 2012 forecast for PEV activities by 40% to $1.619.

SCE asserts that its DP marketing and outreach forecast is necessary to support approximately 612,000 non-residential service accounts in their transition to mandatory TOU rates and default CPP. More than 500,000 are small business customers. SCE claims these activities are necessary to implement the directives of D.08-09-039 and are incremental to the SmartConnect deployment.[680]

Based on the SmartConnect deployment decision, DP customer outreach and education costs in 2012 are to be recorded in the ESCBA. However, large commercial customers were not included in the deployment. SCE's adjustment does not segregate large from small non-residential customers. Given that more than 80% of the commercial customers are small businesses, and some costs will overlap, it is reasonable for SCE to record these costs in the ESCBA for 2012.[681]

SCE's EnergyManager is a group of free and fee-based services to deliver online energy information and tools to 6,600 of its largest commercial and industrial (C&I) customers. Free services grew overall between 2006 and 2009. For fee-based services, SCE experienced a 12% drop in customers and a 23% drop in usage in the three-year period. SCE asserts that usage will increase as more complex rates, programs, and services become available, and the increase supports program changes to reverse negative trends in operating results.[682]

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679 TURN-5 at 6-7.

680 SCE-19 at 22-24, 94-103.

681 SCE-19 at 98.

682 SCE-04, Vol. 03 at 34.

We agree with SCE that elimination of fees and adoption of DP rates will likely increase use of the EnergyManager platform. Therefore, SCE's proposed increase of $155,000 in 2012 is reasonable.

SCE also claims that the addition of four employees for program administration will support 20% growth in Medical Baseline (MBL) applications from 2006-2010, and a 44% increase in Energy Assistance Fund (EAF) application volume in those years. In opposing the increase, DRA points to a decline in medical baseline applications in 2010. We accept the overall growth trend for these customers and find SCE's proposed increase to be reasonable, but urge SCE to dedicate one or more employees to MBL customer communications.

We also find SCE's adjustment to improve web accessibility to be reasonable. SCE claims the funds will support continued auditing and maintenance of SCE.com, training of personnel, remediation of documents to make them accessible to visually impaired customers, and other enhancements to improve usability. Some costs are expected to implement elements of SCE's settlement agreement with DisabRA, and would address complaints from visually impaired individuals who appeared at the PPHs.

Based on the foregoing, the Commission finds reasonable and adopts $11.023 million as the 2012 forecast for this subaccount.

For 2013, SCE's forecast increases to $16.435 million, based on the same categories of adjustments, plus HAN support. DRA recommends $9.75 million. SCE's biggest increase over 2009 is $4.1 million to prepare customers for PEV ($2.77 million) and HAN technologies ($1.34 million).[683] To be consistent, we

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683 JCE at 508, 825, 831.

find it reasonable to reduce the PEV forecast by 40% to $1.661 million and that HAN-related activities continue to be recorded in the ESCBA.

DRA supports an increase of $1.136 million in 2013 to support two new online energy cost tools and a bill forecast program to educate customers, and leverage SmartConnect capabilities to assist customers with energy management. The tools will be developed through 2012 with funds recorded in the ESCBA. In related costs, SCE forecasts an additional $931,000 for marketing and communication. We disagree with DRA that embedded costs exist for marketing and communications because, in 2013, post-deployment SmartConnect related costs move into general rates.

Also in 2013, SCE requests $890,000 for DP marketing, customer education and outreach and includes notices to non-residential customers about actual rates and opt-out provisions of TOU and CPP enrollment.[684] These costs are reasonable because the new rates will likely impact non-residential customers in 2013.

SCE states it has worked with community-based organizations (CBOs) for marketing and outreach efforts, particularly when reaching out to low-income, minority, senior, and small business communities. CBOs are essential partners for the utility in customer education and outreach efforts. We urge SCE to utilize CBOs whenever reasonably possible when implementing such programs. In the next GRC, SCE shall provide in its testimony a description of its efforts to include and work with CBOs in all aspects of customer education and outreach.

684 SCE Work Papers SCE-04, Vol. 03, Ch.4 at 72.

The Commission finds reasonable and adopts $13.992 million for this subaccount in 2013.

6.4.2. Business Unit Management and Support: 907.600

Costs recorded in this subaccount include those incurred in the general management and support of CSBU, such as Finance and Administration, the Program Management Organization, Business Planning, and Regulatory and Tariff Program Support. Historic costs have been on an upward trend since 2005.

SCE forecasts expenses of $10.729 million for 2012, an increase of $1.197 million (11%) over 2009 recorded expenses. The increase is based on the addition of five employees to support major technology initiatives ($1.14 million), and two employees for Finance and Administration ($56,000). There is no dispute on this account and we adopt SCE's forecast.

For 2013, SCE proposes to add three more employees for major technology initiatives, $40,000 for PEV support, and maintain the employees added in 2012. The resulting forecast is $11.123 million. TURN opposes the 2013 PEV funding in 2013.

For this subaccount we find the modest increase for PEV back office support to be reasonable. There is no dispute about the remainder of SCE's 2013 forecast. Therefore, we find SCE's forecast to be reasonable and we adopt it.

6.4.3. Rate Communications: 916.600

Pursuant to Pub. Util. Code §§ 454(a), 491, and 729.5 and Rule 12 of SCE's tariffs, SCE has a continuing obligation to notify customers of rate actions that may affect them. Costs related to providing information to residential and non-residential customers about rate changes and alternate pricing options, including in language communications, are recorded in this subaccount.

SCE forecasts expenses of $1.458 million for 2012 and 2013, equal to 2009 recorded expenses. Historic costs averaged $451,000 between 2005 and 2008, then jumped to over $1.4 million in 2009. SCE explains the abrupt increase in 2009 as the result of communicating 2009 rate increases to customers, and notice to GS-1 customers of a shift from a flat rate to seasonal pricing.

DRA views the 2009 expenses as anomalous and recommends using a five-year average of 2005-2009 recorded expenses. The result is a forecast of $630,000, a 57% reduction. DRA contends that the cost of one-time events, such the GS-1 customer communications, should not be considered in the forecast.[685]

We agree that 2009 is not an appropriate Base Year for the forecast, and note that we have previously authorized funds in the ESCBA and several subaccounts for customer communications regarding alternate pricing options, e.g., DP. Therefore, we apply a three-year average (2007-2009) to mitigate the impacts of one-time costs and reflect other authorized funds for customer communications about rate options. The result is $858,000.

The Commission finds $858,000 a reasonable forecast for this subaccount and adopts it for both 2012 and 2013.

6.4.4. Local Public Affairs: FERC 920

LPA supports the utility's operations by dealing directly with 194 local and regional governments, as well as 13 federally-recognized Native American tribes, and 11 municipal and irrigation district utilities. LPA handles licensing of new transmission and substation projects, and acts as intermediaries between the Company and end-use customers, and as customers in their own right. SCE

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[685] DRA-10 at 76-77.

provides assistance on a variety of electric utility issues including emergency response.

SCE forecasts expenses of $12.624 million for 2012 and 2013, an increase of $1.728 million from recorded expenses of $10.896 million for 2009.[686] The increase is based on two adjustments: $1.152 million for public involvement and regional support, and $577,000 for project licensing support. The request would support 15.3 new FTE's in 2011 and 2012 to address increased workload arising from more transmission and substation projects, and more public involvement activities.[687] According to SCE, one employee would be dedicated to interface with Native American tribes related to transmission issues.

DRA recommends use of a five-year average of historical costs as the most reasonable basis to forecast 2012 costs of $9.297million, a 26% reduction to SCE's LPA forecast.[688] SCE explains variances in historical costs by fluctuating labor rates due to vacancies. In 2008, SCE added 16 positions, 12 for transmission project licensing and four for Public Involvement. In 2009, 18 more employees were added, resulting in an increase of $1.14 million. Despite unprecedented non-labor costs of $564,000 in 2009, SCE states the upward trend since 2007 supports use of LRY.[689]

SCE argues that DRA mistakenly assumes no significant changes in the types of activities going forward. In 2008, SCE created a dedicated group to

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686 SCE states there is no impact on this category from the integration of SmartConnect costs into the 2013 forecast.

687 SCE-04, Vol. 03 at 91.

688 DRA-10 at 78.

689 SCE-04, Vol. 03 at 137.

manage most siting, application, and licensing activities, thus not all costs are reflected in the five-year average. Further, SCE estimates the number of construction projects between 2009-2012 will nearly double, even though siting and licensing projects are expected to decline.[690]

Based on substantial increases in staffing and workload 2008-2009, we are persuaded that use of a three-year average (2007-2009) of recorded expenses ($9.647 million) is a more reasonable reflection of trends in this category. SCE has $564,000 in one-time expenses embedded in 2009 recorded costs, and elsewhere in this decision we have reduced SCE's forecasted 2011-2012 total TDBU capital expenditures, which drive project-related activities, by 9.4%.

Accordingly, the Commission finds it reasonable to reduce SCE's proposed adjustments by $564,000, further reduce the result by 9.4%, and to adopt the result of $10.702 million ($1.728 million - 0.564 = $1.164 x .899 = $1.164 million; multiplied by 90.6% = $1.055 million + $9.647 million = $10.702 million) as both the 2012 and 2013 forecasts. This is a 15.2% decrease from SCE' forecasts.

In addition, at the windstorm PPH, the Commission heard a considerable amount of public concern about SCE's poor communications with local governments during this emergency. SCE admitted that there was a key vacancy at the helm of LPA head at the time, which may have hampered LPA's ability to respond. While comments from PPHs have no evidentiary weight, they do inform our analysis. We encourage SCE to ensure that this position is occupied and maintains an active communication link with the local government entities in its service territory, particularly in emergencies.

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690 SCE-19 at 112.

6.4.5. Business License Tax: FERC 408

SCE is required to pay Business License Tax in order to serve its customers in the cities that levy a business tax on SCE. SCE forecasts expenses of $0.623 million for TY2012, an increase of $141,000 from recorded expenses of $0.482 million for 2009. There is no dispute on this account and we adopt SCE's forecast.

SCE made no separate forecast for this account because no impact on activities is expected from the integration of SmartConnect program.

6.4.6. 2013 Forecasts based on SmartConnect Integration

As discussed, we agree with SCE and DRA that the operational requirements of CSBU will be significantly different in 2013 due to the integration of the SmartConnect program. In each account or subaccount we adopted a 2013 forecast. Note that for three subaccounts unaffected by the SmartConnect program (FERC 916: Miscellaneous Sales; FERC 920: Local Public Affairs; and FERC 408: Business License Tax), we agree with SCE that the 2012 adopted forecast may be escalated by the PTYR adopted herein and added to the overall 2013 CSBU forecast which will then be escalated in 2014 pursuant to the adopted PTYR. The adopted 2012 and 2013 CSID amounts are summarized below:

Customer Service Information and Delivery (CSID) O&M Expense Request ($000s)							
FERC Acct #	**Activity**	**2012 Request**	**2013 Request**	**2012 Adopted**	**2013 Adopted**	**2012 Disallowed**	**2012 Disallowed**
908	Customer Assistance	$37,882	$40,775	$33,934	$37,852	$3,948	$2,923
907	Supervision	10,729	11,123	10,729	11,123	0	0
916	Miscellaneous Sales	1,458	1,458	858	858	600	600
920	:Local Public Affairs	12,624	12,624	10,693	10,693	1,931	1,931
408	Business License Tax	623	623	623	623	0	0
Total		**$63,315**	**$66,603**	**$56,837**	**$61,149**	**$6,479**	**$5,454**

6.5. General Plant Capital Expenditures

SCE forecasts 2010-2012 general capital requirements of $97.4 million, growing to $180 million through 2014.[691] These expenditures support day-to-day operations of CSBU, states SCE, and are distinguished from CSBU Capitalized Software Projects which are discussed in the following section. During the previous five years (2005- 2009), SCE spent $136 million on general capital requirements, averaging $27.2 million per year.

General capital spending is divided into four categories: Structures and Improvements (S&I), Office Furniture and Equipment (F&E), Specialized Equipment, and Meters. About 75% of SCE's 2010-2012 forecast is for meters, but the funding also supports delivery of customer services and to operate the Call Center, Revenue Services, Meter Services, and the Business Customer Division.[692]

SCE developed its forecasts using a budget-based approach which incorporates estimated needs based on forecast employee and customer growth,

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[691] SCE-04, Vol. 04 at 3.

[692] *Id*. at 1.

equipment age and condition, and integration of the SmartConnect program. SCE uses its 2010 forecast of $33.931 million, instead of unadjusted 2010 recorded costs of $25.4 million, because the preliminary figures do not reflect future capital needs by expense category.

DRA forecasts about $53 million of general capital spending for 2010-2012, 46% less than forecast by SCE. In addition to substituting 2010 unadjusted recorded expenditures, DRA also recommends several reductions to 2011 and 2012 forecasts.[693] The difference between DRA and SCE's 2010 forecasts is about $8.5 million.

We agree with SCE that CSBU is in a transition period of customer communications. It must be able to act and react to customers with traditional electric service and a range of evolving programs, devices, and rates supported by new smart technologies and related to Energy Efficiency (EE), DR and other demand side management.

However, actual 2010 recorded costs, even unadjusted, are a reasonable measure for rate recovery in this transitional period. On a project by project basis, we review the 2011 and 2012 costs forecast by SCE to determine whether adjustments should be made for funds authorized but unspent in 2010.

6.5.1. Structures and Improvements

For 2010-2012, SCE forecasts a total of $9.155 million in capital spending, including $5.735 million in 2012 for improvements to the existing Energy Centers and Meter Shop, and to construct a third Energy Center. For 2010 and 2011, SCE forecasts $2.125 million and $1.295 million, respectively. For the years prior to

[693] DRA-10 at 79.

2009, capital spending averaged about $557,000/year, but grew to $2.3 million in 2009 mostly due to energy center costs.[694]

DRA's total 2010-2012 forecast of $6.46 million includes an increase of $806,000 in 2010 to conform with recorded expenditures and a reduction of $3.5 million in 2012 to delete funding for a third energy center.[695] TURN recommends removing $630,000 from SCE's 2010 forecast for meter shop modernization and moving the costs to the ESCBA.

6.5.1.1. Energy Centers

Approximately $5.0 million is forecast for 2010-2012 for facility retrofits and upgrades, various improvements, and changes to meet Leadership in Environmental and Energy Design certification, in order to accommodate more and larger events at the two existing energy centers.[696]

SCE states it needs $6.75 million between 2012 and 2014 to establish a third energy center in Orange County or in an eastern service area to meet a growing demand for education on energy management technologies. Funding is split with the Operations Support unit, and only $4 million is in the CSBU forecast.[697] The request includes funds for an exhibit and demonstration center, meeting, classroom, and conference space, offices, storage, and even catering space.

We do not ignore SCE's claims of growing demand for programs at the two centers, but SCE did not establish that a third center is the best way to

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[694] SCE-04, Vol. 04 at 4, Table II-3.

[695] DRA-10 at 79, Table 10-53.

[696] SCE-04, Vol. 04 at 4, Table II-3.

[697] *Id*. at 4-5 (SCE also seeks $3.25 million in Operations Support to fund permitting, engineering, design, and construction).

expand access to customer and workforce education programs. SCE supports its request by stating most customers will only drive to a convenient proximity, but a third center would have a similar limited radius of effect. SCE also argues that it needs a fixed facility to house certain displays and equipment.

SCE did not compare other creative or more cost efficient alternatives. For example, SCE might explore audio visual upgrades at the two centers to provide video and teleconferencing. Other options might include a combination of mobile facilities, short-term leasing, vendor collaboration, resource sharing, and other less cost options with potential wider availability, particularly since new technologies are still in early stages and facility accommodations may be unknown.

Therefore, the Commission finds it reasonable to disallow $3.5 million from SCE's 2012 request related to establishing a third energy center.

6.5.1.2. Meter Shop

SCE forecast $630,000 in 2010 to complete the meter shop modernization project begun in 2009 to accommodate the increased workload and activities necessitated by the SmartConnect program.[698] No funding is requested in 2011 or 2012. SCE forecasts another $1.44 million in 2013-2014 to redesign, update, and expand to include SmartConnect technologies, including PEVs and HAN, and to train staff.[699] However, we decline to adopt capital forecasts beyond the TY2012.

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698 *Id.* at 6.

699 *Ibid.*

We disagree with TURN that costs for this project should be moved to the ESCBA simply because it will include adapting the facility and equipment to accommodate emerging technologies. The meter shop has been around for decades. TURN did not provide any citation or reference to support its claim that the Commission intended costs for this project to be included in SmartConnect deployment costs. Therefore the Commission finds SCE's forecast reasonable.

In summary, for S&I capital expenditures in 2010-2012, the Commission finds reasonable and adopts DRA's forecasts totaling $6.46 million ($2.931 million in 2010, $1.295 million in 2011, and $2.235 million in 2012).[700]

6.5.2. Office Furniture and Equipment

SCE forecasts a total of $11.3 million for capital expenditures 2010-2012 ($4.7 million in 2010, $4.5 million in 2011, and $2.1 million in 2012) in this category for remodeling, replacements, and ergonomic needs. These costs have historically fluctuated and the five-year average of recorded costs (2005-2009) is $752,000.

SCE expects increased need due to employee growth, forecast remodels of SCE buildings, and includes support for EE and DR program employees. However, SCE only recorded $671,000 in capital expenditures for 2010 due to capital reorganization.[701]

DRA forecasts $2.175 million for 2010-2012 capital expenditures in this category, including $671,000 recorded for 2010 and the five-year average of

[700] JCE at 650, 888.

[701] SCE-19 at 139.

$752,000 for both 2011 and 2012.[702] The difference between SCE's 2010 forecast and recorded 2010 expenditures is $4.028 million.

We generally agree with DRA that a Five-Year Average (5YA) is a reasonable Base Year for this category. SCE chose to delay spending most of its forecast in 2010. However, we acknowledge SCE will add employees in 2011 and 2012, including for EE and DR. Therefore, we add one-half of the difference between SCE's 2010 forecast and recorded amounts ($2.014 million) to DRA's forecasts for 2011 and 2012 to reflect delays in implementation of F&E support for new program employees.[703]

Therefore, the Commission finds reasonable and adopts $0.671 million for 2010, $2.766 million in 2011, and $2.766 million in 2012 for a total of $6.2 million for the three-year period.

6.5.3. Specialized Equipment

This category of capital spending funds equipment in the following areas: Meter Reading Hand Held Devices, Meter Services Tool Kits, Meter Services Specialized Equipment and Temperature Cycle Chambers, and Lab Tools. SCE claims that various costs, including new meter reading devices, will occur in 2013-2014 due to integration of the SmartConnect program, and the ordinary life cycle of test equipment.

SCE total forecast for 2010-2012 is $3.637 million ($1.45 million in 2010, $1.212 million in 2011, and $0.975 million in 2012), and nearly double, $7.86 million, for the 2010-2014 period. SCE's unadjusted 2010 recorded capital

[702] JCE at 652.

[703] Workpapers, SCE-04, Vol. 04 at 32.

expenditures are $6.3 million, but SCE does not explain why it exceeded its own forecast by $4.85 million. Instead, SCE merely states it shifted its general plant capital budget to meet changing operational conditions.[704]

DRA recommends the Commission adopt SCE's 2010 recorded costs, as well as SCE's 2011-2012 forecasts. However, this would result in an excess amount of capital for SCE's projected needs in this category.

Therefore, the Commission finds reasonable and adopts DRA's forecast of $6.3 million in 2010 and zero for 2011 and 2012.

6.5.4. Metering Capital Requirements

This expenditure category includes new meters, replacement meters, infrastructure, meter leasing, Safety/Access, PEV meter readiness, and related costs. SCE's "business case" assumes full use of legacy meters through 2012 and adjusts for smart meter deployment by applying SmartConnect capital benefits.

SCE forecast a total of $73.288 million in capital expenditures for 2010-2012 ($25.66 million in 2010, $24.3 million in 2011, and $23.3 million in 2012), net of Smart Connect benefits.[705] SCE assumes avoided cost metering benefits of $1.595 million in 2010, $5.145 million in 2011, and $8.5 million in 2012 returned to ratepayers through the BRRBA. SCE also estimates spending about $32.3 million in both 2013 and 2014 after the SmartConnect deployment.

Assuming 2010 recorded costs of $17.15 million, DRA recommends a 2010-2012 total of about $36 million ($11.9 million in 2011 and $8.5 million in 2012.[706] For each year, DRA reduced 2010 recorded expenditures by SCE's forecast

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704 SCE-19 at 127.

705 SCE-04, Vol. 4 at 11.

706 JCE at 654.

SmartConnect capital benefits. Underlying DRA's forecast is its view that some legacy meters can be re-used between 2010 and 2012, SCE did not provide support for most 2010 meter purchases, and SCE is recording capital expenses in the ESCBA for all SmartConnect meters.

TURN objects to SCE's forecasts because they overstate customer growth, and provide capital spending for PEV meters which should be charged to PEV customers and HAN readiness which should be recorded in the ESCBA.

SCE disputes that 2010 is representative, arguing that expenses were abnormally low due to SmartConnect meter installations, deferral of other meter costs, and that 2010 was the low point of the economic recession.

SCE's forecasts are excessive. We are persuaded that 2010 is an appropriate base year to forecast meter related costs for 2010-2012 because the declining installation of legacy meters is at the core of this expenditure category. SCE's 2010 forecast was overstated by more than $10 million (65%), an amount not offset by $1.6 million in SmartConnect benefits.

SCE's forecasts are also flawed because PEV costs should not be charged to all customers, HAN costs should be recorded in the ESCBA, and we adopted TURN's lower forecast for new meter sets. However, these adjustments are addressed by our adoption of 2010 recorded costs for 2010-2012. Under this approach, we agree with SCE that the capital benefits should not be used as an offset.

Therefore, the Commission finds it reasonable and adopts $17.1 million for meter capital expenditures in 2010, 2011 and 2012 for a total of $51.300 million.

In total, the Commission adopts $68.499 million of SCE's $97.406 million General Plant CSBU capital expenditure request:

General Plant CSBU Capital Expenditure Request						
	Capital Request by Year ($000)					
Project Description	**2010 Forecast**	**2011 Forecast**	**2012 Forecast**	**Total 2010-2012**	**Adopted**	**Disallowed**
Structures and Improvements	$2,125	$1,295	$5,735	$9,155	$6,461	$2,694
Office Furniture & Equipment	4,699	4,527	2,100	11,326	7,101	4,225
Specialized Equipment	1,450	1,212	975	3,637	3,637	0
Meters	25,657	24,310	23,321	73,288	51,300	21,988
Total	**$33,931**	**$31,344**	**$32,131**	**$97,406**	**$68,499**	**$28,907**

6.6. Capitalized Software

Between 2010 and 2012, SCE forecasts spending $118.293 million by investing in new technologies to meet state and federal policy goals. The request covers eight capitalized software projects. SCE states the projects are necessary to achieve a technology-enabled customer service model by 2014, at a total cost of $200.8 million.

SCE requests $33.883 million in 2010, $41.4 million in 2011, and $43.010 in 2012. The forecasts are budget-based on estimates made in the early planning stages, and involve comparing past projects, identifying project complexity,[707] and determining whether it can be developed internally or by using commercial "off-the-shelf" software (COTS).[708]

DRA recommends the Commission adopt a 2010-2012 total of $75.3 million, 37% less than SCE's forecast.[709] The forecast is based on use of

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[707] Complexity may include review of hardware costs, testing, licensing, vendor and other, support costs, and customization.

[708] SCE-04, Vol.0 4 at 19.

[709] JCE at 656.

2010 recorded costs of $25.3 million, and $25 million for both 2011 and 2012.[710] SCE responds that use of 2010 expenses is flawed because these projects have no historical pattern, and it fails to consider 2010 costs of $79.6 million for capitalized software projects recorded in the ESCBA.

TURN recommends cutting IT projects by 10% to address SCE's failure to minimize skyrocketing IT costs.[711] TURN criticizes SCE for 50% project management costs, 25% contingency costs, the short (five to six years) service life of the software, and argues not all the projects are necessary. TURN would also reduce or eliminate funding for several projects discussed below, including those related to EE and DR where the costs should be subject to 2010-2014 cost-effectiveness tests required for Demand Side Management (DSM) projects.

SCE rejects TURN's criticisms as unsupported. SCE claims its projects are necessary, contingency costs are based on experience, and actual management costs are 33.3%, comparable to similar projects. Regarding cost-effectiveness analysis where projects relate to DR and EE, SCE's position is that the issue is more appropriate to the DR proceeding than the GRC.

6.6.1. Alerts and Notifications

This new system will enable multiple channels of electronic alerts and notifications, states SCE, and allow customers to manage their bills and payments, prepare for planned outages, and manage energy usage. SCE contends that the existing system may meet regulatory requirements but could be more effective and must be able to handle increased demand.

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[710] DRA-10 at 87.

[711] TURN-09 at 2, 7.

SCE forecasts spending $9.33 million in 2012 and $6.780 million in 2013 for the Alerts and Notifications (A&N) project which consists of hardware, software, licensing, and project management costs.[712] DisabRA supports expanding emergency notifications and notice options.

DRA recommends no funding for this project on the grounds that SCE's proposal is unjustified. SCE has not performed any studies or analyses to support its claims that current systems are neither integrated nor scalable to new technologies. TURN opposes funding to the extent it was not subject to DR or DSM cost-effectiveness analysis.

There are no alternative solutions, SCE argues, and making no improvement is not a viable option due to the growing inability to handle increased volumes of customer communications.

Based on revised customer growth estimates, we are not persuaded that SCE must initiate this investment in 2012. Its current systems are meeting demand, including additional outreach to medical baseline and vision impaired customers authorized in this decision. Accordingly, the Commission declines to authorize this request.

6.6.2. Interactive Voice Response

When customers contact the Call Center, SCE currently uses a touch-tone IVR system. SCE forecasts $8.17 million through 2013 to enhance the IVR system, including hardware, software, licensing, and project management costs.

SCE argues the project will upgrade the system with advancements in Advanced Speech Recognition and Text to Speech technologies to improve

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[712] SCE-04, Vol. 04 at 28, Table III-II.

service and encourage self-service, in both English and Spanish. SCE intends to integrate the system with A&N to deliver automated voice messages to customers. It will also have other internal uses, including outbound collections calls.

New hardware and software were implemented by SCE in 2010 but additional application development and software licenses are required for the upgrade.[713] Although IVR reduces the number of calls that require a representative, SCE expects more customer calls due to the many new programs, rates, and devices available.

TURN considers the project unnecessary at this time, particularly as it relates to registration of HAN devices.[714] In addition, SCE has not explored lower cost options to expand customer service menus in the current system.

According to SCE it considered and rejected the option of no improvements to the current IVR system because it would place SCE behind both other utilities' systems and customer expectations.

We are not persuaded that SCE must implement this program in 2011 and 2012. Although it has some appealing features, such as Spanish recognition, SCE did not establish it is essential at this time. The current IVR system is functional, the customer growth forecast was reduced, and both HAN device registrations and DR implementation are delayed. Similar to the A&N project, this may be more appropriate in 2013 or 2014. Therefore, the Commission declines to authorize the request.

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[713] SCE-04, Vol. 04 at 31.

[714] JCE at 890.

6.6.3. Customer Relationship Management

SCE states the Customer Relationship Management (CRM) project will provide a comprehensive, integrated system to manage, track, and report on the company's DSM programs, including EE and DR. It is intended to improve operational efficiencies and replace obsolete systems. Currently, SCE manages more than 75 DSM programs using more than 40 systems.

The CRM project will be implemented by SCE in two phases. The first phase, estimated to cost $44.82 million,[715] is to create a centralized system, including improved vendor and customer interactions, integration with SAP for customer and vendor payments, and improved marketing and outreach. SCE estimates Phase 1 to be completed in 3rd Quarter 2011.

Phase 2, which SCE estimates will cost $20 million and be completed in first Quarter 2013, will install SAP developed upgrades to the CRM software to allow greater automation of the enrollment process.

TURN recommends the entire project be rejected because it has no quantifiable benefit.[716] SCE has a history of five previous initiatives projected at a fraction of the CRM cost, and when later CRM costs are included, the total bill to ratepayers will be over $100 million.[717] According to TURN, because it is a cost of implementing EE and DR projects, it should have been subject to a cost-benefit test, and given lackluster enrollment in DSM programs, SCE has not justified its need.

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[715] SCE-04, Vol. 04 at 43.

[716] JCE at 892.

[717] TURN-9 at 30-31.

SCE states CRM will improve internal controls and management capabilities to offset the lack of quantified benefits. SCE argues that maintaining the status quo is unreasonable because of the annual ongoing system maintenance costs and risks. The company asserts it considered and rejected other alternatives, some of which are described in its testimony.[718]

We understand SCE's concern about greater efficiencies in managing, tracking and reporting on DSM programs. These are high priority programs pursuant to state policy and prior Commission decisions. The Commission will require accurate data on DSM programs and it is reasonable to integrate a large number of programs into one system and eliminate obsolete software. Moreover, we find that CRM involves several programs and is suitable for consideration in the GRC.

We find it reasonable to authorize Phase 1 funding, reduced by 10% to address cost concerns. For 2010, we adopt recorded costs of $19.91 million, and $20.428 for 2011. We do not address Phase 2.

Accordingly, the Commission adopts $40.338 million to implement Phase I of the CRM. SCE should provide a cost-benefit analysis in the next GRC if it seeks to recover any additional CRM costs.

6.6.4. Enhanced Meter and Usage Capabilities

The Commission previously authorized SCE to record in the ESCBA its estimated costs of $154.3 million, to license, develop, and integrate the MDMS

[718] SCE-04, Vol. 04 at 44.

and Network Management Services (NMS) systems.[719] MDMS and NMS are Custom Off-the-Shelf software packages.

The MDMS collects usage and event data from the smart meters, including HAN device data, to support billing, DP, load control, and DR options. The NMS is the security gateway between the meters and MDMS. These systems were purchased from SCE's, Itron, and enhancements regularly become available.

In this GRC, SCE seeks capitalized software costs of $48.60 million for two system enhancements for MDMS and NMS: $31.47 million in 2013, and $17.13 million in 2014. SCE intends the improvements to develop new programs for customers using their smart meters and devices, support new tariffs for DR, PEV, etc., provide billing based on load control programs, and capture and leverage metering data. It will also include technical changes due to operating system upgrades.

We do not address capital forecasts for 2013 and 2014 in this GRC.

6.6.5. HAN Support and Trouble Shooting

SCE based its forecast of $8.3 million in 2012 for the HAN project based on an estimate of 500,000 HAN devices within its service territory by 2014.[720]

The proposed project has two steps: (1) design and implement enhancements and upgrades to the basic HAN functionality delivered as part of the SmartConnect deployment, and (2) design and implement new system functionality to support widespread availability of HAN devices in the future.

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[719] D.08-09-039.

[720] SCE-04, Vol. 04 at 54.

The specific capabilities include improvements for device registration, support for PCTs and other devices, troubleshooting, and developing internal system communications.

DRA opposes any funding for this project on the grounds it is premature to the roll out of this technology.[721] TURN disputes the need for the project because other projects (e.g., DP software) will give customers access to usage data.[722] In addition, TURN thinks the costs, if approved, should be included in the ESCBA.

SCE admits this project is in very early development. It is based on an expectation of wide use of HAN devices in 2013 and 2014, a premise we declined to adopt previously in this decision. Because the HAN technologies and standards are evolving, we have concluded that SCE's existing systems and processes can likely manage the minimal device usage anticipated by SCE's HAN Implementation Plan of 5,000-10,000 devices by 2014.

We agree with SCE that the Commission did not anticipate this type of capital project to be recorded in the ESCBA as part of the SmartConnect deployment costs. We also find that implementation of this project, including software purchase and licensing costs, is premature. The company will have more time to thoughtfully weigh the direction of this type of technology and how best to adapt and integrate HAN-type devices with its system over the next two or three years.

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[721] JCE at 656.

[722] JCE at 891.

6.6.6. Plug-In Electric Vehicle Support Systems

SCE forecasts $2 million in 2012, and $8.4 million by 2014, to support its forecasted enrollment rates for PEVs by upgrading various systems.[723] Planning for this project was initially forecast to begin in 3rd quarter 2012 and to be completed by 2nd Quarter 2014.

According to SCE, the systems are necessary both internally, to streamline work order processing, and for customers, to improve enrollment in DP or PEV rate structures, expedite installation of charging equipment and meters, and to provide more effective customer service. SCE includes upgrades for SCE.com to allow for customer self-service sign-up for PEV services and to monitor the status of the request.

DRA rejects any capital spending in 2012 as premature given the lower forecast of PEVs adopted in this decision, and also asserts that SCE has embedded funding for PEV readiness expenditures.[724] TURN opposes the project on the grounds it should not be paid for through general rates and is too costly.[725]

SCE responds that project costs are reasonable, not included in previously funded PEV activities, are not duplicative, and are justified by its PEV forecast. SCE states it considered continuation of the status quo manual systems, and concluded it would result in declining customer service which could be a

[723] SCE-04, Vol. 04 at 59.

[724] DRA-10 at 92.

[725] TURN-9 at 26; JCE at 864.

disincentive to PEV use.[726] It also rejected a stand-alone PEV system as more expensive without additional benefits.

As applicable to this integrated system response, we find that SCE's proposed schedule for the project is likely to outpace need. Since the project requires integration with other major technology projects, such as CRM authorized in this decision, it is reasonable to slow down the implementation to assure that the inevitable glitches and problems be worked out in the key systems before looping in the PEV support.

SCE should be able to manage the estimated reduced influx of PEVS in 2012, and when CRM and the smart meter data collection systems are established, then complete the software development and other steps.

6.6.7. Regulatory Mandate and Compliance

SCE proposes two projects targeted to regulatory compliance: Intelligent Mail Barcode (IMB) and Dynamic Pricing Rate Analysis and Management Tools. The forecast costs total $40.393 million.

SCE uses various software tools and processes to presort mail to obtain and maximize price discounts. The U.S. Postal Service requires use of the IMB by May 2011 in order to retain discounted postal rates. To implement the IMB, SCE needs to make a change to the software to change the layout and print of customer bills. The project is scheduled to be completed by May 2011 for a total cost of $4.56 million. SCE only seeks $3.663 million in 2010 because it previously recorded $0.892 million in 2009. There is no opposition to this project.

The Commission finds reasonable and adopts SCE's 2010 forecast.

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[726] SCE-04, Vol. 04 at 68-69.

6.6.7.1. Dynamic Pricing Rate Analysis and Management Tools

SCE offers some DP rates today and all large C&I customers with demands of 200 kW or more were defaulted to CPP in 2009. There is little participation from other customers although Commission policies have set in motion new DP rates and DSM programs in the future.

SCE forecasts $36.73 million in capital expenditures between 2010 and 2012 ($3.73 million in 2010, $17 million in 2011, and $16 million in 2012) for system modifications to support new DP rates, associated rate analysis, and energy management tools for use by customers and SCE employees. Because new rate options are more complex than options available today, SCE plans to address customer needs primarily through self-service channels such as SCE.com. This project will implement enhancements to the SCE.com/My Account website to provide customers with simple rate information and analysis tools to manage their energy usage and costs.

DRA recommends only $55,000 in 2010, recorded expenses, and no funding in either 2011 or 2012 because it does not believe that SCE is either committed to the project, nor has justified the expense. TURN argues the whole DP policy should be reviewed, and concludes that these costs are associated with SmartConnect deployment and should be recorded in the ESCBA instead of recovered through general rates.

We are not persuaded by TURN's claim that these project costs are to be recorded in the ESCBA. Although some back office systems related to customer tariffs were included in the ESCBA, this DP project is much broader, and includes TOU and CPP for commercial, industrial, and agricultural customers largely unaffected by the SmartConnect deployment. SCE employees are also expected to use the data.

On the other hand, the documentary support for the project costs is limited and implementation of DP rates is delayed from earlier expectations.

SCE asserts that it is now implementing the project with a new completion date of late 2012. We agree that SCE should have the ability to electronically work with customers to demonstrate the pricing and energy management tools for a range of DP programs. We reduce the overall forecast costs by 10% to $33.057 million to address timing and cost concerns, and add unspent portions of the 2010 forecast to 2011 and 2012.

Therefore, the Commission finds it reasonable to adopt $55,000 for 2010, and to apply the forecast difference of $3.3 million equally between the reduced estimates for 2011 and 2012. The result is $16.95 million in 2011 and $16.05 million in 2012.

In total, the Commission adopts $79.356 million of SCE's total $118,293 million capitalized software request:

CSBU Capitalized Software Capital Expenditure Request						
	Capital Request by Year ($000)					
Project Description	**2010 Forecast**	**2011 Forecast**	**2012 Forecast**	**Total 2010-2012**	**Adopted**	**Disallowed**
Specialized Equipment	$2,300	$0	$0	$2,300	$2,300	$0
Alerts and Notifications	0	0	9,330	9,330	0	9,330
Interactive Voice Response	0	3,790	4,380	8,170	0	8,170
Customer Relationship Mgmt & Data Warehouse	24,190	20,610	3,000	47,800	40,338	7,462
Enhanced Meter and Usage	0	0	0	0	0	0
HAN Support and Troubleshooting	0	0	8,300	8,300	0	8,300
PEV Support Systems	0	0	2,000	2,000	0	2,000

ICPC Phase II	3,663	0	0	3,663	3,663	0
Dynamic Pricing Rate Analysis	3,730	17,000	16,000	36,730	33,055	3,675
Total	**$33,883**	**$41,400**	**$43,010**	**$118,293**	**$79,356**	**$38,937**

6.7. Other Operating Revenues

SCE identifies as OOR services that are not considered within the definition of basic services, the costs for which are recovered through specific fees and charges to end users. Today, the most common of these service fees include the: Service Establishment Charge, Reconnection Charge, Field Assignment Charge, Returned Check Charge and the Late Payment Charge. The cost of providing these services is included in the O&M forecast and the forecast revenue for providing these services is deducted from the Test Year revenue requirement.

SCE proposes updated service fees to reflect its current cost of providing services recovered through OOR, and eliminating other fees. Overall, SCE's forecasts that OOR will decrease $15.609 million from 2009 recorded levels, mostly a result of the remote service switch functionality of the SmartConnect system which will nearly eliminate the need to dispatch a field representative to activate and deactivate service to residential customers.[727]

DRA recommends $43.091 million for 2012 OOR, a 14% increase to SCE's $37.783 million forecast.[728] DRA's forecast is based on an expectation that the company will collect 25% of 2012 OOR at the previously approved rates.

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[727] SCE-04, Vol. 04 at 90, Table IV-28.

[728] DRA-10 at 94.

Until the Commission adopts this decision, SCE will be charging the previously authorized fees. However, the creation of the GRC Revenue Requirement Memorandum Account provides an adjustment mechanism, utilized in prior GRCs, so the request is unnecessary.[729]

7. Information Technology and Business Integration (IT&BI)

The IT&BI business unit is responsible for management of SCE's infrastructure of large and mid-range processors, storage media, communications network, operating systems and application software, and a variety of personal computing and communications devices. SCE deploys at least 680 different active software applications and uses the Software Asset Management (SAM) system to identify most critical software that needs to be refreshed or replaced. SCE claims that more than 28% of its current software is greater than 10 years old.[730]

IT&BI identifies its challenge as trying to both modernize and integrate its existing, aging systems and processes, while adding new ones to accommodate a changing electric environment, including cyber security, renewable power, smart grid, smart meters, and more pricing options. As of December 31, 2009, IT&BI had 1,632 regular and part-time employees and 1,508 supplemental and contracted workers.[731]

SCE requests $310 million in O&M expenses for TY2012. This is a 46% increase over 2009 expenses due to growth in security needs, software licensing,

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[729] SCE-25, Vol. 01 at 14.

[730] SCE-20, Vol. 01 at 5.

[731] SCE-05, Vol. 01 at 1.

business unit support, and support for new capitalized software requested herein. SCE proposes to also record 50% of certain estimated customer benefits as an offset to capitalized software costs. In this decision we adopt $273.042 million for 2012 O&M.

SCE forecasts $686.5 million 2010-2012 capital expenditures, including $318 million in software and $351 million for hardware. SCE estimates total capital spending in this business unit of almost $2 billion through 2014. Although we do not review 2013 or 2014 forecast capital investment, we include SCE's estimates for perspective on SCE's expected rapid IT growth.

The unprecedented IT capital spending has several drivers, including (1) government and regulatory mandates; (2) cyber security; (3) customer-driven energy efficiency; (4) grid reliability; and (5) business resiliency and continuity. SCE claims significant customer benefits will result and proposes to record some quantified benefits as an offset to O&M. However, capital software investment results in recurring maintenance costs throughout the software life cycle, usually 5-7 years.[732]

7.1. Parties' Positions

DRA and TURN raise several concerns about the timing and level of the proposed investments and TURN disputes SCE's benefits calculations.

DRA recommends a 26% reduction to SCE's O&M request to $229.715 million and a 5.8% reduction to the 2010-2012 revised capital

[732] TR at 831,837.

expenditure forecasts of $653.9 million.[733] DRA's 2010 forecast adopts SCE's recorded 2010 capital spending of $217.21 million.

To develop its 2011 and 2012 forecasts, DRA calculated a five-year average (5YA) of capital expenditures (2006-2010) which is approximately $261.63 million. DRA recommended adopting the average of SCE's lower 2011 forecast (approximately $161 million) and DRA's 5YA forecast (resulting in an average of about $211 million between 2011 and 2012) to prompt SCE to accelerate 2011 capital spending in order to take advantage of bonus depreciation provisions in the Tax Relief Act of 2010 (TRA).

DRA also objects to SCE's O&M accounting adjustments, beginning in 2009, which removed contingent worker costs from Account 923 and added them to Account 921. SCE also merged remaining consultant costs in Account 923 into Account 921 because it claimed the amount was nominal and the move facilitated forecasting. DRA argues that this is erroneous, it distorted historic non-labor costs for forecasting purposes, and may have other unknown significant effects.[734] Finally, DRA recommends removal of all MRTU costs from the GRC to be instead recorded in the MRTU Memorandum Account (MRTUMA).[735]

SCE responds that DRA's proposed cuts are drastic and would substantially impact SCE's ability to deliver safe and reliable service in the future. SCE argues its accounting corrections are appropriate and do not impact

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[733] JCE at 662.

[734] DRA OB at 269.

[735] DRA-16 at 4.

ratepayers. Furthermore, SCE argues that the Commission intended MRTU costs to be reviewed in the 2012 GRC.

TURN argues that IT costs are escalating without appropriate controls for necessity or cost effectiveness. TURN recommends that IT funding only be authorized for the minimum requirements to provide electrical service. Specifically, TURN recommends a reduction of $24.13 million to SCE's 2012 O&M, almost entirely for new software support, and credit of 100% (instead of 50%) of ERP benefits to ratepayers.[736]

For 2010-2012 capital expenditures, TURN recommends a 30.8% reduction to $463 million.[737] The capital spending cuts are measured by about $230 million of identified software applications, a 10% decrease to the remaining projects, rejection of ERP cost overruns, and disallowance of $127 million for hardware.

SCE responds that TURN's approach ignores SCE's regulatory directives and what is necessary to provide safe and reliable operations. SCE believes it must also anticipate and prepare for needs reasonably projected into the future.[738] In addition, SCE asserts that not all benefits can be expressed in traditional cost-benefit calculations, and as a regulated company, SCE cannot make decisions based solely on profit or productivity.

We discuss the specifics by account or capital categories below.

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[736] JCE at 812.

[737] TURN-9 at 1.

[738] SCE-20, Vol. 01 at 1.

7.2. Policy Considerations

7.2.1. Market Redesign & Technology Upgrade (MRTU)

The MRTU initiative was approved by the CAISO Board of Governors in 2004 to provide grid improvements, assure grid reliability, and more efficient and cost effective use of energy resources, and to strengthen the IT infrastructure to manage the grid.[739] In Resolution E-4087 (2007), the Commission established the MRTUMA to record SCE's incremental capital-related revenue requirement and implementation O&M expenses for MRTU Release 1 "and all subsequent Releases."[740] Release 1 was scheduled to go "live" in 2008.[741]

SCE sought recovery of 2007-2009 MRTUMA-recorded expenses and received approval of about $65 million subject to audit for verification that the costs were incremental and properly recorded.[742] SCE's 2010 and 2011 MRTU costs recorded in the MRTUMA are currently being reviewed in separate proceedings.[743]

In this GRC, SCE requests elimination of the MRTUMA, arguing it is no longer necessary following implementation in 2009. SCE forecasts test year O&M and capital spending to support MRTU in more than one business unit and characterizes the expenses as "post-MRTU" recurring costs or capital "enhancements."

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[739] SCE-25, Vol. 01 at 7.

[740] Resolution E-4087.

[741] *Id*.

[742] D.11-10-002.

[743] A.12-01-014, A.12-04-009.

DRA opposes termination of the MRTUMA based on Res. E-4087 which it views as requiring all O&M, Administrative and General (A&G), and capital costs related to MRTU to be recorded in the MRTUMA. Other than the 2007-2009 costs under audit, no other MRTU costs have been reviewed for reasonableness. Therefore, DRA argues that no standard has been established by which forecast 2012 MRTU expenses can be measured. Moreover, since the amounts at issue are significant, the Commission and ratepayers would be better served by an aggregate review through the MRTUMA. We agree.

In approving Res. E-4087, the Commission acknowledged the MRTU would require the utilities to obtain new and upgraded systems and to incur expenses for hardware, software licensing, and IT labor to allow continued interactions with CAISO.[744] While stating our expectation that the IOUs would be fully prepared for MRTU, we also found that the MRTU implementation would be a multi-year process and the CAISO had not yet determined all of the requirements for subsequent Releases.

In this GRC, we find SCE's O&M and capital requests that are associated with the overall implementation of MRTU should continue to be recorded in the MRTUMA for review in the ERRA proceedings.

DRA identifies one 2009 MRTU capital project in IT&BI[745] and $3.48 million in associated O&M for new software applications.[746] However, DRA's method of reducing IT&BI capital spending did not segregate any MRTU

744 Res. E-4087.

745 DRA-16 at 10.

746 *Ibid.*

expenditures and it did not support its O&M calculation as discussed below in Section 7.3.1.1.

7.2.2. Enterprise Resource Planning (ERP)

In 2006, SCE launched the ERP system which uses multiple components of SAP[747] computer software to integrate an organization's data and processes into a single system. The ERP investment was completed in 2010. SCE's business case for ERP included quantified ratepayer benefits, in addition to capabilities needed to handle rapid changes in technology and to provide company-wide access to integrated information.

Credit for estimated ERP-related O&M benefits are discussed below and recovery of capital cost overruns are reviewed in Section 7.7.1 (EERP Project).

7.2.2.1. ERP Benefits

In D.09-03-025, Commission authorized $295 million for 2007-2009 to complete Releases 1 through 3 (R1-3) of this project. SCE states the program delivered $31.9 million ($2006) in benefits to ratepayers in 2009-2011.[748]

SCE's 2012 forecast benefit is the difference between the 3YA (2009-2011) of system-wide ERP benefits provided in the 2009 GRC ($31.9 million $2006 constant) and the total steady-state benefit forecast of $38.03 million ($2006 constant). The difference of $6.13 million was escalated to $6.704 million ($2009). SCE asks to record 50% these benefits ($3.352 million) in Accounts 920 and 921

[747] SCE-05, Vol. 03 at 105, fn. 101 (SAP is a leading provider of ERP systems, and the leading utility-specific vendor.)

[748] SCE-05, Vol. 02 at 34-35, Table I-5 and I-6.

and to equally share the benefits with shareholders as an incentive to pursue cost control goals.[749]

TURN would allow 100% of the benefit as an offset to revenue requirement. TURN calculates the TY2012 benefit as $9.2 million based on the difference between 2009 recorded IT benefits from the 2012 IT steady state forecast benefit of $15.353 million.[750] However, after providing omitted work papers, SCE argued the 3YA was appropriate because SCE adjusted that amount out of rates in the 2009 GRC, and similarly reduced IT&BI's 2009 budget.

We are persuaded that use of 3YA is reasonable in order to avoid duplication of benefits to be credited in the 2012 GRC. However, we decline to adopt SCE's proposal to distribute the benefits equally between shareholders and ratepayers due to the substantial cost overruns which SCE incurred and booked to rate base in 2009. No Commission decision requires otherwise.

Therefore, the Commission finds it reasonable and adopts a TY2012 ERP benefit of $6.704 million to be recorded in Accounts 920 and 921.[751]

7.2.3. Productivity, Benefits and Savings

SCE proposes a number of capitalized software projects that it anticipates will result in operational savings, although the benefits are difficult to quantify. In this application, SCE assumed 8% savings from a portion of its forecast 2010-2014 capitalized software investment, or $18 million, and proposed a

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[749] D.91-12-076.

[750] TURN OB at 178-179.

[751] JCE at 816.

50/50 sharing of benefits between ratepayers and shareholders.[752] Benefits would provide an offset against adopted O&M costs in Accounts 920 and 921.

TURN argues that capitalized software should pay for itself during its useful life, or ratepayers on an unsustainable path of ever increasing costs for quickly obsolete investments. TURN views SCE's software savings mechanism as flawed because it neither contains costs nor provides reasonable benefits to ratepayers. Even if 100% of the benefits were allocated to ratepayers, at the end of five or six years the software becomes obsolete. At that point, the ratepayers would not recoup all costs and would have to fund more software upgrades.

An alternate proposal by TURN, the "Sustainable Savings Mechanism," calculates the savings benefits based on 17% of the adopted capitalized software investment, and provides limited exclusions for regulatory mandates. TURN's calculation is based on 100% cost recovery over a six-year service life. The resulting benefit would be $69.5 million in 2012.[753]

Based on the record, we agree that SCE's recognition of 8% productivity benefits from new software investment is reasonable. TURN's proposal mistakenly assumes that all capitalized software will provide productivity benefits of 100% of cost over the lifetime of the software. No other basis for the benefit calculation was provided. On the other hand, we are not compelled by SCE's arguments that equal benefit sharing with shareholders rewards them for capital projects they supported and provides SCE with an incentive to enhance productivity. SCE's shareholders have consistently earned a reasonable return

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752 SCE-11 at 18.

753 TURN-9 at 20, Table 8.

on their investments and SCE, like any public company, should already be motivated to perform its operations efficiently.

Therefore, the Commission finds it reasonable to assume an 8% productivity benefit based on our adopted capitalized software investment. The benefit is to be allocated to ratepayers and recorded equally in Accounts 920 and 921. We estimate this amount to be $13.99 million based on a 22.3% adopted reduction to SCE's 2010-2012 forecast for capitalized software.

7.3. O&M: FERC 517, 920, 921, 931

SCE applied a variety of methodologies to arrive at its total O&M forecast of $309.956 million covering 13 divisions/operational units. These included trending, averaging 3, 4 or 5 years of adjusted, historical costs (3-5YA), LRY, and budget-based for new activities. The O&M is separately calculated for nuclear IT services and recorded in FERC account 517. DRA relied on averages of historical costs to develop its recommendations.

SCE forecasts TY2012 O&M costs for Applications Services ($4.028 million), Computing Services ($2.165 million), and Network Services ($1.219 million) that support SCE's Nuclear Operations in FERC Account 517. These costs did not significantly increase from 2009 to 2012 and no party disputed them.

After review of the record, the Commission finds reasonable and adopts SCE's forecast O&M costs totaling $7.412 million for Account 517 in the three identified categories.

7.3.1. Application Services: 920, 921

This division's primary activities are delivery, testing, and maintaining systems for all of SCE's business units. The inevitable transition to IT integration of most business transactions has generated returns, states SCE, including productivity, improved safety and reliability, replacement of aging infrastructure, and more customer engagement.

SCE forecasts $112.86 million for TY2012 ($66.5 million Labor, $46.3 million Non-labor), an increase of $30.1 million over 2009.[754] Based on a five-year trend, the forecast used LRY, plus additions which include almost $18 million in labor to support ERP phases R2 and R3. Support for incremental growth in software applications accounts for nearly $9 million more.

DRA disputes that historic costs indicate a trend, noting a decrease in total costs in 2008 followed by a 28% increase in 2009. Instead, DRA uses a 3YA to account for historic fluctuations in labor and non-labor costs, resulting in a forecast of $71.62 million.[755] DRA argues SCE's forecast is excessive because (1) some project costs are embedded, and (2) in 2009 SCE moved contingent worker expenses from FERC Account 923 to 921.[756] The effects are not clearly known, admits DRA, but it argues that the result is inflated costs in account 921 making 2009 recorded costs unreliable for forecasting.

SCE explained the decrease in 2008 as deferred software maintenance, and the 2009 increase as support for the ERP release. On the other hand, we agree with DRA that the recording of significant contingent worker expenses in account 921 beginning in 2009 (where costs are escalated through the PTYR) injects inconsistency into the historic non-labor data for forecasting purposes.

Accordingly, the Commission finds it reasonable to use a 3YA of historical costs, plus adjustments for growth. The Commission adopts a TY2012 O&M for

754 SCE-05, Vol. 02 at 5, 30.

755 JCE at 398.

756 DRA-16 at 11.

Application Services of $101.733 million, comprised of $71.62 million, plus SCE's anticipated incremental growth of $28.489 million for Labor and $1.624 million for Non-labor.[757]

7.3.1.1. O&M for New Software Applications: FERC 920, 921

SCE separately forecasts incremental costs for application projects in excess of $5 million. When large systems are implemented, SCE states that both one-time and recurring O&M costs are so significant that they cannot be absorbed into IT&BI forecasts. SCE's 2009 adjusted, recorded costs are $3.477 million after removal of one-time and other atypical expenses.[758]

For TY2012 O&M, SCE forecast $40.681 million ($18.587 million Labor, $22.094 million Non-labor) to support new software applications, including SmartConnect, MRTU, SAM projects, Commodity Management, and SCE.com.[759] That forecast is a normalized average of the 2012-2014 capital spending estimates, using projects with specific O&M forecasts, and both implementation and recurring O&M costs based on an historical ratio (8% and 5%, respectively) to total project cost.[760]

TURN recommends a $24.13 million reduction to SCE's forecast: (1) $8.4 million for SmartConnect project should be recorded in ESCBA; (2) a $9.12 million reduction to reflect TURN's requested 38% reduction to SCE's

[757] SCE-05, Vol. 02 at 29.

[758] Implementation-related O&M expense for ERP was adjusted out of historical costs because the one-time expenses are atypical; SmartConnect implementation O&M is recorded in ESCBA.

[759] SCE OB at 206.

[760] SCE-05, Vol. 02 at 37.

IT&BI new project request; and (3) a $6.61 million reduction for recurring O&M expenses.[761] TURN questions SCE's 5% ratio to total project cost for recurring O&M because the projects should generate productivity and cost benefits.

SCE agreed to remove 2012 costs for SmartConnect implementation by excluding one-third of the request ($2.786 million), but retained one-third of the balance in 2012 for support costs in 2013 and 2014. TURN still disputes any funding.

SCE's requests for implementation and recurring O&M are purportedly based on recorded ratios because historical O&M costs are unavailable, but SCE provided no documentary support. In future GRCs, SCE should present more than a statement of judgment to support historical ratios applied to calculate incremental O&M for new capitalized software.

In this GRC, incremental O&M costs for implementation are reduced to reflect our 21.6% adopted reductions to SCE's 2010-2012 capitalized software forecasts. We also find that there should be some embedded costs for recurring O&M for new large systems which SCE claims will provide operational benefits (e.g., replacement of older software). Therefore, we reduce the 5% adjustment by half to $3.3 million. DRA recommends removal of MRTU-associated O&M of $3.48 million and asks that SCE be directed to continue recording MRTU costs in the MRTUMA. As discussed above, all preceding MRTU-associated expenses are under review, and we direct that they continue to be recorded in the MRTUMA.

[761] JCE at 812.

However, DRA did not support its calculation of $3.48 million, and SCE identified $0.917 million in MRTU-associated O&M for this cost category.[762] Accordingly, the Commission finds reasonable and adopts $26.404 million, equal to the $37.895 million forecast (originally $40.681 million before SCE agreed to remove $2.786 million for SmartConnect) minus $3.3 million for recurring costs, $0.917 million to be recorded in MRTUMA, and 21.6% of the remaining sum ($33.678 minus $7.275 million).

7.3.2. O&M Technology and Risk Management: FERC 920, 921

Technology and Risk Management (TRM) provides architecture, engineering, and cyber security services to protect integrity of IT systems and data. The 2012 forecast is based on LRY, plus incremental costs of almost $18 million, primarily for labor.[763] Incremental cost drivers include pending NERC mandates relating to critical cyber assets and CIP,[764] information security for new technologies and devices, and an ever-increasing number of cyber attacks.[765]

SCE's TY2012 forecast of $34.506 million ($19.94 million Labor, $14.57 million Non-labor) is more than twice what it spent in 2009. In support of the increase, SCE points to a five-year upward trend in historic costs, and SCE

[762] SCE-05, Vol. 02 at 39, Table I-9.

[763] *Id*. at 50-51.

[764] JCE at 471.

[765] TR at 2237.

spending a much smaller portion of its IT budget on security in 2009 than its industry peers.[766]

DRA utilized a 3YA for its forecast of $14.009 million[767] because it viewed historic costs as fluctuating.[768] The forecast also reflects DRA's skepticism about re-assignment of contingent labor costs into Account 921 and whether the 107% estimated growth in risk management is justified. For example, SCE employs a broad definition of cyber attack (e.g., spam) to support its forecast.

Risk management and cyber security measures, including compliance with new NERC/CIP mandates, are necessary and serve to protect the safety of the electrical system as well as the privacy of customer data. We agree with SCE that use of LRY is reasonable given the small and explained variances 2005-2009, and not significantly affected by minor cost transfers from Account 923 to Account 921.

Unlike historic costs in this category, SCE's testimony and work papers do not separately identify amounts forecast to support any particular activity (e.g., NERC/CIP, etc.). This choice limits our ability to compare forecast activity costs to historic activity costs, even though SCE had to undertake such estimation. Thus, the adjustment adopted below is to the total TRM forecast.

SCE's incremental costs did not increase after 2009 as SCE initially expected, due in part to the delay in adoption of NERC/CIP standards expected in 2011. Therefore, the Commission reduces SCE's TY forecast of $34.506 million

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766 SCE-05, Vol. 02 at 52 (SCE spent only 0.8% of its 2009 IT budget on security, the utility industry standard was 4.2%.).

767 JCE at 402, 471.

768 DRA-16 at 12.

by 10% to $31.055 million, using a labor/non-labor distribution pro rata to SCE's forecast.

7.3.3. O&M Infrastructure Operations: FERC 920, 921, 931

Infrastructure Operations provides IT system monitoring and restoration activities, and infrastructure oversight and reporting.[769] O&M expenses in this area are separated into four units: Service Management, Computing Services (nuclear and non-nuclear), Network Services, and Infrastructure Operations Management.

No party disputed SCE's forecasts for Service Management or Network Services. After review of the record, the Commission finds reasonable and adopts SCE's TY2012 forecasts for these units: Service Management ($17.823 million) Network Services ($21.494 million), and Infrastructure Operations Management ($23.903 million).

7.3.3.1. Computing Services: FERC 920, 921

Computing Services manages and maintains SCE's mainframe servers, midrange servers, disk and tape storage, high volume printers and bill inserters, and operating software. According to SCE these activities are necessary for key business processes, including dispatch of repair crews, isolating power service failures, and managing customer service orders.

SCE forecasts $31.338 million ($20.826 million Labor, $10.512 million Non-labor) for TY2012, a 17.9% increase over 2009 recorded costs.[770] The forecast is based on LRY for labor costs due to a four-year upward trend and a 5YA for

[769] SCE OB at 210.

[770] SCE-05, Vol. 02 at 60.

non-labor because costs have fluctuated. The nearly $8 million increase for labor costs includes more FTEs and fewer contingent workers, support for ERP, MRTU and CSBE projects, and support for mainframe, server, and storage growth.

DRA utilizes a 3YA to develop its forecast of $24.92 million based on total recorded expenses instead of dividing labor from non-labor.[771]

We find that SCE's distinction between labor and non-labor historical costs is a reasonable basis for forecast purposes due to use of contingent workers, later hired, and atypical inventory purchases.

Therefore, the Commission finds reasonable and adopts SCE's TY2012 forecast.[772]

7.3.3.2. O&M Business Operations Management: FERC 920, 921

This unit operates the Business Operations Center in support of IT&BI, and includes business relations with other SCE units. Historically, total costs varied between about $13 million in 2005 and 2006, about $20.5 million in 2007 and 2008, and nearly $18 million in 2009.

For TY2012, SCE forecasts $23.291 million ($18.83 million Labor, $4.46 million Non-labor), a 29.8% increase over 2009. The $5.7 million increase for labor (based on a 2007-2009 upward trend) is adjusted for expected growth in the complexity of processes and internal relationships it must manage.[773] During 2007-2009, non-labor costs declined as SCE reorganized the unit and replaced

[771] DRA-16 at 14.

[772] JCE at 401.

[773] SCE-05, Vol. 02 at 87.

contingent workers with employees. This is reflected in SCE's 2012 forecast decrease to non-labor costs of $352,000.

SCE seeks approval for 56 new employees by 2012, including 38 for Business Relations. SCE explains the expansion, in part, as adding management to avoid duplication, managing innovation per the views of IT industry experts and leaders, and "transition of pilot activities in the Business Development area of Product Lifecycle Management from four to upwards of twenty enterprise solutions."[774]

DRA forecast $19.684 million based on a 3YA, and includes no other growth adjustments. DRA views these costs in total, labor and non-labor combined, and sees no trend for forecasting purposes. DRA asserts that the application by SCE of varying forecast methods for labor and non-labor amounts to manipulation of the figures.[775]

SCE is correct that DRA does not specifically address SCE's claimed cost drivers for new employees. However, SCE's request for 56 new FTEs is not well-supported. In particular, a significant majority of the additions are for internal relations to support the "strategic and tactical alignment of IT&BI with the other SCE business units," including six Director positions ($220,000 each) and six executive assistant positions ($80,000 each) for additional Business Unit Executive Support teams."[776] These activities are ongoing responsibilities of this unit, the new FTEs are discretionary, and we find that SCE can and should achieve more cost and labor efficiencies in this area.

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[774] *Id*. at 91.

[775] DRA OB at 275.

[776] SCE-05, Vol. 02 at 84 and Table I-29 at 92.

Therefore, the Commission finds it reasonable to reduce the incremental labor forecast by 25%, or $4.7 million, resulting in a TY2012 forecast of $18.584 million ($14.12 Labor, $4.464 million Non-labor). In total, the Commission adopts $272.806 million of SCE's $309.956 million total O&M forecast:

IT&BI 2012 O&M Expense Forecast				
Account	**Description**	**Requested ($000)**	**Adopted**	**Disallowed**
517	Application Services	$7,412	$7,412	$0
920/921	Application Services	112,860	101,733	11,127
920/921	New Software Applications	40,681	26,168	14,513
920/921	Technology Risk Mgmt	34,506	31,055	3,451
920/921	Service Mgmt and Network Services	39,317	39,317	0
920/921	Computing Services	31,338	31,338	0
920/921	Business Operations Mgmt	23,291	18,584	4,707
920/921	Infrastructure Operations Mgmt	23,903	23,903	0
920/921	Information Technology ERP Benefits	(3,352)	(6,704)	3,352
	IT&BI O&M Expense Total	**$309,956**	**$272,806**	**$37,150**

7.4. Capital Expenditures – Hardware

SCE agreed to use 2010 recorded costs for capital forecasts. SCE's revised request is $351.100 million for 2010-2012 hardware capital expenditures, on its way to an estimated spend of $771 million by 2014. SCE claims several factors drive acquisition and management of its hardware assets:

- Increasing use of technology and information for business operations
- Rapid developments in IT; SmartConnect and ERP hardware components
- Customer and business partner expectations for internet and wireless capabilities
- Regulatory requirements and mandates (e.g., MRTU, NERC/CIP, Sarbanes-Oxley (SOX) reporting)

SCE also seeks to launch large and unusual hardware replacement projects in 2012: the microwave and satellite communication systems (total cost $30 million), and SCEnet II, its wide area network (total cost $75 million). SCE's ongoing risk management project to recover computing systems in the event of a disaster is estimated to cost over $55 million between 2010 and 2014.

TURN recommends the Commission disallow $127.33 million from SCE's 2010-2012 hardware request to correspond to TURN's proposed reduction to capitalized software requests for the same period.[777] Because SCE has management flexibility to shift funds, TURN argues that SCE should be able to achieve cost savings from its capital hardware request. SCE disputes that a link exists between proposed hardware and software expenditures because hardware is included with new software purchases, and 85% of the hardware request is for refresh activities.[778]

DRA recommends a 5.8% overall reduction of SCE's 2010-2012 total capital expenditure forecasts, but identifies no separate reductions to hardware expenditures. SCE agreed to accept use of 2010 recorded capital expenditures,[779] but argues that DRA's use of a 5YA for capital requests is erroneous because capital spending is cyclical, largely driven by refresh cycles.[780] Furthermore, SCE contends that accelerated spending on refresh projects is not in the ratepayers' interest, even if tax savings were achievable.[781]

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777 JCE at 912.

778 SCE OB at 214-215.

779 JCE at 662.

780 SCE OB at 213.

781 *Id*. at 214.

The Commission finds reasonable and adopts SCE's 2010 recorded expenditures for IT capital spending unless otherwise specified below. However, we find that DRA's recommendation to accelerate spending in 2011 is not in the ratepayers' best interests because it could lead to premature refreshment or replacement of assets. We examine the forecast methodology by expenditure category.

7.4.1. Hardware Replacement

SCE states it generally refreshes hardware once because the availability of replacement parts becomes problematic after the refresh cycle due to rapid advancements in hardware technology. SCE refreshes servers, storage, telephone, and data networking equipment every five years; high volume printers and bill inserters are refreshed every seven years. Industry best practice for PCs, states SCE, is to refresh every four years.[782]

7.4.1.1. Uncontested Hardware Forecast Capital Expenditures

No party specifically disputed SCE's nominal $000s forecasts in the categories identified below. SCE's 2010 recorded capital expenditures are $65.051 million (including numerous non-categorized small projects that occurred in 2010 only), $21.47 million or 49.3% higher than SCE forecast:

Project Category	Forecast Activities	2011	2012	Total 2011-12
Mainframe Servers	Refresh every 5 years; expand capacity	$ --	$1,800	$ 1,800
Midrange Enterprise Servers	Refresh every 5 years; support new projects (e.g. ERP, EMS,* OMS**)	35,612	42,558	78,170

782 SCE-05, Vol. 02 at 94.

Disk and Tape Storage	Refresh at end of life (+/- 5yrs), growth; support ERP and Customer Service System (CSS)	8,504	27,550	36,054
High Volume Printers/Bill Inserters	Refresh every 7 yrs	5,257	3,000	8,257
Data and Voice Network	Upgrade/ replace telephone systems and data networks	6,800	12,919***	19,179
Transmission Network and Facilities	Replace damaged, obsolete, failed telecomm network equipment	5,818	10,006	15,824
Telecom Test Equipment	Refresh test equipment	617	719	1,336
Microwave Equipment	Replace damaged, obsolete, failed microwave equipment	1,872	7,787****	9,659
Total		**$64,480**	**$106,339**	**$170,819**
Total adopted uncontested 2010-2012 expenditures: $65.051 recorded (2010) + $170.819 (adopted 2011-12) = $235.870 million.				

*Energy Management System
** Outage Management System
*** includes $8 million for telephone equipment
**** ramp up to replace 20/year

The resulting 2010-2012 total of $235.870 million exceeds SCE's original 2010-2012 forecast of $213.750 million by 10.3%, in order to accommodate unexpected expenditures in 2010.

After review of the record, the Commission finds reasonable and adopts a 2010-2012 total of $235.87 million for these uncontested capital hardware projects.

Other capital hardware expenditures are discussed below.

7.4.1.2. PCs and Related Hardware

SCE states it refreshes approximately 25% of its PC inventory each year based on a four-year life cycle and technology obsolescence. One vendor provides the refreshed and new replacement PCs and laptops.

For 2010-2012, SCE forecast $36.909 million ($11.9 million in 2010, $12.36 million in 2011, and $12.649 million in 2012) to service an estimated 19,600 desktop PCs and laptops. Actual recorded expenses for 2010 are $12.237 million. The forecasts include employee growth and increased mobile and remote workforce needs. The percentage increase in cost and number of devices covered are both approximately 6-7%, although SCE does not explain its growth calculation.

It is reasonable to estimate that a portion of the PCs and laptops would need to be refreshed, but we note that SCE's supporting documentation is limited. For example, SCE does not explain how it calculated device and cost growth, the development of unit cost, or why it is necessary to proactively refresh or replace all PCs and laptops every four years rather than wait until a non-critical PC or laptop experiences problems. Also, if requests for PC to laptop conversions are known, why not maintain the PCs as long as possible before implementing conversions given that laptops are much more expensive than new or refreshed desktop computers?[783]

SCE explained who uses the various personal computers and why, but did not provide sufficient evidence to demonstrate that it undertook any cost minimization analysis as to the devices, unit costs, or timing variations.

Accordingly, the Commission finds it reasonable to adopt the 2010 recorded expense of $12.237 million, and reduce SCE's 2011 and 2012 forecasts by 10%, resulting in our adoption of $11.124 million for 2011, and $11.384 million for 2012, and a total capital expenditure of $34.745 million in this category, 6.7% less than SCE's forecast.

7.4.1.3. Ruggedized Laptops

A portion of SCE's field employees use a special ruggedized laptop due to the harsh field environment. SCE forecasts $12.378 million for 2010-2012

[783] Work Papers, SCE-05, Vol. 02 at 62.

($5.925 million in 2010, $1.6 million in 2011, and $4.853 million in 2012) developed as a budget based forecast to address future growth.[784]

TDBU and Environmental Health & Safety estimate a need for 168 new ruggedized laptops, at the same time CSBU assumes 150 fewer due to smart meter deployment. SCE also asks to refresh such laptops for TDBU and CSBU which will surpass their three-year useful lives during the period of 2010-2014.

SCE's forecast appears excessive given that it will be managing fewer ruggedized laptops in 2012 (2060) than in 2009 (2076), but spending more than twice 2009 recorded expenditures.[785] SCE's 3YA (2010-2012) forecast is 22% more than SCE's most recent historic 3YA (2007-2009). Since SCE delayed purchases until 2007 to acquire new models, 2007-2009 is an appropriate comparison to the rate cycle. We also assume that TDBU will require fewer devices due to the 9.4% reduction to capital expenditures.

Accordingly, the Commission finds it reasonable to adopt 2010 recorded expense of $4.387 million and to reduce SCE's 2011 and 2012 forecasts by 9.4% to $1.44 million and $4.368 million for 2011 and 2012, respectively. The resulting 2010-2012 total is $10.195 million, 17.6% less than SCE's forecast.

7.4.1.4. Copper Wire

SCE replaces copper communication cable with fiber optic cable as needed to preserve the reliability of grid protection and grid protection circuits, provide increased bandwidth, and reduce maintenance. The Average Service Life of

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[784] SCE-05, Vol. 02 at 121.

[785] *Id*. at 122.

copper cable ranges from 25 to 35 years, and at least half of SCE's copper cable is more than 35 years old.[786]

For 2010-2012, SCE forecasts $30.357 million ($9.725 million in 2010, $10.114 million in 2011, and $10.518 million in 2012) to continue funding SCE's 21-year effort to replace all 2,000 miles of copper cable by 2017.[787] SCE's 2010 actual recorded expenditures were $4.918 million.

Historic expenditures trended downward in 2005-2009, which SCE explains is the result of prioritizing the mobile radio system upgrade and time needed to get cable construction permits. As of 2009, SCE had replaced 880 miles. Going forward, SCE estimates it will annually replace about 140 miles of cable and install associated equipment at 24 substations at a cost of $55,000 per mile and $84,000 per substation.[788]

We find the evidence does not support SCE's estimated replacement cost per mile. SCE states the per mile cost is within a range of costs recorded in 2008 for similar work, based on four replacement projects with varying per mile costs. Less than 3 of 71.5 miles presented cost $101,000 per mile, plainly an atypical cost.[789] Nonetheless, the 2008 weighted average of the examples (21.7 miles at $44,800/mile, 26.1 miles at $37,200/mile, 2.8 miles at $101,000/mile, and 20.9 miles at $29,500/mile) is $39,754/mile. When annually escalated at SCE's assumed 4%, the 2010 result is $42,998/mile instead of $55,000. Further escalation to 2011 would be $44,718/mile and $46,507 for 2012.

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786 *Id*. at 135.

787 *Id*. at 135, 137.

788 *Id*. at 138.

789 Work Papers, SCE-05, Vol. 02 at 92.

In addition, we are not persuaded that replacement of all copper wire is necessary by 2017. SCE will have completed replacement of the half of its copper wire that is more than 35 years old by 2010 and no evidence implies that completion of the project by 2018 would impair service or system reliability.

In addition to adopting 2010 recorded expenses, the Commission finds it reasonable to reduce SCE's requests for 2011 and 2012 to reflect an approximate escalated replacement cost of $45,000 and $47,000 per mile, respectively, and for SCE to replace 124 miles annually, completing the project one year later than SCE requested. After incorporating these changes into the total forecast for this activity, the Commission adopts a 2010-2012 total of $21.558 million ($7.994 million for 2011 and $8.646 million for 2012), a 29% reduction to SCE's 2010-2012 forecast.

7.4.1.5. Fiber Optic Cable

This is a new expenditure category in 2012 to replace aging or failing fiber optic cables. SCE began large-scale installation of fiber optic cable in the 1990's and the fiber network provides some of its most critical communications. SCE claims that about 527 miles of cable cannot reliably handle the newer, higher speed optic terminals it is installing to meet increasing network capacity requirements or to support new facilities.

SCE decided to implement a replacement program for its 3,700 miles of fiber optic cable, starting in 2012, to replace about 100 miles per year at a cost of about $6 million annually. SCE's 2012 forecast is $5.948 million based on a unit cost of $55,000 per mile using the same data as for the copper wire replacement project above.[790]

We find the evidence does not support SCE's estimated replacement cost per mile, and incorporate here our discussion from Section 7.4.1.4.

Accordingly, the Commission finds it reasonable to reduce SCE's 2012 forecast to reflect the revised per cost mile of $47,000, and we adopt $5.148 million in 2012, a 13.4% reduction to SCE's forecast.

7.4.1.6. Satellite Terminal Equipment

This is a new expenditure category in 2010 to replace obsolete satellite terminal equipment; the work was previously included in TDBU. SCE uses satellite communications to transmit substation data and remotely control substations in areas where traditional communication is unavailable. There are 300 satellite terminals, most installed before 2000, which SCE asserts are obsolete.

Beginning in 2010, SCE seeks to replace the old terminals with newer terminals at a cost of about $75,000 per terminal. SCE requests $1 million in 2010 to replace 13 terminals and to ramp up to 30 per year thereafter at a cost of about $2.4 million per year.[791] SCE did not provide evidence to support its cost estimate for terminal replacements.

Therefore, the Commission disallows SCE's 2011-2012 request for this activity.

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[790] *Id*. at 142.

[791] SCE-05, Vol. 02, at 144.

7.4.2. Expanded Infrastructure

7.4.2.1. Capital Expenditures: Mobile Radio Network (MRN) and Disaster Recovery

The MRN provides voice communication in support of field personnel engaged in daily operations, new construction, and emergency response. SCE requests $2 million in 2012 to begin the replacement project in order for the new system to be operational by 2015. Total cost of the project is expected to be $30 million by 2014.[792] No party contested this project expense.

After review of the record, the Commission finds that SCE chose a cost-effective alternative, its 2012 request is reasonable, and we adopt it.

Disaster Recovery provides the computing infrastructure necessary to minimize interruption and to recover computing systems in a disaster. For 2010-2012, SCE forecasts $31.813 million ($8.488 million in 2010, $4.684 million in 2011, and $18.641 million in 2012). However, SCE's 2010 actual recorded expenditures were $1.9 million.

The request is primarily to refresh midrange servers, with a spike in 2012 to also refresh tape storage ($8.2 million) and communication equipment between data centers ($4.6 million).[793] No party contested this project expense.

SCE's 2010-2012 request is slightly lower than 2007-2009 recorded expenditures and is supported by cyclical refresh of the redundant systems. Based on the record, the Commission finds SCE's 2010 recorded expenses and 2011-2012 forecasts reasonable and adopts a total of $25.225 million, a 20.7% reduction to SCE's original forecast.

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[792] *Id*. at 148.

[793] *Id*. at 162.

7.4.2.2. Next Generation Network – SCEnet II

This is a new project with no recorded costs. SCEnet is SCE's communication network backbone for voice, data, wireless communications, and electric grid control. SCE asserts that it must begin planning the next generation of SCE.net to address obsolescence, capacity demands, and new connections to the network. Based on internal discussions of operational and business requirements, SCE decided to change the network architecture and extend connectivity to over 100 substations.[794]

SCE forecasts $3.1 million in 2012 to begin installation of 1,000 miles of fiber optic cable and associated equipment to bring SCEnet II connectivity to 121 66 kV substations. SCE plans to spend another $72 million by 2014 to include re-architecture of SCEnet into SCEnet II and expects functionality for 10-15 years.[795]

SCE provided argument in support of the notion that SCE might want to develop certain enterprise communication infrastructure. However, SCE did not provide evidence to support any of the cost estimates comprising this forecast. In particular, SCE's forecast cable installation costs by analogy to recorded costs for another project, and various equipment costs "derived from a range of recorded costs" for other, unidentified projects.[796] Unlike for replacement of fiber optic cable, the range of recorded costs or other more particular cost data is omitted. Even if SCE's argument to begin development of a new intranet were persuasive, SCE failed to support the forecast costs.

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[794] *Id*. at 155.

[795] *Id*. at 156-157.

[796] SCE-05, Vol. 02 at 157.

Therefore, the Commission finds it reasonable to eliminate any 2012 expenditures for this project. Adopted amounts for contested hardware capital expenditures are shown below.

Contested Hardware Capital Expenditures ($000)					
Project Description	**2011 Forecast**	**2012 Forecast**	**Total 2011-2012**	**Adopted 2011-2012**	**Disallowed 2011-2012**
PCs and Related Hardware	$12,360	$12,649	$25,009	$22,508	$2,501
Ruggedized Laptops	1,600	4,853	6,453	5,808	645
Copper Wire	10,114	10,518	20,632	16,640	3,992
Fiber Optic	-	5,948	5,948	5,148	800
Satellite Terminal Equipment	2,375	2,445	4,820	0	4,820
Mobile Radio Network	-	2,000	2,000	2,000	0
Disaster Recovery	4,684	18,641	23,325	23,325	0
Next Generation Network	-	3,100	3,100	0	3,100
Total	**$31,133**	**$60,154**	**$91,287**	**$75,429**	**$15,858**
Total adopted 2010-2012 contested hardware expenditures: $23.943 million recorded (2010) + $75.429 (adopted 2011-12) = $99.372 million.					

Of the total $351.100 million requested for all hardware capital expenditures, we adopt $335.242 million. SCE's recorded 2010 expense for all hardware capital expenditures is $88.994 million, 13.4% more than the $79.933 forecast. The 2010-2012 adopted amount includes $246.248 million for 2011 and 2012, 4.5% less than SCE's total forecast.

7.5. Capital Expenditures – Operating Software

Operating software is primarily used to manage and monitor the health of mainframe servers, midrange servers, storage and personal computers. SCE describes its cost drivers as new software licenses for growth, new capabilities to support new products, and vendor-specified end of life activities. Costs are likely to vary in this expenditure category, states SCE, due to periodic large license agreements (e.g., $15.9 million in 2009 to Microsoft).

SCE forecasts $33.727 million in capital expenditures for 2010-2012 ($15.647 million in 2010, $9.43 million in 2011, and $8.65 million in 2012) covering ten projects. In 2010, SCE actually recorded $25.112 million in capital expenditures for operating software. Estimated costs are intended to support activities including deployment of Office 2010, Windows 7, other system upgrades, software management tools, ERP enhancements and software licensing.[797]

Only one project, Configuration Management Database (CMD) is specifically disputed by TURN. SCE forecasts $3.75 million in expenditures for CMD in 2010-2012, and a total cost of $6.5 million.[798] SCE states it needs the CMD software package to provide greater control of IT&BI operational components to maintain service levels and expedite information collection necessary for design and implementation of new services.

TURN considers CMD duplicative of SCE's Application Portfolio Management System (APMS) which tracks its inventory of software applications, and asserts SCE did not adequately justify the cost. TURN concedes that CMD would add some functionality, particularly an inventory of the relationships between applications and allow for automated, rather than manual, updates.

[797] SCE-05, Vol. 03 at 2.

[798] TURN-9 at 23.

However, SCE did not explain why current systems, including APMS, are inadequate to maintain service levels through this rate cycle.

We agree that SCE did not support the request with an explanation of why current systems cannot maintain service levels, why automated mapping of component relationships is necessary in this rate cycle, or an analysis of why this software is the best or most cost-effective approach to whatever problem may exist.

Therefore, the Commission finds it reasonable to remove the $1.004 million recorded for this project in 2010, and make the corresponding adjustments for 2011 and 2012.

Therefore, the Commission finds reasonable and adopts $24.108 million in 2010, $8.43 million for 2011 and $7.15 million in 2012 to reflect removal of the CMD costs.[799]

7.5.1. Projects Less than $1 million

SCE and DRA have generally agreed that for capitalized software projects of less than $1 million, SCE is not required to submit separate written testimony for each project in its GRC application.[800] SCE recorded $6.154 million for these projects in 2010. However, TURN recommends disallowance of one such $500,000 project, Single View of IT Health (IT Health), because the cost estimate may have increased significantly and the project duplicates the APMS.[801] TURN

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[799] JCE at 901.

[800] SCE-20, Vol. 01 at 19.

[801] TURN-9 at 23.

points to SCE's "Yellowbook," a later version of SCE's capital forecasts, which identifies the IT Health project cost to be $4.75 million.[802]

According to SCE, the IT Health project would implement "Netcool" Monitoring Software to enable consolidation of monitoring tools for computing hardware because current tools are reaching end of life in 2012. SCE distinguishes the functions of APMS, which provides data entry and storage, and that of IT Health, which monitors the products and applications in use.

Additionally, SCE argues that TURN must restrict its analysis to the GRC 2012 request for $500,000 because the Yellowbook is an internal SCE document and changes based on business needs.

Absent more information, we decline to open the door to a project which may grow 850% before completion during the rate cycle. SCE does not explain the difference in the forecast and the Yellowbook estimate contained in a response to data request to TURN. Unknown obstacles may exist and a cost minimization review may be appropriate.

Therefore, the Commission disallows SCE's request for $500,000 for IT Health.[803]

In total, the Commission adopts $47.126 million of the $51.130 million Operating Software request, a 7.8% reduction.

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[802] SCE-10, Vol. 02 at 9.

[803] JCE at 902.

IT&BI Capital Expenditure Forecast: Operating Software					
	Capital Request by Year				
Project Description	**2011 Forecast**	**2012 Forecast**	**Total 2011-2012**	**Adopted 2011-2012**	**Disallowed 2011-2012**
Operating Software	$9,430	$8,650	$18,080	$15,580	$2,500
Projects <$1 million	387	1,397	1,784	1,284	500
Total	**$9,817**	**$10,047**	**$19,864**	**$16,864**	**$3,000**
Total adopted 2010-2012 Operating Software Expenditures: $30.262 of $31.266 million recorded (2010) + $16.864 (adopted 2011-2012) = $47.126 million.					

7.6. Capitalized Software – Software Asset Management (SAM)

The SAM process prioritizes software upgrades and replacements to mitigate risks due to security problems, technology obsolescence, and application failure. In the 2009 GRC, the Commission authorized $7.0 million in SAM capital funding which SCE used to remediate a portion of the application portfolio not being replaced by the ERP system. SCE states that it intentionally lowered its forecast to focus resources to complete ERP by 2010.

SCE originally forecast a total of $145.891 million for 2010-2012 SAM capital spending, including $21.791 million in 2011 and $82.815 million in 2012.[804] Between 2010 and 2014, SCE requested almost $295 million for the 36 SAM projects.[805] Although SCE's aggregate 2010 forecasts totaled $41.285 million, only $6.177 million was actually recorded in 2010 for all SAM projects. We adopt the unitemized total 2010 recorded costs for all SAM projects.

SCE asserts that the projects affect the applications in most critical need of being refreshed by 2014. For each project SCE provided a description of the

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[804] SCE-05, Vol. 03 at 22, Table II-6.

[805] *Ibid.*

problem and the proposed solution, as well as what it calls historical labor hours for similar projects and the actual software cost.[806]

DRA recommends a non-specific 5.8% reduction to all of SCE's IT capital requests. TURN continues its criticism that SCE has no incentive to cut costs and makes no effort to reduce the number of new applications, re-examine functionality, or prioritize projects.[807] SCE's forecasts assume automatic replacement of every piece of software, but cost estimates are rough, consisting primarily of inconsistent labor costs, and labor totals derived from unspecified similar projects. TURN recommends disallowance of several projects discussed below, as well as an additional 10% reduction to all authorized expenditures.

Given SCE's somewhat vague cost estimates, frequent failure to consider alternatives or address overlapping functionalities, and years of experience implementing SAM systems, we find that these capitalized software projects are very likely overestimated. If not separately discussed below, the Commission finds it reasonable to reduce SCE's requested 2011 and 2012 expenditures by 10%, and to adopt the resulting revised forecasts

7.6.1. Computer Aided Design (CAD)/Computer Aided Facility Management (CAFM) Replacement

SCE currently manages more than 221 non-electric facilities at 76 locations using a variety of computing systems and tools that do not integrate with financial, human resource, and operational data contained in ERP systems. This is "not optimal" according to SCE, because the combination of obsolete software

[806] *Id*. at 23 et seq.

[807] TURN-9 at 9.

and databases precludes integration of ERP and facilities data. The result is that SCE's current and future facility planning relies on both manual processes initiated in 1997 and an outside vendor.[808]

SCE requests $6 million in 2012 to begin the $11 million project it expects to complete by 2014. The proposed CAFM technology solution allows integration of current asset and personnel data from ERP with facility data, combined with AutoCAD for enhanced facility drawings.

TURN recommends disallowance of the project, and argues the project highlights the inherent pitfalls of SAM which does not prioritize projects based on expected benefits or minimizing costs. For example, a visual display of facilities is nice to have but not necessary or beneficial to ratepayers.[809] Despite SCE's claim the software will last 15 years like its predecessor, according to TURN, the claim is just speculation.

We are persuaded that SCE's current system relies on aged and obsolete software, as well as third parties, and is unable to maximize the advantages of its prior investments in SAP software, particularly ERP. In addition, we are encouraged by the 15-year service life of the prior system. If SCE follows through on its stated intentions, one benefit is the project will allow more accurate and effective maintenance of safety systems providing a higher level of employee safety and security. Ratepayers should also benefit from efficient planning for use of facilities by employees and contingent workers and the automation of existing manual tasks.

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[808] SCE-05, Vol. 03 at 78.

[809] TURN OB at 204; JCE at 911.

On the other hand, SCE did not demonstrate that it included a review of alternatives or cost minimization before making its software selection. Furthermore, limited information is provided about the cost estimate. Therefore, we reduce SCE's request by 10%.

Accordingly, the Commission finds reasonable and adopts $5.4 million for 2012 expenditures for this project.

7.6.2. Customer Data Warehouse

The Customer Data Warehouse (CDW) is intended to integrate various customer databases, some dating to 1987, into one, centralized data warehouse. The data includes: (1) customer account, rate, bill cycle and meter asset data; (2) historic data beyond 13 months; (3) customer program history and demographic data; and (4) DR event history and capacity data that is part of SCE's Load Control System.[810] The project will also integrate interval usage data collected by the SmartConnect systems.

SCE forecast $8.694 million in 2012 expenditures, and a total cost of $26 million by 2014 to implement CDW. According to SCE, having the data in separate databases creates problems and inefficiencies, including limited customer self-service, limited data access by customer service personnel, cumbersome updating of customer data, and data security, accuracy, and integrity risks.[811]

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[810] SCE-05, Vol. 03 at 35-36.

[811] *Ibid.*

TURN recommends the disallowance of all funds in the GRC because the CDW project is "caused" by the deployment of SmartConnnect. If SCE seeks recovery, then it should record the costs in the ESCBA.

We are persuaded that the CDW project is complementary, rather than duplicative, of the SmartConnect customer data warehouse authorized in D.08-09-039 to collect interval usage data. However, it is reasonable to integrate the projects for the benefit of customers.

On the other hand, SCE did not establish that it undertook a review of alternatives or potential cost efficiencies from implementing the two customer data warehouse projects. Furthermore, limited information is provided about the cost estimate. Therefore, we reduce SCE's request by 10%.

Accordingly, the Commission finds reasonable and adopts $7.825 million for 2012 expenditures for this project.[812]

7.6.3. Enterprise Platform User Interface Refresh

The Enterprise portal was implemented as part of the ERP project R1 in 2008. It provides users access to various ERP functions including time sheets, expense reports, purchase orders, and generation of financial reports. SCE has had problems with the user interface and the ERP vendor, SAP, has announced the interface is inefficient and obsolete.[813]

For 2011-2012, SCE requests $2.017 million ($1 million in 2011 and $1.017 million in 2012) to implement enhancements for (1) TDBU work order

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[812] JCE at 905.

[813] SCE-05, Vol. 03 at 58.

processing; (2) Blackberry Smart Phone access; (3) time sheet entry and approvals; and (4) usability of Performance Appraisals.

TURN argues that ratepayers should not be responsible for funding this project which was only two years old when it experienced negative productivity effects.[814]

SCE responds that large packaged software implementation may contain standard user interfaces that do not adequately address the user's needs.[815] It is the responsibility of the implementing organization to improve what was discovered to be a cumbersome, slow, non-intuitive and ineffective interface. SAP has now made changes to allow for customization and is supporting SCE in that effort.

We are sympathetic to TURN's aversion to fund a refresh which results from design problems admitted by the vendor. On the other hand, the SAP system is broadly deployed, and SCE claims to have no recourse other than to proceed to adapt the software interface to its purpose with the vendor's support.

Accordingly, the Commission finds reasonable and adopts SCE's 2011-2012 forecasts for this project.[816]

7.6.4. Enterprise Platform Search and Classification

SCE deployed the SAP Search and Classification System (TREX) in 2008 as the primary search engine for the corporate internet platform.[817] According to

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[814] TURN OB at 221.

[815] SCE OB at 226.

[816] JCE at 910.

[817] SCE-05, Vol. 03 at 67.

SCE, the current implementation is suffering from performance problems due to limitations with the existing architecture.

SCE sought $1.138 million in 2010 to update TREX after SAP made a significant technology change which forces an upgrade to the platform to retain consistencies across the SAP platform.[818] With large packaged software like SAP, SCE asserts that the large number of components will become obsolete at different times and SCE must replace some to keep the package working together. TREX was an older component.

TURN argues that it is not reasonable for ratepayers to replace or upgrade TREX so soon after it was implemented. The prompt failure of TREX means the prior installation as not used or useful.

We are persuaded by SCE that the upgrade will not only support the total SAP package but will increase performance in applications that support customer systems and ensure vendor support after 2014. Due to the way SCE reported its 2010 capital spending for SAM projects, we are unable to determine whether this project was implemented as planned. However, given the urgency with which SCE explained the need to upgrade its primary search engine, we presume that the expenses are included in 2010 recorded costs.

Therefore, the Commission finds SCE's estimated capital spending to upgrade TREXin 2010 to be reasonable.[819]

7.6.5. Revenue Protection and Law Claims Management

SCE does not agree with TURN's linkage of these two software projects.

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[818] *Ibid*.

[819] JCE at 909.

The Revenue Protection Investigation System (RPIS) supports service investigations of SCE customers when unauthorized electricity usage occurs. SCE claims that RPIS was deployed in 1989, utilizes outdated and unsupported software, poses security and business risks, and requires complete replacement and a major upgrade to Microsoft Access.

SCE requests $6.685 million in 2013 for a replacement application integrated with SAP, CSS, and other systems.[820] TURN disputes that the upgrade is cost-effective, noting SCE only recovered $1.4 million in revenue in 2010.[821]

The Commission declines to review the project at this time as SCE requests no capital expenditures through 2012.

TURN argues that Revenue Protection and Law Claims Management System (CMS) have similar basic functions for incident documentation and the use of SAP for billing and collections. As a result, TURN thinks SCE should integrate the functionalities for cost savings instead of each department having a separate system.

According to SCE, CMS is a custom application implemented in 2004 and used to manage thousands of claims, by and against SCE, each year. Microsoft has not supported the CMS platform since 2008, and SCE claims the system is difficult and costly to maintain through temporary code repairs and security patches. It also provides limited access and requires printout of documents.

SCE stated it would implement the project for a total cost of $5.795 million ($1.419 million in 2010 and $4.376 million in 2011) by replacing CMS with a

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[820] SCE-05, Vol. 03 at 33-34.

[821] TURN OB at 222-223.

purportedly easy-to-use, collaborative system tailored to SCE's processes. SCE will develop the custom replacement in-house at less cost than an over the counter software package.[822]

TURN concludes that the replacement system can be developed for about $1.4 million, the approximate cost of the initial CMS.[823] However, TURN's cost recommendation lacks support.

We agree with SCE that it is reasonable to upgrade the CMS, but acknowledge some overlap in function with the RPIS. We encourage SCE to explore whether any cost savings or functional economies can be found from these common functionalities if and when SCE decides to proceed with a replacement for RPIS. If SCE seeks cost recovery for RPIS in the next GRC, it should include in its testimony a discussion of whether any such cost savings or functional economies were available.

Therefore, the Commission finds the project reasonable and adopts $4.376 million for 2011 to implement the CMS project.

7.6.6. Energy Manager Replacement

SCE EnergyManager® was launched in 2001 as the primary online platform to deliver energy information and tools to SCE's largest C&I customers with Real Time Energy Meters and provides 15-minute interval data online. Some services are free and others are fee-based. SCE contends the program is

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822 SCE-05, Vol. 03 at 27, Work Papers at 97.

823 TURN-9 at 42.

mandated by the Commission, but the services are subject to a combination of technical, vendor, and business obsolescence problems.[824]

SCE asked for $6.07 million in 2010 to update SCE EnergyManager® performance and navigations standards, provide for future system capacity needs, create links to related energy information and tools, and make near real-time energy data available to more customers.[825] The forecast is based on historical costs, and reflects some efficiencies as well as complexities in converting and combining information with SmartConnect.[826] SCE's goal is to provide 15-minute interval data to any customer willing to pay for it and to DR customers for free.

TURN recommends disallowance of $4.42 million because the program is poorly used and too costly.[827] Additionally, SCE is proposing to reduce fees in 2012, and paid services are projected to bring in just $168,000 per year from 188 paying customers.[828] TURN argues that Commission direction to SCE to provide usage information to customers on its website is not a mandate for unlimited ratepayer obligations to pay for information of interest to large C&I customers.

Specifically, TURN disputes $1.92 million for SmartConnect interface which TURN believes should be recorded in the ESCBA. TURN also seeks disallowance of additional funds to replace a DR upgrade approved in the 2009

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[824] SCE-05, Vol. 03 at 29.

[825] *Ibid*.

[826] SCE-20, Vol. 01 at 29-30.

[827] TURN OB at 230,233; JCE at 907.

[828] *Id*. at 231.

GRC (now unsupported by the vendor), and for links to other information on energy efficiency for large C&I customers.

Because SCE reported total 2010 expenditures of $6.177 million for all SAM projects combined, we are unable to determine whether SCE made any expenditures in 2010 for the EnergyManager replacement.

We agree with TURN that the 2009 upgrade appears to have been ill-conceived, and the program has limited participation. Therefore, we decline to approve 100% ratepayer funding of the replacement project. We also find that the project is outside the scope of activities to be recorded in the ESCBA.

On the other hand, as recently as 2011, we directed SCE to provide pricing, interval usage, and cost data to customers and rate comparison information online.[829] Although there is no requirement that SCE provide customers links to EE information, this is likely to cost very little and is compatible with the Commission's overall emphasis on energy efficiency and conservation for all customers.

Therefore, the Commission finds it reasonable to allow 50% of the requested costs, or $3.035 million, and presume the expenditures were made in 2010 as represented by SCE in its testimony.[830]

7.6.7. Design Manager Distribution Service Request Pricing (DSRP) and Capital Work Order Unit Estimate Derivation Project

DSRP application is an internally developed pricing design tool that allows planners to design and price electrical distribution system work. SCE is

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[829] D.11-07-056 at 2.

[830] JCE at 906.

currently upgrading DSRP to include transmission work.[831] SCE states DSRP has pre-existing performance issues not addressed by the upgrade.

SCE requests approval of $2 million in expenditures in 2013 to address performance issues and refresh the architecture to increase performance. The Commission declines to review the project at this time as SCE requests no capital expenditures for the project through 2012.

Capital Work Order Unit Estimate Derivation Project (CWO)

In a related request, SCE also asks for $1.2 million in 2010 for the CWO which is not a SAM project but is linked to Design Manager. The CWO expenditure is intended to streamline financial classification and closing of capital-related work orders.[832] SCE justifies the project based on increased workload, assuming an increase in work orders from 40,000 to 200,000 annually due to more capital work.[833] At hearing, SCE revised its estimate to 109,000 work orders annually.[834]

According to SCE, the software to support the CWO implementation is in place and proposed expenditures are for the deployment cost of 8,285 hours of labor.

TURN recommends disallowance of $1.2 million because it views SCE's claims to be inconsistent with statements it made in the 2009 GRC about fixing the DSRP pricing defect problems and automating unit costs.[835] SCE thinks

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[831] SCE-05, Vol. 03 at 90; also, Work Papers at 126.

[832] SCE-20, Vol. 01 at 32.

[833] SCE-05, Vol. 03 at 124.

[834] TR at 2271.

[835] TURN-9 at 47.

TURN is confused between the functions of DSRP which develops costs and CWO which classifies them for accounting purposes.

TURN did not provide a specific example of a prior inconsistent statement by SCE regarding these CWO functions. Although SCE overestmated the short-term need for the project, we find the combination of emphasis on capital projects to maintain and replace aging infrastructure, and to integrate new programs, provides sufficient support for this project during the rate cycle.

Accordingly, the Commission finds reasonable and adopts SCE's 2010 forecast of $1.2 million for CWO, an amount we presume is included in 2010 recorded costs aggregated for Other Capitalized Software.[836]

For all SAM capital software projects, Commission finds reasonable and adopts $100.962 million for 2010-2012 capital expenditures, including the 10% reduction for 2011 and 2012 forecasts for non-disputed SAM projects. The adopted total is an 8.9% reduction to SCE's revised total forecast, and a 30.8% reduction from its original forecast.

IT&BI Capital Expenditure Forecast – Software Asset Management (SAM)					
	Capital Request by Year				
Project Description	**2011 Forecast**	**2012 Forecast**	**Total 2011-2012**	**Adopted 2011-2012**	**Disallowed 2011-2012**
CAD/CAFM Replacement	$0	$6,000	$6,000	$5,400	$600
Customer Data Warehouse	0	8,694	8,694	7,825	869
Enterprise Platform User Interface Refresh	1,000	1,017	2,017	2,017	0
Enterprise Platform Search and Classification*	0	0	0	0	0
Energy Manager Replacement*	0	0	0	0	0

836 *See*, Section 7.7.5. Table of Capital Expenditures for Other Capitalized Software.

Law Claims Management System	4,376	0	4,376	4,376	0
Capital Work Order*	0	0	0	0	0
Remainder of 2011-2012 items	**$16,415**	**$67,104**	**$83,519**	**$75,167**	**$8,352**
Total	**$21,791**	**$82,815**	**$104,606**	**$94,785**	**$9,821**

* While these projects show no 2011-2012 forecasts, they incurred 2010 recorded expenses. Total adopted 2010-2012 SAM expenditures: $6.177 million recorded (2010) + $94.785 million (adopted 2011-2012) = $100.962 million.

7.7. Other Capitalized Software

Some of SCE's other requests for capitalized software projects were not specifically disputed by TURN or DRA. However, as discussed above, DRA recommends an overall 5.8% reduction to SCE's capital spending and TURN seeks a 10% reduction for authorized projects. As noted above, we generally adopt SCE's 2010 recorded expenditures. One significant exception is the 2010 recorded ERP cost overrun. Excluding ERP, the 2010 recorded costs for Other Capitalized Software are $30.170 million.

No party disputes SCE's forecast for the Project Portfolio Management (PPM) capital expenditures. SCE forecast $1.545 million for the project, based on using existing software, $345,000 for hardware, and $1.2 million for deployment. PPM is a centralized database to manage IT spending, and to enhance its ability to make enterprise-wide decisions regarding prioritization and resource planning.[837] In 2010, SCE recorded $5.083 million to implement PPM, but did not explain why its actual costs were more than three times the original forecast.

Based on a review of the record, the Commission finds SCE's request for $1.545 million to be reasonable and included in 2010 recorded costs.

[837] SCE-05, Vol. 03 at 121.

7.7.1. ERP Project

As described above, in SCE's 2009 GRC, we authorized $295 million in capital expenditures for 2007-2009 to complete Releases 1 through 3 (R1-3) of the ERP.[838] Combined with 2006 recorded expenditures, the estimated total expenditures for ERP were forecast to be $400.7 million.[839] Although SCE completed implementation of ERP in 2010, there were cost overruns of $94.7 million primarily due to delays and changes in project scope.

SCE made expenditures of $45.1 million more than forecast for 2009 and forecasts $49.6 million more for 2010.[840] SCE's position is that the 2009 costs are already booked to rate base, and it seeks recovery of $49.6 million for 2010.[841] As a matter of functionality, SCE argues it was not feasible to halt the project after R2.

Furthermore, SCE claims that even with the additional expenditures, it has shown that the ERP remains cost effective. The analysis provided by SCE includes a present value calculation of the revenue requirements (discounted to $2008) associated with the incremental costs and R3 benefits, resulting in a benefit to cost ratio of 1.03.[842] The stream of benefits identified are a portion of the same benefits SCE used to support the original project, except delayed one year and escalated.[843]

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[838] D.09-03-025 at 234.

[839] SCE-05, Vol. 03 at 104.

[840] JCE at 900.

[841] SCE-20, Vol. 01 at 16.

[842] SCE-05, Vol. 03 at 121, Table III-49.

[843] *Id*. at 120, Table III-48.

TURN recommends the Commission disallow $94.7 million from rate base because the expenditures were imprudent and unauthorized, and SCE's cost-effectiveness analysis is faulty.[844] Specifically, TURN argues the benefits were already counted against the original forecast costs and it is double counting to use them again. In addition, TURN views SCE's count of all R3 benefits against only the cost overruns as invalid. Moreover, delayed benefits have a reduced net present value, and the actual benefits may be less than estimated because fewer software applications were replaced.[845]

SCE insists that which software would be replaced was an estimate and unknown until ERP was fully deployed. If the project had not been completed, no benefits would have been realized. SCE also disputes that it misapplied R3 benefits. After calculating the discounted revenue requirement for the additional expenditures, SCE concludes the project would still be cost-effective even if the actual total cost had been used in the original forecast.[846]

We agree with TURN that SCE's cost-effectiveness analysis is flawed, in part because it did not include previously approved R3 implementation costs in the benefit comparison nor is the R3 benefit allocation supported. Notably, SCE admits that R3 required about half of the ERP implementation costs.[847]

We also question whether SCE prudently managed the project and fully disclosed potential overruns during the 2009 GRC. R1 deployed three months late, in July 2008, because SCE underestimated the time necessary for planned

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[844] TURN-9 at 21.

[845] TURN OB at 199.

[846] SCE-20, Vol. 01 at 14.

[847] *Id*. at 15.

tasks and the complexity of R1 tasks which had to be developed. The R2 deployment slipped from September 2008 to 2009 so that R1 stabilization could occur to allow for generating year-end financial statements.[848] Improvement of interfaces and more employee training on the system also delayed deployment of R2 until March 2009. The two main reasons for the 14-month delay in launching R3 are the prior R1 delays that resulted in revisions to R3 planning. SCE has already recorded the excess 2009 costs of $45.1 million (11.3% of authorized forecast) to rate base and we do not retroactively remove it.

We are cognizant that unexpected problems can occur when implementing a large software system. However, for this project, SCE underestimated foundational tasks, the scope of configuration, user interface problems, and necessary training. Furthermore, SCE had much of this information by July. Thus, we find the 2010 expenditures were not reasonable for purposes of rate recovery.

Therefore, the Commission finds it reasonable to disallow SCE's 2010 request for $49.593 million.[849]

7.7.2. Data Archiving

SCE states that a big challenge is the growing number of application databases which reduces retrieval performance and requires increasing costs to maintain the systems. In 2010, SCE began this project to implement the infrastructure and processes needed to manage data created for the ERP system. SAP data archiving is the only method supported by SAP and provides

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[848] SCE-05, Vol. 03 at 111.

[849] Based on the Results of Operation model, it appears that SCE adjusted this recorded expenditure to $50.957 million.

significant benefits, states SCE, primarily reduction in the need for hard drive space and memory.

SCE requests $2.891 million for 2011-2012 ($2 million in 2011, and $0.891 million in 2012) with most of the hardware purchased in 2011.[850] The purchase of storage and a server account for about $1.89 million, and the rest are for thousands of hours of deployment costs. The total implementation costs are estimated to be $4.14 million by 2014.

SCE has now had many years of experience with data storage and various SAP systems. SCE should be able to achieve some cost efficiencies when integrating new SAP software, instead of developing deployment costs based on earlier SAP projects.

Accordingly, the Commission finds it reasonable to reduce SCE's 2011 and 2012 forecasts by 10% and adopt $1.8 million for 2011 and $0.802 million for 2012.

7.7.3. Business Analytics Improvement

As part of the ERP project, SCE implemented the SAP Business Warehouse (BW) to store ERP data for analytics and reporting, and SAP Business Explorer (BEx) to analyze and report the data. SCE estimates the amount of data stored in BW will triple over the next five years. SCE claims BEx is not the best tool for some types of reporting and wants to implement a new SAP system designed to complement BEx and improve functionality.

For 2011-2012, SCE requests $5.683 million ($3.391 million in 2011 and $2.292 million in 2012) to implement SAP Business Objects Suite of Tools. The

[850] SCE-05, Vol. 03 at 128

total cost to deploy this system is estimated to be $13.2 million by 2014.[851] In the first three years of implementation, SCE's hardware and software expenditures will be about $2.3 million, the remainder is for more than 400,000 hours of labor.[852]

SCE did not establish that this project is necessary for safe and reliable electric service. Even if BEx is not the <u>best</u> tool for all tasks, that is insufficient justification for a capital expenditure to deploy a suite of new software. Moreover, SCE did not support its estimate that the amount of data stored in BW will triple over the next five years, and the estimated labor seems disproportionate to the equipment costs.

Accordingly, the Commissions disallows SCE's 2011-2012 request for capital spending for the project at this time.

7.7.4. Technology and Risk Management

SCE states that its IT systems are becoming more integrated and business critical so that the importance of safeguarding them from cyber attack has increased. SCE's Information Security group is responsible for ensuring that individuals seeking access to business resources are properly authenticated, and for preventing cyber attacks from impacting SCE's business and electric power operations.

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[851] *Id*. at 133.

[852] *Id*. at 133-134.

IT security expenditures begin a dramatic increase in 2009. SCE explains that threats against its critical systems and sensitive information are increasing and more sophisticated than ever before.[853]

No party specifically disputed SCE's nominal $000s forecasts in the following areas. SCE's recorded cost for these categories is $10.998 million, 43% less than SCE's original 2010 forecast of $19.280 million:

Project Category	2010 recorded	2011 forecast	2012 forecast	2010-2012 Total
Perimeter Defense	$3,639	$1,500	$3,110	$8,249
Interior Defense	5,971	6,800	10,300	23,071
Data Protection	1,388	3,154	2,190	6,732
Total	**$10,998**	**$11,454**	**$15,600**	**$38,052**

Upon review of the record, we find that SCE has justified these costs as reasonable and necessary for 2010-2012. Therefore, the Commission finds SCE's forecasts reasonable and adopts them.

7.7.4.1. Common Enterprise Services (CES)

CES are foundational IT services developed for use throughout the enterprise. According to SCE, these services are best built once and repeatedly executed for a wide range of solutions, shared and reused, to avoid proliferation of duplicative costs and services. SCE first recorded expenditures in 2008, spent about $5 million by 2009, and plans to spend more than $37 million between 2010 and 2014.[854]

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[853] *Id*. at 140-141, Table IV-55. (The annual level of cyber attacks grew 230% from 2006 to 2009.)

[854] These costs were authorized in the 2009 GRC as Enterprise Technology Services.

For 2010-2012, SCE initially requested $19.285 million ($6.149 million in 2010, $5.736 million in 2011, and $7.4 million in 2012) to focus on two service categories: Software-as-a- Service (e.g., video streaming) and Development/Platform-as-a-Service (e.g., Service Oriented Architecture.)[855] The former is for users and the latter for developers of IT solutions. SCE describes the benefits as including better cost management, "business agility," and easy availability.[856] We instead adopt SCE's 2010 recorded costs for this project of $7.416 million.

TURN asks the Commission to deny SCE's requests on the grounds that the project is vaguely defined, and there are no tangible or quantifiable benefits to ratepayers to warrant this level of expenditure.[857] TURN argues that SCE justifies the new technology with claims of efficiencies, but declines to quantify the benefits. SCE responds that there are many cost and operational benefits to moving to the model, but it must first be built in order to realize future efficiencies.

In the 2009 GRC, we authorized components for implementation of enterprise services, and are still persuaded that such foundational systems could produce benefits including reduction of duplicative costs. However, SCE provides limited explanation as to how it prioritized the proposed new service categories, or whether it undertook a review to minimize costs.

In order to ensure that SCE focuses only on the most essential enterprise-wide systems during this rate cycle, and aggressively looks to minimize costs, the

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855 SCE-05, Vol. 03 at 161, Table IV-60.

856 *Id*. at 158.

857 TURN-9 at 26; JCE at 915.

Commission finds it reasonable to reduce SCE's 2011 and 2012 forecasts by 10% and adopt 2011-2012 expenditures of $11.822 million.

7.7.5. NERC/CIP

In 2009, FERC approved the first NERC/CIP standards and implementation schedule which provided for phased implementation. NERC is currently working on a new version. SCE expects the version will expand the current scope of assets, and will require a detailed review and assessment of each electronic security asset down to the device and application level.[858] SCE seeks approval for capital spending to develop and implement systems and processes to help ensure that SCE sustains compliance with the standards.

For 2010-2012, SCE requests $26.278 million ($1.8 million in 2010, $10.620 million in 2011, and $13.858 million in 2012) for NERC/CIP implementation.[859] The forecasts are based on SCE's experience with implementing prior NERC/CIP mandates and assume adoption of the proposed NERC/CIP standards. SCE's 2010 recorded expenditure for 2010 was $4.812 million.

Several capital projects will replace technology infrastructure and hardware that no longer support compliance. Other projects will: (1) increase control and management capabilities; (2) expand repository capabilities for compliance evidence; (3) implement infrastructure to maintain an Adequate Level of Reliability; and (4) implement various cyber security capabilities.[860]

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[858] SCE-05, Vol. 03 at 167.

[859] *Id*. at 170.

[860] SCE-05, Vol. 03 at 168.

DRA recommends a $767,000 reduction based on DRA's overall averaging of its own 2011 and 2012 IT capital expenditure forecasts.[861]

SCE must implement adopted NERC/CIP standards and we find that SCE's reliance on prior CIP implementation projects to forecast expending is reasonable. However, we also recognize that SCE's forecasts are based on a proposed version of the standards and are made prior to an actual detailed analysis of implementation.

Therefore, the Commission finds reasonable and adopts SCE's forecasts to initiate implementation of new NERC/CIP standards. However, if adoption of the standards is delayed, we expect SCE to retain funds to complete implementation or re-direct them to other cyber security needs.

The Commission adopts $98.947 million of the total $155.826 million request for Other Capitalized Software.

IT&BI Capital Expenditure Forecast: Other Capitalized Software					
	Capital Request by Year				
Project Description	**2011 Forecast**	**2012 Forecast**	**Total 2011-2012**	**Adopted 2011-2012**	**Disallowed 2011-2012**
Portfolio Project Mgmt *	$0	$0	$0	$0	$0
Enterprise Resource Planning *	0	0	0	0	0
Data Archiving	2,000	891	2,891	2,602	289
Business Analytics improvement	3,391	2,292	5,683	0	5,683
Technology and Risk Mgmt	11,454	15,600	27,054	27,054	0
Common Enterprise Svc	5,736	7,400	13,136	11,822	1,314
NERC/CIP	10,620	13,858	24,478	24,478	0

861 JCE at 666.

Capital Related Work Order*	0	0	0	0	0
Total	**$33,201**	**$40,041**	**$73,242**	**$65,956**	**$7,286**
* While these projects show no 2011-2012 forecasts, they incurred 2010 recorded expenses. Total adopted 2010-2012 Other Capitalized Software expenditures: $32.991 of $82.584 million recorded (2010) + $65.956 million (adopted 2011-2012) = $98.947 million.					

For all Capitalized Software in this section, SCE's revised 2010-2012 total forecast, using 2010 recorded expenses, is $317.739 million. The Commission adopts a total of $247.035 million, a decrease of $70.704 million (22.3%).

7.8. Information Technology Review in Next GRC

TURN raised significant concerns about the hundreds of millions of dollars being spent, just between 2010 and 2012, on IT projects because: (1) there was no evidence that SCE optimizes experience and assets to minimize costs; (2) the software and hardware have relatively short service lives; (3) up to 90% of the estimated costs are for in-house or contract labor; (4) contingency costs vary widely; (5) SCE's showing lacked project prioritization; (6) frequent costly upgrades are expected; and (7) SCE claimed, but did not quantify, productivity benefits.

We agree with TURN that in an era when the large utilities make billion dollar investments in capitalized software projects to upgrade their business and operational systems, respond to regulatory requirements, and integrate new technologies, it is important to ensure that utilities follow best practices for IT solutions. This is so because ratepayers not only pay a return on the capital investment, they also pay ongoing O&M and, not uncommonly, extra charges and labor to fix or modify licensed software and hardware.

The Commission finds that it would be in ratepayers' interest to undertake a more detailed review of SCE's capitalized software requests in the next GRC, particularly related to SCE's cost estimation methodology, approach to cost-effectiveness, and whether reasonable metrics exist to measure benefits. We direct SCE to provide the following as part of its testimony in support of forecast capitalized software projects in its 2015 GRC application:

1. A table listing capitalized software projects funded during 2010-2012, as identified in this GRC across all business units. The table shall include, for each project, SCE's final 2012 GRC forecast, as well as authorized and recorded expenditures;
2. Information about whether SCE employs best industry practices in making its capitalized software project cost estimates, particularly as to in-house labor, project management and contingency;
3. Information about how SCE is effectively optimizing experience and assets to minimize costs of software development and implementation;
4. Information about how SCE is cost effectively planning its system design, including maximizing use of COTS and life extension activities, to meet growing demand for technology solutions; and
5. Information about whether reasonable metrics are available to measure productivity results from IT solutions, and how such metrics would apply to SCE's 2015-2017 capitalized software projects.

8. Human Resources, Benefits, and Other Compensation (HR)

The HR department is responsible for attracting, developing, motivating, and retaining a highly skilled workforce. HR activities include employee relations and development programs, as well as administering compensation and benefit programs for all active and retired employees.

For TY2012, SCE forecasts O&M expenses ranging from Executive Officer and HR departmental salaries and expenses, to employee incentive bonus programs and costs necessary to administer company-wide pension and benefit programs. In the 2009 GRC, the Commission disallowed rate recovery for some incentive and recognition programs.[862]

SCE's combined O&M forecasts for TY2012 total $784.264 million, of which approximately $560 million (72%) is for pensions and benefit program costs. There is one capitalized software project forecast for HR at a cost of $3.1 million in 2010. As set forth below, we adopt $700.66 million for TY2012 O&M and approve SCE's capital spending request.

8.1. Parties' Positions and Policy Considerations

DRA recommends zero recovery for executives' Long-Term incentive (LTI) and 40% recovery for all of SCE's Short-Term incentive (STI) programs (executive, manager, and other employees). The combined disallowance is about $113 million. DRA also seeks disallowance of costs for employee recognition awards, primarily due to a lack of clarity in SCE's $5 million calculation.

TURN follows the 2009 GRC decision which disallowed all executive LTI and 50% of executive STI programs. In this GRC, the result would be a $23 million reduction to SCE's forecast. Additionally, TURN applies different methodologies to arrive at lower test year forecasts for the medical and disability programs and 401(k) contributions.

Joint Parties make the following policy recommendations to the Commission:

- Utilities should be required to disclose philanthropic contributions in the context of the dollar amount of their aggregate executive compensation for the top 25 executives, as reported in GO-77M filings;

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[862] D.09-03-025 at 132-134.

- SCE and DRA should be required to conduct a non-binding ratepayer advisory vote on executive compensation;
- SCE should be required to revise all pension practices in 2012 to follow best practices instituted by California state and local governments, including higher executive contributions;
- For executives and professionals with a pension that could exceed $100,000, SCE should create a voluntary pension plan that is in line with ratepayer expectations; and
- SCE and DRA should be required to jointly develop a plan within three months to ensure that SCE pensions, particularly for new employees, are more in line with realities of state's economy and future pension plans of ratepayers and government employees.[863]

In this decision, we review SCE's requests to ensure that they do not result in employees receiving above-market total compensation, or produce outcomes that are contrary to ratepayer interests.

8.1.1. Total Compensation Study (TCS)

Following longstanding direction from the Commission, DRA and SCE jointly managed the design and scope of a TCS, and jointly selected an expert to perform it, in order to measure SCE's compensation levels against market rates. The Commission has said, "Our objective is to ensure that ratepayers are not burdened with paying compensation levels beyond that which is necessary for [SCE] to provide safe and reliable service at reasonable rates."[864]

SCE and DRA selected Hewitt and Associates[865] (Hewitt) to conduct the study from six companies solicited to respond to the Request for Proposal (RFP).

[863] Joint Parties' OB at 15, 22, 29-30.

[864] TR at 2705; D. (D.87-12-066) 26 CPUC2d 392, 457.

[865] In 2011, Hewitt was acquired by AON and is now known as AON Hewitt.

The results of the TCS are that SCE's aggregate compensation is 4.7% below market levels, as shown in the table below:[866]

Job Category	Base Pay	Total Cash Compensation*	Benefits	Long Term Incentive	Total Compensation
Physical/Technical	9.0%	11.1%	1.8%	---	9.4%
Clerical	-9.5%	-11.4%	-6.4%	---	-10.5%
Professional/Technical	-1.2%	-5.3%	-1.2%	-58.3%	-4.9%
Manager/Supervisor	-4.2%	-12.0%	-7.5%	-83.8%	-15.2%
Executive	1.0%	-8.2%	70.5%	-29.5%	-9.8%
Overall**	**-0.9%**	**-4.0%**	**-2.2%**	**-8.3%**	**-4.7%**

*Total Cash Compensation equals base pay plus short-term incentives.
** Overall numbers are payroll weighted.

SCE asserts that, under cost-of-service ratemaking principles, as long as compensation is essentially at market levels, it is an operating expense of providing service to customers and is recoverable.[867]

DRA argues that a TCS is not a reliable benchmark for overall compensation levels, primarily due to different comparator companies used in different studies and different criteria used to select them.[868] DRA questions the selection of benchmarked executive job classifications, use of some general industry companies, and argues that use of 2009 and older data fails to reflect the changing electric industry or the current economic recession.[869] Finally, DRA states it is reconsidering the value of a total compensation study and asks the Commission to allow it to seek an alternative.[870]

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866 SCE-06, Vol. 02 at 5, Table II-1; TCS at Appendix B.

867 SCE OB at 8.

868 DRA OB at 286.

869 DRA RB at 17.

870 DRA OB at 287-288.

Joint Parties ask the Commission to reject the TCS as to executive compensation because there is an appearance of conflict of interest arising from Hewitt's receipt of other valuable contracts from SCE. Joint Parties conclude that Hewitt is not independent because it has received about $50 million from SCE since 2006 from consulting and outsourcing contracts.[871] In addition, Joint Parties argue the executive comparator group is flawed because it does not include data from the LADWP, a company it views as the most appropriate industry comparison, where similar executive positions are allegedly filled at one-third to one-tenth of the cost.[872]

TURN agrees that receipt of substantial SCE revenues might result in a significant potential for bias; however, TURN believes the substantive problem is the use of "peer group" comparisons for executive compensation. TURN argues the TCS is not a reliable basis to conclude executive compensation is reasonable because the "peer group" method results in an inherent bias towards ever-increasing compensation levels.[873]

SCE defends the TCS process and results as directed by the Commission and co-managed by DRA. SCE points to the testimony of DRA's TCS representative who stated he was actively involved, including the selection of the consultant, reviewing and providing comments, and suggesting methodology changes adopted by the TCS team.[874]

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871 JP-1 at 6.

872 *Id*.

873 TURN OB at 241.

874 SCE RB at 109.

The record indicates that Hewitt received about $8.3 million from SCE in 2009, of which $7.3 million was for benefits administration (outsourcing) services.[875] Between 2006 and 2010, SCE concedes that it paid Hewitt for consulting and outsourcing services, although Hewitt lost the outsourcing contract in 2010 or 2011. Joint Parties did not provide any evidence that the value of SCE's contracts was a substantial part of Hewitt's overall revenue or that any collusion occurred or influence was applied to either the selection of Hewitt or the study results.

To the contrary, DRA's TCS representative stated at hearing that he did not sense SCE's representatives favored selection of Hewitt. He also said decisions were made by consensus and that he felt Hewitt came up with the best proposal.[876] Despite being only one member of a nine person team,[877] he stated he never felt coerced or was denied an opportunity to bring other DRA employees to study team meetings.[878] Thus, there is very little evidence to support parties' concerns about a conflict of interest in the selection of Hewitt to conduct the TCS or SCE influence over results.

Although DRA eventually echoed Joint Parties' objection to the executive comparator group, DRA's late-appearing concerns about selection of benchmarked executive job classifications, exclusion of LADWP, and use of

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875 TR at 1514.

876 TR at 2646, 2648.

877 SCE-06, Vol. 02, Appendix B at B-2 (Four team members from SCE, four from Hewitt, and one from DRA).

878 *Id*. at 2646, 2648-2649.

general industry companies are puzzling in light of testimony that these decisions were among those adopted by the study team at DRA's suggestion.

Hewitt uses databases of compensation and job classification descriptions provided voluntarily by companies to permit benchmarking of similar tasks and responsibilities. LADWP posts some compensation data publicly on its website, but does not submit compensation data to any data source used by Hewitt.[879] For utility technicians and labor, LADWP employees were considered a natural labor pool and LADWP was identified as a comparator for those job categories. When Hewitt asked LADWP for compensation data, it was directed to the public website from which Hewitt was able to extract sufficient information to benchmark jobs and gather data for use in this study.[880]

For executive compensation, the TCS team agreed that size of the company and complexity of the business were the primary factors for comparator companies. The team decided to use a separate comparator group for the executive pay part of the study, instead of one comparator group for all salaried exempt employees, and used companies that had an annual revenue range of +/- 2.5 times SCE's revenue ($8 - $14 billion). DRA suggested the method because it was to be used by PG&E and Sempra in upcoming compensation studies.

Starting with the 13 utility companies from the non-executive utility comparator group, the team added four companies from the non-executive general industry group, and then added seven more general industry companies

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[879] TR at 1528.

[880] *Ibid.*

within the annual revenue range.[881] LADWP was not included because its revenues were below the minimum bar. SCE also argues there are significant differences between executive responsibilities and concerns at a municipal utility and in an investor-owned corporation.

Joint Parties' compensation witness did not offer any documentary support for his conclusions about the total compensation rates or comparability of LADWP executive classifications, nor did this witness address the prevailing assumption that size and complexity are the primary relevant factors for executive comparator companies.

We find the TCS study design and results to be the joint product of DRA, SCE and Hewitt, as the selected consultant. There is no evidence that Hewitt was influenced to impact the outcome of the TCS as a result of receipt of other contract dollars which were apparently a nominal part of Hewitt's revenues, and in any case, have been terminated. Furthermore, there is no evidence that DRA objected to any part of the study design at the time the TCS team was meeting, in its written testimony, or prior to its Opening Brief.

Therefore, as it did in 2009, the Commission finds the TCS study establishes SCE's compensation rates are within market rates, but not whether all elements of proposed compensation are reasonable and qualify for rate recovery.

However, the objecting parties have expressed a variety of concerns about the TCS process as a method, or as configured, for measuring market rate executive compensation, or all compensation, in comparison to SCE's levels for purposes of future GRC reasonableness review. To address these concerns, the

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[881] SCE-06, Vol. 02, Appendix B at B-94.

Commission directs DRA and SCE to jointly hold a workshop open to all parties, within 90 days of the date the decision is adopted, to discuss whether design modifications should be made to the next TCS or an alternative method of data gathering should be utilized for the next SCE rate case. Notice of this workshop shall be sent to the service list of this proceeding and be noticed in the Daily Calendar at least 30 days prior to the workshop.

Within 30 days of the workshop date, SCE and DRA shall jointly file a Tier 2 Advice Letter with the Energy Division which describes the resulting agreement between SCE and DRA as to how this matter shall be handled in the next GRC. If SCE and DRA undertake an RFP for a compensation study in a future GRC, SCE shall ensure that applicants are required to disclose if they receive more than 10% of their annual revenues from other SCE contracts.

8.1.2. Equal Opportunity and Workforce Diversity

An important part of HR's functions is to lead SCE's equal opportunity and diversity efforts within the company's workforce, as well as within the service territory, statewide, and nationwide.[882] In addition to recruitment, retention, leadership development, and communication and education programs, HR provides mandatory diversity and sexual harassment training for employees, and additional training for managers and supervisors. SCE states that a qualified, diverse workforce is fundamental to achieving its business objectives, although SCE does not separately break out its expenses for diversity activities.

We concur with SCE's business case for diversity in its workforce and acknowledge that SCE has sustained progress in increasing representation of

[882] SCE-06, Vol. 01 at 22.

women and minorities in executive and management positions. Using a 20-year comparison (1990-2009), SCE establishes growth in minority employees in every category, although not all gains track the increased number of positions. For example, total executive positions rose from 40 to 162 between 1990 and 2009, while the percentage of minority executives rose from 7.5% to 22.2%.[883] Thus, the number of executive positions grew by 305%, but the percentage of minority employees in those positions grew by less than 200%.

Nonetheless, by the end of 2009, minority employees comprised 21% of the top 100 management positions, 26% of the top 500, and 28% of the top 1,000 positions. We strongly encourage SCE to continue its commitment to a diverse workforce, reflecting its own diverse service territory, particularly as it implements leadership development, workforce and succession planning, and incremental staffing needs.

The Commission finds it reasonable for SCE to continue reporting on workforce composition in its GRCs. In the next GRC, SCE shall add a ten-year comparison by job classification, and an explanation of what steps it has taken to ensure top management leadership development for underrepresented groups, as part of overall availability to SCE employees.

The success of a diverse workforce may rely, to some extent, on a culture of non-discriminatory, equal opportunity throughout the organization. Although SCE's witness had few facts at hand when testifying, her impression was that the number of internal complaints to SCE's Equal Opportunity Office

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[883] *Id*. at 25, Table II-3.

has decreased in the last five years.[884] However, she recalled that the number one category of complaints is in the area of sexual harassment.[885]

The percentage of women in the SCE workforce slightly declined between 1990 and 2009 from 23.83% to 23.45%.[886] Although women have moved into executive and managerial positions at significant rates, there have been decreases in other categories.

HR states it provides sexual harassment prevention training to managers and supervisors on a two-year rotation.[887] We encourage SCE to re-evaluate this schedule and its training module to assess whether changes should be made to ensure effective training reaches all employees within the first year of employment, and frequent refresher courses occur for managers and supervisors.

SCE shall provide in its next GRC, a five-year (2009-2013) summary of the type of complaints made to the Equal Opportunity Office and a description of anti-discrimination and sexual harassment prevention training provided to SCE employees during that period, including any substantial revisions to scheduling and content.

8.2. O&M Human Resources Department: FERC 920, 921, 923, 926

SCE records both HR departmental and executive officer A&G expenses in Accounts 920/921. Departmental and executive officer Outside Services are

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[884] TR at 3854.

[885] *Ibid*.

[886] SCE-06, Vol. 01 at 25, Table II-3.

[887] *Id*. at 23.

recorded in Account 923, and costs associated with departmental employee pensions and benefits are recorded in Account 926.

8.2.1. Salaries and Related Expenses

8.2.1.1. HR Departmental: FERC 920, 921, 923, 926

For TY2012, SCE forecasts $28.384 million ($22.846 million Labor, $5.538 million Non-labor) for HR departmental staff, a 2.7% increase over 2009 recorded costs. The increase is to add seven additional staff to provide HR support at SONGS at a cost of $741,600.[888] SCE states the additional workers are needed to support management and workforce in day-to-day operations, to assist with significant workforce reductions, and to assist with regulatory and compliance requirements.

DRA recommends the Commission adopt $28.013 million by reducing the number of new positions from seven to three, reflected by a $371,000 reduction.[889] DRA argues that total costs have been relatively stable at SONGS since 2005 due to replacement of supplemental workers by FTEs, and raises uncertainties about whether actual staff reductions will occur in this rate cycle.[890]

SCE argues that DRA's position is arbitrary and ignores SCE's need for the positions, although SCE concedes that workforce reductions are uncertain in this rate cycle. Instead, SCE contends that due to various applicable rules and regulations, SCE needs to prepare for the reductions, as well as address NRC concerns about human performance and safety culture.

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888 SCE-06, Vol. 01 at 37.

889 JCE at 403.

890 DRA-13 at 10.

Even assuming that some of the workforce reductions occur in this rate cycle, workforce reductions are routine activities for HR and some existing support for terminating employees and workers should be embedded in HR's previously authorized funding. However, we are persuaded that the NRC's concerns about the safety culture at SONGS are significant and require additional staff to work with SONGS management to address these concerns.

Accordingly, the Commission finds reasonable and adopts $28.171 million for TY2012 O&M, a $213,000 reduction to eliminate two of the seven positions. SCE shall include in its testimony in the next GRC, a description of the programs developed and implemented by these five employees to address the NRC's concerns about safety culture at SONGS.

No party disputes SCE's forecasts for HR departmental Outside Services recorded in Account 923 ($2.742 million) or Employee Pensions and Benefits recorded in Account 926 ($6.813 million).

Based upon a review of the record, the Commission finds reasonable and adopts SCE's TY2012 forecasts for HR departmental costs in Accounts 923 and 926.

8.2.1.2. Executive Officers' Compensation: FERC 920, 921

There are about 30-35 Executive Officers.[891] SCE forecasts a total of $19.548 million in total executive officer cash compensation, expenses, outside services, cash incentives, and a small component for other executive support (e.g., executive assistant to the CEO). Benefits and other compensation are discussed separately below.

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[891] DRA-13 at 24.

SCE asserts that the total compensation package is necessary to attract and retain executives. Executive pay is annually benchmarked against competing companies and an annual review process for salary increases and incentive targets is undertaken by the Compensation Committee of the Edison International (EIX) Board of Directors.

Based on LRY, SCE's TY2012 combined 920/921 forecast is $18.260 million ($15.516 Labor, $2.744 million Non-labor) for executive officers' cash compensation and expenses, including costs for the Executive Incentive Compensation Plan (EIC).[892]

DRA recommends a $5.376 million (60%) reduction to the EIC costs[893] based on its review of the award criteria.[894] DRA and TURN generally agree that 60% of executive incentive goals are based on financial performance, while other goals benefit both shareholders and ratepayers.[895] TURN would continue to limit rate recovery to 50%, a reduction of $3.23 million.[896]

SCE responds that TURN and DRA ignore that SCE's compensation levels are statistically at market, incentive bonuses are a standard of executive pay, shareholders' interest in executive pay is to not reward poor performance, and limiting rate recovery is at odds with cost-of-service ratemaking.[897] SCE also

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[892] SCE-06, Vol. 01 at 43-44.

[893] DRA-13 at 7(Without explanation, DRA used $8.96 million to calculate this amount, instead of $6.461 million used by TURN and SCE, and stated at DRA-13 at 5.)

[894] JCE at 406.

[895] DRA-13 at 7; TURN-3 at 96-97.

[896] JCE at 801; TURN-3 at 98.

[897] SCE-21 at 10-13.

contends that the bonuses are measured to Board-set goals in critical areas of utility performance, and include targets that improve value for both customers and shareholders. Lastly, SCE argues that the proposed reductions would unreasonably place its executives at below market compensation.

DRA and TURN are not wholly mistaken about SCE's goals and other EIC criteria. It is inherent in the nature of a regulated, investor-owned utility that shareholders and ratepayers will not always have identical interests and goals. For example, SCE's investors may well be focused on expanding sales, robust capital investment, and minimizing disallowances to rate recovery, while in the current economy SCE's ratepayers may prioritize low-income programs, exclusions from rate recovery, less expensive fixes rather than capital replacement, and so forth.

Accordingly, the Commission finds reasonable and adopts $15.029 million for TY2012, reflecting TURN's recommendation that SCE may recover 50% of its forecast costs for the executive officers' share of the EIC program.

In our decision today, we are not recommending reduced compensation for executive officers. We are merely assigning certain costs to shareholders based on what is just and reasonable to assign to ratepayers. The TCS did not specify or differentiate between ratepayer and shareholder funding for either comparator company compensation or SCE compensation.

8.2.1.3. Executive Outside Services: FERC 923

For executive officers, SCE forecasts $1.288 million for TY2012 for Outside Services including actuarial valuation of executive benefits plans, benefits calculations, design of executive benefit programs, and other administrative services.[898] More than two-thirds of the recorded costs are for charge backs by EIX officers of a percentage of their salaries and expenses to operate the utility.[899] No party disputed the forecast.

Based on a review of the record, the Commission finds reasonable and adopts SCE's forecast for this category.

8.2.1.4. Stock Options and Long-Term Incentives (LTI)

SCE offers LTI compensation such as stock options, restricted or preferred stock units, and performance shares to its executives. According to SCE, short and long-term incentives form more than half of an executive's total compensation which is below market rate and reasonable.[900] Because these incentives are common, SCE claims it would have trouble recruiting or retaining executives without them.

For TY2012, SCE forecasts $19.805 million for executive LTIs.[901] Although the Commission has not previously authorized SCE to obtain rate recovery for these costs, SCE identifies a few examples of other jurisdictions approving some form of LTI, and points to one prior example of Commission approval in a 1998 GRC for Southern California Gas Company.

TURN and DRA recommend the Commission follow previous practice and exclude LTI costs because they are closely tied to stock performance of the parent company, and other non-utility activities. In the 2009 GRC, we also said:

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[898] SCE-06, Vol. 01 at 45.

[899] *Ibid*.

[900] SCE OB at 242.

[901] JCE at 406, 802.

> Furthermore, in light of the current economic situation and the dire financial circumstances many Californians find themselves in, it is reasonable to limit the level of executive compensation ratepayers are responsible for, provided such reductions do not result in total compensation levels falling below the amount required for [SCE] to attract and retain employees.[902]

These economic conditions persist today.

SCE has argued that each and every element of executive (and all) compensation is necessary to recruit and retain qualified employees. However, SCE agrees that non-compensation factors also play a role. SCE has not provided any evidence to support that LTIs are eligible for rate recovery, nor has it established that disallowance of executive LTI in the 2009 GRC, or a 50% reduction to executive STI, resulted in any impact on retention or attraction of SCE executives.

Accordingly, the Commission finds it reasonable to disallow rate recovery for 100% of executive long-term incentives.

8.2.2. Joint Parties' Executive Compensation Recommendations

As described above, Joint Parties made two policy recommendations regarding executive compensation in future rate cases. First they recommend the Commission order SCE to disclose philanthropic contributions in some relationship to the amount of aggregate executive compensation for the top 25 executives. Joint Parties argue that the Commission and the public should be aware of the high levels of executive compensation, and be able to compare that

902 D.09-03-025 at 135.

with Edison's annual philanthropic contributions to underserved communities.[903]

Joint Parties concede that the Commission has no jurisdiction over SCE's philanthropy and SCE's philanthropic contributions are not part of the scope of this proceeding.

Joint Parties also ask the Commission to require SCE and DRA to conduct a non-binding ratepayer advisory vote on executive compensation.[904] Their argument is that ratepayers "generally absorb more risk than shareholders." SCE opposes the advisory vote on several grounds, including no legal authority to conduct the vote, the vote usurps the roles of the Commission and DRA in ratesetting, and such a major policy shift should be vetted through a rulemaking.

We find that these recommendations lack evidentiary support to establish the relevance and benefit to the GRC, the underlying legal authority, and actual value to ratepayers and the Commission. Accordingly, the Commission declines to adopt the recommendations.

Other recommendations included in the direct testimony of Joint Parties, including limiting executive compensation to twice that of LADWP and directing executives that receive more than $1 million to defer half of their compensation for five or more years, were not developed in the record and not included in their post-hearing briefs.[905] Therefore, we do not address them here.

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[903] Joint Parties OB at 16.

[904] *Id.* at 24.

[905] SCE-21 at 9.

8.3. Capital Expenditures - Capitalized Software

SCE states that new hires wait an average of six days after their start date before getting necessary IT equipment, and 16 days before being fully provisioned. The key problem, according to SCE, is that information must be shared among multiple information systems, many of which are not integrated.

SCE requests $3.086 million in 2010 for the Worker Provisioning Process Enhancement Project. This is a new project to provide an online, automated system to be used by managers to streamline the provisioning process for new SCE employees and contingent workers. SCE claims it will also improve off-boarding retiring/terminating employees.[906]

DRA observes that SCE only recorded expenditures of $1.755 million in 2010, despite SCE's claim that the hardware and software to support implementation have been put in place.[907] Therefore, DRA recommends the Commission only authorize $1.755 million for this project.

On the other hand, TURN recommends no funding for this project on the grounds that it provides minimal benefits in comparison to the cost.[908] Specifically, TURN argues that SCE did not adequately support the need for 16 person years of development of a new system to handle 1000 requests per year.

We are persuaded that the SCE evidence reviewed by TURN was an incomplete assessment of the projected work flow. SCE also provided documentary support for its claim that there were delays in the project plan and

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[906] SCE-06, Vol. 01 at 47.

[907] DRA-13 at 31.

[908] TURN OB at 207.

in receiving invoices, and additional contract work carried over into 2011. Assuming the project is functional for many years, there should be a benefit to ratepayers from having new hires properly provisioned and working productively as soon as possible.

Accordingly, the Commission finds it reasonable and adopts SCE's recorded expenditures of $1.755 million for 2010 and $1.3 million for 2011.

8.4. Short-Term Incentives (STI): FERC 500, 588, 905, and 920/921

SCE describes its STI programs as a cash bonus based on an employee achieving (1) company goals, (2) performance against SCE's total O&M budget, and (3) business unit/department goals.[909] The 2009 goals are described by SCE as focused on customer service, safety, cost control, and efficiency.[910]

The Commission authorized full rate recovery for STI programs in the last three SCE GRCs.[911] However, we had concerns about budget-related goals as criteria for the bonuses and directed SCE to establish a one-way balancing account in 2006, continued in 2009, to track the costs and credit any shortfall to ratepayers. SCE seeks to eliminate the balancing account based on its redesign of the programs.

SCE's TY2012 forecast of $146.795 million includes expenses for three programs: Results Sharing (RS) for about 90% of employees, the Management Incentive Program (MIP) for a small group of senior managers

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[909] SCE-06, Vol. 02 at 13.

[910] *Id*. at 14.

[911] *Id*. at 17.

(about 9% of total employees), and the EIC costs for non-officer executives (135 select senior managers, less than 1% of total employees).[912]

The forecast is based on the 2009 ratio of program costs to recorded labor expense applied to forecast 2010-2012 non-capital labor.[913]

CCUE wants no cuts to the RS portion of SCE's request because "when employees work harder and efficiently to provide reliable service . . . ratepayers also benefit."[914] Based on 2009, where 60.6% of total STI funds were awarded through RS, CCUE estimates that about $90 million would be available in TY2012 for employees eligible for RS awards.

DRA recommends either no funding or an $88 million (60%) reduction to rate recovery for all three STI programs based on excessive growth in this discretionary spending and award criteria which support shareholder interests.[915] According to DRA, SCE's 2012 total forecast is a 42% increase over the four-year (2005-2008) aggregate total of $104.3 million, and a 19% increase over SCE's 2009 costs of $124.8 million.[916] Further support comes from the fact that 2009 recorded costs are 17.3% more than the $106 million authorized by the Commission.

CCUE urges rejection of DRA's recommended RS cut on the grounds that STIs are normal compensation, DRA's proposal is equivalent to a 7.5% base pay cut for most employees, and a 60% reduction will result in cuts to the STI

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[912] *Id*. at 13.

[913] *Id*. at 17.

[914] CCUE OB at 16.

[915] DRA-13 at 6; JCE at 407-410.

[916] *Id*. at 17.

program itself.[917] We disagree and observe that in 2009, SCE actually awarded more than the authorized STI amounts. DRA calculates that even with only 40% ratepayer funding, there would be enough ratepayer funds to give every employee about a 5% annual bonus. DRA argues that 5% is sufficient to motivate improved performance while keeping rates low in difficult economic times.

Furthermore, SCE opposes DRA's proposed reductions because cuts are inconsistent with the results of the TCS which show that employee compensation, including STI awards, are market rate. SCE also argues that DRA misunderstands SCE's corporate goals and how they benefit ratepayers.[918]

In our prior discussion (in Section 8.2.1.2), we agreed that some STI criteria focus on financial performance, cutting O&M, or other goals weighted towards shareholder interests. We also share DRA's concern about rapid growth in discretionary STI costs which are rising much faster than the employee population. It is also notable that the STI funds are distributed in a way that favors executives and managers over rank and file employees who constitute 90% of the workforce.

For example, in 2009 almost one-third of the funds were awarded through the MIP to a group of managers that comprise 9% of the workforce, and another 8% went to the less than 1% who are non-officer executives.[919] Manager targets for bonuses are also up to 20% of annual salary, compared to 4% to 8% for rank and file. Ratepayers may not be well served by a bonus plan weighted heavily

917 CCUE OB at 17.

918 SCE-06, Vol. 02 at 23-29.

919 DRA-13 at 14, Table 13-8.

against the employees most likely to perform day-to-day operations and to interact with customers.

Based on the foregoing, we find that ratepayers should not bear the entire burden of the rapidly growing, discretionary STI program costs which, in some areas, may enhance value for shareholders more than benefit ratepayers. A reduction of ratepayer funding does not automatically mean the program will be reduced. Shareholders may find it in their interest to either replace the funds or direct some fiscal responsibility regarding the extraordinary growth in costs.

Therefore, the Commission finds reasonable and adopts $132.116 million, a 10% reduction in rate recovery, similar to reductions to forecast capital spending and an implied reduction to SCE's workforce forecast. The Commission also finds that ratepayer interests are served by SCE continuing to record all STI costs in the Results Sharing Memorandum Account, a one-way balancing account to assure that ratepayers only fund up to the authorized amount and are not subject to unanticipated and arbitrary liabilities in excess of SCE's forecast.

8.5. Employee Recognition Programs: 560.220, 562.170566.160, 566.250, 582. 170, 588.130, 588.140, 588.150, 588.170, 588.250, 588.270, 588.280, 920/921, and 926

SCE has two Employee Recognition programs for exceptional performance: cash awards in the form of "Spot Bonuses" and non-cash "Awards to Celebrate Excellence" (ACE). SCE claims the low-cost recognition programs are important tools for recognizing exceptional performance and are integral to the total compensation package. However, the programs are not included in the TCS.

The Commission has not previously allowed recovery of the program costs because SCE did not establish ratepayer value and the forecasts were not transparent.[920] These problems persist in this GRC.

For TY2012, SCE forecasts $5.067 million for Spot Bonuses and $6.9 million in ACE program costs spread across labor expenses within individual business units and Account 926 as part of Miscellaneous Benefits Programs.[921] SCE states these forecasts are based on 2009 recorded expenses. However, the amounts do not match other testimony or the JCE which identifies $9.603 million for Spot Bonuses and ACE awards combined.[922]

DRA asks the Commission to continue to allow no rate recovery for these programs for the same reasons as in prior rate cases. DRA claims that SCE provides an aggregate forecast but does not explain its forecast methodology or where in the exhibits the amounts are found. DRA also requests that historic Spot Bonus costs be removed from Account 920 and the ACE award costs be removed from Account 926.

SCE contends that some of these costs were not included in the GRC historical expenses, and the adjustment is duplicative of other DRA adjustments to forecasts made across SCE's business units. This is addressed separately in each business unit.

The Commission finds it reasonable to continue its practice of disallowing rate recovery for these costs for the same reasons given in 2009. SCE's testimony is vague about the amounts and locations of costs included in the forecasts. We

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920 SCE-06, Vol. 02 at 30-31.

921 SCE OB at 236.

922 JCE at 413-426.

agree with DRA that there is no explanation of how the forecast was developed. Nonetheless, we are persuaded that these costs have been removed from forecast costs in the various business units and additional reductions in Accounts 920 and 926 would be duplicative. See discussion of ACE costs in Account 926 in Section 8.6.3.5 Miscellaneous Benefit programs.

8.6. Pensions and Benefits: FERC 926

Included in this section are expenses related to SCE's pension, defined contribution (401(k)), health care, disability, group life insurance, and executive benefit plans. Costs began to rise for these programs beginning in 2009. Between 2005 and 2008, the average annual expense was about $305 million. In 2009, expenses increased 36% to $413 million due in part to the impact of the economic recession on pension plan trust funds.

For TY2012, SCE's forecast is $560.2 million ($nominal) for all employee pension and benefit plans and programs included in the rate request. This is a $147.3 million (35.7%) increase over 2009. SCE's forecasts are derived as a program cost per employee based on 2009 recorded costs, multiplied by its projected number of 2012 employees.

DRA recommends several reductions resulting in a total forecast of $304.25 million, 46% less than SCE's forecast. The biggest differences are for pension and 401(k) costs. TURN's recommendations relate to SCE's methodology for benefit program cost calculations.

8.6.1. Pensions

SCE provides 100% of the contributions to its employees' pension plan and requests full rate recovery for these expenses. The Pension Protection Act of 2006 included significant changes to pension plan minimum funding requirements by focusing on short-term funding adequacy.[923] After the rules became effective in 2008, SCE's pension plan, like others, experienced severe declines in asset value and funding status.[924]

For TY2012, SCE forecasts $168.4 million in pension costs, based not on minimum funding requirements, but on its longstanding policy of contributions and rate recovery calculated to remain level as a percentage of payroll over the life of the plan.[925] Although SCE previously built up "credit balances" from contributions in excess of minimum requirements, SCE estimates the credit balances will be exhausted by 2012 and higher contributions will be required from 2012-2014.

DRA recommends $52.947 million, the equivalent of what the Commission authorized in 2009, because it states SCE has not justified the increase in plan costs.[926] SCE's forecast is 81% more than 2009 actual pension costs, and 218% higher than the 2009 authorized amount. In 2009, SCE's actual recorded costs were $92.63 million, 75% more than the authorized amount.

SCE's request is excessive, argues DRA, because the plan is currently fully funded and earned a higher rate of return in 2009 and 2010 than assumed when SCE developed its forecast.[927] DRA also contends that SCE should reconsider both the nature and funding of its employee retirement plans. CCUE rejects

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923 SCE-06, Vol. 02 at 38.

924 *Id*. at 39.

925 *Id*. at 35, 40.

926 DRA-15 at 4.

927 *Id*. at 6-7.

DRA's proposed cuts as unjustified and supports SCE's forecast, including $4 million to address an estimated 1500 new FTEs.[928]

Both TURN and DRA sought updated information from SCE, including market value of the plan assets at the end of 2010, and asked SCE to recalculate costs assuming different rates of return. DRA wanted SCE to use actual returns of 24.4% in 2009 and 15.4% in 2010 instead of the 6.69% and 6.76% assumed in the report.[929] TURN asked SCE to assume an increase in return from 7.5% to 8.5% beginning in 2011.[930] SCE eventually provided the analyses, including an updated forecast based on 8.5% market returns that resulted in a TY2012 forecast of $167.7 million.

Because SCE's original forecast is so close to the revised forecast based on updated actuarial evaluation and an assumed market return of 8.5%, TURN accepts SCE's forecast.[931] However, DRA criticizes SCE as not providing requested information and choosing to apply a two-year smoothing mechanism[932] (2008-2009) to result in a higher contribution amount.

SCE admits it told DRA it could not do the requested alternate analyses which it viewed as burdensome, but later provided them in unannounced rebuttal testimony without opportunity for DRA to respond.[933] We addressed a

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928 CCUE OB at 18.

929 DRA OB at 295.

930 TURN OB at 256.

931 *Id*.

932 TR at 3163 ("Smoothing mechanism" is a multi-year average of assets rather than the most recent).

933 TR at 3160-3175.

similar shortcoming in the TDBU section, and again remind SCE to notify a party if it plans to produce requested information after initially declining to do so. Here, SCE's claim it did not tell DRA about the new analyses because at that point DRA's direct testimony had been served, is neither fair nor a sufficient excuse for waiting several weeks before unveiling the data in rebuttal testimony.

In the past three GRCs, DRA and SCE have disagreed over pension funding policy, with DRA arguing for only the minimum legally required funding. The Commission adopted SCE's forecasts in 2003, 2006, and 2009, subject to balancing account treatment. DRA's proposed use of actual market returns is flawed because the record establishes that market returns have varied widely since 1995.[934] TURN's suggested 8.5%, in line with the pension fund's 15-year annualized return, is more reasonable.

The record indicates that SCE makes plan administration and forecast development choices that result in forecast plan contributions higher than minimum funding requirements. However, at this time we do not second guess those choices, and note our approval in prior rate cases of SCE's pension funding policy. We see no compelling reason to depart from that policy here.

In order to protect ratepayers, DRA proposes converting the existing two-way balancing account for pension costs into a one-way balancing account, and adding a 25% cost-sharing mechanism for shareholders applicable to contributions in excess of the authorized amounts. We are sympathetic to DRA's concerns about the unlimited pass-through to ratepayers of 100% of all pension

[934] SCE-06, Vol. 02 at 41, Table VII-3.

expenses, but we decline to convert the balancing account as recommended without a broader review of pension plan recovery.

Therefore, the Commission finds reasonable and adopts SCE's TY2012 forecast of $168.4 million and continues the pension balancing account under its current terms and conditions.[935]

8.6.1.1. Pension Policy Recommendations

As in other discretionary spending areas, SCE may lack incentive to pursue cost controls or alternate retirement benefits because ratepayers will fund 100% of its expenses. DRA and Joint Parties offered proposals to the Commission regarding SCE's pension policies in order to address the ratepayers' burden and current adverse economic conditions.

For future rate cases, DRA recommends that SCE explore other options for employee retirement benefits, including eliminating pensions for new employees in favor of a 401(k)plan, splitting pension expense between ratepayers and shareholders, and having employees make contributions to their pensions as most other employees do.[936]

From Joint Parties, the key recommended action is that SCE and DRA should be required to jointly develop a plan to ensure that SCE's pensions, particularly for new employees, "more closely resemble" the pension plans in government, private industry and for ratepayers.[937] Without many specifics, Joint Parties suggested directing new employees to defined contribution plans and requiring executive contributions to the pension fund.

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[935] JCE at 427.

[936] DRA-15 at 8-9.

[937] Joint Parties' OB at 7.

In addition, Joint Parties propose that for SCE's executives and professionals with a pension that could exceed $100,000, SCE should create a voluntary pension plan that is "in line with ratepayer expectations."[938]

We do not adopt these recommendations because the parties did not develop the proposals in the proceeding record, nor establish that the Commission has legal authority to set SCE's pension and retirement policies.

However, SCE last made significant changes to its pension plan to reduce the long-term costs in 1999.[939] There have been many changes to public and private pension design in the intervening years. As part of its testimony in the next GRC, SCE shall provide a review of its pension policies, in light of current best practices and economic conditions, to support its rate recovery request for pension plan funding.

8.6.2. Post Retirement Benefits Other Than Pensions (PBOPS)

In addition to pension benefits, SCE offers other post-retirement benefits including medical, dental, vision, Medicare part B premium reimbursement, an Employee Assistance program, and term life insurance.

Following an investigation into the ratemaking treatment of PBOPs,[940] the Commission established conditions under which rate recovery would be allowed. For example, SCE established independent trusts to manage its PBOP

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938 *Id*. at 6.

939 SCE-06, Vol. 02 at 36.

940 I.90-07-037.

assets. In 2006, the Commission established a two-way balancing account for PBOP costs, which was continued in the 2009 GRC.[941]

For TY2012, SCE forecasts a total of $53.378 million for PBOP costs and recommends continuation of the balancing account.[942] These costs grew significantly in 2009 to $73.5 million, primarily due to a loss of value in plan assets as a result of the 2008 financial crisis.[943] The lower 2012 forecast costs are based on an outside actuarial valuation in 2009 of future plan liabilities. CCUE supports SCE's request, inclusive of its forecast of 1500 new FTEs.[944]

DRA estimates $50.99 million, a $2.39 million (4.5%) reduction to exclude the portion of SCE's forecast attributable to funding for new FTEs in this rate cycle.[945] Similar to its pension arguments, DRA complains that SCE did not provide requested updates to the PBOP actuarial report relied upon by SCE for its forecast. Although DRA states that an update would likely reduce SCE's forecast, it admits the ratepayers are protected by the balancing account.

Accordingly, the Commission finds reasonable and adopts SCE's forecast and continues the balancing account treatment of this amount. Additionally, SCE shall ensure that all federal reimbursements it receives for early retiree health costs, pursuant to the Early Retirement Reinsurance Program, are credited in the PBOP balancing account.[946]

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941 SCE-06, Vol. 02 at 76.

942 *Id.* at 75.

943 *Id*. at 79.

944 CCUE-1 at 19.

945 DRA-15 at 14; JCE at 430.

946 TURN-7 at 18.

8.6.3. Other Benefits

8.6.3.1. 401(k) Savings Plan: FERC 926

SCE's 401(k) Savings Plan is a defined contribution plan where SCE matches up to six percent of an employee's deferred base pay annually. Changes in the size of SCE's workforce, base pay, and plan participation rates are the primary drivers of recorded costs. On average, costs increased 7.2% annually from 2005 to 2009.

For TY2012, SCE's revised forecast is $87.477 million ($nominal) for plan costs, an $18.3 million (26%) increase over 2009 recorded costs of $69.206 million.[947] The forecast is a result of a "projection factor" of 2009 plan costs divided by 2009 total labor dollars, adjusted for labor escalation. SCE supports its forecast with the TCS as evidence of conforming with market rates for total compensation.

DRA recommends $29.731 million for 401(k) costs, utilizing a 2.73% contribution rate applied to SCE's 2009 labor costs, instead of SCE's 6.66%, to develop the projection factor. DRA derived the 2.73% rate by using a 3YA of average employer 401(k) contribution rates as recorded by the Profit Sharing Council of America for 2007-2009.[948] DRA also applied its own labor escalation rates.

CCUE views DRA's 66% reduction as an unjustified attempt to cut employee compensation below market rates by substituting the contribution rate of an unknown group of companies for SCE's actual contribution rates. In

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947 SCE-06, Vol. 02 at 48.

948 DRA-15 at 11; JCE at 428.

addition, states CCUE, DRA's labor escalation rates are flawed because DRA ignores both actual escalation rates and union contract provisions.

If the Commission does not adopt DRA's proposal, then TURN recommends using a five-year average of contributions (6.54%) as a percentage of SCE's labor costs, and application of DRA's labor escalation rates.[949] The result would be $5.219 million reduction to $82.258 million for 2012.[950] Use of SCE's labor escalation rates would result in a forecast of $82.959 million.

DRA's method does not reflect SCE's actual employee participation and contribution levels, or actual labor escalation rates. Labor costs have fluctuated from 2005 to 2009 and TURN's proposed 5YA provides a more reasonable and accurate forecast of 401(k) plan costs. We are not persuaded by SCE that TURN's approach misapplies the data. To the contrary, TURN applies SCE's method but substitutes five years for one year of data to derive the projection factor.

The Commission finds reasonable and adopts TURN's forecast of $82.959 million ($nominal) based on a 5YA projection factor and SCE's labor escalation rates.

8.6.3.2. Medical Programs: FERC 926

SCE's medical benefit programs cover employees and enrolled family members. Major drivers of plan costs include the number of enrolled employees, utilization, and medical inflation rates, as well as a number of program changes implemented to mitigate costs.[951]

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[949] TURN OB at 262; TURN-7 at 9.

[950] JCE at 803.

[951] SCE-06, Vol. 02 at 55.

In the 2009 GRC, the Commission adopted SCE's forecast of $115.9 million, which utilized a 10% escalation of recorded costs. However, out of concern for the significant increase, the Commission established a two-way balancing account for medical costs, including dental and vision expenses.[952] SCE's 2009 recorded costs in the Medical Program Balancing Account (MPBA) were $108.7 million.[953]

For TY2012, SCE's revised forecast for medical program costs is $165.936 million ($nominal).[954] SCE states that passage of comprehensive federal health care legislation[955] imposes new coverage requirements and, along with other industry factors, injects medical plan cost uncertainties. Based on health care trend surveys and its own research of large California-based employers, SCE projects a 10% annual trend rate for medical plan costs 2010-2014. CCUE supports SCE's forecast.

DRA recommends a $49.436 million (30%) reduction based on substitution of Global Insight's medical escalation rates of 4.9% in 2010 and 4.2% in 2011 and 2012. DRA's estimate of $116.5 million also excludes $10 million from the 2009 base year expense to reflect over-collection of health care costs in 2009 and 2010.[956] In support of its forecast, DRA provides several sources with varying results for a range of 2008-2010 medical escalation rates including 3% in 2010

[952] D.09-03-025 at 143.

[953] TURN-7 at 10.

[954] JCE at 429; SCE-06, Vol. 02 at 50.

[955] The Patient Protection and Affordable Care Act and the Health Care and Education Reconciliation Act of 2010.

[956] JCE at 429.

from Kaiser Family Foundation and 7% from the Towers Watson Health Care Cost Survey. It relies on Global Insight's forecast because SCE utilizes Global Insight elsewhere in the GRC to estimate escalation rates.

TURN forecasts $143.57 million in TY2012.[957] TURN contends SCE does not distinguish between per-employee cost increases and increases to employee count. SCE's 2009 recorded cost per employee is $6,391 ($nominal), but TURN thinks the 10% escalation rate that led to SCE's forecast equivalent of $8,507/per employee ($nominal) in the Test Year is excessive.[958] Instead, TURN utilizes DRA's escalation rates without removing the $10 million from 2009 base year expense. The result is a TY2012 per employee cost of $7,280.[959] For 2013 and 2014, TURN applies 4.4% escalation, the result of averaging Global Insight's 2010-2012 rates, to reach per employee costs of $7,585 and $7,904 respectively.[960]

SCE responds that use of the Global Insight health cost index is inappropriate because it includes other health costs, such as dental and vision, which have not been subject to the same cost pressures.[961] Other problems include higher costs in California, and the Global Insight index records zero costs for employers who drop medical coverage. Finally, SCE provided estimated 2011-2015 premium cost trend rates from its actual medical plan providers, all of which exceed 10%.[962]

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[957] *Id*. at 804.

[958] TURN-7 at 12.

[959] *Id*. at 11-12.

[960] TURN OB at 260

[961] SCE-21 at 62.

[962] *Id*. at 65.

We are persuaded that per-employee costs are a reasonable means to forecast medical costs in this rate cycle, but a 10% annual escalation is at the upper end of speculation. TURN's 2012 forecast of $143.570 million, 32% higher than SCE's 2009 recorded costs, is reasonable.[963] On the other hand, based on the range of cost trends presented, the Global Insight rates for 2013 and 2014 are low.

Therefore, for 2013 and 2014, the Commission finds it reasonable to apply a 7.5% escalation rate to the per-employee costs for an increase to $7,826 in 2013 and $8,413 in 2014. This is slightly higher than SCE's 5YA (2005-2009) of medical cost escalation rates.[964] When multiplied by SCE's estimated employee count of 19,171 for those years, the result is $150.032 million in 2013 and $161.286 million in 2014.

SCE seeks termination of the MPBA because it was not requested by any party. We continue to be concerned about the significant and uncertain cost increases forecast and the disparate views in supporting documentation. It is also unknown how reductions to SCE's requested spending adopted in this decision will impact SCE's 2012-2014 workforce headcount, a matter of discretion within SCE. Therefore, the balancing account treatment is continued for medical plan costs.

8.6.3.2.1. Dental and Vision Plans

For TY2012, SCE forecasts a total of $20.9 million ($nominal) for dental plan costs and $4.14 million for vision plan costs. SCE used 2010-2012 trend rates

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963 TURN-7 at 259.

964 SCE-06, Vol. 02 at 55.

of 3.3% for its dental plans and 2% for its vision plan costs. No party disputed these forecasts.[965]

Based upon the record, the Commission finds these forecast plan cost to be reasonable and adopts them.

8.6.3.3. Disability Programs

SCE provides a "comprehensive" short-term disability plan and a Long-Term Disability plan to its employees. SCE states the cost drivers include growth, salary increases, and changes in disability laws which increase program costs. Recorded costs have fluctuated since 2005, increasing 35% in 2009 to $24.5 million.

For TY2012, SCE forecasts a total of $31.424 million ($nominal).[966] The forecast uses LRY as a baseline to derive the projected number of eligible employees which SCE multiplies by the projected per employee cost. An increase of 1% per year was added to reflect the impact of legislative and regulatory changes requiring higher benefit amounts, assuming no corresponding increase to employee contributions.

DRA's TY2012 forecast is $22.234 million based on a 5YA of recorded costs and SCE's escalation rate.[967] TURN supports DRA's forecast but developed its own as an alternative. To reach its forecast of $29.668 million, TURN calculated the 5YA cost per employee of $1,360 ($2009), then applied a 1% escalation for legislative and regulatory changes, plus SCE's labor escalation rates.[968] DRA and

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[965] *Id.* at 68-72.

[966] JCE at 431.

[967] *Id.*

[968] *Id*. at 805.

TURN contend that 2009 is not the most reasonable baseline for SCE's forecast due to unusual claim activity.[969]

SCE argues that use of LRY, instead of a 5YA, is more appropriate because it includes more recent employee demographics, negotiated expansion of mental health benefits effective in 2010, and the 2009 elimination of certain workers' compensation offset payments.[970] There is little evidence to support these arguments, and we find that TURN's forecast based on per employee costs is a reasonable method to capture demographic changes in the workforce.

Therefore, the Commission finds reasonable and adopts $29.668 million ($2009) for TY2012.

8.6.3.4. Group Life Insurance

SCE seeks rate recovery for contributions to premiums for group employee life insurance, accidental death insurance, and business travel accident insurance. SCE generally makes contributions to provide a base level of coverage, and an option for employees to purchase additional coverage.

For TY2012, SCE's forecast is $1.834 million for the Group Life Insurance plan costs, more than twice 2009 recorded costs. The forecast is based on a projected number of eligible employees multiplied by the projected average per employee cost, including a 60% escalation rate in 2010 due to a significant increase in the SCE-provided basic benefit for both life insurance and Accidental Death and Dismemberment coverage.[971]

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[969] DRA-15 at 15; TURN OB at 264-265.

[970] SCE-06, Vol. 02 at 83-88.

[971] *Id*. at 89-91.

DRA calls SCE's increase in benefits in this economy, at ratepayers expense, "unconscionable" and recommends exclusion of the 60% escalation rate for 2010.[972] The result is a forecast of $940,000, a 49% decrease to SCE's forecast. SCE responds that the increase is the result of program changes arising from collective bargain agreements that SCE applied to other employees, and the increased coverage is in line with the marketplace.[973]

This cost category again highlights the difference between what compensation may be market competitive, yet may not be reasonable for rate recovery. SCE agreed to pay for new employee benefits with no accountability to the ratepayers who are expected to freely fund them. SCE chose to extend collectively bargained benefits to other employees, resulting in a doubling of plan costs.

SCE did not demonstrate that these expanded benefits are necessary for the delivery of safe and reliable electric service.

Therefore, the Commission finds it reasonable and adopts DRA's TY2012 forecast of $940,000.

8.6.3.5. Miscellaneous Benefit Programs

Miscellaneous Benefit programs include a 25% discount on electric service, ACE awards, commuter vouchers, corporate relocation, preventive health, and educational reimbursement.

For TY2012, SCE forecasts a total of $9.86 million ($2009) for these programs, a 25% increase from 2009, but provides no breakdown by cost center.

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[972] DRA-15 at 16.

[973] SCE-21 at 71.

As discussed above, DRA wants costs for ACE awards to be disallowed, but also wants removal of ACE costs for the period of 2005-2009 which impacted 2012 forecasts. DRA proposes to accomplish this by removing $7.015 million from the forecast of Account 926. Pursuant to our discussion in Section 8.5, we disallow 2012 ACE award costs, but have addressed the impact of historic ACE costs within the business unit forecasts.

DRA also asks the Commission to disallow costs for SCE's preventive health program because it is duplicative of other funded medical programs, and for work/life programs (e.g., assistance with child and elder care) on the grounds they are not necessary to operate the utility, nor do they provide a clear and identifiable ratepayer benefit.[974]

We are not persuaded that these programs improve safe and reliable electric service or provide ratepayer value by mitigating future medical costs, motivating healthy lifestyle choices, and helping employees balance family and work life.

Accordingly, for TY2012, the Commission finds reasonable and adopts $2.133 million, which reflects reductions of $6.9 million for forecast ACE awards costs, and $827,000 for preventive health and work/life programs.[975]

8.6.3.6. Executive Benefits

SCE pays 100% of the costs of the Executive Benefits program which includes the Supplemental Executive Retirement Plan (SERP) and Survivor and

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974 DRA-15 at 19.

975 JCE at 433.

Disability Benefits plan (SDP). In the 2009 GRC, the Commission allowed rate recovery for 50% of SCE's forecast program costs.[976]

According to SCE, the purpose of SERP is to provide benefits executives cannot receive through the qualified SCE pension plan due to Internal Revenue Code (IRC) limits on covered compensation and payable benefits from qualified plans.[977] The SDP delivers a benefit only when a senior executive dies in-service.[978]

For TY2012, SCE forecasts a total of $16.814 million, a 14.6% increase over 2009 recorded costs of $14.67 million.[979] SCE does not break down the costs between programs, but states the increase is due to an expected increase in the number of eligible executives.

DRA recommends zero funding for these enhanced benefit programs for a select group of about 222 current and former executives.[980] DRA's position is that ratepayers should not be required to bear the costs of exclusive supplemental benefits for executives that exceed what is authorized in the tax code or what is offered to other SCE employees.

SCE responds that these supplemental benefits are a key part of the total compensation package which is at market. However, SCE did not establish it is an essential benefit to recruit executives. Only about one-fourth of the companies in the Hewitt database provide a regular pension, 401(k) plan, <u>and</u> a

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[976] D.09-03-025 at 146.

[977] SCE-06, Vol. 02 at 99.

[978] *Id*. at 100.

[979] JCE at 434.

[980] SCE-33.

supplemental retirement plan for executives, even though the majority of comparator companies do so.[981]

As we did in the 2009 GRC, we find that these benefits are linked to the amount of total compensation awarded to an executive, including performance incentives closely linked to share price of the parent company. Thus, not all of these costs are eligible for rate recovery.

Therefore, the Commission finds reasonable and adopts $8.4 million for this category of expense, or 50% of SCE's forecast.

SCE asks that if the Commission makes a disallowance for this category that there be a commensurate reduction to the Unfunded Pension Reserve offset to rate base, consistent with the treatment in the 2009 GRC.[982] We agree. The Commission allows $700.66 million of the $784.264 million O&M request for HR, Benefits and Other Compensation.

9. Administrative and General (A&G)

The forecast costs reviewed here are limited to the O&M, capitalized software and capitalized expenses not separately presented and justified in individual department or business unit A&G forecasts.

SCE forecasts $309.516 million ($2009) in TY2012 A&G expenses, a 30.6% increase over 2009 recorded expenses of $236.94 million. SCE also requests $19.157 for 2010-2012 capital expenditures related to International Financial reporting Standards (IFRS), Electronic Discovery, and the Enterprise Compliance Management System.

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[981] SCE-32.

[982] D.09-03-025 at 271.

DRA recommends a $76.897 million (24.8%) reduction to O&M, much of which is the result of using average historic costs as the basis of the forecasts. DRA opposes any funding for two of the capital projects, and TURN opposes any funding for the third. TURN also seeks reductions for some specific cost categories.

As discussed below, we adopt $275.937 million in total TY2012 O&M expenses and $16.257 million for 2010-2012 capital expenditures.

9.1. Financial Organizations: FERC 920/921, 923, 926, 930

The Financial Organizations forecast a total of $79.290 million in TY2012 O&M, an increase of $7.8 million (10.4%) over 2009 spending. SCE attributes the increase mostly to compliance costs related to an expected change from U.S. Generally Accepted Accounting Principles to IFRS, and various increased service and transaction fees.[983] SCE also requests $14.5 million for a capitalized software project beginning in 2012 to comply with IFRS.

9.1.1. Controller: FERC 920/921, 923, 926

The Controller's organization forecasts a total of $51.76 million for TY2012 O&M, a $1.935 million increase over 2009 recorded costs due to $4.833 million to conform to IFRS. The forecast covers three accounts: $19.549 million in Accounts 920/921, $31.783 million in Account 923 (Outside Services), and $428,000 in Account 926 (Benefits Accounting).

Historic costs for Accounts 920/921 peaked in 2009 as a result of a reorganization and return of staff assigned to the ERP project, including six

[983] SCE-07, Vol. 01 at 11.

positions authorized in the 2009 GRC. SCE makes a $675,000 reduction to 2009 costs to account for organizational changes.

DRA's total forecast is $35.257million, a $16.5 million (31.9%) reduction mostly to Outside Services.[984] For Accounts 920/921, DRA utilized a 5YA based on its view that labor and non-labor costs have historically varied to reach its forecast of $18.571 million, a $978,000 reduction.[985]

We find that use of a 5YA is a reasonable forecast method for routine activities where costs have historically varied and SCE expects them to again trend downward between 2009 and 2012.

For Account 923, SCE forecast $31.783 million for outside tax and accounting services which it claims are necessary to maintain compliance with tax law. SCE supports the 40% increase since 2008 as cost-effective and beneficial by sustaining tax deductions and avoiding penalties and interest. In reflection of an upward trend, the forecast is based on LRY, plus IFRS transition costs of $4.833 million in 2012 ($14.5 million total for 2012-2014) and a decrease of $2.2 million in estimated future services.[986]

Based on a 5YA, DRA recommends a reduction of $15.525 million, including removal of certain tax consulting costs from the record period and rejection of costs associated with the IFRS capital project.[987] DRA argues most tax consulting services are non-recurring and primarily benefit shareholders because tax expense for ratemaking is static and consulting expertise is more

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[984] DRA-12 at 11.

[985] JCE at 435.

[986] SCE-07, Vol. 01 at 22.

[987] JCE at 436.

relevant to the complicated aspects of post-GRC taxation reflected in the fluctuating effective rates found at the utility and holding company level.[988]

In addition, states DRA, work arising from audits or avoided penalties and interest relate to tax returns, not the tax expense forecast for ratemaking. If an audit results in a lower tax rate, then SCE can offset costs rather than forecast what may be non-recurring costs. Finally, DRA asserts that SCE's in-house tax staff should be able to handle routine tax matters such as historic deductions and forecasting for ratemaking.

SCE argues DRA oversimplifies the tax work required for a GRC, and is mistaken to distinguish costs for consultants. Furthermore, SCE contends that sustained tax positions benefit ratepayers in future years.[989]

The Tax Department's functions (tax modeling, legal research, following changes in tax law, return filing, audit defense, etc.) are essential to the company's compliance with existing tax laws. However, SCE did not adequately explain the trend of substantial increases in Outside Services (28% in 2009) when many activities are routine and its own tax professionals, both lawyers and accountants, have a duty to keep current with applicable laws and ratepayers fund continuing education.

Although Account 923 historic costs have trended upward since 2006, we are persuaded that tax-related outside services are included which primarily benefit shareholders of SCE and EIX by lowering effective rates below the rates used for forecasting purposes. Thus, SCE's forecast is excessive and should be

[988] DRA-12C at 13-14.

[989] SCE-22, Vol. 01 at 39.

reduced to exclude "as-needed" non-recurring and effective tax rate consulting costs.

In the absence of an accurate apportionment, we find it reasonable to instead adopt a 5YA of recorded costs, $22.198 million. We also find that costs related to implementation of as-yet unadopted IFRS standards are premature.

Therefore, for TY2012, the Commission finds it reasonable to adopt for Accounts 920/921 a total of $18.571 million ($15.906 million Labor and $2.665 million Non-labor), and $22.198 million for Account 923. No party disputes SCE's forecast for Account 926. Based on a review of the record, the Commission finds reasonable and adopts SCE's forecast of $428,000. The combined TY2012 total is $41.197 million, a 20.4% reduction.

9.1.1.1. Capital Expenditures: IFRS Project

SCE is requesting $14.5 million in 2012-2013 capital expenditures ($2.9 million in 2012) for a software project to comply with IFRS. SCE expects the Securities and Exchange Commission (SEC) to incorporate IFRS standards for domestic reporting by 2015 or 2016, which would mean that comparative financial statements would be required in 2013 and 2014. The forecast is based on a third-party survey of similar-sized companies which yielded estimates of conversion costs as 0.298% of annual revenue.[990]

DRA recommends zero funding for the project because the necessity is speculative and the costs are not supported.[991] DRA observes that SCE added a

[990] SCE-07, Vol. 01 at 49.

[991] DRA OB at 312-313.

50% factor to the calculation "for technology costs" due to extensive testing it anticipates to assess changes across the ERP and SAP systems.[992]

We agree with DRA that neither the necessity of the project nor the costs are adequately supported by SCE. The record indicates that the SEC is supportive of international standards but has not made a decision to adopt IFRS, nor if SEC did adopt them, when it would require U.S. companies to implement them. No actual vendor cost information is presented, the 50% add-on is highly speculative, and, according to SCE, it is largely the result of other new software systems previously adopted by SCE which make integration particularly challenging.

Accordingly, the Commission declines to adopt this forecast. If the SEC acts, then SCE may seek recovery in the next GRC and include supporting documentation of actual costs, and a description of whether SCE identified any possible efficiencies and opportunities for streamlining integration costs.

9.1.2. Audit Services: FERC 920/921

For TY2012, Audit Services requests $10.271 million, an increase of $1.165 million over 2009 recorded expenses, of which $629,000 in labor expense is to fill five vacancies and hire two FTEs as IT auditors. SCE claims it needs all seven employees due to increased work from SmartConnect, NERC/CIP, energy trading, and new environmental regulations. Other expenses include hiring outside expert audit trainers and travel costs associated with non-utility affiliated company audits.[993]

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[992] SCE-07, Vol. 01 at 49.

[993] SCE-07, Vol. 01 at 24.

DRA uses a 5YA to calculate both labor and non-labor costs to arrive at a forecast of $9.033 million, 12% less than SCE.[994] DRA argues that SCE did not justify its need for seven more employees, stating that SCE's staff was sufficient during the record period and the actual estimated work of the new auditors is vague.

We agree that a 5YA is reasonable to establish a base forecast because these are routine activities and there have been modest historic fluctuations. SCE has identified particular audits it expects to conduct and training it expects to deliver to employees during the rate cycle but does not contrast this with any data to establish the work cannot be accomplished by existing staff. Although we agree that some new activities, such as SmartConnect and NERC/CIP additions, could add to the audit burden, it is reasonable, given the sparse record, to allow only 50% of the requested positions.

Accordingly, the Commission finds it reasonable and adopts $9.616 million ($9.033 + $0.583 million) for TY2012.

9.1.3. Treasurer: FERC 920/921, 930

For TY2012, SCE forecasts a total of $13.327 million, a $3.8 million increase over 2009 recorded expenses, primarily related to higher banking and financing fees.[995]

In Accounts 920/921, SCE forecasts $5.475 million ($4.944 million Labor and $531,000 Non-labor) based on LRY, plus an increase of $517,000 to fill two

[994] JCE at 437.

[995] SCE-07, Vol. 01 at 29; JCE at 438 fn1 (SCE reduced its request by $340,000).

vacancies and add three FTEs to support the capital investment program.[996] The Commission rejected SCE's similar labor request in the 2009 GRC for failure to quantify the extent to which these activities will rely on additional staff.[997]

DRA uses a 5YA (2005-2009) to forecast $4.494 million for Accounts 920/921 because historic costs have fluctuated.[998] DRA argues that SCE did not justify the five positions, providing no explanation of labor hours to work or ratio of people to projects. Therefore, DRA asks the Commission to reject it as it did in 2009.

We agree with DRA that a 5YA average is a reasonable basis of forecast for both Accounts, and the requested positions are not sufficiently justified as beyond the capability of existing staff. Accordingly, the Commission rejects SCE's requested increases of $485,000 in labor and $32,000 in non-labor, and finds reasonable and adopts DRA's TY2012 forecast of $4.494 million.

Costs recorded in Account 930 include bank service operating fees, credit line fees, and bond-related fees. SCE's revised forecast is $7.852 million, a 72% increase over 2009, although historic costs trended downward from 2006 to 2009.[999] The largest increase of $3 million is for higher credit line fees which SCE assumes will apply when it replaces $2.9 billion in expiring credit facilities in 2012.[1000]

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[996] JCE at 438.

[997] D.09-03-025 at 163.

[998] DRA OB at 315.

[999] JCE at 439 (SCE agreed to TURN's request to remove $340,000 from bank fees pursuant to a methodology dispute).

[1000] SCE-07, Vol. 01 at 37.

DRA states that minor historical fluctuations continued in 2010 recorded costs of $4.9 million and recommends adoption of a 5YA (2006-2010) forecast of $4.924 million for Account 930. TURN supports SCE's $340,000 reduction to bank fees reflected in SCE's revised request.

SCE established that it will need to renew credit lines in 2012, and the amount will increase to support SCE's capital investment program to replace infrastructure and continue implementation of smart grid systems. SCE contends that historical fees are not a good predictor of future costs because credit line fee rates have increased substantially due to the 2008 financial market crisis and the resulting dramatic rise in the cost of bank credit.[1001] However, SCE did not explain how it arrived at its estimated fees.

Accordingly, the Commission finds it reasonable to adopt DRA's 5YA as a base year forecast, plus 50% of SCE's estimated credit line fee increases, or $1.522 million, for a total of $6.446 million. This result is a 41% increase over 2009 spending.

9.1.4. Tax Department: FERC 920/921

The Tax Department requests a total of $3.932 million for TY2012 expenses, an increase of $567,000 over 2009 recorded costs. The forecast is based on LRY, plus an increase to fill two vacancies and add two FTEs to support compliance with new IRS and state tax laws. In 2009, the Commission authorized four new positions, and SCE still exceeded authorized spending by $425,000.[1002]

[1001] SCE-22, Vol. 01 at 20.

[1002] D.09-03-025 at 164-165.

DRA recommends a total of $2.942 million based on a 5YA of labor and non-labor costs, and rejection of the two new positions because SCE provided no quantitative justification.[1003] DRA's criticisms do not address SCE's response to use of LRY or its explanation of why a quantitative approach is not appropriate for estimating the time needed for various Tax Department functions.

We find some merit in the general description of expected increased workload, but SCE did not explain why it needed four FTEs, after two were added in 2009 and SCE's spending exceeded authorized funds. Instead we are persuaded that SCE needs to fill its two vacancies but do not find that it sufficiently justified the necessity of two new FTEs.

Accordingly, the Commission finds reasonable and adopts $3.737 million for this account, the sum of 2009 recorded expenses plus $335,000 in labor and $37,000 non-labor, an amount equivalent to the cost of two positions.

9.2. Risk Control: FERC 920/921, 923

The Risk Control Department maintains and operates controls over the procurement activities in the Power Procurement Business Unit (PPBU) and works to mitigate financial exposure.

For TY2012, the Risk Control Department forecasts a total of $6.055 million for O&M, an increase of $715,000 (13.4%) over 2009 recorded costs.[1004] Of that amount, SCE asks for $5.4 million in Accounts 920/921 based on LRY, plus the costs to fill five vacancies and add one FTE. SCE claims it needs the staff due to

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1003 JCE at 440.

1004 SCE-07, Vol. 01 at 56.

changes in the energy markets that increase the complexity and work to comply with regulatory requests and maintain oversight of procurement activities.

DRA recommends $3.847 million, the 5YA, based on the mistaken view that labor and total costs fluctuated historically when in fact they have increased annually.[1005] DRA also argues that SCE did not justify its additional labor request with generalizations about changes in the energy markets, but provided no explanation as to why existing staff cannot handle these tasks.

We are troubled by the fact that SCE ignored the Commission's express direction in the 2009 GRC where we stated, "We authorize [Risk Control] to increase its Full-Time Equivalent employees up to 25, but we reject SCE's proposal to add 15 additional staff."[1006] The extra staffing was rejected as unjustified in light of declining productivity. Yet, SCE went ahead and hired the 15 extra staff by the end of 2009.[1007]

Based on the unauthorized growth of staff to 39 FTEs and two supplemental employees, Risk Control should be able to handle anticipated activities with its existing work force.

Accordingly, the Commission finds reasonable and adopts SCE's 2009 recorded expenses for Accounts 920/921, $4.686 million ($4.29 million Labor and $396,000 Non-labor).[1008]

SCE also forecasts $$654,000 for Account 923 in TY2012 for outside consultants to provide expert views on emerging energy issues. No party

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[1005] *Id.* at 67.

[1006] D.09-03-025 at 172.

[1007] SCE-07, Vol. 01 at 70.

[1008] SCE-07, Vol. 01 at 67; JCE at 441.

disputes them. Based upon a review of the record, the Commission finds SCE's forecast to be reasonable and adopts it.

9.3. Law Department: FERC 920/921, 923, 928, 930

The Law Department forecasts a total of $46.055 million for TY 2012 for Law and Corporate Governance Accounts, and $4.882 million for a capital project relating to electronic discovery. DRA recommends a total reduction of $8.116 million.

9.3.1. In-House Legal Resources: FERC 920/921

For these Accounts, SCE's labor forecast is $24.682 million, based on LRY, escalated at an annual rate of 2.43%, plus $1.716 million for nine additional attorneys and six support staff. Non-labor of $4.504 million is the result of computing an 18.2% ratio of non-labor expenses to labor expenses in 2009 and application of the ratio to 2012 forecast labor expenses. The total request is $29.186 million.[1009]

The number of attorneys has grown since 2005 from 82 to 93 in 2009.[1010] SCE claims the workload growth is due to new legal requirements, particularly related to renewable transmission projects, expanded energy regulation compliance activities, and an uptick in commercial litigation.[1011] In the 2009 GRC, the Commission rejected SCE's $2.5 million request for 31 additional

[1009] JCE at 442.

[1010] SCE-07, Vol. 02 at 13.

[1011] *Id.* at 3-5.

employees because SCE did not justify the need or the costs.[1012] It is unknown how many were hired anyway.

DRA accepts 2009 recorded expenses of $27.157 million, but recommends removal of all costs associated with the requested 15 new employees due to a lack of justification.[1013] SCE disputes the lack of support for its labor request citing extensive direct and rebuttal testimony describing "unprecedented" volumes of work requiring substantial legal assistance. DRA contends SCE's response lacks quantitative specifics.

SCE responds that it has provided alternate workload estimates for permitting activities, and documented additional workload in other areas. SCE's narrative support for new positions identifies six attorneys for various licensing and permitting projects arising from SCE's robust capital investment, and one attorney each for interconnection requests, commercial litigation, and resource policy and planning.

However, we are not persuaded by general statements that SCE needs all of the requested positions. Elsewhere in this decision, we have reduced TDBU capital spending by 9.4%, found SCE's forecast of intergeneration requests excessive, and that SCE has identified a significant number of capital projects which it claims are exempt from regulatory review.

Therefore, the Commission finds reasonable and adopts $27.833 million, the total of 2009 expenses plus estimated costs equivalent to one-third of the requested additional staff: $572,000 Labor, and $104,000 Non-labor.

[1012] D.09-03-025 at 149-150.

[1013] DRA-12 at 26.

9.3.2. Outside Counsel: FERC 923, 928

FERC Account 928 is used to record outside counsel expenses related to regulatory matters, all other outside counsel expenses are recorded to Account 923. SCE states outside counsel fees increased 12.4% from 2005 to 2009, although combined recorded costs fluctuated including a 2007 low of $6.3 million (2009).

For TY2012, SCE's revised forecast totals $13.039 million: $11.128 million for Account 923 (based on LRY) and $1.911 million for Account 928 (based on 4YA).[1014] This is a 1% increase over combined 2009 recorded expenses. To develop its revised forecasts, SCE removed costs for certain non-utility lobbying and litigation costs, and adjusted for a minor accounting error.[1015] Some details of these forecasts are confidential.

DRA recommends a $4.492 million reduction for estimated costs related to various litigation matters and certain fee arrangements on the grounds that ratepayers do not receive incremental benefits to justify funding.[1016] DRA has aggregated recorded costs in five categories and removed them from 2009 recorded costs for both Accounts 923 and 928 to forecast 2012 expenses. SCE disputes some of DRA's calculations.

First, DRA objects to rate recovery of discretionary "bonuses" paid to outside firms retained on a long-term basis. SCE explains that the firms' fees are actually discounted 5%-15%, and the firms can earn some of the discount based on performance, providing an important incentive for excellence. We agree it

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1014 SCE-22, Vol. 02 at 7.

1015 *Id*. at 9, 11.

1016 DRA OB at 322-324.

may be reasonable to provide incentives to outside counsel to motivate them to achieve good results. Combined with reduced fees, it may result in lower costs and revenue requirement. Therefore, we find that these are ordinary recoverable business costs. However, to receive recovery in future GRCs, SCE shall provide information to support that it is obtaining base fees at discount compared to market.

DRA also requests removal of litigation costs related to what it calls ten employment and discrimination cases settled in 2006-2009, from both recorded costs and the 2012 forecast on the grounds that FERC Accounting Release-12 (AR-12) provides:

> …that expenditures made by the utility, resulting from employment practices that were found to be discriminatory by a judicial or administrative decree or that were the result of a compromise settlement…should not be considered as just and reasonable charges to utility operations.[1017]

SCE has repeatedly asked the Commission to change its policy of following AR-12 as to settlements where there is no finding of fault or punitive damages because it is unfair. SCE argues there has been an increase in claims from terminated employees without any evidentiary basis and settlement becomes a cost-risk calculation.[1018] SCE also argued that four of the ten cases contained no allegations of discriminatory acts. [1019]

As to settlements of discrimination claims, we decline to alter our longstanding policy on this issue because the risks of a potentially adverse

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1017 *Id*. at 323.

1018 JCE at 447.

1019 SCE-22 at 10.

verdict still drive any settlement. Unchecked ratepayer recovery could result in a loss of vigilance in preventing discriminatory practices. SCE provided evidence that one of the ten cases did not involve employment discrimination claims. Therefore, we allow 10% of the portion of the forecast attributable to this category.

SCE removed 60% of the costs of its Washington D.C. office. Despite DRA's argument that no costs of the Washington D.C. office should be borne by ratepayers, SCE contends the remaining costs relate to the Tehachapi Wind Storage Project and the Irvine Smart Grid Demonstration Project and provide ratepayer benefit.[1020] We agree.

Finally, DRA seeks removal of all 2005-2009 litigation costs from SCE's Navajo Nation Royalty litigation on the grounds the expenses are non-recurring. DRA argues the costs are unique because it is a ten-year legal case involving a coal-supply royalty dispute associated with the retired Mohave coal-fired plant.[1021]

We are not persuaded the costs are representative of future litigation, as SCE argues, simply because disputes could arise over third-party fuel supplies. The Navajo royalty claims render this litigation atypically complex. However, we agree with SCE that DRA's adjustment mistakenly removed total costs instead of SCE's pro rata share. Because SCE used LRY, we remove SCE's 2009 litigation costs for forecasting purposes.[1022]

[1020] JCE at 445.

[1021] DRA-22 at 14-16.

[1022] JCE at 444.

Accordingly, after accepting SCE's revised forecasts and removing costs discussed above, the Commission finds it reasonable to reduce DRA's adjustment to $2.168 million, and to adopt as follows: $9.505 million in Account 923 and $1.911 million in Account 928.

9.3.3. Corporate Governance and Miscellaneous Expenses: FERC 920/921, 930

Corporate Governance supports the SCE and EIX boards of directors, including compliance with corporate and securities laws. Allocated EIX costs are credited to SCE monthly. SCE states activities have increased due to increased legal requirements and public focus on governance.

For Accounts 920/921, SCE forecasts a total of $704,000 in Accounts 920/921 based on LRY.[1023] No party disputes this forecast. Based on a review of the record, the Commission finds reasonable and adopts SCE's forecast.

SCE's TY2012 revised request is $3.126 million in Account 930 which records fees and expenses paid to members of SCE's board of directors and other associated corporate costs.[1024] The forecast is based on LRY. SCE relies on analyses conducted by a third party compensation consultant for the EIX board in 2009 and 2010 to conclude that the non-employee directors' compensation is reasonable.[1025] TURN withdrew its request for an audit of allocation credits after review of additional SCE information.[1026]

[1023] SCE-07, Vol. 02 at 24.

[1024] JCE at 449.

[1025] SCE-07, Vol. 02 at 28, fn. 39.

[1026] TURN OB at 270; SCE-22, Vol. 02 at 19.

DRA recommends $2.497 million in Account 930 based on its view that ratepayers should not fund supplemental benefits and stock-based compensation for these directors.[1027] SCE's response is that the law requires a corporate board and related expenses are a cost of doing business.

Whether an expense is part of SCE's business model is a separate question from whether the costs are necessary for the delivery of electric service. Similar to our decision declining rate recovery for stock-based compensation for executives, we decline to allow rate recovery for these benefits as to non-employee directors.

Accordingly, the Commission finds reasonable and adopts DRA's TY2012 forecast of $2.497 million for this Account.

9.3.4. Capital Expenditures – Electronic Discovery Project

SCE states its current process for responding to electronic discovery requests is labor intensive, presents technological challenges, and requires outside counsel and consultants. SCE proposes a new automated in-house solution in order to improve compliance, accuracy and efficiency.

For the two phases of this new project, SCE requests a total of $4.882 million: $58,000 in 2010, $1.584 million in 2011, and $3.240 million in 2012.[1028] The forecast is based on a vendor estimate following a Request for Information.

DRA recommends no funding on the basis that SCE has not sufficiently justified the project and cost estimates.

[1027] JCE at 449.

[1028] JCE at 672.

SCE has increasing amounts of data and, going forward, it will become more complex. The Commission expects SCE to be able to timely retrieve necessary information upon our request, in addition to responding to litigation discovery. We are persuaded that SCE reviewed several sources to develop its cost estimate and that the project should result in efficiencies.

Therefore, the Commission finds reasonable and adopts SCE's 2010-2012 request.

9.4. Claims: FERC 920/921, 924, 925

The Claims Division forecasts a total of $50.289 million for all accounts related to Claims activities.[1029] The amounts in dispute relate only to Account 925. Based on the record, the Commission finds reasonable and adopts SCE's forecasts of $3.153 million in Accounts 920/921 for salaries and expenses of Claims personnel and $127,000 in Account 924 for costs related to property insurance activities.[1030]

For Account 925, SCE's forecast of $47 million is comprised of $4.459 million for legal services and litigation costs associated with injuries and damage claims, and $42.550 million for the Claims Reserve.[1031] Historic reserve costs vary widely, with expenses tripling from 2008 to 2009, then increasing another 22% in SCE's 2012 forecast.

DRA's total TY2012 forecast for Account 925 is $41.696 million, including removal of all historic litigation costs associated with the Happy Camp fire

[1029] SCE-07, Vol. 02 at 34.

[1030] *Id*. at 38.

[1031] *See*, SCE-27 at 19. (Some of the information relates to settlements and SCE asserts attorney-client privilege to prevent public disclosure.)

because it views the damages as highly extraordinary, infrequent, and unpredictable within the rate cycle.[1032] In addition, DRA states the Claims Reserve should be based on 2009 recorded expenses of $34.882 million, subject to additional reductions related to the Happy Camp fire and the Navajo Nation Royalty litigation.

SCE disputes DRA's view that costs for "large" fires are non-recurring and should not be routinely included when forecasting legal costs. SCE's estimate is based on trended expenses, and it is certain that fires will occur within SCE's service territory, even if when and where are unknown. SCE criticizes DRA for providing no standard for distinguishing between "large" and "small" fires, nor explaining how SCE could recover the costs of "large" fires excluded from forecasts.

Rate recovery of costs associated with third party wildfire damage claims is not fully settled. There has not yet been any determination of recovery or finding of whether or not SCE has any error or fault in connection with the Happy Camp fire. Thus, we agree that litigation costs are reasonably included in SCE's $4.459 million forecast. However, in the event SCE is later found to be in error or fault, the Commission may take appropriate action to restore these funds to the ratepayers.

Regarding its Claim Reserve forecast, SCE argues that successful litigation strategies of "inverse condemnation" are restricting SCE's access to insurance and leading more wildfire cases to trial.[1033] SCE's forecast is a "backcast" that

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[1032] DRA-12R at 31.

[1033] SCE-22, Vol. 02 at 28.

applies current insurance coverage to historical claims.[1034] DRA objects to the "backcast" method as retroactively increasing historic costs, particularly for 2007 (a high-fire year), and criticizes SCE for being slow to acquire additional insurance. We agree that SCE's "backcast" method is not probative of future claims, particularly since the Commission has not determined what rate recovery will be allowed, if any.

In January 2012, SCE withdrew from a joint utility application seeking rate recovery of third party claims arising from wildfires which exceed insurance coverage.[1035] The Assigned Commissioner Ruling also terminated SCE's Wildfire Memorandum Account.[1036] Other open proceedings have yet to address SCE's liability in relation to past wildfires.[1037]

The swiftly increasing cost of wildfire insurance coverage is a factor in our consideration of this request. In Section 9.10.2, we authorize rate recovery for a $39.6 million increase in wildfire liability premium costs between 2009 and 2012. The coverage includes a substantial deductible.

We are concerned that if ratepayers also backstop 100% of uncovered wildfire claims in the Claims Reserve, SCE lacks incentive to maintain or improve the safety of their operations. SCE's shareholders are also relieved of any exposure for SCE's acts or omissions because the deep pocket of the ratepayers would leave no mark on the realized rate of return.

1034 *Id*. at 28-29.

1035 A.09-08-020.

1036 ACR issued January 10, 2012.

1037 E.g., R.08-11-005, I.09-01-018.

Therefore, we decline to adopt SCE's forecast. In 2009, SCE's reserve forecast was based on a 5YA, but we reduced it to 2006 recorded costs due to insufficient support.[1038] Here, we find that 2009 recorded costs provide a reasonable basis to contain costs in the rate cycle, and decline to pick and choose certain wildfire costs for exclusion.

Accordingly, the Commission finds it reasonable to adopt DRA's forecast utilizing the 2009 recorded costs for the Claims Reserve of $34.882 million.[1039]

9.4.1. Claims Reserve – Navajo Nation Royalty Litigation

DRA recommends removal of any claims reserve impact of the Navajo Nation litigation because it views the case and costs to be unique.[1040] Moreover, DRA criticizes SCE for asserting attorney-client privilege as to estimated settlement amounts at issue for this and the Happy Camp wildfire.

In forecasting claims reserve for TY2012, SCE relied on its trend of litigation expenses over the five-year period from 2005-2009, adjusted for anticipated cost increases expected as a result of changes in SCE's insurance coverage for wildfires. SCE presented a vigorous defense of attorney-client privilege as to anticipated settlement parameters and argued that the privilege does not diminish DRA's ability to probe the reasonableness of SCE's claims reserve.[1041] We agree with SCE's position as to this particular expense.

[1038] D.09-03-025 at 153-154.

[1039] JCE at 451.

[1040] DRA-22 at 14.

[1041] SCE-27 at 20, 28.

Although we found outside counsel costs of the Navajo Nation litigation were not indicative of future outside counsel costs, we decline to make a specific adjustment to the reserve forecast. Instead, as discussed above, we view the 2009 recorded amount, the highest in five years, to be sufficient.

Therefore, the Commission finds it reasonable to make no further adjustments to the Claims Reserve amount set forth above.

9.5. Workers' Compensation: FERC 925

SCE's total forecast of $22.282 million covers expenses for staff of $7.183 million ($4.128 million Labor and $3.055 million Non-labor) and $15.099 million for reserves. DRA recommends a $2.222 million reduction while TURN would remove $1.699 million.

SCE's labor forecast is $578,000 more than 2009 due to the proposed addition of five claims representatives (to 25) and three support staff to handle increased complexity and volume of work. According to SCE, its representatives maintain a case load of about 152 cases, higher than the industry standard.[1042] SCE states it needs to reduce caseload to about 115-120 cases/representative.

DRA recommends a total of $6.313 million for staff costs, based on a 5YA and disallowance of additional staff, resulting in a combined reduction of $870,000.[1043] TURN proposes a reduction of $347,000 (60%) of SCE's incremental request, allowing two claims representatives already hired and 1.2 support staff.[1044]

[1042] SCE-07, Vol. 02 at 55.

[1043] JCE at 452.

[1044] *Id*. at 806.

In the 2009 GRC, SCE asked for seven new claims representatives based on the same arguments presented here. After the Commission authorized four new representatives, SCE only hired two, at the end of 2010.[1045] From this, TURN concludes that SCE does not really need five more claims representatives.

TURN also criticizes SCE's use of one high claim month (June 2010), rather than an annual average, to establish caseload, and claims SCE has mischaracterized the claims data. In addition, the industry standard is 138 cases/representative which is higher than SCE's goal of 120 cases.[1046]

We find TURN's forecast to be more reasonable based on annual claims data and actual industry caseload standards. Therefore, the Commission adopts $6.836 million ($3.781 million Labor and $3.055 million Non-labor).

9.5.1. Workers Compensation Claims Reserve: FERC 925

SCE's Reserve forecast of $15.099 million is a 9.8% increase over 2009, despite a five-year (2005-2009) general downward trend in costs.

SCE used a 3YA in order to exclude regulatory changes that drove high costs in 2005.

DRA recommends use of LRY 2009 recorded expenses of $13.747 million in recognition of changes in the law which are lowering costs.[1047] TURN supports either DRA's forecast, or a 4YA of $13.97 million.[1048]

[1045] TURN OB at 272.

[1046] *Id*. at 275.

[1047] DRA-12 at 36.

[1048] TURN OB at 276.

SCE's reliance on pending workers compensation litigation is too speculative to support reversal of the downward trend in reserve expenses. We also find that based on the downward trend in costs, that LRY is a reasonable method to forecast TY2012 costs.

Accordingly, the Commission finds reasonable and adopts DRA's forecast of $13.747 million for TY2012 Claims Reserve.[1049]

9.6. Ethics and Compliance: FERC 920/921, 923

For TY2012, SCE forecasts a total of $3.1 million in all accounts. SCE uses LRY as the basis for its forecast plus incremental estimated costs. SCE failed to spend over 25% of the$2.112 million authorized in the 2009 GRC.[1050]

SCE requests $2.348 million in Accounts 920/921, a 53.2% increase over 2009, due to a $723,000 increase in labor costs and a corresponding increase of $93,000 in expenses. As of 2009, the department had 11 employees, but SCE claims to need to fill two vacancies and add five new positions in order to handle its workload.

DRA recommends either zero funding, or 2009 recorded costs of $1.532 million to reflect removal of the additional staff costs due to a lack of justification. DRA also views Ethics and Compliance functions as largely for the benefit of shareholders.[1051] To the extent the department ensures compliance with various health and safety, employment, and investor protections, DRA argues it protects SCE from lawsuits, fines and penalties but yields few ratepayer

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[1049] JCE at 453, 807.

[1050] D.09-03-025 at 159.

[1051] DRA OB at 329.

benefits. DRA also points to a dubious record of ethics and compliance in the past, including NRC's 2008 finding of willful safety-related violations.

As a general matter, we find it reasonable to allow SCE to recover its Ethics and Compliance costs from ratepayers. Compliance efforts related to health and safety and employment compliance are clearly linked to safe and reliable utility operations, although SOX compliance inures more to the benefit of shareholders.

We also share DRA's concern about SCE's commitment to the effectiveness of this department. In addition to SCE's failure to spend funds authorized in 2009 and numerous examples of regulatory findings of utility error provided by DRA, SCE's Chief Ethics and Compliance Officer stated that she was only "generally familiar" with these facts.[1052] The bulk of her activity appears to be related to HR and conflict of interest complaints. When she was second in command, she was not included in regulatory actions alleging improper actions by SCE. She also is not consulted regarding ethical reviews affecting the Law Department.[1053] These facts suggest the department may be marginalized and its success not a management priority.

SCE claims that it has developed a comprehensive Compliance Management Program in order to better manage ethics and compliance programs across the company. However, SCE's description of the program does not quantify how SCE arrived at its staffing request.

Despite the generalities of SCE's evidence, the Commission finds it reasonable to adopt 2009 recorded costs, plus allow $529,000 ($469,000 Labor and $60,000 Non-labor) to provide sufficient funding to fill the two vacancies and add

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[1052] TR at 2437-2447.

[1053] *Id*. at 2453, 2456-2457.

50% of the proposed staff increase.[1054] SCE should take this opportunity to more effectively integrate its Ethics and Compliance activities company-wide. In the next GRC, SCE shall provide a description of program improvements achieved by the Ethics and Compliance department since 2010 and a clear description of the scope of its jurisdiction.

9.6.1. Outside Services: 923

For TY2012, SCE forecasts $772,000 for Outside Services, a decrease of $83,000 from 2009 recorded costs. DRA recommends $605,000, a 2YA (2008-2009) as more representative of test year costs.[1055]

SCE explained that its costs increased in 2009 due to consulting services related to the CMP, after one-time development costs were removed. DRA did not address this new program expense, nor otherwise support its view that a 2YA yields a more reasonable forecast.

The Commission finds SCE's forecast to be reasonable and adopts it.

9.6.2. Capital Expenditure – Enterprise Compliance Management System (CMS)

SCE requests approval of capital spending to invest in an integrated CMS to provide a standard system that improves compliance across the company. The total estimated cost is $16.5 million ($nominal), of which $11.375 million is scheduled for 2012. [1056] SCE's forecast utilized a vendor estimate, but some costs are expected to be offset by SCE's ability to leverage existing systems.

[1054] SCE-07, Vol. 02 at 73.

[1055] JCE at 455.

[1056] SCE-07, Vol. 02 at 78.

TURN recommends the project be disallowed due to TURN's view that CMS is duplicative of the Corporate Environmental Health and Safety (CEH&S) system.[1057] If the Commission were to fund it, TURN requests a 10% cut to what it contends are inflated IT costs.

SCE responds that TURN is mistaken about the features of the two systems. The existing CEH&S system, according to SCE, can only manage environmental, health and safety compliance, not all the types of compliance across the company. Even if SCE were somehow able to expand the existing system, it would require a substantial investment and reduce operational benefits that SCE expects to fund ongoing CMS maintenance.

We are persuaded that SCE has examined alternatives and that, on balance, it is reasonable to implement the CMS on a company-wide basis to more effectively manage compliance needs.

Accordingly, the Commission finds reasonable and adopts SCE's proposed 2012 Capital expenditures of $11.375 million.[1058]

9.7. Regulatory Policy and Affairs (RP&A): FERC 920/921

For TY2012, RP&A forecasts a total of $15.446 million for labor and expenses, a $2.454 million (18.9%) increase over 2009.[1059] SCE relied on LRY, and states that $2.409 million of the increase will fund 16 positions to address a substantial and continuing increase in regulatory workload.

[1057] TURN–9 at 45.

[1058] JCE at 898.

[1059] SCE-07, Vol. 03 at 1.

DRA recommends a total of $12.223 million and TURN proposes $1.192 million.

DRA removes funding for additional staff and Affiliate Transaction Rule (ATR) compliance costs. The forecast substitutes an adjusted 5YA for labor costs and rejects SCE's additional staffing as unjustified. DRA argues its position is consistent with the Commission's 2009 rejection of new FTEs and application of a 5YA despite relatively stable RP&A labor costs.[1060] Prior to calculating the 5YA, DRA removed historic Spot Bonuses, ACE awards, and ATR costs which results in a further labor reduction of $815,000.[1061]

We find that DRA's use of an adjusted 5YA for labor is reasonable given minor historic variations, prior GRC treatment, and our decision in Section 8.3 regarding Recognition programs. Despite rejection of SCE's 2009 request for additional staff, RP&A promptly hired 11 employees, pushing labor costs higher and adding them to the 2012 forecast. SCE claims the majority of new employees will work on compliance with NERC Reliability standards and SCE's CMP. However, SCE did not explain or quantify its 2012 calculation of additional labor needs and seems to rely on the fact the positions have been filled to justify them.

TURN agrees with DRA's $450,000 ATR reduction, and also freezes ratepayer funds for salary increases after 2009.[1062] TURN references Commission decisions in other GRCs which reject ratepayer funding for ATR compliance. For example, in SCE's 2009 GRC, we stated, "These compliance costs are incurred to support the operations of SCE's affiliates and, as such, requiring ratepayers to

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[1060] D.09-03-025 at 160.

[1061] DRA OB at 337; JCE at 425,456.

[1062] JCE at 808.

bear those costs would amount to a subsidy of those operations by ratepayers."[1063]

We are not persuaded by SCE's argument that the Commission erred in the 2006 and 2009 GRCs when it disallowed recovery of previously permitted ATR costs because these are ordinary regulatory expenses and benefit ratepayers. We see no evidence to reverse our position. TURN's argument that shareholders be required to pay for RP&A salary adjustments as a matter of fairness is also not convincing just because of salary and intervenor compensation freezes applicable to Commission and party employees.

On the other hand, RP&A likely has additional work due to NERC reliability standards and its CMP even as the record lacks data to parse the particular workload. Therefore, we reduce the incremental labor request by 50%.[1064]

Accordingly, the Commission finds reasonable and adopts $13.428 million (DRA's $12.223 million forecast + $1.205 million) for TY 2012.

9.8. Corporate Membership Dues and Fees: 930.200

The forecast amount is to fund its annual corporate membership to the Edison Electric Institute (EEI), and membership fees to several organizations SCE characterizes as electrical system research and economic development groups.

SCE's revised TY2012 forecast for this department is $1.586 million, a decrease of $162,000 from 2009 spending. In response to TURN's objections and evidence, SCE removed the anticipated EEI dues increase of $241,000 and

[1063] D.09-03-025 at 161.

[1064] JCE at 456.

adjusted the amount of EEI dues applicable to excluded activities by $162,000. However, TURN disagrees with SCE's calculation and argues that an additional $254,000 be removed for lobbying.

It is SCE's burden to establish that requested funds are eligible for rate recovery. Spending data from EEI is apparently hard to come by. TURN had to scour other regulatory agencies to develop its testimony on this issue, and upon review, SCE agreed it had overstated the request. We are not persuaded by SCE's conclusory recalculation that it has accurately removed all lobbying, advertising, public relations, and other costs excluded from ratepayer recovery.

TURN's forecast of $1.284 million also removes payments to California Taxpayers Association (Cal-Tax) and Arizona Tax Research Association (ATRA). According to SCE, it pays annual dues of $42,500 to Cal-Tax and $6,000 to ATRA because these organizations represent taxpayers and lower tax costs which benefits ratepayers.[1065] However, TURN points out that the groups regularly support and oppose legislation, yet SCE did not exclude even disclosed amounts used for lobbying. Moreover, these organizations are focused on tax policy, not the delivery of electrical service, and ratepayers may disagree with their views or even be adversely affected by them.

We agree that advancing policies of tax reduction is inherently political and ratepayers should not fund SCE's membership dues in political organizations, regardless of some attenuated potential rate benefit.

Therefore, the Commission adopts TURN's recommendation of $1.284 million for TY2012.

1065 TURN-3 at 110.

9.9. Corporate Communications: FERC 920/921, 923, 930

According to SCE, Corporate Communications performs service-related functions, including messaging important information on lowering costs, EE, and safety issues.

For TY2012, SCE forecasts a total of $16.759 million in all accounts, a 31.1% increase over 2009 recorded expenses. The increase is primarily due to SCE's request to fill nine vacancies and add 19 new positions.

9.9.1. Labor and Expenses: FERC 920/921

In Accounts 920/921, SCE's forecast is $14.708 million, an increase of $3.358 million (29.6%) over LRY. SCE's position builds upon its request in the 2009 GRC, when the Commission re-approved eight new positions that had been approved in the 2006 GRC but were never filled. SCE now seeks to fill the vacancies in Internal Communications; the new positions would support customer education on smart grid, PEVs, and renewable energy, and bringing audiovisual services in-house.

TURN forecasts a total of $12.133 million for 920/921, including a labor reduction of $1.747 million to allow SCE to fill vacancies but not to add new staff.[1066] For non-labor, TURN makes two adjustments to 2009 costs by removing $828,000 associated with community partnership programs and contingent workers, and SCE's incremental expense for PEV readiness. TURN's views that SCE's PEV forecast is excessive and SCE has substantial PEV information available have been discussed above.[1067]

[1066] JCE at 809.

[1067] Section 5.2.1.4.

DRA's combined forecast is $11.122 million.[1068] For Account 920, DRA's forecast of $6.827 million removes all of SCE's 2012 incremental labor costs, and further excludes $40,000 for a one-time media event and Spot Bonuses from 2009 recorded expenses.[1069] For Account 921, DRA removes $561,000, including associated expenses for new employees, ACE award costs, and support for voluntary community partnerships which SCE describes as promoting cost-effective energy use among underserved groups, and DRA describes as voluntary employee groups working on community improvement and cultural projects.[1070]

DRA's non-staffing reductions are conclusory and unsupported. DRA's proposal to remove five years of recognition award costs is unpersuasive when it does not rely on an historical average to make its forecast.

We agree with TURN that a 30% increase is excessive, particularly for a public relations-type department which may duplicate CSBU education and outreach functions. SCE has also not explained why it failed to utilize previously approved staffing increases, nor explained its calculation of 19 new positions, despite lengthy descriptions of what the department does and purports to do. SCE has not demonstrated its commitment to expand activities after either the 2006 or 2009 GRCs. Therefore, we find TURN's recommendation to authorize sufficient funding to support filling nine vacancies to be reasonable.

Regarding the $452,000 for PEV readiness activities, it is reasonable to apply our prior decision to adopt SCE's lower PEV forecast, resulting in a 40%

[1068] JCE at 472.

[1069] DRA-12R at 45; JCE at 424.

[1070] DRA-12R at 45.

reduction of 2012 PEV expenses.[1071] TURN's other recommended cuts are insufficiently supported.

Accordingly, the Commission finds reasonable and adopts $12.404 million ($8105 million Labor and $4.299 million Non-Labor).

9.9.2. Outside Services: FERC 923

SCE forecasts $905,000 for Account 923 in TY2012 based on a 2YA (2008-2009), plus incremental costs of $342,000 to support ethnic media activities and PEV Readiness. This is a 66% increase over 2009 costs. SCE claims it has to keep up with demographic changes in its customer base and it needs strategic guidance on cultural issues, translation and distribution of materials.

DRA recommends $491,000[1072] based on a 5YA and TURN proposes $544,000[1073] based on LRY.

SCE states it has increased spending since 2006 on ethnic advertising and public relations agencies to reach culturally diverse customers and for communication measurement. These are important activities and SCE should have gained significant knowledge through its efforts to date. Although SCE claims it plans substantial growth, it did not explain how it arrived at its incremental costs. Additionally, SCE did not distinguish why these PEV Readiness expenses are necessary after requesting outreach funds in other spending categories.

Therefore, the Commission finds reasonable and adopts TURN's forecast of $544,000.

[1071] Section 5.2.1.4.

[1072] JCE at 474.

[1073] JCE at 811.

9.9.3. Communications Products: FERC 930

Expenses related to production, design, and distribution of customer information booklets, brochures, and notices, and SCE and EIX annual reports are recorded in this account.

SCE's revised forecast is $1.146 million for TY2012 based on LRY, plus an increase of $259,000 (29%) for expected cost increases related to bill inserts and public safety programs.[1074] SCE agreed with TURN to remove $95,000 in incremental costs related to EAF.

DRA based its forecast of $1.189 million on a 5YA because it views historic costs as fluctuating.[1075] TURN recommends $980,000 based on LRY, plus $93,000 for additional customer safety education.[1076]

TURN disputes the necessity of funding for graphic design expenses for customer newsletters and customer programs for in-home holiday safety. The holiday safety program was dropped in 2009 and there is no evidence that customer safety was diminished. TURN also points out that SCE only spent about 60% of the $1.46 million authorized in 2009.

SCE agrees that holiday safety is addressed through other channels and its explanation of the need for a graphic design consultant to tailor messages is not compelling. Preparation of bill inserts and customer newsletters are routine activities for SCE and there should be embedded costs for these activities.

Accordingly, the Commission finds reasonable and adopts TURN's forecast of $980,000.

[1074] SCE-07, Vol. 03 at 40.

[1075] JCE at 473.

[1076] TURN OB at 289.

9.10. Property and Liability Insurance: FERC 924, 925

SCE forecasts a total of $68 million in A&G expenses for property insurance and liability insurance. The forecasts are based on expected test year premiums as estimated by SCE's primary insurance broker and reflecting SCE's loss history, SCE property values, and overall market conditions. Most insurance is purchased by EIX for itself and its subsidiaries, then the premiums are allocated to each entity.[1077]

9.10.1. Property Insurance: FERC 924

SCE purchases (1) non-nuclear property coverage for its transmission and distribution assets and other plant; (2) blanket crime insurance for losses due to theft and fraud; and (3) nuclear property insurance.

For TY2012, SCE forecasts a total of $15.417 million, an increase of $5.008 million over 2009 recorded based on more utility assets and higher costs for nuclear property insurance as a result of a complex distribution methodology linked to performance of reserves.

DRA recommends $15.108 million, the equivalent of SCE's 2010 recorded expenses for Property Insurance.[1078] SCE argues that DRA ignores the Complex analysis of its broker as to 2012 premiums, which reflect cost escalation through 2012 and growth in SCE's assets.

We are persuaded that SCE's forecast is based on a more reasonable estimate of TY2012 expenses. Therefore, the Commission adopts SCE's forecast of $15.417 million for TY2012.

[1077] SCE-07, Vol. 03 at 52.

[1078] JCE at 475.

9.10.2. Liability Insurance: FERC 925

SCE maintains several types of liability insurance. Total liability insurance expenses have grown from $9 million in 2005 to $13.208 million in 2009. Costs were generally stable from 2005 to 2008, but increased sharply in 2009 primarily due to the cost of wildfire liability insurance and SCE's intent to purchase supplemental wildfire insurance.

For TY2012, SCE forecasts $52.563 million, an increase of $39.355 million over 2009 recorded again due to the presumed cost of wildfire liability insurance. SCE obtained up to $500 million in coverage available for wildfire claims in late 2009 but seeks supplemental coverage going forward. SCE asserts its requested increase is within the range of various proposals considered.

DRA recommends 2010 recorded expenses of $28.366 million.[1079] DRA does not address SCE's discussion of the reasons for rapidly growing wildfire insurance costs, including strict liability theories of recovery approved by California courts.[1080] DRA's reliance on 2010 recorded costs is misplaced because SCE did not purchase supplemental wildfire insurance in 2010, and it excludes any premium escalation to 2012.

If SCE does not have adequate coverage, ratepayers might be exposed for uninsured losses.

Therefore, the Commission finds reasonable and adopts SCE's TY2012 forecast for liability insurance.

The Commission adopts $275.937 million of the $309.516 million request for Administrative and General O&M Expenses, as illustrated in the table below:

[1079] *Id*. at 476.

[1080] SCE-07, Vol. 03 at 66.

Administrative and General O&M Expense Request (000s)				
Section	**Description**	**Requested ($000)**	**Adopted**	**Disallowed**
9.1	Financial Organizations	$79,290	$65,490	$13,800
9.2	Risk Control	6,709	5,340	1,369
9.3	Law Department	46,055	42,450	3,605
9.4	Claims	50,289	42,621	7,668
9.5	Workers' Compensation	22,282	20,583	1,699
9.6	Ethics and Compliance	3,120	2,833	287
9.7	Regulatory Policy and Affairs	15,446	13,428	2,018
9.8	Corporate Membership and Dues and Fees	1,586	1,284	302
9.9	Corporate Communications	16,759	13,928	2,831
9.10	Property and Liability Insurance	67,980	67,980	0
	Administrative and General O&M Expense Total	**$309,516**	**$275,937**	**$33,579**

SCE requested $19.157 million for Administrative and General capital expenses; the Commission adopts $16.257 million of this request and disallows $2.9 million, as illustrated in the table below:

Administrative and General Capital Expenditure Request (000s)						
	Capital Request by Year					
Project Description	**2010 Recorded**	**2011 Forecast**	**2012 Forecast**	**Total2010-2012**	**Adopted**	**Disallowed**
9.1 Fin Org IFRS Project	$0	$0	$2,900	$2,900	$0	$2,900
9.3 Law Dept Electronic Discovery	58	1,584	3,240	4,882	4,882	-
9.6 Ethics and Compliance, Elec. Compl. Mgmt System	0	0	11,375	11,375	11,375	-
Total Capital Expense	**$58**	**$1,584**	**$17,515**	**$19,157**	**$16,257**	**$2,900**

10. Power Procurement Business Unit (PPBU)

The PPBU has four departments: Market Strategy and Resource Planning, Energy Supply and Management, Renewable and Alternative Power, and Power Procurement Finance. SCE expects the departments will have significant increased workload in this rate cycle due to various regulatory and legislative impacts.

For TY2012, SCE forecasts a total of $59.3 million in O&M expenses and $73.4 million in 2010-2012 capital expenditures. SCE's O&M requests are primarily to add 94 employees by 2012 from the 288 total in 2009. To develop its labor forecasts, SCE used a budget-based approach.

SCE claims the staffing is necessary to address new regulatory and legislative initiatives, including: 1) changes in electricity markets such as MRTU; 2) increases in renewable and Combined Heat and Power (CHP) procurement; 3) environmental issues such as GHG and once-through-cooling (OTC); and 4) integrated resource planning.

DRA recommends reducing the O&M expenses by $7.2 million and capital expenditures by $24.1 million, for a total disallowance of $31.3 million, or 23.6% of SCE's forecast.[1081] DRA argues that SCE has not justified most of the new positions. Of the total amount, DRA proposes that MRTU-related capital, labor, and non-labor expenses of $26.05 million be recorded in the MRTUMA.

TURN recommends reductions to capital spending of $18.58 million, a 25.4% reduction to SCE's 2010-2012 forecast. TURN would disallow three projects it views as Demand Response projects which lack Commission-required cost-effectiveness analysis, and make a 10% reduction to other capitalized software.

As set forth below, we adopt $55.146 million for TY2012 O&M and $43.94 million for 2010-2012 capital expenditures. However, more than 80% of the

[1081] DRA-14 at 2-3, Tables 14-1, 14-2.

reduction to capital spending consists of transfer of two capital projects to the MRTUMA.

10.1. DRA's Position

DRA's makes similar objections to most O&M increases. DRA disagrees that additional regulatory and legislative requirements will increase the PPBU workload during the rate cycle. According to DRA, all but one of the initiatives SCE identified are old and most of the associated activities are decreasing rather than increasing.[1082]

DRA specifically rejects SCE's estimate of increased workload from two program areas: the State's 33% RPS and CHP goals. For CHP procurement, DRA asserts that SCE will be dealing with contract renewals rather than new contracts. Regarding the RPS, DRA argues that the contract process has been simplified, many RPS contracts needed to achieve the new target have already been executed, and existing employees were sufficient to implement RPS to date, including addition of 5% in renewables in 2009 alone. DRA also contends that resource integration staffing should be at the CAISO and not at the utility.

SCE estimates a significant increase in the number of contracts it needs to manage related to renewable energy procurement programs such as: (1) Renewable Auction Mechanism (RAM); (2) Solar Photovoltaic Program (SPVP); (3) California Renewable Energy Small Tariff (CREST); (4) GHG; and (5) CHP contracting activities. SCE's position is that the actual effect of achieving

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[1082] DRA OB at 341.

the 33% RPS requires a 65% increase in the amount of renewables, assuming no load growth and 60% project success rate.[1083]

Additionally, SCE manages other large solicitations such as: (1) All-source RFOs; (2) Gas RFOs; (3) RPS RFPs; and (4) other miscellaneous solicitations such as Qualifying facilities (QF) fixed-price RFOs. SCE argues these programs will cause incremental work during the rate cycle.

We find that SCE will face additional legislative and regulatory requirements related to power procurement activities in this rate cycle, and the RPS and CHP programs will result in additional new procurement work for PPBU. In addition to the evidence presented by SCE, the Commission recently found that just implementing the new renewables portfolio content categories "will require all participants in California's RPS market to acquire and provide more information about their transactions than has been needed previously."[1084]

In D.11-12-052, the first of many to implement the new RPS standards, we added new requirements for IOUs. For example, for new contracts, we directed IOUs to make a detailed upfront showing by advice letter, and anticipated modifications to the current advice letter template and RPS compliance spreadsheet.[1085] Furthermore, we determined that the basic contract may be augmented by additional agreements, consistent with SCE's claim that the RPS contracts always include numerous modifications.[1086]

1083 SCE-23 at 21-22.

1084 D.11-12-052 at 8.

1085 *Id*. at 10, 13.

1086 SCE-23 at 22.

Consequently, we disagree with DRA that SCE's workload in this business unit is not likely to increase and do not further discuss these arguments. We discuss specific staffing requests below.

10.2. Market Redesign and Technology Upgrade (MRTU)

In Section 7.2.1, we described the background for this CAISO-initiated bundle of projects to provide a range of grid improvements, and determined that SCE should continue to record expenses associated with implementing MRTU in the MRTUMA.

In PPBU, SCE asserts that certain capital software projects requested by PPBU are "post-MRTU" enhancements and eligible for rate recovery in the GRC, along with incremental O&M costs. We examine the projects individually below to make that determination. For guidance, we review our initial approval of the MRTUMA.

In Res. E-4087, we stated our expectation that the utilities would have the resources necessary to participate in the new market design, Locational Marginal Pricing (LMP), and a day-ahead energy market. Relevant to SCE's PPBU requests, we also recognized that the utilities would need capital investment to integrate with CAISO's new computer systems, including for load management and resource availability. Thus, expenses related to integrating SCE's PPBU functions with the new CAISO MRTU process should be recorded in the MRTUMA.

DRA identifies two PPBU capitalized software projects which it contends are MRTU-driven and should be removed from the GRC:

- CAISO Market Enhancement Program 2010-2011 = $16.4 million

- Future Market & Performance Enhancements 2012 = $7.7 million (total 2012-2014 = $24.7 million)

In O&M, the following labor/non-labor requests for new employees are identified by DRA as appropriate to be recorded in the MRTUMA:

- Market Strategy & Resource Planning: (5) = $468,900/$64,000
- Energy Supply & Management: (8) = $956,782/$131,000
- Power Procurement Finance: (3) = $370,000/$71,000

The totals for DRA's MRTU-based recommended disallowances is $2.062 million in O&M, and $24.1 million in 2010-2012 capital expenditures. As set forth below, we agree with DRA as to the capital projects, but not for the O&M requests.

10.3. Market Strategy and Resource Planning: FERC 557

The four groups comprising Market Strategy and Resource Planning (MS&RP) provide functions that include forecast information and market modeling, assessing cost-effectiveness of projects, monitoring market developments, strategic planning, and provide project management support for regulatory proceedings that involve market rules, resource planning electric policy development.

For TY2012 O&M, SCE forecasts $5.385 million for MS&RP expenses, an increase of $1.55 million (40.5%) over 2009 spending.[1087] The $1.499 million labor increase is to fund 15 new positions, and the non-labor portion contains both

[1087] SCE-08 at 23, 34 (As of 2010, SCE records costs for labor, non-labor, and consulting services in Account 557).

associated costs and fees to consultants to assure regulatory filings are accurate.[1088]

SCE seeks three FTEs in Resource Planning, five in Market Design and Analysis (MD&A), four in Strategic Projects, and three in Resource Policy and Economics (RP&E).

DRA recommends $3.964 million based on approval of two new employees: one each in Strategic Projects and the RP&E.[1089] DRA's general objection is that SCE has not stated anything new or additional that would support or necessitate the addition of new employees to this group. DRA did not review three of the five additional requested positions for MD&A, instead recommending the total labor/non-labor costs of $533,000 be removed and recorded in the MRTUMA.[1090]

We disagree that the proposed positions are part of implementation costs for the MRTU. MD&A has on-going functions of monitoring market developments and affecting market rules. SCE's job descriptions for the new employees appear to adapt current group responsibilities to more complex markets to provide additional market analysis and simulations, plus additional market design and enhancement work due to RPS, GHG, and OTC.

In prior years, some MD&A staff were directly involved in development of the CAISO market into an LMP system.[1091] Since SCE does not seek additional costs for this MRTU activity, we conclude that MD&A has some existing staff to

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1088 *Id*. at 36.

1089 DRA-14 at 21.

1090 JCE at 214.

1091 SCE-08 at 28.

handle incremental costs arising from the more complex market. Accordingly we disallow 60% of the new employee costs sought by MD&A.

We are persuaded by SCE that its Resource Planning Group (RPG) provides key RPS analytical work that impacts CAISO and CEC, and SCE's customers. These efforts exceed prior analytical work and SCE has reasonably supported its request for three positions. In addition, SCE seeks additional support for the Strategic Planning group to address environmental issues, including Assembly Bill 32[1092] and GHG, as well as new technologies. However, SCE did not sufficiently explain how it determined the workload to be generated by as yet unknown future emission reporting requirements. Therefore, we reduce SCE's request in 2012 by 50%.

SCE's explanation for three new positions in RP&E is less compelling. RP&E's routine work includes providing project management for regulatory proceedings involving resource planning and electric policy. According to SCE, the new staff would perform system reliability modeling and lead the LTPP team.[1093] The LTPP proceedings are not new. It is also unclear how the resource planning modeling is different from that done in the RPG.[1094] However, we agree that there will be incremental work in the area of resource planning related to RPS and find the addition of one position is justified.

[1092] Stats. 2006, ch. 488.

[1093] SCE-08 at 32-33.

[1094] *Id*. at 25, 33.

Accordingly, the Commission finds it reasonable to reduce SCE's forecast by $611,000 in labor, and $84,000 in associated labor using the 2009 non-labor to labor ratio of 13.74%.[1095] We adopt the result of $4.690 million in Account 557.

10.4. Energy Supply and Management: FERC 557

The Energy Supply and Management (ES&M) department performs functions associated with the purchase and sale of conventional (non-renewable) capacity, electrical energy, natural gas and related energy products and services. SCE identifies the key drivers for an increasing workload as: (1) implementation of the CAISO's MAP initiatives;[1096] (2) integration of more renewable resources into the planning and operations processes; (3) utilization of real-time demand data for various purposes; and (4) emergence of new markets and products (such as GHG and Renewable Energy Credits.

For TY2012, SCE estimates O&M expenses of $29.566 million, an increase of $10.493 million (55%) from 2009 recorded expenses of $19.07 million. Labor costs account for $5.861 million of the increase. SCE wants to fill 18 vacancies, plus requests an additional 26 employees across five of its seven divisions.[1097]

SCE determined total labor costs by multiplying the 2009 average labor expense per employee of $119,609 by the 182 employees ES&M decided it will need in TY2012.[1098] According to SCE, only its budget-based forecast accurately reflects the anticipated workload. In addition to labor associated costs, SCE's

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[1095] JCE at 205-207.

[1096] "MAP initiatives" refers to markets and performance enhancements required by CAISO as enhancements to MRTU (e.g., Market Release 1).

[1097] TR at 3276.

[1098] SCE-08 at 61.

non-labor forecast includes $3.5 million for California Air resources Board fees, and $1.306 million for consulting services, in the Test Year.[1099]

DRA recommends $26.437 million for ES&M based on a $3.129 million reduction ($2.751 million Labor, $0.378 million Non-labor) to SCE's request for new positions from 26 to three: one in Energy Planning and two in Demand Forecasting.[1100] Although DRA does not support the $1.088 million requested for eight positions for Bidding Strategy & Asset Optimization (BS&AO), it does not oppose recording these costs in the MRTUMA.[1101] DRA's position is that SCE would have adequate staffing if it fills the 18 vacancies, and SCE has not justified the remaining 15 positions.

We incorporate our prior comments regarding SCE's budget-based method which is not preferred by the Commission and requires good evidence to support the forecast.[1102] Secondly, SCE'S forecast labor increase is inconsistent with its supporting evidence. The proposed labor increase of $5.861 million is the equivalent of 49 additional employees, yet SCE's record only refers to 26 new positions and 18 vacancies, a total of 44. Therefore, we find it reasonable to reduce the labor forecast by $598,045 for the unsupported positions, and the non-labor forecast by $82,000 using the 2009 non-labor to labor ratio of 13.74%.

The (BS&AO) group was organized in 2010 to improve SCE's bidding strategies and to prepare to participate in CAISO's convergence bidding process

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1099 *Id*. at 62-63.

1100 DRA OB at 347; JCE at 203-204.

1101 DRA-14 at 25.

1102 Section 2.2.

beginning in 2011.[1103] We are persuaded that with billions of dollars at stake in an increasingly complex market, ratepayers should benefit from SCE's development of a strategic bidding group to improve results with new products and to navigate the new bidding processes.

DRA's characterization of the functions of this group as part of MRTU implementation is strained. Although SCE will be formulating new strategies for bidding in the redesigned markets, requiring additional analysis and evaluation, such procurement activities pre-date MRTU. SCE has chosen to reorganize and expand staff to navigate more complex bidding brought on by MRTU and more energy products, but the requested staff are not directly involved with development and implementation of infrastructure anticipated by Res. 4087. Therefore, we do not view these costs as appropriate to transfer to the MRTUMA.

However, SCE's eight job descriptions include overlapping activities and we expect some efficiencies will occur as experience is gained in this group. Therefore, we find it reasonable to reduce SCE's request by $239,218 in labor and $33,000 associated non-labor expenses, the equivalent of two FTEs.

Energy Operations functions include routine bidding and tracking power transactions, and dispatch of SCE's resource portfolio. DRA's objections to the eight proposed positions are based on the RPS argument we rejected above. On the other hand, SCE's testimony only supported five of the requested positions.[1104] Therefore, we find it reasonable to reduce SCE's labor request by

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[1103] SCE-08 at 56.

[1104] *Id*. at 46-48.

$358,827, the equivalent of three FTEs, and associated non-labor of $49,300 to address the omission.

We are also persuaded that the Demand Forecasting group will need to manage more frequent load data and support integration of bidding Demand Response into the wholesale market.[1105] However, SCE's testimony only supported five of the requested positions.[1106] Therefore, we find it reasonable to reduce SCE's labor request by $119,609, and associated non-labor of $16,400.

Lastly, SCE claims it needs two positions to examine data used for modeling for managing its resource portfolio, and two positions for additional contracting, including those related to replace Department of Water Resource (DWR) contracts expiring in 2011, new out-of-state renewables, and GHG trading. DRA states that SCE has already executed replacement contracts for DWR resources, but supported one position for environmental matters.

We agree with DRA that SCE has long planned for the replacement of the DWR contracts, and one more position should be sufficient for additional work. There are a significant number of vacancies associated with the Energy Planning and the Energy Contracts & Trading groups as of YE2009. The vast majority of their work is routine and on-going, and if the vacancies are filled, plus one additional position, SCE should be equipped to address the additional tasks in 2012. Therefore, we find it reasonable to reduce SCE's labor request by $358,827 and non-labor by $49,500.

[1105] *Id*. at 50; TR at 3281-3283.

[1106] *Id*. at 50-51.

Accordingly, the Commission finds reasonable and adopts $27.66 million ($20.094 million Labor, $7.567 million Non-Labor) for TY2012 to reflect the reductions described above.

10.5. Renewable and Alternative Power: FERC 557

The Renewable and Alternative Power (RAP) department is responsible for implementing, negotiating, managing, and administering all legislative and regulatory initiatives related to (1) PURPA;[1107] (2) California's RPS program; (3) the Renewables Standard Contract Program; (4)SPVP; (5) CREST program; (6) CHP activities; and (7) other contractual matters related to renewable and alternative power.

SCE's TY2012 forecast for RAP O&M expenses is $6.665 million, a 41% increase from 2009 recorded costs of $4.728 million. The estimated labor increase of $1.672 million would fund 17 positions across several divisions.[1108]

According to SCE, the key cost drivers are both the number of new contracts expected and the continued expansion and complexity of renewable programs during the rate cycle.[1109] To develop its forecast, SCE used LRY plus estimated incremental costs method because it viewed historical costs as not indicative of future contracting activity.

DRA recommends a $1.559 million reduction to SCE's forecast because SCE only needs two new positions.[1110] DRA points out that in 2009, PPBU's staff

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[1107] The Public Utility Regulatory Policy Act of 1978 (PURPA) at 16 U.S.C. § 824a-3.

[1108] SCE-08 at 90, Table IV-3.

[1109] *Id*. at 65.

[1110] JCE at 209-211.

was able to procure renewable resources of almost 5% of SCE's retail services, and SCE concedes it has executed a large number of solar contracts to come online in the next five years.[1111] Three of the 17 positions are not expected to be needed until after the Test Year.[1112]

DRA reiterates its position that SCE's current staffing can manage new RPS and CHP contract workload. We do not wholly agree as discussed above. We are also persuaded that GHG goals will impact the complexity of procurement in this rate cycle.

However, SCE 's support for the new positions was generally stated and lacked details of how it arrived at the forecast workload (e.g., 110.5% increase in the number of contracts over 2009)[1113] or quantified the expected workload into 17 additional required employees. SCE also did not explain why it needs more managers than analysts.

SCE specifically requests nine FTEs in Contracts, three in RFP Origination, three in Planning and Financial Analysis, and two in Regulatory and Legislative Matters. Based on our review of the record, we are not able to singularly find support for each proposed position in the Test Year and observe that SCE appears better positioned to meet RPS targets than claimed. Therefore, we find it reasonable to authorize 50% of SCE's incremental labor request for this department, and to reduce associated non-labor at the 2009 ratio of 9.9% to labor.

Accordingly, the Commission adopts $5.746 million ($5.09 million Labor, $656,000 Non-labor) for TY2012 for RAP O&M expenses.

[1111] DRA OB at 348.

[1112] DRA-14 at 34 (citing to SCE's Work Papers).

[1113] Work Papers, SCE-08 at 108.

10.6. Power Procurement Finance: FERC 557

The Power Procurement Finance (PPF) department performs back office activities related to wholesale energy and natural gas transactions including settlements, accounting, financial reporting, accounts payable and receivable, administrative support, budgeting, information management, business systems development, and PPBU-specific training.

For TY2012, SCE forecasts total expenses of $17.724 million, an increase of $3.11 million (21.2%) over 2009 spending, primarily to add 18 new positions.[1114] SCE requests nine new employees in Business Process and Technology Integration (BP&TI), four in Accounting and Reporting (A&R), three in Settlements, and two in People Initiatives.

SCE attributes the increased workload to regulatory and legislative initiatives that will cause market, contract, and compliance changes requiring PPF systems and process changes to settle and account new transactions.[1115] SCE's non-labor forecast increased $1.4 million, primarily to support capital projects, in addition to costs associated with the new employees.

DRA recommends a reduction of $1.114 million, based on the addition of only eight new positions.[1116] These eight FTEs would support additional compliance requirements, environmental issues, smart meters, administrative support, changes in accounting standards, and support for capital projects.[1117]

[1114] SCE-08 at 92.

[1115] *Id*. at 92.

[1116] DRA OB at 350.

[1117] DRA-14 at 52.

DRA disallows ten positions because they relate to RPS and CHP contracts, MRTU implementation, and/or were vacant at the end of 2010.[1118]

DRA points out that PPF boosted its staff by more than 40 between 2005 and 2009, including support for expanded PPBU training programs requested again in this GRC.[1119] SCE's supporting evidence for the new FTEs lacks explanation of how SCE estimates the workload or quantifies the person hours that would lead to an FTE forecast.

In support of four analysts and five managers, SCE claims that BP&TI must adapt to market and regulatory changes, including undertaking strategic planning, developing large technology programs, and coordinating technology initiatives in support of renewable and CHP procurement.[1120] DRA agrees with four FTEs, but recommends removing three positions it would transfer to the MRTUMA and one supporting RPS and CHP contracting.[1121]

In support of three positions in Settlements, SCE states that the MRTU implementation has significantly added to the complexity of contract settlement and payment. DRA disputes the necessity of one position related to RPS and CHP contracts and one position which it would transfer to MRTUMA. We do not agree that it is appropriate to record the cost of one position in the MRTUMA. Settlement activities pre-date the MRTU. The fact that a more complex market may create additional work due to a higher volume, type, and complexity of contracts does not mean that the cost is attributable to MRTU

1118 *Id.*; JCE at 208.

1119 DRA-14 at 43.

1120 SCE-23 at 34.

1121 *Id.* at 34-35.

implementation. Many factors drive this complexity and the functional goals remain the same.

For the four positions in A&R, SCE outlines administrative oversight, technical and compliance review in connection with adoption of IFRS, and support staff to handle more employees. For People Initiatives, SCE claims two FTEs are required for on-going, specialized training for PPBU employees.

We agree that SCE will have to adapt to market changes during this rate cycle, including settling and accounting more transactions (e.g., RPS, CHP, and GHG), and developing or adapting systems and processes. On the other hand, the significant build-up of the staff in PPF between 2006 and 2010 should provide some experience efficiencies to handle the expansion of routine tasks, including training. SCE's reliance on general descriptions of existing tasks and anticipated changes provides little evidence to weigh the actual number of forecasted staff increases.

Based on our review of the record, we find it reasonable to reduce by one-third SCE's incremental labor request for this department ($566,000), and to reduce associated non-labor at the 2009 ratio of 19% to labor ($108,000).

Therefore, the Commission finds it reasonable to adopt $17.050 million, a 15% increase over 2009 recorded expenses.

In summary, the Commission adopts $55.146 million in TY2012 O&M for PPBU, a 7.1% reduction to SCE's forecast. Although SCE chose to present the incremental costs in terms of added employees, we recognize that SCE retains management discretion on how to implement the adopted revenue requirement for PPBU. The results are set forth below:

Power Procurement Business Unit O&M Expense Request ($000s)				
Section	**Description**	**Requested ($000)**	**Adopted**	**Disallowed**
10.3	Market Strategy and Resource Planning	**$5,385**	$4,690	$695
10.4	Energy Supply and Management	**29,566**	27,660	1,906
10.5	Renewable and Alternative Power	**6,665**	5,746	919
10.6	Power Procurement Finance	**17,724**	17,050	674
	Total Power Procurement O&M Expense	**$59,340**	**$55,146**	**$4,194**

10.7. Capital Expenditures

PPBU procures and manages energy assets which include SCE-owned generation, non-SCE-owned generation, long-term power contracts, natural gas contracts, and a variety of other market products.

SCE requests over $111 million between 2010 and 2014 for capital spending for PPBU activities. Approximately two-thirds, $73.35 million, is scheduled for expenditure between 2010 and 2012. SCE proposes spending for capitalized software projects and specialized communications equipment. In the 2009 GRC, SCE's procurement-related capital request was not aggregated, but included more than $58 million for MRTU projects. (We directed these costs to be recorded in the MRTUMA.)

DRA recommends a 2010-2012 reduction of $24.1 million (33%) for two software projects it argues should be recorded in the MRTUMA.[1122] TURN recommends removal of three software projects related to DR programs because SCE did not establish cost-effectiveness which TURN contends is required by D.09-08-027.[1123] TURN would also cut the remaining capitalized software costs by 10% based on its view that SCE's IT costs are inflated. TURN's proposed total

[1122] JCE at 660.

[1123] *Id*. at 896.

2010-2012 reduction is $17.87 million (24.3%), resulting in a capital expense adoption of $55.48 million.

10.7.1. Communication Equipment

SCE states that it must install specialized equipment on every renewable resource in its portfolio in order to effectively operate, including to monitor resources, adjust schedules, settle energy transactions, and respond to dispatch protocols.

SCE requests $6.5 million for 2010-2012: $1.5 million in 2010, and $2.5 million in both 2011 and 2012. The total forecast cost of the project is $11.5 million based on estimated costs for equipment of $150,000 and costs associated with additional tasks of $100,000 per facility.[1124] PPBU estimates an average of ten facilities per year will require installation of the equipment.

No party contests this forecast, but SCE provides no support for its request. There is no source indicated for cost information for either the equipment or "associated costs," nor how SCE concluded it would need to make ten installations per year. Although we agree that SCE likely requires a physical connection to each renewable resource for the reasons offered, SCE's approach to presenting a prima facie case for the request is full of key omissions.

Absent sufficient information to make a more considered reduction, the Commission adopts 50% of SCE's forecast for this expenditure.

10.7.2. Capitalized Software

According to SCE, PPBU's current systems are not capable of capturing SCE's complete portfolio of trades or all the necessary resource characteristics in

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[1124] SCE-08 at 112.

a single repository. SCE requests funding for nine capitalized software projects which it claims will provide the capacity to respond to ever-changing market and regulatory requirements. They are a combination of "in-flight" projects (where requirements and costs are generally known) and future initiatives for which the requirements are not yet fully defined.

For future initiatives, SCE describes its "high level" estimation methodology which looks back several years at similar PPBU projects with equivalent scale.[1125] SCE assigned each project a simple, medium, or high complexity category for either COTS or in-house development.

The level of complexity for COTS projects drives the ratio of vendor, IT, business unit, and hardware estimates to estimated license costs. For in-house projects, SCE utilizes an implementation time frame of three, six, or 12 months and estimates labor accordingly. These forecasts also include business unit labor, as well as business and technical consultants.[1126]

The projects are grouped into four categories described below.

10.7.2.1. Post-MRTU Energy Market Operations

SCE states it needs to improve PPBU system tools to effectively operate in the post-MRTU energy market. In addition, SCE assumes that CAISO will continue to mandate changes to the market structure and PPBU will need to implement four projects to comply with these requirements. SCE's total 2010-2012 request for this category of software projects is $36.85 million.

Both DRA and TURN recommend reductions.

[1125] Work Papers, SCE-08 at 245.

[1126] *Id*. at 250-251.

10.7.2.1.1. CAISO Market Enhancement Programs

According to SCE, the CAISO is required by FERC to implement several MAP enhancements and enhancements to PPBU systems are necessary to support the changes. SCE describes the project as including several initiatives to provide upgrades and enhancements to handle new products (e.g., Convergence Bids), new modeling functionality, and new modeling constraints (e.g., Scarcity Pricing).[1127]

SCE requests $14.4 million in 2010 and $2.0 million in 2011 to implement the high complexity COTS implementation. SCE states it will require significant upgrades to existing infrastructure.

DRA recommends the costs for the project be recorded in the MRTUMA because it is part of adapting to new market design changes implemented as part of MRTU. DRA offers no argument or explanation, and appears to rely on SCE's assertion that these are to integrate MAP enhancements.

For example, FERC required CAISO to implement Scarcity Pricing within 12 months of MRTU, and the Resource Adequacy (RA) Standard Capacity Product. CAISO has required an accelerated settlement and payment timeline, Convergence Bidding, and multi-stage generator modeling.

We find that the project is a continuation of the fine-tuning of the MRTU initiated by CAISO. SCE shall record the costs in the MRTUMA to provide the Commission and the public with the aggregate costs of achieving integration with CAISO's MRTU systems.

[1127] SCE-08 at 114-115.

10.7.2.1.2. Future Market and Performance Enhancements (2012-2014)

The CAISO annually identifies and prioritizes High Priority Market Enhancements that may require changes to the energy market.[1128] SCE states that even though the exact timelines and requirements are still being defined by CAISO, it must be able to respond and implement required systems.

SCE forecasts $7.7 million in 2012, and a total of $24.7 million by 2014, to respond to a range of CAISO priorities, including enhancements to the Standard RA Capacity Product, Load Aggregation Point Granularity, and adjustments to the Real Time and Day Ahead markets. The cost assumptions are based, in part, on the MRTU start-up.

DRA recommends the costs for the project be recorded in the MRTUMA but offers no analysis or argument. SCE describes the projects as post-MRTU MAP enhancements.

Upon review of the record, we find that the project continues the MRTU Releases 1 and 2 build-up of resources and load management tools, and fine-tuning of the resulting markets. Moreover, it is an example of the anticipated, and as yet undefined, capital project which drove creation of the MRTUMA. Although we do not envision the MRTUMA lasting in perpetuity, the lack of a reasonableness review for any post Release 1 costs mitigates the value of terminating the account here. Ratepayers are better served by the Commission's oversight through the MRTUMA of actual costs for the total market redesign and upgrade currently underway.

[1128] *Id*. at 127.

10.7.2.1.3. Long-Term, Mid-Term, and Short-Term Market Simulation Tools

In the pre-MRTU market, PPBU looked at pricing in three congestion zones and 24 tie points. With the introduction of nodal pricing, PPBU evaluates and considers prices at over 4,000 nodes.[1129] In order to better manage energy procurement costs, SCE claims it must expand its modeling capabilities for: (1) forecasting long-term nodal prices to evaluate energy contracts and RFOs; and (2) simulation of the overall market for differing time horizon to manage resource requirements.

For 2010-2012, SCE requests $2.75 million ($500,000 in both 2010 and 2011, $1.75 million in 2012) to develop Short-Term, Mid-Term, and Long-Term Modeling tools.[1130] SCE states it will use some COTS, with significant integration work, plus incur hardware, operating system, and database licensing costs.

TURN recommends the Commission disallow the funding on the grounds that it is related to DR and/or EE programs and proceedings.[1131] If the Commission were to authorize funding, then TURN would apply a 10% reduction.

SCE claims that TURN is mistaken; the tools will instead assist in management of SCE's wholesale energy costs. We agree. TURN did not establish that this project is included in other proceedings, or more than an expansion of existing functions to manage a much larger number of data points, particularly as to resources and timing.

[1129] *Id*. at 116.

[1130] *Id*. at 117.

[1131] TURN-9 at 30.

The Commission finds reasonable and adopts SCE's 2010-2012 forecast of $2.75 million.

10.7.2.1.4. Data Management Platform Upgrade (Phases 3 and 4)

PPBU's current data management system transfers forecasts of load, prices, generation resource outputs, meter data, weather data, and market operations data to PPBU's operating systems. The pre-MRTU system is taxed by higher than planned data storage and transfer requirements.

SCE forecast $10 million ($500,000 in 2010, $4.5 million in 2011 and $5 million in 2012) for the next phases of the Data Management Platform Upgrade. Costs are estimated to grow to $17 million by 2014.[1132] Phase 3 will simplify the interfaces between CAISO and SCE, expand data content to support evolving requirements, and improve retention and archiving. Phase 4 will expand content and add new analytical capabilities. Both Phases are large complexity in-house projects driven mostly by IT and Business unit labor cost: 90% of Phase 3 and 97% of Phase 4 estimated costs.

We share TURN's generally expressed concerns about IT cost estimates and find a 10% reduction reasonable for Phase 4. The forecast includes costs for unknown potential requirements, and SCE utilizes a generic comparable project template of grossly rounded labor costs. Some cost efficiencies should arise from the experience of implementing Phase 3, especially as to expanding data domains. Phase 4 costs are only forecast for 2012.

The Commission finds reasonable and adopts SCE's forecast for 2010 and 2011, and $4.5 million for 2012. The 2010-2012 total is $9.5 million.

[1132] SCE-08 at 122.

10.7.2.2. Integrated Demand Response (DR)

In D.09-08-027, the Commission adopted 2009-2011 DR activities and budgets for SCE and the other IOUs, including $13.158 million for SCE's DR System Support Activities.[1133] In D.10-12-024, we provided a consistent method for estimating the cost-effectiveness of all types of DR programs among the IOUs and each utility's DR portfolio.

The Commission recently considered applications by SCE and the other IOUs for funding to conduct DR programs and associated activities for the years 2012 through 2014.[1134] The consolidated proceeding examined the utilities' compliance with the cost-effectiveness measurements and inputs previously adopted for DR programs. In D.12.04-045, we authorized a 2012-2014 DR budget of $196,338,052 for SCE.

SCE states the two projects below are in response to the Commission's mandate to integrate DR into the CAISO markets. TURN recommends the Commission disallow funding for both projects because SCE stated it did not factor the project costs into DR program cost analysis. TURN also argues the expenditures should be delayed until the DR projects are found to be cost-effective when the IT costs are included.

The Commission has clearly stated that costs that promote DR in general and are not specific to or caused by an individual program (such as the two at issue), should be included in the evaluation of the utility's overall demand

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[1133] R.07-01-041.

[1134] A.11-03-001 (PG&E), A.11-03-002 (SG&E), and A.11-03-003 (SCE) were consolidated.

response portfolio.[1135] We do not find that the projects discussed below were otherwise funded by D.12-04-045.

10.7.2.2.1. Aggregated Demand Response (ADR)

CAISO requires SCE to provide demand forecast information and PPBU needs analytical tools to operate to dispatch ADR as a resource. SCE anticipates modifications to PPBU's short-term dispatch, long-term planning models, and position reports to accommodate DR as a resource for participating load.[1136] Some system requirements are unknown.

SCE requests $9.0 between 2010 and 2012 ($1 million in 2010, $4.5 million in 2011, and $3.5 million in 2012) for initiatives to implement major ADR functions, and to develop two others:

- <u>Interface DR to Customer Service System</u> – to collect customer data (e.g., DR registrations), billing information, and connection information; and
- <u>Interface DR to SCE's Distribution Management System/Advanced Load Control System – to provide instructions to reduce load when necessary.</u>

SCE estimates use of a high complexity COTS and medium complexity implementation which it will adapt to emerging CAISO requirements.[1137]

We agree that SCE needs to integrate its DR programs with the CAISO systems. It does not appear that the ADR functions are included in the $33.8 million previously authorized 2009-2014 DR Systems Support Activities. However, we share TURN's general concern about SCE's forecast costs for

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[1135] D.10-12-024 at 22; D.12-04-045 at 39-40.

[1136] SCE-08 at 133.

[1137] *Id*. at 136.

capitalized software projects, especially when the template method applies gross labor estimates without reflecting any economies or efficiencies from SCE's experience at integrating new applications with SCE's legacy systems.

Therefore, we find it reasonable to reduce the estimated cost by 10%. The Commission finds reasonable and adopts $8.1 million for 2010-2012 capital expenditures associated with the ADR project.

10.7.2.2.2. Risk Management ADR

SCE states it needs to analyze risk associated with advanced DR capabilities. SCE forecasts spending $750,000 in 2012, and $2.25 million through 2014, for a tool to analyze (1) customer response to price signals; (2) customer response based on weather; and (3) price of DR. SCE estimates a medium complexity, in-house solution because of the lack of a COTS software application.

The description of the ADR Risk Management project is reasonable and does not appear to overlap with the previously funded CAISO integration functions.

Based on our previously expressed concern about the unknown system requirements and template cost model, we find it reasonable to reduce the estimated cost by 10%.

Therefore, the Commission finds reasonable and adopts $675,000 for the ADR Risk Management is project in 2012.

10.7.2.2.3. Energy Procurement Planning

SCE states that PPBU needs to develop tools to meet increasingly complex procurement from MRTU and additional regulatory requirements that are or anticipated to be imposed.

10.7.2.2.4. Energy Procurement Planning Management

In order to effectively manage procurement planning to ensure cost-effectiveness and sufficient supply, PPBU states it must replace its spreadsheet applications with specialized, dedicated planning tools to handle the new complexities.

SCE forecasts $1.3 million in 2012, and a total of $7 million by 2014, for the EPPM project which includes several tools to perform analysis of procurement transactions and associated near-term financial exposures and risks.[1138] The forecast includes integration with the Commodity Management Platform discussed below.

DRA did not object and TURN recommends a 10% reduction for all IT.

SCE established a need to improve its data mining and decision analysis tools. However, based on our previously expressed concern about the unknown system requirements and template cost model, we find it reasonable to reduce the estimated cost by 10%.

The Commission finds reasonable and adopts $1.17 million for the EPPM project in 2012.

10.7.2.2.5. Energy Planning Platform

According to SCE, PPBU's current systems are not capable of capturing the complete portfolio and range of resource characteristics in one place.

SCE requests $4.55 million ($2.3 million in 2010 and $2.25 million in 2011) primarily to create a single data repository. It will also add a range of scenario

[1138] *Id*. at 142.

modeling and support SCE's competitive solicitations for power and gas. SCE intends to adapt the project to meet new CAISO and regulatory requirements.

DRA did not object and TURN recommends a 10% reduction for all IT.

SCE established a need for a systematic solution to replace various work-arounds developed to manage data spread out over several business units. However, based on our previously expressed concern about the unknown system requirements and template cost model, we find it reasonable to reduce the estimated cost by 10%.

Therefore, the Commission finds reasonable and adopts $4.095 million for 2011-2012 costs of the Energy Planning Platform.

10.7.2.3. Commodity Management Platform (CMP)

SCE must bid its resources and loads into CAISO's Day Ahead and real Time markets. The current system used by PPBU was implemented in 2003 and has been modified by various "off line," user-developed tools to fill voids that the system could not support.[1139]

SCE proposes the CMP, an integrated technology platform, upon which all energy-related transactions will be managed, settled, invoiced, and reported. It is expected to provide other functions such as inventory management, position management, valuation, and risk analytics. SCE requests a total of $14.4 million ($900,000 in 2010, $8.5 million in 2011, and $5 million in 2012) to implement CMP in two phases, concluding in 2012.

SCE established the need to replace the older system to accommodate the new energy markets. Automating the trade through the payment process is

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[1139] *Id*. at 149.

likely to reduce systemic and operational risk and may decrease operational costs. SCE's forecast includes license and vendor labor costs based on pricing from an RFP process. The in-house labor and hardware costs are higher than the High Complexity template due to the breadth of the new system, as well as expected high data storage requirements.

The Commission finds reasonable and adopts SCE's forecast for this project.

In summary, the Commission adopted $43.94 million (-40.1%) in 2010-2012 capital spending, and directed estimated costs of $24.1 million related to MRTU projects to be recorded in the MRTUMA for rate recovery. Aside from amounts to be recovered through the MRTUMA, the Commission adopted all but $5.310 million, or 7.2% of the $73.350 million request.

Power Procurement Business Unit Capital Expenditure Request ($000s)						
	Capital Request by Year					
Project Description	**2010 Recorded**	**2011 Forecast**	**2012 Forecast**	**Total 2010-2012**	**Adopted**	**Disallowed**
Communications Equipment	$1,500	$2,500	$2,500	$6,500	$3,250	$3,250
CAISO Market Enhancement	14,400	2,000	-	16,400	-	16,400*
Future Market/Performance Enhancement	-	-	7,700	7,700	-	7,700*
Market Simulation Tools	500	500	1,750	2,750	2,750	-
Data Platform Upgrade	500	4,500	5,000	10,000	9,500	500
Aggregate Demand Response	1,000	4,500	3,500	9,000	8,100	900
Risk Management Demand Response	-	-	750	750	675	75
Energy Planning Management Tools	-	-	1,300	1,300	1,170	130

Energy Planning Platform	2,300	2,250	-	4,550	4,095	455
Commodity Management Platform	900	8,500	5,000	14,400	14,400	-
Total PPBU Capital Expense	**$21,100**	**$24,750**	**$27,500**	**$73,350**	**$43,940**	**$29,410****

*Costs to be recorded for recovery through the MRTUMA.
**$24,100 of the disallowed total is costs to be recorded for recovery through the MRTUMA.

11. Operations Support Business Unit (OSBU)

The OSBU provides support and resources for SCE's business operations, including managing and maintaining buildings, offices, yards, land, and land rights. SCE owns or operates 221 buildings and 5.9 million square feet (sq. ft.) of office space across its territory. SCE also manages a fleet of approximately 6,500 vehicles, which are serviced and repaired at 43 SCE garages.[1140]

For OSBU, SCE forecasts a total of $111.925 million ($2009) in TY2012 for A&G expenses, an increase of 32% from 2009 recorded levels. SCE also forecast capital expenditures of $903.694 million ($nominal) over the period of 2010-2014. For 2010-2012, SCE's forecast totals $632.205 million.[1141]

DRA recommends a $31.76 million (39%) reduction to SCE's TY2012 O&M forecast and a $291.776 million (46%) reduction to SCE's 2010-2012 capital spending forecast.[1142] DRA used SCE's 2010 recorded expenditures which are $48.5 million less than SCE's 2010 forecast. TURN suggests several reductions to SCE's capital spending which are detailed in the capital spending discussion.

As addressed below, we adopt $96.818 million in TY2012 O&M, and $511.148 million for 2010-2012 capital expenditures.

[1140] SCE-09, Vol. 01 at 1.

[1141] *Id.* at 3, 5.

[1142] DRA OB at 350-351.

11.1. O&M - A&G: FERC 920/921, 923, 925, 931, and 935

OSBU's A&G expenses increased on average by approximately 15% or $9 million per year between 2005 and 2009.[1143] In the 2009 GRC, SCE requested $78 million for OSBU O&M; however, the Commission rejected SCE's budget-based forecast method for TY2009 and instead adopted $62 million.[1144] In this GRC, SCE reported it spent $84.6 million in 2009 and is requesting $111.925 million for 2012, again using a budget-based forecast.

We do not favor this forecast methodology for operational growth of routine, on-going activities. On the other hand, we have found that SCE is in a temporary state of transition in which it is implementing several new programs and initiatives to comply with statutory and regulatory directives including RPS, SmartConnect, smart grid, DR, DSM, and DP. SCE's headcount, which includes contingent workers, is likely to grow atypically, as is its need for office space during this rate cycle.

Therefore, we carefully review SCE's forecasts, particularly the validity of its assumptions about growth and new activities. We find that several of SCE's forecasts are excessive because SCE assumes that all of its O&M and capital expenditure requests in the GRC application are adopted. Another problem is that the addition of FTEs is supported by general statements of intended activities, rather than any analysis of workload and person hours required. Finally, we observe that SCE's forecasts do not consider economies of scale from

[1143] SCE-09, Vol. 02 at 4.

[1144] D.09-03-025 at 174-175.

repetitive projects, available labor or other embedded costs from closed projects and elimination of obsolete activities due to regulatory changes.

Based on the foregoing, we review SCE's O&M requests below.

11.2. Corporate Environment, Health & Safety (CEH&S): FERC 920/921, 923, 925

CEH&S is responsible for compliance with environmental, health and safety requirements, including the primary responsibility for obtaining environmental permits and other regulatory approvals. As of YE2009, CEH&S had a total of 97 FTEs, three Part-Time employees, and 25 Contingent Workers.[1145]

SCE's total TY2012 revised CEH&S request for all accounts is $12.355 million. The forecast is about 53% more than 2009 recorded costs which SCE claims is necessary due to new regulatory requirements, increased O&M due to completed capital projects, and more environmental assessments related to expanded operations, IR, and new transmission and generation facilities.

For accounts 920/921, SCE requests $7.28 million ($4.788 million Labor, $2.492 million Non-labor), including $1.005 million in labor costs to add 10 new FTEs, for the Air Quality Section, and $1.48 million to add 14 new FTEs overall to CEH&S.[1146] SCE provides general descriptions of what its divisions do and concludes that various numbers of FTEs should be hired to "fully staff" each section.

However, SCE did not include any workload analysis to support its request for (1) ten FTEs for the planned reorganization of the Air Quality section;

1145 SCE-09, Vol. 02 at 17.

1146 *Id*. at 20, 25, 27 and 29.

(2) one in Environmental Consulting Services to manage a Real Property Risk Assessment; (3) one in Environmental Projects for the biological and archeological staff; and (4) two for Water/Waste to manage storm programs. SCE also requests $500,000 of non-labor for environmental studies.

DRA recommends adoption of 2009 recorded costs, $5.202 million, and no additional funding for the fourteen positions or for the environmental studies. DRA argues the proposed costs are unnecessary because the department is engaged in routine, on-going activities.

DRA points out that CEH&S labor costs have been relatively stable, averaging $3.344 million from 2005 to 2009, TDBU has its own staff for environmental assessments, and because some new regulations cited by SCE have been in place since 2009, the compliance costs are embedded. Although DRA claims CEH&S has averaged about $233,000 per year for environmental studies, SCE states this is a misreading of the data and CEH&S only spent about $94,000 annually.[1147]

SCE responds that DRA ignores a 263% increase in capital work 2005-2009 (largely due to the RPS), and wrongly assumes that TDBU does duplicate work and that all implementation costs appear in the year regulations are adopted.

We are persuaded that some additional workload is likely during the rate cycle particularly related to air-quality activities, regulatory compliance, and additional TDBU capital projects. On the other hand, SCE provided insufficient explanation of how it arrived at its estimated labor needs. Furthermore, the

[1147] SCE-24, Vol. 01 at 9.

forecast is overstated because in this decision we have adopted lower growth forecasts and made reductions to SCE's capital spending requests.

Therefore, the Commission finds it reasonable to reduce SCE's incremental labor request by 50%, or $740,000, and associated non-labor by $49,000. In addition, we reduce SCE's non-labor request for the environmental studies by 50% based on embedded funding, reductions to capital projects, and SCE's failure to explain the value of a study relating to maintenance of software tools in the field and why this is not an IT cost.

11.2.1. Outside Services: FERC 923

SCE states it records costs in Account 923 for projects and materials requiring specialized expertise. SCE's TY2012 forecast of $1.503 million is a 204% increase over 2009 recorded expenses of $494,000.

The forecast is based on a 3YA (2007-2009) of recorded costs, plus incremental costs for environmental and compliance safety support, environmental review support, and support for developing and maintaining environmental GIS data bases. These are on-going activities for CEH&S.

DRA recommends adoption of the 5YA of $302,000 for this category of expense due to historic fluctuations in recorded costs. We agree with SCE's criticism that inclusion of 2005-2006 in the 5YA is not reasonable due to little or no spending in those years. Instead, the Commission finds the 3YA of $490,000 ($2009) to be a reasonable basis to forecast the account.

11.2.2. Corporate Safety: FERC 925

SCE records labor and non-labor expenses related to Corporate Safety in this Account. Historic costs have fluctuated between $1.6 million in 2005 and a high of $4.3 million in 2007.

For TY2012, SCE's revised forecast is $3.572 million, 30% more than 2009 recorded expenses.[1148] The labor increase of $541,000 is due to five new FTEs for a restructuring of the Corporate Safety group. The non-labor increase includes $35,000 related to the new FTEs, and funds to support and expand the Safety Culture program among employees.

DRA recommends the new FTEs be disallowed, and non-labor be reduced to $663,000, the 2009 recorded level.[1149] DRA argues that SCE has well-established and successful safety programs in place and does not show why it needs additional staffing or to expand the Safety Culture program.

We applaud SCE for the steady decline in its worker injury rate which demonstrates effective safety programs. This is not the same as acceptance of the current incident rate, as SCE suggests, but support for continued progress. SCE has undertaken other Safety Culture initiatives as a result of the NRC's findings at SONGS, but has not explained how the proposed expansion will complement other currently funded safety programs. SCE's support for the additional employees is vague and derivative of existing functions; however, we consider company-wide support for safety to be a priority.

Accordingly, the Commission finds it reasonable to reduce the labor increment by 20% to reflect reductions made in this decision to SCE's GRC requests, remove the corresponding non-labor of $7,000, and to otherwise adopt SCE's revised forecasts. The result is $3.457 million ($2.515 million Labor, $942,000 Non-labor). We also order SCE to provide, with its next GRC application, a summary of SCE's Safety Culture programs, achievements, and

[1148] JCE at 479.

[1149] DRA-11 at 12.

three years of recorded expenses to assist the Commission in its oversight and review of this important activity.

11.3. Corporate Resources: FERC 920/921, 931, 935

Corporate Resources is responsible for all activities related to managing SCE buildings, including implementation of SCE's settlement agreement with Disability Rights Advocates in the 2009 GRC to improve facility access.

SCE forecasts TY2012 O&M of $55.512 million for all accounts, a $10.8 million (24%) increase over 2009 recorded spending.[1150] The forecast is based on LRY, plus anticipated incremental expenses. The primary cost driver is SCE's expected increase in headcount and the anticipation of adding one million sq. ft. of office space during the rate cycle to accommodate these workers.

For Accounts 920/921, SCE's TY2012 forecast of $31.86 million ($16.27 million Labor, $15.59 million Non-labor), is $5.513 million more than in 2009. The $3.56 million increase in labor costs is due to the annualized cost of 22 FTEs added in 2009 and 2010, plus an additional ten SCE plans to add in TY2012: six in Facility Asset Management and four in Business Resources.[1151]

DRA recommends adoption of $27.39 million, SCE's recorded 2010 expenses for 920/921 because it views SCE's forecast as excessive and 2010 to be representative of SCE's staffing requirements.[1152] DRA contends the request is overstated based on SCE's GRC request, and 2009 recorded costs for these accounts contained embedded expenses for 2005-2009 employee moves.

[1150] SCE-09, Vol. 02 at 44.

[1151] *Id*. at 58, 62.

[1152] JCE at 480.

DRA also observes that after restructuring Corporate Resources in 2007-2008, staffing has been relatively consistent: 221 in 2009 and 216 in 2010.[1153] DRA does not think SCE has justified the new positions.

We agree with DRA that SCE's forecast is excessive. Although SCE disputes that prior TDBU employee moving costs are in 2009 recorded, SCE's growth assumptions are flawed as discussed above. SCE rejects 2010 costs as representative of its needs in TY2012. For example, SCE points to five new facilities that will open and require incremental O&M in 2011, plus additional required space through 2014.[1154]

We are persuaded by SCE's general descriptions that additional staffing and O&M will be necessary to manage the previously authorized expansions. However, the FTE support is vague, and the estimated expansion is overstated. Absent more detailed data, we find it reasonable to reduce SCE's incremental labor forecast by 40% to reflect reductions adopted in the GRC. SCE did not provide detailed information about its non-labor request. We estimate the associated non-labor to labor cost to be $28,000, and remove another $400,000 to reflect a 20% reduction to SCE's estimated 5,000 annual employee moves.[1155]

Accordingly, the Commission finds reasonable and adopts $30.008 million ($14.846 million labor, $15.162 million) for TY2012 Corporate Resources Accounts 920/921.

In addition, no party disputed SCE's forecast of $7.838 million for TY2012 in Account 935 where SCE records costs for maintaining and repairing structures

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[1153] DRA OB at 359.

[1154] SCE -24, Vol. 01 at 18.

[1155] SCE-09, Vol. 02 at 61.

and parking areas. Based upon a review of the record, the Commission finds SCE's forecast to be reasonable and adopts it.

11.3.1. Rents: 931

SCE records expenses in Account 931 for rental and/or lease costs of property and buildings that SCE uses, occupies, or operates, but does not own. SCE forecasts $15.814 million for TY2012, an increase of $5.266 million (50%) over 2009 recorded expenses.[1156] According to SCE, the forecast reflects actual negotiated lease terms for all of the identified facilities. Spending in this category has trended upward since 2005.

DRA recommends $12.13 million, SCE's 2010 recorded expenses, as the more reasonable forecast basis, primarily on the grounds that SCE overstates headcount growth (SCE's estimated 2012 headcount is only 106 workers more than SCE's recorded 2010 headcount).[1157] DRA concludes that the two new buildings leased in 2010 (opening in 2011) are sufficient for DRA's estimated growth and the rents are already embedded in 2010 expenses. Finally, DRA removes $312,000 for the third Energy Center which it opposes.[1158]

SCE provided DRA with copies of its existing leases to support the actual lease contract obligations. Although DRA pointedly notes that ratepayers are not required to pay any and all costs of a lease just because SCE signed it, there is no evidence that any of the leased space is not used and useful nor negotiated at

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[1156] *Id*. at 63.

[1157] DRA OB at 361.

[1158] JCE at 481.

higher than market rates. On the other hand, we remove $312,000 for SCE's proposed third Energy Center which we declined to fund during 2012.[1159]

Therefore, after making the $312,000 reduction, the Commission finds SCE's TY2012 forecast for Account 931 to be otherwise reasonable and adopts it.

11.4. Corporate Security: FERC 920/921, 923

Corporate Security is responsible for protecting all SCE personnel, assets, facilities and operations. No party took issue with SCE's forecast of $94,000 for Account 923 for a vendor to provide background checks of new hires. The Commission finds this forecast reasonable and adopts it.

As of 2009, this division had 45 FTEs, and 150 contract security uniformed security personnel. For TY2012, SCE is forecasting $22.073 million ($9.73 million Labor, $12.343 million Non-labor), a $10.1 million (84.4%) increase over 2009.[1160] The large increase in labor is due to adding another 45 FTEs, 14 of whom will work on an expected new version of NERC/CIP standards.[1161] SCE's request includes new FTEs across all nine divisions of Corporate Security, including 16 in Security Operations and Technology, seven in Investigative Support Services, seven in Investigative and Protective Services, and five in Business Continuity.

Additional drivers for these costs, states SCE, are increased workload due to employee growth, a commitment to enhance Emergency Preparedness, a greater scope and complexity of regulatory mandates, increased responsibilities, and more O&M in support of capital projects.

[1159] Section 11.10.5.

[1160] SCE-09, Vol. 02 at 73.

[1161] *Id.* at 73-74.

DRA recommends $11.97 million, which is SCE's 2009 recorded costs, on the grounds that costs for NERC/CIP standards are embedded from prior versions, no new version has been adopted, and employee growth is overstated.[1162]

We agree with DRA that SCE's forecast is overstated. As discussed in Section 11.12, we do not agree that SCE must incur substantial expenses in 2012 for a possible new version of NERC/CIP. SCE's forecast also does not reflect reductions to SCE's O&M and capital requests contained in this decision, and relies on generalized explanations of how these FTEs would assist, expand, enhance, or coordinate existing capabilities. Furthermore, SCE's itemized list of proposed positions adds up to $3.63 million for 41 positions, rather than $5.245 million for 16 positions utilized by SCE in its 2012 forecast for Account 920.[1163]

Although we consider corporate security to be an important function of providing safe and reliable electric service, we are concerned by SCE's proposal to double its Corporate Security staff without any workload analysis. SCE did not provide any support for some positions and requested funding. In addition, SCE states it has historically not staffed Corporate Security at adequate levels, diverted staff from high value security operations to administrative duties, and left some necessary functions unfulfilled.[1164] These are troubling choices by SCE and cast doubt on SCE's commitment to allocate the authorized funds to actual security activities.

[1162] DRA OB at 368-369; JCE at 482.

[1163] SCE-09, Vol. 02 at 93-99.

[1164] *Id.* at 89.

We also find that SCE's non-labor forecast is excessive and includes incremental costs without sufficient support as to urgency and/or cost. For example, SCE requests $2.35 million for on-going support of capital projects, $647,000 to hire better caliber security officers after release of the new NERC/CIP standards, $200,000 for seismic studies, $175,000 for "Case Management" software, and $25,000 for a video system to study the internet infrastructure. Although some of these projects may have merit, they lack supporting documentation.

Based on the foregoing, we find general support for some additional security activities. However, given the absence of substantive support for SCE's requests, it is reasonable to reduce SCE's incremental labor forecast by 50%, or $2.622 million, and SCE's incremental non-labor forecast by 50%, or $2.429 million.

Accordingly, the Commission finds reasonable and adopts $17.022 million ($7.108 million Labor, $9.914 million Non-labor) for Accounts 920/921.

11.5. Operations Support Services (OS): FERC 920/921

OS provides centralized support to the OSBU Senior Vice President and senior leaders of its departments.

For TY2012, SCE forecasts $11.918 million ($2009): $6.773 million Labor, $5.145 million Non-labor, the equivalent of 2009 recorded expenses. SCE explains that recorded costs increased by more than $10 million between 2006 and 2009 due to centralization of OS planning activities (including transfer of personnel from other business units), a change in chargeback accounting practices, and employee growth.

DRA recommends $4.466 million ($2009) based on 2008 recorded costs because DRA thought it likely that 2009 recorded costs included costs of transferred personnel that were also still in the prior business unit recorded costs.[1165] In rebuttal, SCE stated this was not correct and that it provided documentation to DRA.[1166]

According to DRA, the documentation was inconclusive because the tables did not allow DRA to determine the reductions had actually been made.[1167] We agree that the documentation provided is unclear, and may not support SCE's position.[1168] The document appears to show that approximately $7.2 million was transferred out, and $4.7 million remained. The total is similar to the 2009 recorded costs of $11.9 million.

Given the lack of clarity in SCE's documentation, and the varied historical activities in the account, we find that a 3YA is a reasonable basis to forecast 2012 costs.

Therefore, the Commission finds reasonable and adopts $6.347 million for TY2012 Operations Support costs. Based on the 2009 ratio of labor to non-labor of 56.8%, we allocate $3.605 million to Labor and $2.742 to Non-labor.

11.6. Real Properties: FERC 920/921

The Real Properties group manages land rights for electrical transmission, distribution, and generation, and acquires new land rights to support renewable energy and smart grid initiatives.

1165 JCE at 485.

1166 SCE-24, Vol. 01 at 56.

1167 DRA OB at 374.

1168 SCE-24, Vol. 03 at A-55 – A-60.

No party specifically disputes SCE's TY2012 forecast of $6.2 million ($3.45 million Labor, $2.75 million Non-labor). An increase of $702,000 (25.6%) in labor expense from 2009 levels represents an addition of 37 FTEs to the 2009 staffing of 199 FTEs. The biggest growth is 25 FTEs for the Land Acquisition group based on estimated capital projects and new transmission line permitting work.

We find that the forecast is excessive and not sufficiently support. SCE assumes that its entire GRC request is adopted and it provided generalized descriptions of new FTE workload. For example, in support of the 25 new FTEs, SCE states that it needs the positions to support projects that receive permitting. SCE points to an internal estimate that 57 new transmission line projects are likely to be proposed between 2010-2015; five projects had received permits at the end of 2009.[1169] There is no discussion of the probability of 57 projects going forward, how that would impact the workload of existing employees, or how SCE calculated the number of FTEs it thinks it needs.

We find it reasonable to reduce SCE's incremental labor request by 20%, or $140,000, due to reductions made elsewhere in the decision related to capital projects, and SCE's insufficient explanation of how it arrived at its FTE forecast. SCE provided no information about its 2012 non-labor request, thus, we apply 9.9% ($14,000) to calculate non-labor costs associated with reduced labor.

Therefore, for TY2012, the Commission finds reasonable and adopts $6.046 million ($3.310 million Labor, $2.736 million Non-labor) for Real Properties O&M.

[1169] SCE-09, Vol. 02 at 125.

11.7. Supplier Diversity and Development: FERC 920/921

In 1986, the California Legislature enacted Pub. Util. Code §§ 8281-8285 which made findings about the economic benefits of full and free participation by women-, minority-, and disabled veteran-owned business enterprises (collectively, "DBEs") in utility procurement, an area where these businesses had previously received a low proportion of procurement awards. Among other interests, the Legislature declared that by encouraging expansion of the number of potential suppliers, competition grows and economic efficiencies result to the benefit of ratepayers.

The Commission adopted GO 156 in 1988 to promote greater competition by expanding the available supplier base and to encourage greater economic opportunity for DBEs. In 2009, we initiated a rulemaking, R.09-07-027, to review the impact of GO 156 and its success in encouraging Commission-regulated utilities to seek the full and fair participation of WMDVBEs in their private procurement programs.[1170]

The Supplier Diversity and Development (SDD) organization, manages the procurement of materials/services and warehousing/logistics organizations within Supply Management division of OSBU. SDD identifies several 2009 initiatives it implemented to improve accurate data collection, reporting and analysis of DBE procurement.[1171] O&M costs for SDD trended downwards from

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[1170] D.11-05-019.

[1171] SCE-09, Vol. 02 at 132-133.

2006 ($2.3 million) to 2009 ($1.5 million) because, SCE explains, outreach costs were being covered by other units.[1172]

For TY2012, SCE forecasts $3.3 million, an increase of $1.82 million (123%) over 2009 recorded expenses. The $1.073 million incremental labor increase is due to ten new FTEs that SCE states will lead the development and implementation of new programs created by an increase of $747,000 in non-labor expense. The new programs are: (1) Supplier University; (2) DBE Supplier Registration Portal; (3) Supplier Training Program; and (4) Procurement Spend Planning and Forecasting. SCE also forecasts $473,000 in Outside Services (FERC 923) for costs associated with CPUC Clearinghouse and Professional Services Fees. No party disputed this forecast.

11.7.1. Parties' Positions

DRA recommends the Commission adopt $1.955 million, a 5YA of historic costs. During the record period of 2005-2009, DRA argues that SCE was able to comply with GO 156 and earn a variety of Supplier Diversity awards and honors.[1173] Thus no expansion is justified.

SCE disagrees with DRA's reductions on the grounds that D.11-05-019 included a number of amendments to GO 156 and many recommendations for improving the SDD program. Without additional resources, SCE contends it is unable to address the Commission's decision, particularly by providing and expanding technical assistance (TA) and capacity building (CB) programs.[1174]

[1172] *Id*. at 136.

[1173] DRA OB at 372-373.

[1174] SCE-24, Vol. 01 at 47.

Joint Parties do not discuss the TY2012 O&M request for SDD, but provide testimony that SCE's supplier diversity record is poor in contrast to other large utilities.[1175] Joint Parties criticized SCE's record on meeting the GO 156 target goals for DBE procurement, both by particular disadvantaged group and in the aggregate.[1176]

Joint Parties recommend that SCE be directed to:

- have senior management develop a program to swiftly and significantly improve DBE spending results, particularly as to Disabled Veteran-owned businesses;
- allocate $10 million over five years (1/4 of 1% of total procurement dollars) to develop a robust TA program focused on small businesses, especially DBEs; and
- work closely with CBOs, Commission staff, and other interested parties to develop SCE's improvement plan, to enhance community outreach, and to improve the quality, quantity, and availability of SCE's TA programs.

Joint Parties also recommended that the Commission adopt GO 156 reporting changes to include the total dollars awarded to DBE small businesses.

At the evidentiary hearings, SCE President Litzinger acknowledged some deficiencies in SCE's SDD results.[1177] However, SCE disputes Joint Parties' characterization of its record related to DBE spending by pointing to total dollars spent, both by under-represented group and in the aggregate, instead of the percentage of total procurement dollars. SCE also argues that its TA-Supplier University program was part of D.11-05-019, along with Commission direction to

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[1175] JP OB at 32.

[1176] JP-1 at 6-7.

[1177] TR at 635.

work with CBOs to improve outreach and assistance. According to SCE, its GO 156 reporting is in compliance with Commission requirements.

We affirm our support for the goals of GO 156 because we view them as beneficial for ratepayers and the communities served by the utilities. The recommendations made by Joint Parties are similar to those considered in the broad review of GO 156 conducted in R.09-07-027. For example, we recommended that utilities coordinate outreach and training spending with CBOs working in their service territories to increase the number of certified DBEs and to link small and diverse businesses to available TA and CB. Although we did not adopt the Supplier University proposal, we urged CBOs and utilities to work together to expand and improve the TA and CB elements of that proposal to assure the training actually reaches potentially competitive businesses.[1178] Finally we declined to order a specific amount of procurement dollars to be directed towards an element of a utility's supplier diversity program.

In this context, we turn to SCE's O&M request. We agree with SCE that D.11-05-019 included a number of recommendations for how utilities could improve their supplier diversity programs. It is reasonable for SCE to request additional O&M funds to implement new initiatives and enhanced reporting. On the other hand, it is not clear that SCE has fully embraced our view that utilities would be well served by active engagement with CBOs, particularly those with experience at providing technical assistance to small and diverse businesses. Nowhere in its written testimony did SCE reference working with

[1178] D.11-05-019 at 73-74, FoF 33 and 34.

CBOs. This is the type of narrow vision we observed in the rulemaking decision and urged utilities to reject.

The Commission finds SCE's TY2012 request to be reasonable. However, we also strongly urge SCE to consider our recommendations in D.11-05-019 to work with CBOs on TA and CB, to share resources, conduct outreach, work together, exchange constructive criticism, share best practices, and assist smaller and newer reporting companies with their supplier diversity programs.[1179] This activity may include direct grants, joint ventures, and other collaborative mechanisms to better reach target businesses and business associations. Because SCE is required to provide an annual report to the Commission on its Supplier Diversity program and results, we do not ask for any additional reports in the next GRC.

11.8. Transportation Services Division (TSD)

SCE operates a varied vehicle and equipment fleet. TSD provides fleet management/operational services, aircraft support, crane operations, and other transportation services, as well as providing training and regulatory compliance. TSD costs are charged back and absorbed by SCE's operational business units.[1180] TSD expenses have been growing steadily since 2005.

SCE forecasts TSD O&M chargeback costs of $138.4 million in TY2012, a $22.9 million (20%) increase over 2009. SCE primarily attributes the increase to

[1179] D.11-05-019 at 63, FoF 3.

[1180] SCE-09, Vol. 02 at 152, Table IX-7.

rising fleet ownership costs ($11.6 million) and fuel costs ($7.4 million). The charge backs are allocated 40% to O&M and 60% to capital.[1181]

DRA recommends $127.7 million for TY2012, based on 2010 recorded total expenses, but did not explain why its use of 2010 unadjusted, recorded expenses was more reasonable.[1182]

DRA argues SCE's forecast is excessive because it assumes no reductions by the Commission to SCE's requested capital expenditures or incremental O&M. Both DRA and TURN oppose the OnBoard Technology project discussed in Section 11.14.1, and recommend removal of $1.4 million ($500,000 Labor, $900,000 Non-labor) from SCE's forecast for O&M support.[1183] TURN also objected to SCE's TY2012 vehicle license fee (VLF) estimate of $1.2 million due to a lack of supporting documentation and pending legislation to restore lower rates. In its update testimony, SCE reduced its estimate to $600,000 based on the effective statutory change. For purposes of this GRC, TURN accepts the revised estimate as reasonable.

SCE rejects a direct correlation between reductions to proposed capital spending and its TSD forecast because replacements, rather than additions, are the significant driver of expense. The replacement forecast is driven by expectations of early retirements due to expected new emission standards. SCE is correct that replacements account for more ($53.3 million) than additions ($15.8 million). However, SCE's additions are primarily driven by workload

1181 JCE at 483.

1182 DRA-11 at 32.

1183 JCE at 814.

changes due to infrastructure replacement and growth.[1184] SCE also plans to add 29.5 positions by 2012, including 17 in Fleet Maintenance to manage a larger vehicle inventory.

We find that the $15.8 million in vehicle additions linked to capital projects should be reduced by 10% to reflect reductions made in this decision. We also find it reasonable to remove $1.4 million in O&M related to the OnBoard Technology project that we declined to authorize in Section 11.14.1.[1185]

Accordingly, the Commission finds it reasonable to reduce SCE's forecast by $ 3.180 million, including 10% of estimated additions ($1.58 million) and fleet maintenance ($200,000), and OnBoard Technology O&M ($1.4 million).

Therefore, the Commission approves $135.220 million of the $138.400 million requested for TDS and charged back to individual business units, a reduction of 2.3%.

In summary, the Commission therefore approves a total of $96.818 million of the requested $111.925 million for all other OSBU O&M expenses, a reduction of 13.5%.

Operations Support Business Unit O&M Expense Request ($000s)*				
Section	**Description**	**Requested ($000)**	**Adopted**	**Disallowed**
11.2	CEH&S	$12,355	$10,188	$2,167
11.3	Corporate Resources	55,512	53,348	2,164
11.4	Corporate Security	22,167	17,116	5,051
11.5	Operations Support Services	11,918	6,347	5,571
11.6	Real Properties	6,200	6.046	154

1184 SCE-09, Vol. 02 at 155.

1185 JCE at 814.

11.7	Supplier Diversity	3,773	3,773	-
	Total OSBU O&M Expense*	**$111,925**	**$96,818**	**$15,107**

* Transportation Service Department O&M expenses are charged back to SCE's operational business units and for the purpose of this decision are not included in the table above.[1186] For clarity, we are providing a separate line item showing TSD's 2012 O&M request with respective adopted and disallowed amounts:

Section	Description	Requested ($000)	Adopted	Disallowed
11.8	TSD	$138,400	$135,220	$3,180

11.9. Capital Expenditures

SCE emphasizes that in the 2009 GRC, the Commission reduced the Operations Support capital request by $212 million, or 54.5%, causing a number of projects to be deferred in order to address emerging priorities.

For 2010-2012, SCE's forecast totals $632.205 million: $224.961 million in 2010, $204.748 million in 2011, and $202.496 million in 2012. SCE forecasts a cumulative 2010-2014 total of $903.694 million,[1187] approximately 145% more than SCE spent in the previous five years (2005-2009). To support its budget-based forecast, SCE provided an explanation of the need for each project and a cost breakdown.

SCE first provided 2010 recorded expenditures for OSBU of $162.429 million, but in its post-hearing Opening Brief, SCE claimed 2010 recorded costs are actually $176.48 million. This number is supported

[1186] These costs are recorded to both the O&M FERC accounts and capital work orders for SCE's business units, with TSD's costs charged back to and embedded within the forecasts and testimony of the individual business units.

[1187] SCE-09, Vol. 03 at 1, fn. 2. (This total excludes forecast capital expenditures for one project currently in confidential negotiations. However, SCE's potential expense is nominal when compared to total annual spending for Corporate Resources.)

in the Joint Comparison Exhibit.[1188] However, SCE requests adoption of its 2010 forecast.

To develop a project scope, SCE utilized headcount and seat increases from across SCE's application, and higher capital spending to replace aging infrastructure and equipment. To develop its forecasts, SCE estimated costs for: (1) construction; (2) furniture, IT and equipment; (3) design, plan check and permitting fees; (4) a variable project management cost; and (5) a 10% contingency factor.[1189] This is a reasonable method, despite objections to some of SCE's numbers.

SCE bases its non-electric facility seat demand not only on a projected increased headcount of all FTEs, part-time employees and contingent workers, but also on shifts to more seated workers. For capital projects, SCE assumed an increase of approximately 2,500 seated workers by 2012 and 3,000 by 2014.

Although we do not review 2013 or 2014 forecast capital investment, we include SCE's estimates for perspective on SCE's requested growth in capital spending.

11.9.1. Parties Positions

DRA recommends adoption of 2010 recorded expenditures of $162.429 million, a reduction of $62.5 million (27.8%) to SCE's 2010 forecast.[1190] Based on a 6YA (2005-2010) of historical costs, DRA recommends adoption of $89 million in both 2011 and 2012. The 5YA (2005-2009) of annual capital

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[1188] JCE at 577.

[1189] SCE-09, Vol. 03 at 10.

[1190] DRA-11 at 37.

spending by OSBU is $74 million. DRA did not comment on SCE's updated recorded 2010 OSBU capital expenditures.

DRA is concerned that OSBU capital spending has increased from a low of $23.7 million in 2005to a record high in 2010. DRA criticizes certain capital projects, and emphasizes that it does not necessarily approve of others. DRA recommends use of the 6YA as the most reasonable method to forecast 2011 and 2012 expenditures by capturing recent trends. SCE criticizes DRA's position as ignoring SCE's testimony supporting the necessity and expense of each individual project.

TURN argues that SCE's request is excessive and should be substantially scaled back. TURN recommends several reductions to SCE's 2010-2012 forecast, including elimination of the contingency factor from all 2012-2014 construction estimates, lower project management and furniture costs, and decreases to certain project estimates.[1191]

We adopt SCE's updated 2010 recorded capital expenditures because it is the most current information about actual capital spending.[1192] Although historic costs are informative, we do not adopt DRA's capital forecasts based on averages of recorded spending. SCE is in a period of transition which drives many OSBU projects, particularly related to efficient reallocation of space, new and complex technologies, and facility safety and reliability. Instead we examine each project below.

1191 TURN-5 at 23.

1192 SCE provided 2010 unadjusted, recorded capital expenditures for OSBU in the aggregate; therefore, the RO model will reduce each 2010 project forecast by 21.551% to achieve the differential between SCE's total 2010 forecast and total recorded expenditures.

11.9.2. Contingency and Project Management Costs

TURN recommends the Commission eliminate SCE's proposed 10% contingency factor. SCE states it is both reasonable based on its experience, and industry practice, for construction projects to include a 10% contingency factor. For 2012, SCE's forecast for contingency costs is $7.884 million.

In the 2009 GRC, the Commission rejected a similar proposal by SCE and found that application of a generic contingency adjustment to a "rough order of magnitude (ROM)" cost estimate was unreasonable.[1193] SCE states it understood the Commission's concerns in 2009 and has reduced the contingency from 15% to 10% and applied it only to hard construction costs.[1194]

As before, we find that SCE's cost estimates are at a preliminary stage and not sufficiently reliable to make a determination that any contingency is warranted. The Commission finds it reasonable to remove the 2012 contingency factor of $7.884 million for such construction projects. This adjustment is addressed by project below.

SCE argues that all of SCE's non-electric facility projects require project management services.[1195] SCE included a project management cost for each construction project based on other aggregated costs multiplied by what it calls an industry standard percentage.[1196] SCE estimates $6.55 million for 2012.

[1193] D.09-03-025 at 247.

[1194] SCE-24, Vol. 02 at 41.

[1195] SCE-24, Vol. 03 at 47.

[1196] SCE-09, Vol. 03 at 10.

TURN asserts that SCE's proposed project management costs are excessive and unjustified. SCE estimates project management costs as high as 24%, with an average of 6.71%.[1197] TURN recommends removal of SCE's estimated $6.55 million for 2012 project management costs, and application of a 3% project management cost totaling $2.807 million to authorized capital expenditures for that year in its place, a differential of $3.743 million.[1198]

SCE provided very little support for its requested project management costs. SCE stated it applied varying percentages to building construction costs, and furniture, signage, and IT costs. However, SCE did not establish that the calculated percentages or amounts are reasonable. On the other hand, TURN's support for 3% is ambiguous and limited.[1199]

We are not persuaded that project management costs should be a flat percentage of project costs, but SCE's estimated percentages are opaque; they do not correlate to project costs or complexity. For example, the GO4 Infrastructure/Restack project is more complex and costly than the GO3 Infrastructure/Restack project, yet GO4 has a lower management percentage of 7.5%, while the less expensive GO3 project applies 8.03%.

Therefore, absent better evidence, the Commissions finds it reasonable to reduce the difference between SCE's and TURN's 2012 project management forecasts by 50%, or $1.872 million of the $3.743 million differential.[1200]

[1197] TURN OB at 311.

[1198] *Id*. at 312.

[1199] TURN-5 at 25.

[1200] JCE at 929.

11.9.3. Furniture Costs

SCE forecasts expenditures of $7.773 million in 2012 for furniture, including workstations, desks, chairs, conference room tables/chairs, and equipment.[1201] SCE estimates spending $26.2 million in 2012-2014.

TURN argues that SCE's furniture costs have grown from $6,500/person in 2009, vary widely in the OSBU capital estimates and exceed the $6,800/person used by CSBU for its 2012 forecasts.[1202] Although SCE did not breakdown costs in this category, TURN estimates that SCE requests about $10,000/workstation. TURN seeks a reduction of approximately 34%, to $5.103 million, in 2012, based on $6,800/person.

SCE argues that TURN erred in its calculations. First, SCE states its estimated furniture costs are $8,715/person.[1203] Second, the comparison of 2009 and 2012 furniture costs ignores an expanded work scope in the 2012 forecast. Lastly, SCE claims that CSBU costs are inapposite because CSBU purchases are often specialized ergonomic components and CSBU does not furnish common areas.[1204]

SCE did not address the widely varying furniture costs included in its cost estimates. Some of SCE's project descriptions refer to additional furniture, but this did not necessarily correlate to the furniture costs. For example, the River grade Remodel includes workstations for 299 people, but includes no reference to other furniture needs. SCE's furniture estimate equates to $10,585 per person.

[1201] SCE-24, Vol. 02 at 44.

[1202] TURN-5 at 26-27.

[1203] SCE-24, Vol. 02 at 46.

[1204] *Id*. at 45.

We understand that common area furniture may be included, but find that the furniture forecasts of SCE's planning estimates are excessive and unsupported. Therefore, we reduce SCE's 2012 OSBU capital furniture requests by 50% of the difference between SCE's and TURN's forecasts, or $2.284 million, discussed by project below.[1205]

11.10. Corporate Resources - Capital

SCE's 2010-2012 forecast is $527.849 million for 2010-2012 Corporate Resources projects in six categories. SCE plans to make 70% of its estimated 2010-2014 expenditures, of more than $750 million, by 2012. Substitution of 2010 recorded expenditures reduces the 2010-2012 forecast to $474.644 million.

The table below summarizes SCE's forecasts and 2010 recorded expenses for Corporate Resources.

SCE's CORPORATE RESOURCES CAPITAL PROJECTS ($nominal 000s)

Category Description (#) projects	Forecast 2010	Recorded 2010	Forecast 2011	Forecast 2012	Forecast 2010-2012	Forecast 2010-2014 Total
New Buildings (2)				$37,000	$37,000	$126,750
Headquarters (8)	71,758	61,684	45,100	10,300	127,158	127,158
Critical Facilities (4)	43,000	20,003	71,600	8,700	123,300	143,100
Field Facility Asset Preservation (14)	26,828	10,705	11,765	23,300	61,893	64,493
New Field facilities (6)	27,955	15,902	21,007	13,650	62,612	62,612
Blankets (10)	27,962	36,006	31,214	56,710	115,886	230,366
TOTALS (44)	$197,503	$144,298	$180,686	$149,660	$527,849	$754,479

[1205] JCE at 927.

11.10.1. New Buildings

SCE added over 650,000 sq. ft. of office space in 2009 and 2010 to accommodate expected growth. In its Opening Brief, SCE took its adjusted 2014 seat count of about 3,000, and increased it again to 3,490 new seats based on overcrowding. No reference to the record for this increase was provided. SCE states new facilities to seat workers require 24 to 36 months of advance planning.

SCE requests $37 million in 2012 to begin New Building projects to provide 1,500 of the required new seats by 2014.[1206] SCE identifies three projects: Metro (construct two buildings, 250,000 sq. ft./mostly TDBU); Orange County (acquire one building/100,000 sq. ft./TDBU and CSBU); and General Office 2 (GO2) Renovation (repurpose 50,000 sq. ft. of old data center for general employees). SCE forecasts the total costs of the projects to be $126.75 million by 2014.

DRA recommends no funding because it views the facilities as unnecessary.[1207] According to DRA, SCE seated its 26,256 workers in 2010 within existing facilities. SCE has two other projects that will provide space for 1,150 additional employees in 2011: General Office 5 (GO5) and Pomona Innovation 3 building.[1208]

We acknowledge that SCE will have some worker growth from 2009 to 2012 and some decrease in unseated workers such as meter readers. We also agree that new facility projects require significant lead time. On the other hand, SCE's forecasts assume that its entire O&M and capital requests will be approved and SCE will spend the revenue as set forth in the GRC application. In fact, this

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[1206] SCE-09, Vol. 03 at 13-14.

[1207] JCE at 677.

[1208] DRA-11 at 39.

decision makes significant reductions to SCE's requests and SCE will make further operational choices after a revenue requirement is adopted. SCE's enhancements to the employee count are also vague and unsupported.

In addition, there are inconsistencies between SCE's testimony and supporting work papers for these projects. For example, SCE states the Metro buildings will house 900 employees,[1209] yet the project Planning Detail Sheet states the two buildings will provide 2,500 seats.[1210] We find the forecast costs for new facilities are rough cost estimates based on overstated need.

We do not specifically disallow any particular project, but observe that SCE should reconsider its need to begin to build and acquire 350,000 sq. feet in 2012. For example, there is some evidence that the Orange County project may be oversized, if not unnecessary, and the size of the Metro project might be reduced if the GO2 Renovation proceeds.

Therefore, the Commission finds reasonable and adopts a total of $20 million in 2012, inclusive of $3.125 million in adjustments discussed previously for contingency ($2.482 million), furniture ($213,000), and project management ($430,000):[1211] the equivalent of the $12 million sought by SCE for planning and engineering costs related to the Metro project, and a portion of the additional planning and engineering costs sought by SCE for new leased space which it can apply to revising its plans for new facilities to correspond to lower worker growth and the actual capacity of the Metro Buildings.

[1209] SCE-09, Vol. 03 at 13-14.

[1210] Work Papers, SCE-09, Vol. 03 at 32 (Scope).

[1211] JCE at 925-929.

11.10.2. Headquarters

SCE requests funds for remodeling and renovating its office buildings at the Rosemead headquarters, and to acquire additional office space. According to SCE, its headquarters buildings are overcrowded, must be upgraded for safety, and remodeled to meet changing business needs.

SCE's revised 2010-2012 forecast is $117.084 million covering eight capital projects, and estimates no further capital spending in this rate cycle.

For each project, SCE provided a project detail sheet and a breakdown of the planning estimate. No party specifically disputed any project within this category of capital spending.

TURN recommends reductions to all 2012 capital projects, and identified contingency, furniture, and program management costs in this category. As discussed above, we adopt $2.113 million in reductions to SCE's 2012 forecast of $447,000 in contingency and $1.666 million in furniture and contract management costs, respectively.[1212]

Based upon a review of the record, we find that SCE has justified the eight projects to renovate and remodel older buildings and building systems (e.g., electrical, mechanical, heating, ventilation and air conditioning (HVAC), etc.). New office space will also be added in critical areas.

Therefore, the Commission finds reasonable and adopts $53.287 million for 2011 and 2012 ($45.100 million in 2011 and $8.187 million in 2012).

[1212] JCE at 925, 929.

11.10.3. Critical Facilities

Critical Facilities contain crucial corporate operations and require 24/7 operational status. For 2010-2012, SCE forecasts a total of $123.3 million ($71.6 million in 2011 and $8.7 million in 2012) to replace specialized electrical, heating/cooling, and mechanical infrastructure.[1213] In 2010, SCE recorded $20 million, less than half of the $43 million it originally forecast.

Of the four projects SCE identifies, TURN opposes any funding for the Rosemead Data Center (RDC) and DRA opposes any funding for the Alhambra Data Center (ADC).

According to SCE, the RDC was originally constructed in 1974 to standards that no longer match the workloads required for today's more complex data environment. The RDC has also exceeded the industry standard for useful life of a data center.

SCE identified five critical areas of severe operational deficiencies that cannot be addressed without long-term shutdown of the building. SCE concluded it is no longer cost-effective to schedule the repairs and improvements necessary to extend and expand the RDC. Of particular concern are electrical power load and temperature systems.

Given SCE's projected future computing needs, including highly data intensive applications discussed elsewhere in this decision (e.g., SAP, ERP, SmartConnect) and cyber security requirements, SCE determined the most cost-effective solution was to construct a new data center. The data centers are discussed separately below.

[1213] SCE-09, Vol. 03 at 35.

No party specifically disputed two of the projects in this category: the Irwindale Business Center (IBC) Purchase and Remodel ($19.8 million) and the DPC Phase 4 AGOC Upgrades[1214] ($10.3 million). Upon review of the record, we find that SCE has justified the need and estimated expense for the DPC project which will address three critical areas of risk in the building that contains the TDBU Grid Control Center. The Commission adopts SCE's 2010 recorded expenditures and 2011 forecast of $1 million. No expenditures are forecast in 2010-2012 for the IBC project and we do not review it here.[1215]

11.10.3.1. ADC

This $103 million capital project includes the costs necessary to construct the building ($66 million), build out the network infrastructure ($21 million), and migrate the existing applications from the RDC ($16 million).

DRA recommends no additional funding for the ADC because the Commission authorized over $30 million twice before for data center replacement, but SCE's management delayed the project.[1216] SCE also requested almost $23 million in 2009 capital expenditures to refresh RDC equipment.[1217] DRA argues it is unreasonable for ratepayers to provide funding for the third time, regardless of the solution proposed.

SCE explains its changing solutions for the data center replacement project are the result of a complex project, extensive planning, and rapidly changing

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[1214] SCE does not provide a detailed explanation of the name of this project.

[1215] JCE at 925 shows one $80,000 expenditure which will be disallowed for forecasted contingency cost in 2012 for the IBC purchase and remodel.

[1216] JCE at 678.

[1217] DRA OB at 364.

technology, particularly due to emerging smart grid and SmartConnect requirements.

We find that SCE has justified the need for this project. After consideration of alternative sites, and a competitive bid process for construction, SCE selected SCE-owned brownfields land as the site to build the ADC and selected the lowest bidder for construction.[1218] TURN did not remove any contingent or project management costs for this project.

Therefore, the Commission finds it reasonable to adopt SCE's 2011-2012 forecasts for this project.

11.10.3.2. Rosemead Data Center (RDC) – Useful Life Extension

The data center replacement project was originally presented in SCE's 2006 GRC where we approved $31.5 million to replace the building. However, SCE reallocated the funding to what it calls more critical spending linked to increased load growth. In the 2009 GRC, we approved $40 million to construct an annex to the RDC to take critical load off the RDC, but SCE concedes that by the time the decision was issued, it was planning the new ADC. SCE does not identify what happened to the 2009 funds, except to say the funds were either "conserved or expended for projects benefiting ratepayers."[1219]

SCE forecasts $10 million ($5.5 million in 2010, and $4.5 million in 2011) to perform significant upgrades to the electrical and HVAC systems which it claims are necessary to ensure reliability until the ADC is completed in 2013.

[1218] SCE-09, Vol. 03 at 49.

[1219] SCE-24, Vol. 02 at 18.

According to TURN, SCE spent $6.4 million in 2010 which will become a stranded cost due to SCE's switch to a new data center. TURN recommends disallowance of 2010 recorded costs and the $4.5 million requested in 2011.[1220]

We are persuaded that some capital spending is necessary to maintain a strong degree of reliability for RDC until the ADC is operational. The upgrades are essential and probably will not be stranded because SCE intends to re-purpose the RDC facility. In any case, risk of an electrical system failure arising from reduced maintenance is not acceptable at such a critical facility. However, SCE should have conserved enough of the 2009 authorized funds to support the RDC life extension costs because SCE had already decided to build a new data center and knew it would need to make critical upgrades to support the RDC in the interim.

Therefore, the Commission disallows SCE's 2011 request of $4.5 million.

11.10.4. Field Facility Asset Preservation

SCE's 2010-2012 forecast of $61.893 million ($26.828 million in 2010, $11.765 million in 2011, and $23.3 million in 2012) covers 14 projects to preserve, maintain or enhance the value of SCE's field facilities, relocate or repurpose facilities, and to address changes in the physical environment. All but one, are expected to be completed by 2012. SCE's 2010 recorded expenditures of $10.705 million are 60% less than SCE's forecast.

TURN focuses on one project, SmartConnect – Meter Reader Space Reclamation. As a result of the SmartConnect deployment, space formerly used by meter readers and field employees at 22 service centers will become available

[1220] JCE at 923.

for remodeling to standard office space. SCE estimates spending $6.3 million in 2011 and $2.6 million in 2012 for the renovations.

TURN does not oppose the project, but sees the expenditures as the result of SmartConnect deployment which should be recovered through the ESCBA.[1221] We disagree. As discussed previously, the ESCBA was established to capture the costs of deployment and integration of smart meters, not ancillary costs.

TURN also identified three projects for specific reductions to SCE's 2012 forecast related to contingency, furniture, and project management costs:[1222]

- Long Beach Regional Office Remodel - $1.161 million
- TDBU Training Facility (TDBU Training) - $810,000
- SmartConnect Meter Reader Space Reclamation - $387,000

We find it reasonable to reduce SCE's forecasts in the manner discussed above, a total of $1.43 million for contingencies and $928,000 for furniture and contract management costs, a total of $2.358 million.

Although SCE explained the need for each of the 14 projects, the evidence was inconsistent as to the cost model SCE used and did not prioritize projects. In general, we agree with SCE's argument that remodeling, renovating, and re-purposing are cost efficient ways to deal with space availability and space demands within the company.

Therefore, we adopt SCE's $35.065 million 2011-2012 forecasts for the Field Facility Asset Preservation projects, subject to the reductions described above. Further, we remind SCE that the additional office space generated by these

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1221 TURN-5 at 28; JCE at 922.

1222 JCE at 924-929.

projects will reduce the number of seats SCE will need to develop or acquire through new facilities.[1223]

11.10.5. New Field Facilities

For 2010-2012, SCE forecasts capital expenditures of $62.612 million ($27.955 million in 2010, $21.007 million in 2011, and $13.65 million in 2012) for six projects. SCE recorded $15.902 million for 2010 expenditures.

The largest request is $21.7 million to purchase and remodel an office building in Santa Clarita to accommodate worker growth and space needs for field crews and equipment, primarily due to IR and major transmission projects. SCE's project list includes additional parking, unit relocations, and expansion of yard and office space.

Two projects are at issue. TURN does not dispute SCE's need for the Gateway Parking Structure project, but views SCE's 2010-2012 forecast of $11.970 million as excessive.[1224] TURN contends SCE's costs work out to be about $100/sq. ft., in contrast to evidence that the industry standard is $52.60/sq. ft. TURN recommends reducing SCE's 2012 forecast to cap project spending at $7.133 million, using the standard cost.

SCE did not rebut this argument and we reduce SCE's total forecast to $7.133 million. In addition to 2010 recorded costs ($0.447 million), the Commission finds it reasonable to levelize the remaining authorized expenditures of $6.686 million and adopt $3.343 million in 2011 and 2012. SCE's forecast contingency costs of $479,000 are included in the overall reduction.

[1223] *See*, Section 11.10.1.

[1224] JCE at 921.

DRA recommends disallowance of $3.25 million in 2012 for construction of a third Energy Center in leased space.[1225] Consistent with our discussion in CSBU Section 6.5.1.1, the Commission disallows funds for this project at this time. As we said, this project is neither urgent nor necessary for the delivery of safe and reliable electric service.

TURN also identified reductions of $397,000 to SCE's 2012 forecast for the Supply Chain Material Transport, Land, Building and Improvements project related to contingency and furniture costs.[1226] We find these reductions to be reasonable: $352,000 for contingencies and $45,000 for furniture. SCE provided sufficient evidence to justify the other requested projects. Therefore, the Commission adopts SCE's 2011 and 2012 forecast capital expenditures subject to the reductions above.

11.10.6. Blankets

Capital spending is separated into ten project categories for ongoing expenditures in similar types of work where the costs are relatively small. For 2010-2012, SCE requests $115.886 million, and estimates spending $230.366 million by 2014.

SCE's 2010 recorded 2010 expenditures were $36.006 million, $8 million more than SCE's initial forecast of $27.962 million. Both DRA and TURN recommend reductions to 2011-2012 expenditures for two categories: Service Center Modernization and Energy Efficiency.

1225 *Id.* at 679.

1226 JCE at 924-927.

Service Center Modernization

SCE estimates $10 million in 2012, and annually through 2014, to support modernizing five of SCE's 36 Service Centers.[1227]

DRA recommends zero funding because it questions the necessity of the projects.[1228] DRA states SCE only spent about 3% of the more than $48 million requested in 2009 for similar projects, cancelling seven of the ten projects and deferring two more.

TURN observes that SCE's decision not to spend the authorized funds undercuts its 2009 claim that the identified centers were functionally obsolete.[1229] In addition, TURN proposes expenditure reductions for three of the service centers based on repair and replacement estimates contained in a 2007 SCE Facilities Report.[1230]

SCE responds that substantial funding cuts in 2009 resulted in a focus on seating workers, but the service centers continue to incur the effects of insufficient maintenance.[1231] Moreover, the repair and replacement estimates in the Facilities Report do not include Furniture, Fixtures, and Equipment, soft costs, or costs related to changes in the use of the buildings.

The Service Centers are important to reliability and ratepayer satisfaction. We are persuaded that TURN's comparison of SCE's project forecasts to the

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[1227] SCE-09, Vol. 03 at 104 (The Service Centers are in San Joaquin, Santa Ana, Fullerton, Redlands, and Ontario).

[1228] JCE at 680.

[1229] TURN-05 at 32.

[1230] JCE at 919.

[1231] SCE-24, Vol. 02 at 25.

Facilities Report repair estimates is misplaced. On the other hand, we apply the previously adopted reductions for contingency, furniture, and project management costs totaling approximately $1 million.

Therefore, the Commission finds reasonable and adopts $9 million for 2012 expenditures.

Energy Efficiency

SCE requests $5 million annually from 2010-2012 to implement energy efficiency, sustainability, and conservation projects for its own non-electric building portfolio. Recorded expenditures for 2010 were only about $3 million which SCE attributes to a permit delay.[1232]

In 2009, we reduced SCE's request from $20 million annually to $5 million, directed SCE to treat it as a pilot program, and to report back in the 2012 GRC.[1233] SCE actually recorded only $1.4 million in 2009, but presumes the Commission intended to maintain funding in this rate cycle. In support, SCE describes several solar/PV, lighting replacement, and water conservation projects it intends to undertake between 2010 and 2014.[1234]

DRA recommends $2.5 million per year to reflect SCE's actual expenditures in 2009-2010.[1235] TURN recommends $1 million annually limited only to energy efficiency projects.[1236]

[1232] *Id*. at 31.

[1233] D.09-03-025 at 241.

[1234] SCE-09, Vol. 03 at 110-113.

[1235] JCE at 681.

[1236] *Id*. at 920.

SCE would apply the majority of funds to water conservation, primarily landscaping projects. TURN argues such projects should be funded through O&M savings achieved from lower water bills over a five-year period. This is reasonable, but we disagree that SCE's solar PV projects for its own buildings meet the purposes of SCE's recently scaled-back SPVP program.

As we said in 2009, SCE should actively promote and take the lead in energy efficiency and conservation. However, it is hard to assess SCE's initiatives because SCE did not provide the sort of cost-benefit information we expected.

For 2011-2012, we adopt $3 million each year, similar to SCE's 2010 recorded expenditures. In the next GRC, SCE shall provide a cost-benefit analysis of the Energy Efficiency Blanket projects it has implemented since 2009, and allocate quantified cost savings after 2011 as an offset to revenue requirement through the BRRBA.

Finally we also reduce SCE's 2012 forecasts for the Service Center Modernization Program by $896,000, the Garage Modernization Program by $536,000, and for the Small Projects Blanket category by $513,000, for contingency, furniture, and project management adjustments.[1237]

11.11. CEH&S – Capital

SCE's 2010-2012 forecast for this category of capital spending is $31.873 million. A summary of SCE's request is provided below.

[1237] *Id*. at 925, 927, and 929.

CEH&S Capital Projects ($nominal 000s)						
Description	Forecast 2010	Recorded 2010	Forecast 2011	Forecast 2012	Forecast 2010-2012	Forecast 2010-2014
CEH&S Compliance Mgmt System	$11,000	$8,722	$11,000		$22,000	$22,000
Wetlands Restoration	3,133	3,938	2,011	2,026	7,170	11,857
SONGS Reef Construction	1,126	1,069	751	826	2,703	5,488
TOTALS	$15,259	$13,729	$13,762	$2,852	$31,873	$39,345

The largest project proposed by SCE is implementation of the Compliance Management System (CMS) to automate company-wide compliance activities related to environment, health, and safety rules and policies. SCE forecast $11 million in 2011 to complete Phase 3 and fully implement CMS.

For 2011-2012, SCE also seeks $4.037 million to continue implementation of the Wetlands Restoration project and $1.577 million to continue monitoring the SONGS Reef Construction project. Both of these projects are conditions attached to SCE's Coastal Development Permit for SONGS and remain incomplete.

No party disputed the CEH&S capital projects. Upon review of the record, the Commission adopts 2010 recorded expenditures and finds SCE's 2011-2012 forecasts to be reasonable and adopts them.

11.12. Corporate Security – Capital

As discussed previously, SCE expects NERC to soon issue Version 4 of the CIP standards; Version 3 became effective in October 2010. SCE also implements other security systems projects primarily directed at thefts, break-ins, and cyber crime.

SCE's estimated capital spending totals $28.2 million for 2010-2012, including $24.2 million to initiate the Critical Infrastructure Protection Physical Security project (CIPPS). SCE's total budget-based forecast of $34.6 million for

CIPPS is the result of multiplying a hypothetical installation cost of $288,500 per site by 120 locations which SCE believes will fall with the scope of Version 4.[1238]

Corporate Security Capital Projects ($nominal 000s)						
DESCRIPTION	**Forecast 2010**	**Recorded 2010**	**Forecast 2011**	**Forecast 2012**	**Forecast 2010-2012**	**Forecast 2010-2014**
CIPPS Project				$24,200	$24,200	$34,620
Security systems	2,000	981	1,000	2,000	5,000	13,500
TOTAL	**$2,000**	**$981**	**$1,000**	**$26,200**	**$29,200**	**$48,120**

DRA relied on a 4YA (2007-2010) of NERC/CIP recorded costs to arrive at its forecast of $1.5 million for 2012 capital expenditures.[1239] DRA views SCE's request as speculative because NERC has not adopted new standards.

Recorded expenses from 2007-2010 are insufficient because far more locations are currently projected to be in the scope of Version 4, according to SCE. For example, 2009 expenditures addressed Version 1 which only covered 37 locations. SCE observes that DRA's proposal would result in an unacceptable 25-year timeline for compliance.

We agree with DRA that the standards have not been adopted and SCE's hypothetical estimate is speculative. On the other hand, NERC filed Version 4 with FERC in February 2011; prior versions have been approved 12-16 months after filing, with effective dates five to 12 months later.[1240] Based on the historical timeline, any Version 4 would not likely become effective until

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[1238] SCE-09, Vol. 03 at 148.

[1239] DRA-11 at 44.

[1240] SCE-24, Vol. 02 at 52.

2013 at the earliest. Both Versions 2 and 3 became effective in 2010, yet DRA states SCE recorded less than $1 million related to the CIP implementation.

It is reasonable for SCE to keep its eye on the NERC process and to undertake some preliminary planning based on the Version 4 submitted for review. However, it is premature for SCE to assume that it could deploy a new version to the remaining 83 sites in 2012, or that its forecast is more than a rough estimate.

Therefore it is reasonable to reduce SCE's 2012 CIPPS request to $3 million, a 29% increase over 2009 recorded, to support advance planning. If a Version 4 is adopted, the majority of these costs will most likely occur in 2013-2014. Upon review of the record, we find SCE's other 2011-2012 forecasts for Corporate Security projects to be reasonable and adopt them.

Therefore, in addition to 2010 recorded, the Commission finds reasonable and adopts $1 million in 2011 and $5 million in 2012 for Corporate Security projects.

11.13. Transportation Services – Capital

SCE forecasts $9.319 million for 2010-2012 capital expenditures in four project categories for Transportation Services and recorded $994,000 in 2010. Vehicle purchase costs drive additional expenses to $15.228 million by 2014, and are the result of a change in lessor and lease termination options.

Transportation Services Capital Projects ($nominal 000s)						
DESCRIPTION	**Forecast 2010**	**Recorded 2010**	**Forecast 2011**	**Forecast 2012**	**Forecast 2010-2012**	**Forecast 2010-2014**
Vehicle Purchase	$1,500	$445	$1,350	$2,400	$5,250	$9,650
TSD Tools	412	579	410	920	1,742	2,615
Helicopter Parts/Equipment	200	(30)	205	810	1,215	1,852

Helicopter Lease Buyout			1,112		1,112	1,112
TOTAL	**$2,112**	**$994**	**$3,077**	**$4,130**	**$9,319**	**$15,228**

We observe that SCE's estimated costs spike for one year in 2012 in every sub-category except the one-time lease buyout. However, no party disputed any specific project.

Therefore, the Commission finds reasonable and adopts SCE's 2011-2012 capital forecasts for Transportation Services.

11.14. Other Capital Projects

SCE forecasts capital expenditures for IT and other projects totaling $33.964 million for 2010-2012, recording $2.427 million in 2010. IT projects account for more than 60% of the total, and more than half of the total IT estimate is for the OnBoard Technology project.

IT and other Capital Projects ($ nominal 000s)						
DESCRIPTION	**Forecast 2010**	**Recorded 2010**	**Forecast 2011**	**Forecast 2012**	**Forecast 2010-2012**	**Forecast 2010-2014**
OnBoard Technology				$10,600	$10,600	$15,600
SM-Diverse Business Enterprises	500	0		1,500	2,000	3,500
SM-Contract Authoring Replacement	1,920	0	1,680		3,600	3,600
Technology Capability Initiative				3,550	3,550	5,299
High Definition/Infrared/Still Camera			1,000		1,000	1,000
IT SUB-TOTAL	2,420	0	2,680	15,650	20,750	28,999
Supply Mgmt-Dept Furniture & Equipment	1,120	392	1,965	365	3,450	4,180

Various Rights-Of-Way Acquisitions	850	(1,311)	850	850	2,550	4,250
OSBU Capital Projects-Blanket Work Orders Under $1 million	3,697	3,346	728	2,789	7,214	9,092
IT&OTHER TOTAL	**$8,087**	**$2,427**	**$6,223**	**$19,654**	**$33,964**	**$46,521**

No party objected to any of the Other Capital projects, with the exception of OnBoard Technology which is discussed separately below.

One project bears comment. Between 2010 and 2012, SCE requests over $2 million for Supply Management-DBEs to improve the ability of business units to have timely information necessary to increase identification and development of diverse businesses. The project builds on earlier efforts by SCE that developed reporting processes, procedures and tools to ensure accurate reporting and better internal accountability regarding spending with DBE suppliers.[1241]

As we stated previously, the Commission strongly supports the goals of GO 156 for a procurement process that encourages a broadly representative supplier pool. Based upon a review of the record, the Commission finds reasonable and adopts SCE's 2011 and 2012 forecasts, and 2010 recorded expenditures for projects in this category except for Onboard Technology.

11.14.1. OnBoard Technology Project

SCE wants to install OnBoard telemetry in all of its 4,500 on-road vehicles to improve fleet management through vehicle-specific performance monitoring. According to SCE, the technology also provides broad asset mapping, a fuel

[1241] SCE-09 at 167.

efficiency module, a driver behavior module, and is complementary to the TDBU/GIS/CMS project.[1242]

SCE forecasts spending $10.6 million in 2012 to launch the project, and another $5 million to complete it.[1243] SCE states other large companies have such technologies which can result in fuel savings, more nuanced servicing, and more informed purchase/sale decisions.

DRA and TURN recommend no funding for this project. DRA argues that SCE has not justified the need for the project, and failed to spend $3 million requested in the 2009 GRC for a similar Fuel Tracking /Monitoring system.[1244] TURN also focuses on the economics of the project and SCE's failure to quantify or apply potential cost savings to offset the project cost.[1245] Taking SCE's broad assumptions of 12.5% annual fuel savings, the $3,500 per vehicle cost would not be recovered for eight years.

SCE conceded that in 2009 the state of onboard technology was in flux causing SCE to decide to wait a few years before starting the project. The regulatory landscape is still in flux, according to SCE, and SCE did not establish any urgency for this project.[1246]

Therefore, the Commission disallows SCE's 2012 request for $10.6 million for the Onboard Technology project.

[1242] Section 5.14.1.1.

[1243] SCE-09, Vol. 03 at 160.

[1244] DRA-11 at 45, JCE at 918.

[1245] TURN-5 at 28-29.

[1246] SCE-24, Vol. 02 at 9.

The total adopted OSBU capital expenditures for 2010-2012, using 2010 recorded expenditures, is $511.131 million, a decrease of $72.593 million (12.7%).

Operations Support Business Unit Capital Expenditure Request ($000s)					
Capital Request by Year					
Project Description	Forecast 2011	Forecast 2012	Total 2011-2012	Adopted	Disallowed
11.10.1 New Buildings	-	$37,000	$37,000	$20,000*	$17,000
11.10.2 Headquarters	45,100	10,300	55,400	53,287	2,113*
11.10.3 Critical Facilities	71,600	8,700	80,300	75,800	4,500
11.10.4 Field Facility Asset Preservation	11,765	23,300	35,065	32,706	2,359*
11.10.5 New Field Facilities	21,007	13,650	34,657	25,817	8,840*
11.10.6 Blankets	31,214	56,710	87,924	80,979	6,945*
11.11 CEH&S	13,762	2,852	16,614	16,614	0
11.12 Corporate Security	1,000	26,200	27,200	6,981	20,219
11.13 Transportation Services	3,077	4,130	7,207	7,207	0
11.14 Other Capital Projects	6,223	19,654	25,877	15,277	10,600
Total OSBU Capital Expense	**$204,748**	**$202,496**	**$407,244**	**$334,668**	**$72,576**

Total adopted OSBU Capital expenditures: $176.480 million recorded (2010) + $334.668 million (adopted 2011-2012) = $511.148

*Inclusive of adjustments for contingency, furniture and/or project management costs.

For all OSBU Capital expenditures, SCE's revised 2010-2012 forecast, using 2010 recorded expenses, is $511,021 million, a decrease of $72.703 million (12.8%).

12. Ratemaking

Revenue requirements are calculated by a computer model developed by SCE referred to as the Results of Operations (RO) model. DRA concluded that it reflected the appropriate method of determining the Summary of Earnings.[1247]

[1247] DRA OB at 375.

In April 2011, SCE updated the RO model to account for SCE's proposals to handle bonus depreciation resulting from the TRA and removal of costs associated with SONGS seismic studies and license renewal. DRA used the updated RO model to calculate its Results of Operations.

In addition to the GRC revenue requirements forecast in this proceeding, SCE also tracks certain costs in balancing accounts and memorandum accounts. Recovery of those accounts is determined through various other proceedings, such as the Energy Resource Recovery Account (ERRA), to recover generation-related fuel and purchased power costs. SCE requests that some of these previously authorized balancing accounts and memorandum accounts be continued and others be terminated. We discuss these below.

12.1. Elimination or Modification of Accounts

DRA and other parties ask the Commission to deny various SCE requests to eliminate certain accounts and integrate cost recovery into the GRC. SCE's argues that retention of the balancing and memorandum accounts is supported by parties as an alternative to properly analyzing whether SCE's forecasts are reasonable. We disagree. The Commission has previously considered these issues elsewhere in the decision and found that retention in this rate cycle of the following accounts serves as a protection to ratepayers:

- <u>Solar Photovoltaic Project Balancing Account</u> – In Section 4.6.1.4, we declined to adopt SCE's request to eliminate the SPVPBA particularly in light of uncertainties arising from a revised and reduced program.
- <u>Fuel Cell Project Memorandum Account</u> – In Section 4.6.3, we declined to adopt SCE's request to eliminate the FCPMA because the project has been delayed and modified, including the loss of one of three projects.

- Market Redesign and Technology Upgrade Memorandum Account – In Section 7.2.1, we declined to eliminate the MRTUMA because we found that MRTU implementation was expected to be a multi-year process and CAISO has not yet determined all requirements for subsequent Releases.
- Medical Program Balancing Account – In Section 8.6.3.2, we declined to adopt SCE's request to eliminate the MPBA because we continue to be concerned about the significant and uncertain cost increases forecast and the disparate views in supporting documentation.
- Project Development Division Memorandum Account – In Section 4.5, we declined to eliminate the PDDMA because we found that SCE should continue to demonstrate that tracked expenses are associated only with authorized support functions.

In Section 8.6.1, we agreed with SCE to retain the Pension Costs Balancing Account (PCBA) as a two-way balancing account. We declined to adopt DRA's recommendations to either covert the PCBA to a one-way balancing account or to impose a shareholder cost-sharing mechanism for pension costs as insufficiently supported and premature given there has been no broad review of pension cost recovery.

12.2. Sale of Four Corners

In Section 4.2.2.5, we discussed the authorized sale of the Four Corners power plant on or by October 1, 2012. For purposes of ratemaking, SCE asked the Commission to authorize its full 2012 O&M request for Four Corners, and promised to reduce the revenue requirement, as of the sale date, by removing all included Four Corners' costs, including O&M, depreciation, and the return and taxes associated with the reduced rate base.[1248]

Primarily due to changes in the law regarding GHG, and the proposed sale, we agreed with DRA that the 2012 O&M expenses should be reduced to exclude the pro rata costs of the Unit 5 overhaul scheduled for 2014. We reduced SCE's 2012 O&M forecast by 25% to reflect the estimated sale date. We still expect SCE to make the additional reductions impacting revenue requirement as of the actual sale date.

12.3. Other Operating Revenues (OOR) Service Fee Implementation

In Section 6.7, we discussed CSBU-related OOR. Overall, SCE forecasts TY2012 CSBU-related OOR of $37.783 million, a decrease of $15.609 million from 2009 recorded levels. We rejected DRA's request to reduce the forecast based on timing of the release of this decision because the 2012 GRC Revenue Requirement Memorandum Account addresses the timing differences.

12.4. Credit to Catalina Electric for A&G Allocation

SCE proposed a fixed credit of $900,000 against its total A&G expenses as the appropriate allocation to Catalina Island to reflect the amount to be recovered from SCE's Catalina water and gas revenue requirements. TURN objected to SCE's calculation and recommended the credit be calculated using SCE's four-factor allocation of 0.00085213% applied to the total A&G dollars authorized in this GRC, excluding franchise fees.[1249]

[1248] SCE-25, Vol. 01 at 13.

[1249] TURN-3 at 103.

SCE agrees with TURN's proposal for the A&G allocation. The Commission finds it reasonable and adopts it.

12.5. Shareholder Sharing of Pension and Benefit Costs

As in prior rate cases, SCE removed pension and benefits costs associated with below-the-line FERC accounts when calculating costs for ratepayers, a total of $2.78 million in 2012. After TURN questioned whether all such labor costs had been removed, SCE removed an additional $109,000.

TURN calculated all TY2012 pension and benefit costs it viewed as associated with labor assigned to shareholders in the GRC process. SCE agreed to remove TURN's total of $754,000 from the revenue requirement. The Commission finds this result reasonable and adopts it.

13. Sales and Customer Forecast

SCE forecasts 4,898,748 customers in 2010, growing to 4,955,992 in 2012, and to 5,042,591 by 2014.[1250] We previously discussed SCE's customer and meter forecasts in Section 5.7.5. We found that SCE's forecasts were excessive due to overly optimistic assumptions about economic growth and residential building during the rate cycle. Instead, we adopted TURN's base (middle) case forecast for new meter sets, the equivalent of about 27% less than SCE's 2010-2012 forecast, and 17% less than SCE's 2010-2014 forecast, covering all customer categories. TURN did not provide corresponding revised forecasts for SCE's customers and sales.

Between 2011 and 2012, application of the 27% reduction to SCE's forecast 2009-2012 customer increase yields a count of 4,940,536.

[1250] SCE-10, Vol. 01 at 59, Table VI-21.

The Commission finds the latter method a reasonable method to forecast customer growth and adopt the TY2012 customer forecast of 4,949,062.

13.1. Sales Forecast

SCE forecasts electricity sales of 83,334 Gigawatt hours (GWh) in 2010, 84,729 GWh in 2011, and 85,920 GWh in 2012. SCE attributes sales of 85,849 GWh in 2009 to abnormal summer weather. Assuming a moderate economic recovery beginning in 2011, SEC's forecast reflects a 1.7% increase in sales between 2010 and 2011, and 1.4% between 2011 and 2012.[1251] SCE and DRA relied on econometric models to forecast electric sales to various customer classes.[1252] DRA concluded the results were sufficiently similar that DRA does not dispute SCE's sales forecasts.

However, we adopted a lower forecast of customer growth as described above. Based on adoption of a 27% lower forecast of new meter sets by 2012, we calculate a similar reduction to SCE's forecast increase to sales between 2009 and 2012. The Commission finds reasonable and adopts the resulting revised sales forecast of 85,221.6 GWh for TY2012.

14. Cost Escalation

SCE filed its application and prepared its testimony using, in part, baskets of labor and non-labor escalation rates from IHS Global Insight's Utility Cost Information Service (UCIS).[1253] Pursuant to the Rate Case Plan, SCE updated its labor and non-labor escalation rates based on the UCIS O&M Costs projection for

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[1251] *Id*. at 43.

[1252] DRA OB at 376 (SCE used ISI Global Insight, and DRA used UCLA Anderson Forecast for the Nation and California, for sales projections).

[1253] SCE-10, Vol. 01 at 64.

2Q2011.[1254] Similarly, SCE updated its non-labor escalation rates for Palo Verde and Four Corners, and the capital escalation rates for labor costs historically embedded in capital expenditures.[1255]

DRA disagrees with SCE's labor escalation which is discussed below. No party disputed SCE's non-labor escalation rates. However, In D.12-03-034, we approved SCE's sale of its interest in Four Corners in 2012, therefore, no escalation rate is necessary for subsequent years. Escalation rates for post test years are discussed below in Section 16.

The Commission finds reasonable and adopts SCE's updated non-labor and capital labor escalation rates for 2010-2012.

14.1. Labor Escalation

SCE's proposed 2010 labor escalation rate of 3.3% is based on a weighted average of represented and unrepresented employees and historic wages and salaries paid. For 2011 and 2012, SCE initially used a weighted average of forecast labor escalation rates from HIS Global Insight's UCIS related to electric power workers. For 2011, SCE updated the rate to reflect a 4% wage increase for SCE's represented employees.[1256] SCE's updated proposed labor escalation rates are 2.71% in 2011 and 2.61% in 2012, 3.0% in 2013, and 2.65% in 2014.[1257]

DRA proposes using the Global Insight forecast for represented workers for the purposes of 2010 and 2011 cost escalation. The result is a rate of 2.8% in

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[1254] SCE -84 at 31-32, Tables IX-8 and IX-9.

[1255] *Id*. at 33, Table IX-10.

[1256] *Id*. at 17.

[1257] *Id*. at 31.

2010, 2.49% in 2011, and 2.22% in 2012.[1258] DRA did not explain the basis for its substitution of Global Insight indices for known labor costs in 2010 and 2011, other than the 4% union contract increase is much higher than the Global Insight forecasts.[1259] CCUE argues that DRA's approach is flawed because it does not include known labor rates from enforceable labor contracts.[1260]

DRA's position is unsupported and, according to SCE, is at odds with DRA's position in both prior SCE rate cases, and PG&E's 2011 GRC.[1261] SCE argues it would be unreasonable to not use the agreements which are valid, enforceable, and necessary to attract talent.[1262]

We do not embrace SCE's premise that whatever wages and increases are included in a collective bargaining agreement with its represented workers are *ipso fact*o reasonable for purposes of rate recovery or labor escalation. However, in this proceeding, DRA failed to present any argument that the escalation rate based on bargained for wage increases is unreasonable, or that SCE's methodology was flawed.

Therefore, the Commission finds reasonable and adopts SCE's updated labor escalation rates for 2010-2012.

1258 DRA-4 at 7-8.

1259 *Id*. at 6.

1260 CCUE OB at 21-22.

1261 SCE OB at 307.

1262 *Id*. at 308.

15. Other Operating Revenue (OOR)

Company-wide, SCE forecasts $187.091 million in OOR recorded in FERC Accounts 450 through 456 and subtracted from total operating costs to determine the TY revenue requirement.[1263]

We previously addressed account-specific OOR issues in Sections 5.17.7 and 6.7 and adopted SCE's forecasts. In addition, we address OOR from sale of property in Section 18 and from sale of Non-Tariffed Products and Services in Section 21 of this decision.

As identified above, the Commission has adopted an aggregate TY2012 OOR forecast of $165.608 million, 11.5% less than SCE's request.[1264]

16. Post Test-Year Ratemaking (PTYR)

SCE asks the Commission to adopt a PTYR mechanism to provide additional revenues it views as necessary to cover the costs of doing business in 2013 and 2014 due to factors including inflation, limited productivity gains, and customer growth.[1265]

[1263] SCE-10, Vol. 01 at 71.

[1264] *See*, Section 5.17.7 TDBU OOR = $110.441 million; Section 6.7 CSBU OOR = $37.783 M; Section 18 Property Sale gain = $.713 M; Section 21 NTP&S = $16.671 million. Total OOR = $165.608

[1265] *Id*. at 96.

SCE's Changes to Revenue Requirements ($000s) CPUC Jurisdictional[1266]			
Description	**2012**	**2013**	**2014**
11/10 Application	$6,285,299	$6,883,781	$7,495,907
SCE Adjustments from DRA/Intervenors	6,200,673	6,702,971	7,297,333
RO Model corrections/Rebuttal	6,213,879	6,720,810	7,320,927
JCE &Update Testimony	6,294,278	6,782,720	7,399,657
Final Difference from Application	8,979 (+0.1%)	<101,061> (-1.5%)	<96,250> (-1.3%)
Proposed Annual Revenue Requirement difference		$488,442 (+7.8%)	$616,937 (+9.1%)

The Commission has historically taken various approaches to address a utility's request to recover cost increases that occur between test years. After a period of performance-based ratemaking that ended with the 2003 GRC, the Commission restored a revenue requirement adjustment mechanism for SCE. For 2004-2005, the Commission's adopted PTYR mechanism escalated 2003 O&M and adopted SCE's budget-based forecast of capital expenditures.

In SCE's 2006 GRC, the Commission instead applied escalation rates to both O&M and capital spending for both PTYRs.[1267] The Commission modified its approach again in the 2009 GRC, with escalation of one combined O&M and capital-related revenue requirement by two specific percentages for 2010 and 2011 (4.25% and 4.35%, respectively).[1268]

16.1. SCE's Position

SCE recommends essentially the same PTYR as it did in 2009. For 2013 and 2014, SCE proposes O&M escalation using the methodology in

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1266 SCE-25, Vol. 01 at 1, Table I-1; SCE-84 at 2, Table I-1.

1267 SCE OB at 309-310.

1268 D.09-03-025 at 306.

Section 14 with some adjustments. SCE would "true-up" the escalation by incorporating bargained wage increases approved before this decision is adopted, and the most recent Global Insight labor and non-labor escalation rates, through an AL filed by November 1 of the prior year. CCUE supports SCE's plan to include contracted wage increases in labor escalation rates.[1269]

For capital-related cost increases, SCE's PTYR includes capital additions associated with its budget-based forecast of capital expenditures, totaling about $4.7 billion in 2013 and $4.1 billion in 2014. According to SCE, the escalation based on SCE's Board-approved capital budget, would be subject to a one-way balancing account if its capital spending budgets are not fully implemented. PG&E supports SCE's proposed method of separately computing expense and capital adjustments.[1270]

As discussed previously, SCE assumes full deployment of SmartConnect in 2012 and inclusion of SmartConnect costs in 2013. Lastly, SCE expects to update the revenue requirement for authorized SONGS refueling outage costs and include a mechanism to address major exogenous changes to SCE's costs (i.e., the Z-factor).

SCE argues that the PTYR adopted in 2009, and proposed by DRA in 2012, contained a methodological error. Specifically, SCE states the flat rate adjustments left costs incurred during construction of capital projects "stranded" in FERC Account 107, Construction Work in Progress (CWIP). Thus, the authorized revenue requirement for 2010, states SCE, was insufficient to recover CWIP when a project went into rate base in 2010. As a result of the adopted

[1269] CCUE OB at 23.

[1270] PG&E OB at 2.

2009 PTYR, SCE claims it was forced to temporarily restrain capital spending to ensure that recorded costs did not exceed the 2010 and 2011 authorized revenue requirements.

SCE views DRA's and Aglet's PTYR mechanisms as "unsound" and not supportive of SCE's credit rating which is adverse to ratepayer interests.[1271] The Consumer Price Index (CPI) does not adequately track SCE's capital-related costs (e.g., depreciation, return, taxes), argues SCE, and any prior adoption through settlements is not precedential. Moreover, SCE argues that DRA proposes to continue the error adopted in 2009 which will prevent recovery in 2013 of year-end 2012 CWIP which will close to rate base in 2013.

16.2. DRA's Position

DRA does not oppose a PTYR but argues that SCE's mechanism will yield excessive increases in 2013 and 2014. DRA's alternative proposals are very similar to what it proposed in the 2009 GRC:[1272]

- Increases to 2012 base revenue requirement from the Urban CPI would be 2.0% for 2013 and 2.2% for 2014, net of any revenue requirement for Four Corners;
- Three components of costs would receive separate treatment:
    - No more than $227.7 million of SCE's requested $251.3 million in SmartConnect revenue requirement should be included in the 2013 revenue requirement;
    - Amortization of legacy meters is included in 2012 revenue requirement, remains embedded in 2013 and 2014, and is not escalated; and

[1271] SCE-25, Vol. 01 at 35-36.

[1272] DRA OB at 405-406.

- o The $48.1 million difference between DRA's 2012 and 2013 forecast for customer-related expenses be incorporated into development of the 2013 and 2014 attrition revenue requirement;

- Alternatively, if the Commission adopts a mechanism similar to SCE's proposal, then increase the adopted 2012 levels of plant additions by 2.5% for inflation. O&M expenses should be escalated by 2.0% in 2013 and 2.2% in 2014 based on the CPI. Medical benefits would be escalated separately by 5% in 2013 and 6% in 2014.

We summarize the resulting differences between SCE's proposed PTYR and DRA's primary proposal below.

Post Test Year Base Revenue Requirements ($000s)[1273] SCE v. DRA			
Description	SCE revised Revenue Requirements	DRA Recommended	DRA v. SCE
2012	6,294,278	5,439,152	< 855,126> (-13.5%)
2013	6,782,720	5,657,942	<1,124,778> (-16.6%)
2012 to 2013 Proposed Change	+488,442 (+7.8%)	+218,790 (+4.0%)	<269,652>
2014	7,399,657	5,777,320	<1,622,337> (-21.9%)
2013 to 2014 Proposed Change	616,937 (+9.1%)	119,378 (+2.1%)	<497,559>

DRA argues that use of CPI is simpler than multiple indices and observes that SCE's proposed increases exceed the attrition increases granted to any utility in recent years.[1274] In addition, SCE's 2008-2012 wage escalation rates are more than 30% higher than Global Insights Average Hourly Earnings increase for the

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1273 DRA-21 at 3, Tables21-2 and 21-3, SCE-84 at 2, Table I-1.

1274 *Id*. at 14-16.

same years.[1275] Further, the CPI-based attrition mechanism offers SCE an incentive to better manage labor expenses in 2013-2014. DRA claims that as long as SCE has a "blank check" for rate recovery of any negotiated wage increases, SCE's management has no incentive to control labor costs.[1276]

SCE anticipates full deployment of SmartConnect by 2012. However, if deployment is delayed into 2013, SCE proposes to file an AL to adjust the 2013 revenue requirement to recover "business as usual" CSBU expenses instead. DRA does not oppose this result but argues the amount should be capped at $227.7 million to reflect impacts of the TRA. Although supportive of a Z-factor mechanism, DRA's position is that SCE must continue to meet the criteria outlined in D.05-03-023, and include exogenous events that decrease costs.

Lastly, DRA rejects SCE's characterization of the 2009 PTYR mechanism as erroneously "stranding" CWIP, as well as SCE's inclusion of budget-based capital additions, notwithstanding creation of a one-way balancing account.[1277] The farther out in time the projects are planned, the greater the likelihood they will change or be eliminated, states DRA. Furthermore, parties did not have the time or resources to review SCE's estimated 2013 and 2104 capital spending.

16.3. Aglet's Position

Aglet directly challenges SCE's claim it needs to recover PTY cost increases from higher capital spending or the impact of inflation on operating expenses. By reference to Commission adopted reductions to SCE's requests in prior GRCs,

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[1275] *Id.* at 16

[1276] *Id.* at 17.

[1277] DRA-21 at 21-22.

Aglet argues that SCE has not provided sufficient evidence that its capital requests are necessary and any reductions will compromise service or earnings.

Aglet echoes DRA's criticisms of SCE's proposed PTYR. For example, Aglet observes that SCE's mechanism is overly complicated because it relies on many different escalation factors and specific forecasts of capital costs for hundreds of projects spanning two years.[1278] Of concern to Aglet is that complexity provides an incentive to inflate cost estimates.[1279]

Aglet accepts DRA's primary recommendation to apply CPI-based fixed percentages consistent with the Commission's decision in the 2009 GRC. Aglet has long supported use of CPI forecasts to escalate utility revenue requirements in attrition years because it is simple, widely understood by consumers, is easily verified, is rarely revised, and shows no long-term bias compared to utility price indices.[1280] Aglet arrived at a slightly different escalation rate of 1.9% for 2013 and provided no calculations of 2013 or 2014 proposed revenue requirements. Although in support of a Z-factor mechanism, Aglet requests that SCE be limited to intentional government acts as adopted in the settlement of PG&E's 2011 GRC.

However, Aglet rejects DRA's alternate PTYR proposal because it is unnecessarily complicated and utilizes 2012 plant additions for PTY revenue requirements.

[1278] Aglet-1 at 21.

[1279] Aglet OB at 23.

[1280] Aglet-1 at 27.

16.4. Discussion

We agree with SCE that a PTYR is appropriate during this rate cycle because of significant infrastructure replacement, integration of new technologies, and uncertain economic conditions. However, we declined to adopt similar proposals from both SCE and DRA in the 2009 GRC. We find our comments in 2009 to still be applicable:

> 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. In addition, no party other than SCE provided or analyzed detailed post-TY plant addition forecasts in determining increases. We cannot fault other parties for not recommending detailed PTYR budgets . . . [it] imposes a significant burden on resources.[1281]

Although there were some scattered instances of a party reviewing SCE's attrition year capital forecasts, it was very limited in light of the substantial capital requests put forth by SCE. We also declined to review them in this decision. Similar to 2009, SCE demonstrated that a PTYR forecast based solely on the CPI may understate the reasonable capital spending needs for post-test years in this rate cycle.

SCE's argument that the 2009 PTYR was fundamentally flawed because it underfunded capital additions in attrition years is unpersuasive. SCE's long lead time from developing GRC capital forecasts, SCE's managerial discretion to reallocate authorized funds, and the Commission's review of 2013 and

[1281] D.09-03-025.

2104 capital expenditures in the next GRC, all weigh against use of forecast capital spending in a PTYR.

We are not persuaded to alter the Z-Factor mechanism in this GRC, as Aglet suggests. No specific Z-Factors have been identified for this rate cycle, but SCE believes the mechanism provides assurance that a process is in place to address unanticipated major variations in SCE's costs. As to DRA's concern, it is clear from the 2003 GRC decision that the Z-factor applies to unexpected increases and decreases to utility costs.[1282]

In Section 6, we addressed the anticipated deployment of SmartConnect in 2012 by adopting a separate 2013 CSBU forecast which is subject to the PTYR for 2014. If SCE does not complete deployment it may file a Tier 2 AL and seek approval of an adjustment to attrition year revenue requirement, but a simple "business as usual" estimate may be flawed in light of anticipated benefits and actual reduced costs.

As an alternative to its budget-based approach, SCE recommends DRA's second proposal, modified by SCE to use its own labor and non-labor escalation rates and escalation of 2012 capital additions to rate base.[1283] DRA agrees if this mechanism is adopted that using adopted 2012 plant additions is more reasonable than SCE's budget-based forecasts.

DRA did not support its recommended 2.5% escalation rate for 2012 capital additions, nor did SCE calculate escalation rates for capital additions for the alternate PTYR.

[1282] D.04-07-022 at 279.

[1283] SCE-25, Vol. 01 at 50.

In order to arrive at an escalation rate for 2012 capital additions, we reviewed SCE's updated 2013 -2014 capital escalation rates in light of 2012 forecast capital additions.

We adopt a modified version of DRA's alternative PTYR mechanism. Based on the record, we conclude the following features are reasonable:

- SCE's updated non-labor escalation rates,[1284] excluding Four Corners;
- Separately escalate medical benefits by 7.5%[1285] in 2013 and in 2014; for other authorized benefit programs use the authorized labor and non-labor escalation rates;
- SCE's updated labor forecasts of 3.0% for 2013 and 2.65% for 2014;[1286]
- Escalation of adopted 2012 capital additions by 3.05 % in 2013, and 2.93% in 2014;[1287]
- By November 1 of the prior year, SCE shall file a Tier 2 AL to establish the authorized revenue requirement for 2013 and 2014 based on the most recent Global Insight labor and non-labor escalation rates and asset retirements;
- 2013 CSBU expenses and capital expenditures are separately calculated in Section 6 of the decision per the request of SCE and DRA. These costs will be escalated in 2014 based on the PTYR adopted herein;

1284 SCE-84 at 32-33.

1285 Section 8.6.3.2.

1286 SCE-84 at 31.

1287 SCE-89 at 34, Table 1X-12 (Based upon IHS Global Insight Cost Trends of Electric Utility Construction 2012 Second Quarter Projection); escalation is average, excluding Generation Decommissioning Projects and Mountainview which are unrepresentative.

- The 2013 SmartConnect revenue requirement is incorporated into the 2013 revenue requirement and subject to the PTYR for 2014;
- SCE will continue its flexible outage schedule mechanism to cover nuclear refueling costs in attrition years; and
- Continuation of the existing Z-factor mechanism.

SCE argued the 2009 PTYR escalated the total 2009 revenue requirement, which is net of OOR, and implicitly assumed that tariffed service revenues would also similarly escalate. However, the decision did not authorize any fee increases that generate OOR. Aglet and DRA both argue that SCE addressed the matter through an AL seeking an OOR adjustment.

We find that the authorized PTYR assumes the impact of all post test year issues including OOR.

Accordingly, the Commission finds reasonable and adopts the modified alternate PTYR set forth above for 2013 and 2104.

17. Productivity

SCE presented the results of its Total Factor Productivity (TFP) analyses, as required by prior Commission decisions. SCE undertook two measures of TFP growth: (1) sales weighted by average customer rate; and (2) output defined by peak demand.[1288] DRA tested SCE's conclusions and found SCE's productivity results to be reasonable.[1289] SCE forecasts TFP declines in TY2012 by either measure.[1290] No party has contested those results.

[1288] SCE-11 at 2.

[1289] DRA-20 at 2.

[1290] SCE-11 at 13-14.

However, SCE observed:

> Because they are conducted at such a high level, the total factor productivity studies that are typically provided in a General Rate Case proceeding do not generally yield useful data for utility operational and investment decisions. They can be useful in the context of certain types of performance-based ratemaking, but . . . they have not proven useful in General Rate Cases. The Commission should remove the requirement that SCE submit a corporate productivity study in the General Rate Case.[1291]

DRA and Aglet agree that TFP studies should be eliminated. We concur that the TFP studies did not assist the Commission in this GRC.

The Commission finds it reasonable to eliminate the requirement that SCE submit a corporate productivity study with its GRC applications.

18. Electric Plant

SCE provides 2009 recorded electric weighted average plant balances and expected balances for 2010-2014. The balances are separated by FERC class of plant for depreciable Plant, Land, and Intangibles. Depreciable Plant and Intangibles are included in SCE's proposed depreciation reserve, and Total Plant-in-Service is included in rate base.

SCE estimates Total Plant will grow from about $29.5 billion in 2009 to more than $37.5 billion in 2012, an $8 billion (27%) increase, largely driven by SCE's large forecast for capital investment across all business units.[1292] Costs of Removal are included in the budget of capital expenditures, but recorded as a debit to depreciation reserve rather than capitalized to Plant. SCE also forecasts

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[1291] *Id*. at 4.

[1292] SCE-10, Vol. 02 at 1- 2, Table I-1.

asset retirements primarily based on vintage year accounting or historical ratios of retirement to plant balances.[1293]

18.1. Corporate Center Capital Budget

There are 15 budget items that comprise the capital expenditure forecast for the Corporate Center. The only category in excess of $1 million annually is PPBU Furniture and Equipment (F&E) which is driven by expected staff increases and the need for specialized furniture and equipment, especially for the trading floor.[1294]

For 2010-2012, SCE forecasts $3.311 million: $1.05 million in 2010, $1.103 million in 2011, and $1.158 million in 2012. We are persuaded by SCE that due to increasing market complexity associated with more resources, more data, CAISO time deadlines, and least cost dispatch load forecasting, that trade floor workstations require high performance, specialized F&E. However, we reduced the PPBU TY2012 O&M request, primarily for new FTEs, by 7%, and the PPBU 2010-2012 capital request by 40% (although most of that was referred to MRTUMA).[1295] Therefore, the PPBU F&E requirement is also reduced.

Accordingly, the Commission finds it reasonable to reduce the 2010-2012 PPBU F&E request by 15% annually through 2012.

18.2. Gains and Losses on Sale of Property

Pursuant to Commission policy, gains and losses on minor sales of property are allocated between shareholders and customers.[1296] Ratepayers

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[1293] *Id*. at 15.

[1294] *Id*. at 16.

[1295] Sections 10.6 and 10.7.

[1296] *See*, D.06-05-041, as modified by D.06-12-043.

receive 100% of after-tax gains/losses on sale of depreciable property, and receive 67% (33% for shareholders) of gains/losses on sale of non-depreciable property. Historical gains/losses have varied widely, dropping more than 75% from 2006 to 2007, and increasing 2500% from 2008 to 2009.

SCE adopted a 3YA to arrive at itsTY2012 estimate of $0.713 million in customer gains from such sales.[1297] SCE contends this method is reasonable, conforms to the three-year GRC cycle, and was adopted by the Commission in 2009.[1298] SCE's reasoning is grounded in achieving symmetry within the three-year rate cycle, and asserts that a 5YA will lead to inequitable results.

DRA forecasts $1.788 million in gains, 151% more than SCE's total, based on a 5YA.[1299] DRA did not discuss why a 5YA is reasonable other than the result is comparable to 2009 recorded gains of $1.7 million.[1300]

We are not persuaded that use of a 5YA, rather than a 3YA, erroneously impacts ratepayers or shareholders because it is a forecast of 2012 estimated sales results using historical trends. The question is what assets are likely to be sold, and which historical period best reflects sale revenues going forward. Here, SCE's undisputed claim is its forecast is based on the service life of the property and whether it is depreciable. We find SCE's forecast to be more developed than DRA's.

Therefore, the Commission finds reasonable and adopts SCE's forecast of $0.713 million in gains allocated to customers in 2012.

[1297] SCE-25, Vol. 02 at 1.

[1298] SCE OB at 318.

[1299] JCE at 376.

[1300] DRA-10 at 98, Table 10-64.

19. Taxes

Although SCE files tax returns as part of EIX's consolidated corporate returns, for ratemaking purposes the Commission reviews SCE's tax liabilities and benefits on a separate return basis. In this GRC, SCE provides stand-alone estimates of income taxes, payroll taxes, and other miscellaneous taxes for the years 2010 through 2014. Prior Commission decisions cover aspects of SCE's income taxes and, according to SCE, have been incorporated into its forecasts.[1301]

DRA and TURN take exception to some aspects of SCE's proposed methodologies for computing estimated taxes. Other differences in parties' income tax recommendations are attributed to underlying pre-tax income amounts or rate base amounts caused by differences in forecasts on matters such as O&M, A&G, depreciation, and capitalization. Final tax expense amounts will be determined by the R/O model.

In April 2011, SCE updated its tax expense estimates to reflect the impact of the TRA on tax depreciation, deferred taxes, rate base, the Section 199 Manufacturer's Deduction, and other resulting changes to revenue requirement.[1302] SCE's updated estimate of CPUC jurisdictional TY2012 tax expense totals $807.465 million ($nominal): $541.308 million for taxes on income, $90.272 million for payroll and other taxes, and $175.884 million in ad

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[1301] SCE-10, Vol. 02 at 24 (e.g., D.88-01-061, 27 CPUC 2d 310 (1988); D.87-09-026, 25 CPUC 2d 299 (1987); D.84-05-036, 15 CPUC2d 42 (1984)).

[1302] SCE-15 at 1 (Tax Relief. Unemployment Insurance Reauthorization, and Job Creation Act of 2010).

valorem property taxes.[1303] This is an increase over total 2009 recorded taxes of $72.198 million (9.8%).[1304]

DRA recommends a decrease of $6.346 million in 2012 based on two minor adjustments. TURN recommends a $1.069 million reduction to the payroll tax forecast and elimination of SCE's Employee Stock Ownership Plan Tax Memorandum Account (ESOPTMA). We discuss these issues below.

19.1. Income Taxes

For ratemaking purposes, SCE collects income tax expense from customers as if depreciation were calculated on the straight line method over the projected life of the asset. However, for tax purposes, SCE may apply accelerated depreciation.

Accelerated tax depreciation results in a temporary difference between cash taxes paid and recoverable income tax expense for financial reporting and ratemaking purposes. The problem is resolved through tax normalization, applying the general premise that taxes recorded for an accounting period are matched to revenues and expenses recorded for the same period. The Internal Revenue Code (IRC) requires regulated utilities, in determining rates using cost of service methodology, to use normalization to calculate federal income tax expense for utility plant-related temporary differences. Ratepayers benefit from the accelerated depreciation through "normalization" and the use of a deferred tax reserve. The accrued deferred tax liability is treated as an interest free loan

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1303 SCE-15, Appendix A at Table II-4; updated in SCE-84, Attachment A (Estimated Revenue Requirements at Authorized Base Revenue Requirement).

1304 SCE-84, Attachment A (Estimated Revenue Requirements at Authorized Base Revenue Requirement).

from the federal government and is credited against rate base to reduce the near-term revenue requirement from ratepayers. Because SCE's large tax reduction results in negative tax liability, SCE requests the Net Operating Loss (NOL) be booked as an Accumulated Deferred Income Tax (ADIT) asset that increases rate base and provides a return.

19.1.1. Effects of Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 (TRA)[1305]

The TRA includes amendments to IRC §168(k) that provide for either 50% or 100% bonus depreciation for certain eligible assets depending on the start of construction and the placed in service date.

As a result of the TRA, SCE re-computed its federal tax depreciation deduction for ratemaking purposes.[1306] SCE claims that, on a stand-alone basis, the deduction will generate an NOL for 2011 and 2012. According to SCE, the increase in current depreciation increased deferred tax balances as of 2010, reduces rate base for 2012 and future years, and indirectly eliminates the Section 199 Manufacturer's deduction in 2012. SCE estimates a $26 million reduction to the 2012 revenue requirement, and a total 2012-2014 reduction of $280 million.[1307]

SCE states it did not apply the Manufacturer's deduction in 2012, or credit the estimated $148 million NOL as an offset to rate base, because SCE estimates no federal income tax liability. SCE argues the portion of the deductions resulting in a 2012 NOL did not defer any tax and, consistent with the

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[1305] JCE at 694.

[1306] SCE-15 at 3.

[1307] *Id*. at 1.

normalization requirements of IRC § 168(f)(2), cannot be reflected as a reduction to rate base until SCE receives the cash savings in 2013.[1308] If the Commission were to require violation of the normalization rules, SCE states the resulting severe penalties would have long-term adverse consequences for ratepayers. PG&E agrees with SCE's analysis.

In support of its position, SCE provided its own rebuttal testimony, testimony from outside tax counsel, and administrative rulings from FERC and other state utility commissions.[1309] Although not precedential, we look to an IRS Private Letter Ruling which applies normalization rules to similar facts.[1310] The utility taxpayer's use of bonus depreciation resulted in an NOL, and the IRS agreed it was appropriate and consistent with IRS normalization rules to defer the associated tax liabilities to the year when the taxpayer realizes an actual benefit.

DRA opposes SCE's delay of estimated deferred tax liabilities to later years and recommends the Commission allow the deferred tax to be recognized and flowed through as a rate base adjustment in the same year the associated depreciation is recognized.[1311] In support DRA makes a number of arguments, including: (1) the forecast NOL is uncertain at the utility or corporate level and should be disregarded to avoid inequity to ratepayers; (2) SCE's proposed delay is essentially a carry forward of an NOL and D.84-05-036 excludes the effect of NOL carry forwards and carry backs in ratemaking; (3) there is no adverse

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[1308] SCE-84 at 20.

[1309] SCE-85.

[1310] IRS PL. 8818040 (2/09/1988).

[1311] DRA-90 at 2.

impact on shareholders; and (4) immediate recognition will significantly reduce the revenue requirement in 2012, 2013, and 2014.[1312]

In support of its position, DRA points to the sizeable federal tax expense remaining in the TY revenue requirement and to what it views as an unsupported assumption of a 2012 NOL. DRA states it was unable to verify SCE's claimed NOL modeling. Furthermore, DRA asserts it correctly applies the Commission's direction in D.84-05-036 to exclude carry backs and carry forwards from the test year income tax calculation to reasonably match benefits and burdens.[1313]

Lastly, DRA argues that the SCE stand-alone estimated NOL is not a basis to omit the effects of the Manufacturer's deduction since it may be available at the corporate level. DRA estimates the TY revenue requirement impact on SCE is $27.6 million for the deferred tax and $29.4 million for the Manufacturer's deduction.

We are not persuaded by DRA's arguments on either issue. The utility's Manufacturer's deduction is eliminated by the NOL and there is no evidence to support DRA's hypothesis that it is a benefit available for the corporate return. We also agree with SCE that it is appropriate to delay the offset to rate base until the deferred tax is actually realized. The Commission has previously acknowledged the application of normalized tax accounting for accelerated depreciation rather than flow-through accounting. "The effect of the [normalization] laws was that the Commission could no longer require utilities

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1312 *Id*. at 3-4.

1313 DRA Update OB at 5.

to flow through to ratepayers the substantial tax benefits associated with accelerated depreciation…."[1314]

We have also held that deferred taxes are booked for ratemaking purposes only when two conditions are met: there are tax savings associated with use of accelerated versus straight line depreciation; and taxes have been collected from the ratepayers.[1315] There cannot be a tax savings unless and until the 2012 NOL is applied to reduce SCE's taxable income in a future year. We recently confirmed the application of normalization and said, "The federal Internal Revenue Code allows for the deduction of accelerated depreciation only if the depreciation expense is normalized for ratemaking purposes."[1316]

Specifically to the effects of the TRA, on June 23, 2011, we issued Resolution (Res.) L-411A to authorize utilities to establish a memorandum account to track bonus depreciation and deferred tax liabilities so the Commission could later decide whether some costs might be included in rates without regard to retroactive ratemaking. SCE and SDG&E were exempted to allow the matter to be addressed in their pending GRCs.

In Res. L-411A, the Commission found there is likely to be an impact from taking the bonus depreciation on working cash calculations, reduction or elimination of the Manufacturer's deduction, and impacts involving contributions-in-aid-of-construction (CIAC). We observed that the benefits would not be symmetrical:

[1314] D.04-02-063 at 113.

[1315] SCE-84 at 19.

[1316] D.10-12-058 at 13.

> Some of these impacts result in revenue requirement increases primarily in the year(s) in which bonus depreciation is taken, while the revenue requirement reduction resulting from the increase in the deferred tax reserve is spread over a longer period. Thus, although the overall revenue requirement impact of taking bonus depreciation benefits ratepayers, the revenue requirement impact in the years in which bonus depreciation is taken may actually be a revenue requirement increase.[1317]

On the other hand, we decline to follow SCE a step further where it seeks to record to rate base, in 2011 and 2012, the unused deferred tax liability as an asset. SCE relies on a decision from FERC and two states, New Mexico and Connecticut, which approved this accounting result. We are not bound by the decisions of these agencies, and at least one other state agency (AZ) reached a different result.[1318]

We find it is not appropriate to include the NOL in rate base for ratemaking purposes. First, it is a placeholder amount and, second, it would be unfair to ratepayers to essentially pay a carrying charge on SCE's expected future recovery of a tax benefit when the ratepayers have already paid the tax expense in rates.

It is the intent of the Commission that SCE comply with the normalization method of accounting and tax normalization regulations. However, SCE did not provide any statute or regulation which requires the Commission to permit a rate of return on a temporary ADIT asset. SCE may track the NOL, and if SCE later obtains a ruling from the IRS which affirms SCE's position, SCE may file a Tier 2 AL with the Energy Division seeking an adjustment to revenue requirement.

[1317] Res. L-411A at 4.

[1318] SCE-85, Attachment 4.

Therefore, the Commission finds SCE's application of the TRA bonus depreciation to TY2012 tax expense and delay recording the unused deferred tax liabilities against rate base until 2013 to be reasonable. To the extent tax normalization rules require recording the NOL to rate base in 2011 or 2012, no rate of return is authorized.

19.1.2. Meals and Entertainment (M&E) Expenditures

Tax laws cap the business deduction for M&E at 50%.[1319] In its forecast, SCE includes a negative deduction of $5.246 million, 50% of the estimated amount of M&E embedded in its forecast capital, O&M, and A&G expenses. The Commission has consistently rejected rate recovery of entertainment, political, and social expenses of utilities because it is an unfair economic burden on ratepayers.[1320]

As it did in the 2009 GRC, DRA recommends the Commission disallow the adjustment because SCE does not show that these expenses are justified as a business function.[1321] The Commission agreed in 2009 to exclude all M&E costs because we found that SCE did not provide records to demonstrate the meals and travel expenses were not for entertainment-related activities.

SCE responds that in this GRC, using new accounting software, it can distinguish between business and entertainment expenses. Based on a 2YA

[1319] IRC §§ 62(a), 274(n).

[1320] D.09-03-025 at 315.

[1321] *Ibid*.

(2008-2009), SCE calculated a 10.36% adjustment for entertainment expense and escalated the remaining 2009 M&E.[1322]

DRA remains critical because it has no way to verify whether SCE's adjustment is appropriate for 2012, or what SCE's actual 2012 forecasts are for M&E embedded and unidentified in various FERC accounts. As a result of these problems, DRA argues that SCE did not meet its burden of proof and the entire reduction should be removed.[1323]

SCE's accounting system provided a limited summary of 2008-2009 M&E which appears to remove clearly identified entertainment expenses (e.g., holiday parties) to support the 10.36% adjustment.[1324] Although SCE does not provide 2012 M&E estimates by FERC account, SCE applied 2010-2011 escalation rates which are not excessive.

Accordingly, the Commission declines to reduce or remove SCE's proposed M&E deduction to test year income tax expense.

19.1.3. Research and Development (R&D) Credits

SCE's estimated Taxes on Income does not include a reduction for an R&D credit authorized by IRC § 41. In response to DRA queries, SCE states it plans to apply a $1.1 million credit in 2010, and use all of the available credit before it is due to expire at the end of 2011.

DRA points out the credit may be carried forward for up to 20 years and would include a $1.1 million R&D credit in the TY2012 forecast.[1325] SCE argues

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[1322] SCE-25, Vol. 02 at 7.

[1323] JCE at 718.

[1324] Work Papers, SCE-10, Vol. 03, ch.3 at 41-42.

[1325] DRA OB at 412-413; JCE at 717.

DRA's proposal is inconsistent with ratemaking principles, current tax law, and the Commission's tax guidance that carry backs and carry forwards are excluded from test year income tax calculation.[1326]

We agree with SCE that the availability of a carry forward tax credit into TY2012 and its application to 2012 tax expense is not supported by evidence. The Commission declines to make the requested adjustment.

19.1.4. Employee Stock Ownership Plan (ESOP)

When calculating Taxes on Income, SCE includes a $29.8 million deduction for dividends paid on EIX stock held by SCE employees through SCE's ESOP. However, an IRS regulation proposed in 2005 would restrict the deduction to the entity that owns the underlying stock.[1327] In the 2009 GRC, we approved SCE's request for an ESOPTMA to track the revenue requirement effect of the deduction. SCE asks to continue the ESOPTMA until the final regulations have been issued or the tax years are no longer subject to audit.

TURN did not offer any changes to the proposed ESOP dividend deduction, but recommends the ESOPTMA should either be terminated or zeroed out at the end of 2010 or 2011.[1328] First, TURN argues that even if the IRS acts to restrict the deduction to EIX, the Commission is not bound by that decision for ratemaking purposes. Second, even if the regulation is viewed as dispositive, there is no indication of when it would become effective.

The proposed regulation has been pending for several years and, even if adopted, any effective date is speculative. In general, we review forecast tax

[1326] SCE-25, Vol. 02 at 7; DRA-18 at 4.

[1327] TURN-97.

[1328] JCE at 726.

expenses based on current tax laws. In 2009, we allowed SCE to track the associated revenue requirement due to the size of the deductions in case a final regulation impacted the rate cycle. However, the proposed regulations are stale and unlikely to be adopted, let alone become effective, in this rate cycle.

Therefore, the Commission finds it reasonable to adopt SCE's forecast dividend deduction and to discontinue the ESOPTMA.

SCE may file a Tier 3 AL if it seeks to make an adjustment to the 2012-2014 revenue requirement as a result of a final IRS regulation that restricts the ESOP dividend deduction to EIX during the rate cycle.

19.2. Payroll Tax

SCE originally forecast $96.213 million for TY2012 payroll taxes based on 2009 recorded costs and SCE's 2010-2014 forecasted labor, excluding the capitalized portion.[1329] SCE assumed the total wages subject to social security taxes were capped at $114,900 per employee.[1330]

TURN relied on a different source to determine the wage limit was likely to decrease in 2012 and calculated a $1.069 million reduction to SCE's forecast.[1331]

In its Update testimony, SCE re-calculated estimated social security taxes to incorporate a more recent forecast of the 2012 estimated wage limitation.[1332] Utilizing a wage base limitation of $110,100, SCE decreased its TY2012 payroll tax estimate by $1.475 million.

[1329] SCE-10, Vol. 02 at 36.

[1330] TURN OB at 328.

[1331] TURN-3 at 121.

[1332] SCE-84 at 27.

The Commission finds it reasonable to adopt the more recent wage base limitation of $110,100 when calculating payroll tax expense for TY2012.

19.3. Property taxes

SCE is required to pay ad valorem (property) taxes to the taxing authorities of each state in which taxable property is located. SCE updated its Property Tax estimate to reflect actual property tax rates for 2010-2011 which are slightly lower than SCE's forecast.

For TY2012, SCE's updated forecast of total property tax expense is $205.949 million ($nominal).[1333] No party disputes the forecast, with the exception of post-sale expenses for Four Corners. However, in this decision, we have also adopted reductions to SCE's 2010-2012 forecast capital expenditures used as the basis of its property tax forecast.

Accordingly, the Commission finds reasonable and SCE's forecast for 2012 Property Tax expense, adjusted by the RO model for reductions to SCE's forecast capital expenditures.

20. Rate Base

Rate base is the depreciated asset value of SCE's net investments used to provide service to its customers. The major components of rate base are Fixed Capital, Adjustments, Working Cash, and Deductions for reserves. SCE is allowed to earn a rate of return on the sum of these rate base components which are developed on a weighted average basis.

For 2012, SCE originally estimated approximately $37.5 billion in Fixed Capital, and a weighted Average Depreciated Rate Base (ADRB) of

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[1333] *Id.* at 29.

$19.4 billion.[1334] DRA recommends several adjustments to the rate base calculation resulting in an estimated ADRB of $17.6 billion in 2012.

TURN makes several recommendations related to Working Cash, including a $211 million reduction to rate base for customer deposits.

We discuss the parties' recommendations below by topic.

20.1. Fixed Capital

SCE's fixed capital forecast is based on its own 2010-2014 capital expenditure forecast in the GRC. In this decision, we have authorized less capital spending than SCE requested and Fixed Capital will be adjusted accordingly.

20.2. Adjustments

20.2.1. Customer Advances

Customer Advances for Construction represent refundable amounts provided by applicants (generally developers) in advance of constructing new distribution facilities that will later be served by SCE. These funds are a liability to SCE until reimbursed to the developers. Consistent with Commission rules, SCE does not pay interest for holding these monies. As an interest free source of funds, SCE applies the Customer Advances as an offset to rate base.[1335]

At the end of ten years, any remaining balance is forfeited by the developer and converted to CIAC offsetting plant. SCE forecasts a total 2012 reduction to rate base of $75.386 million based on the average balance of Customer Advances. SCE expects the balance to continue its decline consistent

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[1334] SCE-10, Vol. 02 at 46, Table IV-11 (assumes Four Corners Decommissioning Scenario).

[1335] SCE-10, Vol. 02 at 47.

with the recent downturn of construction activity and the trend of recorded/forecasted meter sets.[1336] There are also Customer Advances for Temporary Services.

DRA forecasts a total 2012 reduction of $86.825 million based on adjustments to SCE's forecast methodology for both categories of Customer Advances.[1337]

SCE's forecast for Construction is based on a 3YA advance per meter set of $374 to forecast expected customer advance cash inflows. The estimated account outflows were developed using the recorded refund pattern of the last 10 years. DRA does not dispute the number of meter sets, but proposes a 5YA of $541 because the longer time period covers some economic growth, smooths the data, and reflects slow economic improvement.

SCE responds that DRA's forecast is excessive because during 2005-2006, Customer Advances and Meter sets were at the highest in recent history. SCE's 3YA cost is also close to 2010 actual advances of $325 (2009).[1338] We agree that the 3YA is a reasonable approach given the slow pace of economic recovery. We do not make any further adjustments based on the meter set forecast which includes additions from other than new development.

For Temporary Services, cash advances and refunds do not necessarily correspond with meter sets. SCE'S 2012 forecast balance of $6.893 million (2009) reflects a continued downward trend declining at 3 percent per year.[1339]

[1336] *Ibid*.

[1337] JCE at 684.

[1338] SCE-25, Vol. 02 at 12.

[1339] SCE-10, Vol. 02 at 49.

DRA recommends using the 2009 recorded amount of $7.553 million because SCE did not explain its application of a negative 3% growth factor.

In rebuttal, SCE provides 2005-2010 year end account balances, including annual growth, which began a significant decline in 2008 and averaged about -6% over the recorded period.[1340] We observe that SCE's data suggests at least a 3% negative growth between 2009 and 2012 is reasonable, even though the data reflects year-end instead of average balances.

The Commission finds reasonable and adopts SCE's 2012 forecasts for 2012 Customer Advances.

20.2.2. Customer Deposits

SCE forecast an annual weighted average of $211.070 million in customer deposits for 2012.[1341] DRA and TURN recommend the Commission continue the previously adopted policy of treating customer deposits as an offset to rate base in developing the revenue requirement.[1342] All parties agree that SCE should be able to recover, as an expense, the estimated interest it would have to pay to refund the deposits.

Beginning in the 2003 GRC, the Commission required SCE to offset rate base by some amount of customer deposits on the grounds that the deposit balances could be treated like a source of permanent working capital.[1343] SCE asks the Commission to reject this policy which only applies to SCE, and argues

[1340] SCE-25, Vol. 02 at 13.

[1341] JCE at 939.

[1342] DRA OB at 421.

[1343] SCE-10, Vol. 02 at 75.

the deposits are debts of the utility and fundamentally different than other working cash adjustments.

In support of its view, SCE points to the Commission's Standard Practice U-16 (SP U-16) which states that only non-interest-bearing customer deposits are to be included in working cash calculations. Although this is only guidance, other parts of SP U-16 state that working funds are by definition interest-free and their availability comes from timing differences in collection prior to payment of operating expenses.[1344] SCE contends that customer deposits are declining and offers arguments that include (1) the deposits would be treated as debt in a bankruptcy; (2) by offset to rate base, the Commission adds debt and reduces equity; and (3) by reducing equity, earnings decrease and SCE's credit quality is weakened.[1345]

TURN has successfully argued in the past that customer deposits represent a source of capital the utility has on a permanent basis, unlike short-term debt used for certain low-risk inventories, balancing account under-collections, etc.[1346] Over time, SCE continually holds a significant block of funds and the only difference is that it must pay short-term interest. SCE's commercial paper rate has been less than 0.5% and has averaged 0.25%. SCE did not rebut TURN's claim that the policy has not previously impacted SCE's credit rating.

In this GRC, SCE proposes a modification to total rate base offset in furtherance of the goals of GO 156. SCE states it has established a deposit program with minority and community banks where funds are flowed through a

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1344 *Id*. at 77.

1345 SCE-25, Vol. 02 at 35-40.

1346 TURN-3 at 132.

certificate of deposit (CD) placement service into numerous accounts below FDIC limits. SCE seeks approval to place up to 10% of customer deposits into the program where many of the banks also do business in minority communities.[1347]

At the national level, average CD rates are comparable to the commercial paper rate customers earn on their deposits. However, rates received from banks in the program may differ from the national average.

SCE proposes that any difference between the commercial paper rate and the deposit earnings rate be borne by ratepayers.

The Commission has repeatedly urged the utilities to work to achieve the goals of GO 156, particularly in under-utilized areas such as financial services. We agree that placement of a portion of customer deposits into minority and community banks would enhance SCE's efforts in this area. However, the GO program is voluntary and if there is any difference between the commercial paper rate and the deposit earnings rate, it should be borne equally by ratepayers and shareholders.

The Commission declines to alter its policy of making an offset to 2012 rate base for customer deposits, with the exception that up to 10% of 2012 customer deposits may be placed into CDs through SCE's minority and community bank program. If any earnings differences occur they are to be shared 50/50 by shareholders and ratepayers.

Therefore, the Commission finds it reasonable to offset 90% of the forecast of 2012 customer deposits, $189.97 million, against rate base, and authorize SCE to utilize 10%, $21.1 million, in the minority bank program for the purpose of

[1347] SCE-10, Vol. 02 at 83.

earning interest at or near the commercial paper rate. SCE is entitled to claim as an expense the interest for that portion of customer deposits that are applied as a reduction to rate base at the three-month commercial paper rate.

20.3. Working Capital

Working Capital for ratemaking purposes is the average investment required of shareholders on a continuing basis beyond the investment in plant-in-service and other specified rate base items. For SCE, these rate base components include Materials and Supplies Inventory, Mountainview Emission Credits Inventory, and requirements for Cash Working Capital.[1348]

No party disputes SCE's 2012 estimated value of $9.329 million for Mountainview Emission credits which the Commission finds reasonable and adopts.[1349] The disputed categories are discussed below.

20.3.1. Materials and Supplies (M&S)

M&S Inventory is maintained for new plant construction and O&M required to operate existing plant. SCE stated its historic M&S balance demonstrated a consistent increasing trend, growing at an average compound annual growth rate (AGR) of 8.8% since 2005.[1350] Based on its forecast capital spending, SCE assumes that M&S Inventory levels will increase at an average compound AGR of 6.4% from 2010 to 2014. SCE's 2012 forecast average annual balance for all M&S is $242.984 million ($nominal).[1351]

[1348] SCE-10, Vol. 02 at 50.

[1349] *Id*. at 59.

[1350] *Id*. at 51.

[1351] *Id*. at 49.

Average Balance of M&S for 2012, SCE Share ($nominal 000s)[1352]				
Description	**DRA Recommends**	**SCE Proposed**	**Difference from SCE**	**Adopted**
Transmission & Distribution (T&D)	$116,094	$144,747	$28,653 (-19.8%)	$131.140 (-9.4%)
Current Generation	114,611	114,611	0	114,611
Other Generation	5,020	5,062	42 (-0.1%)	5,062
General	7,396	7,396	0	7,396
Rate Base Adjustment	(28,832)	(28,832)	0	(26,531)
Total	$214,289	$242,984	$28,695 (-11.84%)	$231,678 (4.7%)

For 2012 T&D M&S, SCE forecast $144.747 million, excluding large transmission projects, and utilizing a 10.3% AGR. The forecast was based on the same regression methodology the Commission found reasonable in the 2009 GRC.[1353] The analysis indicates that for each $1 million in incremental T&D construction expenditure there is a need for about $60,000 in additional T&D M&S inventory to support the project activity.

DRA takes issue with SCE's T&D M&S forecast and instead recommends the 2010 recorded weighted average of $116.094 million.[1354] DRA views SCE's 2012 estimate as excessive because it is 39.2% higher than the 2009 recorded level, and 24.1% higher than the 2010 recorded level.

In the alternative, DRA forecasts $115.117 million based on $40,000 in additional T&D M&S inventory for each $1 million in DRA's (not SCE's) forecast of incremental TDBU capital expenditures. The $40,000 M&S ratio is what was adopted by the Commission in the 2009 GRC. DRA argues that SCE did not

1352 *Id*. at 58; DRA-19 at 6.

1353 D.09-03-025 at 273.

1354 JCE at 685.

explain the increase and notes that the correlation factor between expenditures and inventory is stronger in the 2009 regression analysis.[1355]

We have previously discussed the necessary growth in T&D capital expenditures during this rate cycle particularly related to maintaining safety and reliability for the electrical system. Given the strong correlation between inventory and expenditures, adoption of the 2010 balance would be insufficient.

As in the 2009 GRC, we generally find SCE's methodology to be reasonable. Although the correlation factors are slightly lower (0.88 to 0.89) in this GRC, we are persuaded that the correlation is still strong at a 95% confidence level, and the $60,000 ratio is the result of more recent data (2007-2009).[1356]

However, SCE's forecast requires an adjustment. SCE included all of its forecast for TDBU capital expenditures in all jurisdictions and outside the TDBU testimony.[1357] SCE criticizes DRA's alternative because it addresses only the CPUC jurisdictional portion, and both includes and excludes T&D capital expenditures differently than SCE.[1358]

We think it is reasonable to look to business unit capital expenditures for purposes of this component. Elsewhere in this decision, we reduced 2011-2012 capital spending for TDBU by 9.4% and for Generation by 24%. Therefore, the Commission finds it reasonable to adopt the same adjustments to SCE's forecast

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1355 DRA-19 at 8.

1356 SCE-25, Vol. 02 at 15.

1357 *Id.* at 16.

1358 *Id.* at 18.

incremental T&D and Generation M&S forecasts. These changes also result in a reduction to the associated accounting adjustments.[1359]

We decline to follow DRA's rejection of SCE's estimated increase of $42,000 to support the McGrath power plant currently under construction.[1360] In Section 4.4.2.3, we authorized $20 million in 2012 capital spending to complete construction of this peaker unit and SCE's minor adjustment is reasonable.

Accordingly, the Commission finds reasonable and adopts a 2012 Total M&S Inventory forecast of $204.171 million.[1361]

20.3.2. Working Cash

In its Update testimony, SCE increased its initial 2012 forecast of Working Cash by $93 million (39.5%) to reflect income tax changes arising from the TRA.[1362] SCE's resulting combined estimate is $328.187 million.[1363]

Working cash is the capital supplied by shareholders to meet day-to-day utility operational requirements by bridging the gap between the time funds are required for services and the receipt of revenues for those services. Working cash is included in rate base to compensate shareholders for this investment. The SP U-16 provides that working cash include both the lead lag and Operational Cash requirements.

The Operational Cash requirement is the average balance of funds SCE investors provide the utility to meet its daily operational needs. SCE's lead lag

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[1359] SCE-25, Vol. 02 at 18.

[1360] JCE at 686.

[1361] SCE-25, Vol. 02 at 18.

[1362] SCE-15 at 6.

[1363] SCE-10, Vol. 02 at 46.

study determines the funds required from investors to cover the timing difference between when operating expenses are paid and when revenues are received.

In connection with the Operational Cash requirement, working capital benefits associated with the deployment of SmartConnect were not captured in the recorded history supporting the Revenue Lag calculation. Therefore SCE proposes additional Operational Cash adjustments to reduce rate base for the benefits authorized in D.08-09-039. No party disputed these adjustments.

The Commission finds SC E's proposed SmartConnect reductions to rate base of $11.784 million in 2012, $14.011 million in 2013, and $14.298 million in 2014 to be reasonable and adopts them.[1364]

DRA recommends increases to SCE's forecast, primarily due to differences with the lead lag study.[1365] SCE and TURN have resolved some issues, but TURN still recommends reductions to rate base for various adjustments, and another $20 million reduction related to gas option prepayments.[1366]

20.3.2.1. Cash Balances

Both DRA and SCE accept that minimum required bank balances should be included in working cash. SCE estimated a $5.9 million balance based on the average balance remaining at the end of the business day that SCE was unable to otherwise invest. DRA recommends the cash balance be removed, consistent with the Commission's actions in SCE'S 2006 and 2009 GRCs.[1367]

[1364] SCE-10, Vol. 2 at 67.

[1365] DRA-19 at 9, Table 19-4.

[1366] TURN OB at 337.

[1367] DRA-19 at 10.

The SP U-16 states the only amounts that should be considered in determining the cash requirement are "the required minimum bank deposits that must be maintained and reasonable amounts of working funds.[1368] This is to avoid double counting of the costs-- once in the lag study and again in the operational requirement.

SCE concedes the $5.9 million is not an institutionally required minimum balance. Instead, SCE argues it is functionally required because the amount represents the average balance remaining at the end of the business day which SCE is unable to invest due to the nature of banking operations and deadlines. We rejected this argument in 2009 and found it reasonable to strictly interpret our standard to facilitate ratemaking, to incentivize the utility to effectively manage its cash, and to impose any potential consequences of inefficient cash management on the company rather than the ratepayers.[1369]

The Commission finds it reasonable to remove the $5.9 million Cash Balance from the Working Cash forecast.[1370]

20.3.2.2. Prepayments

SCE advances prepayments, including prepaid rents, software, license fees, insurance, gas options premiums, and other miscellaneous prepayments, that have not accrued to operating expenses and are included in working cash. For 2012, SCE forecasts $120.272 million for prepayments. DRA and TURN both dispute some parts of this forecast.

[1368] *Ibid*.

[1369] D.09-03-025 at 266.

[1370] JCE at 687.

Mountainview Hot Gas Path (HGP) Fee

In Section 4.4.1.1., we adopted TURN's and DRA's recommendation to remove the portion of the HGP fee in TY2012 O&M because it related to overhaul activities in 2015, beyond the rate cycle. SCE sought to normalize the 2014 payment over the rate cycle.

Both TURN and DRA also recommend removal from 2012 rate base of SCE's estimated one-third of the prepayment of the fee scheduled for 2014.[1371] They argue it is beyond this rate cycle and even if SCE expects to incur the prepayment in October 2014, it is inappropriate to normalize the prepayment backwards to 2012.

SCE's response is that it has already removed one-third of the costs associated with the 2015 HGP Inspection from TY2012, so it is appropriate to include the amount in rate base as the average amount of working capital required over the 2012-2014 rate cycle.

The Commission finds it reasonable to allow inclusion of the prepayment in 2014 working cash capital.

T&D Prepaid Line Rents

SCE forecasts $9.061 million in T&D Prepaid Line Rents in 2012 and includes a weighted average amount of $5.445 million in 2012 rate base.[1372]

SCE states its 2010 recorded amount was in line with its estimates and supports the reasonableness of the estimate. We agree.

DRA recommends using the 2009 weighted average recorded level of T&D Prepaid Line rents of $1.589 million, a decrease of $3.856 million to SCE's

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[1371] *Id.* at 688, 936.

[1372] DRA-19C at 11, fn. 21.

estimate, to be consistent with its testimony in TDBU regarding line rents.[1373] However, we find that reliance on historical costs is misplaced in light of SCE's evidence that the rent charges will increase during the rate cycle. Consequently, the Commission finds SCE's forecast is more reasonable and adopts it.

20.3.2.3. Gas Options

SCE uses natural gas in power generation. To hedge the company's exposure to commodity price risk, SCE purchases options, pays the premiums up-front, and amortizes the amount over the terms of the option contracts. For 2012, SCE forecasts a 33% increase in option premiums above 2009 year-end levels, and states it is primarily due to the additional load requirements due to expiring contracts and hedging requirements pending in the LTPP proceeding.[1374] The actual premium estimate is confidential. For purposes of working cash, we consider the Expense lag.

TURN recommends a $20 million reduction to the working cash rate base based on a more recent forecast of the Gas Option Premium balance from SCE.[1375] TURN noted that IOU hedging requirements were under review in another proceeding, and SCE's forecast would lock into rate base SCE's view of how much hedging should be done.[1376] This led to TURN's recommendations that SCE be required to (1) update its forecast if the Commission adopted hedging changes; and (2) true-up its 2012 and 2013 gas option amounts for 2013 and 2014 ratemaking.

[1373] JCE at 689.

[1374] SCE-10, Vol. 02 at 60-61.

[1375] JCE at 940.

[1376] TURN-3 at 125.

SCE contends that TURN mischaracterizes the data provided which included a Gas Option premium expense forecast and a six-month Premium Turnover Calculation. By using the shorter turnover period to recalculate the premium balance, TURN's forecast resulted in a higher forecast premium balance.[1377]

TURN did not refute SCE's explanation. We are persuaded that use of six months of 2011 Turnover data in TURN's calculation is less representative than SCE's use of an entire year of data, because hedging activity increases during the last half of the year.[1378] On the other hand, SCE's 2012 option premium target is likely inflated due to SCE's overly optimistic load growth estimates addressed earlier in this decision.

On the other hand, we agree with TURN's other concern that Commission changes to utility hedging policy would impact SCE's hedging and related prepayment forecasts. The Commission adopted such material changes earlier this year. In D.12-01-033, we determined that ratepayers have been paying for too much hedging. Through the authorized flat-rate hedging methodology, ratepayers fund hedging to protect against relatively minor rate increases.[1379] Therefore, we concluded the hedging should shift from a flat-rate to being indexed to system-average rates, a change which should result in lower costs.[1380]

Therefore, the Commission finds it reasonable to calculate the associated working cash for gas option prepayments based on a 15%, not 33%, increase over

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[1377] SCE RB at 170-171.

[1378] *Id.* at 170.

[1379] D.12-01-033 at 26.

[1380] *Id.* at 46, COL 9, 10.

2009 recorded amounts. Given our action on hedging policy, prepayment levels do not need to be updated annually.

20.3.2.4. Other Accounts Receivable (OAR)

SCE developed its original 2012 forecast of $71.8 million based on escalating 2009 recorded OAR using various inflation rates. TURN and SCE identified errors in the forecast leading SCE to revise its calculation. Utilizing 2010 recorded OAR and SCE's escalation factors, plus an adjustment for Non-Tariffed Products & Services (NTP&S), SCE's revised forecast OAR for 2012 is $37.483 million. TURN does not dispute the updated forecast.

The Commission finds SCE's revised forecast of $37,483 million to be reasonable and adopts it.

20.3.2.5. Long-Term Incentive Plan

In Section 8.2.1.4, we disallowed rate recovery for executive LTI, and the parties agree that a corresponding increase of $6.211 million to working cash is the appropriate consequence.[1381] The Commission finds reasonable and adopts that amount.

20.3.2.6. Deductions to Claims Reserves

Elsewhere in the decision, we adopted DRA's proposed reductions to SCE's forecasts for Workers' Compensation/Injuries and Damages Claims Reserves. SCE states that based on DRA's Results of Operations model, these amounts result in a corresponding increase to rate base of $2.593 million. DRA did not dispute SCE's position.

[1381] SCE-25, Vol. 02 at 23.

Accordingly, the Commission finds the 2012 adjustment to rate base reasonable and adopts it.

20.3.2.7. Lead/Lag Study – Revenue Lag

Following the Commission's policy, SCE's determination of working cash includes a lead/lag analysis. SCE's study determined the Revenue Lag as net lag days between the time lag between the utility services rendered and the receipt of the associated revenues for those services.

For Revenue Lag, SCE's revised weighted average estimate is 41.5 days for 2012, determined by using the Accounts Receivables to Sales Ratio method we accepted in the 2009 GRC.

Unless discussed separately, the Commission finds SCE's latest revised revenue and expense lag day estimates to be reasonable and adopt them.

20.3.2.8. Lead/Lag Study – Expense Lag

SCE's lead/lag study also determined the Expense Lag as the time lag between the recording of the utility costs such as purchased power, labor, and materials and payment of those costs. SCE provides a table of expense lag days for various costs, some of which are related to power procurement and are confidential.[1382]

Both DRA and TURN object to aspects of the expense lead/lag study and provided alternate calculations of lag days for certain categories. Longer lag times result in reduction to rate base. The still disputed categories are discussed below.

[1382] SCE-10, Vol. 02 at 69, Table IV-25.

20.3.2.8.1. Taxes

SCE states that tax accruals and tax payment patterns vary from year to year, so it utilized a 5YA (2005-2009) of annual tax payments and refunds. The analysis also adjusted the timing pattern of 2005-2007 payments to reflect new corporate estimated tax regulations enacted in 2008. The result is SCE's estimated Federal Income Tax (FIT) lag of 73.8 days and a California Corporate Franchise Tax/California State Income Tax (CSIT) lag of 53.0 days.[1383] These estimates are longer than the 46.1 lag days and 20.5 lag days, respectively, that SCE requested and the Commission adopted in 2009.[1384]

DRA argues that use of 2005 data in SCE's 5YA was error because large refunds in that year were anomalous. Based on a 4YA (2006-2009), DRA calculated 88.71 lag days for FIT and 68.95 days for CSIT.[1385] SCE rejects DRA's use of a 4YA instead of a 5YA and argues that 2005 is not anomalous because refunds have occurred in four of the previous eight years.

In the 2009 GRC, a similar dispute arose when DRA utilized LRY (2006) to estimate tax lag days, instead of the 5YA (2002-2006) used by SCE. SCE argued that 2006 was anomalous and should not be solely relied upon for forecasting.[1386] In that decision, we agreed that use of a 5YA was more reasonable than use of one anomalous year.[1387] However, we responded to the facts presented and did not adopt an ongoing commitment to employ a 5YA.

[1383] *Id*. at 73.

[1384] D.09-03-025 at 257.

[1385] DRA-19 at 13; JCE at 690.

[1386] D.09-03-025 at 254.

[1387] *Id*. at 257.

Based on the record, we find that both 2005 and 2006 had lag day calculations far out of step with the recent historical record. Furthermore, the new tax regulations were fully implemented in 2009 and continued an upward trend in lag days. Therefore, we find that a 3YA (2007-2009) is a reasonable basis to estimate FIT and CSIT lag days.

Accordingly, the Commission finds reasonable and adopts a 3YA average of SCE's calculated lead lag days for FIT of 83.28 days and 61.59 days for CSIT.

20.3.2.8.2. Funded Pension Provisions and PBOPs

SCE developed its 17.0 lag day estimate for Funded Pension Provisions based on averaging the actual total 2009 payment of $98.02 million into four equal quarterly payments.[1388] SCE used July13, the mid-point of expense recovery during the year, as the mid-year date for calculating expense lags.

DRA calculated 75.09 lag days based on SCE's actual 2009 quarterly payments of $12 million, $12 million, $25 million, and $49.02 million.[1389] SCE argues the payment stream was anomalous due to market performance.[1390] TURN agrees with DRA's approach but substituted actual 2010 payments.

TURN also proposes rate base reductions of $5.3 million due to pension lag, and $1.195 million for PBOP lag based on using July 1 as the mid-year point for calculating the lag.[1391] TURN's mid-year method adds 11.5 lag days (total 28.5 days); use of 2010 actual payments adds 1.74 days (to 30.24 days).[1392]

1388 SCE-10, Vol. 02 at 72.

1389 DRA-19 at 13; JCE at 692.

1390 SCE OB at 327.

1391 JCE at 937; TURN OB at 338.

1392 TURN-3 at 129.

SCE defends its use of the midpoint of expense recovery by reference to the Commission's approval of the method in the 2009 GRC to calculate Income Tax lags.[1393] We agreed then that SCE's methodology was more likely to reflect what would actually occur in the test year since it was based on actual recorded information.[1394]

TURN's position is rooted in its expert's opinion that use of the mid-point of expense recovery is unheard of and self-serving. Yet, TURN did not respond or explain why the use by SCE in this instance was distinguishable from that adopted in the 2009 GRC.

On the other hand, we agree with DRA's proposal to utilize actual 2009 payments, in tandem with use of the 2009 mid-year point based on actual payments. We are not persuaded that use of a different year's actual payments is appropriate or improves the reasonableness of the result. DRA estimates 75.09 lag days based on use of actual 2009 payments. SCE did not dispute this calculation, only the approach.

Therefore, the Commission finds reasonable and adopts a rate base reduction based on a pension expense lag day estimate of 75.09 days. We make no adjustment related to the PBOP expense lag.

20.3.2.9. Benefits Other Than Pensions

In response to TURN's inquiries, SCE revised its zero lag day estimate for employee benefits and unfunded executive retirement benefits to 3.06 lag days.

[1393] SCE-25, Vol. 02 at 28.

[1394] D.09-03-025 at 257.

SCE decided to apply a weighted composite lag of 3.18 days for benefits and zero days for unfunded pensions.[1395] The related rate base reduction is $692,000.

TURN also recommends adding the lag days for payroll to the calculation of 401(k) lag days to account for the fact that SCE does not pay the benefit until payday.[1396] TURN's view is that the benefit is earned when the worker earns his or her wages or salary.[1397]

SCE disagrees and claims TURN confuses benefit calculations with accrued expense. According to SCE, it does not incur 401(k) benefits expense until the employee contributes funds to the 401(k) plan. Both employee contributions and 401(k) benefit payments are funded on payday resulting in a short lag of 0.98 days.

SCE also argues that TURN's analogy to wages and salaries, for which SCE calculates 11.9 lag days, is mistaken because no expense accrues until the employee makes the 401(k) contribution upon receipt of wages. It is expensed when the contribution is processed.

The parties agree that SP U-16 does not provide clear guidance on the point and the utility has some discretion. TURN argues that SCE has made an accounting choice and the distinction is without a real difference. We agree. SCE also argues that 401(k) benefits are part of total compensation and has not explained why they should be accrued differently.[1398] For purposes of

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[1395] SCE-25, Vol. 02 at 32.

[1396] JCE at 938.

[1397] TURN-3 at 130.

[1398] Section 8.6.3.1.

calculating the expense lag, we are persuaded that wages and 401(k) contributions accrue at the same time.

Accordingly, the Commission finds reasonable and adopts TURN's recommendation to apply SCE's labor lag days to 401(k) expense.

20.4. Unfunded Pension Reserves

In Section 8.6.3.6., we disallowed rate recovery for 50% of SCE's forecast Executive Benefits program costs. All parties agree that there should be a corresponding reduction to the Unfunded Pension Reserve offset to rate base of 50% of the projected impact of $14.8 million.[1399]

Therefore, the Commission finds reasonable and adopts an Unfunded Pension Reserve offset to rate base of $7.4 million.

20.5. Legacy Meters

In Section 6.2.1., we discussed D.08-09-039 which authorized SCE to fully deploy the AMI, or SmartConnect, program, and to recover costs up to $1.63 billion for deployment activities during the 2008 to 2012 period. We incorporate that discussion herein by reference. As SCE deploys SmartConnect throughout its territory, SCE must retire the replaced older electromechanical meters (legacy meters), many of which could otherwise provide useful service for up to 16 years.[1400] D.08-09-039 did not specifically address ratemaking for the retired legacy meters.

SCE's requested revenue requirement includes the annual depreciation expense and authorized rate of return on the remaining undepreciated balance of

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[1399] SCE-25, Vol. 02 at 34.

[1400] *Id*. at 42.

legacy meters, including those replaced by smart meters. SCE's recorded plant balance for the legacy meters as of December 31, 2010 was $321.814 million, with an associated depreciation reserve of $13.115 million, resulting in a net plant balance of $308.699 million.[1401]

SCE defends its request on the grounds that SCE and its investors embraced the state and Commission policy to implement smart meters, the Commission found deployment to be cost effective without a reduced return, and penalizing investors by removal from rate base or a reduced return will discourage utilities from replacing existing assets with new technologies.[1402]

In PG&E's 2011 GRC, we addressed the same issue presented in settlement and concluded that the utility could recover the undepreciated cost of its legacy meters over a six-year amortization period. We stated:

> With respect to the lone remaining issue that relates to the ratemaking treatment for the undepreciated plant balance associated with electric meters that are replaced by SmartMeters, that plant balance will be amortized over a six-year period with the associated rate of return on the unamortized balance reduced to 6.3% to reflect the reduced regulatory risk for that plant.
>
> In balancing the considerations of reduced risk to PG&E of recovering shareholder investment, the interest of the ratepayers who are now paying a full rate of return on the new SmartMeters, and the cause of the early retirement of the electromechanical meters, we will authorize a return on equity of 6.55% for the electromechanical meters.[1403]

[1401] DRA OB at 24.

[1402] SCE OB at 332.

[1403] D.11-05-018 at 63.

PG&E urges the Commission to adopt a similar policy regarding SCE's legacy meters based on the exhaustive briefing and Commission review in PG&E's GRC. In the alternative, PG&E recommends the Commission award SCE a full rate of return.[1404]

20.5.1. Other Parties' Positions

Aglet, DRA, and TURN take the position that the retired legacy meters are no longer "used and useful" and should be excluded from rate base, resulting in SCE earning no rate of return on the undepreciated balance as it is amortized over an accelerated six-year timeframe.[1405]

In the alternative, DRA recommends the same six-year amortization period but with a reduced 4.5% rate of return (based on the average of the five-year Treasury Note Yield).[1406] In support of its alternative recommendation, DRA relies on several Commission decisions which set a reduced rate of return on unamortized balances of certain retired utility assets.

TURN agrees with DRA's a six-year amortization period which is consistent with the Commission's approach in previous decisions addressing rate recovery of plant that is no longer "used and useful."[1407] TURN acknowledges the Commission's action on legacy meters in the PG&E GRC, but argues the Commission has a more developed record here to support a zero rate for SCE.

In the PG&E GRC, the Commission referred to two facts: the AMI was encouraged by the Commission to implement DSM and the AMI implementation

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[1404] PG&E OB at 15.

[1405] SCE-25, Vol. 02 at 42.

[1406] DRA-10 at 102.

[1407] TURN-11 at 4.

was found to be cost effective.[1408] However, TURN argues that the favorable ratemaking treatment SCE received for its AMI investment is a sufficient benefit, estimated by TURN to be approximately 12.91%, or $157.5 million 2012 and $450 million during the rate cycle.[1409]

Furthermore, TURN submits that SCE's initial cost-benefit analysis is speculative and untested.

Aglet argues that providing SCE with a return on two meters per customer is unfair and poor policy, and if the Commission approves such a return that it be limited to the reduced rate and short amortization period approved in the PG&E GRC.[1410]

SCE's rebuttal includes a review of several Commission decisions it contends support the view that "used and useful" is not a bar to rate recovery and the actual standard is "just and reasonable."[1411] PG&E supports SCE's position and argues the "used and useful" principle is intended to ensure utilities do not build excess generation capacity, but should not apply to deter investment in new technologies.[1412]

PG&E also rejects the view that return on the new AMI investment is anything more than the minimum necessary to attract equity capital. PG&E points to our statement in PG&E's 2011 GRC that it is appropriate to consider if

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1408 D.11-05-018 at 55.

1409 TURN-11 at 6.

1410 Aglet OB at 34.

1411 SCE-25, Vol. 02 at 43-48.

1412 PG&E-2 at 2-2.

Commission action led to stranded assets when considering ratemaking.[1413] Lastly, PG&E argues that a six-year amortization period does not bear on SCE's risk of cost recovery which is driven by the adequacy of the overall revenue requirement.[1414]

20.5.2. Discussion

Our longstanding regulatory principle is that investors should earn a return on used and useful plant, although we have made some exceptions to the policy based on particular circumstances.

We agree with DRA and TURN that the Commission decisions cited by SCE in support of its position to ignore whether plant is used or useful, are distinguishable for various reasons.[1415] DRA and TURN offered Commission decisions that support a reduced rate of return on the unamortized balance of investment in certain situations. Furthermore, we do not agree with SCE that a reduced rate of return on the legacy meters is a "penalty" on investors or discourages a utility from investing in technological change. Here, investors are aware of the industry's shift to smart grid and smart meters as a national trend, state policy, and part of the regulatory landscape. They also may earn the full rate of return on $1.2 billion in new AMI equipment.

The record is not more developed as TURN suggests, although TURN has continued its questions about the costs and benefits of SmartConnect. In this GRC, we follow the analysis we undertook on the same issue for PG&E. Given the cause of the retired meters and the fact benefits are accruing to ratepayers

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1413 *Id*. at 2-3 (Citing D.11-05-018 at 55).

1414 *Id*. at 2-4.

1415 TURN OB at 355-357.

from deployment as an offset to rates, we are persuaded it is fair and reasonable to deviate from the general principle of excluding a rate of return on the net plant balance of assets that are no longer used and useful.

Under a six-year amortization, SCE will still receive full recovery of the December 31, 2010 undepreciated legacy meter plant balance and a rate of return on the unamortized amounts. However, we believe that the applicable rate of return should be adjusted consistent with our decision in PG&E's 2011 GRC. SCE developed its own calculations in the event the Commission decided to adopt similar treatment, and concluded the reduced rate of return for common equity would be 6.72%, resulting in a rate of return on the legacy meters of 6.46%.[1416]

Accordingly, the Commission finds reasonable and adopts a six-year (2012-2017) amortization period for SCE's retired legacy meters and authorizes a return of 6.46% for the meters.

20.6. Four Corners

As described in Section 4.2.2.1, the Commission approved the Sale Agreement for Four Corners Generation Station on October 1, 2012 and found reasonable SCE's 2012 proposed capital spending of $1.88 million.

SCE includes the following items related to Four Corners in the development of its estimated 2012 rate base:

- $4.174 million ($nominal) in M&S inventory;
- $305.798 million in coal fuel costs as part of the fuel lag days determination for working cash capital; and

[1416] SCE-25, Vol. 02 at 50.

- $6.843 million in property taxes (New Mexico) as part of the lag days associated with Taxes Other Than Income.[1417]

SCE utilizes these expenses in its rate base calculations as if Four Corners will be in rate base for the entire calendar year of 2012. As we discussed above, this GRC decision assumes that Four Corners will be sold by October 2012 pursuant to D.12-03-034.

All assets, deductions, and calculations associated with Four Corners in SCE's 2012 Rate Base shall be removed from rate base as of the effective date of the sale.

20.7. Mohave

As discussed in Section 4.2.1, SCE has partial ownership of the coal-fired generation units at Mohave which closed in 2005 and are undergoing decommissioning. We authorized 2009-2011 capital expenditures of $31.9 as proposed by SCE, subject to balancing account review. According to SCE's Depreciation Study, at the end of 2009, SCE had approximately $54 million of net plant investment in Mohave, and estimated decommissioning costs of $36 million.[1418] SCE proposes to amortize the remaining capital investment and decommissioning costs over the current authorized remaining life of 6.5 years.

TURN does not oppose cost recovery, but recommends a zero rate of return for the remaining investment and decommissioning costs on the grounds the plant is no longer used and useful.[1419] According to TURN, the situation is dissimilar to legacy meters because SCE and its co-owners made a decision to

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[1417] DRA-19 at 15-16.

[1418] SCE-10, Vol. 03 at 20.

[1419] TURN-11 at 9.

close Mohave instead of making the investment to bring the plant into environmental compliance. This, claims TURN, is more similar to the facts of PG&E's Humboldt Bay Power Plant (HBPP) where the Commission authorized recovery of remaining net investment, but no return on the amount.[1420]

SCE reiterates its arguments from the legacy meter discussion above in opposition to TURN's position. Closing Mohave is consistent with California's aggressive targets for GHG reductions, states SCE, and SCE should not be penalized for doing so. Moreover, SCE's comparison with HBPP is erroneous because HBPP is a nuclear facility and decommissioning is financed by an external trust. For Mohave, the decommissioning activity is a necessary cost of providing service and reduction of the rate of return is a denial of cost of service ratemaking principles.[1421]

Regarding Humboldt, the Commission stated:

> In the case of a premature retirement, the ratepayer typically still pays for all of the plant's direct cost even though the plant did not operate as long as was expected. The shareholder recovers his investment but should not receive any return on the undepreciated plant. This is a fair division of risks and benefits.[1422]

We agree that SCE should be allowed to recover its remaining net investment and decommissioning costs for Mohave and view our analysis of risks and benefits for HBPP to be generally applicable. Shareholders should not

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[1420] *Id*. at 10.

[1421] SCE-25, Vol. 02 at 51.

[1422] D.85-08-046; 18 CPUC2d 592.

receive a rate of return on the undepreciated, non-operational plant or decommissioning expenses.

SCE argues that nuclear plant decommissioning is distinguishable because it is funded by ratepayers through external trusts during the life of the plant. This assures that the ratepayers receiving the benefit of the plant also incur the costs of closing the plant. As for other capital investment, removal costs are included in the budget of capital expenditures, but recorded as a debit to depreciation reserve rather than capitalized to Plant. Here, SCE and its co-owners apparently did not adequately plan ahead for decommissioning expense, otherwise there would be sufficient depreciation reserve.

No party requested acceleration of the authorized remaining life of 6.5 years for SCE to amortize its capital investment and decommissioning costs. However, for simplification, we modify the authorized remaining life to six years, or two rate cycles.

Therefore, the Commission finds reasonable and adopts TURN's recommendation that SCE be allowed to recover its remaining net investment in plant and decommissioning costs over six years of remaining life, and to earn no return on plant investment.

21. Non-Tariffed Products and Services

Within OOR is a subset of revenues derived from NTP&S, including use of rights-of-way, Edison Carrier Solutions, and Camp Edison. SCE uses and obtains a profit from utility property for purposes other than the provision of utility services and is required to share those revenues with ratepayers. In D.99-09-070, the Commission adopted a Gross Revenue Sharing Mechanism (GRSM) for OOR generated from NTP&S. "Incremental" costs of providing the

NTP&S, those that would not have been incurred "but for" the NTP&S, are recovered from shareholders.

One component of the GRSM provides for the first $16.671 million of gross revenues to flow to ratepayers.[1423] SCE is required 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.

TURN raises a number of concerns about the GRSM and SCE's cost recording, many of which it raised in the 2009 GRC. For example, in both the 2009 and 2012 GRCs, TURN recommended: (1) the GRSM be either modified or eliminated; (2) if GRSM is retained then increase the threshold revenues to $27.6 million based on a 3% annual inflation adjustment from 1999; and (3) the Commission should conduct an audit of NTP&S activities and suspend the sharing mechanism until the audit is completed.[1424]

Of particular interest to TURN is SCE's manner of identifying, recording, and reviewing incremental costs of providing NTP&S. SCE relies on its Business Units to identify incremental costs, which are unverified, and TURN lists several examples of reporting errors for such costs.[1425] As an example, TURN queries how SCE reports no incremental costs for the highly developed (e.g., cable and wi-fi) campgrounds at Camp Edison which generate $1 million annual revenues.

[1423] SCE-25, Vol. 02 at 58; *c.f.* D.09-03-025 at 301 (citing D.99-09-070) which uses $16.773 million.

[1424] TURN-11 at 17-18.

[1425] *Id*. At 20-22.

SCE states it is not required to break down costs by lease, for example, and TURN notes SCE allocates incremental costs by associated revenue, thus hampering any effective Commission review.[1426]

Also provoking concern is Edison Carrier Solutions (ECS), "a dedicated shareholder-funded business unit whose purpose is to provide telecommunications services to third party customers."[1427] ECS accounts for about half of the NTP&S revenue and uses a mix of ratepayer-funded and shareholder-funded assets to provide services. TURN asserts that SCE's cost-recording practices make it difficult to determine incremental cost.

SCE strongly defends the NTP&S program as working for ratepayers and argues the GRSM is applied correctly. Since 1999, when the GRSM was adopted, SCE states that ratepayers have received $316.6 million of revenue credits while incurring no incremental costs, risks, or liabilities.[1428] Additionally, since inception, annual NTP&S revenues have grown to more than $90 million, with shareholders incurring $492.9 million in incremental costs and investing $168.3 million in capital.

SCE also responds to TURN's criticisms and rejects TURN's recommendations as unsupported and unjustified. For example, SCE argues: (1) the GRSM is working as intended as shown by revenue growth; (2) robust accounting procedure for ECS and enhanced employee training result in accurate incremental costs; (3) ratepayers have received the large majority of revenues; (3) TURN ignores substantial shareholder investments including $168.5 million

[1426] *Id*. at 25.

[1427] *Id*. at 23.

[1428] SCE-25, Vol. 02 at 56.

into ECS; (4) increasing the GRSM threshold would exacerbate the asymmetrical benefit accruing to ratepayers; and (5) TURN's proposed audit is unnecessary because SCE's errors were reporting errors, not recording errors, and another audit is duplicative of the Affiliated Transactions audit.[1429]

The last external NTP&S audit was in 2006, as part of the Affiliate Transactions Audit, and had two recommendations for SCE: revise accounting standards to improve accuracy and timely reporting and timely submission of the annual NTP&S report to the Commission. SCE accepted the recommendations and stated it would revise its internal NTP&S incremental costs and accounting, improve its training related to incremental costs, and submit its annual reports by March of each year.[1430]

In SCE's 2009 GRC, we noted that cost recovery had been a recurring issue since 2003. We observed that the regulatory framework had changed significantly since the GRSM was created and the threshold was calculated based on SCE's incremental costs to provide NTP&S in 1995.[1431] We also found "significant ambiguity" about the circumstances under which SCE may recover its NTP&S costs from ratepayers. We were also 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 the program.[1432]

[1429] *Ibid*. at 57.

[1430] TURN-11 at 25-26.

[1431] D.09-03-025 at 301.

[1432] *Ibid*.

We agreed with TURN that the Commission should "revisit" NTP&S and the GRSM, but in a separate rulemaking not in the GRC. Such a rulemaking did not occur and the issues returned in this proceeding.

We continue to believe that the GRC is not the place to modify the established GSRM and TURN has not provided sufficient evidence to do support a specific alternative. SCE offered some explanation of its practices, but did not overcome all of the doubts raised by TURN. Reporting errors that do not affect ratepayers provide little comfort that SCE's recording is more error-free. Significantly, it is not clear that SCE actually acted to implement its responses to the 2006 audit, or to respond to our concerns as articulated in the 2009 GRC decision.

We remind the parties that pursuant to Rule 6.3 of the Commission's Rules of Practice and Procedure, they may petition the Commission to initiate a rulemaking to adopt, amend, or repeal a regulation which applies to an entire class of entities or activities.

For purposes of this GRC, we lack sufficient evidence to make changes to SCE's estimated OOR. However, we agree that the next Affiliated Transactions audit managed by the Energy Division should include a focused review of the NTP&S program, including SCE's development of incremental costs, to ensure that SCE is accurately identifying them and recording them. Inadvertently omitted incremental costs would adversely impact ratepayers by inclusion in general rates. This audit should provide a basis for consideration in a future rulemaking of whether to modify the NTP&S threshold amount and/or the GSRM.

Therefore, the Commission makes no changes to the existing NTP&S provisions or revenue sharing mechanism, and includes the $16.671 million threshold amount in the OOR test year estimate. As discussed above, the Commission also orders the Energy Division to ensure that the next Affiliated Transaction audit includes the NPT&S audit described above.

22. Depreciation

The purpose of depreciation expense is to recover the original cost of fixed capital assets for investors, less net salvage value, over the life of the asset. Depreciation expense is a legitimate cost of service.

In this GRC, SCE applied the Straight-Line Remaining Life Depreciation method, historically applied by the Commission, where the undepreciated asset amount (original cost less accumulated depreciation plus estimated net salvage) is depreciated in equal portions over the remaining life of the asset.[1433] The net salvage value includes the cost of removal (COR) of the asset at the end of its useful life and any salvage value the asset may have at the time.

SCE combines most assets into broad groups for purposes of calculating depreciation which include a wide range of service lives and retirement characteristics. The grouping of assets affects the level of depreciation accruals and accumulated depreciation.[1434]

SCE claims that the accumulated depreciation balance as of the end of 2009 should be $2.7 billion higher because previously authorized depreciation rates have not kept pace with removal costs resulting in a deficit in accumulated depreciation.[1435] Therefore, SCE requests that depreciation expense adopted in

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[1433] SCE-10, Vol. 03 at 6.

[1434] *Ibid.*

[1435] *Id.* at 13, Table III-2.

this GRC address the past accumulated depreciation deficit, as well as the going-forward costs.

For 2012, SCE proposes depreciation expense of $1.572 billion ($nominal), an increase of $511 million (49%) over the 2009 authorized level.[1436] The request includes $452 million for Changes in Plant Balances, $11 million towards SCE's claimed accumulated depreciation deficit, and $48 million to avoid further deficit going forward.

DRA proposes reductions to depreciation expense of $124.6 million.[1437] TURN proposes combined reductions totaling $272 million.[1438] SCE contends the primary goal of the proposals is cost deferral.

Due to the large dollars at stake, and the wide range of possibilities, we prefer to be conservative in adjusting net salvage ratios, rates or accruals.

22.1. SCE's Depreciation Study

SCE performed a depreciation study to support its request for a significant increase to depreciation expense in 2012. SCE provided a comparison of SCE's proposed depreciation rates for transmission, distribution, and general plant accounts, to authorized rates from the 2009 GRC.[1439] As of December 31, 2009, SCE states that 15 of 18 categories of T&D plant categories have an Accumulated

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1436 SCE-10, Vol. 02 at 19; SCE OB at 338 (SCE revised total depreciation expense to $1.572 billion).

1437 DRA-17 at 2.

1438 TURN-1 at 4.

1439 SCE-10, Vol. 03 at 11, Table II-1.

Depreciation deficit, most of it in accounts for SCE-10, Vol. 03 line transformers, distribution poles, services, and T&D station equipment.[1440]

SCE also provided a comparison of depreciation service lives and associated retirement curves for its transmission, distribution, and general plant accounts as authorized for 2009-2011, and as proposed by SCE for 2012-2014.[1441] For mass property net salvage rates (NSR), SCE's study analyzes gross salvage and COR as ratios of original cost of historic plant retirements. The results of SCE's analysis is that in 11 T&D accounts, proposed NSR are more negative than currently authorized net salvage ratios.[1442]

22.2. Parties' Positions

DRA does not dispute SCE's proposed service lives, but disagrees with all of the changes SCE proposes to NSR.[1443] Although DRA did not conduct a net salvage analysis, DRA argues no changes are warranted based on policy reasons. In SCE's 2009 GRC, the Commission agreed with DRA that retaining previously adopted NSR would keep customer rates lower at a time of economic downturn, without impacting safe and reliable service.[1444] DRA asserts the circumstances are unchanged in 2012.

DRA also disputes SCE's claimed accumulated depreciation deficit of $2.7 billion, which DRA calls an undocumented "theoretical reserve

[1440] *Id.* at 13, Table III-2.

[1441] *Id*. at 21, Table IV-3.

[1442] SCE-10, Vol. 03 at 74, Table V-25.

[1443] DRA OB at 429.

[1444] D.09-03-025 at 179-180.

imbalance."[1445] Other DRA considerations include: (1) SCE has some of the highest negative net salvage ratios among the three IOUs;[1446] (2) the Commission has acted in the past to mitigate the depreciation impact on ratepayers;[1447] and (3) in the previous five years (2005-2010) SCE allocated $1.5 billion to the depreciation reserve, but only spent $0.95 billion, leaving a 37% margin embedded in current net salvage rates.

TURN takes issue with SCE's proposed mass property life calculations and net salvage values, arguing that SCE's request for an increase in depreciation expense is based on unusual depreciation procedures and practices that produce questionable results.[1448]

Specifically, TURN recommends life adjustments to 10 of the top 12 mass property accounts (measured by plant investment) resulting in a stand-alone reduction of $141million in depreciation expense. For net salvage values, TURN makes adjustments to 10 accounts resulting in a standalone reduction of $167 million. The combined impact of both life and net salvage adjustments is $272 million based on plant as of December 31, 2009.[1449]

TURN's view is that SCE's claimed application of judgment to set property lives or net salvage rates is often insufficiently supported with any explanation of how that judgment was applied, or what was considered in the process. SCE and TURN differ over whether depreciation rates should reflect known changes

[1445] DRA-17 at 9.

[1446] *Id*. at 12, Table 17-3.

[1447] *Id*. at 12-13.

[1448] TURN-1 at 2.

[1449] *Id*. at 4.

in utility practices that will have near term effects on service lives or costs of removal. Another TURN criticism is that SCE did not follow its own study's results.

Both DRA and TURN recommend that SCE be required to change its accounting so that all Third Party Reimbursements (TPR) are assigned to gross salvage. Lastly, DRA wants SCE to be ordered to report accounting changes in its GRC testimony, and TURN asks that SCE be ordered to provide a Retirement Cause Analysis and an Industry NSR Comparison Analysis.

These issues are discussed below.

22.3. Mass Property Lives

The depreciation rate for mass property accounts depends on the estimated remaining life of that group of assets. Estimation of the remaining life requires both the average service life (ASL) for the group and the dispersion pattern. According to SCE, it relied on informed judgment and analysis of life estimates with the Simulated Plant Records (SPR) model.[1450]

SCE generally relied on several factors to select the retirement dispersion curve which represents the percent of original placements retiring in each year.[1451] There are four basic groups of curves utilized: Left Modal (L), Symmetrical (S), Right Modal (R), and Original Modal (O), depending on the relationship of the most frequent retirements to the ASL.

TURN objects to SCE's use of "judgment" without SCE establishing how it obtained the actual values being proposed for each account. In its testimony,

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1450 SCE-10, Vol. 03 at 15.

1451 TURN-1 at 9 ("Aged retirement data" means when the dollar amount of an asset is retired, its in-service date is also known).

TURN reviewed Account 353-Transmission Station Equipment, which applied a 40 R1 life-curve combination to illustrate typical problems TURN had with SCE's study, including:

- The lack of any identifiable connection between generalized statements and a 40 year service life;
- No explanation of why ASL for SCE is shorter than industry averages;
- No information on how a comparison to industry dispersion patterns led to the proposed life-curve;
- No explanation of why SCE's proposal is not the best or highest ranked or most frequent pattern from the SPR;
- Relevant work papers include questions to SCE personnel but have no responses; and
- Nothing specific in the account narrative supports the chosen life-curve combination any more than alternates proposed by TURN.[1452]

SCE responds that TURN selectively chose data to support longer life estimates, erroneously relied on industry statistics, and mistakenly ignored the judgment of SCE's experienced personnel.[1453] For example, SCE contends sole use of SPR results is misplaced because SPR ranking can be unreliable, especially where there are changing life characteristics.[1454] SCE argues that critical judgment based on experience must still be applied.

Regarding dispersion pattern selection, SCE looked at changing life characteristics, retirement patterns, SPR results, and compared results to

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[1452] *Id.* at 10-17.

[1453] SCE-25, Vol. 03 at 38.

[1454] *Id.* at 6.

industry curves.[1455] For each account, SCE provided a description of the factors affecting retirement and its view of SPR reliability.

The Commission has recognized in past GRC decisions that the determination of depreciation parameters is a matter of judgment, just as with any other forecast in this GRC. However, we agree with TURN that SCE's use of "judgment" is often opaque and SCE's explanation of changes to ASL and dispersion patterns yielding the curve-lives tends to be limited and conclusory. On the other hand, TURN's testimony tends to place heavy reliance on the SPR results and yields ASL without much support other than the R-curve. We reviewed each account for the support offered to proposed changes.

No party disputes SCE's proposed Life Analysis for Accounts 352, 357, 358, 359, 361, 370, 373, and 390. Upon review of the record, the Commission finds SCE's proposed Mass Property ASL for these accounts to be reasonable and adopts them. Below is a table that summarizes SCE's and TURN's differences for the remaining accounts which are discussed in the sections that follow.

Disputed Mass Property Average Service Lives Transmission and Distribution Plant					
Account	**Description**	**Authorized 2009 GRC ASL/LC**	**SCE Proposed 2012**	**TURN proposed 2012**	**Adopted**
	TRANSMISSION PLANT				
353	Station equipment	40 R1	40 R1	45 R0.5	40 R1
354	Towers & Fixtures	65 S3	60 R5	65 S5	65 R5
355	Poles & Fixtures	45 R1	45 R1	50 R1	50 R1
356	Overhead Conductors & Devices	50 R4	50 R4	55 R3	50 R4

[1455] *Id.* at 59.

	DISTRIBUTION PLANT				
362	Station Equipment	45 R1	45 R1.5	50 R0.5	45 R1.5
364	Poles, Towers & Fixtures	45 R0.5	40 R1	45 R0.5	45 R1
365	Overhead Conductors & Devices	45 R0.5	40 R1	45 R0.5	45 R0.5
367	Underground Conductors & Devices	30 R2	30 R2	40 R1	40 R1
368	Line Transformers	30 S3	30 R1.5	36 R0.5	30 R1.5
369	Services	35 R2	40 R2	46 R1	40 R2

22.3.1. Transmission Plant

We briefly discuss each account in dispute.

a. Account 353 – SCE proposes no change to the 40 R1 curve-life. TURN argues the ASL is increasing as seen in the SPR, and the R0.5 dispersion pattern is a better fit to the SPR analysis.[1456] We conclude that 40 R1 is reasonable. TURN's support for the R0.5 is limited to noting a small incremental difference from moving to R0.5, and R0.5 is closer than R2 to R1, but R0.5 is rarely used in industry.[1457] Although there is some indication of increasing service life, there is insufficient evidence to change the ASL. We adopt no change for this account.

b. Account 354 – SCE proposes to change from 65 S3 to 60 R5 based on engineering judgment. TURN argues SCE lacks support for reducing ASL, noting SCE's proposed life-curve assumes a maximum life of less than 100 years despite SCE's admission some equipment lasts that long.[1458] We agree SCE did not adequately support the decrease in ASL, but SCE did support that a Right Modal dispersion pattern is reasonable. Therefore, we adopt a 65 R5 curve-life.

1456 TURN-1 at 24-27.

1457 *Id.* at 24-25.

1458 *Id.* at 28-29; SCE-10, Vol. 03 at 23.

c. Account 355 – SCE proposes no change to 45 R1 curve-life based on recent retirement experience. New treatment of wood poles starting in 2004 to extend ASL to 60 years was not considered by SCE because the allocation is for existing investment, one-third of the account is non-wood, and only 40% of pole retirements are caused be deterioration.[1459] TURN recommends a 50 year ASL due to: (1) the upward ASL trend over time; (2) new, treated wood poles have a 60-70 year life span and account for 36% of the group's assets; (3) more concrete and steel poles in the group; and (4) more inspections means fewer retirements.[1460] We are persuaded that a 50 year ASL is reasonable and adopt a 50 R1 curve-life.

d. Account 356 – SCE proposes no change to its 50 R4 curve-life because retirement factors suggest retirements increasing over time due to corrosion and fatigue. TURN recommends a 55 R3 curve-life because the account is largely aluminum conductor steel-reinforced conductors which if properly installed and maintained can have a useful life of over 70 years.[1461] The R3 dispersion pattern is the most common in industry, while the R4 pattern shows an upward ASL trend. The difference between R3 and R4 is small, but R3 is linked to an ASL of 59 years, 28% higher than industry ASL.[1462] Therefore, we adopt no change to this account.

In summary, the Commission finds SCE's proposals reasonable for Accounts 353 and 356, TURN's proposal reasonable for Account 355, and made a reasonable change to the dispersion pattern for Account 354. The Commission adopts these results.

1459 SCE-25, Vol. 03 at 23-24.

1460 TURN-1 at 30-32.

1461 *Id*. at 34.

1462 SCE-25, Vol. 03 at 76.

22.3.2. Distribution Plant

a. Account 362 – SCE proposes changing the dispersion pattern from R1 to R1.5 based on engineering judgment that retirements will not be flat or low modal, but increase with age and concentrate at ASL. Also, the R1.5 yields a 45 year ASL in line with SCE's expectations. TURN believes the ASL should be 50 years because SCE's prior lower life estimates have not occurred, engineering statements about retirements are vague, and the SPR analysis supports longer ASL.[1463] Unlike R1.5, the R0.5 pattern does not conform with the retirement patterns identified by SCE's engineers, nor the choice of most of the industry. Therefore, we adopt a 45 R1.5 curve-life.

b. Account 364 – SCE proposes 40 R1, a decrease to ASL and a wider dispersion pattern based on the experience of SCE engineers and industry.[1464] SCE states the R1 curve is consistent with SCE's retirements and is common in industry. We agree with TURN's arguments about increasing service life for these poles, as CA made for Account 355-Transmission Poles. However, TURN did not adequately support use of the R0.5 pattern, used infrequently by industry. Therefore, we adopt a 45 R1 curve-life.

c. Account 365 – SCE proposes 40 R1, a decrease to ASL and a wider dispersion pattern based on the R1 curve yielding an ASL it views as consistent with industry, retirement characteristics, and engineering judgment. TURN proposes no change from 45 R0.5 because the data supports lengthening service lives and the engineering judgment was focused on a small portion of the assets. SCE did not adequately support a shorter service life which drove its R1 selection. Therefore we adopt no change to the curve-life for this account.

1463 TURN-1 at 37.

1464 SCE-10, Vol. 03 at 30.

d. <u>Account 367</u> – SCE proposes no changes for this account, the largest mass property account with a $3.5 billion investment. SCE asserts the 30-year ASL is based on the design life of the majority of electrical distribution equipment, and it used engineering judgment and industry experience to favor the R2 curve. SCE acknowledges both the varying, and changing, life characteristics for property in this account, but does not address this fact. SCE's assumption that the average service life of Distribution Underground Conductors and Devices mirrors the design life of most distribution equipment is not persuasive, particularly in light of SCE's accelerated equipment inspection, repair, and replacement schedules which will likely extend equipment life. We agree with TURN that the 30-year service life also likely understates the evolving nature of the assets in this account. The R1 curve is associated with a 40-year service life and is reasonable given the longer assumed service life for the account. Therefore, we adopt 40 R1 for this account.

e. <u>Account 368</u> – SCE proposes 30 R1.5, a different dispersion pattern than S3 adopted in 2009. SCE states the significant difference in the ASL of the assets in this account tend to cause a wider dispersion. TURN proposes 36 R0.5 because it views SCE's ASL as too short compared to industry, and unsupported by anything other than "judgment." Statistical analysis suggests lives are lengthening. The R0.5 and R1 curves indicate small increases to ASL. TURN did not adequately support the 6 year increase to ASL, and the R1.5 curve yields a 30-31 year ASL. Therefore, we adopt a 30 R1.5 curve-life.

f. <u>Account 369</u> – SCE proposes 40 R2, an increase in ASL, based on varying ASL among the assets in the account, and industry use of R1 to R3 curves. The R2 curve, most frequently selected curve by industry, yields a 40 year ASL. TURN proposes a 46 R1 curve-life, even though it views SCE's ASL increase as unsupported. The R1 curve ranked higher for this account than the R2 curve but TURN did not adequately support its selection of a 46 year ASL. The

> R1 curve, while ranked lower, yields an ASL closer to the limited engineering information provided. Therefore, we adopt a 40 R2 curve-life for the account.

In summary, the Commission finds reasonable and adopts SCE's proposal for Accounts 368 and 369, TURN's proposals for Accounts 365 and 367, no change to Account 362, and a revision to the dispersion pattern for Account 364.

22.4. Mass Property Net Salvage

Net Salvage is equal to the gross salvage less the COR associated with a retirement. It is expressed either as a dollar amount or as a percentage of the original plant cost. Negative net salvage results when the COR exceeds the original cost of the asset. SCE states its net salvage analysis considered 15 years (1995-2009) of historical retirements and excludes anomalous retirements.

For 2012, SCE seeks an increased NSR for 11 T&D accounts because it claims the reserve accounts are currently deficient.[1465] SCE states it developed the forecast based on retirement data, analysis of historical net salvage ratios, and application of informed judgment.

In SCE's 2006 GRC, we increased the NSR for the first time in 10 years. In the 2009 GRC, we made no changes to NSR, primarily to prevent rate shock during the economic recession, notwithstanding SCE's claim that it had a deficit in accumulated depreciation due to the rates.

22.4.1. Parties' Positions

The essential dispute is methodology. SCE solely relies on historical data and judgment. TURN views SCE's historical data as unreliable, skewed to high negative net salvage, and instead looks to comparison with industry averages

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[1465] *Id*. at 74, Table V-25.

and its own expert's judgment. Both TURN and DRA oppose SCE's proposed salvage values as excessive; both claim SCE did not explain or support its use of "judgment" to develop NSR.

DRA proposes no changes again in the 2012 GRC on the grounds that: (1) SCE did not document its claimed deficit; (2) SCE has collected but not spent \$2.6 billion in rates for future COR; (3) retaining the current rates creates no adverse impact on shareholders who always recover the capital investment and COR; and (4) any rate increase above what SCE will already receive will harm ratepayers already stretched by the economic recession.[1466] DRA also claims that SCE has the some of the highest NSR among the three IOUs.[1467]

SCE replies DRA is in error to ignore the reserve deficit, deferral increases costs to future customers, and DRA should have performed an independent analysis to determine if DRA's proposals are in the best interests of customers over the life of the assets.[1468] SCE also strongly disagrees that no risk arises if SCE is unable to recover the cost of retiring an asset because expenditures may not earn a full return.

TURN developed its own NSR for 10 T&D accounts.[1469] TURN views SCE's negative 53% overall NSR for its T&D accounts to be excessive when compared to industry, including PG&E's most recently authorized rates.[1470]

[1466] DRA-17 at 10-11.

[1467] *Id.* at 12, Table 17-3.

[1468] SCE-25, Vol. 03 at 88, 96.

[1469] TURN-1 at 57.

[1470] *Id.* at 54.

Factors TURN identified as contributing to high negative net salvage include: (1) SCE allocates too much replacement activity cost to COR rather than new replacement investment; (2) SCE has not analyzed whether the current mix of investment reflects historic retirements in its historical net salvage database; and (3) SCE has not considered whether its historical database reflects too much emergency-related retirement rather than less expensive planned retirement, more likely to occur in the future.[1471]

SCE rejects, as invalid, comparisons to the NSR of the other major electric utilities due to differences that can result from company practices, policies, and other conditions (e.g., unit classification, labor rates, accounting practices, local regulations, weather, etc.). In addition, SCE views TURN's NSR estimates as unreasonably below actual COR.

SCE claims its study establishes that capital costs for asset installation and removal are not likely to change relative to past periods, and supports the reasonableness of SCE's proposals.[1472] To the extent that SCE proposed NSR less than indicated by its study, SCE states it was an effort to phase in adequate rates and avoid large rate increases.

22.4.2. Discussion

Regarding documentation of the accumulated depreciation deficit, SCE's basis to change its rates, we recall the function of the reserve is to allocate cost recovery for the cost of installation and removal of a group of assets over the service life. The Commission previously adopted depreciation rates and service

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[1471] *Id*. at 55.

[1472] SCE-25, Vol. 03 at 40.

lives, and SCE has made the resulting cost allocations. The calculated "deficit" is the mathematical difference between what SCE asked for and what was authorized by the Commission.

On the other hand, slightly different assumptions would significantly influence the sufficiency of the accumulated depreciation reserve. Thus, SCE's deficit argument is self-fulfilling because it presumes that its assumptions in prior GRC requests were correct, including constant escalation of COR, even though some assumptions were not adopted by the Commission or borne out by actual retirements.

For purposes of this GRC, we do not determine whether the $2.7 billion claimed deficit is an accurate number. Some deficit may exist based on our decision in 2009 to defer consideration of any changes due to economic conditions and the potential impact on ratepayers. Instead, we address whether SCE has met its burden of proof to support specific requests in this GRC, or another proposal is shown to be reasonable.

SCE does not dispute that its proposed NSR are much higher than industry, or that it has collected $2.6 billion in rates for future retirements. SCE illustrated that a comparison of NSR among major electric utilities has limited value because some relevant factors are unknown. We are also not persuaded to retain existing rates just because SCE currently accrues negative net salvage at a level higher than annual recorded COR. Even if SCE will have sufficient funds to cover removal or net salvage costs in the foreseeable future, it leaves the question of long-term intergenerational equity versus short-term rate tolerance.

We review SCE's proposed salvage rates for reasonableness, as well as the resulting impact on revenue requirement.

TURN's question of the whether the historic retirement data reflects the current investment in the group is a reasonable concern. SCE's response that its asset groups are too large and retirements too voluminous to make review feasible, is incomplete. SCE's study focused on rolling bands of historical average net salvage costs and claims to have selected bands appropriate to data fluctuations or trends. If SCE had provided more information about the assets within its accounts and application of judgment as part of the study, this concern might not remain open.

A related concern of TURN's is that historic data does not reflect a likely decrease in higher cost emergency-related replacements following enhanced inspection and maintenance approved in this and the 2009 decision. SCE calls this the "Yugo Fallacy" to reflect TURN's example of assets with very different retirement cost characteristics shifting in proportions within the group over time. Although SCE does not factor effects of near-term changes (e.g. enhanced asset inspections) until the results appear in historical data, we are not persuaded it is irrelevant solely based on SCE's position that the expert analysis and judgment it applied obviate the need for discussion.[1473] Again, if SCE had been more responsive about its asset classes and how it applied judgment, the parties and the Commission would have better information to weigh the reasonableness of SCE's proposals.

Based on the foregoing, we examine the net salvage proposals of SCE and other parties below. Accounting and reporting issues raised by the parties are discussed separately.

[1473] *Id*. at 47.

22.4.3. Net Salvage Rates by Account

SCE either made no change to its current NSR or proposed to reduce the negative salvage value for Accounts 352, 357, 358, 359, 366, and 370, as well as for General Plant accounts (390-398). No party disputed SCE's proposed NSR for these accounts. Based upon a review of the record, the Commission finds SCE's proposals for the identified accounts to be reasonable and adopts them.

Although TURN does not dispute SCE's proposed negative NSR for Account 361 (Distribution Structures & Improvements) and Account 368 (Distribution Line Transformers), DRA opposes any changes.

For each account, SCE provided 15 years of recorded NSR, as well as the 15 year, 10 year, and five year (15/10/5) averages, and three year rolling averages (3YRA). Where SCE proposes a negative NSR less than indicated by the study, SCE states its proposal is more conservative to phase in reduction of its claimed depreciation reserve deficit. Although not unreasonable given the Commission's past decisions to mitigate rate impacts of depreciation expense, the results are somewhat arbitrary.

The table below summarizes the disputed NSR for the remaining accounts:

Disputed Mass Property Net Salvage Percentage Rates (negative)					
Account	**Description**	**Authorized 2009 GRC**	**SCE Proposed**	**TURN Proposed**	**Adopted**
	Transmission Plant				
353	Station Equipment	5%	(10%)	(5%)	(5%)
354	Towers & Fixtures	(70%)	(85%)	(40%)	(70%)
355	Poles & Fixtures	(70%)	(85%)	(70%)	(70%)
356	Overhead Conductors & Devices	(80%)	(85%)	(40%)	(80%)

	Distribution Plant				
361	Structures & Improvements	(20%)	(25%)	---	(25%)
362	Distribution Equipment	(10%)	(20%)	(10%)	(20%)
364	Poles, Towers, & Fixtures	(190%)	(200%)	(90%)	(190%)
365	Overhead Conductors & Devices	(100%)	(110%)	(70%)	(110%)
367	Underground Conductors & Devices	(60%)	(60%)	(20%)	(60%)
368	Line Transformers	0	(10%)	---	0
369	Distribution Services	(75%)	(100%)	(75%)	(85%)
373	Street Lighting	(15%)	(30%)	(15%)	(20%)

22.4.3.1. Transmission Plant

a. Account 353 – SCE supports the change from +5% to -10% by reliance on 15 years of negative net salvage, including 3YRA ranging from -6% to -25%, most recently(2007-2009) at -21%. TURN proposes a -5% NSR based on industry range of 25% to -25%, indicating zero. TURN also thinks SCE understates gross salvage by not reflecting escalating prices for scrap copper which is eight times higher in 2009 than in 2000 and likely to continue to rise. SCE has significant retirement experience resulting in ongoing negative NSR, but neither SCE nor TURN has more than a general basis for their proposals. We are not persuaded a general upward trend of copper prices impacts this account, or that SCE's negative NSRs are wholly accurate. On balance, a -5% NSR provides a reasonable adjustment for this rate cycle. Therefore, we adopt -5% NSR for this account.

b. Account 354 – This account has had about 0.3% retirements. SCE proposes the change from -70% to -85% based on widely fluctuating NSR, ranging from -2% to -268% over 15 years, averaging -113%. TURN argues nominal retirements render historic data unreliable for forecasting and SCE did not consider relevant factors. For example, as retirements increase, economies of scale may lead to lower per unit costs. Also, -85% NSR is an outlier in comparison to industry data where mean, median, and mode values are all about -20%. We agree the reliability of historical data is limited, and high negative NSR years may disproportionately reflect high cost emergency replacements, given the long ASL of these assets. In these circumstances, it is reasonable to consider that SCE's estimate is far outside industry norms. SCE has not met its burden to support a change for this account. Therefore, we adopt no change.

c. Account 355 - SCE proposes the change from -70% to -85% based on recent retirement experience and an inflation-escalated analysis of current COR that yielded a -94% NSR. A significant amount of gross salvage comes from TPR. Although NSR recently declined, SCE believes as the account matures more non-reimbursed retirements will occur. TURN thinks SCE's historic NSR is overstated, in part due to high COR in years with lots of emergency replacements. TURN criticizes SCE's inflation-escalated COR because it does not consider the pole characteristics or circumstances of retirement. Lastly, SCE's -85% is an outlier in comparison to industry data where mean, median, and mode values indicate -30% to -40%. SCE has retired 20% of this account and both gross salvage and COR vary significantly. SCE did not support its view that non-reimbursed retirements would grow, and its attempt to rebut TURN's claimed impact of emergency retirements was undercut by various errors in its own table. Under these circumstances, it is reasonable to consider that SCE's estimate is significantly outside industry norms. SCE has not met its burden to support a change for this account. Therefore, we adopt no change to the account.

d. Account 356 – This account has had few retirements and SCE claims historic retirements are not representative of future retirements. SCE explained that a significant amount of gross salvage comes from TPR which is not expected to continue. SCE proposes to change from -80% to -85% based on fluctuating NSR, ranging from -34% to -195% over 15 years, averaging -111%. TURN argues SCE's database is unreliable due to TPR accounting, COR allocation when replacement occurs, and excessive emergency replacements. SCE's proposed -85% is an industry outlier, the most negative in the industry and approximately three times the industry average. TURN's proposed -40% is also one of the most negative in the industry. Given the unreliability of historical data, TURN's reference to industry comparisons is not unreasonable. When SCE is far outside industry norms, it raises questions about the reasonableness of its proposal, especially when SCE asserts the gap will only widen in the future. On the other hand, TURN's proposal is insufficient to recover current net salvage costs. Neither SCE nor TURN has met its burden to support a change for this account. Therefore, we adopt the current NSR of -80%.

In summary, the Commission finds reasonable and adopts TURN's proposal for Account 353, and no changes for Accounts 354, 355, and 356.

22.4.3.2. Distribution Plant

a. Account 361 - SCE proposes the change from -20% to -25% based on increasing COR and 15 years of negative NSR. The 3YRA ranges from a low of -15% (2004-2006) to -40% (2007-2009), but averaged -25% in last 10 years.[1474] SCE did not explain why 2009 COR and gross salvage are unusually high. DRA opposes any changes to existing NSR. SCE has had a significant number of retirements in this account resulting in a 15YA of -23% NSR, increasing to -32% for 2005-2009.[1475] Even excluding 2009, COR and negative NSR are slightly increasing over time. Therefore, we adopt SCE's proposal which matches the 10YA for NSR.

b. Account 362 - SCE proposes the change from -10% to -20% based on recent retirement information and increasing

[1474] Work Papers, SCE-10, Vol. 03 at 87.

[1475] SCE-10, Vol. 03 at 92 (SCE's table contained a mathematical error for 5YA net salvage).

NSR over time, with a 15YA of -24%. According to SCE, COR increased in the historic period and averaged 44% in the previous five years. TURN requests no change to the NSR because SCE did not explain its choice and 21% of the account is transformers which contain large amounts of copper. SCE has significant retirement history in this account resulting in ongoing negative NSR. We are not persuaded an upward trend in copper prices impacts this account, nor that the limited industry comparison is useful. TURN criticizes SCE for not using more recent time bands, but these bands support an even higher negative NSR. Although SCE should have explained why 2009 COR and NSR are unusually high, even if excluded, the evidence supports increasing negative NSR. Therefore, we adopt -20% NSR for this account.

c. <u>Account 364</u> – SCE's proposal to change from -190% to -200% is based on recent retirement experience, stable gross salvage, and increasing COR. SCE states the 15 year average NSR is -310%, and the (2005-2009) five year average is -385%. In addition to its consistent criticisms of SCE's historical NSR, TURN argues that SCE's proposal is the most negative value compared to industry information and suggests this is partly due to early, high cost emergency retirements. TURN's suggestion is unsupported. Further, TURN's claim that -90% NSR will yield an annual recovery similar to the average net salvage dollars reported for 2005-2009 does not address intergenerational equity. SCE's proposed -200% would result in a slight over-collection based on SCE's current average net salvage cost per pole. Therefore, we adopt the more conservative position of no change for this account.

d. <u>Account 365</u> - SCE proposes the change from -100% to -110% based on recent retirement experience. Historic NSR range from -82% (2002) to -239% (2009) although SCE does not explain why 2009 COR and net salvage are unusually high. The 15YA NSR is -137%. Based on four year experience bands, SCE demonstrates relatively stable gross salvage and increasing negative net salvage values.

TURN's recommends -70% based on its criticisms of SCE's database and comparison to industry statistics which average between -25% to -30% NSR. TURN also hypothesizes that COR may be inflated by SCE's removal practices. TURN's arguments lack support. SCE has had significant retirements in this account, primarily conductor, and TURN did not rebut SCE's claim that -70% NSR represents a cost per foot that is about 40% of the current costs of retirement. This is more persuasive than the limited utility of industry comparisons. Therefore, we adopt -110% NSR for this account.

e. <u>Account 367</u> – SCE proposes no change to the -60% for this account. Although there have been some fluctuations in NSR, SCE states the underlying trend has been higher negative NSR, averaging -102% over 15 years. As gross salvage dollars from TPR decline, COR is increasing. In support of -20%, TURN focuses on one portion of the account—removal of underground cable. Because the cable is removed only if the conduit is needed for replacement cable, TURN argues that SCE's practice of charging the cost to COR, instead of replacement, inflates COR. TURN also criticizes SCE's lack of aged retirement data because it prevents review of whether historical data is representative. TURN did not rebut SCE's assertion that it follows FERC accounting rules which define installation and removal by activity. Further, TURN's claim that -20% NSR will yield an annual recovery similar to the average net salvage dollars reported for 2005-2009, does not address intergenerational equity. The historical data is presented in a variety of time bands and all indicate negative NSR significantly in excess of -60%. Therefore, we adopt SCE's proposal for no change to this account.

f. <u>Account 368</u> – SCE proposes to change from 0% to -10% based on recent retirement information and 15 years of negative NSR, averaging -11%. DRA opposes any changes to 2009 NSR. Gross salvage values and COR have both recently trended upward, while NSR has been fairly flat. SCE relies solely on the fact of a negative NSR to support its proposal, but did not explain why NSR has not become more negative as COR rises. SCE has not met its burden of proof to support a change in this account and we adopt none.

g. Account 369 – SCE proposes to change from -75% to -100% based on recent retirement experience and 15 years of more negative net salvage, averaging -187%. The 5YA is -215% NSR. Removal costs have grown substantially since 2005 but vary significantly between underground and overhead assets. TURN rejects the historic data as unreliable, in part because it is not segregated between overhead and underground services. TURN recommends no change because SCE's proposal is at the high end of industry comparison, which averages between -30% and -40%. TURN also asserts that higher cost removals could be avoided by abandoning more underground services in place. SCE has significant retirement history in this account where about two-thirds of the investment is associated with underground services. SCE's request for a 33% increase to negative net salvage in such a large account is not reasonable, where retirement costs vary widely and removal is not always required. We adopt a more conservative increase to -85% NSR for this rate cycle.

h. Account 373 – SCE proposes to change from -15% to -30% based on recent retirement experience and a 15YA NSR of -49%, increasing to a -66% average in the last five years (2005-2009). TURN states SCE's estimated NSR is excessive and argues the historical data is skewed. TURN states SCE's proposal is at the high end of industry, which averages between -5% and -10% NSR. SCE has had a significant number of retirements in this account, costs are predictable for this type of asset, and during the 15 year period Gross Salvage declined while COR increased. As we have said, industry statistics have limited utility with these facts. However, doubling the existing rate for this rate cycle is not reasonable, especially given that SCE's proposal is somewhat arbitrary. Therefore we adopt a more conservative -20% for this account.

In summary, the Commission finds reasonable and adopts SCE's proposed increases for Accounts 361, 362, and 365, modifications to TURN's proposals for Accounts 369 and 373, and no changes for Accounts 364, 367, and 368.

22.5. Accounting Requirements

DRA and TURN have raised two net salvage-related accounting issues: (1) allocation of TPR; and (2) allocation of replacement costs.[1476]

Currently, when SCE receives a TPR to offset retirement and construction-related expenditures, a portion is credited to the depreciation reserve, but the majority is credited to gross plant. For example, SCE received about $58 million in TPR funds in 2010 and allocated $8.8 million to depreciation reserve.

TURN and DRA disagree with SCE's practice, largely based on regulatory gross salvage definitions which include "reimbursements."[1477] TURN recommends SCE be ordered to return to its pre-2004 accounting practice whereby the entire reimbursement for replacement activity is credited to gross salvage, instead of CAIC.[1478] DRA's recommendation is similar but includes all TPRs whether related to a replacement or not. TURN and DRA assert the changes are consistent with FERC's accumulated depreciation definition, and the gross salvage definition by National Association of Regulatory Utility Commissioners (NARUC), as well as SCE's own treatment of gross salvage in computing NSR.[1479]

[1476] JCE at 110, 727.

[1477] DRA-17 at 17.

[1478] TURN-1at 58.

[1479] DRA-17 at 17.

SCE contends DRA and TURN are mistaken, particularly about FERC rules which clearly require contributions for construction-related costs to be recorded as an offset to Plant-in-Service, with no distinction between replacement or new activity.[1480] SCE also argues that DRA and TURN's supporting authority is taken out of context from the FERC Gas Uniform System of Accounts (USOA), and they ignore other applicable authority.

We are persuaded by SCE that FERC rules specifically require contributions for construction-related costs to be recorded as an offset to Plant-in-Service.[1481] The portion of the reimbursement collected to offset retirement should be allocated to depreciation reserve, consistent with DRA's citations to definitions of salvage. No party disputes that this is the current practice of SCE.

Accordingly, the Commission declines to order SCE to make the requested accounting change related to TPR.

TURN also asks the Commission to direct SCE to change the way it allocates costs for replacement activity.[1482] According to TURN, SCE allocates significant levels of costs associated with replacement activity to COR instead of the cost of the new replacement investment.[1483] TURN claims SCE's practice leads to overstated COR, more negative net salvage values, and uncertainty about the reliability of SCE's historical retirement data. Because the net salvage analysis relies on a very small sample, TURN is correct that the impact of a small

[1480] SCE-25, Vol. 03 at 12.

[1481] *Id*. at 12.

[1482] JCE at 727.

[1483] TURN-1 at 55.

misallocation can be magnified into millions of dollars of additional depreciation expense.

When a retirement occurs in connection with a replacement of plant, SCE puts all work on one work order. SCE assigns to COR the portion of costs associated with removal activity; the rest of the costs are booked to new construction. SCE states the allocation is driven by the activity performed pursuant to FERC rules which do not distinguish between whether replacement occurs.[1484] According to TURN, sometimes the allocation is 50% of the work order cost, and can be up to 66.7%.[1485]

We agree the FERC rules support SCE's accounting practice as described, but SCE seems to misunderstand TURN's objection. At least part of TURN's concern is the allocations vary significantly and it is not clear that SCE is making the proper allocations. For example, if heavy equipment is needed to both remove plant and install plant, how does SCE apportion the cost?

The Commission declines to order SCE to change its basic practice, but SCE should review its allocation practices to be sure that <u>all</u> installation-related costs are booked to Plant-in-Service, instead of COR.

22.6. Reporting Requirements

DRA recommends SCE be required to report any accounting changes it plans to make in the future as part of its rate case testimony. Although SCE's changes to TPR accounting since 2004 sparked DRA's recommendation, other parties complained during the proceeding that such undisclosed changes hinder

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[1484] SCE-25, Vol. 03 at 15.

[1485] TURN-1 at 64.

review of SCE's application. We do not imply that accounting changes are intended to obfuscate data. However, a primary function of the GRC process is for public and Commission review of SCE's past and future use of ratepayer funds. Due to the extent of SCE's operations, some kinds of accounting changes between GRCs can have significant, but largely invisible effects.

SCE states it routinely makes numerous accounting changes for all kinds of reasons, but reports in its GRC those changes which impact revenue requirement.[1486] DRA examines the utility's operations as part of a GRC application, including internal and external financial statements which are one source of accounting changes. In Section 2.5, we directed SCE to provide clear tables tracking Generation and TDBU capital expenditures in the next GRC. According to SCE, it would disclose relevant accounting changes with that testimony.

Therefore, the Commission does not find an additional separate reporting requirement of accounting changes is necessary at this time.

TURN recommends new reporting requirements for SCE to: (1) provide aged life analysis data; (2) conduct a study of differences in NSR between SCE and industry; and (3) conduct a retirement cause analysis.[1487]

SCE began collecting aged data for use in its life analysis in June 2008.[1488] SCE has acknowledged the reliability limits of its life analysis based on simulated life data. We agree that aged data is likely to be more reliable. In the next GRC,

[1486] JCE at 111.

[1487] TURN-1 at 4, 84.

[1488] SCE-25, Vol. 03 at 16.

SCE should inform the Commission whether it used any aged data, and if not, when sufficient data is expected to be available.

SCE rejects TURN's calls for retirement cause and industry comparison analyses as irrelevant and diversions from addressing the reasonableness of its net salvage costs.[1489] TURN is concerned that wide differences in COR based on the cause of retirement may be so substantial that it could justify deviation from historical analysis. However, the task of identifying individual retirement causes is overwhelming and TURN did not offer any more cost effective means to explore this factor.

In its next GRC, SCE should include a better description of changes to underlying causes of retirement, life characteristics, or mix of investments considered when forecasting ASL or NSR in an account. If SCE provides more transparency of its application of judgment to depreciation forecasting, it will aid the Commission and intervenors in understanding SCE's analysis and the judgment applied to its forecast.

The proposed comparison of SCE's NSR to industry statistics is rooted in the basic difference of opinion over the reliability of SCE's historical data. TURN and DRA have raised various concerns and, instead, turned to industry statistics as a point of comparison, resulting in the observation that SCE's NSR is often far outside industry averages for large T&D accounts. This is a troubling fact, despite several factors which may reasonably drive differences.

We do not find that the cost of such a study would necessarily benefit ratepayers, but agree that industry statistics may provide an indication of

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[1489] *Id.* at 18.

excessive costs. SCE shall provide testimony in its next GRC to provide more information about COR in asset accounts where SCE's proposed NSR is at least 25% more than comparable industry averages.

23. Settlements

The Commission has a long, well-established policy of supporting the resolution of disputed matters through settlement.[1490] In doing so, the Commission has acknowledged that settlements advance several important goals, such as reducing the time and expense of litigation, conserving scarce Commission resources, and allowing the parties to reduce risks associated with litigation.[1491]

This decision approves three settlement agreements entered into by SCE and, individually, Disability Rights Advocates (DisabRA), Vote Solar Initiative (VSI), and California Coalition of Utility Employees (CCUE). The only contested settlement is with CCUE.

23.1. Standard of Review

We review the settlements pursuant to Rule 12.1(d) which provides that, prior to approval, the Commission must find a settlement "reasonable in light of the whole record, consistent with the law, and in the public interest."

In assessing settlements, the Commission considers all of the settlement provisions. In light of strong public policy favoring settlements, the Commission will not base its conclusions on whether any single provision is the optimal

1490 *See, e.g.*, D.05-03-022 at 8-9.

1491 D.05-11-005 at 16.

result, but rather, "whether the settlement as a whole produces a just and reasonable outcome."[1492]

23.2. Disability Rights Advocates

SCE and DisabRA propose a bilateral settlement (Settlement Agreement #1) to adopt a mutually acceptable outcome to certain access issues raised by DisabRA as an intervenor in SCE's 2012 GRC.[1493] The terms and conditions of Settlement Agreement #1 represent a compromise of their respective litigation positions.

In SCE's 2009 GRC, the Commission adopted a settlement between the same parties which addressed issues of public access to SCE facilities, right of way access to streets and sidewalks affected by permanently installed utility property or construction, internet access, and emergency communications with customers. The Commission directed SCE to document and demonstrate in the 2012 GRC that SCE made significant and useful changes to utility operations as a result of the settlement.[1494]

DisabRA raised similar issues in this GRC regarding the impact of SCE's practices on people with disabilities, including: (1) follow-up to issues from the 2009 GRC settlement; and (2) accessibility of SCE's communications with its customers.

[1492] D.05-11-005 at 16.

[1493] Joint Motion by SCE and DisabRA filed on August 22, 2011.

[1494] *Id.* at 326.

23.2.1. Settlement Agreement

Settlement Agreement #1,[1495] effective for the 2012-2014 rate cycle, provides that SCE agrees, in part, to:

- Continue to survey Service Centers and payment centers to determine if additional remediation is required;
- Train Service Center staff to prevent mobility barriers and assist customers with vision disabilities;
- Post customer assistance information on SCE's website and use reasonable efforts to ensure that future website changes are compliant with Web Access Standards, as defined;
- Continue to accommodate customer communication preferences for alerts and notifications, conduct outreach to medical baseline (MBL) customers regarding emergency notifications, and continue outreach to inform customers of alternative bill formats (e.g., large print);
- Continue to address compliance with SCE's Pedestrian Traffic Control Manual at construction sites;
- Reserve travel paths for all new utility poles located in Pedestrian Rights of Way; and
- Continue provision of an annual report to DisabRA regarding implementation efforts.

23.2.2. Discussion

DisabRA and SCE (collectively "Settling Parties #1") reflect different interests affected by this proceeding. Settlement Agreement #1 establishes facts jointly agreed to by Settling Parties #1. The fact that the settlement is uncontested generally supports its adoption. As set forth below, we find that

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[1495] Settlement Agreement #1 is attached to Joint Motion filed August 22, 2011.

Settlement Agreement #1 meets the criteria for a settlement pursuant to Rule 12.1(d).

First, the settlement is reasonable in light of the whole record. SCE and DisabRA entered into a similar agreement adopted in the previous GRC. DisabRA was an active participant in this proceeding to assert that additional efforts were still required to achieve the goals of the prior settlement.[1496] It filed a protest and submitted testimony that made recommendations of how SCE could improve communications with, and address the needs of, its disabled customers. SCE also provided testimony on these issues.

The record shows that both parties voluntarily participated in negotiations for several months before Settlement Agreement #1 was reached after significant give-and-take, including related O&M and capital spending caps for remediation costs.

Therefore, Settlement Agreement #1 addresses the issues in the proceeding in a reasonable manner in light of the record as a whole. We also find that the settlement does not contravene any statute or Commission decision or rule and is consistent with the law and Commission precedent.

Lastly, we find that the proposed settlement is in the public interest and in the interest of SCE's disabled customers who will be better protected and better served as a result of the settlement's terms and conditions. The settlement sets forth standards, compliance timelines, reporting and other criteria, and also saves the time and resources of the Settling Parties.

[1496] Joint Motion at 1.

Based on the foregoing, we approve Settlement Agreement #1 as proposed.

23.3. Vote Solar Initiative (VSI)

SCE and VSI proposed a bilateral settlement to adopt a mutually agreeable outcome to issues regarding SCE's obligation to consider distributed generation (DG) as an energy alternative.[1497] The terms and conditions of the settlement agreement (Settlement Agreement #2) represent a compromise of their respective litigation positions.[1498]

VSI intervened in the proceeding to focus on the issues of whether and how SCE is reflecting the impact of distributed generation resources -- including solar generation -- on SCE's Electric System Planning, and the related transmission and distribution capital upgrades and O&M forecasts.

23.3.1. Settlement Agreement #2

In the proposed settlement, SCE agrees to take steps to improve its consideration and documentation of DG as a possible alternative to capital investments in its distribution system. The steps include:

- <u>Tracking DG projects</u>: Beginning in 2012, track wholesale and retail DG projects and incorporate data into peak demand forecasts at the distribution and A-bank substation levels;
- <u>Screening Studies</u>: Beginning in 2012, conduct screening studies as part of SCE's annual distribution system planning process to determine if DG is a viable alternative for any planned distribution upgrades;

1497 Joint Motion by SCE and VSI filed on September 2, 2011.

1498 Settlement Agreement #2 is attached to Joint Motion filed September 2, 2011.

- Dependable generation: Where metered generator output data is readily available to facilitate a "dependable generation" calculation, calculate the "dependable generation" amount based on actual operating history during peak load periods, and incorporate that calculation into distribution substation and critical load forecasts; and
- Pilot Request For Proposal: Test the market with one pilot RFP during the 2012 GRC cycle for viable DG alternatives to distribution system upgrades.

In connection with Settlement Agreement #2, both parties withdrew their direct and rebuttal testimony related to this topic.

23.3.2. Discussion

VSI and SCE (collectively "Settling Parties #2") reflect different interests affected by this proceeding. Settlement Agreement #2 establishes facts jointly agreed to by Settling Parties #2. The fact that the settlement is uncontested generally supports its adoption. As discussed below, we find that Settlement Agreement #2 meets the criteria for a settlement pursuant to Rule 12.1(d).

First, the settlement is reasonable in light of the whole record. Settlement Agreement #2 was reached after careful analysis of the positions of the affected parties. SCE and VSI reached agreement after conducting discovery, serving prepared testimonies, evaluating their respective positions, and engaging in numerous discussions regarding the merits of those issues.[1499] The record demonstrates that each of the Settling Parties made significant concessions to resolve the issues in this proceeding in a manner that reflects a reasonable compromise of their respective litigation positions.

[1499] Joint Motion by SCE and VSI at 5.

Therefore, the Settlement Agreement addresses the issues in the proceeding in a reasonable manner in light of the record as a whole. We also find that the settlement does not contravene any statute or Commission decision or rule and is consistent with the law and Commission precedent.

Lastly, we find that the proposed settlement is in the public interest. The agreed-upon obligations address SCE's future efforts to ensure that DG resources are considered and included, to the extent feasible, in SCE's distribution planning process as an alternative to capital investments in traditional system upgrades.[1500] If SCE is able to incorporate DG in a way that reduces SCE's capital costs, ratepayers may benefit. The settlement also saves the time and resources of the Settling Parties.

Based on the foregoing, we approve Settlement Agreement #2 as proposed.

23.4. CCUE and Reliability Investment Incentive Mechanism (RIIM)

23.4.1. Background

SCE has been subject to some form of distribution reliability mechanism since 1997. The current form, with both a capital spending element and a staffing element, was first adopted in the 2006 GRC. The purpose of RIIM is to provide SCE with an incentive to spend funds authorized for reliability-related activities and not divert them to other activities or short-term profits.

[1500] *Id*. at 6.

The level of forecasted expenditures subject to RIIM has grown from $2.46 billion in the 2006-2008 rate cycle to $3.4 billion for 2009-2011. In this GRC, SCE proposes $4.4 billion for 2012-2014.[1501]

The basic mechanism of RIIM is to identify certain categories of TDBU capital expenditures particularly related to long-term electric service reliability; if SCE spends less than authorized over the GRC cycle, SCE credits ratepayers for the difference between recorded and authorized spending. A second element is a target for hiring field personnel directly working on reliability-related projects. Similarly, if SCE hires fewer than the target number of employees, ratepayers would receive a credit.

The RIIM identifies a list of distribution capital categories in two groups. "Reliability Investment" (Category A) capital spending includes infrastructure replacement, preventive maintenance, and load growth; "High Priority" (Category B) expenditures include new service, storms, and breakdown maintenance. In past rate cycles, if SCE spent less in one category than authorized, SCE had to either increase spending in the other reliability category or refund the difference to ratepayers. If SCE spent more in one category than authorized, the target expenditures in the other category were reduced.

The Commission's adoption of the 2006 and 2009 RIIM settlements has been driven less by the alleged benefits, and more by findings that the proposed expenditures were necessary and justified. In both GRC decisions, we shared some parties' concerns about whether RIIM would actually provide the desired incentive to spend on long-term reliability projects, and whether the selected

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[1501] TURN OB at 165.

programs were the most appropriate.[1502] For example, in 2009, we found the record did not demonstrate that SCE's system reliability would necessarily be improved by earmarking expenditures.[1503] However, in both 2006 and 2009, we determined the RIIM functioned much like a one way balancing account, and served the interests of ratepayers by requiring SCE to spend the funds consistent with their authorized reliability purpose.

In this proceeding, SCE proposed 2012-2014 RIIM targets of $3.1 billion in reliability-related capital expenditures, $1.3 billion in high priority exceptions, and the addition of 150 reliability-related workers assuming authorized funding.[1504] SCE argues that RIIM is the best available methodology for measuring its commitment by tracking costs directly related to maintaining service reliability and addressing long-term reliability through infrastructure replacement. TURN opposes continuation of RIIM.

23.4.2. Settlement Agreement #3

On October 20, 2011, SCE and CCUE (Settling Parties #3) submitted a timely Joint Motion for Approval of Settlement (Joint Motion), within thirty days of the Update hearing. SCE and CCUE propose a bilateral settlement to adopt a revised version of the RIIM.[1505] According to the Joint Motion, Settlement Agreement #3[1506] establishes facts jointly agreed to by Settling Parties #3, and the

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[1502] D.06-05-016 at 331.

[1503] D.09-03-025 at 323.

[1504] SCE-03, Vol. 01 at 34 (Table V-3), 35 (Table V-4).

[1505] Joint Motion by SCE and CCUE filed on October 20, 2011.

[1506] Settlement Agreement #3 is attached to Joint Motion filed October 20, 2011.

terms and conditions represent a compromise of their respective litigation positions.

SCE's original RIIM proposal and settlement position are similar as to these points:

- The capital expenditure targets will be what the Commission authorizes;
- If the expenditures in Category B exceed what is authorized, the Category A expenditure target will be reduced by the difference, and if they are less than authorized, then the Category A investment target will be increased;
- If SCE spends less than 100% of the total capital expenditure target, the underspend will be refunded to ratepayers; and
- If SCE falls short of the Employee Target, it will refund $18,000 for each employee up to a shortfall of 30 employees. If the shortfall is more than 30, SCE will refund $80,000 for each additional employee.

The difference between SCE and CCUE involves the RIIM Employee Target of adding 150 employees during this rate cycle. SCE originally proposed the target only if the Commission adopted its TY2012 request of $68.3 million for training and safety related O&M expenses. Settlement Agreement #3 provides that SCE adopt the Employee Target, but the number can be reduced if the Commission decreases SCE's O&M request. In addition, the settlement provides that SCE can use contract workers, under certain conditions, to meet the target. CCUE did not express a position on either issue in testimony or in its post-hearing brief, but did state it was pursuing negotiations with SCE.[1507]

[1507] CCUE RB at 3.

A summary of SCE's latest proposed RIIM capital expenditures is in the table below:

SCE's Expenditure Requests in RIIM Categories ($million)[1508]			
	Reliability Investment Categories	**2012 Request**	**2012 - 2014 Requests**
Category A	Distribution Infrastructure Replacement	$314	$976
	Preventive Maintenance	120	392
	Load Growth	501	1,265
	Substation Infrastructure Replacement 472	155.0	472.0
Sub-Total			$3,105
Category B	New Service	153	597
	Storms & Claims	70	429
	Breakdown Replacement	133	277
	PEV Readiness	9	68
Sub-Total		365	1,309
TOTAL		$1,455	$4,414

23.4.3. Responses to the RIIM Settlement

TURN recommends terminating the RIIM because there is no evidence the program has enhanced long term reliability and some of the TDBU programs are not primarily reliability-related.[1509] If the RIIM is continued, TURN seeks modifications, primarily to require SCE, if it has underspending in Category B, to either refund the difference or spend the funds on a limited subset of the programs in Category A (e.g., Distribution Deteriorated Pole Replacement, Worst Circuit Rehabilitation, and Cable Replacement programs). If any PEV funding is authorized, then TURN requests it become a part of "New Services" in

[1508] Joint Motion at Appendix A (Settlement Agreement), Attachments A, B.

[1509] TURN-9 at 51.

Category B. CCUE generally supported continuation of the RIIM in rebuttal to TURN's opposition.[1510]

On October 21, 2011, TURN filed Initial Comments opposing the Joint Motion on the ground no actual "settlement" occurred because there was no material difference between the settling parties. TURN argues that if there is no record of any disagreement, then the settlement cannot be reasonable. Moreover, if SCE can label an agreement as a "settlement" and rely on a policy favoring settlements, it gains litigation advantage over non-utility parties that cannot similarly "settle" their positions.

TURN's policy point is well taken, however, we disagree the record is wholly devoid of disagreement. CCUE's record on RIIM is sparse and parties should not be able to leverage similar positions as a "settlement." On the other hand, the Commission also favors hearing matters on their merits. Here, we give the parties the benefit of the doubt. In its post-hearing brief, CCUE states it is in settlement negotiations with SCE on RIIM, and it is not unreasonable to infer a difference related to the Employee Target which became contingent in SCE's 2012 proposal.

Similarly, we give TURN the benefit of the doubt and accept the "Further Comments" TURN filed which articulate familiar criticisms of RIIM, including that the capital categories are not all clearly linked to long-term reliability, enhanced reliability is not measured, and the incentives do not benefit ratepayers.[1511]

[1510] CCUE-1 at 27.

[1511] *See*, Further Comments of TURN Calling for Denial of the SCE and CCUE Joint Motion at 4-5.

23.4.4. Discussion

As discussed below, we find that Settlement Agreement #3 meets the criteria for a settlement pursuant to Rule 12.1(d).

CCUE and SCE have both common and distinct interests affected by this proceeding. Settling Parties #3 claim to share an interest in the delivery of safe and reliable electric service, and view enhanced infrastructure replacement as critical to that goal. CCUE members benefit if SCE expands capital spending which requires additional workers. Their interests regarding RIIM diverge as to whether SCE is committed to hiring a certain number of employees.

SCE agreed to modify its position on two elements of the Employee Target: (1) SCE adopts the Target with reductions only related to the O&M funding level, benefitting CCUE, and allows contract workers, benefiting SCE. SCE contends the settlement is reasonable in light of the whole record because it has supported all of the employee additions and capital expenditures in testimony, only authorized amounts will be used as the targets, ratepayers get what they pay for, and SCE does not recover authorized funds diverted to non-reliability activities.

Elsewhere in this decision we found that SCE has justified, to the extent authorized, additional employees and expenditures in the key RIIM categories. The settlement modification to permit contract workers to meet the target is a reasonable option often applied by SCE to meet its staffing needs. We have also previously concluded that some limits on diversion of reliability-related funds are better than none. Less persuasive are SCE's claims of litigation benefits when TURN, the only opponent of RIIM, is not a party to the agreement. However, the settlement meets two of three changes to RIIM recommended by TURN.

As to TURN's other change, we are not persuaded that requiring refund of unspent Category B funds, unless used for a few discrete Category A activities, is a significant improvement to RIIM. The purpose of RIIM is to provide management flexibility within a defined range of activities so that funds for load growth or emergencies are available if needed, but can be re-allocated to important maintenance and repair of long-term reliability assets if unused.

We acknowledge some disagreement has persisted since 2003 over whether all of the Category A capital spending groups are directly related to long-term reliability. In fact, SCE and CCUE agreed to remove one area (PCB Transformer Replacement) for that reason. This concern persists and weighs against the overall claimed settlement benefits.

We also retain our concern about the impact of the RIIM incentives: whether it results in a diversion of Category A funds (as in 2006-2008) or an incentive to overspend in Category A (as in 2009-2011). SCE claims error in TURN's 2009-2011 ratemaking scenario which, with certain assumptions, results in a larger benefit to shareholders than ratepayers. It is unclear if this is only because different timing would yield different results under the ratemaking mechanism.

We return to our conclusions in 2003 and 2006 to find the RIIM settlement reasonable: our priority concern for long-term reliability is amplified by SCE's aging infrastructure, and ratepayers benefit when SCE must spend funds for long-term reliability projects as authorized. Under cost-of-service ratemaking, without RIIM, SCE is otherwise able to redirect unspent funds freely, including to shareholder profits.

On the other hand, the RIIM has existed since 2006, through two rate cycles, and SCE has not brought forward information to demonstrate whether the RIIM expenditures have improved long-term reliability, or whether the hundreds of authorized employees hired were actually dispatched to reliability activities. There has also been lingering concern about whether activities were properly recorded in RIIM categories. Accordingly, in order to be reasonable in light of the whole record, we find that the persistent uncertainty about the effects of the program should be addressed.

Therefore, after consultation with the Commission's Energy Division, SCE shall obtain an independent audit of the 2010-2011 RIIM expenditures to identify authorized and recorded expenditures in each of the subaccounts and programs included within SCE's broad RIIM categories. No later than September 1, 2013, SCE shall submit the results of the audit by Tier 2 AL to the Directors of the Commission's Energy Division and Consumer Protection and Safety Division, along with a comparison of short-term reliability statistics (i.e., SAIDI and SAIFI) to total RIIM expenditures since 2003.[1512] Although this may not provide a clear view of long-term effects, no long-term reliability metrics have been proposed. SCE shall serve the AL on the service list for this proceeding.

Going forward, SCE shall consult with DRA, CCUE, TURN and other interested parties about the feasibility of developing a RIIM-like program for the next GRC which includes both key reliability <u>and</u> safety expenditures.

The terms of the settlement comply with all applicable statutes and prior Commission decisions, and reasonable interpretations thereof. Therefore, we find Settlement Agreement #3 is consistent with the law.

The Settling Parties argue the settlement is in the public interest because it advances the Commission's commitment to reliable electric service for California customers and ensures SCE does not divert funds authorized for

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[1512] D.96-09-045.

reliability-related activities for other purposes or profits. We generally agree that long-term reliability involves focused inspections and replacement of critical infrastructure and the RIIM settlement will continue to provide SCE with an incentive to make the appropriate expenditures.

In conjunction with the audit and analysis discussed above, the Commission and the public should be in a position to discuss an alternative to RIIM in the next GRC that includes key safety expenditures (there is some overlap) and reasonable metrics to assess the program's effectiveness.

Based on the foregoing, the Commission approves Settlement Agreement #3 as proposed, subject to SCE obtaining the audit of 2009-2011 RIIM expenditures as described above.

24. Jurisdictional Cost Separation

SCE provided some forecasts on a "total company' basis, i.e., including costs subject to Commission jurisdiction and costs subject to FERC jurisdiction. SCE states the RO Model imposes cost separation by jurisdiction, following a method previously approved by the Commission and FERC.[1513]

In Results of Operations, DRA recommended the Commission adopt the jurisdictional allocation factors used by SCE and DRA, and previously approved by the Commission.[1514] The only differences between SCE and DRA came from different estimations of SCE's revenue requirement.

[1513] SCE OB at 346.

[1514] DRA-2 at 9.

Nonetheless, DRA later raised the issues of appropriate allocation and double recovery related to NERC/CIP expenses.[1515] DRA believes SCE has improperly collected these costs in at least one prior rate case cycle (2009 GRC) and NERC/ CIP costs were embedded in SCE's historical costs.[1516] During cross-examination, SCE's witness eventually stated the NERC/CIP costs are 100% FERC jurisdictional and would be excluded from the GRC revenue requirement when the RO model is run.[1517]

However, SCE sought and obtained NERC/CIP costs in the 2009 GRC. It is unknown whether the 2009 RO model removed the costs from the 2009 revenue requirement, but if NERC/CIP costs are embedded in historical rates there is a potential of either double recovery or inflated recorded costs.[1518] DRA argues that since the Commission cannot know at this time how much SCE has and will over-collect in this category, the Commission should not approve any of SCE's requested 2012 rate increase until either an audit is completed or an Order Instituting Investigation is initiated.

SCE dismisses DRA's concerns as unexplained. This is insufficient. DRA established an apparent inconsistency in SCE's testimony, and the possibility of either inflated historical costs or double recovery. Neither of these situations may have occurred, but SCE did not address the contradictions. However, since DRA approved the RO model, including jurisdictional allocations, we do not bar SCE's application based on this point.

[1515] DRA OB at 210-212.

[1516] *Id*. at 210.

[1517] TR at 1136, 1140-1143.

[1518] TR at 1137.

Instead, the Commission finds it reasonable to require SCE to file a Tier 2 AL within 90 days of the date of this decision, which identifies all NERC/CIP costs recorded for 2009-2011 that were authorized in the 2009 GRC, the source of rate recovery (i.e., CPUC or FERC), and, if FERC jurisdictional, an explanation of whether these costs were included as embedded historical costs in SCE's 2012 GRC testimony.

25. Other Issues

25.1. Allowance for Funds Used During Construction (AFUDC)

AFUDC represents the estimated cost of debt and equity funds used to finance utility-plant construction. SCE and DRA agree that the AFUDC formula prescribed by FERC should be used which includes as inputs short-term debt, long-term debt, preferred stock, and common equity.[1519]

SCE's calculation of its AFUDC forecast for TY2012 includes total average CWIP of $1.587 billion, with $295 million covered by average short-term debt. By 2014, SCE estimates total forecast average CWIP will increase to $1.665 billion, with just $55 million covered by average short-term debt.[1520] SCE developed its AFUDC rates from a financial forecast which factored SCE's construction plans, the amount of funds generated internally, and long-term financing requirements.[1521]

1519 DRA-22 at 27 (SCE applies a short-term debt rate of 4.4%, a long-term debt rate of 6.06%, a preferred stock rate of 6.01%, and a common equity rate of 11.60%.

1520 *Id*. at 29, Table 22-6.

1521 SCE-27 at 44.

DRA views SCE's AFUDC estimates as based on unrealistically low estimates of short-term debt available for financing CWIP. DRA instead recommends adoption of $1 billion as the amount of short-term debt used to calculate SCE's AFUDC rates for 2010-2014.[1522] The amount is reasonable, argues DRA, due to SCE's short-term debt balance reaching that level in 2009, and D.08-10-015 which granted SCE's request to double its short-term debt limit to $2 billion.[1523]

We are persuaded that SCE's short-term debt level should not be fixed for AFUDC, and $1 billion is well above its average 2010 short-term debt balance of $151 million.[1524] SCE primarily relies on long-term securities to fund large capital projects, relying on short term debt when market conditions temporarily make long-term financing unattractive.[1525] To the extent SCE had high levels of short-term debt in 2008 and 2009, SCE's explanation that it was the temporary result of the financial crisis, is reasonable.

In addition, SCE argues that DRA's proposal would increase SCE's debt ratio, result in greater reliance on short-term debt, and have adverse consequences on SCE's credit quality due to increased roll-over risk. DRA's proposal could increase debt contrary to the debt-equity ratio adopted in the Cost of Capital proceeding, and could harm ratepayers by increasing the cost of capital.

[1522] DRA-22 at 30.

[1523] A.08-06-012, A.08-06-013.

[1524] SCE OB at 352.

[1525] SCE-27 at 48.

Accordingly, the Commission does not adopt DRA's recommended $1 billion floor for short-term debt in AFUDC.

Forecasts of Short-Term Debt Rates[1526]					
Year	**2010**	**2011**	**2012**	**2013**	**2014**
SCE	0.33%	3.60%	4.40%	4.40%	4.40%
Global Insight	0.23%	0.34%	1.76%	3.83%	4.02%
Difference	0.10%	3.23%	2.64%	0.57%	0.38%

Short-term debt rates are not included in Cost of Capital proceedings. SCE forecast interest rates for short-term debt based on unsupported internal calculations that DRA considers unreasonably high. DRA recommends the Commission adopt the Global Insight rates for 3-month commercial paper. DRA does not explain why these rates are more reasonable.

SCE's lack of support for its own calculation favors consideration of the externally developed short-term debt rates offered by DRA for 2012-2014. There is a significant difference, and we find it reasonable to adopt the average of the two proposed rates: 3.08% for 2012, 4.11% in 2013, and 4.21% in 2014. These short-term debt rates should be used to develop the AFUDC rates for this rate cycle.

Lastly, based on the FERC formula, the table below shows SCE's forecast AFUDC rates for 2010-2014, and DRA's recommended AFUDC rates. DRA's rates are based on DRA's recommended short-term debt amounts and rates recommended above, and are calculated following SCE's methodology. DRA states that if its recommendations are adopted by the Commission, ratepayers will save approximately $276.5 million over the five-year period.

[1526] DRA-22 at 32, Table 22-8.

Gross AFUDC Rates 2010-2014[1527]					
	2010	**2011**	**2012**	**2013**	**2014**
SCE	8.136000%	7.957836%	7.786296%	7.589544%	8.417376%
DRA	3.669432%	2.829108%	4.293636%	5.840436%	5.821860%
Difference	4.466568%	5.128728%	3.492660%	1.749108%	2.595516%

In the 2009 GRC, the Commission adopted the 2007 AFUDC rate of 7.7204% for 2007-2011.[1528] In the current GRC, SCE forecasts different AFUDC rates of 8.1360% and 7.9578% for 2010 and 2011, respectively. DRA estimates much lower rates for these years. Neither party explains why they vary from the adopted rate in the 2009 GRC. Absent a modification of that decision, we retain our approved rate for 2010-2011.

Based on the 2012-2014 short-term debt rates adopted above, when utilized in SCE's methodology, the following estimated rates result for 2012-2014: 7.66857% in 2012; 7.632651% in 2013, and 8.560065% in 2014.

The Commission finds these estimated AFUDC rates to be reasonable and adopts them.

26. Pending Motions

To the extent that motions properly filed and served by parties in this proceeding have not been ruled upon, they are denied.

27. Comments on Proposed Decision

The proposed decision of the ALJ in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments and/or Reply Comments were filed on or before the due dates by

[1527] *Id*. at Table 22-9.

[1528] D.09-03-025 at 320.

SCE, DRA, TURN, Aglet, Joint Parties, Sierra Club, CCUE, WPTF, SDG&E, and PG&E. In addition, SCE filed and served information about claimed input errors in the Results of Operations model.

No substantive changes have been made to the Proposed Decision. Based on the Comments received and corrections of identified errors, the following significant changes to the Proposed Decision have been made:

- Identified I. 12-10-013 as the OII which will conduct the reasonableness review for the SONGSMA;
- Changed the date by which SCE must file an application for review of McGrath expenses from October 31, 2012 to December 31, 2012;
- Changed the date by which SCE must provide the results for the pole-loading study from January 31, 2013 to July 1, 2013;
- Corrected the adopted Uncollectibles factor from 0.203% to 0.205% to reflect uncontested adjustments;
- Added clarifying language to affirm the Commission expects SCE to conform with tax normalization rules related to accelerated depreciation, but does not authorize a rate of return on the Net Operating Loss;
- Corrects the rate of return on the legacy meters from 6.55% to 6.46%, derived from a return on equity of 6.72%;
- Conform text to the table, Findings of Fact, and Conclusions of Law for Account 367 Mass Property Life (If not changed would result in additional $100 million in revenue requirement for depreciation reserve, as is, no change to revenue requirement because the RO model used the correct information);
- The 2012 revenue requirement has decreased from $293.814 million to $271.908 million; and
- The estimated revenue requirement for 2013 would be $6.029 billion and $6.385 billion for 2014, a decrease from the Proposed Decision of $48.8 million in 2013 and $40.9 million in 2014.

On November 15, 2012, SCE submitted to Energy Division two proposed reductions, totaling $117 million, to Present Rate Revenues (PRR). SCE's calculation of PRR has been in the record since SCE's initial GRC application. If SCE's request were adopted, the revenue requirement would increase by $117 million. Although SCE claimed that the amounts were erroneous because they reflected activities estimated for the 2012 rate cycle, the items were identified throughout the GRC proceeding as from the 2009-2011 rate cycle and, therefore, properly included in PRR. Various other errors identified by SCE were verified and incorporated in the revised Results of Operations model which led to approximately $14 million in 2012 O&M reductions, $48 million in additional 2010 – 2012 capital expenditures, and a $21 million decrease in depreciation expense.

28. Assignment of Proceeding

Timothy Alan Simon is the assigned Commissioner and Melanie M. Darling is the assigned Administrative Law Judge in this proceeding.

Findings of Fact

<u>Section 2</u>

1. When SCE re-directs funds authorized for one purpose to a different purpose, it is relevant to the Commission's oversight role and consideration of revenue requests.

2. If SCE were to routinely present essential GRC data in a clear, obvious, and consistent manner in its testimony, parties and the Commission could more expeditiously evaluate it, and fewer data requests and less confusion would result.

3. SCE primarily relied on "budget-based" forecasting that uses a variety of methods to develop a "base year" forecast, and adds incremental increases tied to each cost driver SCE identifies for future work.

4. The Commission has previously observed that because utility spending plans are not always implemented as intended, budget-based forecasts generally are given less weight than forecasts based on recorded costs absent a showing supporting the contrary approach.

5. SCE's use of budget-based forecasting, often with multiple increments for each 2012 cost, contributed to the record number of data requests.

6. For its forecasting, DRA primarily relied on historical costs and the concept of "embedded costs" which are those previously approved and available in existing rates.

7. Complete reliance on historical costs to forecast future needs may not be reasonable for some future costs, e.g., expanded programs, new programs, new technologies, new information.

8. The Nuclear Regulatory Commission (NRC) has required certain safety-related actions be taken to ensure a "safety culture" exists at SONGS.

9. The adopted O&M costs and capital expenditures enhance the overall safe and reliable operation of SCE's electrical system.

Section 4

10. SCE forecasts $568.860 million in total TY2012 O&M and $1.054 billion in 2011-2012 capital expenditures. SCE's total 2010 recorded Generation capital spending is $431.917 million.

11. SCE's GRC request for SONGS-related expenses was made based on normal operating conditions before SONGS Units 2 and 3 ceased operations in January 2012.

12. The GRC record does not contain evidence regarding SCE's operating response or expenses following the shutdown of the two units.

13. It is in the interests of ratepayers for SCE to track all SONGS-related O&M, savings, and capital expenditures after January 1, 2012 in a memorandum account for future reasonableness review.

14. The safe operation of the SONGS facilities is a primary concern for the Commission and effect of the current non-operation of the SONGS units on SCE's forecast safety expenses is unknown.

15. SCE's forecast for SCE's share of TY2012 SONGS O&M expenses is $270.5 million.

16. Ratepayers have funded excess positions for two years in order to rectify management problems at SONGS.

17. No party objected to SCE's forecast of basic 2012 O&M SONGS 2 and 3 expenses.

18. SCE proposes personnel reductions for SONGS, which will yield an estimated $150 million in savings over the rate cycle.

19. SCE seeks to allocate its $19.3 million share of net cost savings 50/50 between ratepayers and shareholders based on prior Commission approval of such sharing.

20. DRA and TURN contest any allocation of savings to shareholders.

21. No party opposes continuation of the flexible refueling outage schedule mechanism for the 2012-2014 GRC cycle.

22. SCE's total 2010-2012 capital forecast for its share of SONGS-related expenditures, including $103.517 million from prior years, is $496.327 million. SCE's forecast for 2012 capital spending is $151.114 million.

23. For the HPT project at SONGS Units 2 and 3, SCE forecast $22.466 million in 2011 and recorded $10.209 million in 2010. The HPT project will be suspended in 2012.

24. DRA did not establish that a cost cap associated with turbine work removed from the Steam Generator Replacement Project is applicable to the HPT project.

25. SCE demonstrated that the expected 48 MW output gain can be achieved through new HPTs.

26. For 2012, SCE requests $1.1 million (100% share) for a Service Air Piping project with benefits for worker safety and tool and equipment life.

27. SCE received funding in the 2009 GRC for the Service Air Piping project but deferred it for other projects.

28. SCE requests $1.2 million in 2012 for the Site Parking and Pedestrian Lighting project to improve lighting in three parking lots.

29. Improved lighting in the SONGS parking lots will improve safety for employees, workers, and guests.

30. SCE did not adequately support a 42% contingency for the SONGS lighting project.

31. The SONGS cafeteria has not been upgraded since the 1980s.

32. SCE requests $1.5 million (100% share) in 2011 capital spending for the cafeteria remodeling project and has already replaced the ventilation and fire suppression systems.

33. The cafeteria remodel project will improve working conditions and wellbeing for SONGS employees, workers, and guests who use the facilities.

34. Even under shutdown conditions, SCE has employees, workers, and others on-site and will continue to do so until the SONGS units are either started or decommissioned.

35. SDG&E is a 20% co-owner of SONGS and its request for cost recovery includes a request to continue its balancing accounts for SONGS.

36. SDG&E is subject to the same conditional allowance of post-2011 SONGS-related O&M and capital spending adopted for SCE.

37. SCE forecasts its share of TY2012 Palo Verde O&M expenses to be $83.1 million and no party objects to this O&M forecast.

38. SCE is responsible as a co-owner of Palo Verde for its share of expenses related to continued safe operation and maintenance of the facility.

39. SCE forecasts $117.236 million for 2010-2012 Palo Verde capital expenditures.

40. The Design Basis Manuals for Palo Verde are safety-related and need to be reviewed, completed, and updated.

41. SCE is responsible for its share of the cost to replace the existing NATM at Palo Verde with a new set of administrative and technical procedures in order to address program administration inefficiencies identified by the NRC.

42. SCE requests $0.5 million for 2012-2014 annual O&M expenses for decommissioning costs at the Mohave Generating Station.

43. SCE forecasts its share of decommissioning capital expenditures to be $31.9 million through 2011 and no party opposes the forecast.

44. SCE proposes to continue the Mohave Balancing Account approved in the 2006 GRC until 2014 or until final disposition of the plant site.

45. The Commission's EPS prohibits Commission approval of a "long term financial commitment" that extends the life or increases the capacity of a coal fired plant that does not meet the greenhouse gas EPS.

46. SCE forecasts a $44.343 million TY2012 O&M expense for the Four Corners Generating Station (Four Corners).

47. In 2009, the Commission granted SCE a partial EPS exemption limited to pre-2012 forecasted capital expenditure costs authorized under the Four Corners co-tenancy agreements.

48. D.09-03-025 capped Four Corners' costs at $178.6 million and required SCE to show in the 2012 GRC that capital costs less than $1 million are reasonable, and costs greater than $1 million are both reasonable and necessary.

49. SCE submitted a report in the 2012 GRC regarding the viability of continued SCE ownership in Four Corners and provided support for $45.616 million in 2007-2011 capital expenditures requested in the GRC.

50. On November 15, 2010, SCE filed an application to sell its ownership share in Four Corners, effective October 1, 2012.

51. On March 30, 2012, in D.12-03-034, the Commission approved SCE's sale of its share in Four Corners and found it reasonable to allow SCE to make $1.88 million in necessary capital expenditures in 2012 for its estimated share of routine plant operation and environmental compliance.

52. Commission approval of all requested Four Corners capital spending for 2007-2011 would total approximately $123 million.

53. SCE's hydro generating plant TY2012 O&M request of $57.6 million is $11.2 million higher than 2009 recorded expenses and includes 28 additional employees.

54. SCE's method of choosing a separate forecasting method for Hydro O&M labor and non-labor costs in each FERC account maximized the base year forecast.

55. SCE forecasts capital spending on hydro projects of $104.5 million in 2010, $93.1 million in 2011, and $95.5 million in 2012; recorded 2010 expenditures are $77.930 million.

56. SCE spent $15.3 million less in 2010 on capital projects than estimated.

57. The substation projects at Magmagen, Mt. Tom, and Skiland will not be in service during this rate cycle.

58. SCE did not justify the need for the Bridgeport project because the equipment is relatively young and no operational history was provided.

59. SCE did not establish that the $7.35 million Lee Vining Substation relocation project is sufficiently developed for this rate cycle.

60. SCE's claim that the Lundy Reline Conveyance System (Lundy) is a FERC-approved project SCE is required to construct is somewhat misleading because it is part of a voluntary settlement SCE reached with objecting parties to its FERC license for Lundy.

61. SCE did not disclose that the Lundy license settlement agreement provided for ratepayer funds to be placed in an account over which neither the Commission nor SCE would have control.

62. SCE presented the Commission with no information about the potential scope and estimated cost of future environmental and legal work for the Lundy project.

63. SCE requests $15.626 million in 2011 and $12.3 million in 2012 for capital expenditures related to FERC relicensing projects.

64. ESRA sought capital spending reductions for relicensing projects because it is concerned about the accuracy of SCE's forecasts and disputes that many of the projects will be completed during the rate cycle.

65. SCE is on pace to spend less than 30% of the funds authorized for relicensing activities in 2009-2011.

66. SCE demonstrated it is likely that GHG-related permitting delays by SWRCB will be resolved during this rate cycle and some of the pending relicensing projects identified by SCE will be completed by 2014.

67. ESRA requests that SCE be required in future rate cases to include an exhibit that provides a status update for all capital projects which have received authorized funding in a prior GRC, and to identify safety-related projects.

68. SCE forecasts TY2012 O&M expenses of $49.042 million for Mountainview Power Plant.

69. SCE agreed with DRA to remove a confidential amount forecast for a Hot Gas Inspection prepayment and tax related to a 2015 overhaul.

70. Mountainview recorded expenditures in 2010 were $14.07 million and SCE forecasts capital spending of $4.6 million in 2011 and $18.9 million in 2012.

71. SCE and TURN used different methodologies to forecast capital spending for Mountainview under "Blanket Work Orders."

72. During 2011 and 2012, SCE is adding first-time inventory of capital spare parts prior to the upcoming major overhauls of Unit 3 and Unit 4 steam turbines at Mountainview.

73. SCE's revised forecast for TY2012 O&M of $11.299 million for all five peaker plants includes costs of increased dispatch, NERC compliance, and the McGrath peaker plant.

74. The recent SONGS outages and management of renewable generation resources expected to be added to the grid during 2011 will increase peaker dispatch during the rate cycle.

75. SCE requested peaker capital expenditures of $1.7 million in 2011 and $1.3 million in 2012, unrelated to construction of the McGrath peaker.

76. SCE previously recorded $42.5 million in McGrath construction costs and forecasts spending $20 million in 2012 to complete construction.

77. SCE has purchased most of the major equipment for McGath, begun construction after settlement of all permit issues, and put McGrath on track to be online in 2012.

78. In the 2006 GRC, the Commission authorized SCE's PDD to conduct certain generation support activities recorded in the PDD Memorandum Account. SCE requests to discontinue the PDDMA and obtain cost recovery through traditional ratemaking.

79. SCE's PDD forecast for TY2012 O&M is $5.80 million.

80. In D.09-06-049, SCE was authorized to own, install, operate, and maintain 250 MW of distributed solar PV projects and to seek competitive bids for power purchase agreement for electricity from independently produced (IPP) 250 MW of rooftop solar PV. Total SPVP program costs for 2008-2014 of $962.5 million in capital spending were deemed reasonable.

81. The Commission required review of the program's performance and SCE's operation of the facilities in SCE's annual ERRA proceeding, and required that all SPVP program costs, and capital costs in excess of $3.85/W should be subject to reasonableness review in the GRC.

82. SCE forecasts TY2012 O&M of $4.239 million, plus confidential lease costs.

83. SCE requests approval of 2009 and 2010 recorded capital expenses of $18.108 million and $122.991 million, respectively, and $85.037 million annually in 2011 and 2012.

84. SCE requests to terminate the SPVPBA created to record the difference between actual costs and program revenue.

85. On February 23, 2012, the Commission partially granted SCE's petition to modify D.09-06-049 and to reduce to 125 MW both the SCE and the IPP portion of the program, and then reassigned the 250 MW to a separate competitive solicitation.

86. SCE reduced its TY2012 O&M forecast for Catalina Island by $198,000 to $4.531 million, in response to a savings issue identified by TURN.

87. SCE forecasts $25.469 million for 2010-2012 capital projects at Catalina Island: $7.213 million in 2010, $12.110 million in 2011, and $6.146 million in 2012.

88. SCE recorded Catalina expenditures of $7.980 million in 2010.

89. The micro turbines provided by SCAQMD, which require capital investment, benefit the Catalina generation infrastructure due to lower emissions and improved system reliability.

90. DRA and TURN oppose funding for capital projects that received funding in previous GRCs, but TURN agrees that current offices are insufficient to house electric-only employees.

91. SCE deferred the Main & Garage Building Betterment project in 2010-2011 due to increased capital spending required by its settlement with SCAQMD.

92. The Station Betterment project is a $2.893 million replacement for the $5 million Administration Building disallowed in the 2009 GRC. SCE also added $2.3 million to expand the Main Building project in 2012 to provide additional office space.

93. SCE wrote off to expense $1.276 million for a feasibility study of an undersea cable to deliver electricity to Catalina, a project it later abandoned.

94. TURN recommends a $20 million penalty by reducing rate base for what TURN asserts is imprudent management of the undersea cable project.

95. SCE is authorized to install, own, and operate three fuel cell units with a combined capacity of up to 3.0 MW on three separate California state university campuses.

96. SCE records costs in a Fuel Cell Project Memorandum Account and is authorized to recover up to $19.11 million in capital costs and $8.9 million in non-fuel O&M for the 10-year life of its fuel cells.

97. SCE reduced its original capital forecast by 44% because actual 2010 recorded costs were $208,119 and one of the projects has been cancelled.

98. SCE forecasts $0.89 million in TY2012 O&M, and $10.608 million in 2010-2012 capital spending.

<u>Section 5</u>

99. SCE's revised forecast for total TY2012 TDBU O&M expenses is $598.045 million.

100. SCE's revised 2012 forecast total TDBU capital expenditures are $1.831 billion, a 13.9% increase over 2009.

101. SCE's capital estimate includes significant work related to transmission interconnection, infrastructure replacement, distribution construction and maintenance, and development of smart grid and other advanced technologies.

102. DRA proposes $476.789 million for TY2012 TDBU O&M, and asks that SCE be required to clearly provide historic employee headcounts by subaccount in future GRCs and address embedded funding for routine activities.

103. DRA proposes TDBU capital spending reductions of $648 million for 2011-2012, a 20% reduction to SCE's request.

104. TURN proposes reductions to TDBU capital proposals and O&M expenses, including no funding for PEVs.

105. CCUE recommends adoption of SCE's forecasts and urges rejection of DRA and TURN proposed TDBU reductions on the grounds the cuts would impair system maintenance and reliability.

106. The POLB asked the Commission to adopt, maintain, and implement programs which encourage use of the Port, but did not provide any specific proposals for consideration.

107. POLB requests revisions to Tariff Rules 2.H, 15, and 16 regarding Private Lines and Added Facilities on the grounds that these tariffs allow SCE too much discretion.

108. For ATO, SCE forecast $23.790 million for TY2012 O&M, and approximately $170 million for 2010-2012 capital expenditures.

109. DRA's TY2012 O&M forecast is $15.254 million based on different forecasting methodologies.

110. TURN recommends a TY2012 O&M forecast of $18.171 million based on disallowance of PEV costs and transfer of HAN-related activities to the ESCBA.

111. During this rate cycle, SCE will test the compatibility of HAN appliances and devices with the SmartConnect metering system to ensure that SCE customers will be able to choose from a wide spectrum of devices.

112. SCE's authorized funding for Research, Development, and Demonstration is tracked in a one-way balancing account.

113. There is a significant amount of uncertainty about the pace of PEV adoption by SCE's customers.

114. SCE provided low, medium, and high scenario forecasts for PEV adoption by customers by 2014, totaling 83,000, 146,000, and 221,000 vehicles, respectively.

115. There were about 100 PEV's in SCE's territory as of February 2011.

116. SCE forecasts $4.514 million in TY2012 O&M for PEV Readiness, including hiring 21 FTEs.

117. For ATO capital expenditures, SCE requests a 2010-2012 total of $173.6 million: $37.463 million in 2010, $64.392 million in 2011, and $71.752 million in 2012.

118. DRA requests reductions to ATO capital spending based on SCE's failure to spend funds authorized for 2009 and 2010 and because other projects are not required.

119. TURN recommends broad disallowances for ATO capital projects because SCE did not perform cost-benefit analyses for its ATO capital projects.

120. For proposed smart grid-related capital projects, utilities are required to either provide a cost-benefit analysis, as described in D.10-06-047, or explain why the information cannot be provided.

121. In 2010, SCE recorded almost three times its forecast cost of $3.8 million, and increased by 58% its total 2010-2012 forecast capital cost for the Circuit Automation project. SCE did not explain why it could not perform the anticipated work within original estimates.

122. Costs may be difficult to estimate with new and experimental technology, including the Smart Distribution Transformers.

123. SCE requests $14.871 million during 2010-2012 for the Distribution System Efficiency Enhancement Project.

124. SCE did not adequately explain how it arrived at its intended number of DSEEP radio installations per year.

125. DRA's use of an historical average to forecast spending is supported by historically fluctuating capital expenditures for the DSEEP program.

126. SCE forecasts $16.043 million in capital funding in 2012 for the Integrated Smart Distribution project comprised of a three-part pilot project.

127. The emergence of distributed generation puts increasing demands on distribution systems that were not designed for two-way flows of electricity.

128. The Irvine SmartGrid Demonstration project will yield data relevant to determining the value of the Self Healing Circuit project.

129. SCE did not demonstrate that its request for $3.0 million in 2012 for the Substation Automation 3 project to support NERC/CIP standards not yet adopted is reasonable and necessary.

130. SCE requests $26.735 million in 2010-2012 to develop the DMS to replace the current system.

131. Although necessary to maintain operation safety and reliability, the DMS system has shown escalating expenditures, and SCE failed to complete the project with the $20 million authorized in 2009.

132. SCE requests $11.157 million for 2010-2012 Online Transformer Monitoring: $1.217 million in 2010 recorded costs, and estimates of $4.911 million in 2011 and $5.029 million in 2012.

133. Transformer monitoring is a key factor in ensuring system reliability and manual transformer testing is far less expensive than online monitoring.

134. In the 2009 GRC, SCE was authorized to spend $13.0 million for the Phasor Management and WASAS program but spent the funds on another device to support an expanded scope for the project.

135. SCE requests $19.1 million and $10.9 million respectively for 2011 and 2012 for the Phasor Measurement and WSAS to provide better system reliability, manage transmission system stress, and avoid close operating margins.

136. SCE requests $6.756 million in 2010 capital to develop a new C-RAS system, $16.541 million in 2011.

137. SCE's interconnection estimates are excessive.

138. SCE spent less than $1 million on the project during 2009-2010 and did not otherwise establish the urgency of the CRAS project.

139. SCE requests $8 million for 2012 and $25.58 for 2012-2014 for the Smart Grid Cyber Security program to manage risks associated with deployment of smart grid communications equipment over the next 10 to 20 years.

140. There is a need to plan for cyber security related to the future deployment of smart grid equipment in order to protect customer privacy and system reliability.

141. SCE's cost analysis for Smart Grid Cyber Security relies on engineering judgment and estimated quantities of equipment to secure systems and equipment, some of which have yet to be developed, and to communicate with systems not yet deployed by other utilities.

142. Based on the roughly estimated costs and unknown factors, DRA requests that SCE be ordered to perform a cost/benefit study or initiate a test program for Smart Grid Cyber Security.

143. For Advanced Technology Laboratory projects, SCE's revised 2010-2012 request is $13.717 million, based on internal cost estimates and increased by 2010 recorded expenses.

144. SCE forecast $3.587 million for 2010-2012 capital spending on Capacitor Automation and Grid Dispatch.

145. For TY2012, SCE forecasts $5.305 million in O&M for Transmission Interconnection Planning, using LRY to estimate labor which results in the largest increase in the historical data.

146. Since 2007, SCE has incurred additional NERC regulatory activities and has received an increase in interconnection requests since 2009.

147. SCE's TY2012 forecast for subaccount 587.210 is $1.327 million, a 37.66% increase over its 2009 recorded expenses to fill four vacant positions.

148. DRA recommends use of 2009 expenses based on insufficient justification for additional labor costs and no cost-benefit analysis for additional inspectors.

149. SCE assumes that total customer growth will average 1% per year, and forecasts retail sales to grow by 1.5% annually between 2010 and 2012.

150. AECA established that SCE's load forecasts from the 2009 GRC were too high.

151. In 2009, SCE spent $73 million less than authorized for Load Growth capital projects because it applied the funds to different activities SCE viewed as more immediately necessary.

152. SCE demonstrated that some load growth will occur in this rate cycle, and that even if SCE does not use all of its current capacity by 2014, SCE will need to initiate some new projects to be in place as growth continues into the next rate cycle.

153. CCUE supports SCE's 2010-2012 capital forecast for Load Growth projects of $1.329 billion, including recorded 2010 expenses of $360.06 million, and $467.77 million for 2011 and $491.019 million for 2012 based on SCE's "likely case" peak load.

154. An estimate of SCE's unused distribution capacity for the test year would assist the Commission's review SCE's forecast Load Growth.

155. No evidence was offered to rebut SCE's requests in six categories: A-Bank Plan, Subtransmission VAR Plan, Distribution Substation Plan Circuits, Distribution Plant betterment, Distribution VAR Plan, and Generator Interconnection program.

156. Based on internal planning studies, SCE forecasts $53.221 million in 2011 and $33.419 million in 2012 for capital spending on SCE's Subtransmission Lines plan.

157. In addition to 2010 recorded expenditures, DRA recommends reductions of $2.607 million in 2011 and $3.829 million in 2012 based on SCE's failure to timely identify construction authority for five of the projects in response to DRA's Data Request.

158. SCE instead provided some new information about the five Subtransmission Line projects in rebuttal, but DRA's motion to strike the data was granted by the ALJ.

159. SCE forecast capital spending of $117.328 million in 2011 and $119.761 million in 2012 for the DSP. Recorded 2010 expenditures are $101.749 million.

160. Expenditures for several DSP projects were previously approved in the 2009 GRC but deferred due to permitting delays.

161. DRA recommends removing 35 DSP projects for which SCE initially provided no authority to construct because they are not likely to be completed during this rate cycle.

162. SCE agreed to remove two DSP projects totaling $140,000 in 2011 and $12.601 million in 2012 because they would not be completed during the rate cycle.

163. In rebuttal testimony, SCE provided new information about the permit status of the remaining 33 projects, but the evidence was stricken in the same ruling excluding the belated Subtransmission Lines data.

164. TURN recommends elimination of $22.971 million for the Presidential Substation that SCE admits it does not expect to construct in 2012.

165. Based on the record, some DSP projects appear on their face to be likely to qualify for an exemption from a permit to construct, and others do not.

166. SCE recorded $3.683 million in 2010 capital spending for the SERP.

167. SCE replaced 26 circuit breakers in 2011 and plans to replace 271 by 2014. SCE's forecast expenditures for replacements increased by 50% from 2011 to 2012, but decreased 14.7% from 2010 to 2011.

168. DRA recommends the Commission extend SCE's replacement schedule for the SERP because SCE did not establish it is required to complete the replacements by 2014, nor did SCE demonstrate an operational or safety imperative to do so.

169. No PEV expenditures were made in 2010. SCE estimates expenditures of $2.089 million in 2011 and $8.523 million in 2012 based on an internal analysis of infrastructure equipment upgrades needed to accommodate the emerging PEV market.

170. DRA and TURN oppose any capital funding for PEV Readiness on several grounds, including that SCE's timetable for rolling out the PEV readiness program is based on excess forecasting and unsupported costs.

171. In D.11-07-029, the Commission directed SCE to pursue the development of necessary infrastructure for PEVs.

172. SCE's recorded 2010 capital expenditures for T&D Infrastructure Replacement are $184.846 million, nearly one-third higher than SCE previously forecast.

173. SCE's revised total capital spending forecasts are $180.64 million in 2011 and $350.249 million in 2012, resulting in a 2010-2012 total of $715.734 million to address the growing volume of infrastructure in need of replacement each year.

174. DRA accepts SCE's 2011-2012 estimates in eight of fourteen categories, and replaced SCE's 2010 IR forecasts with 2010 recorded data, which is undisputed by SCE.

175. SCE recorded 2010 expenditures of $35.947 million in its CRP, and forecasts spending $38.874 million in 2011 to replace 154 miles of cable and $74.514 million in 2012 to replace 300 miles.

176. SCE's 5YA for cable replacements is 47.6 miles per year.

177. Through CRP, WCR, and OSR, SCE plans to replace a total of 267 miles in 2011 and 489 miles in 2012, far more than the 116 miles replaced in 2009.

178. SCE developed its 2012 cable replacement goals based on an external report that assessed system reliability in 2030 based on different replacement scenarios.

179. TURN and DRA recommend a $21.383 million reduction to SCE's 2011-2012 request in order to deploy the CRP at a slower pace.

180. The small improvement in reliability projected in 2030 between replacing 415 miles, instead of 276 miles, annually (CRP and WCR) does not warrant the additional cost of expedited replacements in this rate cycle.

181. SCE estimates that 3,000 conductor miles of Cable-In-Conduit (CIC) will fail in service in the next twenty years.

182. CCUE supports SCE's request for $13.357 million in 2011 and $30.560 million in 2012 to replace 36 conductor miles annually to fund 15 projects as a pilot program to investigate cost-efficient methods for CIC replacement.

183. DRA recommends eliminating $35.614 million of SCE's 2011-2012 CIC request.

184. Aging CIC must eventually be replaced and the best methodology has not yet been established.

185. No party takes issue with SCE's proposed A-bank transformer replacement expenditures.

186. SCE forecasts $16.582 million in capital expenditures for 2011 and $42.512 million in 2012 for B-Bank transformers.

187. Historically, SCE has replaced between four and 14 B-Bank transformers per year.

188. DRA recommends reducing the number of 2012 B-Bank replacements from 40 to 30 on the grounds that SCE's request is not supported by historical replacements.

189. SCE forecasts $215.296 million in 2011 to replace 147 circuit breakers and $22 million in 2012 to replace 215 more. SCE recorded 2010 costs of $12.023 million.

190. SCE's own failure analysis predicts that 75 circuit breakers will fail annually.

191. DRA recommends a $3.564 million reduction to SCE's 2012 forecast because SCE has never replaced more than 159 circuit breakers in a year.

192. Some of SCE's 4 kV circuits are incapable of carrying the expected load during a significant one-in-ten-year heat storm.

193. SCE forecasts capital expenditures for 4 kV circuit replacement cutovers of $17.214 million in 2011 and $30.167 million in 2012. In 2012, SCE intends to increase to 5,168 amps to be transferred.

194. No party disputes SCE's 2011 estimate for 4 kV circuit cutovers or SCE's cost per amp.

195. DRA recommends a $9.734 million reduction to 2012 forecasts, based on an annual 3,500 amp transfer level which DRA believes will allow SCE to meet its 2014 and 2020 goals.

196. For the 4 kV substation elimination program, SCE forecasts a 2012 capital expenditure of $34.286 million to eliminate seven substations it identifies as old and obsolete.

197. SCE based its forecast unit cost on internal studies of the estimated costs to eliminate other substations in 2012. No prior expenses have been recorded for this activity.

198. DRA recommends no funding for the 4 kV substation elimination program based on inadequate justification for either the unit costs or immediate commencement.

199. SCE established that the 4 kV substations will need to be eliminated over the next decade but did not establish the necessity of funding the new program at proposed levels.

200. No party disputes SCE's 2010-2012 forecast capital expenditures of $1.473 million ($2009) annually to support SSID.

201. SCE forecasts $14.480 million of TY2012 O&M expenses for Engineering Design and Project Management, and no party disputed the forecasts for subaccounts 588.220 and 595.220.

202. SCE's 2012 O&M forecast for subaccount 560.220 is $8.899 million using a LRY base year for non-labor which is inflated due to one-time costs of $10.6 million for a TLCS.

203. SCE spent $3.36 million on the TLCS and diverted about $2.3 million to other transmission work due to changed circumstances.

204. SCE did not adequately explain why it needs additional funding for the preliminary mitigation phase of the study.

205. DRA recommends a $1.336 million reduction to SCE's forecast for subaccount 560.220 based on a 5YA and removal of employee recognition costs.

206. SCE did not establish that discretionary employee bonus/recognition programs provide an identifiable benefit to ratepayers and are not necessary to operate the electrical system.

207. SCE argues use of a five-year average is inappropriate because it does not take into account the separate factors that drive activities and costs in the Transmission/substation operations supervision and engineering, subaccount 560.220.

208. SCE forecasts $1.125 million in TY2012 O&M for subaccount 580.220 primarily to hire three FTEs to implement compliance with expected new NERC/CIP standards during this rate cycle.

209. Based on declining historical costs and unknown embedded costs for prior NERC/CIP implementation, DRA recommends no increase to SCE's 2009 recorded costs of $0.798 million.

210. If new NERC/CIP standards are adopted, SCE will have to plan and execute implementation by the established effective date.

211. SCE did not adequately support the contract engineering cost estimate which is 210% in excess of SCE's work estimate.

212. Undergrounding electrical systems have both safety-related and reliability advantages.

213. In 2010, SCE spent only $21.942 million of the $30.5 million forecast for Rule 20A conversions.

214. SCE forecast $30.594 million in 2011 and $31.332 million in 2012 for Rule 20A conversions based on escalation of 2009 recorded costs.

215. For Rule 20B expenditures, SCE forecasts $27.047 million in 2011 and $34.418 million in 2012. SCE's 2010 recorded expenditures are $15.078 million, approximately 40% less than forecast, including SCE's and the applicant's share.

216. For Rule 20C expenditures, SCE forecasts $9.016 million in 2011 and $11.473 million in 2012. SCE's 2010 recorded expenditures are $5.259 million, approximately 40% less than forecast.

217. Based on SCE's pattern of excessive forecast costs for Rule 20B/C conversions, DRA recommends basing 2011 and 2012 expenditures on 2010 recorded expenses.

218. Underground conversion projects are in a downward trend due in part to the economy, but demand remains and SCE has long-term projects underway.

219. No party sought reductions to SCE's 2011-2012 forecasts for Distribution Relocations of $32.567 million in 2011 and $33.348 million in 2012. SCE's 2010 recorded capital expenses are $31.994 million.

220. No party sought reductions to SCE's 2010-2012 forecasts for Distribution Added Facilities of $8.264 million ($2009) annually.

221. SCE bases its forecast of customer growth on the new meter set forecasts, and primarily relies on a ratio to forecast building permits to forecast the meter sets.

222. SCE's rate of customer growth has generally declined since 2005, but SCE forecasts growth of 4.5% during the rate cycle.

223. DRA accepts SCE's forecast for sales and customer growth and proposed no changes to SCE's capital forecast for meter sets.

224. TURN recommends reducing SCE's new meter forecast to more accurately reflect lower growth arising from the on-going effects of the economic recession.

225. SCE's actual number of meter sets for 2010 and the first half of 2011 were significantly lower than SCE's forecasts.

226. TURN presented a "base" case and "low" case to forecast new meter sets based on a forecast for building permits using more recent data.

227. TURN recommends using a calculated average of the TURN base and low cases, resulting in 25-28% fewer residential meters than SCE forecasts.

228. SCE provided inconsistent testimony and did not adequately explain or support its proposed new meter sets calculation in light of TURN's new building permit data.

229. SCE forecasts customer growth-related expenditures in 10 categories totaling $108.293 million in 2010, $114.337 million in 2011 and $153.3 million in 2012.

230. SCE's total 2010 meter-related recorded expenditures are $101.208 million.

231. No party disputes SCE's 2011-2012 forecasts for Street Lighting and Agricultural customer growth expenditures.

232. TURN's reductions are a result of substituting its revised forecasts of customer growth.

233. The Commission has previously directed SCE to refine its maintenance priority system in order to concentrate resources on appropriately prioritized

conditions. Most of the work is performed according to SCE's DIMP, but other Commission General orders also apply.

234. Beginning in 2009, SCE modified its inspection routine to provide that when a qualified worker is at a structure, all identified maintenance items will be completed, regardless of the item's scheduled due date.

235. SCE did not establish that its grid approach to inspections is less costly in part due to higher costs per inspection.

236. SCE substantially underestimated the number of corrective actions to be completed in 2010 but plans to clear the backlog by the end of 2011.

237. SCE forecasts $108.289 million for additional T&D Inspection and Maintenance O&M expenses in TY2012 based on 2009 recorded expenses in four subaccounts, plus incremental expenses for proposed activities.

238. DRA forecasts total T&D Inspection and Maintenance costs of $98.281 million for TY2012 based on 2009 recorded expenses.

239. No party disputes SCE's TY2012 O&M forecasts for overhead detail inspections and annual patrols.

240. SCE forecasts $5.533 million in subaccount 583.120 for 2012 Wood Pole Intrusive Inspections, utilizing 2009 recorded cost-per-inspections adjusted for pre-test year contract negotiations.

241. General Order 165 requires intrusive inspections of wood poles every 10 years for poles 15 years old or older, and every 20 years for all poles previously inspected.

242. SCE has 1.34 million distribution poles and CCUE supports SCE's levelized approach to performing 130,000 inspections per year consistent with a 10-year inspection cycle.

243. In SCE's 2009 GRC, the Commission found that 130,000 inspections per year was excessive and reduced the forecast by 17%.

244. Due to fluctuating historical costs, DRA recommends $3.939 million for 2012 Wood Pole Intrusive Inspections using a 5YA of 77,327 inspections per year.

245. SCE did not establish its ability to undertake 130,000 intrusive inspections of wood poles in 2012.

246. Reduction of SCE's2012 forecast by 17% is comparable to 112,320 inspections per year.

247. There is no evidence of a coordinated assessment of poles in SCE's territory, particularly jointly-owned poles, to determine whether they are overloaded.

248. SCE forecasts a cost of $1.687 million to perform 152,886 Underground Detail Inspections in 2012 in order to conform to DIMP and GO 165.

249. SCE generally supported an increase to inspections between 2009 and 2012, but did not establish the basis for a 15% increase in total inspections required, nor distinguish between types of equipment or inspections.

250. SCE incurs expenses related to Vegetation Management in relation to high voltage distribution lines in order to comply with GO 95 and Public Resources Code §§ 4292-4293.

251. SCE forecasts $52.934 million for 2012 Vegetation Management O&M, including $10.1 million for high fire area costs. Most of the increase is due to new Commission requirements that require more clearance in VHF areas.

252. SCE has been recording VHF costs in a memorandum account but requests these costs be included in base rates.

253. D.09-08-029 provided that the FHPMA would remain open until the first GRC after the rulemaking proceeding closed. The rulemaking is still open.

254. DRA recommends a reduction of $5.66 million to SCE's forecast based on LRY, and requests that all Vegetation Management costs be recorded in a one-way balancing account in 2012 to review whether specific expenses were properly recorded and the extent of embedded costs.

255. SCE has added workers to comply with new VHF requirements and provided evidence that cost per trim in high fire areas is higher due to more tree removals and overhang removals in high fire areas.

256. SCE rebutted DRA's suggestion that VHF costs may not be accurately booked, and no other evidence was presented to support the need for a one-way balancing account for Vegetation Management.

257. For TY2012, SCE forecasts $39.712 million for the Preventive Maintenance O&M recorded in subaccount 593.120 in TY2012 based on an expected total of 16,500 more inspections between 2012 and 2014.

258. SCE established that it modified its repair program to identify repair items early, and DIMP and GO 165 require some assets to have detailed inspections every five years.

259. DRA forecasts $37.710 million for preventive maintenance based on the view that 2009 reflects the first full year of costs under the DIMP program and includes embedded costs for all major activities to be performed in 2012.

260. SCE TY2012 forecast of $4.031 million for Distribution Apparatus O&M, a 15% increase over 2009, is based on a five-year average unit repair cost and estimated 2012 inspections, adjusted to account for forecast new equipment.

261. SCE forecasts approximately $1.2 billion for Inspection and Maintenance (I&M) capital expenditures 2010-2014 which SCE estimates will be necessary to address the results of DIMP and GO 165-required inspections.

262. SCE forecasts total I&M capital expenditures of $220.703 million in 2011 and $246.613 million in 2012.

263. DRA recommends a $153.2 million decrease to SCE's total 2011-2012 I&M capital forecast.

264. SCE estimates $120.448 million in 2011 and $134.485 million in 2012 for the Capital Preventive Maintenance portion of its I&M forecast. SCE's 2010 recorded capital expenditures are $100.084 million.

265. DRA and TURN recommend reductions ($57 million and $43.9 million, respectively) to SCE's forecasts for Capital Preventive Maintenance.

266. SCE adequately supported its statistical forecast methods and unit costs, and established that increases in inspection-driven repairs are likely to increase through 2012.

267. SCE's estimates $10.087 million in 2011 and $14.755 million in 2012 for the Underground Structure Replacement portion of the T&D I&M forecast based on replacement of 50 underground vaults in 2012.

268. In 2010, SCE forecast capital expense for Underground Structure Replacement of $8.9 million, but actually spent $5.6 million to replace 16 vaults.

269. DRA recommends $5.764 million for 2011 and $5.902 million 2012 for Underground Structure Replacement expenditures, based on 2010 recorded costs and replacement of 20 vaults in 2012.

270. Although SCE established a replacement backlog exists, SCE did not adequately support its proposed acceleration of the underground vault replacement schedule.

271. SCE forecasts expenditures of $101.345 million in 2011 and $116.464 million in 2012 to replace 7,857 and 8,818 deteriorated distribution

wood poles per year, respectively. In 2010, SCE recorded $91.404 million in capital spending.

272. DRA forecasts $59.202 million in wood pole replacement costs for 2011 and $60.621 million in 2012 based on a various factors, including that SCE will replace 4,700 poles per year.

273. DRA's forecast method does not account for a backlog of wood pole replacements, and applies an erroneous failure rate to its expected inspection rate.

274. SCE recorded Joint Pole Credits of $9.285 million in 2010, and forecasts $11.835 million in 2011, and $15.501 million in 2012.

275. SCE estimates $1.7 million in 2011 and $1.904 million in 2012 for Wood Pole Disposal costs. SCE recorded $1.945 million in 2010.

276. SCE records Joint Pole Credits as an offset to disposal costs.

277. Based on its own estimates of fewer pole replacements, DRA forecasts lower Joint Pole Credits and Wood Pole Disposal costs in 2011 and 2012.

278. The number of intrusive pole inspections is a primary driver of total pole replacements.

279. SCE forecasts $4.489 million in 2011 and $4.596 million in 2012 to remove facilities from rate base that are no longer used and useful, basing its forecast on a 4YA (2005-2008).

280. SCE did not adequately explain why its recorded 2010 expenditures of $9.185 million was more than double its original forecast of $4.41 million.

281. For Removal of Idle Facilities, DRA recommends the Commission adopt SCE's original 2010-2012 forecast of $13.495 million ($nominal), allow 2010 recorded expenses of $9.185 million, and apportion the remainder of the forecast equally between 2011 and 2012.

282. SCE's TY 2012 forecast for O&M expenses is $5.699 million for the DP&FA group.

283. DRA estimate for the O&M expenses is $4.080 million, including a reduction of $1.619 million in subaccount 588.130.

284. No party contests SCE's TY2012 request of $0.604 million for subaccount 589.130 Distribution Line Rents or $0.665 million for Facility Inventory Mapping in subaccount 588.130.

285. SCE requests $0.953 million ($2009) for O&M expenses in TY2012 in this sub-category of the Field Accounting Office, based on 2009 recorded O&M expenses.

286. SCE established that its workload is increasing for the Joint Pole Organization and forecast $3.175 million for TY2012 Joint Pole expenses, primarily to support six new positions.

287. SCE's forecast of $0.302 million for TY2012 Miscellaneous Expenses in subaccount 588.130 includes $220,000 for discretionary employee recognition costs.

288. Grid Operations play a critical role in ensuring SCE complies with applicable reliability standards.

289. For Grid Operations, SCE requests approximately $90 million in TY2012 O&M expenses over 15 programs in 12 subaccounts.

290. No party contests SCE's forecast O&M for subaccounts 560.170 Transmission Substation Supervision, 587.170 Customer Generated Troubleman Work, 585.170 Street Light Patrols, and 596.170 Street Light Maintenance Costs.

291. For TY2012, SCE requests $6.057 million for its GCC O&M expenses in subaccount 561.170, primarily to add 10 new FTEs. This number is twice what SCE added in the previous five years combined.

292. SCE established a need to increase staffing at the alternate GCC pursuant to a 2010 NERC requirement but did not address embedded costs from closed regulatory activities, or provide a workload analysis.

293. SCE requests a total of $25.549 million in total TY2012 O&M costs for two subaccounts: 562.170 Transmission Substation Costs ($10.64 million) and 582.170 Distribution Substation Costs ($14.909 million).

294. SCE based its forecasts on the number of substations it expects to have in its system in 2012, the five-year average cost per substation, and allocation of the total among the three subaccounts using historical ratios.

295. DRA recommends small reductions to both subaccounts, totaling $831,000, based on a 5YA of historical costs.

296. CCUE supports SCE's forecasts of TY2012 O&M for storm-related service restoration costs for subaccount 573.170 Transmission Related Storm Costs ($3.731 million) and subaccount 598.170 Distribution Related Storm Costs ($18.732 million), based on a 5YA.

297. DRA recommends a reduction of $2.419 million for Transmission storm damage based on a 3YA, and $9.727 million for Distribution storm damage based on a different forecasting method.

298. DRA did not establish that its 3YA for Transmission storm or LRY for Distribution storm damage are reasonable by alleging the years are "normal" or "routine." Weather is the primary driver of these costs.

299. SCE rebutted DRA's suggestion that SCE failed to remove CEMA-related costs from recorded expenses.

300. SCE forecast TY2012 O&M for Overhead Distribution Line Operations in subaccount 583.170 to be %4.722 million based on a historical ratio of projected expenditures for capital reactive maintenance.

301. Recorded costs have trended upward, but SCE did not explain why current workforce is insufficient.

302. DRA and TURN recommend $4.129 million based on LRY, or alternatively make a reduction based on recommended lower levels of funding than SCE for capital reactive maintenance.

303. SCE requests $10.307 million for TY2012 O&M for subaccount 593.170 Breakdown Maintenance of Overhead Distribution Lines based on SCE's capital request in the GRC.

304. DRA utilized LRY as a basis for its O&M forecast of $8.996 million for subaccount 593.170.

305. SCE did not establish a correlation between the fluctuations in recorded costs for this subaccount and SCE's capital expenditures.

306. SCE based its TY2012 O&M forecast of $1.906 million for the Circuit Mapping portion of subaccount 588.170 on 2009 recorded expenses.

307. DRA applied a 5YA to address a steep increase between 2008 and 2009 resulting in a reduction of $460,000 to SCE's forecast.

308. For Outage Data Management O&M costs in subaccount 588.170, SCE based its TY2012 forecast of $1.936 million on 2009 recorded expenses.

309. SCE began recording expenses for this activity in 2007, and DRA used a 3YA (2007-2009) to forecast $1.668 million for TY2012.

310. Outage Data Management expenses increased between 2007and 2009 but SCE did not provide specific line items details for review and analysis.

311. SCE requests $1.453 million in TY2012 O&M expenses for Street Light Mapping and Inventory in subaccount 588.170, based on the number of street lights expected in the system, the labor cost per unit, and the ratio of labor costs to total costs.

312. Based on widely varying historical expenses, DRA and TURN recommend using 2009 recorded costs of $1.185 million for the TY2012 forecast.

313. TURN also objects to $25,000 for an energy efficient street light evaluation which is duplicative and unnecessary.

314. SCE forecast $1.022 million for Other Expenses recorded in subaccount 588.170, including $105,000 for discretionary employee recognition expenses.

315. SCE recorded $17.342 million for 2010 capital spending and forecasts $14.888 and $18.345 million, respectively, in 2011 and 2012 for Grid Operations Capital.

316. No party contests SCE's 2011-2012 capital forecast of $1.955 million for Facilities Operational expenditures.

317. SCE forecasts replacing 4,000 street light poles and associated components as part of its street light replacement program in 2012.

318. For the Street Light Replacement Program, SCE recorded $11.337 million in 2010, and forecasts $13.922 million in 2011 and $17.356 million in 2012.

319. Based on a 3YA of SCE's street light replacement expenditures, DRA proposes allowing $11.341 million for 2011 and $11.613 million for 2012, and recommends CSCE replace 2,021 steel street poles and light poles annually.

320. The three-year (2007-2009) average for SCE's pole replacement is skewed by a very low pole replacement number for 2008.

321. SCE estimated a twenty year cycle of replacement is 3,115 per year, approximately 50% between DRA's recommended three year average for pole replacement at 2,021 and SCE's stated need to replace 4,000 poles per year.

322. SCE has not established an accelerated need for the pole replacement program in 2010-2012.

323. SCE forecasts a total of $56.125 million for DCM TY2012 O&M expenses.

324. To develop its forecasts, SCE models failure rates and system growth to forecast how many assets will be replaced each year by DCM. The result is multiplied by SCE's historic unit replacement cost for each asset.

325. CCUE supports SCE's forecast expenses and replacement schedules.

326. DRA forecasts a total of $29.497 million for DCM, almost all of it in two subaccounts; overhead and underground breakdown expenses.

327. DRA's DCM forecasts are based on historic costs and assumed current funding levels are adequate to fund necessary future activities.

328. TURN recommends more than $22 million in reductions to SCE's DCM TY2012 O&M forecast.

329. No party contests SCE's forecast of $2.653 million for Subaccount 580.140 Operations Supervision and Engineering.

330. SCE's TY2012 O&M forecast for Construction Related Expenses in subaccount 583.140 is $735,000, including a $153,000 increase for an expected increase in civil inspections.

331. SCE's forecasted 2011-2012 total TDBU capital expenditures are reduced by 9.4%.

332. SCE's TY2012 O&M forecast for Meter-Related expenses in subaccount 586.140 is $6.41 million after SCE agreed to a reduction of $290,000 presented by TURN.

333. DRA did not adequately support its forecast of $5.583 million for Meter-Related expenses in TY2012.

334. TURN's forecast of $5.796 million is based on the lower meter set forecast adopted herein, a 3YA for meter replacements, and lower contractor costs.

335. SCE asks the Commission to shift the funding of a baseline of $670,000 in service guarantee credits from shareholders to ratepayers and provided five years of recorded payouts in support.

336. SCE did not establish a basis to reverse the Commission's longstanding policy on service guarantee credits.

337. SCE's TY2012 O&M forecast for Miscellaneous Distribution Expenses in subaccount 588.140 is $3.779 million, including $773,000 in discretionary employee recognition costs.

338. Breakdown and CWO Maintenance, usually capital-related expenses, are recorded in subaccount 593.140 for the overhead portion and in subaccount 594.140 for the underground portion.

339. SCE's total TY2012 revised forecast for subaccounts 593.140 and 594.140 totals $41.587 million which SCE states is linked to its estimated system needs in the future.

340. For Overhead-related expenses in 593.140, SCE forecast $9.783 million for breakdown and $20.094 million for CWO expenses in TY2012, for a combined total of $29.877 million.

341. Overhead CWO expenses nearly tripled between 2008 and 2009, and nearly triple again in SCE's 2012 forecast.

342. SCE has not adequately supported its Overhead and Underground CWO forecasts which are inflated by SCE's assumption that all capital spending requests would be authorized.

343. SCE established some increase to Overhead Breakdown expenses, but did not establish that its new correlation ratios for Breakdown expense to capital are valid.

344. DRA recommends $10.172 million for the combined total of Overhead expenses, based on a 5YA of recorded costs.

345. DRA's reliance solely on 5YA does not adequately recognize that SCE is expected to perform more breakdown maintenance expense in this rate cycle than in 2009-2011.

346. TURN's combined forecast for Overhead expenses in 593.140 is $14.386 million, the equivalent of 2009 recorded costs.

347. For TY2012 Underground-related expenses in 594.140, SCE forecast $7.629 million for Breakdown and $4.082 million for CWO expenses, resulting in a combined total of $11.71 million.

348. SCE reduced its original Underground CWO expense forecast to the equivalent of 2009 recorded expenses.

349. DRA recommends $7.501 million for the combined total of Underground expenses, based on a 5YA of recorded costs.

350. TURN's combined forecast for Underground expenses in 593.140 is $10.739 million, the equivalent of 2009 recorded costs.

351. SCE forecasts $265.379 million for DCM capital expenditures in 2012, primarily for inspection-driven capital maintenance or in-service failures.

352. DRA and TURN propose reductions to various subcategories of expenditures.

353. For Distribution Storm Capital Expenditures, SCE revised its original capital forecasts to $38.497 million in 2011 and $39.418 million in 2012 in response to TURN's identification of a calculation error.

354. In 2010, SCE recorded $38.166 million in capital spending for Distribution Storm Capital Expenditures.

355. SCE modified its original 2011-2012 capital forecasts for Distribution Claims Damage as suggested by TURN, to reduce the net claims percentage paid by ratepayers from 50% to 45.67% of gross claims. The resulting reduction is $5.084 million over the 2010-2012 period.

356. SCE's revised forecasts are $20.577 million in 2011 and $21.071 million for 2012. SCE's 2010 recorded expenditures were $17.208 million.

357. SCE proposes to spend $338.5 million for 2010-2012 Distribution Breakdown Maintenance capital expenditures: $108.434 million for 2011 and $118.293 million for 2012. SCE recorded $111.775 million for 2010 expenditures.

358. SCE's asset-based forecast includes the assumption that economic growth will spur customer growth and lead to significant asset growth.

359. DRA and TURN claim SCE's growth estimates are unreliable, SCE presented low correlation coefficients, and did not adequately support linkage to failure rates.

360. DRA relied on 3YA of replacement unit counts to develop an $18.947 million (8.4%) reduction to SCE's 2011-0212 forecast Distribution Breakdown Maintenance capital expenditures.

361. TURN generally agreed with DRA's approach, but applied a 2YA for overhead transformers and underground cable, resulting in a $21.319 million (9.4%) reduction to SCE's request.

362. Due to SCE's old infrastructure, SCE will likely have short-term continued increases for Breakdown capital expenditures.

363. Historical replacement units capture (with lag) increasing breakdowns as the median age of an asset category increases.

364. Prior Breakdown maintenance is a reasonable basis to develop a forecast of growth in this category, and no significant value is added by applying different averages to some equipment categories.

365. SCE forecasts $57.127 million in 2011 and $64.068 million in 2012 for capital expenditures to purchase replacement Distribution Transformers.

366. TURN forecast a total 2011-2012 reduction of $9.517 million based on its own lower forecast of customer growth.

367. SCE forecasts $3.188 million in 2011 and $3.264 million in 2012 for Tools and Work Equipment. SCE recorded $4.312 million in 2010, a record high.

368. SCE's historic costs for Tools and Work Equipment fluctuated between 2005 and 2009, including a 159% increase between 2008 and 2010.

369. SCE's tool purchases in 2009 and 2010 were largely anomalous, based on the evaluation in those years of the safety of current tools.

370. Historical costs should account for wear and tear on SCE's tools.

371. Based on historic fluctuations and recent anomalous tool purchases, DRA relied on a 5YA to arrive at its forecast of $2.170 million in 2011 and $2.222 million for 2012.

372. SCE forecasts $32.143 million for TY2012 Substation Construction and Maintenance O&M expenses in nine subaccounts.

373. DRA does not contest SCE's forecasts for T&D substation expenses incurred in non-TDBU business units, T&D substation maintenance crew supervision, and maintenance of T&D grounds and facilities.

374. SCE developed its budget-based forecast for Substation Construction and Maintenance (SC&M) O&M expenses by using 2009 recorded expenses plus incremental expenses for proposed activities.

375. DRA forecasts $26.184 million for Substation Construction and Maintenance O&M expenses, generally using either SCE's LRY or 5YA (2005-2009) as its basis to forecast future expenditures.

376. SCE forecasts $12.881 million for TY2012 O&M for Transmission Substation I&M in subaccount 570.150, covering five line items and capital-related expenses, based on a forecast asset count and estimated growth.

377. In all sub-categories, recorded expenses have fluctuated between 2005 and 2009.

378. DRA's combined total forecast for 570.150 is $9.36 million, including use of 2009 recorded expenses for three sub-categories: Circuit Breakers, Relay Inspection & Maintenance, and Miscellaneous Equipment.

379. Except for the sub-category of capital-related expenses, SCE's use of proposed, but not authorized, capital expenditures as a basis for subaccount 570.150 forecasts is not reliable.

380. The underlying cost drivers for capital-related (CWO) expenses are capital projects.

381. For CWO expenses, SCE's weighted average ratio of expenses to capital is not adequately supported, but the result is sufficiently close to 5YA to be reasonable.

382. SCE's TY2012 forecast O&M for Substation Miscellaneous Expenses in subaccount 588.150 are $674,000, including $113,000 for discretionary employee recognition expenses.

383. SCE's TY2012 forecast O&M for Distribution Substation I&M in subaccount 592.150 is $11.76 million over four sub-categories. SCE developed its forecast based on asset count, estimated growth and unit cost per asset.

384. DRA used SCE's LRY as a basis for its subaccount 592.150 TY forecast of $9.748 million and recommended reductions to the sub-categories of circuit breakers, relay, and miscellaneous equipment inspection and maintenance costs.

385. Inspection and maintenance of Distribution Substation circuit breakers, and miscellaneous equipment, recorded costs and units replaced varied considerably between 2005 and 2009.

386. SCE's TY2012 forecast for Distribution Substation for Relay I&M includes costs for additional NERC-related activities.

387. For all SC&M capital expenditures, SCE forecasts spending $218 million between 2010 and 2012 in six sub-categories.

388. DRA does not contest SCE's forecasts for Substation Storm Capital and Substation Claims.

389. For Substation Capital Maintenance capital expenditures, SCE forecasts spending $41.933 million in 2011 and $42.952 million in 2012. SCE recorded $33.449 million in capital spending in 2010.

390. DRA recommends a $15.161 million reduction to SCE's 2011-2012 forecast Substation Capital Maintenance capital expenditures based on a 5YA of historical costs.

391. Although SCE spent more than $33 million in 2010, SCE has not established the necessity or the capability to accelerate its planned maintenance to unprecedented levels in 2011 and 2012.

392. Since 2007, SCE's Substation Rule 20B and 20C capitalized expenditures have been declining and 2010 recorded expenditures of $2,000 are substantially lower than in 2009.

393. SCE forecasts $500,000 in 2011 and $512,000 2012 for Substation Rules 20B and 20C capitalized expenditures based on a 5YA of record costs.

394. DRA recommends $185,000 in 2011 and $189,000 in 2012, a combined reduction of $638,000 due to declining expenditures in this category.

395. SCE forecasts expenditures of approximately $14.4 million annually for 2011 and 2012 for Substation Added Facilities paid for by SCE, based on known and upcoming workload.

396. DRA used a 5YA to develop its forecasts of $5.1 million in 2011 and $5.3 million in 2012 for SCE-paid Substation Added Facilities.

397. For Substation Added Facilities paid for by the customer, SCE forecasts $22.3 million in 2011 and $18.7million in 2012.

398. DRA used a 5YA to develop its forecasts of $$5.1 million in 2011 and $5.3 million in 2012 for customer-paid Substation Added Facilities.

399. For total TY2012 Transmission O &M, SCE forecasts $56.364 million covering ten subcategories in five subaccounts using a budget-based approach.

400. DRA forecasts reductions in every sub-category except Transmission Maintenance.

401. SCE forecasts a total $3.851 million for subaccount 563.160 consisting of Overhead transmission Line Inspections and Intrusive Pole Inspections.

402. DRA forecasts a total of $2.683 million in TY2012 based on LRY because recorded costs have been declining since 2007 in this subaccount and SCE spent less than authorized in 2009.

403. Expenses and unit costs for Overhead Line Inspections fluctuate according to a number of variables, primarily fire and weather.

404. SCE did not establish that it is able to add the proposed 188 miles per year during 2011 and 2012 or that installation of overhead line miles bears a direct correlation to actual inspection costs in that year.

405. SCE's TY2012 forecast pole inspection costs of $0.680 million are based on the number of intrusive pole inspections SCE expects to perform in 2012 and SCE's unit cost of $46,000 per inspection.

406. SCE's pole inspection costs have historically varied widely.

407. SCE's commitment to perform pole inspections on a 10-year cycle under its new grid-based inspection program is in the ratepayer's interest and conforms with SCE's previous commitments to CAISO.

408. DRA recommends a reduction to SCE's intrusive pole inspection forecast to $74,000, based on a LRY forecast.

409. In would benefit ratepayers to assess whether the ramped up inspection schedule results in enhanced reliability and safety.

410. SCE forecasts $0.991 million for TY2012 expenses for Underground Transmission Line Inspections in subaccount 564.160 based on a 5YA of cost per line mile, including an estimated addition of 25 miles between 2010 and 2012.

411. DRA forecasts $0.720 million for Underground Transmission Line Inspections in subaccount 564.160, the equivalent of LRY because recorded expenses have been declining.

412. SCE's total TY2012 forecast is $7.230 million for Miscellaneous and Other Transmission Expenses recorded in subaccount 566.160.

413. SCE established that new transmission lines will be added during this rate cycle which will have some impact on SCE's workload.

414. On the grounds that SCE did not justify additional funding, DRA's Miscellaneous Transmission forecast is $4.904 million, equal to SCE's 2009 recorded expenses.

415. SCE's TY2012 Other Transmission Expenses forecast is $2.090 million, including the addition of $1.630 million for the new Transmission Program, which is designed to attract, train, and retain transmission linemen.

416. Employees who commit to the three-year training program receive a bonus.

417. SCE established that its retention rate for transmission linemen has significantly improved, to 97%, since the Transmission Program went into effect.

418. DRA recommends removal of all discretionary employee bonus and recognition programs from Other Transmission Expenses: $1.63 million for the Transmission Program and $0.680 million for other employee awards.

419. SCE forecasts $8.224 for TY2012 Transmission Line Rents O&M recorded in subaccount 567.160.

420. SCE supported its forecast based on expected increased rents by providing contract information.

421. DRA's proposal to adopt 2009 recorded expenses of $5.538 million for Transmission Line Rents O&M is not well supported, and reliance on historical costs in this category is misplaced.

422. For Transmission Maintenance expenses recorded in subaccount 571.160, SCE's TY2012 forecast of $8.861 million is not contested by any party.

423. SCE developed its TY2012 forecast of $3.929 million for Insulator Washing expenses recorded in subaccount 571.160 by using an average unit cost and estimated line miles for 2012.

424. DRA's use of LRY to develop its Insulator Washing expenses forecast of $3.709 million does not account for expense fluctuations due to weather, equipment and vehicle costs, and line location.

425. SCE's forecast $9.043 million for TY2012 Road and Right Of Way (ROW) Maintenance O&M recorded in subaccount 571.160.

426. SCE did not adequately support its forecast by explaining widely varying recent historical costs, or establishing a correlation between line miles and expenses in this category.

427. DRA utilized a 5YA of Road and ROW Maintenance expenses to develop its TY2012 forecast of $8.624 million to reflect external factors that drive expenses.

428. SCE requests $14.235 million for Capital-Related O&M expenses recorded in subaccount 571.160, a 43.4% increase over 2009 recorded expenses.

429. DRA recommends 2009 recorded expenses for TY2012 Capital-Related O&M because historical costs capture routine expenses and SCE's forecast assumes its entire TDBU capital budget will be adopted.

430. For 2011-2012 Transmission capital expenditures, SCE requests $41.321 million, some of which is FERC jurisdictional. SCE recorded 2010 capital spending is $16.914 million.

431. Except for Transmission Deteriorated Poles, no party contests SCE's proposed 2011-2012 Transmission capital expenditures.

432. For Transmission Deteriorated Poles capital expenditures, SCE forecasts $14.595 million in 2011 and $14.966 in 2012 based on replacing 800 poles each year.

433. DRA recommends $5.338 million in 2011 and $5.474 in 2012 for Transmission Deteriorated Poles based primarily on the 20-year inspection cycle of GO 165, sufficient funding to replace 293 poles per year.

434. For T&D BP&TI, SCE forecasts total TY2012 O&M expenses of $20.217 million, offset by $1.456 million in productivity benefits, for a net request of $18.761 million.

435. No party contested SCE's proposal to evenly allocate productivity benefits between shareholders and ratepayers.

436. SCE's TY2012 estimate for BP&TI subaccount 588.270 is $12.373 million, of which $7.734 million is for capital-project related costs.

437. DRA's forecast is $5.041 million lower because DRA removed $7.523 million from 2009 recorded costs related to GIS and WISER as non-recurring costs before using a 5YA to forecast O&M for subaccount 588.270.

438. Capital-project related costs are linked to specific projects undertaken during the rate cycle.

439. SCE's TY2012 forecast O&M for Non-Capital Project is $3.5 million, based on a ratio of enhancement to original capital spending for new capital software projects that is levelized over 2010-2014.

440. Non-Capital Project recorded costs have fluctuated since 2005 and the 5YA is similar to 2009 recorded expenses of $2.291 million.

441. SCE did not adequately support the increase for Non-Capital Project costs in 2012, nor demonstrated that a prior ratio of upgrade costs to capital software expense is applicable to different, not yet purchased software.

442. Based on 5YA of recorded costs, SCE's TY2012 forecast for Miscellaneous expenses recorded in 588.270 is $1.139 million, including $282,000 for discretionary employee recognition costs.

443. SCE's TY2012 estimate for BP&TI O&M for subaccount 566.270 is $7.844 million, comprised of $6.013 million for IMM and $1.831 million for

capital-related expenses, based on LRY expense of $6.013 million, plus the 3YA 2012-2014 forecast average for the C-RAS and Phasor Measurement projects.

444. DRA recommends $6.013 million, LRY expenses, based on its assumption that embedded funding associated with closed or completed projects could be re-directed to test year projects.

445. No party contests SCE's forecasts for 2011-2012 BP&TI capital expenditures of $39.001 million for two projects: GIS and CMS. SCE recorded 2010 capital spending of $17.352 million.

446. SCE forecasts $68.311 million in TY2012 O&M expenses to support the Technical Services Organization.

447. SCE's 2012 forecasts of $20.712 million for subaccount 566.250 Transmission Safety programs and $38.918 million for subaccount 588.250 Distribution Safety Programs support safety programs based on SCE's requested number of new hires.

448. There is a benefit to ratepayers from SCE employees, particularly field personnel, to be trained to perform their work safely and to spot safety concerns on the job.

449. SCE did not adequately explain the necessity of its forecast 30% increase in Training Seat-Time funding in comparison to 2009 recorded costs.

450. This decision makes various reductions to SCE's forecasts for O&M and capital expenditures in TDBU which will result in a lower number of employees to be hired in this rate cycle.

451. DRA did not establish that 2009 expenditures are sufficient to handle new employees and new training activities.

452. DRA did not establish that SCE's TY2012 forecast of $2.926 million for TDBU Environmental Services in subaccount 582.250 is excessive.

453. No party contested SCE's TY2012 forecast of $0.517 million in subaccount 573.250 and $5.238 million for subaccount 598.250 for T&D Toxic Waste Disposal.

454. For T&D Business, Regulatory and Financial Planning, SCE forecasts $13.271 million for TY2012 O&M expenses.

455. No party contested SCE's TY2012 forecast of $0.222 million for subaccount 580.280 TDBU Chargebacks for Services.

456. DRA recommended use of 2009 recorded expenses for all Business, Regulatory and Financial Planning subaccounts, and a $168,000 reduction for discretionary employee recognition costs.

457. SCE will have more interconnection contracts to process during this rate cycle than the previous rate period.

458. SCE did not adequately establish the need for 33 new employees or why SCE needs to hire an outside contractor to identify SCE assets subject to potential new NERC/CIP standards and to develop new controls and enforce NERC/CIP compliance.

459. No party recommended adjustments to SCE's 2012 capital expense request of $7.586 million for the Business, Regulatory and Financial Planning Organization.

460. For TY2012, SCE forecasts $107.314 million for T&D Other Costs across 12 subaccounts.

461. SCE forecasts $111.801 million in TY2012 T&D OOR.

462. DRA recommends a $15.035 million total reduction to Other Costs and an increase of $1.130 million to OOR.

463. TURN recommended reductions of $7.723 to TY2012 Other Costs.

464. No party contests SCE's forecasts for the following subaccounts: 566.282 – Transmission Facility Maintenance ($4.602 million); 584.281 – Transformer Credits (<$2.455> million); and 586.281 – Meter Credits (<$6.437> million).

465. SCE's revised TY2012 forecast for Transmission Work-Order Write-Offs recorded in subaccount 560.281 is $2.676 million, based on the 5YA percentage of write-offs to recorded transmission capital expenditures, multiplied by 1/3 of the 2012-2014 forecast capital expenditures for transmission interconnection projects and transmission substation planning projects.

466. In SCE's 2009 GRC, the Commission approved SCE's forecast methodology linking transmission write-off costs to total TDBU forecast capital expenditures.

467. Both TURN and DRA base their TY2012 forecasts for Transmission Work-Order Write-Offs on a 5YA of recorded costs, $1.538 million, instead of SCE's requested, but unapproved, 2012-2014 forecast transmission capital expenditures.

468. TURN also excludes from its forecast an additional $799,000 for two write-offs it concludes are non-recurring, one of which is $3.9 million and confirmed by SCE to be unusual.

469. SCE did not establish the reliability of its write-off ratios, either historically or prospectively, and did not explain why large non-recurring write-offs in one year did not skew the average ratio.

470. SCE reduced its TY2012 forecast of $10.253 million Distribution Work-Order Write-Offs costs by $252,000, after re-classifying certain expenses identified by TURN. The forecast is derived from the average historical percentage of write-offs to distribution capital expenditures, multiplied by average 2012-2014 forecast distribution capital expenditures.

471. DRA based its forecast of $8.214 million on a 5YA average for Distribution Work-Order Write-Offs, after removing $3.4 million associated with the Catalina fire as unusual and non-recurring expenses.

472. TURN also based its TY2012 forecast of $7.971 million on a 5YA of recorded historical expenses after making certain adjustments for unusual expenses.

473. SCE did not adequately establish the reliability of widely fluctuating historical recorded expenses for Distribution Work-Order Write-Offs between 2005 and 2009, including a 263% increase in 2009.

474. SCE did not establish that all of its historic write-offs are likely to occur in this rate cycle, including the Catalina undersea cable and the USAT write-off.

475. SCE's TY2012 forecast of $10.187 million for Underground Utility Locating Services is based on 2009 recorded costs, instead of the 3YA utilized by DRA.

476. Based on a 2YA (2009-2010), TURN recommends the Commission adopt $9.755 million for Underground Utility Locating Services, a $0.439 million reduction to reflect declining units of work and decreasing costs through 2010.

477. SCE's TY2012 forecast for Claims Write-offs recorded in subaccount 583.281 is $6.046 million based on 5YA, including a $3.298 million write-off related to the Catalina fire.

478. DRA and TURN also use a 5YA for Claims Write-offs, but recommend removing the write-off associated with the Catalina fire and reach slightly different results.

479. The Catalina fire write-off is an extraordinary occurrence.

480. SCE forecasts $9.066 million for TY2012 Facility Maintenance Distribution O&M recorded in subaccount 580.282, based on 2009 recorded expenses.

481. For TY2012 Transmission Allocated Costs recorded in subaccount 568.281, SCE forecast $14.370 million based on anticipated transmission O&M, capital, and other work activities.

482. DRA used LRY as a basis for its TY2012 Transmission Allocated Costs forecast of $11.977 million and objects to SCE's reliance on requested but unauthorized capital expenditures.

483. SCE forecasts $45.453 million for TY2012 Distribution Allocated Costs, based on anticipated distribution O&M, capital, and other work activities.

484. DRA used LRY as a basis for its TY2012 Distribution Allocated Costs forecast of $41.507 million and objects to SCE's reliance on requested but unauthorized capital expenditures.

485. As part of the OOR forecast, SCE forecast $26,000 for Meter Damage and Temporary Services which corresponds to substantial declines in recorded revenues in 2008 and 2009 resulting from accounting changes.

486. DRA used a 5YA for its TY2012 estimate of $1.134 million and raised concerns about the effect of the claimed accounting changes on revenue requirement.

487. SCE did not establish that its accounting system, SAP, does not record expenses used to forecast future costs before the expenses are offset to zero.

488. SCE estimates $1.150 million in TY2012 combined OOR recorded in subaccounts 456.308 Transmission Services for Generation and 456.340 Non-CAISO Services by escalating 2009 recorded revenue to years 2012-2014 and averaging the result for TY2012.

489. DRA used a 5YA as a basis to forecast $1.172 million for combined TY2012 OOR recorded in subaccounts 456.308 and 456.340.

490. SCE forecasts $38.823 million in TY2012 OOR from SCE-Financed Added Facilities recorded in subaccount 454.300 primarily based on new facilities expected to be constructed between 2012 and 2014.

491. SCE forecasts $11.938 million in TY2012 OOR from Customer-Financed Added Facilities recorded in subaccount 456.700 primarily based on new projects expected to be constructed between 2012 and 2014.

492. Elsewhere in the decision, the Commission adjusted the incremental increase in capital-related TDBU O&M expenses that drive revenue for these types of Added Facilities by 9.4%.

Section 6

493. For total CSBU, SCE forecast TY2012 O&M of $300.4 million ($2009) for TY2012 covering the two CSBU divisions: CSOD and CSID.

494. SCE's budget-based forecasting includes incremental increases to base year costs, by funded activity, to reflect anticipated growth due to factors such as customer growth, Dynamic Pricing (DP), SmartConnect deployment, HAN-related activities, PEVs, and new technologies.

495. SCE's CSBU capital request for 2010-2012 is $215.699 million: $67.814 million in 2010 $72.744 million in 2011 and $75.141 million in 2012. SCE recorded $50.768 million in 2010 capital spending.

496. More than $118 million of SCE's 2010-2012 capital expenditures forecast is for capitalized software to implement smart energy policies and practices, and to engage customers in energy management.

497. The deployment of Edison SmartConnect meters through 2012 presents forecasting challenges for attrition years due to the substantial differences in pre- and post-deployment customer-related operations.

498. SCE and DRA each proposed separate 2013 O&M requests to reflect integration of SmartConnect into general rates.

499. Although SmartConnect deployment expenses are currently tracked in the ESCBA, beginning in 2013, most of these expenses will merge into general rates through a separately adopted CSBU 2013 O&M estimate.

500. SCE's TY2012 O&M forecast assumes no SmartConnect meter deployments. In addition to $1.4 million in additional incremental costs, SCE's separate 2013 O&M forecast assumes full SmartConnect deployment and includes net SmartConnect operating costs of $23.0 million and benefits $58.2 million.

501. In D.08-09-039, the Commission established a $1.42/meter/month benefit through 2012 for meters installed during the deployment period, but did not specifically address calculation of post-deployment operational benefits.

502. TURN contests SCE's calculation of SmartConnect costs and benefits in 2013 and asks the Commission to continue the 2012 benefit formula into 2013 in order to provide ratepayers more than $30 million in additional benefits.

503. SCE is authorized to record in the ESCBA: (1) costs to conduct outreach, marketing, and education on DP and DR programs to customers receiving the new meters; and (2) capital expenses related to new back office systems and customer tariffs, programs, and services.

504. In D.09-08-028, the Commission directed SCE to develop and implement DP rates by January 1, 2012, but full deployment of the DP program has been delayed and DP tariffs have not yet been adopted.

505. TURN and DRA contest some or all of SCE's inclusion of $3.839 million in incremental DP costs in 2012 and $3.057 million in 2013 O&M forecasts, and $36.73 million for capitalized DP-related software expenses.

506. The approximate weighted difference between SCE's customer growth forecast used in its CSBU forecasts and the lower estimate adopted in this decision, is 17%.

507. SCE's requests for $9.044 million in TY2012 O&M, and $12.572 million in capital spending for PEV Readiness are based on a forecast of PEV penetration of SCE's service territory which is not adopted in the decision.

508. SCE requests TY2012 O&M costs and capital spending on HAN-related activities in CSBU, TDBU and IT&BI to meet functionality requirements.

509. For CSBU, SCE requests incremental adjustments of $1.157 million for 2012 O&M expenses related to HAN, and $2.908 million for 2013.

510. Implementation costs for HAN-related activities expected to have been recorded in the ESCBA by 2012 have been deferred due to program delays arising from technology uncertainties.

511. SCE will have unanticipated work with new devices related to HAN functionality and integration with SCE's systems.

512. Pursuant to D.11-07-056, SCE developed a HAN smart meter implementation plan which provides for an initial rollout of 5,000 devices, much less than SCE's original forecast of 116,000 customers by 2012.

513. Following the December 2011 severe windstorm in SCE's service territory, SCE conducted an internal and external review of its emergency preparedness and response and found it had not met its own service restoration targets and its public communications were flawed.

514. Rapid emergency response and accurate customer and local government communications during a prolonged outage are important elements of SCE's system accountability and should be part of routine advance planning.

515. SCE identified several initiatives it would undertake to improve emergency response.

516. For all CSOD categories (excluding Uncollectibles), SCE forecasts $237.096 million for total 2012 O&M, including SmartConnect benefits of $26.078 million, and $209.040 million for 2013.

517. For nearly all CSOD programs, SCE proposed several incremental adjustments to 2009 recorded costs, and requests additional FTEs based on SCE's forecasts and requests in its application.

518. SCE's forecast method for CSOD O&M is disputed by DRA and TURN both for use of LRY as the Base Year, and for utilizing SCE's unadopted forecasts to estimate staffing and program requirements.

519. TURN opposes all funding in CSBU for PEV Readiness and HAN program costs.

520. For Business Units Management and Support, SCE forecasts $14.63 million for 2012, an increase of $2.568 million includes 14 new FTEs and adjustments that include Customer growth, PEVs, and HAN.

521. For 2013, SCE forecasts an additional $142,000 for additional FTEs to support SCE's planned rollout of new technologies.

522. DRA's forecast of $13.332 for 2012 and 2013 is the 5YA of varying recorded costs, and results in a 10.5% increase in 2012 over 2009.

523. For Meter Reading Expenses recorded in FERC 902, SCE forecasts $45.113 million for 2012, an increase of $812,000 to account for customer growth.

524. For 2013, SCE adds an additional $328,000 for customer growth but reduces its overall forecast to $12.34 million as a result cost reductions from smart meter deployments.

525. DRA rejects SCE's customer growth adjustments and requests $44.3 million in 2012 and $12.012 million in 2013.

526. SCE did not establish a correlation of meter read costs to customer growth in 2012 and 2013, during the period of transition to remote electronic meter reading.

527. For SmartConnect Operations Center (SOC) expenses recorded in subaccount 902.300, SCE forecasts $1.089 million for non-SmartConnect deployment costs related to PEV and HAN.

528. For 2013, SCE forecasts $13.115 million, an $11.9 increase to support ongoing O&M of the SmartConnect telecommunication data management system, including $3.3 million for 29 new FTEs, and $1.192 million for HAN and PEV.

529. DRA and TURN reject inclusion of HAN and PEV costs, and DRA forecast $4.098 million for 2013 based on deployment costs recorded in the ESCBA.

530. SCE's SOC functions will be different in 2013; in addition to assuming all O&M, the SOC will change to a 24/7 operation.

531. SCE forecasts a total of $115.102 million in 2012 for Customer Records and Collections(CRC) recorded in six subaccounts under FERC 903, including $820,000 of adjustments to LRY for customer growth and other estimated program changes and benefits.

532. For 2013, SCE forecasts $115.963 million including $580,000 in adjustments for customer growth, program changes, SmartConnect post-deployment operations, and PEV costs, as well as benefits from productivity initiatives and SmartConnect deployment.

533. In reaching its 2012 CRC forecast of $106.015 million and 2013 CRC forecast of $10.29 million, DRA rejects all of SCE's adjustments in three

subaccounts, but does not contest SCE's forecasts for subaccounts 903.100, 903.300, and 903.700.

534. For subaccount 903.200 Credit, SCE forecast $17.815 million for 2012 and $11.662 million for 2013, including a $6.7 million offset for SmartConnect productivity benefits.

535. SCE established a correlation between Credit expense and customer growth, but did not adequately support all of its proposed adjustments to this subaccount for 2012 and 2013.

536. For subaccount 903.500 Billing, SCE forecast $17.902 million for 2012, including incremental adjustments for customer growth, PEVs, and special needs billing format.

537. SCE's 2013 forecast of $21.364 million also includes additional increments for 78 new FTEs and an offset of $1.502 million in SmartConnect operational benefits.

538. SCE established a correlation between billing expense and customer growth, but did not adequately support all of its proposed adjustments to this subaccount for 2012 and 2013.

539. For subaccount 903.500, DRA relies on LRY to recommend $17.170 million in 2012, and $15.668 million for 2013; DRA contests SCE's need for additional employees and new special needs billing costs when only 146 customers were enrolled in 2010.

540. For subaccount 903.800 Customer Communication Organization (CCO), SCE forecast $47.020 million for 2012 CCO costs, including incremental adjustments for higher call volume, longer call times, wage increases, and a $651,000 offset for productivity savings.

SCE's 2013 forecast of $50.559 million also includes SmartConnect and other productivity benefits totaling $2.55 million.

541. Although SCE supported some adjustment for more calls and longer calls following SmartConnect deployment, SCE did not adequately support its total proposed adjustments to this subaccount for 2012 and 2013.

542. SCE requests $3 million in both 2012 and 2013 for wage increases but did not address the discretionary spending choices by SCE executives to pay competitive wages to managers, executives, and other employees.

543. At the PPH, members of the public criticized SCE's customer service representatives for limited responsiveness, attitude, lack of information, wait time, and other problems.

544. For subaccount 903.800, DRA relies on LRY to recommend $39.485 million for 2012 CCO costs and $38.095 million for 2013, including diversion of productivity benefits to fund possible increases, and acceptance of the 2013 SmartConnect benefit of $1.4 million.

545. In Account 904, SCE records all revenue components of uncollectible customer accounts; recorded expenses are authorized based on an estimate of uncollectible expense factor expressed as a percent of gross SCE revenue.

546. For TY 2012, SCE forecasts an Uncollectible Factor of 0.229%, slightly below the current factor of 0.240% and slightly above an eight-year adjusted average from 2000-2009 (excluding 2005-2006) of 0.227%, resulting in 2012 expenses of $15.7 million for Account 904.

547. Aglet recommends using the 10YA of recorded Uncollectible Factors, 0.203%, because it finds no justification for excluding 2005-2006, increased to 0.205% to reflect four uncontested adjustments.

548. SCE did not adequately support the exclusion of two years from SCE's calculation.

549. For Miscellaneous Expenses recorded in Account 905, SCE forecast $14.534, including $2.3 million in adjustments for more customer outreach and education for SCE's special needs customers.

550. SCE's 2013 forecast of $15.936 million includes new SmartConnect costs.

551. DRA's forecast for Miscellaneous Expense is $12.325 million in 2012, the equivalent of LRY, and $12.281 million in 2013, because it views SCE's activities in this category to be routine.

552. SCE did not demonstrate a basis to alter Commission policy of shareholders funding payments to customers in SCE's Service Guarantee program.

553. No party contests SCE's 2012 and 2013 forecasts for CSBU Safety program expenses recorded in 580.100 and 580.300.

554. For subaccount 586.100 Meter Turn Off and Turn On expenses, SCE forecast $18.474 million for 2012 costs, including incremental adjustments for customer growth and after hours support.

555. SCE's 2013 forecast of $8.223 million includes $11.6 million in SmartConnect benefits and $1.5 million in costs.

556. No party contested SCE's 2012-2013 forecasts for this subaccount.

557. For Test and Inspect Meters expenses recorded in subaccount 586.400, SCE's 2012 forecast is $11.196 million, including incremental additions of $1.34 million to add 11 new FTE's to address customer growth, PEVs, and HAN activities.

558. For 2013, SCE's forecast of $11.334 million adds six more FTEs, in addition to the 2012 adjustments, and includes SmartConnect benefits of $1.8 million and $1.35 million in costs.

559. SCE established that customer growth will have an impact on meter-related expenses.

560. For 2012, DRA recommends the Commission adopt 2009 recorded expenses of $9.856 million with no adjustments. For 2013, DRA recommends $9.375 million, excluding all of SCE's proposed adjustments except for SmartConnect costs and benefits.

561. Meter compatibility with HAN applications is part of the original SmartConnect deployment functionality to be recorded in the ESCBA.

562. For Customer Installation expenses recorded in subaccount 587.500, SCE's 2012 forecast is $5.458 million and 2013 forecast is $375,000, including a $2.7 million offset for SmartConnect benefits.

563. For Management and Supervision expenses recorded in subaccount 587.800, SCE's 2012 forecast is $2.34 million and $2.36 million in 2013.

564. No party contests SCE's 2012-2013 forecasts for subaccounts 5587.500 and 587.800.

565. For subaccount 587.200 which captures Energy Theft-related costs, SCE forecasts $2.905 million for 2012, the equivalent of LRY; For 2013, SCE's forecast increases by $1.908 million for SmartConnect revenue protection requirements, including 22 new FTEs for new energy theft programs.

566. DRA and TURN recommend the Commission reject SCE's incremental costs on the grounds that, (1) SCE's projected theft cases are speculative, (2) fewer meter readers will cause a decline in theft investigations, and (3) adequate staff exists to address future theft cases.

567. In D.09-09-026, the Commission acknowledged that energy theft losses would likely increase once meter readers were gone unless replaced with AMI assisted energy theft programs.

568. SCE's proposed addition of 22 FTEs to bring the total Energy Theft employees to 56 is excessive and does not address existing labor resources.

569. SCE's 2012 forecast is $1.689 million for Repair Billing Meter expenses recorded in subaccount 597.400, an increase of $30,000 from 2009 recorded expenses to account for customer growth.

570. For 2013, SCE adds $252,000 in incremental costs, for a total forecast of $1.911 million, to support three new FTEs for more complex metering installations and adjust for customer growth.

571. No party contests SCE's forecasts for subaccount 597.400.

572. SCE anticipates higher costs for CSID activities due to its technology-enabled customer service models, new customer service and outreach initiatives, new and flexible rates, infrastructure for emerging technologies (e.g., PEVs, HAN), local community support and transmission licensing.

573. For total CSID O&M, SCE forecasts $63.316 million in 2012, in eight subaccounts, based on various incremental adjustments to 2009 recorded costs totaling $9.773 million, and including requests for additional FTEs based on SCE's forecasts and requests in its application.

574. The largest adjustment is $5.6 million for expanded communications on new, more complex rate options, online energy information, and program support.

575. No party contested 2009's use as the Base Year for CSID subaccounts.

576. No party contested SCE's 2012-2013 Customer Assistance forecasts in subaccounts 908.620 Technical Services ($7.4 million total) and 908.630 Economic Development ($4.954 million total).

577. TURN and DRA contest some of SCE's adjustments in other Customer Assistance –related subaccounts.

578. For Account Management expenses recorded in subaccount 908.600, SCE's 2012 forecast is $15.534 million, an increase of $894,000 from 2009 recorded expenses for 15 new FTEs in support of PEVs, DP, and Outage Communications.

579. For 2013, SCE's forecast increases to $15.610 million and also includes one more FTE for PEV support.

580. DRA contests incremental increases for Outage Communications and PEV activities, resulting in a reduction of $455,000 to SCE's 2012 Account Management expenses forecast.

581. TURN opposes SCE's 2012 request for ten FTEs ($439,000) to support increased DP inquiries from small, non-residential customers and disagrees with SCE as to whether these DP-related costs should be recorded in the ESCBA.

582. Costs for Outage Communications are generally routine and SCE did not establish the necessity of additional staff with a generalized expectation of equipment failure.

583. O&M costs recorded in subaccount 908.610 support SCE's Energy Centers for which SCE claims growing demand. SCE requests capital funding to create a third Energy Center and requests staff support in this subaccount.

584. For 2012, SCE forecasts expenses of $2.110 million, an increase of $165,000 from 2009 recorded expenses primarily for three new FTEs to provide more training and programs for customers.

585. For 2013, SCE requests an additional $202,000 for three employees to staff a new Energy Center which is not authorized in this decision.

586. Although DRA contests SCE's 2012 adjustment for new Energy Center FTEs, SCE established that seminar attendance is increasing and demand exists beyond current resources.

587. For Program Management expenses recorded in subaccount 908.640, SCE forecasts $14.262 million for 2012, an increase of $5.648 million over 2009 recorded expenses, including six new FTEs to support adjustments for PEV, DP, web accessibility, program administration, and SCE Energy Manager programs.

588. For 2013, SCE's forecast increases to $16.435 million, based on the same adjustments plus HAN support.

589. DRA used LRY to forecast 2012 Program Management O&M of $8.614 million which rejects all proposed adjustments as unsupported or funded by embedded expenses.

590. For 2013, DRA supports an increase of $1.136 million to support two new online energy cost tools and a bill forecasting program to educate customers about energy management, but contests $931,000 for marketing and communications costs previously recorded in ESCBA.

591. SCE will have new expenses in 2013 as post-deployment SmartConnect related costs for marketing and communications will move into general rates.

592. TURN recommends removal of the PEV and DP adjustments, as well as elimination of increased EnergyManager staffing due to disappointing participation levels.

593. SCE established that its DP marketing and outreach expenses of $890,000 are necessary to support 612,000 non-residential service accounts in transition to mandatory TOU rates and default CPP.

594. A small portion of the commercial customers targeted by SCE's DP customer outreach and education program in 2012 were not included in the SmartConnect deployment.

595. Community-based organizations (CBOS) are essential partners for SCE in customer education and outreach, particularly for low-income, minority, senior, and small business communities.

596. The addition of four employees for program administration could support significant growth in Medical Baseline (MBL) and EAF application volume since 2006.

597. SCE EnergyManager is a group of free and fee-based services to deliver online energy information and tools to 6,600 of its largest commercial and industrial customers.

598. Elimination of fees and adoption of DP rates will likely increase use of the EnergyManager platform in 2013.

599. For Business Unit Management and Support expenses recorded in subaccount 907.600, SCE forecasts $10.729 million for 2012, an increase of $1.197 million over 2009 recorded expenses to add seven FTEs primarily to support new technology initiatives.

600. For 2013, SCE proposes to also add three more employees for major technology initiatives and $40,000 for PEV support, resulting in a 2013 forecast of $11.123 million.

601. No party contests SCE's 2012 forecast for subaccount 907.600, but TURN contests PEV funding added in 2013.

602. For Rate Communications expenses recorded in subaccount 916.600, SCE forecasts $1.458 million for 2012 and 2013, equal to 2009 recorded expenses.

603. Historic costs have varied significantly, averaging $415,000 between 2005 and 2008, and increasing to more than $1.4 million in 2009.

604. SCE explains the increase in 2009 as the result of communicating 2009 rate increases to customers, and notice to some customers of a shift to seasonal pricing.

605. DRA views the 2009 Rate Communications expenses as anomalous and recommends used a 5YA of recorded expenses to reach a forecast of $630,000.

606. For Local Public Affairs (LPA) recorded in FERC 920, SCE forecasts expenses of $12.624 million for 2012 and 2013, an increase of $1.728 million from 2009 recorded expenses, including fifteen new FTEs to support public involvement and project licensing related to more transmission and substation projects.

607. DRA recommends a 5YA as the most reasonable basis to forecast 2012 LPA costs, yielding a 2012 forecast of $9.297million, 26% less than SCE's forecast.

608. SCE has $564,000 in one-time expenses embedded in 2009 local public affairs recorded costs.

609. No party contests SCE's forecast expenses of $0.623 million for TY 2012 for Business Licenses Taxes recorded in FERC 408.

610. CSBU is in a transition period for customer communications where it must be able to respond to customers with traditional service, as well as the evolving programs, devices, and rates supported by new smart technologies.

611. For CSBU, SCE forecasts 2010-2012 General Plant capital expenditures of $97.4 million over four categories: Structures and Improvements (S&I), Office Furniture and Equipment (F&E), Specialized equipment (SE), and Meters.

612. SCE's 2010 recorded expenditures of $25.4 million for General Plant are $8.53 million less than SCE's 2010 forecast.

613. SCE supports its forecasts based on internal calculations of customer and employee growth, equipment age and condition, and integration of SmartConnect.

614. DRA's 2010-2012 forecasts for General Plant capital expenditures totaling $53 million are based on a combination of 2010 recorded expenditures and spending reductions.

615. For S&I, SCE forecast $9.155 million for 2010-2012, but recorded $806,000 more in 2010 than forecast, and estimated $1.295 million for 2011 and $5.735 million in 2012.

616. DRA's 2010-2012 capital S&I forecast totals $6.46 million to reflect 2010 recorded expenses and removal of $3.5 million in 2012 to delete funding for a third energy center.

617. SCE requests $3.5 million in 2012, as part of a $7.25 million third energy center project, but did not establish that a third energy center is the best way to expand access to customer and workforce education programs.

618. SCE forecasts a total of $11.326 million for 2010-2012 capital expenditures for F&E, but recorded only $671,000 in 2010, more than $4 million less than SCE forecast.

619. SCE delayed spending most of its 2010 F&E forecast and plans to add more employees in 2011 and 2012.

620. Because F&E costs have historically fluctuated, DRA forecasts $752,000 for 2011 and 2012, the 5YA of recorded costs, plus 2010 recorded expenditures of $2.175 million.

621. SCE's total 2010-2012 SE forecast is $3.637 million, including $1.212 million in 2011 and $0.975 million in 2012. SCE recorded $6.3 million in capital spending for SE in 2010, $4.85 million more than its forecast of $1.45 million.

622. SCE did not justify the necessity for additional SE expenditures in 2011 and 2012 after $4.85 million of excess spending in 2010.

623. SCE forecasts a total of $73.288 million for 2010-2012 Metering Capital expenditures, including increases for customer growth, PEV meters, and HAN readiness, and reductions of $15.24 million for SmartConnect benefits recorded in the BRRBA.

624. DRA based its 2010-2012 forecasts totaling $36 million on 2010 recorded expenses, annually reduced by SCE's expected benefits.

625. For CSBU, SCE requests a2010-2012 total of $118.293 million, including $41.4 million in 2011 and $43.010 in 2012, for eight Capitalized Software projects which consist of hardware, software, licensing, and project management costs.

626. SCE's recorded 2010 Capitalized Software expenses are $25.3 million, 25% less than SCE's 2010 forecast of $33.88 million.

627. DRA's Capitalized Software forecast is $75.3 million, utilizing 2010 recorded expenses, and $25 million for 2011 and 2012.

628. In addition to project-specific reductions or eliminations, TURN asks the Commission to reduce all Capitalized Software requests by 10% to address cost escalation, including excess contingency and project management costs.

629. SCE estimates spending $9.33 million in 2012 and $6.780 million in 2013 for the Alerts and Notifications (A&N) project.

630. SCE did not demonstrate that current A&N systems are insufficient to meet demand, or that the proposed replacement program is cost-effective.

631. SCE forecast $8.17 million through 2013 to enhance the Interactive Voice Response (IVR) system.

632. The current IVR system is functional and SCE did not establish an immediate need for replacement or review lower cost options.

633. SCE proposes a two phase Customer Relationship Management (CRM) project to provide more accurate data on DSM programs: Phase 1, estimated to cost $44.82 million to be completed in 2011 and Phase 2 estimated to cost $20 million and be completed 2013.

634. The CRM project involves several programs, in addition to EE and DR.

635. TURN recommends rejection of the CRM project because it has no quantifiable benefit.

636. For the HAN troubleshooting project planned to deliver device registration and support, SCE based its 2012 forecast of $8.3 million on an estimate of 500,000 HAN devices within its service territory by 2014.

637. TURN and DRA contest the project, in part due to HAN program delays and other approved SCE projects which provide usage data to customers.

638. SCE forecasts $2 million in 2012, and $8.4 million by 2014, for the PEV Support Systems project to upgrade systems to improve enrollment in DP or PEV rate structures, expedite installation of charging equipment and meters, and to provide more effective customer service.

639. SCE's proposed implementation schedule for the PEV Support Systems project will outpace need in this rate cycle due to lower forecast PEVs and integration with other projects that have yet to be completed.

640. No party contested SCE's 2010 expenditure of $3.663 million to adopt the Intelligent Mail Barcode (IMB) in order to comply with new U.S. Postal Service requirements related to presorted mail and discount postage rates.

641. SCE recorded $55,000 in 2010 for the Dynamic Pricing Rate Analysis and Management Tools project (DPRA) for system modifications to support new DP rates, associated rate analysis, and energy management tools.

642. SCE forecast $36.73 million in DPRA capital expenditures between 2010 and 2012: $3.73 million in 2010, $17 million in 2011, and $16 million in 2012.

643. The DPRA project is broad, and includes TOU and CPP for commercial, industrial, and agricultural customers largely unaffected by the SmartConnect deployment.

644. Delayed implementation of DP rates reduced SCE's spending in 2010.

645. SCE obtains CSBU-related OOR through specific fees and charges to end users for non-basis services and proposes to update some fees to reflect the current costs and eliminating other fees.

646. SCE's forecasts that CSBU-related OOR will decrease $15.609 million from 2009 recorded levels, primarily due to remote service switch functionality of the SmartConnect system which will nearly eliminate the need to dispatch a field representative to activate and deactivate service to residential customers.

<u>Section 7</u>

647. For TY2012, SCE requests $310 million for IT&BI O&M, a 46% increase over 2009, to modernize aging infrastructure and address growth in security needs, software licensing, business unit support, and support for new capitalized software requested herein.

648. SCE forecasts $686.5 million in 2010-2012 IT&BI capital expenditures, including $318 million for software and $351 million for hardware, some of which is SCE's response to regulatory requirements and to prepare for anticipated system needs.

649. SCE recorded IT&BI capital spending in 2010 of $217.21 million, slightly less than its $225.85 million forecast.

650. DRA recommends a 5.8% overall reduction of SCE's 2010-2012 total capital expenditure forecasts, but identifies no separate reductions.

651. Capitalized software investments result in recurring O&M costs throughout the software life cycle which is usually between 5 and 7 years.

652. In 2007, the Commission established the MRTU Memorandum Account (MRTUMA) for SCE to record incremental capital-related revenue requirement and implementation O&M expenses.

653. SCE requests elimination of the MRTUMA because it views implementation as complete, and inclusion of forecast O&M and capital spending related to MRTU to be incorporated into general rates as of 2012.

654. Implementation of MRTU is a multi-year process and CAISO has not yet determined all of the requirements for subsequent releases.

655. Except for the 2007-2009 costs currently being audited, no other MRTU costs have been reviewed for reasonableness, providing little guidance for review in this GRC.

656. TURN identifies 2010-2012 capital expenditures cuts of $230 million that it views as unnecessary to provide electric service, and applies a 10% decrease to remaining capital projects to address cost escalation.

657. SCE was authorized to spend $295 million in 2007-2009 to complete releases 1 through 3 of the ERP system to integrate the utility's data and processes into a single system.

658. SCE recorded cost overruns for the ERP project in 2009 of $49.1 million and in 2010 of $45.6 million, and seeks rate recovery of the total.

659. SCE forecast 2012 ERP-related productivity benefits of $6.74 million ($2009) based on the difference between the 3YA (2009-2011) of system-wide ERP benefits previously authorized and the total steady-state forecast of $38.03 million ($2006), escalated to 2009 dollars.

660. TURN calculates the ERP benefits to be $9.2 million based on 3YA and contests SCE's plan to share 50% of the ERP benefits with shareholders.

661. SCE assumes 8% savings from a portion of its forecast 2010-2014 capitalized software investment, or $18 million, and requests 50/50 sharing of the benefits between ratepayers and shareholders.

662. Because software investment rapidly becomes obsolete, TURN proposed an alternative "Sustainable Savings Mechanism" which assumes 100% cost recovery of adopted capitalized software investment over a six-year service life, resulting in a $69.5 million benefit in TY2012.

663. TURN's assumption that all capitalized software will provide 100% productivity benefits over the lifetime of the software is unsupported and ignores other factors including regulatory requirements.

664. DRA contests as a distortion, SCE's O&M accounting adjustments which removed contingent worker costs from FERC 923 and added them to FERC 921 for forecasting purposes.

665. Recording of significant contingent worker expenses in account 921 beginning in 2009, injects inconsistency into the historic non-labor data for forecasting purposes.

666. No party contests SCE's TY2012 O&M forecasts for Applications Services ($4.028 million), Computing Services ($2.165 million), and Network Services ($1.219 million) that support SCE's Nuclear Operations in FERC Account 517.

667. SCE forecasts $112.86 million for TY2012 (non-nuclear) Application Services in FERC 920 /921, an increase of $30.1 million over 2009, based on a five-year trend increased by $18 million in labor to support ERP and $9 million to support new software.

668. DRA's forecast of $71.62 million for Application Services is based on a 3YA to account for historical fluctuations, embedded project costs, and inconsistent recording of contingent worker costs.

669. For TY2012, SCE forecasts $40.681 million in O&M to support New Software Applications, including SmartConnect, MRTU, Software Asset Management (SAM) projects, Commodity Management, and SCE.com based on a normalized average of SCE's 2012-2014 estimated, but unadopted, capital spending.

670. SCE assumes 8% O&M for implementation of new software and 5% recurring O&M costs based on historical ratios to total project cost, but did not provide its supporting calculations.

671. SCE will have some embedded costs available for recurring O&M for new large systems which will replace older software.

672. TURN supports a $24.13 million reduction to SCE's forecast based on adopted reductions to SCE's new software project request, recording the SmartConnect project in ESCBA, and elimination of recurring O&M costs.

673. SCE removed one-third of SmartConnect implementation costs forecast for 2012, and normalized the remaining 2013 and 2014 support costs across 2012-2014 resulting in a $2.786 million reduction in 2012.

674. DRA did not establish that SCE included $3.48 million of MRTU-related expenses, instead of the $917,000 identified by SCE.

675. SCE's TY2012 O&M Technology and Risk Management (TRM) forecast of $34.506 million is more than twice what it spent in 2009, based on LRY plus incremental costs of nearly $18 million primarily for labor.

676. Risk management and cyber security, including compliance with NERC/CIP mandates, are necessary and serve to protect the safety of the electrical system as well as the privacy of customer data.

677. SCE did not separately identify amounts forecast for any particular activity, and incremental costs did not increase after 2009 as SCE expected due to delay of NERC/CIP standards.

678. No party disputed SCE's TY2012 forecasts of $17.823 million for Service Management, $21.494 million for Network Services, and $23.903 million for Infrastructure Operations Management.

679. For Computing Services, SCE's TY2012 forecast is $31.388 million, including a nearly $8 million increase for more FTEs, support for large software projects, and support for mainframe, server and storage growth.

680. SCE's historical labor and non-labor costs for Computing Services have varied differently due to use of contingent workers, later hired, and atypical inventory purchases.

681. SCE forecasts $23.291 million for Business Operations Management TY2012 O&M, based on increased labor and declining non-labor, to support business relations with other SCE business units which SCE expects to become more complex in this rate cycle.

682. The combined labor/non-labor 3YA (2007-2009) is $19.684 million and combined historical costs for this activity have varied significantly.

683. SCE did not establish the necessity of adding all 56 new employees by 2012, a significant majority of which are for internal relations, including six Director positions at $220,000 each, plus six executive assistants.

684. Some of the activities identified by SCE's Business Operations forecast are ongoing responsibilities of the unit for which embedded costs are available.

685. SCE's revised request for 2010-2012 Hardware Capital Expenditures of $351.100 million, including 2010 recorded expenditures, did not rely on its capitalized software requests.

686. TURN requests disallowance of $127.33 million to correspond with reductions to IT software projects adopted in this decision.

687. No party contested SCE's 2010-2012 Hardware forecasts in eight categories totaling $$235.870 million for : Mainframe Servers, Midrange Enterprise Servers, Disk and Tape Storage, High Volume Printers/Bill Inserters, Data and Voice Network, Transmission Network and Facilities, Telecom Test Equipment, and Microwave equipment.

688. SCE refreshes approximately 25% of its PC and Related Hardware inventory each year.

689. For 2011-2012, SCE forecast $36.909 million ($11.9 million in 2010, $12.36 million in 2011, and $12.649 million in 2012) to service an estimated 19,600 desktop PCs and laptops. Actual recorded expenses for 2010 are $12.237 million.

690. SCE did not demonstrate that it undertook any cost minimization analysis or establish how it calculated device and cost growth, the development of unit cost, or why it is necessary to proactively refresh or replace all PCs and laptops every four years.

691. SCE forecasts $12.378 million for Ruggedized Laptops in 2010-2012 ($5.925 million in 2010, $1.6 million in 2011, and $4.853 million in 2012) developed as a budget based forecast to address future growth. SCE recorded $4.387 million in 2010 expenditures.

692. SCE purchased a significant number of new model ruggedized laptops in 2007.

693. For 2010-2012, SCE forecasts $30.357 million to replace copper communication cable with fiber optic cable: $9.725 million in 2010, $10.114 million in 2011, and $10.518 million in 2012. SCE's 2010 recorded expenditures were $4.918 million.

694. SCE did not establish that its cost for copper cable replacement would be $55,000 per mile or that replacement of all copper cable is necessary by 2017.

695. SCE will have completed replacement of the half of its copper wire that is more than 35 years old by 2010.

696. SCE requests $6 million annually, beginning in 2012, to initiate a new program to replace 100 miles per year of its 3,700 miles of fiber optic cable.

697. SCE's forecast is $5.948 million based on a unit cost of $55,000 per mile of fiber optic cable using the same data as for the copper wire replacement project.

698. SCE requests $1 million in 2010 to replace 13 satellite terminals and $2.4 million per year thereafter to replace 30 per year.

699. SCE did not support its cost estimate for Satellite Terminal Equipment replacements of about $75,000 per terminal for 300 terminals.

700. No party contested SCE's request of $2 million in 2012 to begin the $30 million replacement of its Mobile Radio Network (MRN) which provides voice communication in support of field personnel.

701. SCEnet II is a new project proposed by SCE to begin planning the next generation of its voice, data, wireless communications and electric grid control.

702. SCE forecasts $3.1 million in 2012 to begin installation of 1,000 miles of fiber optic cable and associated equipment to bring SCEnet II connectivity to 121 66kV substations.

703. SCE supported its interest in developing a new enterprise communication infrastructure (intranet), but not any of the cost estimates comprising the forecast.

704. For 2010-2012, SCE forecasts $31.813 million for Disaster Recovery to conduct cyclical refresh of redundant systems. SCE's 2010 actual expenditures were $1.9 million.

705. For IT&BI Operating Software capital spending, SCE forecasts $33.727 million covering 10 projects for 2010-2012: $15.647 million in 2010, $9.43 million in 2012, and $8.65 million in 2012. SCE's 2010 recorded expenditures are $25.112 million.

706. A $3.75 million project, Configuration Management Database (CMD),is contested by TURN as duplicative of SCE's Application Portfolio Management System (APMS) which tracks its inventory of software applications.

707. SCE did not explain why current systems are inadequate to maintain service levels through this rate cycle, why automated mapping is necessary now, or why this software package is the best or most cost-effective approach.

708. SCE recorded $6.154 million for projects less than $1 million in 2010 and forecasts $387,000 in 2011 and $1.397 million in 2012.

709. TURN asks that one $500,000 project, Single View of IT Health, be disallowed based on SCE's inconsistent internal cost estimates.

710. SCE forecast a total of $145.891 million for 2010-2012 Software Asset Management (SAM) capital spending: $41.2 million in 2010, $21.791 million in 2011, and $82.815 million in 2012.

711. Because SCE reported total 2010 expenditures of $6.177 million for all SAM projects combined, there is no evidence of project specific expenditures.

712. SAM consists of numerous processes which prioritize software upgrades and replacements to mitigate risks.

713. SCE's provides limited support for its SAM cost estimates and does not, consider alternatives or overlapping functions, or address efficiencies from years of experience implementing SAM systems.

714. For SAM, SCE requests $6 million in 2012 to begin the Computer Aided Facility Management (CAFM) project which allows integration of current asset and personnel data from ERP with facility data, combined with AutoCAD (Computer Aided Design) for enhanced facility drawings.

715. SCE established its current system relies on aged and obsolete software, as well as third parties, and ratepayers may benefit from efficient planning for use of facilities.

716. For SAM, SCE forecast $8.694 million in 2012 expenditures to implement the Customer Data Warehouse (CDW) to integrate various customer databases into one, centralized data warehouse.

717. For SAM, SCE requests $2.017 million in 2011-2012 to implement enhancements to the Enterprise Platform User Interface Refresh project to correct design problems admitted by the vendor.

718. SCE established that it has no recourse to the vendor except to adapt the enhancements with vendor support.

719. For SAM, SCE requests $1.138 million in 2010 to update its primary search engine, the SAP Search and Classification System (TREX), after SAP made a significant technology change which forces an upgrade to the platform.

720. TURN requests disallowance of the expenses to replace or upgrade TREX so soon after it was implemented in 2010.

721. SCE established the TREX upgrade will increase performance in applications that support customer systems and ensure vendor support after 2014.

722. For SAM, SCE requests $5.795 million ($1.419 million in 2010 and $4.376 million in 2011) to replace the obsolete Revenue Protection and Law Claims Management (CMS)with a purportedly easy-to-use, collaborative system tailored to SCE's processes developed in-house.

723. TURN did not support its alternate cost estimate of $1.4 million, or establish overlapping functions exist with SCE's proposed 2013 Revenue Protection Investigations System (RPIS) to investigate unauthorized usage.

724. For SAM, SCE requests $6.07 million in 2010 to update SCE EnergyManager® to provide online energy information and tools to SCE's largest Commercial and Industrial customers with 15-minute interval data.

725. In 2011, the Commission directed SCE to provide pricing, interval usage, and cost data to customers and rate comparison information online.

726. TURN requests $4.32 million be disallowed because the EnergyManager program is poorly used, too costly, and includes funds to replace a recent DR upgrade and related to SmartConnect.

727. SCE requests $1.2 million in 2010 for the Capital Work Order Unit Estimate Derivation Project (CWO) which is not a SAM project but is linked to Design Manager.

728. SCE supported the CWO project based on assuming an increase in work orders from 40,000 to 200,000 annually due to more capital work.

729. The combination of emphasis on capital projects to maintain and replace aging infrastructure, and to integrate new programs, provides sufficient support for the CWO project.

730. For uncontested SAM projects, SCE forecast $$16.415 million in 2011 and $67.104 million in 2012, for a 2012-2012 total of $83.519 million.

731. For IT&BI Other Capitalized Software, SCE forecast $73.242 million for 2011-2012, and recorded $32.991 million in 2010, excluding ERP.

732. No party disputes SCE's forecast of $1.545 million in 2010 for the Project Portfolio Management (PPM), $3.538 million less than SCE recorded for this project to develop a centralized database to manage IT spending, and improve prioritization and resource planning.

733. SCE was previously authorized to make $295 million in capital expenditures during 2007-2009 to complete Releases 1 through 3 (R1-3) of the ERP; combined with 2006 recorded spending, total ERP expenditures were forecast to total $400.7 million.

734. SCE reported ERP cost overruns of $94.7 million: $45.1 million in 2009 which SCE recorded to rate base and $49.6 million in 2010 for which SCE seeks rate recovery on the grounds the projects is still cost-effective.

735. TURN requests the entire $94.7 million be disallowed because the expenditures were imprudent and unauthorized, and SCE's cost-effectiveness analysis is faulty.

736. SCE's cost-effectiveness analysis for the ERP cost overruns is faulty, and SCE did not prudently manage the project or disclose potential large overruns during the 2009 GRC.

737. SCE requests $2.891 million for SAP Data Archiving in 2011-2012: $2 million in 2011 and $0.891 million in 2012.

738. SCE's forecast is based on deployment costs for earlier SAP projects and does not reflect cost efficiencies achievable due to SCE's substantial experience with data storage and SAP systems.

739. For Business Analytics Improvement, SCE requests $3.391 million in 2011 and $2.292 million in 2012 to implement SAP Business Objects Suite of Tools to improve analysis of ERP data.

740. SCE did not support its estimate that the amount of data stored in Business Warehouse will triple over the next five years, or that the project is necessary for sale and reliable electrical service.

741. For IT security projects, Technology and Risk Management (TRM), SCE provided 2011-2012 capital forecasts in three areas totaling $27.054 million: $11.454 million in 2011 and $15.6 million in 2012. SCE recorded $10.998 million in 2010, 43% less than its forecast of $19.28 million.

742. No party specifically disputed SCE's TRM forecasts.

743. IT&BI supports Common Enterprise Systems (CES), foundational systems developed for use throughout the enterprise.

744. For 2011-2012, SCE requests $13.136 million, $5.736 million in 2011 and $7.4 million in 2012, to focus on two service categories for users and developers of IT solutions. SCE recorded $7.416 million for this project in 2010, more than the $6.419 million forecast.

745. TURN requests the CES expenses be disallowed because SCE did not demonstrate tangible or quantifiable benefits to ratepayers.

746. SCE was previously authorized to implement CES and such foundational systems could produce benefits, but SCE did not explain how it prioritized the projects or whether it attempted to minimize costs.

747. For 2010-2012, SCE requests $26.278 million ($1.8 million in 2010, $10.620 million in 2011, and $13.858 million in 2012) for identified NERC/CIP compliance projects, including replacing technology infrastructure and

hardware, expand repository capabilities, and implement cyber security capabilities. SCE recorded $4.812 million in 2010.

748. TURN raised several concerns about increasing IT project costs because: (1) most hardware and software have short service lives; (2) up to 90% of estimated costs are for in-house or contract labor; (3) SCE did not establish IT priorities; (4) contingency costs vary widely; (5) SCE did not appear to optimize experience and assets to minimize costs; (6) frequent costly upgrades are expected; and (7) SCE does not quantify claimed productivity benefits.

Section 8

749. SCE's combined Human Resources (HR) O&M forecasts for TY2012 total $775.2 million, of which approximately $560 million (72%) is for pensions and benefit program costs.

750. DRA and SCE jointly managed the design and scope of a Total Compensation Study, and jointly selected Hewitt to perform it, in order to measure SCE's compensation levels against market rates.

751. DRA later disavowed some aspects of the TCS and asks for authority to use an alternative in the next GRC.

752. Joint Parties ask the Commission to reject the TCS as to executive compensation because of an appearance of conflict of interest arising from Hewitt's receipt of other contracts from SCE.

753. SCE demonstrated a business case for diversity in its workforce and over twenty years (1990-2009) SCE has increased representation of women and minorities in executive and management positions.

754. For TY2012, SCE forecasts $28.384 million ($22.846 million Labor, $5.538 million Non-labor) for Salaries and Related Expenses for HR departmental staff.

755. The increase to HR departmental staff is to add seven additional staff, at a cost of $741,600, to provide HR support at SONGS for workforce reductions, safety compliance programs, and other activities.

756. No party contests SCE's forecasts for HR Departmental Outside Services recorded in Account 923 ($2.742 million) or Employee Pensions and Benefits recorded in Account 926 ($6.813 million).

757. SCE forecasts a total of $19.548 million in total Executive Officer cash compensation, expenses, outside services, cash incentives, and a small component for other executive support.

758. For costs recorded in FERC 920/921, SCE's TY2012 forecast is $18.260 million ($15.516 Labor, $2.744 million Non-labor) for executive officers' cash compensation and expenses, including costs for the Executive Incentive Compensation Plan (EIC).

759. DRA and TURN agree that the majority of EIC goals are based on financial performance and request rate recovery be limited to 40%-50% of SCE's request.

760. No party contested SCE's forecast of $1.288 million for Executive Outside Services recorded in FERC 923.

761. For TY2012, SCE forecasts $19.805 million for executive long term incentives (LTIs).

762. The Commission has previously denied rate recovery for LTI costs because they are closely tied to stock performance of the parent company, and other non-utility activities.

763. For HR Capitalized Software expenditures, SCE requests $3.086 million in 2010 for the Worker Provisioning Process Enhancement Project but only recorded $1.755 million.

764. SCE forecasts $146.795 million for TY2012 short-term cash incentive (STI) programs for its employees: Results Sharing for 90% of employees, Management Incentive Program for a small group of senior managers (9%), and the EIC costs discusses above.

765. SCE records STI costs in a one-way balancing account which it seeks to eliminate in this GRC based on redesign of the programs.

766. DRA requests no funding or a 60% reduction to rate recovery for all three STI programs based on excessive growth in this discretionary spending and award criteria which support shareholder interests.

767. For TY2012, SCE provides inconsistent and unsupported testimony about the amounts forecast for Spot Bonuses and ACE program costs, and such costs have not previously been authorized for rate recovery.

768. For TY2012, SCE's forecast is $560.2 million ($nominal) for all employee pension and benefit plans and programs included in the rate request, a $147.3 million (35.7%) increase over 2009.

769. SCE provides 100% of the contributions to its employees' pension plan and requests full rate recovery for these expenses.

770. For TY2012, SCE forecasts $168.4 million in Pension costs, 81% higher than 2009 recorded costs.

771. SCE lacks incentive to pursue cost controls or alternate retirement benefits when ratepayers will fund 100% of its pension expenses.

772. DRA requests a reduction to $52.947 million, the equivalent of 2009 authorized expenses, because SCE the plan is currently fully funded and earned a higher rate of return in 2009 and 2010 than assumed when SCE developed its forecast.

773. Because SCE's original forecast is so close to the revised forecast based on updated actuarial evaluation and an assumed market return of 8.5%, TURN accepts SCE's pension forecast.

774. DRA asks that the existing two-way balancing account for Pension costs be converted into a one-way balancing account, and to add a 25% cost-sharing mechanism for shareholders, applicable to contributions in excess of the authorized amounts.

775. For TY2012, SCE forecasts a total of $53.378 million for Post-Retirement Benefits Other than Pensions (PBOPs) costs and recommends continuation of the two-way balancing account.

776. DRA estimates $50.99 million for PBOPs, a $2.64 million (4.9%) reduction to exclude the portion of SCE's forecast attributable to funding for new FTEs in this rate cycle.

777. For Other Benefits, SCE's revised its TY2012 forecast for 401(k) Savings Plan costs to $87.477 million ($nominal), an $18.3 million (26%) increase over 2009.

778. SCE matches up to 6% of an employee's deferred base pay annually, and developed its forecasts based on a "projection factor" of 2009 plan costs divided by 2009 total labor dollars, adjusted for labor inflation.

779. DRA requests $29.731 million for 401(k) costs, utilizing a lower national contribution rate, SCE's 2009 labor costs, and DRA's own labor escalation rates.

780. TURN requests a $5.219 million reduction to $82.959 million, based on a 5YA of contributions (6.54%) as a percentage of SCE's labor costs, and application of SCE's labor escalation rates.

781. In 2009, the Commission established a two-way balancing account for medical costs, including dental and vision expenses.

782. SCE's 2009 recorded costs in the Medical Program Balancing Account (MPBA) were $108.7 million.

783. For TY2012, SCE's revised forecast for medical program costs is $165.936 million ($nominal) utilizing a 10% escalation for medical plan costs.

784. DRA and TURN rely on Global Insight's lower medical escalation rates of 4.9% in 2010 and 4.2% -4.4% in 2011 and 2012 to calculate $116.5 million and $143.57 million, respectively, for TY2012.

785. Forecasts of medical cost escalation rates vary widely and are speculative in this period of transition to the federal Affordable Care Act.

786. No party contested SCE's TY2012, SCE forecasts of $20.9 million ($nominal) for Dental plan costs and $4.14 million for Vision plan costs.

787. For TY2012, SCE forecasts a total of $31.424 million ($nominal) for Disability programs, using LRY as a baseline to derive the projected number of eligible employees which SCE multiplies by the projected per employee cost, increased by 1% annually to account for legislative and regulatory changes.

788. Because 2009 included unusual claim activity, DRA's forecast of $22.234 million is based on a 5YA of recorded costs and SCE's escalation rate, and TURN instead calculates the 5YA cost per employee and escalates for labor and regulatory impact it to reach $29.668 million.

789. For TY2012, SCE's forecast is $1.85 million for the Group Life Insurance plan costs, more than twice 2009 recorded costs, based on a projected number of eligible employees multiplied by the projected average per employee cost, including a 60% escalation rate in 2010 due to a significant increase in the SCE-provided basic benefits in case of injury or death.

790. SCE did not demonstrate that the expanded insurance benefits are necessary for the delivery of safe and reliable service and DRA calls for disallowance of the 60% escalation rate for 2010.

791. For TY2012, SCE forecasts a total of $9.86 million ($2009) for Miscellaneous Benefit programs, a 25% increase from 2009, but provides no breakdown by cost center.

792. SCE did not establish that that the preventive health and work/life program benefits are not duplicative of other funded medical programs, or necessary to operate the utility, or provide a clear and identifiable ratepayer benefit.

793. For TY2012, SCE forecasts a total of $16.814 million for the Executive Benefits program which includes the Supplemental Executive Retirement Plan and a supplemental disability benefits plan.

794. The Commission has previously allowed rate recovery for 50% of SCE's forecast costs for the Executive Benefits program.

795. SCE did not demonstrate that the Executive Benefits program is essential to recruit executives when many companies do not offer these benefits, which are linked to financial performance incentives.

796. DRA recommends zero funding for these enhanced benefit programs for a select group of about 222 current and former executives.

<u>Section 9</u>

797. SCE's TY2012 forecast for A&G expenses is $309.516 million which represents O&M and capital expenditures not separately presented in individual business units.

798. SCE requests $19.157 for 2010-2012 capital expenditures related to IFRS, Electronic Discovery, and the Enterprise Compliance Management System.

799. DRA recommends a $76.897 reduction to total O&M for the A&G unit, based on a 5YA forecast method.

800. For the Controller, SCE's TY2012 forecast is $51.76 million recorded in three FERC Accounts: 920/921, 923 (Outside Services), and 926 (Benefits Accounting). No party contests SCE's forecast for Benefits Accounting.

801. For Accounts 920/921, DRA's forecast is $18.571 million, $978,000 less than SCE's forecast, based on a 5YA forecast method.

802. For Account 923 Outside Services, SCE's forecast is $31.783 million for services to remain in compliance with tax law, avoid penalties and interest, and sustain tax deductions.

803. DRA requests a $15.525 million reduction to Outside Services for tax consulting costs which it views as primarily affecting post-GRC taxation and benefitting shareholders.

804. SCE did not adequately explain the trend of substantial increases in Outside Services when many tax matters for ratemaking are routine and SCE has its own professionals.

805. SCE requests $2.9 million in 2012 to begin a $14 million capitalized software project to comply with IFRS which SCE expects to be adopted for U.S. corporations by 2015 or 2016.

806. SCE's capital forecast is based on a third party survey of similar-sized companies yielding estimates of conversion costs as a factor of annual revenue.

807. SCE did not establish either the necessity of implementing the project in this rate cycle or the basis for the cost estimate which includes a 50% factor for "technology costs."

808. SCE forecasts $10.72 million for Audit Services recorded in Accounts 920/921 to fill five vacancies and hire two FTEs as IT auditors due to increased

work from SmartConnect, NERC/CIP, energy trading, and new environmental regulations.

809. DRA used a 5YA to calculate labor and non-labor costs for Audit Services and arrived at a forecast of $9.033 million.

810. SCE described some of the anticipated work of the additional FTEs, including new activities that could increase the audit burden, but SCE did not contrast the workload with that managed by existing staff so as to justify a need for seven FTEs.

811. SCE's TY2012 forecasts total $13.667 million for the Treasurer in Accounts 920/921 and 930, primarily related to higher banking and financing fees.

812. For Accounts 920/921, SCE forecasts $5.475 million based on LRY and an increase of $517,000 to fill two vacancies and add three FTEs to support the capital investment program.

813. DRA forecasts $4.494 million for Accounts 920/921, the 5YA and no funding for the five positions.

814. SCE did not support the five positions with an explanation how SCE calculated the workload to labor request.

815. For Treasurer's costs recorded in Account 930, SCE forecasts $7.852 million which includes bank service operating fees, credit line fees, and bond-related fees.

816. SCE established it will need to renew credit lines in 2012 to support SCE's capital investment program but did not explain how it calculated its estimated fees.

817. For Treasurer's Account 930, the 5YA of recorded expenses is $4.924 million.

818. SCE's Tax Department requests $3.932 million for TY2012 expenses recorded in Accounts 920/921 based on LRY, filling two vacancies, and adding two FTEs to support compliance with new IRS and state tax laws.

819. DRA recommends $2.942 million for Tax Department expenses recorded in Accounts 920/921, the 5YA of labor and non-labor costs.

820. SCE provided support for use of LRY to forecast Tax Department expenses and some description of expected increased workload, but not why it needs four FTEs.

821. SCE forecasts a TY2012 total of $6.055 million for Risk Control expenses recorded in Accounts 920/921 based on LRY plus the cost of six positions to handle increased complexity of compliance with regulatory requests and oversight of procurement.

822. SCE did not explain why existing Risk Control staff cannot handle the estimated workload after SCE added 15 positions disallowed in the 2009 GRC.

823. No party contests SCE's forecast of $654,000 for Risk Control expenses recorded in Account 923 for outside consultants on emerging energy issues.

824. SCE's forecasts for all Law Department O&M is $46.055 million and $4.882 million for a capitalized software project, a total of $50.946 million for TY2012 recorded in Accounts 920/921, 923, 928, 930. DRA recommends a total reduction of $8.116 million for Law and Corporate Governance.

825. For In-House Legal Resources recorded in Accounts 920/921, SCE's total forecast is $29.186 million, including $1.716 million in labor for nine additional attorneys and six support staff to address new legal requirements related to renewable transmission, expanded regulatory compliance, and more litigation.

826. SCE provides some support for additional positions but lacks quantitative explanations to justify all 15 positions when the decision reduces TDBU capital

spending, finds SCE's forecast of intergeneration requests excessive, and accepts SCE's identification of many capital projects as exempt from regulatory review.

827. SCE records Outside Counsel expenses related to regulatory matters in Account 928 and all other Outside Counsel expenses in Account 923.

828. SCE forecasts a TY2012 total of $13.039 million for Outside Counsel costs: $11.128 million for Account 923 based on LRY and $1.911 million for Account 928 based on a 4YA.

829. DRA requests that $4.492 million be disallowed from the total based on several reductions and its view that ratepayers do not receive incremental benefits from costs related to various litigation matters and fee arrangements.

830. SCE's payment of discretionary "bonuses" to outside firms retained on a long-term basis who discount their fees compared to market and meet performance incentives may be an ordinary business expense.

831. SCE includes in its Outside Counsel recorded costs, and the 2012 forecast, litigation costs related to ten employment and discrimination cases settled in 2006-2009 and asks the Commission to change its policy of following FERC Accounting Release-12 (AR-12) for settlements and prevents ratepayer recovery of costs.

832. The AR-12 policy benefits ratepayers because the risks of a potentially adverse verdict drive settlement and unchecked ratepayer recovery could result in a loss of SCE's vigilance in preventing discriminatory practices.

833. SCE provided evidence that one of the ten cases did not involve employment discrimination.

834. Forty percent of the costs of SCE's Washington D.C. office relate to renewable power projects and benefit ratepayers.

835. Corporate Governance and Miscellaneous Expenses (CG&ME) recorded in Accounts 920/921 and 930 support the SCE and EIX boards of directors including compliance with corporate and securities laws.

836. No party contests SCE's TY2012 forecast of $704,000 for accounts 920/921 based on LRY.

837. SCE's TY2012 request for CG&ME recorded in Account 930 is $3.126 million, based on LRY, and includes fees and expenses paid to members of SCE's board of directors and other associated corporate costs.

838. TURN withdrew its request for an audit of allocation credits after review of additional information from SCE.

839. SCE relies on an external analysis by a compensation consultant for the EIX board in 2009 and 2010 to conclude that the non-employee directors' compensation is reasonable and an ordinary cost of doing business.

840. DRA's TY2012 forecast of $2.497 million for Account 930 excludes ratepayer funding of supplemental benefits and stock based compensation for directors.

841. Whether an expense is a part of SCE's business model is a separate question from whether SCE establishes that costs are necessary for the delivery of safe electric service.

842. SCE proposes total of $4.882 million in 2010-2012 capital expenditures for the Electronic Discovery project, a new automated in-house solution to improve compliance, accuracy, and efficiency for electronic discovery requests.

843. SCE's Electronic Discovery requests are $58,000 in 2010, $1.584 million in 2011, and $3.240 million in 2012, based on a vendor estimate.

844. SCE forecasts a TY2012 total of $50.289 million for Claims-related activities covering Accounts 920/921, 924, and 925.

845. No party contests SCE's forecasts of $3.153 million for Accounts 920/921 921 for salaries and expenses of Claims personnel and $127,000 for Account 924 for property insurance activities.

846. For Account 925, SCE's total forecast of $47 million, is comprised of $4.459 million for legal services and litigation costs related to injuries and damages claims, and $42.550 million for the Claims Reserve.

847. SCE's Claims reserve forecast reflects the results of its "backcast" of current insurance to historical claims and includes expected increases in fire litigation, but does not reflect allowable rate recovery, if any.

848. DRA proposes reductions to the Claims Reserve forecast based on exclusion of certain litigation cost as either non-recurring or not subject to rate recovery or, in the alternative, a forecast based on 2009 recorded expenses of $34.882 million, subject to reductions for the Happy Camp fire and Navajo Nation Realty litigation.

849. If ratepayers fund 100% of uncovered wildfire claims in the Claims Reserve, then SCE's lacks incentive to maintain or improve the safety of its operations.

850. SCE's total TY2012 forecast of $22.282 million covers Workers' Compensation expenses for staff of $7.183 million ($4.128 million Labor and $3.055 million Non-labor) and $15.099 million for reserves, all recorded in Account 925.

851. SCE's labor forecast includes an incremental increase over 2009 of $578,000 to fund five claims representatives and three support staff to handle increased complexity and volume of work.

852. DRA and TURN request labor cost reductions based on decreasing or eliminating SCE's proposed staff increases in part due to SCE's use of an atypical month to estimate employee workload.

853. TURN's forecast of $6.836 million for Account 925 is based on annual claims data and actual industry caseload standards.

854. SCE's Worker's Compensation Claims Reserve forecast for Account 925 is $15.099 million, a 9.8% increase over 2009 despite a five-year downward trend in expenses.

855. SCE used a 3YA in order to exclude regulatory changes that drove high Workers Compensation Claims costs in 2005, and estimates of higher costs going forward due to pending litigation.

856. TURN supports DRA's forecast of $13.747 million for Workers Compensation Claims based on LRY due to recent changes in the law which are lowering costs.

857. SCE forecasts a TY2012 total of $3.1 million for Ethics and Compliance (E&C) in Accounts 920/921 and 923 based on LRY plus incremental costs.

858. For Accounts 920/921, SCE forecasts $2.348 million, a 53% increase over 2009 expenses, including an $816,000 increase to fill two vacancies and add five new positions, bringing the E&C total to 18.

859. The E&C department has limited compliance responsibilities, largely related to HR and conflicts of interest, some health and safety matters, and Sarbanes-Oxley (SOX) reporting.

860. SCE did not adequately support its request for seven additional staff.

861. DRA's E&C forecast is zero because it views the activities as primarily benefitting shareholders or, in the alternative, 2009 recorded costs of $1.532 million.

862. SCE's forecast for E&C Outside Services recorded in Account 923 is $772,000 based on LRY.

863. SCE requests $11.375 million in 2012 capital spending to launch the Enterprise Compliance Management System (CMS), estimated to be completed in 2013 for a total cost of $16.5 million, based on vendor estimates and some productivity benefits.

864. SCE presents the CMS as an integrated compliance management system to provide a standard system that improves compliance across the company.

865. SCE established that CMS is not duplicative of the more limited Corporate Environmental Health and Safety system.

866. SCE forecasts a TY2012 total of $15.446 million for Regulatory Policy and Affairs (RP&A) expenses recorded in Accounts 920/92 based on LRY and an incremental increase for 16 new positions to address a continuing increase in regulatory workload.

867. DRA forecasts $12.223 million for RP&A, a 5YA of recorded costs, reduced for historic Spot Bonuses, ACE awards, and Affiliated Transaction Rule (ATR) compliance costs ($815,000), and no increases for additional staff.

868. In prior GRCs, the Commission has disallowed rate recovery of ATR costs because they support the operations of SCE's affiliates which ratepayers should not subsidize.

869. SCE's revised TY2012 forecast for Corporate Membership Dues and Fees recorded in Account 930.200 is $1.586 million for membership fees for Edison Electric Institute (EEI) and industry research and economic development groups.

870. TURN's forecast of $1.284 million excludes funds for Corporate Membership Dues and Fees it views as supporting lobbying, advertising, public relations costs excluded from ratepayer recovery.

871. SCE forecasts a TY2012 total of $16.582 million for Corporate Communications Accounts 920/921, 923, 930, an incremental increase of $3.976 million to fill nine vacancies in Internal Communications and add nineteen new positions for customer education on new technologies.

872. For Accounts 920/921, SCE did not explain why it has not utilized prior authorized staffing increases or how it calculated 19 new positions as necessary.

873. DRA's and TURN's forecasts remove some or all of the incremental increases, including $452,000 for PEV Readiness.

874. For Outside Services recorded in Account 923, SCE's TY2012 forecast of $905,000, a 66% increase over 2009, is based on a 2YA, plus $342,000 to support PEV readiness and ethnic media activities.

875. SCE does not explain how it arrives at its incremental costs for future substantial growth and does not distinguish how these PEV expenses are distinguishable from other authorized PEV outreach funds.

876. SCE's revised forecast for Communications Products in Account 930 is $1.146 million for TY2012 based on LRY, plus an increase of $259,000 for expected cost increases related to bill inserts and public safety programs.

877. Preparation of bill inserts and customer newsletters are routine activities and there should be embedded costs.

878. TURN agrees to LRY as a base forecast and removes all increments except $93,000 for customer safety education.

879. SCE forecasts a total of $68 million for Property and Liability Insurance expenses recorded in Accounts 924 and 925, respectively, based on expected test year premiums estimated by SCE' primary insurance broker.

880. For Property Insurance, SCE's forecast is $15.417 million reflects SCE's loss history, SCE property values, and overall market conditions.

881. SCE forecasts a total of $15.417 million for TY2012 Property Insurance expenses based on more assets and higher costs for nuclear property insurance arising from a complex industry methodology.

882. For Liability Insurance expenses, SCE forecasts $52.582 million, an increase of $39.355 million over 2009 recorded due to the estimated costs of additional supplemental wildfire coverage.

883. DRA's forecast of $28.366 million for Liability Insurance expenses, the equivalent of 2010 recorded expenses, does not address escalation of existing premiums or supplemental wildfire insurance costs.

Section 10

884. For the Power Procurement Business Unit (PPBU), SCE's budget-based forecast for TY2012 O&M expenses is $59.3 million, including addition of 94 employees.

885. SCE supports the staffing increase as necessary to address new regulatory and legislative initiatives, including MRTU, increases in renewable and Combined Heat and Power (CHP) procurement, GHG, one-through-cooling (OTC), and integrated resource planning.

886. For 2010-2012, SCE forecasts $73.4 million in PPBU capital expenditures.

887. TURN requests reductions to SCE's capital forecast, including a 10% reduction to authorized capitalized software projects.

888. DRA seeks reductions to SCE's O&M and capital forecasts, and requests that MRTU-related capital, labor, and non-labor expenses of $26.05 million not be allowed and instead be recorded in MRTUMA.

889. SCE is authorized to record in the MRTUMA, expenses related to integrating SCE's PPBU functions with the new CAISO MRTU process.

890. SCE's PPBU workload will increase during the rate cycle due to additional legislative and regulatory requirements related to power procurement activities, programs such as RPS and CHP, and other large solicitations.

891. PPBU has four departments: Market Strategy and Resource Planning (MS&RP), Energy Supply and Management (ES&M), Renewable and Alternative Power (RAP), and Power Procurement Finance (PPF).

892. For MS&RP, SCE forecasts $5.385 million for TY2012 O&M expenses recorded in Account 557covering four work groups to provide forecast information, market modeling, cost-effectiveness assessments, strategic planning, and project support for regulatory proceedings involving market rules.

893. SCE's $1.499 million labor increase is to fund 15 new positions and associated costs and fees for regulatory filing consultants comprise the non-labor increase.

894. SCE seeks three FTEs in Resource Planning, five in Market Design and Analysis (MD&A), four in Strategic Projects, and three in Resource Policy and Economics (RP&E).

895. DRA's TY2012 forecast for MS&RP is $3.964 million based on authorizing two new staff positions, one in Strategic Projects and one in RP&E.

896. DRA identifies three new positions in MD&A as MRTU-related and proposes to defer $$533,000 in labor/non-labor costs to be instead recorded in the MRTUMA.

897. Some MD&A staff were involved in MRTU development, but SCE's job descriptions for the positions include providing additional market analysis and simulations, and market design and enhancement work due to RPS, GHG, and OTC.

898. For MS&RP, SCE established the need to add eight new positions: three in RPG, two in MD&A, two in Strategic Planning, and one in RP&E.

899. For ES&M, SCE forecasts $29.556 million for TY2012 O&M expenses recorded in Account 557covering seven divisions, to provide functions associated with the purchase and sale of conventional (non-renewable) capacity, electricity, natural gas and related energy products and services.

900. SCE's $5.861 million labor increase is to fill 18 vacancies and 26 new positions; in addition to associated costs, the non-labor forecast includes $3.5 million for CARB fees and $1.306 million for consulting services.

901. SCE's forecast labor increase for ES&M of $5.861 million is based on an average labor expense per employee of $119,609, or the equivalent of 49 positions.

902. DRA's forecast is $26.437 million based on filling the 18 vacancies in ES&M, plus three new positions: one in Energy Planning and two in Demand Forecasting to achieve sufficient staffing for the rate cycle.

903. The Bidding Strategy & Asset Optimization (BS&AO) division develops bidding strategies to improve SCE's results in an increasingly complex market with new products and new bidding processes.

904. DRA did not establish that the proposed eight positions in BS&AO would undertake MRTU implementation activities.

905. SCE supported 35 positions for ES&M based on increasing workload including implementation of CAISO's MAP initiatives, more renewable resource integration into the planning and operations processes, utilization of real-time demand data, and the emergence of new markets and products like GHG and RECs.

906. For TY2012, SCE's forecast for Renewable and Alternative Power (RAP) department O&M expenses is $6.665 million, a 41% increase from 2009 to address expected higher numbers of new contracts and the continued expansion and complexity of renewable programs during the rate cycle.

907. SCE's estimated labor increase of $1.672 million is to fund 17 positions across several divisions.

908. DRA's forecast of $5.106 million reflects addition of two new positions which DRA finds sufficient for RAP to manage its workload.

909. SCE's support for the 17 new positions in ES&M is general and lacks details of how SCE determined the forecast workload, how it quantified the expected workload into 17 new employees and why it needs more managers than analysts.

910. For TY2012, SCE forecasts total expenses of $17.724 million for the Power Procurement Finance (PPF) department, a 21 % increase over 2009 to address workload increases from regulatory and legislative initiatives that SCE expects to cause market, contract, and compliance changes requiring PPF to modify how it settles and accounts new transactions.

911. SCE's estimated labor increase of $1.699 million is to add 18 new positions: nine in BP&TI, four in Accounting and Reporting, three in Settlements, and two in People Initiatives; the forecast $1.4 million increase for non-labor is mostly for capital projects.

912. DRA's forecast of $16.11 million includes a reduction of $1.114 million, representing 10 positions, because the positions relate to RPS and CHP contracts, MRTU implementation, and/or were vacant at the end of 2010.

913. DRA did not establish that any of the positions in the Settlements group or BP&TI involve implementation of MRTU.

914. SCE did not establish the necessity of adding 18 new positions to PPF through generalized descriptions of existing tasks and anticipated changes, which overlooked the significant staffing increases between 2006 and 2010 and did not explain how SCE quantified the request into 18 positions.

915. For 2010-2012 capital expenditures, SCE estimates $73.35 million for capital spending for ten PPBU projects.

916. TURN requests a $17.87 million reduction to SCE's forecast based on removal of three software projects related to DR and a 10% decrease to remaining capitalized software expenses for cost inflation.

917. DRA's capital forecast excludes two software projects and supports recording the $24.1 million expense in the MRTUMA.

918. No party contested SCE's 2010-2012 $6.5 million ($1.5 million in 2010, and $2.5 million in both 2011 and 2012) request for the Communications Equipment project to install specialized equipment on every renewable resource.

919. SCE did not provide a source for its cost information for either the $150,000 equipment cost or "associated costs" of $100,000 per facility.

920. SCE requests funding for nine capitalized software projects to provide the capacity to respond to changing market and regulatory requirements.

921. SCE requests $36.85 million for four Post-MRTU Energy Market Operations software projects based on its "high level" cost estimation methodology.

922. SCE requests $14.4 million in 2010 and $2.0 million in 2011 for the CAISO Market enhancement project which continues the fine-tuning of the MRTU to new markets.

923. SCE forecasts $7.7 million in 2012 for the Future Market and Performance Enhancements project which continues the MRTU Releases 1 and 2 build-up of resources and load management tools.

924. For 2010-2012, SCE requests $2.75 million ($500,000 in 2010 and 2011, $1.75 million in 2012) to develop Short, Mid, and Long-Term Modeling tools to assist with management of wholesale energy costs.

925. TURN did not establish that the Short, Mid, and Long Term Market Simulation Tools project is related to EE and/or DR programs or proceedings.

926. SCE forecast $10 million ($500,000 in 2010, $4.5 million in 2011 and $5 million in 2012) for phase 3 and 4 of the Data Management Platform Upgrade to simplify interfaces between CAISO and SCE, expand data content to support evolving requirements, and improve retention and archiving.

927. SCE's support for Phase 4 of the Data Management Platform Upgrade includes costs for unknown potential requirements, and SCE bases the forecast on a generic comparable project template with grossly rounded labor costs.

928. SCE requests funding for two Demand Response (DR) projects in response to the Commission's mandate to integrate DR into the CAISO markets: Aggregated Demand Response (ADR) and Rsik Management ADR.

929. TURN requests the Commission disallow funding for both DR projects because costs have not been factored into the DR program costs analysis.

930. For the ADR project, SCE requests $9.0 million between 2010 and 2012 to integrate DR programs with CAISO systems.

931. To launch the Risk Management ADR project, SCE requests $750,000 in 2012 to develop a tool to analyze customer response to DR price signals.

932. SCE forecasts $1.3 million in capital spending in 2012 to begin the $8.3 million Energy Procurement Management Project (EPPM) project which

includes tools to perform analysis of procurement transactions and near-term financial exposures and risks.

933. SCE requests $4.55 million in 2010-2011 for the Energy Planning Platform Management (EPPM)to create a single data repository to add a range of scenario modeling and support SCE's competitive solicitations for power and gas.

934. SCE proposes the Commodity Management Platform (CMP), an integrated technology platform, to manage all energy related transactions.

935. SCE requests a total of $14.4 million to implement the Commodity Management Platform (CMP) in two phases, concluding in 2012.

936. SCE established a need to replace the older CMP system to accommodate new energy markets through automated trade and payment processes to reduce systemic and operational risk and costs.

Section 11

937. For Operations Support Business Unit (OSBU), SCE forecasts TY2012 O&M expenses of $111.925 million in six categories, excluding Transportation.

938. SCE's OSBU capital and O&M forecasts are excessive.

939. For O&M, SCE's uses a budget-based forecast method, assumes that the O&M and capital expenditure forecasts made by SCE in this GRC are adopted, and supports requests for additional staffing with general statements of intended activities instead of an analysis of workload and person hours required.

940. For 2010-2012, SCE forecasts OSBU capital expenditures of $632.205 million over 10 capital expenditure categories.

941. SCE's capital forecasts do not consider economies of scale, available labor or other embedded costs from closed projects.

942. SCE forecasts TY2012 O&M of $12.355 million for the Corporate Environment Health & Safety (CEH&S) division across Accounts 920/921, 923, and 925, a 53% increase over 2009 recorded costs.

943. For CEHS O&M recorded in Accounts 920/921, SCE's forecast is $7.28 million, including 14 new positions, to address air quality activities, regulatory compliance, and additional TDBU capital projects.

944. SCE's non-labor forecast includes $500,000 for an environmental study disputed by DRA as duplicative and unnecessary.

945. For CEH&S Outside Services expenses recorded in Account 923, SCE forecasts $1.503 million, an increase of more than $1 million, to support routine, ongoing activities.

946. For CEH&S Corporate Safety costs recorded in Account 925, SCE forecast $3.572 million, a 30% increase over 2009, to add five new employees to restructure the Corporate Safety group and to expand the Safety Culture program.

947. SCE did not demonstrate how its Safety Culture initiatives are distinguishable and complementary to other currently funded safety programs at SCE.

948. SCE's Corporate Resources expects a substantial increase in headcount during the rate cycle and plans to add one million sq. ft. of office space to accommodate them.

949. SCE forecasts TY2012 O&M of $55.512 million for Corporate Resources across Accounts 920/921, 931, and 935, a 24%increase over 2009, to address an expected increase in headcount and office space. No party contests the $7.838 million forecast for Account 935.

950. For O&M recorded in Accounts 920/921, SCE's forecast is $7.28 million, including funding for 22 FTEs already hired and 10 more in 2012 for Facility Asset Management and Business Resources. SCE's non-labor forecast included costs for 5,000 annual employee moves.

951. SCE's TY2012 forecast is $15.814 million, a 50% increase over 2009, for rental and lease costs of property and buildings that SCE uses, occupies, or operates recorded in Account 931.

952. SCE forecasts a total of $22.167 million for Corporate Security in Accounts 920/921 and 923. No party contests the $94,000 forecast for Account 923.

953. For expenses recorded in Accounts 920/921, SCE forecast $22.073 million, a $10.1 million (84.4%) increase over 2009, to address employee growth, Emergency Preparedness, more complex regulatory mandates, and support for capital projects.

954. The $4.485 million increase to SCE's labor costs is to add 45 employees across nine divisions of Corporate Security, 14 to work on the expected new version of NEDRC/CIP standards.

955. DRA's forecast of $11.97 million, 2009 recorded costs, disallows funding for NERC/CIP activities because DRA assumes there are embedded costs from prior versions, no new version has been adopted, and SCE overstates employee growth.

956. Corporate security is an important function, but SCE asks to double its Corporate Security staff without a workload analysis or providing support for some positions and requested funding.

957. SCE forecasts TY2012 total O&M of $11.918 million for Operations Support Services, the equivalent of 2009 recorded expenses for Accounts 920/921.

958. DRA's forecast used 2008 recorded costs due to unresolved concerns that 2009 expenses included double counted costs.

959. No party contests SCE's forecast of $6.2 million for total Real Properties TY2012 O&M expenses, including a $702,000 labor increase to add 37 employees, 25 for the land Acquisition group based on estimated capital projects.

960. SCE provided insufficient support for the addition of 37 new FTEs.

961. No party contested SCE forecasts a total of $3.3 million for the Supplier Diversity and Development (SDD) organization to manage procurement of materials and services within the Supply Management division.

962. For Accounts 920/921, SCE's incremental labor increase of $1.82 million (123%) over 2009 costs, is to add 10 new FTEs to lead development and implementation of new programs, including (1) Supplier University; (2) DBE Supplier Registration Portal; (3) Supplier Training Program; and (4) Procurement Spend Planning and Forecasting funded by the incremental non-labor increase of $747,000.

963. SCE also forecasts $473,000 in Outside Services recorded in Account 923 to support the Supplier Clearinghouse.

964. DRA's forecast is $1.955, a 5YA, based on SCE's compliance with GO 156.

965. Joint Parties and SCE have differing views on the nature of SCE's record on supplier diversity, although Joint Parties took no position on SCE's forecast SDD budget.

966. The Commission has previously considered proposals similar to those made by SCE in this proceeding, including directing SCE to allocate $10 million over five years to develop a Technical Assistance program.

967. For the Transportation Services Division (TSD), SCE forecasts TY2012 O&M chargeback costs of $138.4 million, a 20% increase over 2009, primarily due to rising fleet ownership costs and fuel costs.

968. SCE's increase will support addition of 29.5 positions, including 17 in Fleet Maintenance to manage a larger vehicle inventory.

969. DRA's forecast for Fleet Maintenance is $127.7 million based on 2010 recorded expenses.

970. SCE's vehicle additions are primarily driven by workload changes due to infrastructure replacement and growth.

971. For OSBU 2011-2012 capital expenditures, SCE forecast a total of $407.244 million: 204.748 million in 2011, and $202.496 million in 2012 covering ten capital project categories, each with several projects.

972. SCE accepts adoption of its 2010 recorded OSBU capital expenditures of $176.48 million, $28.268 million less than SCE's original 2010 forecast.

973. SCE's OSBU capital forecasts include an aggregate total of $7.884 million for a 10% contingency factor, and $6.55 million for aggregate project management costs which widely vary.

974. TURN's forecasts remove project management fees that widely vary, and apply a 3% management fee to the OSBU capital projects.

975. TURN also makes a $2.67 million reduction to SCE's estimated $7.773 million for 2012 capital furniture expenditures due to unexplained widely varying costs and different forecast methodologies.

976. For New Buildings, SCE requests $37 million in 2012, to begin construction of two buildings (Metro),acquire one building (Orange County), and General Office 2 Renovations (GO2).

977. There are inconsistencies in the record about the number of employees to be seated and the expanded capacity from each New Building project; forecast costs are very rough estimates and based on overstated need.

978. For Headquarters capital projects, SCE's 2010-2012 revised forecast of $117.084 million covering eight projects to remodel and renovate office buildings at SCE's Rosemead headquarters.

979. For Critical Facilities, SCE's 2011-2012 forecasts a total of $80.3 million to replace specialized electrical, heating/cooling, and mechanical infrastructure. SCE's 2010 recorded expenditures of $20 million are less than half of SCE's forecast $43 million.

980. No party contests the DPC Phase 4 AGOC Upgrades project.

981. SCE's data center replacement project will address overcrowding and critical load at the RDC by constructing the replacement ADC.

982. SCE forecasts $103 million to construct the building, buildout network infrastructure, and to migrate existing applications.

983. SCE forecasts $10 million in 2010 and 2011 to perform significant upgrades to the RDC to ensure reliability until the ADC is completed.

984. TURN opposes any funding for the Rosemead Data Center (RDC) and DRA opposes any funding for the Alhambra Data Center (ADC).

985. SCE did not apply or retain the $40 million authorized in the 2009 GRC for RDC life extension costs to the upgrades for which it seeks funding in this GRC.

986. For Field Facility Asset Preservation, SCE's 2011-2012 forecast is $35.065 million covering 14 projects to preserve, maintain, or enhance the value of SCE's field facilities. SCE's recorded 2010 capital spending is $10.705 million, less than SCE"s 2010 forecast of $26.828 million).

987. TURN's forecast includes removal of $2.358 million from three projects for contingency, management and furniture costs in 2012, and $8.9 million in 2011-2012 for the SmartConnect-Meter Reader Space Reclamation project to be recorded in the ESCBA.

988. For New Field Facilities, SCE's 2011-2012 capital forecast is $34.657 million. SCE's 2010 recorded capital expenditures are $15.902 million, less than $27.955 million SCE originally forecast.

989. SCE did not rebut TURN's reductions to the Gateway Parking structure project costs from $11.970 million to $7.133 million to cap costs at the industry standard of $52.60/sq. ft.

990. TURN also identified $397,000 in reductions to SCE's 2012 forecast related to contingency, management, and furniture costs for other projects.

991. For Blankets capital expenditures, SCE's 2010-2012 forecast is $115.886 million for ten project categories. SCE's 2010 recorded expenditures are $36.006 million, $8 million than SCE's forecast of $27.962 million.

992. DRA and TURN request disallowance of SCE's $10 million request in2012 for the Service Center Modernization project category because SCE spent only 3% of $48 million authorized in 2009.

993. SCE's Service Centers are important to reliability and ratepayer satisfaction and continue to incur effects of deferred maintenance.

994. SCE requests $5 million annually from 2010 to 2012 to implement energy efficiency (EE), sustainability, and conservation projects for its own non-electric buildings. Recorded expenditures for 2010 were about 43 million.

995. DRA requests a reduction to $2.5 million annually, and TURN supports $1 million annually limited to EE projects while asking that water conservation projects be funded through savings.

996. No party contested SCE's 2011-2012 forecast of $16.614 million for CEH&S capital projects which includes implementation of CMS. SCE recorded $13.729 million in 2010 expenditures.

997. For Corporate Security, SCE forecasts $27.2 million for 2011-2012 capital expenditures, including $24.2 million to initiate the Critical Infrastructure Protection Physical Security project (CIPPS).

998. SCE's CIPPS forecast is the result of multiplying a hypothetical installation cost of $288,500 per site by 120 locations SCE believes will fall within the scope of a Version 4 of NERC/CIP standards which could be adopted.

999. No party contested SCE's 2011-2012 capital forecast of $7.207 million for Transportation Services projects. SCE recorded $994,000 for 2010.

1000. SCE's 2011-2012 capital forecast of $25.877 million for Other Capital Projects, includes $10.6 million in 2012 to initiate the OnBoard Technology project.

1001. DRA and TURN request zero funding for the OnBoard Technology project because SCE did not spend $3 million authorized in 2009 for a similar monitoring system and neither justified a more elaborate system or quantified or applied any productivity savings.

<u>Sections 12-15</u>

1002. Revenue requirements are calculated by a computer model developed by SCE referred to as the Results of Operations (RO) model.

1003. SCE agreed with TURN to recalculate the fixed credit against total A&G expenses to be recovered from SCE's Catalina Island water and gas revenue requirements.

1004. SCE agrees to TURN's adjustments to TY2012 pension and benefit costs associated with labor assigned to shareholders in the GRC.

1005. SCE forecast 4,949,062 customers in 2012.

1006. SCE forecasts electricity sales of 85,222 Gigawatt hours (GWh) in 2012.

1007. In Update testimony, SCE updated its cost escalation data and provided labor, non-labor and capital labor escalation rates.

1008. DRA contested SCE's use of contract wage increases for represented employees as part of the updated labor escalation rates of 2.71% in 2011 and 2.61% in 2012.

1009. SCE forecasts $187.091 million in company-wide OOR recorded in Accounts 450 through 456 and subtracted from total operating costs to determine the Test Year revenue requirement.

Section 16

1010. SCE proposes a Post Test-Year Ratemaking mechanism (PTYR) that includes capital additions associated with its budget-based forecast of 2013 and 2014 capital expenditures totaling more than $4 billion each year.

1011. The existing annual November Advice Letter (AL) process provides a method of implementing the revenue requirement for years 2013 and 2014.

1012. SCE's PTYR would escalate O&M based on the GRC escalation rate methodology, updated at the time of the AL filing.

1013. DRA proposes a PTYR based on the Urban Consumer Price Index which would result in a 4.0% revenue increase for 2013 and 2.0% for 2014.

1014. DRA alternatively proposes that PTYR capital-related cost increases be determined by escalating adopted 2012 capital additions to develop 2013 and 2014 requirements.

1015. Aglet prefers the UCPI to SCE's PTYR based on simplicity and proposed a 1.9% escalation rate for 2013 and revision of the Z factor.

Sections 17-19

1016. SCE presented the results of its Total Factor Productivity (TFP) analyses as required by prior Commission decisions.

1017. No party contests SCE's request to eliminate the requirement that SCE submit a corporate productivity study with its GRC application.

1018. For 2010-2012, SCE requests $3.11 million for 15 capital expenditures for the Corporate Center.

1019. SCE forecast $713,000 for TY2012 Gains on Sale of Property.

1020. In April 2011, SCE updated its tax expense estimates to reflect the impact of the TRA on tax depreciation, deferred taxes, rate base, the Manufacturer's Deduction, and other resulting changes to revenue requirement.

1021. SCE's updated estimate of CPUC jurisdictional TY2012 tax expense totals $807.465 million ($nominal): $541.308 for taxes on income, $90.272 million for payroll and other taxes, and $175.884 million for property taxes.

1022. As a result of the accelerated depreciation element of the TRA, SCE estimates a $26 million reduction to 2012 revenue requirement and a total 2012-2014 reduction of $280 million.

1023. SCE requests to continue the Employee Stock Ownership Plan Tax Memorandum Account (ESOPTMA) established to track ESOP dividend deductions in case a pending 2005 IRS regulation restricting access to the deduction if it is adopted.

Section 20

1024. SCE forecasts a total 2012 reduction to rate base of $75.386 million based on the average balance of Customer Advances.

1025. SCE estimates an annual weighted average of $211.07 million in Customer Deposits for 2012, and asks for approval to place up to 10% of customer deposits into a community and minority bank program to earn returns comparable to the commercial paper rate.

1026. No party contests SCE's forecast for Mountainview Emission Credits as part of Working Capital.

1027. SCE's 2012 forecast average annual balance for Materials and Supplies (M&S) Inventory is $242.984 million which is driven by capital expenditures

1028. For Working Cash, SCE's updated 2012 forecast of $328.187 million reflects income tax changes provided in the TRA.

1029. The SP U-16 provides that Working Cash include both the lead lag and Operational Cash requirements.

1030. No party contests SCE's proposed adjustments to Operational Cash requirements to reflect SmartConnect reductions to rate base.

1031. Changes to utility hedging policy by the Commission are intended to result in lower Gas Option premiums.

1032. Reductions adopted to SCE's forecasts for Workers' Compensation/ Injuries and Damage Claims Reserves result in a corresponding increase to rate base.

1033. SCE 's determination of Working Cash includes a lead/lag analysis.

1034. For Revenue Lag, SCE's weighted average estimate is 41.5 days for 2012.

1035. SCE developed Expense Lag days for various costs, several of which are disputed by DRA and TURN.

1036. SCE and DRA utilized different historical averages to develop different lag day forecasts for tax payments.

1037. DRA and TURN contest SCE's use of July 13, a mid-point of expense recovery during the year, as the mid-year date for calculating expense lags for pensions and PBOP funding.

1038. TURN contests SCE's application of zero lag days to 401(k) contributions.

1039. SCE's requested revenue requirement includes the annual depreciation expense and authorized rate of return for SE's retired electromechanical Legacy Meters.

1040. Aglet, DRA, and TURN request that the legacy Meters be excluded from rate base as no longer "used and useful" and be subject to an accelerated six-year amortization.

1041. SCE included Four Corners-related items in development of its 2012 rate base assuming the power plant would remain in rate base for all of 2012.

1042. SCE requests to amortize the remaining capital investment at Mohave and the decommissioning costs over the current remaining life of 6.5 years, including earning rate of return.

<u>Section 21</u>

1043. A Gross Revenue Sharing Mechanism (GRSM) determines how much of the net OOR derived from Non-Tariffed Products and Services (NTP&S) is allocated to ratepayers, and includes a threshold of $16.671 million before revenues begin to flow to shareholders.

1044. SCE relies on its business units to identify incremental costs, which are unverified, errors have occurred, and the last external audit of NTP&S was in 2006.

1045. SCE has not established that the existing GRSM results in an accurate picture of benefits received.

<u>Section 22</u>

1046. SCE performed a depreciation study to support its request for a significant increase to depreciation expense in 2012 to $1.572 billion, of which $452 million is for Changes in Plant Balances.

1047. TURN disputes SCE's proposed mass property life calculations and joins DRA in opposing SCE's net salvage rates (NSR).

1048. SCE's support for its proposed average service lives (ASL) and life curves for mass property groups is limited and largely based on "judgment."

1049. TURN's proposed service lives were derived from industry statistics and a simulated model of life estimates.

1050. Negative net salvage results when the Cost of Removal (COR) exceeds the original cost of the asset.

1051. SCE supports its request to increase the NSR for 11 T&D accounts with historical data and "judgment."

1052. Both TURN and DRA contest SCE's proposed salvage values as excessive, and TURN developed alternative NSR for 10 T&D accounts based on industry averages and its own expert analysis.

Conclusions of Law

Section 2

1. The Commission and the public should be able to track the progress of previously authorized large capital projects through subsequent GRCs.

2. In its next GRC application, SCE should provide the Commission with tables which provide historical and forecast CPUC jurisdictional amounts by sub-categories for Generation and TDBU capital expenditures in excess of $1 million.

3. A reasonable forecasting methodology is related to the facts and circumstances of the proposed work activity at issue.

4. In its GRCs, SCE should establish that proposed capital projects are necessary and that SCE has prudently examined alternatives for cost-effectiveness before seeking Commission approval.

5. In its next GRC application, SCE should provide the Commission a clear explanation of the workload analysis used to develop estimated labor increases, and an explanation of why new employees must be hired during the test year.

6. In its next GRC application, SCE should provide the Commission with an estimate of unused distribution capacity for the test year, and address it in connection with SCE's forecast Load Growth during the rate cycle at issue.

7. In its next GRC application, SCE should provide the Commission a summary of its SONGS-Safety Culture programs, achievements, and three years of recorded expenses.

8. The O&M costs and capital expenditures adopted in this decision are reasonable.

Section 4

9. It is reasonable to adopt SCE's recorded, unadjusted 2010 generation capital expenditures as a reasonable reflection of ratepayer expense.

10. It is reasonable to authorize SCE to establish SONGSMA, effective January 1, 2012, to track 100% of O&M, 100% of cost savings from personnel reductions, 100% of capital expenditures, and 100% of maintenance and refueling outages, if any, and identify all safety-related costs.

11. SCE should file an application by January 30, 2013 for a reasonableness review of post-2011 SONGS-related expenses. The application should be consolidated with I.12-10-013 where the Commission will examine the costs for reasonableness consistent with a review of the extraordinary circumstances of the extended non-operation of the SONGS units in 2012.

12. It is reasonable to adopt a 100% allocation of the net savings to ratepayers from SONGS workforce reductions delayed since 2009.

13. SCE should report on the actions taken and total expenses incurred to address NRC concerns beginning in 2009, any shareholder costs, and identify whether the expenses are recurring in the next forecast for SONGS O&M.

14. It reasonable to continue the flexible outage schedule mechanism for the three-year (2012-2014) GRC cycle.

15. The evidence does not support that SCE's forecasts for RFO expenses associated with outages in 2012 are reasonable.

16. SCE's requested share of 2011 HPT expenditures is reasonable and adopted.

17. SCE's request for additional funding for the Service Air Piping project is not adopted because SCE did not demonstrate its diversion of prior funding was reasonable.

18. It is reasonable to reduce SCE's request for the Site Parking and Pedestrian Lighting project at the SONGS facility to reflect a 20% contingency factor, resulting in $1.014 million which is reasonable and adopted.

19. SCE's forecast for the Cafeteria Remodel project is reasonable and adopted.

20. Subject to refund, it is reasonable to allow SCE to recover, in the TY2012 revenue requirement, the following SONGS-related expenses: (1) SONGS O&M costs up to $270.5 million; and (2) 2012 capital expenditures up to $138.356 million. Identified savings associated with implementation of identified workforce reductions should be credited as an offset.

21. It is reasonable to apply to SDG&E, the same conditional allowance of post-2011 SONGS-related O&M and capital expenditures adopted for SCE.

22. To the extent SDG&E recovers post-2011 SONGS-related expenses in rates, amounts are subject to refund in the proceeding opened to review the SONGSMA.

23. SCE's forecast TY2012 O&M, and forecast 2011-2012 capital expenditures for Palo Verde are reasonable and adopted.

24. SCE's forecast TY2012 O&M, and forecast 2011-2012 capital expenditures, for the Mohave Generating Station are reasonable and adopted.

25. Continuation of the Mohave Balancing Account is reasonable so that costs will be subject to a reasonableness review, and to provide ratepayers protection against unknown cost.

26. SCE established the reasonableness and necessity of the expenditures as required for its pre-2012 Four Corners capital projects, and addressed the viability of its continued ownership of Four Corners.

27. Replacement equipment lasting beyond 2016 does not equate with plant life extension because ownership agreements, fuel supply contract, and land leases expire that year.

28. SCE's 2007-2009 Four Corners capital expenditures of $8.548 million, $21.513 million recorded expenditures for 2010, and $9.619 million forecast for 2011 are reasonable, do not violate EPS, and are adopted.

29. SCE's estimated 2012 O&M should be reduced to $30.065 million to reflect sale on October 1, 2012 and to exclude pro rata costs of the Unit 5 overhaul scheduled for 2014. No O&M costs are authorized for 2013 or 2014.

30. If the Four Corners sale does not occur, SCE should limit post-2011 funding to O&M and capital expenditures identified in the Decommissioning Case and include in the 2015 GRC a showing that each post-2011 expenditure is reasonable, necessary and in service of Decommissioning.

31. If the Four Corners sale is delayed, SCE should be authorized to establish a Four Corners Memorandum Account to track expenses incurred between October 1, 2012 and the delayed sale date.

32. For hydro TY2012 O&M, it is reasonable to eliminate the $1.6 million "account estimating" adjustments to the base year arising from SCE's choice of forecasting method, resulting in a total of $56.0 million.

33. In future GRCs, SCE should explain the relationship of the timing of new hires to SCE's provision of safe and reliable delivery of service.

34. It is reasonable to add the $15.3 million unspent in 2010 to the 2011 forecast to pay for the Tule Fire Damage Flume Replacement.

35. SCE's 2011 and 2012 forecasts for Hydro capital expenditures other than the substations, relicensing, and Lundy flowline projects are reasonable.

36. SCE made a reasonable showing of necessity for proposed substation expenditures, including the construction of the Control, Inyo, June Lake, White Mountain, and Zack substations.

37. It is reasonable to reduce SCE's 2011-2012 capital forecasts to reflect elimination of the Bridgeport and Lee Vining substation projects.

38. It is reasonable to eliminate funding for the Lundy Reline Conveyance System in the amount of $.025 million in 2011 and $4.5 million in 2012 because it is not necessary for the safe and reliable delivery of electrical service to SCE's ratepayers.

39. For FERC relicensing, it is reasonable to reduce both the 2011 and 2012 capital forecasts by $4.2 million, approximately 10% of the 2009-2011 underspend, to adjust for SCE's previous excessive forecasting, resulting in $11.426 million for 2011 and $8.1 million for 2012.

40. It is reasonable to reduce Mountainview TY2012 O&M by $.307 million for labor expenses because SCE did not establish the need for three new positions.

41. TURN's forecasts for three categories of Blanket Work orders at Mountainview using a 3YA of historical costs, escalated to $0.310 million in 2011

and $0.320 million in 2012, are more reasonable that SCE's method. SCE's Capital Spare Parts forecasts of $0.79 million in 2011 and $0.988 million in 2012 are reasonable.

42. SCE's revised forecast for TY2012 peaker O&M, and $3.0 million forecast for 2011-2012 capital expenditures are reasonable and adopted.

43. It is neither necessary nor within the scope of the GRC to re-visit the need to construct the McGrath peaker.

44. Based on prior Commission approval to construct the McGrath peaker, and the fact that construction is permitted and underway, SCE's $20 million 2012 capital forecast and $0.841 million O&M forecast are reasonable.

45. It is reasonable to require SCE to record all funds it spends on McGrath construction which shall be reviewed for reasonableness in a subsequent proceeding and subject to refund if not found to be reasonable.

46. SCE's PDD forecast for TY2012 O&M is reasonable because PDD continues to operate within the scope of its primary support functions and has not presented costs associated with research, development, and demonstration functions.

47. It is reasonable to continue the PDDMA at this time to ensure that only authorized support functions are funded by ratepayers.

48. It is reasonable to reduce SCE's forecast TY2012 SPVP O&M costs by 50%.

49. It is not reasonable to "true-up" SCE's 2010 SVPV capital expenditures because the Commission previously found program capital spending beneath the threshold amounts to be reasonable.

50. SCE's recorded 2009 and 2010 capital expenditures are reasonable and adopted.

51. It is not reasonable to terminate the SPVPBA because it serves as an appropriate protection for ratepayers in light of a reduced and revised program.

52. SCE should complete development and operation of its 125 MW of solar PV projects by 2014 within the revised O&M and capital spending limits adopted by the Commission, unless later modified by Commission action.

53. SCE's revised TY2012 O&M forecast of $4.532 million for Catalina is reasonable and adopted.

54. SCE's deferral of the Catalina Control Room and Main & Garage Building projects in order to comply with the SCAQMD settlement is reasonable.

55. SCE's forecast 2011-2012 costs for the Catalina Station Betterment project are not reasonable.

56. Total 2011-2012 capital expenditures of $15.364 million for Catalina are reasonable and adopted.

57. SCE's evaluation of alternatives for electricity delivery to Catalina customers, including the undersea cable feasibility study, to be reasonable in light of regulatory compliance obligations.

58. The record does not demonstrate that TURN's proposed $20 million reduction to rate base is supported in relation to SCE's conduct, or not arbitrary as to amount.

59. SCE's TY2012 O&M forecast of $0.89million and the revised 2010-2012 capital forecast of $10.608 million are reasonable and adopted.

60. The FCPMA is an appropriate mechanism for the Commission to review the FCP costs prior to rate recovery for this new program.

<u>Section 5</u>

61. It is reasonable to reduce SCE's revised forecast to $562.247 million for TY2012 total TDBU O&M.

62. It is reasonable to adopt SCE's recorded, unadjusted capital expenditures for 2010, and $4.507 billion in 2010-2012 capital expenditures, across all project categories.

63. The tariff changes proposed by POLB are outside the scope of this GRC.

64. The TY2012 costs for HAN-related activities in ATO subaccount 580.260 are within the SmartConnect deployment plan scope and within the deployment period, and should be recorded in the ESCBA for review.

65. DRA's use of a historic average costs is a reasonable basis to forecast costs for ATO subaccounts 560.260 and 580.260.

66. SCE's forecast for subaccount 580.261 related to RD&D is reasonable and SCE is restricted to activities that meet the criteria for permissible RD&D projects as set forth in § 740.1.

67. SCE's medium PEV forecast is not reasonable based on 2011 estimates of PEV presence in SCE territory.

68. SCE's "low" forecast of 83,000 PEVs being served in SCE's territory by the end of the rate case cycle is a more reasonable forecast, an amount about 40% less than the medium case by 2014.

69. Based on adoption of SCE's low PEV estimate, it is reasonable to adopt 60% of the increase between 2009 recorded and SCE's 2012 forecast for subaccount 588.260, or $3.622 million.

70. SCE's 2011-2012 forecasts for Smart Distribution Transformers, Capacitor Automation and Grid Dispatch, and Phasor Measurement capital expenditures are reasonable and adopted.

71. For Circuit Automation, SCE's 2010 recorded expenditures of $11.68 million and 2011 forecast of $3.922 million, and DRA's forecast of $1.434 million for 2012 are reasonable and adopted.

72. If SCE seeks additional funding for the Smart Distribution Transformers, it should provide the Commission with a cost-benefit analysis of the program using the data it intends to acquire with its 2012 Forecast.

73. For DSEEP, DRA's 2011 and 2012 forecast expenditures of $4.475 million and $4.582 million, respectively, are reasonable and are adopted.

74. It is reasonable to reduce SCE's 2012 forecast by $10.721 million to eliminate the Self-Healing Circuit project for the remainder of the Integrated Smart Distribution Project.

75. It is not reasonable to allow SCE's $3.0 million request Substation Automation 3 in 2012 because the request is premature and not well supported.

76. It is reasonable to reduce SCE's proposed 2011-2012 capital expenditures for the DMS program to $7.735 million each year to contain escalating costs.

77. It is reasonable for SCE to make a gradual transition from manual sampling of transformers to OTM and to reduce SCE's 2011-2012 forecast capital expenditures for OTM to $3.5 million in each year to balance the impact on ratepayers.

78. SCE's forecast 2010-2012 capital expenditures of $30.281 million for Phasor Management and WASAS are reasonable and adopted.

79. It is reasonable to limit SCE's recovery for CRAS to its 2010 recorded expenditures and the balance of the 2010 forecast ($6.392 million) in 2011 so that SCE can re-evaluate the current necessity of CRAS in light of revised interconnection estimates and SCE's recent utilization of new, advanced RAS systems with more capability.

80. SCE's request for $8 million in 2012, to begin an estimated $25.6 million project for smart grid cyber security, is not reasonable because it is premature and puts ratepayers at risk of obsolescence.

81. It is reasonable to reduce SCE's request for Smart Grid Cyber Security to $1 million in 2012 to initiate a smart grid cyber security test program to better determine costs and potential benefits as the relevant technology and equipment is developed over the next decade.

82. It is reasonable for SCE to provide a cost/benefit analysis of the Smart Grid Cyber Security Solution in its next GRC, including the optimal timing for deployment in an evolving technological environment.

83. It is reasonable to allow DRA's proposed 2010-2012 total of $11.31 million and to levelize the capitalized expenditures in 2011 and 2012.

84. It is reasonable to require SCE to provide a least cost analysis in the next GRC to support new construction versus leasing the laboratory space.

85. The Commission finds reasonable SCE's capital spending for capacitor automation and Grid operation forecasts and adopts them.

86. In total, the Commission adopts $120.597 million of SCE's $173.608 million capital investment request for Transmission and Distribution Advanced Technology Projects for 2010 through 2012, and disallows $53.011 million.

87. A 3YA of both labor and non-labor costs, with labor costs adjusted for 10.4% growth, half of the growth sought by SCE for Transmission Interconnection Planning, is reasonable and adopted. The result is $3.197 million for subaccount 561.210 for labor costs and $0.984 for non-labor, for a total of $4.181 million.

88. SCE did not clearly establish a need for four additional inspectors, nor explain why embedded costs do not exist for their positions.

89. It is reasonable for SCE to assume that the demand for Power Quality Services is rising.

90. For subaccount 587.210 in TY2012, it is reasonable to reduce SCE's requested increase of inspectors by 50%, resulting in $1.146 million for subaccount 587.210.

91. SCE should include in its next GRC application in the Load Growth testimony an estimate of unused distribution capacity for the test year and other Commission Findings of Fact regarding SCE's forecast Load Growth during the rate cycle at issue.

92. SCE's forecasts for the A-Bank Plan, Subtransmission VAR Plan, Distribution Substation Plan Circuits, Distribution Plant betterment, Distribution VAR Plan, and Generator Interconnection program are reasonable and adopted.

93. SCE has a duty to be forthcoming about the construction status of its projects, including potential permitting or anticipated exemptions, so the Commission can evaluate the viability of a project coming into service during the rate cycle.

94. The record is insufficient to establish that the five Subtransmission line projects identified by DRA are likely to come into service during the rate cycle period.

95. It reasonable to reduce SCE's Subtransmission line capital expenditure requests and adopt $50.614 million for 2011 and $29.590 million for 2012.

96. It is reasonable to reduce SCE's 2011-2012 DSP capital request by 50% of DRA's remaining recommended decrease, or $20.763 million in 2011 and $36.341 million in 2012.

97. It is reasonable to disallow all 2011-2012 forecast expenditures for the Presidential Substation Project because it will not be constructed during 2012, will likely be modified, and may not be constructed during the rate case cycle.

98. For DSP capital, a total of $281.734 million for 2010-2012 is reasonable and adopted.

99. It is it reasonable to spread SERP replacements over six years and normalize the costs to $8.143 million per year for 2011 and 2012.

100. To reflect our adoption of SCE's "low" PEV forecast, it is reasonable to reduce SCE's forecast by 40% and adopt PEV readiness capital expenditures of $1.253 million in 2011 and $5.114 million in 2012.

101. It is reasonable to adopt a $62.586 million reduction to SCE's total 2010-2012 Infrastructure Replacement capital expenditure request of $715.734 million.

102. SCE's forecast for the eight uncontested Infrastructure Replacement expenditures for 2011-2012 are reasonable and adopted.

103. SCE's 2012 forecast for replacing 415 circuit miles of cable annually is not reasonable in light of past experience, and the TURN/DRA recommendation of 276 circuit miles is more reasonable.

104. DRA's recommendation, which results in a $27.694 million reduction to SCE's 2012 CRP forecast, is reasonable and is adopted along with SCE's 2011 forecasts.

105. SCE's proposed replacement of 36 conductor miles per year, 0.3% of the total CIC population, is not excessive. SCE's 2011-2012 forecasts are reasonable and adopted.

106. SCE should carefully document the data collection from the CIC pilot program, as well as other efforts it undertakes to develop a best practice and most cost effective method for replacement.

107. SCE's requested 2011-2012 proposed expenditures for replacement of the A-Bank transformers are reasonable and adopted.

108. Replacement of 30 B-Bank transformers in 2012 is more reasonable than 40 because SCE has not yet accomplished even half that amount in one year.

109. It is reasonable to adopt SCE's 2011 forecast of $16.582 million to replace 16 transformers, and to reduce SCE's 2012 forecast to $31.890 million to reflect replacement of 30 transformers.

110. SCE should document the B-Bank transformer replacements performed in this rate cycle and submit the names, locations, and ages of the replaced transformers in support of the next GRC request in this category.

111. DRA's forecast replacement of 175 circuit breakers in 2012 is more reasonable than SCE's forecast since SCE has not replaced more than 159 in a year.

112. It reasonable to reduce SCE's 2012 circuit breaker replacement forecast to $18.436 million and also adopt SCE's 2011 forecast.

113. DRA's proposed transfer at least 3,500 amps annually beginning in 2012 as part of a levelized approach is reasonable because it will result in SCE exceeding its stated 2014 and 2020 goals.

114. For 4 kV Cutovers, SCE's 2011 forecast of $17.214 million in 2011 and DRA's proposed $20.433 million in 2012 are reasonable and adopted.

115. SCE did not establish that its estimated 4 kV substation elimination unit costs are reliable or that it is reasonable to initiate the program at the pace SCE proposes.

116. It is reasonable for SCE to coordinate, to the extent possible, its cutover program and its substation elimination programs to best ratepayer advantage.

117. It is reasonable to adopt a $10.972 million reduction to SCE's 2012 request, resulting in $23.314 million to begin the program in 2012.

118. SCE's 2010-2012 capital forecast for SSID of $4.591million is reasonable and adopted.

119. SCE's uncontested O&M forecasts in subaccounts 588.220 and 595.220 are reasonable and adopted.

120. It is reasonable to reduce SCE's non-labor forecast for subaccount 560.220 by $0.676 million, 50% of DRA's recommendation, to reflect exclusion of employee bonus funds and a portion of the previously authorized, but unused TLCS funds which SCE could have retained for other phases of the study.

121. It is reasonable to reduce SCE's proposed engineering contract expenses by 50%, $125,000 per year, and adopt $1 million in TY2012 O&M for subaccount 580.220.

122. In order to encourage more underground conversions, it is reasonable to adopt SCE's 2011 and 2012 forecasts for Rule 20A projects.

123. It is reasonable to reduce SCE's 2011 and 2012 forecasts for Rule 20 B and Rule 20 C conversion by 40% to reflect recent conversion expenses and address existing long-term projects.

124. SCE's 2011 and 2012 forecast capital spending amounts for Distribution Relocations are reasonable and adopted.

125. SCE's 2011 and 2012 forecast capital spending amounts for Distribution Added Facilities are reasonable and adopted.

126. SCE's residential and non-residential meter set forecast is not reasonable because it does not sufficiently account for longer term effects of the economy on growth during the rate cycle.

127. TURN's "base" case for new meter sets is a more reasonable basis to estimate meter sets and customer growth and is adopted. The result is an overall weighted average reduction of 17% to SCE's forecast based on customer growth.

128. It is reasonable to adopt SCE's total 2010 meter-related recorded expenditures.

129. It is reasonable to adopt SCE's uncontested 2011 and 2012 forecasts for Street Lighting and Agricultural customer growth expenditures.

130. For all other Residential and Commercial Customer Growth expenditure work categories, it is reasonable to adopt TURN's "base" case recommendations, resulting in an aggregate total of $95.847 million and $106.855 million in 2011 and 2012, respectively.

131. SCE's uncontested TY2012 O&M forecasts for overhead detail inspections and annual patrols are reasonable and adopted.

132. SCE should move towards a 10-year intrusive inspection cycle for wood poles to mitigate fire and other hazards.

133. SCE should use up to $0.753 million of its O&M request for subaccount 583.120 to perform full inspections of a statistically valid random sample of loaded poles, utility-owned and jointly-owned, to determine whether the loads meet current legal standards. To the extent that the Commission orders, through any other proceeding, an examination of pole loads within SCE's territory, the study ordered here shall be coordinated to avoid duplication. Any unspent funds must be used for intrusive pole inspections unless the Commission is advised to the contrary by a Tier 2 Advice Letter.

134. It is reasonable to adopt SCE's forecast for TY2012 Wood Pole Inspections O&M, inclusive of funds to perform the described pole load assessment.

135. Upon completion of the pole load assessment, SCE should serve the summary results of the study on the service lists for this GRC and R.08-11-005, and provide pole-by-pole results to the Director of CPSD, no later than March 1, 2013.

136. In the next GRC, SCE should provide information about how many priority 1, 2, and 3 conditions were identified by the actual number of intrusive inspections performed in 2012 and 2013 so that the Commission may evaluate the utility of an accelerated inspection program.

137. SCE's 2012 forecast for Underground Detail Inspections in subaccount 584.120 is not reasonable.

138. To estimate the increase over LRY for subaccount 584.120, it is reasonable to average the number of inspections from 2007-2009, after DIMP was initiated, and multiply the result of 142,321 inspections by the $11 cost per inspection, adopt $1.566 million for TY2012.

139. DRA's proposal to establish a one-way balancing account for Vegetation Management is not reasonable because it lacks evidentiary support.

140. It is reasonable, and consistent with D.09-08-029, to retain the FHPMA for this rate cycle.

141. SCE's forecast of $52.934 million for TY2012 O&M expenses for Vegetation Management is reasonable and adopted.

142. DRA's complete reliance on 2009 recorded costs for Preventive Maintenance is not reasonable in view of increasing inspections and repairs during the rate cycle.

143. SCE's TY2012 O&M forecast of $39.712 million for Preventive Maintenance in subaccount 593.120 2012 is reasonable and adopted.

144. The full expenses of an inspection cycle may not be fully seen until a cycle has been completed. It is reasonable to assume that there will be additional inspection costs in 2012 if the first five-year cycle has not yet been completed.

145. SCE's TY2012 Distribution Apparatus O&M expense forecast is reasonable and adopted.

146. It is not reasonable for DRA to solely rely on historical costs of Capital Preventive Maintenance programs because DRA's forecast excludes the impact of increased inspections and aging infrastructure that will increase repairs.

147. SCE's forecasts for 2011 and 2012 capital spending for the Capital Preventive Maintenance portion of I&M proposed expenditures are reasonable and adopted.

148. In the next GRC, SCE should include with any request for additional funding of Asset Based Preventative Maintenance, a description of how many replacements were performed annually after 2010, the number of new replacements identified, and the number, priority, and estimated cost of backlog replacement projects, if any.

149. DRA's forecast for Underground Structure Replacement is not reasonable because it does not account for vaults previously identified for replacement.

150. It is reasonable to reduce SCE's 2011-2012 forecasts for Underground Structure Replacement to $9.7 million per year, sufficient to replace 37 vaults per year, and resolve the backlog by 2015.

151. In the next GRC, SCE shall include with any request for funding of the Underground Structure Replacement program, a description of how many replacements were performed annually after 2010, the number of new replacements identified, and the number, priority, and estimated backlog of replacement projects, if any.

152. It is not reasonable to use a five year average of intrusive inspections that spans two inspection cycles, nor to develop a forecast that does not account for SCE's backlog of poles already pending replacement in a three-year cycle.

153. DRA's forecast methodology is not reasonable in part because DRA's forecasts for distribution wood pole replacements in 2011 and 2012 are too low.

154. SCE's forecast 2011 and 2012 capital expenditures for Wood Pole Replacements are reasonable and adopted.

155. It is reasonable to reduce SCE's forecast Joint Pole Credits to $11,243 and $14,726, respectively, for 2011 and 2012, and reduce SCE's proposed pole disposal costs to $1.615 and $1,809 million, respectively, for 2011 and 2012, to reflect previous reductions to actual intrusive pole inspections.

156. As suggested by DRA, it is reasonable to reduce SCE's 2011-2012 capital forecast for Removal of Idle Facilities to conform with SCE's original 2010-2012 forecast, by apportioning the remainder of SCE's forecast equally between 2011 and 2012 after deduction of $9.185 million recorded in 2010.

157. SCE's uncontested forecasts of $0.604 million for subaccount 589.130 Distribution Line Rents and $0.665 million for Facility Inventory Mapping in subaccount 588.130 are reasonable.

158. It is reasonable to reduce SCE's TY2012 forecast for Field Accounting Office O&M by 5% ($48,000) to reflect lower forecasts for system growth and related work activities.

159. SCE's TY2012 forecast of $3.175 million for Joint Pole O&M is reasonable.

160. It is reasonable to reduce SCE's 2012 O&M forecast for Miscellaneous Expenses in subaccount 588.130 to exclude employee recognition awards.

161. SCE's uncontested TY2012 O&M forecasts for subaccounts 560.170 Transmission Substation Supervision, 587.170 Customer Generated Troubleman Work, 585.170 Street Light Patrols, and 596.170 Street Light Maintenance Costs are reasonable and adopted.

162. It is reasonable to reduce SCE's TY2012 forecast O&M for the GCC by $0.951 million, 60% of SCE's proposed increase.

163. SCE's forecasts for subaccounts 562.170 and 582.170 are reasonable and adopted because SCE's methodology reflects the key drivers for these costs.

164. SCE's TY2012 O&M forecasts for subaccounts 573.170 and 598.170 for T&D storm damage costs are reasonable and adopted.

165. Based on historical trend, SCE's 2009 O&M for Overhead Distribution Line Operations is a more reasonable basis to forecast 2012 expenses than a calculation based on SCE's unauthorized request.

166. The forecast approach of DRA and TURN is reasonable and $4.129 million is adopted for TY2012 O&M for subaccount 583.170 Overhead Distribution Line Operations.

167. For subaccount 583.170 Overhead Distribution Line Operations, the forecast approach of DRA is more reasonable than SCE's approach and DRA's resulting forecast of $8.996 million is reasonable and adopted.

168. For the Circuit Mapping portion of subaccount 588.170, DRA's forecast method is more reasonable than SCE's approach and DRA's resulting forecast of $1.446 million is reasonable and adopted.

169. DRA's use of a 3YA is a reasonable method to address limited available data, and DRA's forecast of $1.668 million for the Outage Data Management component of subaccount 588.170 is reasonable and adopted.

170. It is reasonable to reduce SCE's O&M forecast for the Streetlight Mapping & Inventory component of subaccount 588.170 by $254,000 to adjust for a 20% lower forecast of new street lights and to remove the street light study. The resulting $1.199 million is reasonable and adopted.

171. It is reasonable to exclude employee recognition expenses included in SCE's forecast for Other Expenses in subaccount 588.170. The resulting difference of $0.917 million is reasonable and adopted.

172. It is reasonable to adopt SCE's uncontested 2011-2012 capital forecasts for Facilities Operation expenditures.

173. It is reasonable to reduce SCE's Street Light Replacement Program 2011 and 2012 forecasts by 50% of the difference from DRA's estimate to reflect a steady replacement program. The result of $12.362 million in 2011 and $14.485 million in 2012 is reasonable and adopted.

174. SCE's uncontested TY2012 forecast of $2.653 million for Subaccount 580.140 Operations Supervision and Engineering is reasonable and adopted.

175. It is reasonable to reduce TDBU capital-related O&M expenses, based on a 9.4% reduction in SCE's forecasted 2011-2012 total TDBU capital expenditures.

176. It is reasonable to reduce SCE's TY2012 O&M forecast increase for Construction Related Expenses in subaccount 583.140 to $138,000 and to adopt it.

177. TURN's TY2012 O&M forecast methodology for Meter-Related expenses in subaccount 586.140 is reasonable and the resulting forecast of $5.796 million is reasonable and adopted.

178. SCE's proposal to have ratepayers fund baseline service guarantee credits should be denied. No reasonable basis has been established to change the Commission's policy and shift funding of service guarantee credits from shareholders to ratepayers.

179. It is reasonable to reduce SCE's TY2012 $3.779 million O&M forecast for Miscellaneous Distribution Expenses in subaccount 588.140 by $733,000 to remove employee recognition expenses and adopt the result of $3.006 million.

180. SCE's TY2012 forecast for Overhead CWO expenses is excessive and not reasonable.

181. It is reasonable to reduce SCE's TY2012 forecast for Overhead CWO expense by 9.4% of SCE's incremental increase between the 2012 forecast and

2009 recorded expenses. The result is a $1.339 million reduction to $18.755 million which is reasonable and adopted.

182. TURN's recommendation of $8.535 million for Overhead breakdown maintenance expense is reasonable and adopted.

183. SCE's revised TY2012 forecast for Underground CWO expense of $4.082 million is reasonable and adopted.

184. TURN's recommendation of $6.657 million for Underground Breakdown expense is reasonable and adopted.

185. SCE's 2011 and 2012 forecasts for Distribution Storm Capital Expenditures totaling $77.915 million are reasonable and adopted.

186. SCE's capital forecasts of $20.577 million in 2011 and $21.071 million in 2012 for Distribution Claims Damage expenditures are reasonable and adopted.

187. SCE's 2011-2012 forecast for Distribution Breakdown Maintenance capital expenditures is not reasonable because its methodology is insufficiently supported.

188. It is reasonable to modify DRA's forecasts based on 3YA of replacement units for all equipment categories, and to adjust it by 5%, the average annual growth in this category between 2005 and 23009, in order to account for increasing age-related failures and a small number of new asset failures.

189. Forecasts capital expenditures for Distribution Breakdown Maintenance of $107.793 million for 2011 and $113.182 million for 2012 are reasonable and adopted.

190. TURN's capital forecasts of $53.936 million in 2011 and $57.742 million in 2012 for Distribution Transformers are reasonable and adopted.

191. Elsewhere in this decision, we adopted TURN's forecast of customer growth. Accordingly, the Commission finds it reasonable to reflect it here and adopt TURN's forecasts of distribution transformer capital expenditures.

192. For Tools and Work Equipment, DRA's forecasts of $2.170 million for 2011 and $2.222 million for 2012 are reasonable and adopted.

193. SCE's uncontested TY2012 O&M forecasts for various SC&M subaccounts are reasonable and adopted.

194. SCE's TY2012 forecasts for Circuit Breakers, Relay Inspection & Maintenance, and Miscellaneous Equipment are not reasonable.

195. For Transformer Maintenance, SCE's estimated $0.687 million is reasonable and adopted.

196. DRA's TY2012 O&M forecasts for Circuit Breakers, Relay Inspection & Maintenance, and Miscellaneous Equipment based on LRY are reasonable and adopted.

197. It is reasonable to reduce SCE's TY2012 O&M forecast for capital-related expenses in subaccount 570.150 by 9.4% of SCE's incremental increase between the 2012 forecast and 2009 recorded expenses. The result is a $0.104 million reduction to $4.142 million which is reasonable and adopted.

198. It is reasonable to reduce SCE's TY2012 O&M forecast for Substation Miscellaneous Expenses in subaccount 588.150 by $113,000 to remove employee recognition expenses.

199. SCE's uncontested TY2012 forecast for Distribution Substation Transformer I&M of $1.488 million is reasonable and adopted.

200. SCE's TY2012 forecast for Distribution Substation for Relay I&M of $1.944 million is reasonable and adopted.

201. It is reasonable to adopt a 5YA of $3.541 million for TY2012 O&M for Miscellaneous Equipment and $3.258 million for Circuit Breakers in subaccount 592.150.

202. SCE's uncontested 2011 and 2012 forecasts for Substation Storm Capital and Substation Claims are reasonable and adopted.

203. DRA's forecasts of $34.424 million in 2011 and $35.3 million in 2012 for SCM spending are reasonable and adopted.

204. DRA's forecasts of $185,000 in 2011 and $189,000 in 2012 for Substation Rule 20B and 20C capitalized expenditures are reasonable and adopted.

205. DRA's reliance on 5YA historical costs to forecast Substation Added Facilities expenditures is less reliable than SCE's forecast method based on actual planned work following pending and approved applications for added facilities.

206. SCE's total combined 2011Added Facilities forecasts of $36.752 million in 2011 and $33.084 million in 2012 are reasonable and adopted.

207. SCE's uncontested TY2012 O&M forecast of $8.224 million for Transmission Maintenance is reasonable and adopted.

208. It is reasonable to utilize overhead line inspection 2009 recorded costs as recommended by DRA for a TY2012 O&M forecast of $2.609 million.

209. SCE is able to ramp up its transmission pole inspections and may double its 2011 inspections to 10,614 in 2012.

210. It is reasonable to reduce SCE's forecast to provide for 10,614 inspections resulting in $0.488 million, an amount which is reasonable and adopted.

211. SCE should include with the next GRC, a summary of the transmission pole inspection results by category (i.e., 1, 2, or 3) of identified repair in order to assist the Commission's review of the reasonableness of SCE's accelerated inspections.

212. It is reasonable to reduce SCE's TY2012 forecast for Underground Transmission Line Inspections in subaccount 564.160 by 10% because other factors besides planned work drive expenses.

213. SCE's forecast of $5.140 million for TY2012 Miscellaneous Transmission Expenses in subaccount 566.160 is reasonable and adopted.

214. DRA's request to remove funds for the Transmission Program is denied because the program benefits ratepayers by developing a more stable workforce in a key area that impacts reliability and safety.

215. SCE's TY2012 forecast of $2.090 million for Other Transmission expenses in subaccount 566.160 is reasonable and adopted.

216. In order to provide the Commission with data to evaluate the reasonableness of the Transmission program, SCE should provide a cost-benefit analysis in the next GRC.

217. SCE's TY2012 forecast of $8.224 for Transmission Line Rents O&M recorded in subaccount 567.160 is reasonable and adopted.

218. SCE's uncontested TY2012 forecast of $8.861 million for Transmission Maintenance expenses recorded in subaccount 571.160 is reasonable and adopted.

219. SCE's TY2012 forecast of $3.929 million for Insulator Washing expenses recorded in 571.160 is reasonable and adopted.

220. DRA's forecast of $8.624 million, modified to accept SCE's Labor to Non-labor ratio of 40%, for TY2012 Road and Right Of Way Maintenance O&M is more reasonable than SCE's forecast because it is based on recorded costs.

221. It is reasonable to reduce SCE's TY2012 Capital-Related O&M forecast by $405,000 (9.4%) to reflect the actual reductions adopted in this decision to total requested TDBU capital expenditures.

222. It is reasonable to adopt the modified forecast of $13.83 million for TY2012 Capital-Related O&M recorded in subaccount 571.160.

223. DRA's recommended reduction in replacement of Transmission Deteriorated Poles is not adopted because DRA did not consider the 604 pole replacement backlog or 249 new poles identified for replacement in its forecast.

224. SCE's 2011-2012 forecast of $29.561 million for Transmission Deteriorated Poles is reasonable and SCE's use of a 10 year inspection cycle for wood poles benefits ratepayers.

225. For total 2011-2012 Transmission capital expenditures, SCE's request of $41.321 million is reasonable and adopted.

226. It is reasonable to equally allocate $2.912 million in BP&TI productivity benefits between shareholders and ratepayers.

227. SCE's forecast of $7.734 million for BP&TI capital project costs is reasonable and adopted, given the Commission's approval of capital funding for the GIS, CMS and DMS programs elsewhere in the decision.

228. For TY2012 O&M for Non-Capital Project expenses it is reasonable to adopt $2.291 million, the 5YA of historical costs.

229. It is reasonable to reduce SCE's TY2012 forecast for Miscellaneous O&M to exclude employee recognition expenses, and to adopt $0.857 million.

230. SCE's request for TY2012 O&M for Transmission Substation IMM and IT funding in subaccount 588.271 should be reduced to reflect disallowance of the CRAS project. The resulting $6.92 million is reasonable and adopted.

231. SCE's uncontested forecast of $39.001 million for 2011-2012 BP&TI capital expenditures is reasonable and adopted.

232. It is reasonable to reduce SCE's total forecast for T&D Safety Programs to $56.143 million to reflect a 10% reduction to SCE's forecast number of new

employees resulting from various reductions to SCE's TDBU forecasts in this decision and to adopt this amount.

233. SCE's TY2012 forecasts for TDBU Environmental Services in subaccount 582.250 and in subaccounts 573.250 and 598.250 for T&D Toxic Waste Disposal are reasonable and adopted.

234. For T&D Business, Regulatory and Financial Planning costs recorded in subaccount 566.280, it is reasonable to reduce SCE's non-NERC/CIP labor forecast by 50% of the differential between DRA and SCE, SCE's NERC/CIP labor request by 25%, and SCE's non-labor forecast by $575,000 for an asset study not fully justified in the record.

235. It is reasonable to reduce SCE's $1.423 million forecast for subaccount 588.280 Distribution Construction Contract Management by $168,000 to remove discretionary employee recognition costs.

236. It is reasonable to adopt SCE's uncontested TY2012 forecast of $0.222 million for subaccount 580.280.

237. SCE's 2012 uncontested capital expense request of $8.895 million for the Business, Regulatory and Financial Planning Organization is reasonable and adopted.

238. SCE's uncontested TY2012 O&M forecasts for the following Other Costs subaccounts: 566.282 Transmission Facility Maintenance; 584.281 Transformer Credits; and 586.281 Meter Credits, are reasonable and adopted.

239. SCE did not establish that its TY2012 forecasts for Transmission Work Order Write-Offs are reasonable.

240. It is reasonable to base the TY2012 forecast for Transmission Work-Order Write-Offs on a 5YA of recorded costs after removing 50% of the extraordinary

$3.9 million write-off. The result of $1.198 million is reasonable and adopted for subaccount 560.281.

241. It is reasonable to base the TY2012 forecast for Distribution Work-Order Write-Offs on a 5YA of recorded costs after removing 50% of the extraordinary USAT write off and 100% of the Catalina $1.276 million write-off because similar costs are unlikely to occur during this rate cycle. The result of $8.230 million is reasonable and adopted for subaccount 588.281.

242. For Underground Utility Locating Services O&M, it is more reasonable to adopt TURN's TY2012 forecast of $9.755 million, than SCE's forecast, because it reflects the recent trend of declining work.

243. TY2012 forecast for Claims Write-offs recorded in subaccount 583.281.

244. SCE's forecast is not reasonable because it Catalina fire expense that is so far outside SCE's historical costs that it unfairly skews the TY forecast.

245. For TY2012 forecast for Claims Write-offs recorded in subaccount 583.281, it is reasonable to exclude 50% of the Catalina write-off as calculated by TURN from the historical average, and reduce SCE's forecast by $0.330 million to $5.716 million.

246. DRA's use of a 5YA of historical costs to develop its TY2012 forecast for Facility Maintenance Distribution is not reliable because SCE has materially changed the costs recorded in this subaccount since 2008.

247. SCE's TY2012 forecast of $9.066 million for Facility Maintenance Distribution O&M is reasonable and adopted.

248. It is reasonable to reduce SCE's TY2012 forecast for Transmission Allocated Costs recorded in for subaccount 568.281 by 10% to account for reductions made to SCE's TY2012 Transmission-related forecast O&M, and the resulting $12.933 million is adopted.

249. It is reasonable to reduce SCE's Distribution Allocated Costs forecast recorded in subaccount 590.281 by 5% to account for reductions made to SCE's TY2012 Distribution-related forecast O&M, and the resulting $43.180 million is adopted.

250. SCE's TY2012 forecast for Meter Damage and Temporary Services OOR recorded in subaccount 451.100 is reasonable.

251. In the next GRC, SCE should provide a breakdown by subaccount of how much OOR was recorded in other subaccounts with the offsetting expense, and how much had not been offset by the end of the calendar year in which it was recorded.

252. SCE's TY2012 forecast of $1.150 million in combined OOR recorded in subaccounts 456.308 Transmission Services for Generation and 456.340 Non-CAISO Services is more reasonable than a 5YA and is adopted.

253. It is reasonable to reduce SCE's forecast OOR increases over 2009 recorded revenue by 9.4%. The resulting forecast revenues for subaccount 454.300 of $38.567 million and for subaccount 456.700 of $1.173 million are reasonable and adopted.

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254. It is reasonable to adopt a separate 2013 forecast for CSBU O&M to reflect integration of SmartConnect deployment costs into general rates because the PTYR would not adequately adjust for the unique set of costs transferred.

255. SCE's itemized SmartConnect benefits by subaccount is a more reasonable method of estimating 2013 benefits than TURN's request to retain the 2012 formula, because SCE's method follows the business case review in the deployment proceeding.

256. It is reasonable for SCE to continue recording certain HAN-related functionality costs in the ESCBA.

257. In the next GRC, SCE should provide a spreadsheet of 2008-2015 SmartConnect costs and benefits credited by FERC account/subaccount and capital program.

258. It is reasonable for SCE to record 2012 DP expenses in the ESCBA in conformity with the Commission's expectation that the initial functionality of the DP program would be part of deployment.

259. To the extent authorized, it is reasonable to reduce CSBU incremental adjustments for DP activities in 2013 by 40%, excluding customer education and outreach, to reflect that the program is behind schedule.

260. SCE should track 2012-2014 DP expenses and provide them in the next GRC for Commission review of overall program costs.

261. To the extent authorized, it is reasonable to reduce CSBU incremental adjustments for customer growth in 2012 and 2013 by 17%.

262. SCE reasonably expects to incur more work as the number of PEVs in its service territory increases and SCE's proposed PEV activities are consistent with Commission policy as articulated in the Alternative-Fueled Vehicle Rulemaking.

263. To the extent authorized, it is reasonable to reduce CSBU incremental adjustments for PEV activities by 40% in 2012 and 2103.

264. Given the delays in development and use of HAN devices, including PCTs and IHDs, it is reasonable, and promotes transparency for SCE to continue to record HAN-related costs in the ESCBA through 2014.

265. SCE should provide a report to the Commission by January 30, 2013 which describes the progress made by the utility in each of the internal and external initiatives SCE identified to improve emergency response.

266. For Business Units Management and Support costs, DRA's forecast method of 5YA is reasonable; DRA's 2012 forecast is adopted and it is reasonable to increase DRA's 2013 forecast by $142,000.

267. SCE's 2009 recorded expenses is a reasonable basis to forecast 2012 and 2013 O&M for Meter Reading Expense and is adopted, exclusive of SCE's proposed increments for customer growth which are unsupported.

268. It is reasonable to reduce SCE's 2012 and 2013 forecasts for SOC O&M by removing HAN and reducing PEV costs, resulting in $457,000 in 2012 and $12.385 million in 2013.

269. SCE's 2012-2013 forecasts for subaccounts 903.100, 903.300, and 903.700 are reasonable and adopted.

270. For CRC subaccount 903.200, it is reasonable to reduce SCE's 2012 incremental increases to $465,000 and in 2013 to $988,000, and to adopt the resulting net forecasts of $17.65 million for 2012 and $11.260 million for 2013.

271. It is reasonable to assume 500 customers (50%) may seek enlarged bills and 500 seek Braille bills in 2012, based on coordinated customer outreach activities between SCE and Disability Rights Advocates.

272. For CRC subaccount 903.500, it is reasonable to reduce SCE's 2012 incremental increases to $289,000 and in 2013 to $2.653 million, and to adopt the resulting net forecasts of $17.613 million for 2012 and $18.711 million for 2013.

273. It is reasonable to reduce to $1 million per year, SCE's request for funds to support customer service representative wage to provide an incentive for SCE executives to re-direct funds for this purpose.

274. For subaccount 903.800, it is reasonable to reduce SCE's 2012 forecast adjustments by 50% to reflect some increased number of calls, lower per call

costs, and the utility of automated response systems. The result of is a 2012 adjustment of $1.333 million and in 2013 of $1.496 million.

275. Aglet's proposed 10YA is a reasonable basis to determine the Uncollectible Factor and the resulting factor of 0.205% results in 2012 expense of $14.051 million.

276. It is reasonable to reduce SCE's 2012 and 2013 Miscellaneous Expenses forecasts by $200,000 each to exclude ratepayer funding of Service Guarantee payments and adopt the result of $$14.334 million in 2012 and $15.736 million in 2013.

277. SCE's 2012 and 2013 forecasts for CSBU Safety program expenses recorded in 580.100 and 580.300 are reasonable and adopted.

278. SCE's 2012-2013 forecasts for Meter Turn Off and Turn On expenses recorded in subaccount 586.100 are reasonable and adopted.

279. It is reasonable to reduce SCE's 2012 and 2013 forecasts for Test and Inspect Meters expenses recorded in subaccount 586.400 by excluding HAN and decreasing PEV-related costs. The result of $10.344 million for 2012 and $10.044 million in 2013 is reasonable and adopted.

280. SCE's 2012-2013 forecasts for subaccounts 587.500 and 587.800 are reasonable and adopted.

281. SCE's 2012 forecast for subaccount 587.200 is reasonable and adopted; SCE's 2013 forecast should be reduced by $638,000 to address some growth in this category, resulting in a reduction from $4.813 million to $4.175 million which is reasonable and adopted.

282. SCE's uncontested forecasts for subaccount 597.400 are reasonable and adopted.

283. SCE's uncontested 2012-2013 forecasts in subaccounts 908.620 Technical Services and 908.630 Economic Development are reasonable and adopted.

284. Costs to respond to customer inquiries about DP fall within costs related to DP customer education and "customer tariffs, programs, and services" which are to be recorded in the ESCBA through 2012.

285. It is reasonable to reduce SCE's 2012 forecast for Account Management by excluding the incremental additions for DP and Outage Communications, and reducing forecast PEV costs.

286. The resulting 2012 forecast for subaccount 908.600 of $14.825 million is reasonable and adopted.

287. For 2013, after DP prices are expected to implemented, it is reasonable for SCE to add additional staff, and reduce the PEV expenses by 40%, resulting in $15.130 million which is reasonable and adopted.

288. SCE's 2012 and 2013 forecasts in subaccount 908.610 to staff and support SCE's Energy Centers are reasonable and adopted; even though we do not authorize construction of a new Energy Center, the additional staff in will allow SCE to expand its customer programs using creative and less costly solutions.

289. For subaccount 908.640, it is reasonable for SCE to record 2012 DP customer outreach and education costs in the ESCBA even though a small portion of the customers affected were not part of the deployment due to overlapping costs.

290. SCE should work with CBOs whenever reasonably possible when implementing customer outreach and marketing to low-income, minority, senior, and small business communities.

291. SCE's proposed 2012 increases for the EnergyManager platform, for staff to support growth of Medical Baseline and EAF applications, and to improve web accessibility, are reasonable.

292. For subaccount 908.640, the resulting $11.023 million, including reduced PEV costs, is reasonable and adopted for 2012.

293. We find it reasonable to make similar adjustments to SCE's 2013 forecast and to exclude HAN-related activities which should be recorded in the ESCBA. The resulting $13.992 million is reasonable and adopted.

294. SCE's small increase in subaccount 907.600 for PEV back office support in 2013 is reasonable.

295. SCE's 2012 and 2013 forecasts for subaccount 907.600 are reasonable and adopted.

296. SCE's forecast method is not adopted for subaccount 916.600 because 2009 is not an appropriate base year for the Rate Communications forecast due anomalous costs.

297. It is reasonable to apply a 3YA to mitigate the impacts of one-time costs for Rate Communications and to reflect other authorized funds for customer communications about rate options.

298. A reasonable forecast for subaccount 916.600 is $858,000 and it is adopted for both 2012 and 2013.

299. Based on substantial increases in staffing and workload during 2008-2009, use of a 3YA (2007-2009) of recorded expenses is a more reasonable basis to forecast LPA expenses than LRY or 5YA.

300. Elsewhere in this decision we have reduced SCE's forecasted 2011-2012 total TDBU capital expenditures, which drive project-related activities, by 9.4%.

301. It is reasonable to use the 3YA of $9.647 million as a base year for LPA expenses, and reduce SCE's proposed adjustments by $564,000, further reduce the result by 9.4%, and to adopt the result of $10.702 million as both the 2012 and 2013 forecasts.

302. SCE should ensure that the leadership position at LPA is occupied and the individual maintains active communication with local governments, particularly during emergencies.

303. SCE's uncontested 2012 forecast for Business Licenses Taxes is reasonable and adopted.

304. SCE's 2010 recorded costs of $25.4 million, even unadjusted, are a reasonable measure for rate recovery of CSBU's 2010 General Plant capital expenditures in this transitional period and are adopted.

305. SCE's forecast of $3.5 million to construct a third energy center is not reasonable because SCE should examine more creative and less costly alternatives that overcome the limited radius effect of a fixed site.

306. SCE's costs for the Meter Shop project do not qualify for reimbursement through the ESCBA as deployment costs simply because the project will include adapting the facility and equipment to accommodate emerging technologies.

307. DRA's forecast for 2010-2012 S&I capital is reasonable and adopted.

308. A 5YA is a reasonable Base Year for F&E capital expenditures.

309. It is reasonable to add 50% of the difference between SCE's 2010 forecast and recorded amounts to DRA's 2011-2012 forecasts to reflect deferred implementation of F&E support for new program employees, and to adopt the aggregate 2010-2012 result of $7.101 million.

310. DRA's proposed 2010-2012 SE forecast is not reasonable because it would result in authorized spending in excess of SCE's established necessity.

311. SCE's 2010 recorded expenditures of $6.3 is reasonable and adopted for 2010-2012 because it exceeds SCE's total 2010-2012 forecast and SCE did not justify additional spending.

312. PEV meter costs should not be charged to all customers.

313. SCE's 2010 recorded Meter Capital spending is an appropriate base year to forecast meter related costs for 2010-2012 because the declining installation of legacy meters is reflective of the changeover to AMI.

314. It is reasonable to adopt $17.1 million annually for 2010-2012 Meter Capital expenditures.

315. SCE's proposed capital spending in 2012 for the A&N project is not reasonable and not adopted.

316. It is not reasonable to implement a new version of the IVR program by 2012.

317. Phase 1 funding for the CRM project, reduced by 10% to address cost concerns, is reasonable based on potential efficiency benefits. For 2010 and 2011, costs of $19.91 million and $20.428, respectively, are reasonable and adopted.

318. SCE should provide a cost-benefit information in the next GRC if it seeks to recover Phase 2 CRM costs.

319. Implementation of the HAN troubleshooting project is premature and SCE's proposed expenditures are not adopted.

320. It is reasonable to slow implementation of the PEV Support Systems project and SCE's 2012 request for project is not adopted.

321. SCE's 2010 IMB expenditures in 2010 are reasonable and adopted.

322. SCE should have the ability to electronically work with customers to demonstrate the pricing and energy management tools for a range of DP programs.

323. It is reasonable to reduce SCE's 2011 and 2012 forecasts for DPRA by 10% to address timing and cost concerns, and add unspent portions of the 2010 forecast equally to 2011 and 2012.

324. For the DPTA project, it is reasonable to adopt $16.95 million in 2011 and $16.05 million in 2012, in addition to 2010 recorded expenditures.

325. The creation of the GRC Revenue Requirement Memorandum Account provides an adjustment mechanism, utilized in prior GRCs, so the request for updated service fees to reflect current cost of providing services recovered through OOR is unnecessary.

326. SCE's forecast for 2012 OOR is reasonable and adopted.

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327. SCE's O&M and capital requests that are associated with the overall implementation of MRTU should continue to be recorded in the MRTUMA for review.

328. SCE's calculation of TY2012 ERP benefits of $6.704 million is reasonable and adopted.

329. It is reasonable to record the total adopted ERP benefit of $6.704 million into FERC 920 and 921 due to the $45 million for cost overruns which SCE booked to rate base in 2009.

330. SCE shareholders consistently earn the authorized return on their investment and should not need additional productivity benefits as a reward or incentive to make appropriate capital investment.

331. SCE's calculation of 8% productivity benefits, based on adopted capitalized software investment, is reasonable and adopted as a 100% allocation to ratepayers in FERC 920 and 921.

332. It is reasonable to adopt SCE's uncontested forecast O&M costs totaling $7.412 million recorded in FERC 517 for Applications, Computing, and Networking Services.

333. For IT&BI Application Services, a 3YA of historical costs, plus adjustments for growth, is a reasonable basis to forecast TY2012 O&M, and $101.733 million, comprised of $71.62 million, plus SCE's anticipated incremental growth of $28.489 million for Labor and $1.624 million for Non-labor is adopted.

334. It is reasonable for SCE to record $917,000 in the MRTUMA, to reduce the recurring O&M adjustment by half to $3.3 million, and to reduce the remaining incremental O&M costs for New Software Applications by 21.6% to reflect lower capitalized software forecasts adopted in this decision.

335. The resulting amount of $26.404 million for New Software Applications TY2012 O&M is reasonable and adopted.

336. There should be some embedded costs for recurring O&M for new large systems which SCE claims will provide operational benefits (e.g, replacement of older software and systems).

337. SCE's forecast method for TRM costs is reasonable given the small and explained historical cost variances, and minor cost transfers for contingent workers in this expense category.

338. It is reasonable to reduce SCE's TRM forecast by 10% to $31.055 million due to limited supporting documentation.

339. SCE's uncontested TY2012 forecasts for Service Management, Network Services, and Infrastructure Operations Management are reasonable and adopted.

340. SCE's TY2012 Computing Services forecast is reasonable and adopted.

341. SCE can and should achieve more cost and labor efficiencies in the cost category of Business Operations.

342. It is reasonable to reduce the incremental labor forecast for Business Operations by 25%, or $4.7 million, resulting in a TY2012 forecast of $18.584 million for O&M Business Operations Management ($14.12 Labor, $4.464 million Non-labor).

343. It is reasonable to adopt SCE's recorded 2010 capital expenditures for IT&BI capital projects.

344. For the eight categories of uncontested Hardware Capital Expenditures, it is reasonable to adopt $64.480 million in 2011 and $106.339 million in 2012.

345. It is reasonable to forecast that a portion of the PCs and laptops will need to be refreshed annually.

346. It is reasonable to reduce SCE's 2011-2012 PC and Related Hardware forecasts by 10%, resulting in adoption of $11.124 million for 2011 and $11.384 million for 2012, and total 2010-2012 capital spending of $34.745 million.

347. A 3YA of SCE's historical costs from 2007-2009 is a reasonable basis to forecast Ruggedized Laptops expenditures, and SCE's 2011 and 2012 forecasts should be reduced by 9.4%, to $1.44 million and $4.368 million, respectively, to reflect fewer devices required by TDBU.

348. It is reasonable to adopt a total of $10.195 million for 2010-2012 Ruggedized Laptops capital expenditures.

349. The evidence does not support SCE's estimated replacement cost of $55,000 per mile of copper cable; no evidence suggests that completion of the copper cable replacement project in 2018 instead of 2017 would impair service or system reliability.

350. SCE's forecasts for Copper Wire replacement in 2011 and 2012 should be reduced to reflect an approximate escalated replacement cost of $45,000 and $47,000 per mile, respectively, and for SCE to replace 124 miles annually.

351. SCE's 2010-2012 forecasts for Copper Wire replacement should be reduced to a total of $21.558 million: $7.994 million for 2011 and $8.646 million for 2012, which is reasonable and adopted.

352. SCE's 2012 fiber optic cable forecast should be reduced to reflect the revised per cost mile of $47,000, resulting in $5.148 million for 2012, which is reasonable and adopted.

353. SCE's 2011-2012 request for satellite terminal equipment is not adopted.

354. SCE's uncontested 2012 forecast of replacement expenses for the MRN is reasonable and adopted.

355. SCE's request for $3.1 million in 2012 to begin planning Next Generation Network, or SCEnet II, is not adopted.

356. To reflect SCE's 2010 recorded expenditures, SCE's 2010-2012 forecast for Disaster Recovery should be reduced to a total of $25.225 million, which is reasonable and adopted.

357. It is reasonable to adopt $24.108 million for general Operating Software capital expenditures in 2010, $8.43 million for 2011 and $7.15 million in 2012 to reflect removal of $3.75 million for CMD costs.

358. For Operating Software Projects Less Than $1 million, a total of $7.438 million is reasonable and adopted for 2010-2012 to reflect removal of $500,000 in 2012 for the IT Health project.

359. SCE's CAD/CAFM forecast should be reduced by 10% to reflect limited information about the cost estimate and alternatives, resulting in $5.4 million for 2012 expenditures which is reasonable and adopted.

360. CDW expenses should not be recorded in the ESCBA because CDW is complementary, rather than duplicative, of the SmartConnect customer data warehouse.

361. SCE's CDW forecast should be reduced by 10% to reflect limited information about the cost estimate and alternatives, resulting in $7.825 million for 2012 expenditures which is reasonable and adopted.

362. SCE's 2011-2012 forecasts for the Enterprise Platform User Interface Refresh project are reasonable and adopted.

363. It is reasonable to adopt SCE's 2010 capital spending of $1.138 million for the TREX upgrade.

364. SCE's forecast of $4.376 million to implement the CMS upgrade is reasonable and adopted.

365. The EnergyManager activities described are not deployment related and do not qualify to be recorded in the ESCBA.

366. It is reasonable to reduce SCE's request for EnergyManager capital expenses by 50% to $3.035 million because the 2009 DR upgrade was ill-conceived.

367. SCE's CWO 2010 forecast of $1.2 million is reasonable and adopted.

368. For all other SAM projects, which are uncontested, it is reasonable to reduce the requested 2011 and 2012 SAM capital expenditures by 10% and to adopt the resulting total of $75.167 million.

369. SCE's 2010 forecast of $1.545 million in PPM capital expenditures is reasonable and adopted.

370. SCE's request for $49.593 million for the ERP cost overruns is not adopted.

371. SCE's 2011 and 2012 Data Archiving forecasts should be reduced by 10%, resulting in $1.8 million for 2011 and $0.802 million for 2012, which are reasonable and adopted.

372. SCE's 2011-2012 request for capital spending for the Business Analytics project is not adopted.

373. SCE's 2011-2012 forecasts totaling $27.054 million for TRM capital projects are reasonable and adopted.

374. It is reasonable to reduce SCE's 2011 and 2012 forecasts for CES to provide incentive to SCE to focus on the most essential enterprise-wide systems during this rate cycle, and aggressively look to minimize costs. The resulting 2011-2012 capital expenditures of $11.822 million are reasonable and adopted.

375. SCE's forecast method for NERC/CIP capital spending is more reasonable than DRA's approach of averaging DRA's own 2011 and 2012 forecasts.

376. SCE's 2011-2012 capital forecasts to maintain compliance with NERC/CIP standards are reasonable and adopted.

377. It is in ratepayers' interest for the Commission to undertake a detailed review of SCE's capitalized software requests in the next GRC, particularly related to cost estimation methodology, approach to cost-effectiveness, and whether reasonable metrics exist to measure benefits.

378. SCE should provide as part of its testimony in support of forecast capitalized software projects in its 2015 GRC, the information identified in the ordering paragraphs.

<u>Section 8</u>

379. The TCS design and results are the joint product of DRA, SCE and Hewitt and there is no documentary evidence to support that Hewitt had a conflict of

interest or that the selection of benchmarked job classifications or comparator companies was flawed.

380. The TCS establishes SCE's compensation rates are within market rates, but not whether all elements of proposed compensation are reasonable.

381. DRA and SCE should jointly hold a workshop open to all parties to discuss whether design modifications should be made to the next TCS or an alternative method of data gathering should be utilized for the next SCE rate case.

382. If SCE and DRA undertake an RFP for a compensation study in a future GRC, SCE should ensure that applicants are required to disclose if they receive more than 10% of their annual revenues from other SCE contracts.

383. SCE should continue reporting on workforce composition in its GRCs, modified to include a 10-year comparison by job classification, and an explanation of what steps SCE has taken to ensure top management leadership development for underrepresented groups, as part of outreach to all SCE employees.

384. SCE shall provide in its next GRC, a five-year (2009-2013) summary of the type of complaints made to the EEO and a description of anti-discrimination and sexual harassment prevention training provided to SCE employees during that period, including any substantial revisions to scheduling and content.

385. The NRC's concerns about the safety culture at SONGS are significant and SCE should allocate additional staff to work with SONGS management to address these concerns.

386. It is reasonable to reduce SCE'S HR Departmental costs by $213,000 because reductions are uncertain in this rate cycle and adopt $28.171 million for TY2012 O&M.

387. SCE should include in its 2015 GRC testimony, a description of the programs developed and implemented by these employees to address the NRC's concerns about safety culture at SONGS.

388. SCE's TY2012 forecasts for HR Departmental Outside Services and Employee Pensions and Benefits are reasonable and adopted.

389. SCE's forecast for Executive Officers Compensation should be reduced to $15.029 million to reflect a 50% reduction to recovery for executive officers' share of the EIC program.

390. SCE's uncontested forecast of $1.288 million for Executive Outside Services recorded in FERC 923 is reasonable and adopted.

391. It is not reasonable for ratepayers to fund Executive LTIs and SCE's TY2012 LTI forecast is not adopted.

392. Joint Parties' recommendations related to executive compensation lack evidentiary support and are not adopted.

393. It is reasonable to adopt SCE's 2010 recorded expenditures of $1.755 million and $1.3 million for 2011 for the Worker Provisioning Process Enhancement project.

394. It is not reasonable for ratepayers to bear the entire burden of the rapidly growing, discretionary STI program costs which, in some areas, may enhance value for shareholders more than benefit ratepayers.

395. SCE's STI forecast should be reduced by 10%, similar to reductions to forecast capital spending and an implied reduction to SCE's workforce growth.

396. It is in the interest of ratepayers for SCE to continue to record all STI costs in the Results Sharing Memorandum Account, to ensure that ratepayers only fund up to the authorized amount and are not subject to unanticipated and arbitrary liabilities in excess of SCE's forecast.

397. SCE's forecasts for Employee Recognition Programs, i.e., Spot Bonuses and Ace Awards, are not adopted.

398. It is reasonable for SCE to continue its practice of funding pensions above minimum funding requirements to keep contributions level as a percentage of payroll over the life of the plan.

399. Basing a Pension funding forecast on short-term market returns is not reasonable.

400. DRA's request to convert the balancing account is not adopted at this time and would be best reviewed in the context of broader review of pension cost recovery.

401. It is reasonable to adopt SCE's TY2012 forecast of $168.4 million and continue the pension balancing account under its current terms and conditions.

402. As part of its testimony in the next GRC, SCE should provide a review of its pension policies, in light of best practices and economic conditions, to support its rate recovery request for pension plan funding.

403. DRA's and Joint Parties' pension policy recommendations are not adopted because the proposals are not developed in the record and parties did not establish the Commission's legal authority to set SCE's pension and retirement policies.

404. SCE's forecast for PBOP costs is reasonable and adopted.

405. DRA's 401(k) forecast method is not reasonable because it does not reflect SCE's actual employee participation and contribution levels.

406. TURN's forecast of $82.959 million ($nominal) for 401(k) expenses based on a 5YA projection factor and SCE's labor escalation rates is reasonable and adopted.

407. TURN's 2012 medical program forecast of $143.570 million, 32% higher than SCE's 2009 recorded costs, is reasonable and adopted.

408. The evidence supports application of a 7.5% escalation rate for attrition years which results in $150.032 million in 2013 and $162.286 million in 2014 for medical programs.

409. SCE's uncontested TY2012 forecasts for Dental and Vision plan costs are reasonable and adopted.

410. The evidence did not support SCE's use of LRY as the most appropriate basis to forecast Disability program costs.

411. TURN's forecast based on historic per employee costs is a reasonable method to capture demographic changes in the workforce and the resulting forecast of $29.668 million is reasonable and adopted.

412. DRA's TY2012 Group Life Benefit Plan forecast of $940,000 is reasonable and adopted because SCE did not demonstrate that the expanded Group Life benefits are necessary for the delivery of safe and reliable electric service.

413. For TY2012, the Commission finds reasonable and adopts $2.133 million for Miscellaneous Benefits, which reflects reductions of $6.9 million for forecast ACE awards costs, and $827,000 for preventive health and work/life programs.

414. It is reasonable to reduce SCE's TY2012 forecast for the Executive Benefits program by 50% and to adopt the result of $8.4 million.

<u>Section 9</u>

415. It is reasonable to reduce SCE's TY2012 forecast of $309.516 million for Administrative and General (A&G) O&M expenses by $33,579 million and to adopt the balance of $275.937 million.

416. It is reasonable to reduce SCE's 2010-2012 A&G capital forecast from a total of $19.157 million to $16.257 million, a reduction of $2.9 million.

417. SCE's tax-related Outside Services are excessive and it is reasonable to apply a 5YA to the Controller's forecasts for Accounts 920/921and 923, resulting in $18.571 million and $22.198 million, respectively.

418. Including SCE's uncontested forecast of $428,000 for Account 926, the combined total for all Accounts of $41.197 million for the Controller's organization is reasonable and adopted.

419. SCE's capital request of $2.9 million in 2012 for the IFRS project is not adopted.

420. DRA's 5YA is reasonable to establish a base forecast for Audit Services and SCE's request for seven positions should be reduced by 50%, using SCE's labor/non-labor ratio for this category. The result of $9.616 million is reasonable and adopted for Accounts 920/921.

421. For the Treasurer costs recorded in Accounts 920/921, DRA's 5YA is reasonable to establish a base forecast, resulting in $4.94 million which is reasonable and adopted.

422. For Treasurer costs recorded in Account 930, DRA's 5YA base year forecast, plus 50% of SCE's estimated credit line fee increases, or $1.522 million, results in a total of $6.446 million which is reasonable and adopted.

423. For TY2012 Tax Department expenses recorded in Accounts 920/921, it is reasonable to adopt $3.737 million, the sum of the 2009 recorded expenses and $335,000 Labor and $37,000 Non-labor to fill the two vacancies.

424. DRA's use of a 5YA for Risk Control expenses recorded in Accounts 920/921 is not reasonable where labor and total costs have trended upwards.

425. It is reasonable to adopt SCE's 2009 recorded expenses of $4.686 million for Risk Control costs recorded in Accounts 920/921 ($4.29 million Labor and $396,000 Non-labor).

426. SCE's uncontested TY2012 forecast of $654,000 for Risk Control costs in Account 923 is reasonable and adopted.

427. It is reasonable to reduce SCE's incremental labor request by two-thirds and adopt $27.833 million for In-House Legal Resources recorded in Accounts 920/921, the equivalent of 2009 recorded expenses, plus $572,000 in Labor and $104,000 Non-labor.

428. The Commission declines to change its longstanding policy on the issue of following AR-12, but it is reasonable to allow rate recovery for 10% of SCE's request for this component of its forecast.

429. The 2005-2009 litigation costs related to SCE's Navajo Nation Royalty litigation should be excluded from 2009 Outside Counsel litigation costs for forecasting purposes because the litigation is atypically complex.

430. The remaining 40% of costs associated with SCE's Washington D.C. office relate to the Tehachapi Wind Storage Project and the Irvine Smart Grid Demonstration Project and provide a ratepayer benefit.

431. It is reasonable to reduce SCE's revised forecast and DRA's proposed reductions to arrive at $9.505 million for Account 923 and $1.911 million in Account 928 which are reasonable and adopted.

432. SCE's uncontested forecast of $704,000 for Accounts 920/921 for CG&ME expenses is reasonable and adopted.

433. SCE's request for ratepayer funding of supplemental benefits and stock based compensation for directors in Account 930 is not adopted.

434. DRA's TY2012 forecast of $2.497 million for CG&ME expenses for Account 930 is reasonable and adopted.

435. SCE's 2010-2012 request for $4.882 million to implement the Electronic Discovery Project is reasonable in view of SCE's increasing amounts of complex

data and the expectation that SCE will be able to timely retrieve necessary information upon regulatory request.

436. SCE's uncontested forecasts of $3.153 million in Accounts 920/921 and $127,000 in Account 924 are reasonable and adopted.

437. If no determination of recovery or finding that SCE had error or fault in connection with the Happy Camp fire has been made, litigation costs are reasonably included in Account 925 and SCE'sTY2012 forecast of $4.459 million is reasonable and adopted.

438. SCE's backcast method may result in an unreliable forecast; it is more reasonable to adopt DRA's 5YA of $34.882 million for Claims Reserve expenses recorded in Account 925.

439. No further reductions to the Claims Reserve are reasonable related to the Navajo Nation Royalty litigation.

440. TURN's TY2012 forecast of $6.836 million ($3.258 million Labor and $3.055 million Non-labor) is reasonable and adopted.

441. DRA's TY2012 forecast of $13.747 million for the Workers Compensation Claims Reserve expenses recorded in Account 925is reasonable and adopted.

442. E&C activities related to health, safety and employment compliance are linked to safe and reliable utility operations and recoverable in rates.

443. For E&C Accounts 920/921, the 2009 recorded expenses are a reasonable base forecast, and the addition of $529,000 ($469,000 Labor and $60,000 Non-labor) to provide for filling the two vacancies and adding 50% of the proposed staff increase, results in a total of $2.061 million, which is reasonable and adopted.

444. SCE should more effectively integrate its Ethics and Compliance activities company wide.

445. In the next GRC, SCE should provide a description of E&C program improvement achievement since 2010 and a clear description of the scope of its activities.

446. SCE's forecast of $722,000 for Outside Services in Account 923 is reasonable and adopted.

447. SCE's request for $11.375 million in capital spending to launch CMS is reasonable and adopted.

448. For TY2012 RP&A expenses, DRA's adjusted 5YA forecast of $12.223 million plus $1.205 million, 50% of the incremental labor forecast, is reasonable and adopted.

449. The funded activities identified by TURN for Subaccount 930.200, are excluded from ratepayer recovery, resulting in $1.284 million for TY2012 which is reasonable and adopted.

450. For Corporate Communications Accounts 920/921, it is reasonable to reduce SCE's incremental labor request for TY2012 to avoid duplication of CSBU customer education and outreach activities, provide sufficient funding for nine positions, and reduce the PEV request to conform with the lower adopted forecast. The result of $12.404 million is reasonable and adopted.

451. For Account 923, TURN's forecast of $544,000 based on 2009 recorded expenses is reasonable and adopted.

452. For Communications Products in Account 930, it is reasonable to adopt TURN's forecast of $980,000 which adds $93,000 to 2009 recorded expenses, an approximate $12% increase.

453. SCE's TY2012 forecast of $15.417 million for Property Insurance expenses is more reasonable than 2010 recorded expenses and is adopted.

454. SCE's TY2012 forecast for Liability Insurance expenses of $52.582 million is reasonable and adopted.

Section 10

455. It is reasonable to reduce SCE'sTY2012 forecast for PPBU O&M to $55.146 million.

456. DRA's forecast assumption that PPBU will not have an increased workload during the rate cycle is not a reasonable basis to reduce SCE's O&M forecasts for PPBU.

457. The evidence does not support DRA's position that the three positions in MD&A are for MRTU implementation activities and it would be unreasonable to reduce SCE's forecast for that reason.

458. It is reasonable to reduce SCE's TY2012 forecast for MS&RP O&M by $611,000 in labor, and $84,000 in associated labor using the 2009 non-labor/labor ratio of 13.74%.

459. The resulting total of $4.69 million MS&RP O&M is reasonable and adopted.

460. It is reasonable to reduce SCE's labor forecast for ES&M by $598,045 for the five unsupported positions and the non-labor forecast by $82,000 using SCE's 2009 non-labor/labor ratio of 13.74%.

461. The evidence does not support that any of the positions SCE requested in ES&M are for MRTU-related activities.

462. It is reasonable to reduce SCE's TY2012 O&M forecast for ES&M by $1.686 million for labor and $230,000 for associated non-labor expenses.

463. The resulting total of $27.66 million ($20.094 million Labor, $7.567 million Non-Labor) for TY2012 ES&M costs is reasonable and adopted.

464. It is reasonable to reduce SCE's incremental labor request for RAP by 50% and to reduce associated non-labor based on the 2009 ratio of 9.9% non-labor/ labor.

465. The resulting total of $5.746 million ($5.09 million Labor, $656,000 Non-labor) for TY2012 for RAP O&M costs is reasonable and adopted.

466. The evidence does not support DRA's position that four positions in PPF are for MRTU implementation activities and it would be unreasonable to reduce SCE's forecast for that reason.

467. It is reasonable to reduce by one-third SCE's incremental labor request for the PPF department unit ($566,000), and to reduce non-labor at the 2009 ratio of 19% to labor ($108,000).

468. The resulting total of $17.050 million, a 15% increase over 2009 recorded expenses is reasonable and adopted.

469. It is reasonable to adopt SCE's recorded 2010 capital expenditures totaling $21.1 million for PPBU capital projects.

470. It is reasonable to reduce SCE's capital forecast for Communication Equipment expenditures by 50% because the record general support for the project but not for the cost estimate.

471. SCE should record the capital expenditures for the CAISO Market Enhancement Programs project and the Future Market and Enhancements project in the MRTUMA to provide the Commission and the public with the aggregate costs of achieving integration with CAISO's MRTU systems.

472. SCE's 2010-2012 forecast of $2.75 million for Long-Term, Mid-Term, and Short-Term market stimulation tools is reasonable and adopted.

473. It is reasonable to reduce SCE's forecast expenses in 2012 for the Phase 4 portion of the Data Management Platform Upgrade by 10% to address vague elements of the estimate.

474. The resulting total of $9.5 million for the Data Management Platform Upgrade is reasonable and adopted.

475. It is reasonable to consider SCE's requests for the DR-related capital projects in the GRC because DR expenditures that arise from specific programs were not considered in the Commission's overall review of DR activities and budgets.

476. To address an element of vagueness in SCE's cost estimates supporting PPBU capital forecasts, it is reasonable to reduce SCE's 2010-2012 capital spending forecasts for the following projects: ADR, ADR Risk Management, Energy Procurement Planning Management, and the Energy Planning Platform.

477. It is reasonable to adopt SCE's forecasts for 201-2012 capital spending, reduced by 10%, for ADR, ADR Risk Management, Energy Procurement Planning Management, and the Energy Planning Platform.

478. SCE's 2010-2012 request of $14.4 million to implement CMP in two phases is reasonable and adopted.

479. It is reasonable to reduce SCE's forecast 2010-2012 capital spending forecasts for PPBU by $29.46 million, but more than 80% of the capital reduction is eligible for recovery through the MRTUMA.

<u>Section 11</u>

480. It is reasonable to reduce SCE's forecast of OSBU O&M by $15.107 million and adopt a total of $96.818 million.

481. For CEH&S, it is reasonable to reduce SCE's forecast O&M for Accounts 920/921 by 50% of the incremental labor request ($740,000), associated non-labor ($49,000), and 50% of the study costs ($250,000).

482. For CEH&S costs in Account 923, it is reasonable to adopt the 3YA of $490,000, and for Account 925 to reduce the incremental labor increase by 20% to reflect reductions made to SCE's GRC requests, and another $7000 for associated non-labor.

483. Total CEH&S TY2012 O&M of $10.188 million is reasonable and adopted.

484. For Corporate Resources expenses recorded in Accounts 920/921, it is reasonable to reduce the incremental labor increase by $1.424 million and the non-labor forecast by $428,000,resulting in a total of $30.008 million.

485. It is reasonable to reduce SCE's forecast for Account 931 by $312,000 for the third energy center disallowed elsewhere in this decision.

486. For total Corporate Resources TY2012 O&M, it is reasonable to reduce the total request by $2.164 million and adopt the resulting total of $53.348 million.

487. For Corporate Security expenses recorded in Accounts 920/921, it is reasonable to reduce the incremental labor and non-labor increases by 50%, or $2.622 million and $2.429 million, respectively.

488. For total Corporate Security TY2012 O&M, it is reasonable to reduce SCE's forecast by $5.051 million to $17.116 million, including SCE's uncontested forecast for Account 923.

489. For Operations Support Services TY2012 O&M, it is reasonable to adopt $6.347 million based on a 3YA of recorded costs and application of the 2009 labor/non-labor ratio of 56.8%.

490. For Real Properties TY2012 O&M, it is reasonable to reduce SCE's incremental labor increase by 20% ($140,000) and non-labor by $14,000 to reflect reductions to capital projects in this decision.

491. Total Real Properties TY2012 O&M of $6.046 million is reasonable and adopted.

492. The Commission supports the goals of GO 156 because they are beneficial for ratepayers and the communities served by the utilities.

493. It is reasonable for SCE to request O&M funds to implement new initiatives and enhanced reporting prompted by D.11-05-019 which reviewed and updated GO 156.

494. SCE should fully embrace the Commission's view that utilities would be well served by active engagement with CBOs in their service territory, as set forth in D.11-05-019, to achieve better results with the SDD program.

495. SCE's TY2012 forecast of $3.3 million for SDD O&M is reasonable and adopted.

496. It is reasonable to reduce SCE's TSD O&M forecast by $3.180 million, including 10% of estimated additions ($1.58 million) and fleet maintenance ($200,000), and OnBoard Technology O&M ($1.4 million).

497. The resulting total of $135.220 million for TY2012 O&M for TSD is reasonable and adopted.

498. It is reasonable to adopt SCE's 2010 recorded capital expenditures for OSBU in place of SCE's 2010 forecasts.

499. For OSBU capital projects it is reasonable to eliminate the 10% contingency factor, and to reduce project management and Furniture costs by 50% of the difference between SCE's and TURN's calculations.

500. SCE should reconsider the need to begin to build and acquire 350,000 sq. ft. of office space in 2012.

501. It is reasonable to reduce SCE's New Buildings capital forecast to $20 million in 2012, inclusive of adjustments for contingency, project management, and furniture expenses, and adopt it.

502. It is reasonable to reduce SCE's Headquarters 2012 capital forecast by $2.113 million for contingency, project management, and furniture expenses and adopt the result.

503. SCE's uncontested capital forecast of $10.3 million for the DPC Phase 4 AGOC Upgrades project is reasonable and adopted.

504. It is reasonable to reduce SCE's 2011-2012 forecast of $80.300 for Critical Facilities by $4.5 million in 2011 because previously authorized funds should have been applied to necessary RDC life extension activities.

505. The resulting 2011-2012 total of $75.8 million in capital expenditures for Critical Facilities is reasonable and adopted.

506. The SmartConnect-Meter Reader Space Reclamation project costs are ancillary to the deployment and integration of smart meters to SCE's systems and do not qualify for ESCBA treatment.

507. It is reasonable to reduce SCE's 2011-2012 forecasts for the Field Facility Asset Preservation capital projects by $2.359 million for contingency, management, and furniture costs. The resulting 2011-2012 total of $32.706 million is reasonable and adopted.

508. It is reasonable to reduce SCE's 2011-2012 capital forecasts for New Field Facilities by $8.840 million and adopt the resulting total of $25.817 million.

509. It is reasonable to reduce SCE's 2012 forecast for the Service Center Modernization project by $1 million to reflect contingency, management, and furniture expenses.

510. It is reasonable to reduce SCE's 2011-2012 forecast to $3 million annually for Energy Efficiency projects in 2011-2012.

511. For all Blankets project categories combined, the revised total forecast of $80.979 million is reasonable and adopted.

512. It is reasonable to adopt $16.614 million for 2011-2012 CEH&S capital projects.

513. It is reasonable to reduce SCE's 2012 Corporate Security CIPPS request to $3 million, a 29% increase over 2009 costs, to support advanced planning activities for Version 4, which if adopted is most likely to become effective in 2013 or 2014.

514. For Corporate Security, the revised 2011-2012 total forecast of $6 million is reasonable and adopted.

515. SCE's uncontested 2011-2012 forecast of $7.207 million for Transportation Services is reasonable and adopted.

516. It is reasonable to reduce SCE's 2011-2012 forecast for Other Capital Projects to exclude the OnBoard Technology project. The resulting total of $15.277 million is reasonable and adopted.

<u>Sections 12-15</u>

517. SCE's requests to terminate the following balancing and memorandum accounts are not adopted: SPVPBA, Fuel Cell Project Memorandum Account, MRTUMA, Medical Program Balancing Account, and PDDMA.

518. TURN's proposal for the A&G allocation for Catalina Island water and gas operations is reasonable and adopted.

519. TURN's proposed TY2012 pension and benefit costs associated with labor allocated to shareholders of $1.917 million is reasonable and adopted.

520. It is reasonable to reduce SCE's TY2012 forecast number of customers to 4,949,062 and electricity sales to 85,222 GWh.

521. SCE's updated labor, non-labor and capital labor escalation rates are reasonable and adopted.

522. It is reasonable to adopt $165.608 million for companywide OOR for TY2012.

Section 16

523. It is reasonable to adopt an annual November Advice Letter filing to implement the revenue requirement change for 2013 and 2014.

524. A PTYR is reasonable and adopted which includes the following:

- SCE's updated labor and non-labor escalation rates;
- Escalation of adopted 2012 capital additions by 3.05% in 2013 and by 2.93% in 2014;
- Separately adopted 2013 CSBU O&M and capital expenditures escalated in 2014;
- Continuation of the Z factor and the flexible outage schedule mechanism for nuclear refueling costs in attrition years;
- Escalation of medical benefits by 7.5%; and
- No revenue requirement for Four Corners expenses.

Sections 17-19

525. It is reasonable to eliminate the requirement that SCE submit a TFP study with its GRC application.

526. It is reasonable to reduce SCE's forecast for Corporate Center capital expenditures by 15% of SCE's 2010-2012 forecast for PPBU F&E.

527. SCE's forecast for TY2012 Gains on Sale of Property is reasonable and adopted.

528. SCE's application of bonus depreciation to TY2012 tax expense and delay recording the unused deferred tax liabilities against rate base until 2013 are accepted tax normalization and are reasonable and adopted.

529. It is not reasonable for ratepayers to also provide a rate of return on the net operating loss.

530. SCE's proposed M&E deduction to test year income tax is reasonable.

531. It is reasonable to apply the ESOP dividend deduction to tax expense and to discontinue the ESOPTMA.

532. It is reasonable to reduce SCE's property tax forecast reductions adopted to SCE's forecast capital expenditures.

<u>Section 20</u>

533. SCE's 2012 forecast for Customer Advances is reasonable and adopted.

534. SCE is authorized to place up to 10% of its customer deposits into the Certificate of Deposit placement program utilizing minority and community banks; the remaining Customer Deposits are to be recorded as an offset to rate base.

535. It is reasonable to reduce SCE's forecast M&S inventory to $231.678 million.

536. It is reasonable to remove the $5.9 million Cash Balance from the Working Cash forecast.

537. SCE's Working Cash forecasts for Operational Cash Prepayments and Other Accounts Receivable are reasonable and adopted.

538. It is reasonable to reduce SCE's Gas Option premium expense from 33% more than 2009 recorded costs to a 15% increase.

539. It is reasonable to increase rate base by $2.593 million to reflect 2012 reductions to Claims Reserves.

540. SCE's forecast 2012 weighted average estimate Revenue Lag is reasonable and adopted.

541. A 3YA is a reasonable basis to forecast lag days for federal and state income tax payments.

542. DRA's calculation of a pension expense lag day estimate of 75.09 days based on actual 2009 payments is reasonable and adopted; no adjustment should be made to SCE's estimated PBOP expense lag.

543. It is reasonable to add the lag days for payroll to the calculation of 401(k) lag days because the benefit is part of compensation and earned with wages or salary.

544. All other uncontested lag day estimates forecast by SCE are reasonable and adopted.

545. A reduced rate of return on Legacy Meters is not a penalty on investors who are aware of the industry's technological changes.

546. A six-year amortization period for SCE's retired Legacy Meters and an authorized return on equity of 6.72% and rate of return on Legacy Meters of 6.46% is reasonable and adopted.

547. All assets, deductions, and calculations associated with Four Corners in SCE's 2012 rate base shall be removed from rate base as of the effective date of the sale.

548. SCE should be able to recover its net investment in Mohave plant and decommissioning costs over six years of remaining life, but it is not reasonable to earn a rate of return.

Section 21

549. There is insufficient evidence to make changes to SCE's estimated OOR derived from NTP&S.

550. The next Affiliated Transaction Audit ordered for SCE by the Commission should include an audit of the NTP&S program.

Section 22

551. SCE's proposed Mass Property ASL for Accounts 352, 356, 357, 358, 359, 361, 362, 368, 369, 370, 373, and 390 are reasonable and adopted.

552. SCE's proposed Mass Property ASL for Accounts 353 , 354, 355, 364, 365, and 367 are modified as discussed in the body of this decision and are reasonable and adopted as modified.

553. SCE's proposed NSR for Mass Property Accounts 352, 357, 358, 359, 361, 62, 365, 366, 367, and 370 are reasonable and adopted.

554. SCE's proposed NSR for Mass Property Accounts 353, 354, 355, 356, 364, 368, 369, and 373 are modified as discussed in the body of this decision and are reasonable and adopted as modified.

Section 23

555. The proposed settlement between SCE and Disability Rights Advocates is reasonable in light of the whole record, consistent with the law, in the public interest, and is adopted.

556. The proposed settlement between SCE and VSI is reasonable in light of the whole record, consistent with the law, in the public interest, and is adopted.

557. SCE should obtain an independent audit of the 2010 and 2011 RIIM expenditures to identify authorized and recorded expenditures by subaccount and program and provide a comparison of RIIM expenditures to identified reliability metrics.

Section 24

558. The jurisdictional allocation factors used by SCE in its RO model are reasonable and adopted.

ORDER

IT IS ORDERED that:

1. Application 10-11-015 is granted to the extent set forth in this Decision. Southern California Edison Company is authorized to collect, through rates and through authorized ratemaking accounting mechanisms, the 2012 test year base revenue requirement set forth in Appendix C, effective January 1, 2012.

2. Southern California Edison Company shall file its next General Rate Case for test year 2015 pursuant to the applicable Rate Case Plan adopted in Decision 89-01-040, as modified.

3. Within 20 days of the effective date of this decision, Southern California Edison Company shall file revised tariff sheets to implement the revenue requirement, accounting procedures, and charges authorized in this Order and to incorporate the relevant findings 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. Southern California Edison Company 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. Southern California Edison Company is authorized to implement its proposed revenue balancing account to adjust for sales variations and its proposed Post-Test Year Ratemaking mechanism for both 2013 and 2014 to the

extent consistent with the foregoing discussion, findings of fact, and conclusions of law.

6. Southern California Edison Company shall continue the Authorized Base Revenue Requirement Balancing Account.

7. Because the Commission and the public should be able to track the progress of previously authorized large capital projects from one general rate case to the next, for Generation and Transmission and Distribution Business Unit capital expenditures in excess of $1 million, Southern California Edison Company shall submit with its direct testimony in its next general rate case, tables which provide historical and forecast California Public Utilities Commission jurisdictional amounts by sub-categories, as follows:

> (1) The table for each business unit shall provide five years (2008-2012) of recorded costs, 2012 authorized capital spending, and Southern California Edison Company's 2013, 2014, and 2015 capital requests by organization within these business units.
>
> (2) For the Generation table, the data shall be presented by generation source categories; for the Transmission and Distribution table, the data should be presented by organization (e.g., Infrastructure Replacement, Capital Maintenance, etc.).

8. With Southern California Edison Company's (SCE) next general rate case application, SCE shall provide an explanation of the workload analysis used to develop estimated labor increases.

9. With Southern California Edison Company's (SCE) next general rate case application, SCE shall provide a summary of San Onofre Nuclear Generating Station-Safety Culture programs, achievements, and three years of recorded expenses.

10. Southern California Edison Company (SCE) shall establish a San Onofre Nuclear Generating Station Memorandum Account (SONGSMA), effective

January 1, 2012, to track 100% of Operations and Maintenance cost, 100% of cost savings from personnel reductions, 100% of capital expenditures, and 100% of maintenance and refueling outages, if any. No later than January 31, 2013, SCE shall file an application for a reasonableness review of the expenses tracked in the SONGSMA. All expenses disallowed by the SONGSMA review shall be refunded to ratepayers; all savings allowed shall be credited to the ratepayers.

11. Given the very unusual circumstances of the San Onofre Nuclear Generating Station (SONGS) shutdown, San Diego Gas & Electric Company (SDG&E) shall participate in the proceeding where the Commission reviews expenses recorded in the San Onofre Nuclear Generating Station Memorandum Account, which will establish SDG&E's pro rata share of reasonable SONGS TY2012 Operations and Maintenance and post-2011 capital spending that is not addressed in SDG&E's own general rate case, Application 10-12-005.

12. In its next general rate case application, Southern California Edison Company shall provide the Commission with a summary of actions taken and total expenses incurred to address regulatory concerns of the Nuclear Regulatory Commission beginning in 2009, any shareholder costs, and identify whether any of the expenses are recurring its next general rate case application.

13. Southern California Edison Company shall continue the two-way balancing account to record the ongoing costs associated with Mohave Generating Station.

14. Southern California Edison Company may establish a Four Corners Memorandum Account to track expenses incurred between October 1, 2012 and the delayed sale date and file an application for reasonableness review after the sale of Four Corners is completed.

15. Southern California Edison Company shall file an application for the review of all construction related expenditures for the McGrath peaker plant no later than December 31, 2012.

16. In its next general rate case application, Southern California Edison Company (SCE) shall provide the Commission with an estimate of unused distribution capacity for the test year, including other Commission Findings of Fact (e.g. from the Resource Adequacy and Long-Term Procurement Proceedings), and address it in connection with SCE's forecast Load Growth during the rate cycle at issue.

17. Southern California Edison Company(SCE) shall use up to $0.753 million of its Operations and Maintenance request for subaccount 583.120 to perform full inspections of a statistically valid random sample of loaded poles, utility-owned and jointly-owned, to determine whether the loads meet current legal standards, as follows:

(1) To the extent that the Commission orders, through any other proceeding, an examination of pole loads within SCE's territory, the study ordered here shall be coordinated to avoid duplication;

(2) SCE must use any unspent funds for intrusive pole inspections unless the Commission is advised to the contrary by a Tier 2 Advice Letter; and

(3) SCE shall serve the summary results of the study on the service lists of this proceeding and Rulemaking 08-11-005, and provide the pole-by-pole results to the Director of Consumer Protection and Safety Division, no later than July 31, 2013. Southern California Edison Company (SCE) shall include the results with SCE's next Distribution Inspection and Maintenance Plan annual report.

18. Following receipt of the pole load study results, the Director of Consumer Protection and Safety Division shall make recommendations to the Commission

about what steps, if any, are necessary to assure that Southern California Edison Company's poles are not overloaded going forward.

19. Because the Commission will evaluate the value of an accelerated inspection program, with its next general rate case application, Southern California Edison Company shall provide information summarizing how many priority 1, 2, and 3 conditions were identified by the actual number of intrusive wood pole inspections performed in 2012 and 2013.

20. Because the reliability consequences of in-service failure of transmission poles is substantial, Southern California Edison Company shall provide with its next general rate case application, a summary of the transmission pole inspection results by category (i.e., 1, 2, or 3) of identified repair.

21. With its next general rate case application, Southern California Edison Company shall identify the portion of 2012 recorded costs related to terminated, superseded, and completed activities, and a review of steps considered or taken to minimize training costs, including low or no cost vendor support of new technologies.

22. Southern California Edison Company shall file revised tariffs to implement the service fees adopted herein.

23. Because the Commission needs to evaluate the SmartConnect program after full deployment, Southern California Edison Company is directed to provide a spreadsheet of 2008-2015 SmartConnect costs and benefits credited by Federal Energy Regulatory Commission account/subaccount and capital program. This is not a duplicate reasonableness review.

24. Southern California Edison Company shall continue the Edison SmartConnect Balancing Account in this rate cycle and to record their expenses anticipated by Decision 08-09-039 for Home Area Network and related

programs for programmable communicating thermostats and in-home display devices.

25. In order to provide the Commission with a complete review of expenses related to Dynamic Pricing (DP) activities, Southern California Edison Company shall track 2012-2014 DP expenses recovered through the general rate case (GRC) and include the results with its next GRC application.

26. Southern California Edison Company (SCE) shall provide a report to the Commission via a Tier 2 Advice Letter, no later than January 31, 2013, which describes the progress made by SCE with each of the post-November 2011 windstorm initiatives it identified to the Commission, by ex parte letters made part of the proceeding record, to improve communications and customer satisfaction in times of emergency.

In addition to the service list of this proceeding, SCE shall serve the Advice Letter on the Directors of the Commission's Energy Division, Consumer Service and Information Division, and Consumer Protection & Safety Division.

27. Because it is in ratepayers' interest to undertake a more detailed review of Southern California Edison Company (SCE) capitalized software requests in the next general rate case (GRC), SCE is directed to provide the following as part of its testimony in support of forecast capitalized software projects in its next GRC:

(1) A table listing capitalized software projects funded during 2010-2012, as identified in this GRC across all business units. The table shall include, for each project, SCE's final 2012 GRC forecast, as well as authorized and recorded expenditures;

(2) Information about whether SCE employs best industry practices in making its capitalized software project cost estimates, particularly as to in-house labor, project management and contingency;

(3) Information about how SCE is effectively optimizing experience and assets to minimize costs of software development and implementation;

(4) Information about how SCE is cost effectively planning its system design, including maximizing use of custom over-the-counter software and life extension activities, to meet growing demand for technology solutions; and

(5) Information about whether reasonable metrics are available to measure productivity results from information technology solutions.

28. Southern California Edison Company (SCE) shall continue reporting on workforce composition in its general rate case, modified to include a 10-year comparison by job classification and an explanation of steps SCE has taken to ensure top management leadership development for underrepresented groups.

29. Southern California Edison Company (SCE) shall provide in its next general rate case, a five-year (2009-2013) summary of the type of complaints made to the Equal Employment Office and a description of anti-discrimination and sexual harassment prevention training provided to SCE employees during that period, including any substantial revisions to scheduling and content.

30. Within six months of the effective date of this decision, Division of Ratepayer Advocates and Southern California Edison Company (SCE) are directed to jointly hold a workshop open to all parties in this proceeding to discuss whether design modifications should be made to the next Total Compensation Study or an alternative method of data gathering should be utilized for the next SCE general rate case.

31. Southern California Edison Company shall continue to track the authorized and recorded Results Sharing costs in a memorandum account. When the actual Results Sharing payouts for 2012-2014 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.

32. Southern California Edison Company shall continue the two-way balancing account for pension costs and for Post-Retirement Benefits Other than Pension consistent with the terms authorized in Decision 06-05-016.

33. Because there have been many changes to public and private pension design since Southern California Edison Company (SCE) last reviewed its pension policies in 1999, as part of its testimony in the next general rate case, SCE shall provide a review of its pension policies, in light of best practices and economic conditions, to support its rate recovery request for pension plan funding.

34. Because the Commission will review the aggregate costs of achieving integration with the California Independent System Operator's (CAISO) Market Redesign and Technology Upgrade (MRTU) systems, Southern California Edison Company is directed to record in the Market Redesign and Technology Upgrade Memorandum Account (MRTUMA) the capital expenditures for the CAISO Market Enhancement Programs project and the Future Market and Enhancements project, in addition to MRTU-associated Operations and Maintenance identified in the decision.

35. As a protection to ratepayers, Southern California Edison Company is directed to continue the following accounts and may seek recovery of certain costs in the Energy Resource Recovery Account or other proceeding:

(1) Solar Photovoltaic Project Balancing Account

(2) Fuel Cell Project Memorandum Account

(3) Medical Program Balancing Account

(4) Project Development Division Memorandum Account

36. Southern California Edison Company (SCE) shall remove from rate base all assets, deductions, and calculations associated with SCE's ownership share in Four Corners Generation Station Units 4 and 5 effective as of the completion of the sale of that interest.

37. Southern California Edison Company shall not earn a rate of return on undepreciated plant and decommissioning costs for the Mohave Generating Station.

38. Southern California Edison Company shall amortize the undepreciated balance of electromechanical electric meters replaced by smart meters, a net plant balance of $308.699 million at the end of 2010, over the six-year period of 2011-2016. The applicable rate of return on the unamortized meter balance shall be 6.72%.

39. Southern California Edison Company shall file an annual November Tier 2 Advice Letter to implement changes to its revenue requirement for post-test years 2013 and 2014 consistent with the requirements set forth in this decision.

40. Because the last external Non-Tariffed Products and Services (NTP&S) audit was in 2006, as part of the Affiliate Transactions Audit, the Commission's Energy Division is directed to ensure that the next Affiliate Transactions Audit managed by the Energy Division includes a focused review of the NTP&S program, including Southern California Edison Company's (SCE) development of incremental costs, to ensure that SCE is accurately identifying them and recording them.

41. The Disability Rights Advocates' Settlement with Southern California Edison Company submitted for approval on August 22, 2011 is adopted without modification.

42. The Vote Solar Initiative's Settlement with Southern California Edison Company submitted for approval on September 2, 2011 is adopted without modification.

43. The Coalition of California Utility Employees' Settlement with Southern California Edison Company (SCE) submitted October 22, 2011 to modify and continue the Reliability Investment Incentive Mechanism (RIIM) is adopted. Because the Commission and some parties retain concerns about the impact of the RIIM incentives, SCE shall obtain an independent audit of the recorded 2010-2011 RIIM expenditures to identify authorized and recorded expenditures in each of the subaccounts and programs included within SCE's broad RIIM categories. Prior to contracting for the independent audit, SCE shall file a Tier 1 Advice Letter with the Energy Division which identifies the proposed auditor. No later than September 1, 2013, SCE shall submit the results of the independent RIIM audit by Tier 2 Advice Letter to the Director of the Energy Division, along with an analysis of short-term reliability statistics (e.g., System Average Interruption Duration Index, System Average Interruption Frequency Index) tracked with RIIM expenditures since 2003.

44. Application 10-11-015 is closed.

This order is effective today.

Dated, November 29, 2012, at San Francisco, California

MICHAEL R. PEEVEY
President
TIMOTHY ALAN SIMON
MICHEL PETER FLORIO
CATHERINE J.K. SANDOVAL
MARK J. FERRON
Commissioners.

APPENDIX A

A.10-11-015 Service List

APPENDIX A

SERVICE LIST – A.10-11-015

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(End of Appendix A)

APPENDIX B

Glossary

APPENDIX B

(Acronyms used in Proposed Decision)

Acronyms	Description
A&G	Administrative and General
A&R	Accounting and Reporting
AACE	Association for the Advancement of Cost Engineering
ACE	Awards to Celebrate Excellence
ADC	Alhambra Data Center
ADR	Aggregated Demand Response
ADRB	Average Depreciated Rate Base
AES-TEC	Advanced Energy Storage Technology Evaluation Center
AGCC	Alternate Grid Control Center
AGR	Annual Growth Rate
AGTAC	Agricultural Technology Application Center
ALJ	Administrative Law Judge
AMI	Advanced Metering Infrastructure
APMS	Application Portfolio Management System
APS	Arizona Public Service
ASL	Average Service Life
ATO	Advanced Technology Organization
ATR	Affiliate Transaction Rule
ATRA	Arizona Tax Research Association
BEx	Business Explorer
BOON	Best Option Outside Negotiation
BP&FM	Business Planning and Financial Management
BP&TI	Business Process and Technology Integration
BS&AO	Bidding Strategy & Asset Optimization

BW	Business Warehouse
C&I	Commercial and Industrial
CAD	Computer Aided Design
CAFM	Computer Aided Facility Management
CAISO	California Independent System Operator Corporation
Cal-Tax	California Taxpayers Association
CARB	California Air Resources Board
Catalina	Santa Catalina Island
CB	Capacity Building
CBCC	California Black Chamber of Commerce
CBOs	Community-based organizations
CCO	Customer Communication Organization
CCUE	California Coalition of Utility Employees
CD	Certificate of Deposit
CDW	Customer Data Warehouse
CEH&S	Corporate Environmental Health and Safety
CEMA	Catastrophic Event Memorandum Account
CEQA	California Environmental Quality Act
CES	Common Enterprise Services
CHP	Combined Heat and Power
CIAC	Contributions in Aid of Construction
CIC	Cable-in-Conduit
CIP	Critical Infrastructure Protection
CIPPS	Critical Infrastructure Protection Physical Security
CMD	Configuration Management Database
CMP	Compliance Management Program
CMS	Consolidated Mobile Systems
CMS	Clams Management System

CMS	Compliance Management System
COR	Costs of Removal
COTS	Commercial Off-the-Shelf (software)
CPCN	Certificate of Public Convenience and Necessity
CPI	Consumer Price Index
CPP	Critical Peak Pricing
CPSD	Consumer Protection and Safety Division
CPUC	California Public Utilities Commission
C-RAS	Centralized Remedial Action Scheme
CREST	California Renewable Energy Small Tariff
CRP	Cable Replacement Program
CS&ID	Customer Service and Information Delivery
CSBE	Customer Service Bill Enhancement
CSBU	Customer Service Business Unit
CSID	Customer Services and Information Division
CSIT	California State Income Tax
CSOD	Customer Services Operations Division
CTAC	Customer Technology Application Center
CW	Contingent Workers
CWIP	Construction Work in Progress
CWO	Capital Work Order
DAP	Department Annual Program
DBEs	Disabled Veteran-owned Business Enterprises
DCM	Distribution Construction and Maintenance
DCMS	Distribution Control and Monitoring System
DGA	Dissolved Gas Analysis
DGSS	Distribution Grid Support System
DIMP	Distribution Inspection and Maintenance Program

DisabRA	Disability Rights Advocates
DMS	Distribution Management System
DP	Dynamic Pricing
DP&FA	Distribution Planning and Field Accounting
DR	Demand Response
DRA	Division of Ratepayer Advocates
DSEEP	Distribution System Efficiency Enhancement Project
DSP	Distribution Substation Plan
DSRP	Distribution Service Request Pricing
DWR	Department of Water Resource
EAF	Energy Assistance Fund
ECS	Edison Carrier Solutions
EDS	Economic Development Services
EEI	Edison Electric Institute
EIC	Executive Incentive Compensation
EIX	Edison International
EO	Energy Operations
EPPM	Energy Procurement Planning Management
EPS	Emissions Performance Standard
ERCP	Energy Regulation Compliance Program
ERP	Enterprise Resource Planning
ERRA	Energy Resource Recovery Account
ES&M	Energy Supply and Management
ESCBA	SCE SmartConnect Balancing Account
ESOP	Employee Stock Ownership Plan
ESOPTMA	Employee Stock Ownership Plan Tax Memorandum Account
ESP	Electric System Planning

FAO	Field Accounting Organization
FCP	Fuel Cell Project
FCPC	FERC Compliance, Policy and Contracts
FCPMA	Fuel Cell Program Memorandum Account
FERC	Federal Energy Regulatory Commission
FHPMA	Fire Hazard Prevention Memorandum Account
FIT	Federal Income Tax
Four Corners	Four Corners Generation Station
FSR	Field Service Representative
GCC	Grid Control Center
GHG	Greenhouse gas
GIS	Geographic Information System
GO	General Order
GRC	General Rate Case
GRSM	Gross Revenue Sharing Mechanism
GWh	Gigawatt hours
HAN	Home Area Network
HBPP	Humboldt Bay Power Plant
HGP	Hot Gas Path
HPT	High Pressure Turbine
HR	Human Resources
HVAC	Heating, Ventilation, and Air Conditioning
Hydro	Hydroelectric
IBC	Irwindale Business Center
IEC	International Electrotechnical Commission
IFRS	International Financial Reporting Standards
IHDs	In-Home Displays
IMM	Interdepartmental Market Mechanism

IOUs	Investor-Owned Utilities
IPP	Independently Power Produced
IR	Infrastructure Replacement
IRC	Internal Revenue Code
ISFSI	Independent Spent Fuel Storage Installations
IT	Information Technology
IT&BI	Information Technology and Business Integration
IVR	Interactive Voice Response
JCE	Joint Comparison Exhibit
Joint Parties	Black Economic Council, National Asian American Coalition, and Latino Business Chamber of Greater Los Angeles
kV	kilovolt
LADWP	Los Angeles Department of Water and Power
LAP	Load Aggregation Point
LBRO	Long Beach Regional Office
LCD	Least Cost Dispatch
LED	Light Emitting Diode
LEV	Low Emission Vehicle
LMP	Locational Marginal Pricing
LPA	Local Public Affairs
LRY	Last Recorded Year
LTD	Long-Term Disability
LTI	Long-Term Incentive
LTPP	Long-Term Procurement Plan
Lundy	Lundy Reline Conveyance System
M&E	Meals and Entertainment
M&S	Materials and Supplies

MAP	Markets and Performance
MBA	Mohave Balancing Account
MBL	Medical Baseline
MD&A	Market Design and Analysis
MDMS	Meter Data Management System
MIP	Management Incentive Program
Mohave	Mohave Generation Station
Mountainview	Mountainview Power Plant
MPBA	Medical Program Balancing Account
MRN	Mobile Radio Network
MRTU	Market Redesign and Technology Upgrade
MRTUMA	Market Redesign and Technology Upgrade Memorandum Account
MSO	Meter Services Organization
MW	Megawatt
MWh	Megawatt-hour
NATM	Nuclear Administrative and Technical Manual
NERC	North American Electric Reliability Corporation
NOL	Net Operating Loss
NRC	Nuclear Regulatory Commission
NTP&S	Non-Tariffed Products and Services
O&M	Operations and Maintenance
OAR	Other Accounts Receivable
OB	Opening Brief
OOR	Other Operating Revenue
OSBU	Operations Support Business Unit
OSR	Oil Switch Replacement
OTC	Once-through-cooling

Palo Verde	Palo Verde Nuclear Generating Station
PBGS	Pebbly Beach Generating Station
PBOPs	Post-Retirement Benefits Other Than Pensions
PCBA	Pension Costs Balancing Account
PCTs	Programmable Communicating Thermostats
PDD	Project Development Division
PDDMA	Project Development Division Memorandum Account
PEV	Plug-in Electric Vehicle
PFM	Petition for Modification
PG&E	Pacific Gas and Electric Company
POLB	Port of Long Beach
PPBU	Power Procurement Business Unit
PPF	Power Procurement Finance
PPH	Public Participation Hearing
PPM	Project Portfolio Management
PTC	Permit to Construct
PTEs	Part-Time Employees
PTYR	Post-Test year ratemaking mechanism
PURPA	Public Utility Regulatory Policy Act
PV	Photovoltaic
QF	Qualifying Facilities
R&D	Research and Development
RA	Resource Adequacy
RAM	Renewable Auction Mechanism
RAP	Renewable and Alternative Power
RAS	Remedial Action Schemes
RD&D	Research, Development, and Demonstration
RDC	Rosemead Data Center

RECs	Renewable Energy Credits
RFI	Request for Information
RFP	Request for Proposal
RIIM	Reliability Investment Incentive Mechanism
RO	Results of Operations
ROM	Rough Order of Magnitude
ROW	Right of Way
RP&A	Regulatory Policy and Affairs
RP&E	Resource Policy and Economics
RPG	Resource Planning Group
RPIS	Revenue Protection Investigation System
RPS	Renewable Portfolio Standard
RRMA	Revenue Requirement Memorandum Account
RS	Results Sharing
RSO	Revenue Services Organization
RSS	Remote Service Switch
RTDS	Real-Time Digital Simulator
RTEM	Real Time Energy Meters
S&ES	Safety and Environmental Services
SA3	Substation Automation 3
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SAM	Software Asset Management
SAP	Systems, Applications, and Products
SC&M	Substation Construction and Maintenance
SCADA	Supervisory Control and Data Acquisition
SCAQMD	South Coast Air Quality Management District
SCE	Southern California Edison Company

SDD	Supplier Diversity and Development
SDG&E	San Diego Gas & Electric Company
SDP	Survivor and Disability Benefits Plan
SEC	Securities and Exchange Commission
SERP	Substation Equipment Replacement Program
SERP	Supplemental Executive Retirement Plan
SGRP	Steam Generator Replacement Project
SOC	SmartConnect Operations Center
SOLO	Street and Outdoor Lighting Organization
SONGS	San Onofre Nuclear Generating Station
SONGSMA	San Onofre Nuclear Generating Station Memorandum Account
SOX	Sarbanes-Oxley
SPVP	Solar Photovoltaic program
SPVPBA	Solar Photovoltaic Project Balancing Account
Sq. ft.	Square feet
SSID	Shop Services and Instrumentation Division
STI	Short-Term Incentive
SWRCB	State Water Resources Control Board
T&D	Transmission and Distribution
TA	Technical Assistance
TCS	Total Compensation Study
TDBU	Transmission and Distribution Business Unit
TFP	Total Factor Productivity
TFP	Total Factor Productivity
TLCS	Transmission Line Clearance Study
TOU	Time of Use
TRA	Tax Reform Act

TRM	Technology and Risk Management
TSD	Transportation Services Division
TURN	The Utility Reform Network
TY	Test Year
UCIS	Utility Cost Information Service
UOG	Utility-owned Generation
USAT	Ultra Small Antenna Terminal Satellite System
VHF	Very High Fire
VLF	Vehicle License Fee
VSI	Vote Solar Initiative
WASAS	Wide-Area Situational Awareness
WCR	Worst Circuit Rehabilitation
WECC	Western Electricity Coordinating Council
WISER	Wires Investment Strategy Efficiency Review
WPTF	Western Power Trading Forum

(END OF APPENDIX B)

Southern California Edison
2012 General Rate Case
Application
Results of Operations Model
Table of Contents - Appendices

APPENDIX C

Southern California Edison Company
2012 Results of Operations
Thousands of Dollars

Line No.	Item	Adopted	SCE Request (Based on November 2011 Update Testimony)	Difference (SCE Request Less Adopted)
1.	**TOTAL OPERATING REVENUES**	5,670,748	6,294,060	623,312
2.	**OPERATING EXPENSES:**			
3.	Production			
4.	Steam	16,274	63,284	47,010
5.	Nuclear	359,768	431,737	71,969
6.	Hydro	56,000	57,610	1,610
7.	Other	126,328	135,572	9,245
8.	Subtotal Production	558,370	688,203	129,833
9.	Transmission	87,740	94,501	6,761
10.	Distribution	465,850	497,422	31,572
11.	Customer Accounts	209,595	213,822	4,227
12.	Uncollectibles	11,213	14,413	3,200
13.	Customer Service & Information	45,521	50,069	4,548
14.	Administrative & General	819,383	967,022	147,639
15.	Franchise Requirements	50,053	57,037	6,984
16.	Revenue Credits	(149,979)	(151,304)	(1,325)
17.	Subtotal	2,097,745	2,431,186	333,441
17.	Escalation	174,598	201,929	27,331
18.	Depreciation	1,222,299	1,433,862	211,563
19.	Taxes Other Than On Income	248,145	266,156	18,011
20.	Taxes Based On Income	463,314	541,309	77,995
21.	Total Taxes	711,459	807,465	96,006
22.	**TOTAL OPERATING EXPENSES**	4,206,101	4,874,443	668,342
23.	**NET OPERATING REVENUE**	1,317,312	1,419,617	102,305
24.	**RATE BASE**	15,072,221	16,224,197	1,151,976
25.	**RATE OF RETURN**	8.74%	8.75%	0.01%
26.	Four Corners	88,388		(88,388)
27.	Mohave	(5,552)		5,552
28.	Legacy Meters	64,500		(64,500)
29.	**REVENUES AT PRESENT RATES**	5,398,840	5,398,840	0
30.	**NET INCREASE OVER PRESENT RATES**	271,908	895,220	623,312

APPENDIX C

Southern California Edison Company
2012 Total Company Results of Operation
Thousands of Dollars

Line No.	Item	Adopted
1.	**TOTAL OPERATING REVENUES**	6,125,630
2.	**OPERATING EXPENSES:**	
3.	Production	
4.	Steam	16,274
5.	Nuclear	359,768
6.	Hydro	56,000
7.	Other	126,328
8.	Subtotal Production	558,370
9.	Transmission	176,261
10.	Distribution	471,311
11.	Customer Accounts	209,595
12.	Uncollectibles	12,435
13.	Customer Service & Information	45,521
14.	Administrative & General	856,145
15.	Franchise Requirements	55,510
16.	Revenue Credits	(183,805)
17.	Subtotal	2,201,343
18.	Escalation	184,665
19.	Depreciation	1,352,807
20.	Taxes Other Than On Income	282,259
21.	Taxes Based On Income	547,600
22.	Total Taxes	829,859
23.	**TOTAL OPERATING EXPENSES**	4,568,673
24.	**NET OPERATING REVENUE**	1,556,957
25.	**RATE BASE**	17,814,154
26.	**RATE OF RETURN**	8.74%

APPENDIX C
Southern California Edison
2012 Results of Operations
Sales Forecast

	Adopted
Sales Forecast (GWh)	
Residential	28,433
Commercial	41,593
Industrial	8,157
Other Public Authority 1/	5,682
Agricultural	1,357
	85,222
Customer Forecast (No. of Customers)	
Residential	4,317.6
Commercial	551.9
Industrial	11.3
Other Public Authority 1/	46.0
Agricultural	22.2
	4,949.1

1/ Includes Streetlighting class.

Appendix C
Southern California Edison
Test Year 2012 General Rate Case
Operation And Maintenance Expenses
Thousands of Dollars
Category: Total Production

Line No.	Account No.	Description	CPUC Adopted
1.		TOTAL STEAM	16,274
2.		TOTAL NUCLEAR	359,768
3.		TOTAL HYDRO	56,000
4.		TOTAL OTHER	126,328
5.		TOTAL PRODUCTION Constant 2009$	558,370
6.		Escalation	48,722
7.		TOTAL INCLUDING ESCALATION (2012$)	607,091
8.		LABOR, NON-LABOR AND OTHER EXPENSE DETAIL:	
9.		Total Company Constant 2009$	
10.		Labor	319,395
11.		Non-Labor	226,259
12.		Other	12,716
13.		Subtotal Total Company	558,370
14.		Escalation:	
15.		Labor	28,299
16.		Non-Labor	20,423
17.		Other	-
18.		Subtotal Total Company	48,722
19.		TOTAL INCLUDING ESCALATION (2012$)	607,091

Appendix C
Southern California Edison
Test Year 2012 General Rate Case
Operation And Maintenance Expenses
Thousands of Dollars
Category: Steam Production

Line No.	Account No.	Description	CPUC Adopted
1		Operation	
2.	500	Operation Supervision and Engineering	15,775
3.	501	Fuel	-
4.	502	Steam Expenses	-
5.	505	Electric Expenses	-
6.	506	Miscellaneous Steam Power Expenses	194
7.	507	Rents	-
8.	509	Allowances	-
		TOTAL OPERATION	15,969
9.		Maintenance	
10.	510	Maintenance Supervision and Engineering	-
11.	511	Maintenance of Structures	-
12.	512	Maintenance of Boiler Plant	-
13.	513	Maintenance of Electric Plant	-
14.	514	Maintenance of Miscellaneous Steam Plant	305
15.		TOTAL MAINTENANCE	305
16.		TOTAL STEAM Constant 2009$	16,274
17.		Escalation	1,445
18.		TOTAL STEAM INCLUDING ESCALATION (2012$)	17,719
19.		LABOR, NON-LABOR AND OTHER EXPENSE DETAIL:	
20.		Total Steam Constant 2009$	
21.		Labor	16,075
22.		Non-Labor	199
23.		Other	-
24.		Subtotal Total Steam	16,274
25.		Escalation:	
26.		Labor	1,424
27.		Non-Labor	20
28.		Other	-
29.		Subtotal Total Steam	1,445
30.		TOTAL STEAM INCLUDING ESCALATION (2012$)	17,719

Appendix C
Southern California Edison
Test Year 2012 General Rate Case
Operation And Maintenance Expenses
Thousands of Dollars
Category: Nuclear Production

Line No.	Account No.	Description	CPUC Adopted
1.		Operation	
2.	517	Operation Supervision and Engineering	77,191
3.	518	Nuclear Fuel Expense	-
4.	519	Coolants and Water	5,875
5.	520	Steam Expenses	33,684
6.	523	Electric Expenses	5,504
7.	524	Miscellaneous Nuclear Power Expenses	114,618
8.	525	Rents	1,599
9.		TOTAL OPERATION	238,471
10.		Maintenance	
11.	528	Maintenance Supervision and Engineering	33,722
12.	529	Maintenance of Structures	9,715
13.	530	Maintenance of Reactor Plant Equipment	10,419
14.	531	Maintenance of Electric Plant	8,799
15.	532	Maintenance of Miscellaneous Nuclear Plant	58,642
16.		SONGS 2&3 Refueling Outage Adjustment	-
17.		TOTAL MAINTENANCE	121,297
18.		TOTAL NUCLEAR Constant 2009$	359,768
19.		Escalation	32,192
20.		TOTAL NUCLEAR INCLUDING ESCALATION (2012$)	391,960
21.		LABOR, NON-LABOR AND OTHER EXPENSE DETAIL:	
22.		Total Nuclear Constant 2009$	
23.		Labor	222,905
24.		Non-Labor	136,863
25.		Other	-
26.		Subtotal Total Nuclear	359,768
27.		Escalation:	
28.		Labor	19,750
29.		Non-Labor	12,442
30.		Other	-
31.		Subtotal Total Nuclear	32,192
32.		TOTAL NUCLEAR INCLUDING ESCALATION (2012$)	391,960

Appendix C
Southern California Edison
Test Year 2012 General Rate Case
Operation And Maintenance Expenses
Thousands of Dollars
Category: Hydro Production

Line No.	Account No.	Description	CPUC Adopted
1.		Operation	
2.	535	Operation Supervision and Engineering.	6,065
3.	536	Water for Power	3,856
4.	537	Hydraulic Expenses	3,045
5.	538	Electric Expenses	3,584
6.	539	Miscellaneous Hydraulic Power Generation Expenses	17,113
7.	540	Rents	2,814
8.		TOTAL OPERATION	36,477
9.		Maintenance	
10.	541	Maintenance Supervision and Engineering	2,245
11.	542	Maintenance of Structures	2,184
12.	543	Maintenance of Reservoirs, Dams and Waterways	5,574
13.	544	Maintenance of Electric Plant	6,602
14.	545	Maintenance of Miscellaneous Hydraulic Plant	2,918
15.		TOTAL MAINTENANCE	19,523
16.		TOTAL HYDRO Constant 2009$	56,000
17.		Escalation	5,433
18.		TOTAL HYDRO INCLUDING ESCALATION 2012$	61,433
19.		LABOR, NON-LABOR AND OTHER EXPENSE DETAIL:	
20.		Total Hydro Constant 2009$	
21.		Labor	25,153
22.		Non-Labor	30,847
23.		Other	-
24.		Subtotal Total Hydro	56,000
25.		Escalation:	
26.		Labor	2,229
27.		Non-Labor	3,204
28.		Other	-
29.		Subtotal Total Hydro	5,433
30.		TOTAL HYDRO INCLUDING ESCALATION (2012$)	61,433

Appendix C
Southern California Edison
Test Year 2012 General Rate Case
Operation And Maintenance Expenses
Thousands of Dollars
Category: Other Production

Line No.	Account No.	Description	CPUC Adopted
1.		Operation	
2.	546	Operation Supervision and Engineering	4,328
3.	547	Fuel	-
4.	548	Generation Expenses	7,756
5.	549	Miscellaneous Other Power Generation Expenses	16,894
6.	550	Rents	2,862
7.		TOTAL OPERATION	31,840
8.		Maintenance	
9.	551	Maintenance Supervision and Engineering	2,057
10.	552	Maintenance of Structures	1,223
11.	553	Maintenance of Generating and Electric Plant	31,320
12.	554	Maintenance of Miscellaneous Other Power Generation Plant	3,531
13.	555	Purchased Power	-
14.	556	System Control and Load Dispatching	1,210
15.	557	Other Expenses	55,147
16.		TOTAL MAINTENANCE	94,488
17.		TOTAL OTHER Constant 2009$	126,328
18.		Escalation	9,652
19.		TOTAL OTHER INCLUDING ESCALATION (2012$)	135,980
20.		LABOR, NON-LABOR AND OTHER EXPENSE DETAIL:	
21.		Total Other Constant 2009$	
22.		Labor	55,262
23.		Non-Labor	58,350
24.		Other	12,716
25.		Subtotal Total Other	126,328
26.		Escalation:	
27.		Labor	4,896
28.		Non-Labor	4,756
29.		Other	-
30.		Subtotal Total Other	9,652
31.		TOTAL OTHER INCLUDING ESCALATION (2012$)	135,980

Appendix C
Southern California Edison
Test Year 2012 General Rate Case
Operation And Maintenance Expenses
Thousands of Dollars
Category: Transmission Expenses

Line No.	Account No.	Description	CPUC Adopted
1.		Operation:	
2.	560	Operation Supervision and Engineering	7,448
3.	561	Load Dispatching	4,781
4.	562	Station Expenses	6,301
5.	563	Overhead Line Expenses	1,542
6.	564	Underground Line Expenses	444
7.	565	Transmission of Electricity by Others	-
8.	566	Miscellaneous Transmission Expenses	22,047
9.	567	Rents	4,094
10.		TOTAL OPERATION	46,657
11.		Maintenance:	
12.	568	Maintenance Supervision and Engineering	7,417
13.	569	Maintenance of Structures	1,607
14.	570	Maintenance of Station Equipment	12,582
15.	571	Maintenance of Overhead Lines	17,363
16.	572	Maintenance of Underground Lines	-
17.	573	Maintenance of Miscellaneous Transmission Plant	2,115
18.		TOTAL MAINTENANCE	41,084
19.		TOTAL TRANSMISSION EXPENSE Constant 2009$	87,741
20.		Escalation	7,339
21.		TOTAL INCLUDING ESCALATION (2012$)	95,080
22.		LABOR, NON-LABOR AND OTHER EXPENSE DETAIL:	
23.		Total Constant 2009$	
24.		Labor	36,033
25.		Non-Labor	51,302
26.		Other	407
27.		Subtotal	87,742
28.		Escalation:	
29.		Labor	3,076
30.		Non-Labor	4,263
31.		Other	-
32.		Subtotal	7,339
33.		TOTAL INCLUDING ESCALATION (2012$)	95,081

Appendix C
Southern California Edison
Test Year 2012 General Rate Case
Operation And Maintenance Expenses
Thousands of Dollars
Category: Distribution Expenses

Line No.	Account No.	Description	CPUC Adopted
1.		Operation:	
2.	580	Operation Supervision and Engineering	30,677
3.	582	Station Expenses	17,791
4.	583	Overhead Line Expenses	19,764
5.	584	Underground Line Expenses	(879)
6.	585	Street Lighting and Signal System Expenses	578
7.	586	Meter Expenses	27,851
8.	587	Customer Installations Expenses	16,918
9.	588	Miscellaneous Distribution Expenses	123,018
10.	589	Rents	597
11.		TOTAL OPERATION	236,315
12.		Maintenance:	
13.	590	Maintenance Supervision and Engineering	44,703
14.	591	Maintenance of Structures	486
15.	592	Maintenance of Station Equipment	10,112
16.	593	Maintenance of Overhead Lines	127,924
17.	594	Maintenance of Underground Lines	14,598
18.	595	Maintenance of Line Transformers	1,068
19.	596	Maintenance of Street Lighting and Signal Systems	5,279
20.	597	Maintenance of Meters	1,669
21.	598	Maintenance of Miscellaneous Distribution Plant	23,692
22.		TOTAL MAINTENANCE	229,531
23.		TOTAL DISTRIBUTION EXPENSE Constant 2009$	465,846
24.		Escalation	45,113
25.		TOTAL INCLUDING ESCALATION (2012$)	510,959
26.		LABOR, NON-LABOR AND OTHER EXPENSE DETAIL:	
27.		Total Constant 2009$	
28.		Labor	224,386
29.		Non-Labor	238,684
30.		Other	2,783
31.		Subtotal	465,853
32.		Escalation:	
33.		Labor	19,881
34.		Non-Labor	25,232
35.		Other	-
36.		Subtotal	45,113
37.		TOTAL INCLUDING ESCALATION (2012$)	510,966

Appendix C
Southern California Edison
Test Year 2012 General Rate Case
Operation And Maintenance Expenses
Thousands of Dollars
Category: Customer Accounts Expenses

Line No.	Account No.	Description	CPUC Adopted
1.	901	Supervision	13,332
2.	902	Meter Reading Expenses	44,758
3.	903	Customer Records and Collection Expenses	112,471
4.	904	Uncollectible Accounts	11,213
5.	905	Miscellaneous Customer Accounts Expenses	35,235
6.		TOTAL CUSTOMER ACCOUNTS Constant 2009$	220,808
7.		Escalation	17,546
8.		TOTAL INCLUDING ESCALATION (2012$)	238,354
9.		Less: Account 904 (Uncollectible Accounts)	(11,213)
10.		TOTAL LESS ACCOUNT 904 (2012$)	227,141
11.		LABOR, NON-LABOR AND OTHER EXPENSE DETAIL:	
12.		Total Constant 2009$	
13.		Labor	139,148
14.		Non-Labor	65,761
15.		Other	15,899
16.		Subtotal	220,808
17.		Escalation:	
18.		Labor	12,329
19.		Non-Labor	5,217
20.		Other	-
21.		Subtotal	17,546
22.		TOTAL INCLUDING ESCALATION (2012$)	238,354
23.		Less: Account 904 (Uncollectible Accounts)	(11,213)
24.		TOTAL LESS ACCOUNT 904 (2012$)	227,141

Appendix C
Southern California Edison
Test Year 2012 General Rate Case
Operation And Maintenance Expenses
Thousands of Dollars
Category: Customer Service And Information And Sales Expenses

Line No.	Account No.	Description	CPUC Adopted
1.	907	Supervision	10,729
2.	908	Customer Assistance Expenses	33,934
3.	909	Informational and Instructional Advertising Expenses	-
4.	910	Miscellaneous Customer Service and Informational Expenses	-
5.	912	Demonstrating and Selling Expenses	-
6.	913	Advertising Expenses	-
7.		TOTAL CUSTOMER SERVICE & INFORMATION	44,663
8.	916	Miscellaneous Sales Expenses	858
9.		TOTAL SALES EXPENSE	858
10.		TOTAL CSI AND SALES EXPENSE Constant 2009$	45,521
11.		Escalation	3,970
12.		TOTAL INCLUDING ESCALATION (2012$)	49,491
13.		LABOR, NON-LABOR AND OTHER EXPENSE DETAIL:	
14.		Total Constant 2009$	
15.		Labor	25,976
16.		Non-Labor	19,545
17.		Other	-
18.		Subtotal	45,521
19.		Escalation:	
20.		Labor	2,302
21.		Non-Labor	1,668
22.		Other	-
23.		Subtotal	3,970
24.		TOTAL INCLUDING ESCALATION (2012$)	49,491

Appendix C
Southern California Edison
Test Year 2012 General Rate Case
Operation And Maintenance Expenses
Thousands of Dollars
Category: Administrative And General Expenses

Line No.	Account No.	Description	CPUC Adopted
1.		Operation:	
2.	920	Administrative and General Salaries/Office Supplies and Expenses	337,541
3.	921	Administrative and General Salaries/Office Supplies and Expenses	167,890
4.	922	Administrative Expenses Transferred - Credit	(124,335)
5.	923	Outside Services Employed	37,096
6.	924	Property Insurance	14,324
7.	925	Injuries and Damages	110,327
8.	926	Employee Pensions and Benefits	264,451
9.	927	Franchise Requirements	50,053
10.	928	Regulatory Commission Expenses	1,829
11.	930	General Advertising Expenses-Miscellaneous General Expenses	441
12.	931	Rents	17,941
13.		Reduction for Productivity Savings/A&G Credit for Catalina Utilities	(14,093)
14.		TOTAL OPERATION	863,466
15.		Maintenance:	
16.	935	Maintenance of General Plant	5,970
17.		TOTAL MAINTENANCE	5,970
18.		TOTAL A&G Constant 2009$	869,437
19.		Escalation	51,910
20.		TOTAL INCLUDING ESCALATION (2012$) 1/	921,347
21.		Less: Account 927 (Franchise Requirements)	(50,053)
22.		TOTAL LESS ACCOUNT 927 (2012$)	871,294
23.		LABOR, NON-LABOR AND OTHER EXPENSE DETAIL:	
24.		Total Constant 2009$	
25.		Labor	348,700
26.		Non-Labor	255,476
27.		Other	265,260
28.		Subtotal	869,436
29.		Escalation:	
30.		Labor	30,308
31.		Non-Labor	21,602
32.		Other	-
33.		Subtotal	51,910
34.		TOTAL INCLUDING ESCALATION (2012$)	921,346
35.		Less: Account 927 (Franchise Requirements)	(50,053)
36.		TOTAL LESS ACCOUNT 927 (2012$)	871,293

Appendix C
Southern California Edison
Test Year 2012 General Rate Case
Operation And Maintenance Expenses
($000)
Category: Total O&M Expenses

Line No.	Description	CPUC Adopted
	NON-ESCALATED	
1.	Production	
2.	Steam	16,274
3.	Nuclear	359,768
4.	Hydro	56,000
5.	Other	126,328
6.	Subtotal - Production	558,370
7.	Transmission	87,740
8.	Distribution	465,850
9.	Customer Accounts	209,595
10.	Uncollectibles (Account 904)	11,213
11.	Customer Service and Informational and Sales	45,521
12.	Administrative and General	819,384
13.	Franchise Requirements (Account 927)	50,053
14.	TOTAL O&M EXPENSE Constant 2009$	2,247,726
	ESCALATED	
15.	Production	
16.	Steam	17,718
17.	Nuclear	391,960
18.	Hydro	61,433
19.	Other	135,980
20.	Subtotal - Production	607,091
21.	Transmission	95,079
22.	Distribution	510,963
22.	Customer Accounts	227,141
23.	Uncollectibles (Account 904)	11,213
24.	Customer Service and Informational and Sales	49,491
25.	Administrative and General	871,294
26.	Franchise Requirements (Account 927)	50,053
27.	TOTAL O&M EXPENSE 2012$	2,422,325
	ESCALATION	
28.	Production	
29.	Steam	1,444
30.	Nuclear	32,192
31.	Hydro	5,433
32.	Other	9,652
33.	Subtotal - Production	48,721
34.	Transmission	7,338
35.	Distribution	45,112
35.	Customer Accounts	17,546
36.	Uncollectibles (Account 904)	0
37.	Customer Service and Informational and Sales	3,970
38.	Administrative and General	51,910
39.	Franchise Requirements (Account 927)	-
40.	TOTAL ESCALATION	174,597

Appendix C
Southern California Edison
Test Year 2012 General Rate Case
Operation And Maintenance Labor Expenses
($000)
Category: Total O&M Expenses

Line No.	Description	CPUC Adopted
	NON-ESCALATED	
1.	Production	
2.	Steam	16,075
3.	Nuclear	222,905
4.	Hydro	25,153
5.	Other	55,262
6.	Subtotal - Production	319,395
7.	Transmission	36,033
8.	Distribution	224,386
9.	Customer Accounts	139,148
10.	Uncollectibles (Account 904)	0
11.	Customer Service and Informational and Sales	25,976
12.	Administrative and General	348,701
13.	Franchise Requirements (Account 927)	0
14.	TOTAL O&M EXPENSE Constant 2009$	1,093,639
	ESCALATED	
15.	Production	
16.	Steam	17,499
17.	Nuclear	242,655
18.	Hydro	27,382
19.	Other	60,158
20.	Subtotal - Production	347,694
21.	Transmission	39,109
22.	Distribution	244,267
22.	Customer Accounts	151,477
23.	Uncollectibles (Account 904)	-
24.	Customer Service and Informational and Sales	28,278
25.	Administrative and General	379,009
26.	Franchise Requirements (Account 927)	-
27.	TOTAL O&M EXPENSE 2012$	1,189,834
	ESCALATION	
28.	Production	
29.	Steam	1,424
30.	Nuclear	19,750
31.	Hydro	2,229
32.	Other	4,896
33.	Subtotal - Production	28,299
34.	Transmission	3,075
35.	Distribution	19,881
35.	Customer Accounts	12,329
36.	Uncollectibles (Account 904)	-
37.	Customer Service and Informational and Sales	2,302
38.	Administrative and General	30,308
39.	Franchise Requirements (Account 927)	-
40.	TOTAL ESCALATION	96,194

Appendix C
Southern California Edison
Test Year 2012 General Rate Case
Operation And Maintenance Non Labor Expenses
($000)
Category: Total O&M Expenses

Line No.	Description	CPUC Adopted
	NON-ESCALATED	
1.	Production	
2.	Steam	199
3.	Nuclear	136,863
4.	Hydro	30,847
5.	Other	58,350
6.	Subtotal - Production	226,259
7.	Transmission	51,301
8.	Distribution	238,683
9.	Customer Accounts	65,761
10.	Uncollectibles (Account 904)	-
11.	Customer Service and Informational and Sales	19,545
12.	Administrative and General	255,476
13.	Franchise Requirements (Account 927)	-
14.	TOTAL O&M EXPENSE Constant 2009$	857,025
	ESCALATED	
15.	Production	
16.	Steam	219
17.	Nuclear	149,305
18.	Hydro	34,051
19.	Other	63,106
20.	Subtotal - Production	246,681
21.	Transmission	55,564
22.	Distribution	263,915
22.	Customer Accounts	70,978
23.	Uncollectibles (Account 904)	-
24.	Customer Service and Informational and Sales	21,213
25.	Administrative and General	277,078
26.	Franchise Requirements (Account 927)	-
27.	TOTAL O&M EXPENSE 2012$	935,429
	ESCALATION	
28.	Production	
29.	Steam	20
30.	Nuclear	12,442
31.	Hydro	3,204
32.	Other	4,756
33.	Subtotal - Production	20,422
34.	Transmission	4,263
35.	Distribution	25,232
35.	Customer Accounts	5,217
36.	Uncollectibles (Account 904)	-
37.	Customer Service and Informational and Sales	1,668
38.	Administrative and General	21,602
39.	Franchise Requirements (Account 927)	-
40.	TOTAL ESCALATION	78,403

Appendix C
Southern California Edison
Test Year 2012 General Rate Case
Operation And Maintenance Other Expenses
($000)
Category: Total O&M Expenses

Line No.	Description	CPUC Adopted
	NON-ESCALATED	
1.	Production	
2.	Steam	0
3.	Nuclear	-
4.	Hydro	-
5.	Other	12,716
6.	Subtotal - Production	12,716
7.	Transmission	406
8.	Distribution	2,781
9.	Customer Accounts	4,686
10.	Uncollectibles (Account 904)	11,213
11.	Customer Service and Informational and Sales	-
12.	Administrative and General	215,207
13.	Franchise Requirements (Account 927)	50,053
14.	TOTAL O&M EXPENSE Constant 2009$	297,063
	ESCALATED	
15.	Production	
16.	Steam	0
17.	Nuclear	-
18.	Hydro	-
19.	Other	12,716
20.	Subtotal - Production	12,716
21.	Transmission	406
22.	Distribution	2,781
22.	Customer Accounts	4,686
23.	Uncollectibles (Account 904)	11,213
24.	Customer Service and Informational and Sales	-
25.	Administrative and General	215,207
26.	Franchise Requirements (Account 927)	50,053
27.	TOTAL O&M EXPENSE 2012$	297,063
	ESCALATION	
28.	Production	
29.	Steam	-
30.	Nuclear	-
31.	Hydro	-
32.	Other	-
33.	Subtotal - Production	-
34.	Transmission	-
35.	Distribution	-
35.	Customer Accounts	-
36.	Uncollectibles (Account 904)	-
37.	Customer Service and Informational and Sales	-
38.	Administrative and General	-
39.	Franchise Requirements (Account 927)	-
40.	TOTAL ESCALATION	-

Appendix C
Southern California Edison
Test Year 2012 General Rate Case
Taxes - Other
Thousands of Dollars

Line No.	Class of Plant	CPUC Adopted
1.	**Ad Valorem Taxes**	167,676
2.	**Payroll Taxes**	
3.	Federal Insurance Contribution Act (FICA)	75,015
4.	Federal Unemployment Tax Act	476
5.	State Unemployment Tax Act	2,537
6.	Total Payroll Taxes	78,028
7.	Misc. Taxes	3,109
8.	ITC Amortization on CTC Property	(668)
9.	ARAM Expense on CTC Property	0
10.	Total Taxes Other Than Income	248,145

Appendix C
Southern California Edison
Test Year 2012 General Rate Case
Taxes - Income
Thousands of Dollars

Line No.	Description	CPUC Adopted
1.	**California Corporation Franchise Tax**	
2.	Operating Revenues	5,523,413
3.	Operating Expenses	2,272,343
4.	Taxes Other Than Income	248,145
5.	Subtotal Expenses	2,520,488
6.	Income Tax Adjustments (Sch M)	1,927,467
7.	California Taxable Income	1,075,458
8.	CCFT Tax Rate	8.541%
9.	California Corp Franchise Tax	85,216
10.	Arizona Income Tax Rate	0.1741%
11.	New Mexico Income Tax Rate	0.0276%
13.	Arizona Income Tax	1,737
14.	New Mexico Income Tax	275
16.	Total Other State Income Taxes	2,012
17.	Total State Income Taxes	87,229
18.	**Federal Income Tax**	
19.	Operating Revenues	5,523,413
20.	Operating Expenses	2,272,343
21.	Taxes Other Than Income	248,145
22.	Total State Income Taxes	87,229
23.	Less: Current Year's CCFT	85,216
24.	Plus: Prior Year's CCFT	77,636
25.	Subtotal Expenses	2,600,137
26.	Income Tax Adjustments (Sch M)	3,304,662
27.	Federal Taxable Income	(381,386)
28.	FIT Rate	35.000%
29.	Federal Income Tax	(160,685)
30.	Taxes Deferred (Plant)	546,557
31.	Taxes Deferred (AFUDC Debt)	10,166
32.	Taxes Deferred (Cap. Int.)	(17,941)
33.	Contributions in Aid of Construction	6,700
34.	Investment Tax Credit	(8,547)
35.	Accrued Vacation Pay	(164)
36.	Total Federal Income Taxes	376,086
37.	Total Taxes-Income (State and Fed)	463,314

Appendix C
Southern California Edison
Test Year 2012 General Rate Case
Depreciation and Amortization Expense
Thousands of Dollars

Line No.	Class of Plant	CPUC Adopted
1	DEPRECIATION	
2	Generation	
3	Nuclear	
4	San Onofre 2&3 Sunk	66,537
5	Palo Verde	28,696
6	Other Production	33,548
7	Coal	13,703
8	Hydro	21,711
9	Mountainview	28,480
10	Total Generation	192,675
11	Transmission	
12	Land	890
13	Substations	54,373
14	Lines	30,946
15	Total Transmission	86,209
16	Distribution	
17	Land	1,108
18	Substations	66,021
19	Lines	573,897
20	Total Distribution	641,026
21	General	155,699
22	TOTAL DEPRECIATION	1,075,609
23	AMORTIZATION	
24	Radio Frequency	448
25	Hydro Relicensing	3,741
26	Miscellaneous Intangibles	24
27	Capitalized Software	194,591
28	TOTAL AMORTIZATION	198,804
	Total Edison Smart Connect Adjustment	(52,117)
29	TOTAL DEPRECIATION AND AMORTIZATION	1,222,297

Appendix C
Southern California Edison
Test Year 2012 General Rate Case
Summary of Electric Rate Base
Thousands of Dollars

Line No.	Item	CPUC Adopted
1	**FIXED CAPITAL**	
2	Plant in Service	30,541,910
3	Capitalized Software	1,194,844
4	Other Intangibles	160,598
5	Subtotal Plant in Service	31,897,352
6	**ADJUSTMENTS**	
7	Customer Advances for Construction	(75,386)
8	Customer Deposits	(189,970)
9	Total Adjustments	(265,356)
10	**WORKING CAPITAL**	
11	Materials & Supplies	191,409
12	Mountainview Emission Credits	9,329
13	Working Cash	221,150
14	Total Working Capital	421,888
15	**DEDUCTIONS FOR RESERVES**	
16	Accumulated Depreciation Reserve	(13,767,796)
17	Accumulated Amortization	(551,870)
18	Accum. Def. Taxes - Plant	(2,802,777)
19	Accum. Def. Taxes - Capitalized Interest	83,987
20	Accum. Def. Taxes - CIAC	117,420
21	Accum. Def. Taxes - Vacation Accrual	25,417
22	Unfunded Pension Reserve	(86,045)
23	Total Deductions for Reserves	(16,981,664)
24	**RATE BASE**	15,072,220
25	**DEPR'N & AMORT EXPENSE**	1,222,297

Appendix C
Southern California Edison
Test Year 2012 General Rate Case
Total Weighted Average Plant
Thousands of Dollars

Line No.	Class of Plant	CPUC Adopted
1.	PLANT	
2.	Generation	
3.	Nuclear	
4.	San Onofre 2&3 Sunk	4,757,476
5.	Palo Verde	1,955,224
6.	Other Production	704,059
7.	Coal	337,476
8.	Mountainview	711,686
9.	Hydro	1,038,584
10.	Total Generation	9,504,505
11.	Transmission	
12.	Land	93,096
13.	Substations	1,919,792
14.	Lines	1,015,841
15.	Total Transmission	3,028,729
16.	Distribution	
17.	Land	113,698
18.	Substations	2,108,904
19.	Lines	14,456,340
20.	Total Distribution	16,678,942
21.	General	2,289,243
	ESC Adjustment	(959,510)
22.	TOTAL PLANT	30,541,909
	INTANGIBLE PLANT	
23.	Radio Frequency	17,919
24.	Hydro Relicensing	142,189
25.	Miscellaneous Intangibles	489
26.	Capitalized Software	1,194,844
27.	TOTAL INTANGIBLE PLANT	1,355,441
28.	TOTAL PLANT IN SERVICE	31,897,350

Appendix C
Southern California Edison
Test Year 2012 General Rate Case
Working Cash
Thousands of Dollars

LINE NO.	ITEM	CPUC Adopted
	Operational Cash Requirement	
1.	Cash	0
2.	Special Deposits	283
3.	Working Funds	137
4.	Prepayments	102,360
5.	Other Accounts Receivable	35,874
	Less:	
6.	Employees' Withholding and Accrued Vacation	102,682
7.	Long-Term Incentive Plan	0
8.	Workers Comp & Inj. & Dam. Claims	16,820
9.	User Taxes	23,008
10.	Edison Smart Connect Adjustment	11,278
11.	Total Operational Cash Requirement	(15,134)
12.	Working Cash Capital Required as a Result of Paying Expenses in Advance of Collecting Revenues	236,285
13.	Net Amount of Working Cash Capital Supplied by Investors	**221,151**

Appendix C
Southern California Edison
Test Year 2012 General Rate Case
Development of Average Lag In Payment Of Operating Expenses
(Thousands of Dollars)

LINE NO.	Description	Expenses	AVERAGE NO. OF DAYS LAG	DOLLAR-DAYS LAG
1.	Fuel	581,793	31.46	18,302,852
2.	Purchase Power QF USPS	2,025,053	50.80	102,872,692
3.	Purchase Power QF EFT	801,992	44.31	35,536,277
4.	Purchase Power Non-QF	3,164,050	33.77	106,838,371
5.	Subtotal (Lines 1-4)	6,572,888	40.10	263,550,193
	Transmission -Distribution - Customer Accounts - Customer Service & Information - Admin. & Gen.			
6.	Company Labor	1,182,340	11.91	14,081,666
7.	Company Labor - Results Sharing	119,096	234.03	27,871,700
8.	Other O&M	591,095	28.29	16,720,895
9.	Goods & Services	809,615	29.48	23,867,456
10.	Materials Issued from Stores	20,334	0.00	0
11.	Insurance Provisions	24,454	0.00	0
12.	Injuries & Damages Provisions	120,495	0.00	0
13.	Funded Pension Provisions	168,406	75.09	12,645,607
14.	Benefits & Unfunded Pension Provisions	54,928	5.17	283,976
15.	P.B.O.P Provisions	53,629	115.33	6,185,033
16.	Franchise Requirements	115,074	254.43	29,278,272
17.	Uncollectibles	27,128	0.00	0
18.	CPUC Reimbursement Fees	0	0.00	0
19.	Sub-Total (Lines 4 - 15)	3,286,594	39.84	130,934,604
20.	Depreciation	1,352,807	0.00	0
21.	Decommissioning	22,726	28.87	656,223
22.	Taxes - Other Than Income	282,957	32.75	9,267,671
23.	Taxes - Based on Income	556,789	11.14	6,203,283
24.	Mountainview - O&M	0	0.00	0
25.	Mountainview - Depreciation	0	0.00	0
26.	Mountainview - Taxes	0	0.00	0
		0	0.00	0
27.	Total Operating Expenses	12,074,762	**34.01**	410,611,974
28.	Average Days Lag in Collection of Revenues	41.47		
29.	Average Days Lag in Payment of Expenses	34.01		
30.	Excess Revenue Lag	7.46		
31.	Average Daily Expense	33,082		
32.	Working Cash	246,886		

Southern California Edison
Test Year 2012 General Rate Case
Operation And Maintenance Expenses
(Nominal $000)
Category: Other Operating Revenue

Line No.	Account No.	Description	CPUC Adopted
1.	450.100	Late Payment Charges - C&I	7,260
2.	450.150	Late Payment Charges - Residential	10,381
3.	451.110	Returned Check Charges	1,028
4.	451.200	Reconnection Charge	-
5.	451.250	Service Establishment Charge	-
6.	451.300	Connection Charge - Residential	7,562
7.	451.310	Connection Charge - Non Residential	3,416
8.	451.320	Connection Charge - Pole	56
9.	451.600	Field Assignment Charge	-
10.			29,703
11.	450	Forfeited Discounts - remaining accounts	-
12.	451	Miscellaneous Service Revenues - remaining accounts	1,280
13.	453	Sales of Water and Water Power	507
14.	454	Rent from Electric Property	53,732
15.	456	Other Electric Revenues	64,175
16.		Gains/Losses on Sale of Property	582
17.		TOTAL OTHER OPERATING REVENUE	149,979

Appendix C
Southern California Edison
Test Year 2012 General Rate Case
Net-To-Gross Multiplier

Line No.	Description	CPUC Adopted
1.	Revenues	1.00000
2.	Uncollectibles Tax Rate	0.00203
3.	Uncollectibles Amount Applied	1.00000
4.	Uncollectibles Juris.	0.00203
5.	Subtotal	0.99797
6.	Franchise Fees Tax Rate	0.00906
7.	Franchise Fees Amount Applied	1.00000
8.	Franchise Fees Juris.	0.00906
9.	Subtotal	0.98891
10.	Arizona/New Mexico Income Tax Rates	0.00202
11.	Other State I.T. Amount Applied	0.98891
12.	Other State I.T. Juris.	0.00199
13.	Subtotal	0.98691
14.	S. I. T. Rate	0.08541
15.	S. I. T. Amount Applied	0.98891
16.	S. I. T. Juris.	0.08446
17.	Subtotal	0.90245
18.	Federal Income Tax	0.35000
19.	Federal Income Tax Amount Applied	0.98691
20.	Federal Income Tax Juris.	0.34542
21.	Net Operating Revenues	0.55703
22.	Uncollectible and Franchise Fees Factor	1.01122
23.	State & Federal CompositeTax Factor	1.67228
24.	**N-T-G MULTIPLIER**	**1.7952**

Appendix C
Southern California Edison
Test Year 2012 General Rate Case
Nuclear Refueling O&M Expense
(Thousands of Dollars)

Line No		Cost per Refueling 2009 $	Cost per Refueling 2012 $
1	SONGS 2&3		
2	Labor	8,259	8,991
3	Non Labor	37,751	41,595
4	Total	46,010	50,586
5	Less Participants	(10,026)	(11,047)
6	SCE Share	35,984	39,539

Appendix C
Southern California Edison
Test Year 2012 General Rate Case
Jurisdictional Allocation
(Thousands of Dollars)

Line No.	Item	% for 2012 FERC %	CPUC-GRC %	Total %
1.	**TOTAL OPERATING REVENUES**	9.83%	90.17%	100.00%
2.	**OPERATING EXPENSES:**			
3.	Production			
4.	Steam	0.00%	100.00%	100.00%
5.	Nuclear	0.00%	100.00%	100.00%
6.	Hydro	0.00%	100.00%	100.00%
7.	Other	0.00%	100.00%	100.00%
8.	Subtotal Production	0.00%	100.00%	100.00%
9.	Transmission	50.22%	49.78%	100.00%
10.	Distribution	1.16%	98.84%	100.00%
11.	Customer Accounts	0.00%	100.00%	100.00%
12.	Uncollectibles	9.83%	90.17%	100.00%
13.	Customer Service & Information	0.00%	100.00%	100.00%
14.	Administrative & General	4.29%	95.71%	100.00%
15.	Franchise Requirements	9.83%	90.17%	100.00%
16.	Revenue Credits	18.40%	81.60%	100.00%
17.	Subtotal	4.71%	95.29%	100.00%
18.	Escalation	5.45%	94.55%	100.00%
19.	Depreciation	9.65%	90.35%	100.00%
20.	Taxes Other Than On Income - Property	15.39%	84.61%	100.00%
21.	Taxes Other Than On Income - Payroll	4.29%	95.71%	100.00%
22.	Taxes Based On Income	15.39%	84.61%	100.00%
23.	Total Taxes	14.27%	85.73%	100.00%
24.	**TOTAL OPERATING EXPENSES**	7.94%	92.06%	100.00%
25.	**NET OPERATING REVENUE**	15.39%	84.61%	100.00%
26.	**RATE BASE**	15.39%	84.61%	100.00%
27.	**RATE OF RETURN**			

9END OF APPENDIX C)

Appendix D
Southern California Edison
Test Year 2012 General Rate Case
2013 and 2014 Summary of Earnings
Thousands of Dollars

Line No.	Item	CPUC Adopted 2013	CPUC Adopted 2014
1.	**TOTAL OPERATING REVENUES**	6,028,741	6,385,074
2.	**OPERATING EXPENSES:**		
3.	Production		
4.	Steam	16,274	16,274
5.	Nuclear	359,768	359,768
6.	Hydro	56,000	56,000
7.	Other	126,328	126,328
8.	Subtotal Production	558,370	558,370
9.	Transmission	87,740	87,740
10.	Distribution	453,709	455,833
11.	Customer Accounts	180,716	184,504
12.	Uncollectibles 1/	12,117	12,836
13.	Customer Service & Information	50,159	50,159
14.	Administrative & General	818,799	825,056
15.	Franchise Requirements 2/	54,092	57,302
16.	Revenue Credits	(155,734)	(157,912)
17.	Subtotal	2,059,967	2,073,889
18.	Escalation	240,634	298,662
19.	Depreciation	1,423,505	1,537,768
20.	Taxes Other Than On Income	259,687	273,380
21.	Taxes Based On Income	505,337	554,128
22.	Total Taxes	765,024	827,508
23.	**TOTAL OPERATING EXPENSES**	4,489,130	4,737,826
24.	**NET OPERATING REVENUE**	1,539,611	1,647,248
25.	**RATE BASE**	16,932,885	18,141,142
26.	**RATE OF RETURN**	8.74%	8.74%
27.	Mohave	-4824	-2788
28.	Legacy Meters	64500	64500

Appendix D
Southern California Edison
Test Year 2012 General Rate Case
Operation And Maintenance Expenses
Thousands of Dollars
Category: Distribution Expenses - 2013

Line No.	Account No.	Description	CPUC Adopted
1.		Operation:	
2.	580	Operation Supervision and Engineering	31,642
3.	582	Station Expenses	17,791
4.	583	Overhead Line Expenses	19,764
5.	584	Underground Line Expenses	(879)
6.	585	Street Lighting and Signal System Expenses	578
7.	586	Meter Expenses	17,437
8.	587	Customer Installations Expenses	15,483
9.	588	Miscellaneous Distribution Expenses	121,541
10.	589	Rents	597
11.		TOTAL OPERATION	223,954
12.		Maintenance:	
13.	590	Maintenance Supervision and Engineering	44,703
14.	591	Maintenance of Structures	486
15.	592	Maintenance of Station Equipment	10,112
16.	593	Maintenance of Overhead Lines	127,924
17.	594	Maintenance of Underground Lines	14,598
18.	595	Maintenance of Line Transformers	1,068
19.	596	Maintenance of Street Lighting and Signal Systems	5,279
20.	597	Maintenance of Meters	1,889
21.	598	Maintenance of Miscellaneous Distribution Plant	23,692
22.		TOTAL MAINTENANCE	229,751
23.		TOTAL DISTRIBUTION EXPENSE Constant 2009$	453,705
24.		Escalation	57,157
25.		TOTAL INCLUDING ESCALATION (2013$)	510,862
26.		LABOR, NON-LABOR AND OTHER EXPENSE DETAIL:	
27.		Total Constant 2009$	
28.		Labor	213,142
29.		Non-Labor	237,787
30.		Other	2,783
31.		Subtotal	453,712
32.		Escalation:	
33.		Labor	25,846
34.		Non-Labor	30,949
35.		Other	362
36.		Subtotal	57,157
37.		TOTAL INCLUDING ESCALATION (2013$)	510,869

Appendix D
Southern California Edison
Test Year 2012 General Rate Case
Operation And Maintenance Expenses
Thousands of Dollars
Category: Customer Accounts Expenses - 2013

Line No.	Account No.	Description	CPUC Adopted
1.	901	Supervision	13,474
2.	902	Meter Reading Expenses	24,397
3.	903	Customer Records and Collection Expenses	108,292
4.	904	Uncollectible Accounts	12,117
5.	905	Miscellaneous Customer Accounts Expenses	34,553
6.		TOTAL CUSTOMER ACCOUNTS Constant 2009$	196,632
7.		Escalation	20,611
8.		TOTAL INCLUDING ESCALATION (2013$)	217,243
9.		Less: Account 904 (Uncollectible Accounts)	(12,117)
10.		TOTAL LESS ACCOUNT 904 (2013$)	205,126
11.		LABOR, NON-LABOR AND OTHER EXPENSE DETAIL:	
12.		Total Constant 2009$	
13.		Labor	112,197
14.		Non-Labor	67,632
15.		Other	13,004
16.		Subtotal	192,833
17.		Escalation:	
18.		Labor	13,605
19.		Non-Labor	7,006
20.		Other	-
21.		Subtotal	20,611
22.		TOTAL INCLUDING ESCALATION (2013$)	213,444
23.		Less: Account 904 (Uncollectible Accounts)	(12,117)
24.		TOTAL LESS ACCOUNT 904 (2013$)	201,327

Appendix D
Southern California Edison
Test Year 2012 General Rate Case
Operation And Maintenance Expenses
Thousands of Dollars
Category: Customer Service And Information And Sales Expenses - 2013

Line No.	Account No.	Description	CPUC Adopted
1.	907	Supervision	11,123
2.	908	Customer Assistance Expenses	38,178
3.	909	Informational and Instructional Advertising Expenses	-
4.	910	Miscellaneous Customer Service and Informational Expenses	-
5.	912	Demonstrating and Selling Expenses	-
6.	913	Advertising Expenses	-
7.		TOTAL CUSTOMER SERVICE & INFORMATION	49,301
8.	916	Miscellaneous Sales Expenses	858
9.		TOTAL SALES EXPENSE	858
10.		TOTAL CSI AND SALES EXPENSE Constant 2009$	50,159
11.		Escalation	5,834
12.		TOTAL INCLUDING ESCALATION (2013$)	55,993
13.		LABOR, NON-LABOR AND OTHER EXPENSE DETAIL:	
14.		Total Constant 2009$	
15.		Labor	28,260
16.		Non-Labor	21,899
17.		Other	-
18.		Subtotal	50,159
19.		Escalation:	
20.		Labor	3,427
21.		Non-Labor	2,315
22.		Other	92
23.		Subtotal	5,834
24.		TOTAL INCLUDING ESCALATION (2013$)	55,993

(END OF APPENDIX D)