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

PUBLIC UTILITIES COMMISSION

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Ratesetting

TO PARTIES OF RECORD IN APPLICATION (A.) 10-12-005 AND A.10-12-006

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

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

Parties to the proceeding may file comments on the proposed decision as provided in Article 14 of the Commission's Rules of Practice and Procedure (Rules), accessible on the Commission's website at www.cpuc.ca.gov. Pursuant to Rule 14.3, opening comments shall not exceed 25 pages.

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

/s/ MARYAM EBKE for
Karen V. Clopton, Chief
Administrative Law Judge

KVC:JT2/avs

Attachment

Decision **PROPOSED DECISION OF ALJ WONG** **(Mailed 3/29/2013)**

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of San Diego Gas & Electric Company (U902M) for Authority, Among Other Things, to Increase Rates and Charges for Electric and Gas Service Effective on January 1, 2012.	Application 10-12-005 (Filed December 15, 2010)
And Related Matter.	Application 10-12-006

DECISION ON GENERAL RATE CASES OF SAN DIEGO GAS & ELECTRIC COMPANY AND SOUTHERN CALIFORNIA GAS COMPANY

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DECISION ON GENERAL RATE CASES OF SAN DIEGO GAS & ELECTRIC COMPANY AND SOUTHERN CALIFORNIA GAS COMPANY

Summary

San Diego Gas & Electric Company (SDG&E) and Southern California Gas Company (SoCalGas) filed the above-captioned general rate case applications on December 15, 2010. The focus of SDG&E's application is to establish the revenue requirement and rates for it to provide electric and natural gas services for the test year period from January 1, 2012 through December 31, 2012, and the post-test years. SoCalGas' application is to establish the revenue requirement and rates for it to provide natural gas service to its customers for the test year period from January 1, 2012 through December 31, 2012, and the post-test years. The two applications have been consolidated.

Today's decision adopts a combined gas and electric Test Year 2012 revenue requirement of $1,749,376,000 for SDG&E, and a Test Year 2012 revenue requirement of $1,951,712,000 for SoCalGas. In addition, a mechanism for the post-test years of 2013 through 2015 is adopted.

As updated by SDG&E and SoCalGas in Exhibit 596, SDG&E originally requested a test year 2012 revenue requirement of $1,848,737,000, and SoCalGas requested a test year 2012 revenue requirement of $2,112,476,000. Today's adopted revenue requirement for SDG&E is $99.361 million lower than what SDG&E had requested, and is $160.764 million lower than what SoCalGas had requested.

Today's adopted 2012 revenue requirements represent a $140.156 million increase over SDG&E's present 2012 rates of $1,609,221,000 and a $78.369 million increase over SoCalGas' present 2012 rates of $1,873,343,000.

The Division of Ratepayer Advocates (DRA), and other parties, have recommended that adjustments be made to the cost forecasts of both SDG&E and SoCalGas. As discussed throughout this decision, we have adopted some of the adjustments that the other parties have recommended. As a result of the adoption of those adjustments, and as shown in Attachment B of this decision, that results in our adopted 2012 revenue requirements for SDG&E and SoCalGas of $1,749,376,000 and $1,951,712,000, respectively.

For a typical all-electric residential customer of SDG&E using 500 kilowatt hours per month (kwh), the customer's electric rates would go up about $6.55 per month, a 7.7% increase in monthly electric rates.

Among the issues resolved in this proceeding are the following:

- Adopts a test year 2012 revenue requirement for SDG&E of $1,749,376,000, and for SoCalGas of $1,951,712,000.
- For the post-test years, adopts DRA's recommendation to use the index from the United States Bureau of Labor Statistics, known as the Consumer Price Index – Urban, to adjust the test year 2012 revenue requirements of SDG&E and SoCalGas for the post-test years of 2013, 2014, and 2015.
- The adopted revenue requirements, and post-test year ratemaking mechanism will provide the necessary funds to allow SDG&E to operate its electric and natural gas transmission and distribution system safely and reliably at reasonable rates.
- The adopted revenue requirements, and post-test year ratemaking mechanism will provide the necessary funds to allow SoCalGas to operate its natural gas transmission, gas distribution, and gas storage systems safely and reliably at reasonable rates.
- Provides the necessary monies to fund the gas transmission and distribution pipeline integrity programs

required of SDG&E and SoCalGas by the federal government.

- Provides the necessary monies to maintain and replace aging electric and gas delivery infrastructure so as to ensure the safe and reliable delivery of electricity and natural gas to customers.
- Provides the necessary monies to comply with state and federal environmental regulations.
- Provides the necessary monies to allow SDG&E to install smart grid technologies to better monitor the electric grid, to improve reliability as a result of the growth in renewable power in SDG&E's service territory, and to respond more quickly to outages.
- Provides the necessary monies to allow SDG&E to trim trees and brush away from overhead electric lines to lessen the danger of wildfires.
- SDG&E's share of the costs in 2012 at the San Onofre Nuclear Generating Station (SONGS) are subject to customer refund pending the outcome of the reasonableness review of the SONGS outage as ordered in Decision 12-11-051.
- Requires SDG&E to submit a Gas Transmission and Distribution Safety Report, and SoCalGas to submit a Gas Transmission and Distribution and Gas Storage Safety Report, to the Commission's Safety and Enforcement Division, and Energy Division, which will enable Commission staff to monitor whether the amounts being spent on natural gas pipeline maintenance and capital projects are being performed in a manner that improves the safety and integrity of the gas transmission and distribution systems of SDG&E and SoCalGas, and the gas storage system of SoCalGas.
- Reduces the period that SDG&E is allowed to recover the costs associated with the original installation of the electromechanical electric meters that have now been replaced by smart meters.

- Adopts the settlement between SDG&E, SoCalGas, and the Center for Accessible Technologies regarding access issues by persons with disabilities.

1. Procedural Background

San Diego Gas & Electric Company (SDG&E) and Southern California Gas Company (SoCalGas) filed separate general rate case (GRC) applications with the Commission on December 15, 2010.[1] On January 7, 2011, the two applications were consolidated.

After the filing of responsive pleadings to the two applications, a prehearing conference (PHC) was held on January 31, 2011. This PHC was held in conjunction with the PHC in the GRC application of Southern California Edison Company (SCE) in Application (A.) 10-11-015. The purpose of holding the joint PHC was to discuss the overlapping schedules between the GRC applications of SDG&E and SoCalGas, and the GRC application of SCE, and the possible resource constraints that parties faced.

Following the January 31, 2011 PHC, the procedural schedule for this proceeding was addressed in the March 2, 2011 scoping memo and ruling (scoping ruling) of the assigned Commissioner and the Administrative Law Judge (ALJ). As described in the scoping ruling, the request of the Division of Ratepayer Advocates (DRA) for a delay in the procedural schedule of the GRC applications of SDG&E and SoCalGas was granted, and the procedural schedule for these two consolidated applications was extended to allow the SCE hearings to proceed before hearings were held in the consolidated applications.

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[1] At times, we refer to SDG&E and SoCalGas in this decision as the "Applicants."

The scoping ruling also granted the January 10, 2011 joint motion of SDG&E and SoCalGas to establish memorandum accounts to "record the difference between the rates currently in effect for utility service and the final rates adopted in the GRCs in the event a final Commission decision is not rendered in time for 2012 rates to take effect January 1, 2012." (Scoping Ruling at 5-6.) The scoping ruling recognized that due to the procedural delay in processing the consolidated GRC applications, that granting the joint motion to establish the memorandum accounts was warranted. SDG&E and SoCalGas then filed advice letters (AL) to establish their respective GRC memorandum accounts.

Six public participation hearings (PPHs) were then held for SoCalGas, and four PPHs were held for SDG&E.[2] In addition to the PPHs, a number of letters and e-mails regarding the two applications were received by the Commission. A summary of the correspondence and the comments from the PPHs is described in the next section of this decision.

Evidentiary hearings began on November 30, 2011 and concluded on January 26, 2012. A total of 23 days of evidentiary hearings were held, and almost 600 exhibits were identified and used during the course of these proceedings.[3]

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[2] Two of the PPHs for SoCalGas were held in conjunction with PPHs for SCE in A.10-11-015.

[3] The showing by the Applicants consists of direct testimony, rebuttal testimony, workpapers in support of direct and rebuttal testimony, and other exhibits used during the examination of witnesses. The showing by the other parties consists of direct and rebuttal testimony, and other exhibits used during the examination of witnesses.

Opening briefs were filed on April 3, 2012, and reply briefs were filed on May 1, 2012.

A settlement was reached between the Center for Accessible Technology (CforAT), and SDG&E and SoCalGas, concerning certain access issues that were originally raised by Disability Rights Advocates. That settlement was attached to the February 24, 2012 joint motion for adoption of this settlement, which is discussed later in this decision. No other settlements were reached.

To the extent that any outstanding motions or requests have not been addressed in this decision, we deny those outstanding motions or requests. We also confirm all of the oral and written rulings that the assigned ALJ has issued in this proceeding.

2. Background of the Two Applications

2.1. Relief Requested

The two applications cover test year 2012, with rates effective January 1, 2012. For the post-test year (PTY), the Applicants recommend that a PTY ratemaking mechanism be adopted for the three subsequent years of 2013, 2014 and 2015.

SDG&E's GRC application seeks authorization to revise its current base rate revenues to recover its projected costs of providing its electric and gas operations, facilities and infrastructure, and other necessary functions, to provide electricity and natural gas services to its customers. SDG&E requests that the Commission adopt its test year 2012 revenue requirement of $1,848,737,000, and that its revenue requirements be reflected in rates beginning January 1, 2012.[4]

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[4] SDG&E's revenue requirement of $1.848 billion is made up of $1.527 billion for its electric revenue requirement, and $321 million for its gas revenue requirement.

SDG&E also requests that its PTY mechanism be adopted for the proposed attrition years of 2013, 2014, and 2015. In addition, SDG&E requests that the Commission approve its regulatory balancing and memorandum accounts as set forth in its testimony.

SDG&E operates and maintains an electric and natural gas distribution system that serves about 1.4 million electric customers, and about 845,000 gas customers. The service territory covers about 4,100 square miles from southern Orange County to the California-Mexico border.

SoCalGas' GRC application seeks authorization to revise its current base rate revenues to recover its projected costs of providing its gas operations, facilities and infrastructure, and other necessary functions, to provide natural gas services to its customers. SoCalGas requests that the Commission adopt its test year 2012 revenue requirement of $2,112,476,000 and that its revenue requirement be reflected in rates beginning January 1, 2012. SoCalGas also requests that its PTY mechanism be adopted for the proposed attrition years of 2013, 2014, and 2015. In addition, SoCalGas requests that the Commission approve its regulatory balancing and memorandum accounts as set forth in its testimony.

SoCalGas operates and maintains a natural gas distribution and transmission system with about 3,990 miles of large and high-pressure pipeline, and about 97,400 miles of gas distribution pipeline that serve about 5.6 million gas customers. The primary function of SoCalGas' distribution network is to receive natural gas from SoCalGas' transmission system and to redeliver the gas at a lower pressure to serve residential and commercial customers. SoCalGas also operates four underground gas storage facilities with a working capacity of about 134 billion cubic feet (Bcf). SoCalGas' service territory covers an area of about 20,000 square miles from portions of the central valley to southern Orange County and Imperial County.

SDG&E and SoCalGas are related companies owned by the same corporate parent, Sempra Energy (Sempra). Due to their corporate structure, and the businesses that they are in, there are some shared services between the two utilities and their corporate parent.

Shared services are activities performed by functional areas at one utility or at the Corporate Center for the benefit of (i) the other utility, (ii) corporate center, and/or (iii) an unregulated affiliate. A shared service provided by SDG&E or SoCalGas will be allocated and billed to the entity or entities receiving the service. A utility receiving the shared service from the other utility will include in its own book expense any costs that were allocated and billed to it.

Non-shared services are activities provided by functional areas at one utility that benefit only the utility performing the activity, the costs of which do not need to be allocated and billed out to other entities. These non-shared services costs may include labor costs and non-labor costs. For services provided to the utility by the Corporate Center, those costs are treated as non-shared services costs by the utility, consistent with how outside vendor costs are treated.

2.2. PPHs and Correspondence

PPHs were held throughout the service territories of SDG&E and SoCalGas regarding their GRC applications. In addition, a number of letters and e-mails were received concerning their GRC applications. Many of the comments at the PPH, and the correspondence, opposed any rate increases due to the state of the economy, and their economic circumstances. Many pointed out that there have been no recent Social Security increases, and that their own salaries have not increased. Consumers are also faced with having to cut expenses, and many are forced to choose between what bills they should pay. The comments at the PPH and in the correspondence also suggest that the utilities should be fiscally responsible and reduce their costs in various areas, including employee and management salaries and benefits. During the PPHs, there were also a number of witnesses that supported the utilities' need to invest in their infrastructure, the utilities' involvement in various community endeavors, and SDG&E's electric vehicle proposal.

3. Analysis Approach and General Issues

3.1. Analysis Approach

This decision generally follows the outline set forth in the Applicants' opening brief. In each section concerning the issues raised by the GRCs of SDG&E and SoCalGas, we describe the background of the particular costs that are being addressed in that particular section. This is followed by a summary of the parties' positions, and then a discussion of the costs and other issues that have been raised. Since the evidence and arguments in this proceeding are voluminous, we focused our attention on the major points of contention and did not try to summarize every nuance of the parties' positions in this decision.

Similarly, due to the volume of exhibits, and the number of issues raised in each section, we have not addressed every single issue that parties have raised during this proceeding. To do so would have taken more time, and increased the length of this decision.

However, that does not mean that we have overlooked the issues raised by the parties. We exhaustively reviewed all of the exhibits in this proceeding, as well as the arguments made by the parties in their briefs, and considered all of the arguments and issues that parties have raised in deciding what costs should be adopted.[5] This review and evaluation process included the following:

- Reviewed of all the exhibits and briefs pertaining to each section of this decision, including the uncontested costs. The exhibits reviewed include the direct and rebuttal testimony, the workpapers, and the other exhibits used during the examination of the witnesses.
- Reviewed and evaluated the positions of the parties on each issue raised, and compared and evaluated each parties' forecasted costs and methodologies to the historical costs, to the various averages or trends, to each other's forecasts, and to the drivers of those costs.
- Considered the state of the economy and the economic outlook as described in the parties' exhibits, and compared the forecasts of the parties in light of the historical economic conditions.
- After going through this review and evaluation process, we then decided on what test year 2012 cost, or outcome on an issue, was reasonable in light of all of those considerations.

The above review and evaluation process has allowed us to decide on revenue requirements for SDG&E and SoCalGas which provide safe and reliable service at just and reasonable rates, as required by Pub. Util. Code § 451. Attachment B of this decision contains the results of operations for SDG&E and SoCalGas, which incorporates into the results of operation model all of the costs we have found to be reasonable, and which are adopted in today's decision.

[5] We note that the parties' opening and reply briefs oftentimes simply repeated the direct or rebuttal testimony of the parties.

3.2. Are Rate Increases Justified?

Several of the parties have raised concerns about the state of the economy, and that SDG&E and SoCalGas should not be seeking rate increases at this time. This was also a theme raised by many of the speakers at the PPHs, and in the correspondence the Commission received concerning the two GRC applications. Since this issue directly affects all of the cost increases that SDG&E and SoCalGas are requesting, we address this overarching issue.

It must be kept in mind, that the Commission's duty and obligation under Pub. Util. Code § 451 is to establish just and reasonable rates to enable SoCalGas and SDG&E to provide safe and reliable service for the convenience of the public, ratepayers, and employees, while allowing SDG&E and SoCalGas an opportunity for their shareholders to earn a fair return on the property that the companies use in providing their utility services. (*See* D.04-12-015 at 64, Conclusion of Law 7.)

The parties who oppose the proposed increases contend that due to current economic conditions, ratepayers cannot afford any increase in their electric and gas rates. They also contend that ratepayers have had to reduce their spending, and SDG&E and SoCalGas should do the same as well.

The Applicants contend that despite the state of the economy, their costs have been increasing due to additional federal, state, and local regulations, as well as increases in the cost of materials and new technology, and the growth of their respective utility systems to meet growing demand. As a result, the Applicants contend that additional workers are needed to monitor, implement, and to comply with these new regulations, and to operate these new technologies. In addition, the aging utility infrastructure will be replaced by this new equipment and new technologies.

The Applicants included two proposals to help mitigate the rate impact on their customers during this economic downturn. The first proposal is to request zero funding for each Applicant's working cash requirement in test year 2012. This proposal will have the effect of excluding the working cash requirement from rate base, and earning a rate of return. The second proposal is to continue the two-way balancing account treatment of pensions and post-retirement benefits other than pensions (PBOP), and to hold the pension and PBOP funding at 2009 recorded levels for test year 2012. The Applicants propose that any shortfall or surplus from the 2009 recorded level of expense will be recorded in the pension and/or PBOP balancing accounts for recovery in the subsequent year. This second proposal will have the effect of keeping pensions and PBOP at 2009 levels, which will delay for at least one year the recovery of the projected $35 million pension funding increase and $16 million PBOP funding increase.

Both of the Applicants' proposals are of benefit to ratepayers in test year 2012, and will help reduce the impact on ratepayer bills. In addition, many of the parties to these proceedings have challenged the various increases in costs as described throughout this decision. In our review and analyses of those issues, we have adopted a number of their suggestions and made appropriate reductions to certain costs. All of these reductions result in a lower revenue requirement than what SDG&E and SoCalGas have requested, and in just and reasonable rates.

3.3. Overview of Forecasting Methodologies

3.3.1. Background

The Applicants' GRC showing consists of a number of different cost forecasts for each utility-related service that they plan to offer during the test year 2012 rate cycle. Some of the other parties recommend that other methodologies be used to develop the cost forecasts. Since the forecasting methodologies are an integral part of developing the many different cost forecasts, it is appropriate to discuss our overall approach to the forecasting methodologies.

In general, most of the forecasts of the Applicants' customer service expenses are based on a five-year average of 2005 through 2009 of costs and activities. To estimate their 2010 to 2012 expenses, the Applicants used the five-year average and made various adjustments to the five-year average depending on the cost centers. The Applicants contend that the five-year average methodology is of sufficient length to capture a variety of conditions such as the state of the economy, customer turnover, energy and gas prices, and weather conditions. The Applicants deviated from using the five-year average in some instances.

3.3.2. Position of the Parties

3.3.2.1 SDG&E and SoCalGas

The Applicants contend that their use of the five-year average of 2005 through 2009 provides a consistent representation of costs and activities for each cost center. This five-year period was the most current five-year range that was available at the time the forecasts were being prepared for the GRCs. According to the Applicants, the five-year average that they use covers a variety of business cycle conditions including fluctuations in the state of the economy, customer turnover, energy and gas prices, weather conditions, regulations, and changes in appliance technologies.

The Applicants contend that DRA, The Utility Reform Network (TURN) and Utility Consumers' Action Network (UCAN) used several alternative and inconsistent forecasting methodologies for customer service related costs and activities. One example of this is where the same witness used by TURN and UCAN used different forecasting methodologies for SDG&E and SoCalGas for the same customer service field and customer contact workgroups or cost centers. The Applicants contend that such inconsistencies demonstrate that the goal of the TURN and UCAN witness was to reduce estimated expenses regardless of the facts.

The Applicants also contend that the use of recorded 2010 cost data by DRA, TURN and UCAN should be rejected. The Applicants contend that the use of recorded 2010 data is not permissible under the updating process contained in the Rate Case Plan, and to analyze the most recent recorded data in the existing timeframe for resolving a GRC would be time consuming. The Applicants also argue that the use of recorded 2010 data has not been subjected to a careful and thorough analysis of the interrelated cost drivers, which could affect the reliability of that data. The Applicants also argue that DRA, TURN and UCAN appear to selectively use the recorded 2010 data in an effort to reduce the test year forecasts of operation and maintenance (O&M) and capital spending.

3.3.2.2. Position of DRA, TURN and UCAN

DRA points out that the Commission has stated in prior decisions that there are a number of acceptable methodologies for forecasting test year costs. In some instances, the Commission approved use of the most recent recorded costs. In the Applicants' last GRC decision, the use of more recent data was also an issue. Although the Commission rejected the use of the more recent data in Decision (D.) 08-07-046, it acknowledged that in deciding whether more recent data should be used depends on whether the more recent data "is compatible with the other years of recorded data in order to derive trends and forecasts." (D.08-07-046 at 9.) DRA contends that its use of adjusted 2010 data is in a format compatible with the data the Applicants used. DRA further asserts that another compelling reason for using the 2010 data is due to the "deep recession that started in 2008 and intensified in 2009 and 2010." (DRA Opening Brief at 9.) As a result, DRA maintains the Applicants' 2010 forecast was over-optimistic because it was based on 2009 data. Since the 2012 forecasts of the Applicants "build on 2010 spending, or in some cases the entire increase from 2009-2012 was 'predicted' for 2010, such errors for 2010 persist in 2012 Test Year estimates." (DRA Opening Brief at 10, footnote omitted.)

DRA also contends that the Applicants frequently referred to recorded 2010 data for certain forecasts of costs, or used variations of their 2005-2009 methodology for certain forecasts. Since the Applicants selectively used actual 2010 data or variants of the five-year methodology to develop their forecasts, DRA contends that the Commission should also consider the alternative methodologies of DRA and the other intervenors, which employed the use of actual 2010 data in certain instances.

TURN and UCAN contend that the goal of the Commission should be to develop a reasonable forecast of what the Applicants will spend to provide service during test year 2012. In developing this reasonable revenue requirement forecast, TURN and UCAN believe that the Commission should not limit itself to a limited number of preferred forecasting methods that are applied in a rigid fashion. Instead, the Commission should use the methodology that provides the most reasonable forecast for the cost that is at issue. Thus, if "the use of 2010 recorded data will produce a more accurate forecast of 2012 test year costs, the 2010 data should be used." (TURN and UCAN Opening Brief at 8.)[6]

TURN and UCAN also point out that in the Applicants' last GRC, the Commission rejected the Applicants' argument against the use of recently recorded data. Since the recorded 2010 data is in a format consistent with the historical data, there is no issue about data incompatibility.

The Applicants have also argued that if 2010 data is used, it should be used in a uniform manner. TURN and UCAN point out, however, that the Applicants did not treat the 2009 data in the same manner for all of the Applicants' forecasts.

TURN and UCAN contend that the Applicants have downplayed the importance of their 2010 and 2011 forecasts. The Applicants argue that any comparison of actual 2010 cost data to the Applicants' 2010 forecasts in this GRC should be viewed with caution, and no inference should be drawn about the accuracy of the test year 2012 forecast. However, TURN and UCAN believe the Commission should use the recorded 2010 costs as a basis of comparing it to the reasonableness of the Applicants' forecasts for 2010 through 2012. TURN and UCAN point out that the recorded 2010 amounts were significantly below the Applicants' forecasts for that same year. An example of this is that the total 2010 recorded O&M spending for the Applicants was about $82 million below the GRC forecasts for 2010. TURN and UCAN contend the Commission should reject the Applicants' arguments that it is unfair to use 2010 recorded amounts for forecasting the test year 2012 revenue requirement.

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[6] The Federal Executive Agencies (FEA) also recommend that the Commission allow the use of 2010 data for developing the forecast of electric distribution costs.

TURN and UCAN also contend that the use of the more recent recorded data is appropriate because it more closely reflects the internal budgets that the Applicants developed to allow the Applicants' senior management team to plan their respective budgets for the year, and to monitor that budget process. TURN and UCAN contend that this internal budgeting process of the Applicants demonstrates that the Applicants "can develop a more accurate forecast when doing so serves their purpose." (TURN and UCAN Opening Brief at 15.)

3.3.3. Discussion

This issue about using the most recent recorded data in a GRC is not new to this Commission. In the prior decision regarding the Applicants' last GRC, similar arguments were made about the use of the most recent recorded data, and this same issue was discussed by the Commission in D.08-07-046. In that decision, the Commission rejected the argument that the use of the most recent recorded data was contrary to the updating procedure set forth in the Rate Case Plan. The Applicants have not brought our attention to any new facts in this proceeding which would cause us to change our mind.[7] Simply put, the use of more recent data by the parties is not prohibited by the Rate Case Plan.

However, as D.08-07-046 sets out, before this recent data can be used, the Commission needs to ensure that the recorded data is in a format "compatible with the other years of recorded data in order to derive trends and forecasts." (D.08-07-046 at 9.) The Applicants have not asserted that the recorded 2010 data is incompatible with the historical data.

[7] Nor are we persuaded by the Applicants' argument that the 2010 recorded data should be disregarded entirely. As DRA, TURN and UCAN point out, the Applicants' testimony also contain several instances where the Applicants used recorded 2010 data to support their cost forecasts.

TURN and UCAN point out that the Commission should consider the various methodologies that the Applicants and the other parties use, including the use of recorded 2010 data for the costs at issue if it is used to develop a reasonable forecast. We agree with TURN and UCAN in this regard. Each proposed methodology must be reviewed and considered for each cost forecast, and the Commission needs to weigh the competing arguments as to which methodology yields a more reasonable forecast. That means for certain cost forecasts, the use of more recent recorded data will more closely reflect the continuing effects of the economic downturn. For other cost forecasts, it may be appropriate to use the five-year average methodology that the Applicants primarily rely on, as this may be more representative of various business cycle conditions. As the Commission previously stated in a prior GRC for SCE:

> As discussed in prior Commission decisions, there are a number of acceptable methodologies for forecasting test year costs.…Depending on circumstances, one method may be more appropriate than others. Under other circumstances, two or more methods may be equally appropriate. In general, the parties' testimony should explain (1) why its proposed methodology is appropriate, (2) why it is better than methodologies proposed by other parties and (3) why the results are reasonable. The Commission must weigh this information in deciding which methodology should be used and how it should be used." (D.06-05-016 at 10-11.)

To the extent the parties disagree on the appropriate methodology that should be used, including the use of recorded 2010 data, we will use the approach set forth in D.06-05-016 to analyze what methodology should be adopted to develop the individual cost forecasts. For the cost forecasts where we used 2010 recorded data, we will explain our reasons for using that methodology. For cost forecasts where we choose to use the Applicants' methodology, we have weighed and considered using the competing methodologies but rejected those competing methodologies in favor of the Applicants. Our picking and choosing of what the appropriate methodology to use for the cost forecasts will allow us to develop cost forecasts that we believe are reasonable to both ratepayers and the Applicants, and are as accurate as they can be within our GRC ratemaking framework.

3.4. Settlement of Accessibility Issues

The witnesses for the Cfor AT sponsored two pieces of testimony in these proceedings.[8] The issues raised by Cfor AT include the following: physical access barriers that disabled persons encounter at in-person payment locations, or because of the Applicants' repair or construction work; and communication access issues to address the needs of customers who have disabilities that affect their ability to use standard forms of communication. The Applicants provided testimony addressing accessibility issues in various exhibits.

On February 24, 2012, a Joint Motion for Adoption of Settlement was filed by the Applicants and Cfor AT (Joint Motion).[9] The Joint Motion requests that the Commission adopt the "Memorandum of Understanding San Diego Gas & Electric Company, Southern California Gas Company and Center for Accessible Technology" (MOU Settlement) that was attached to the Joint Motion as Attachment A. In the MOU Settlement, the Applicants and Cfor AT have agreed to a mutually acceptable outcome on certain access issues that were initially

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[8] In an October 21, 2011 ALJ ruling, the Cfor AT was granted party status as the successor to the Disability Rights Advocates.

[9] In accordance with Rule 12.1(b) of the Commission's Rules of Practice and Procedure, a settlement conference was held on February 9, 2012.

raised by the Disability Rights Advocates in these proceedings, and which were subsequently addressed by Cfor AT in Exhibits 593 and 594. No responses to the Joint Motion were filed.

The MOU Settlement builds upon the prior Memorandum of Understanding (prior MOU), approved by the Commission in D.08-07-046, by continuing efforts to ensure and monitor that the Applicants' branch offices and authorized payment locations are accessible.[10] The MOU Settlement also continues efforts and training to ensure that the Applicants' website is accessible to customers with disabilities.

With respect to SDG&E's emergency customer communication system, the MOU Settlement provides for the following: the system will continue to be tested regularly by SDG&E and problems will be addressed if they occur; SDG&E will continue to perform outreach to existing and new medical baseline and life support customers, and to identify households that have a person with a disability, in order to determine their preferred method of contact in an emergency; and SDG&E will conduct outreach with community based organizations that serve the elderly or disabled to encourage those persons to contact SDG&E as to their preferred method of contact in an emergency.

Regarding written communications, the Applicants agree in the MOU Settlement to examine how they can improve the accessibility of standard written notices through large print or alternative formats, and to provide annual

[10] As part of the prior MOU that was adopted in D.08-07-046, the Applicants were ordered in this proceeding to perform certain studies to document and demonstrate that there were significant and useful changes made to the Applicants' operations and facilities as a result of the prior MOU. This information was contained in various exhibits that the Applicants sponsored in this proceeding.

training on disability issues to all staff who design or develop content for written customer notices, including training on disabilities that can interfere with a customer's ability to read standard print. If there are other Commission proceedings that affect communications access, the parties agree to meet and discuss the potential impact on the MOU Settlement.

On pedestrian rights of way issues, the MOU Settlement provides that the Applicants will continue to use the revised construction standards that were developed in the prior MOU and to incorporate the importance of these revised standards and pedestrian access as part of the Applicants' annual training on construction and safety related issues, and to make contractors aware of these revised standards and issues. Job site inspections of construction work by the Applicants and contractors will include physical accessibility of pedestrian pathways, and any deficiencies are to be corrected immediately. In addition, SDG&E agrees that when new above ground poles are installed, that a minimum width for the path of travel be established. SDG&E also agrees to make local governments aware of which undergrounding projects have the most existing impediments to accessibility, and to coordinate with local governments to improve the accessibility of the pedestrian right of way when a project includes work around utility poles. SDG&E also agrees to submit an AL, with Cfor AT's support, requesting that SDG&E's Electric Rule 20A be amended to add wheelchair access as a consideration.

The MOU Settlement also addresses: the Applicants' providing Cfor AT with annual reports and agreeing to hold quarterly status calls; dispute resolution procedures concerning the MOU Settlement; the Applicants' agreement that the issues resolved in the MOU Settlement by Disability Rights Advocates and Cfor AT have made a substantial contribution for the purposes of intervenor compensation; and that unless the MOU Settlement is materially altered by the Commission, that the costs of implementing the MOU Settlement will be included as part of the final adopted revenue requirement in these proceedings and no additional rate recovery will be requested.

In deciding whether the Joint Motion should be granted or not, we are guided by Rule 12.1(d) of the Commission's Rules of Practice and Procedure. That subdivision states: "The Commission will not approve settlements, whether contested or uncontested, unless the settlement is reasonable in light of the whole record, consistent with laws, and in the public interest."

The MOU Settlement continues the efforts from the prior MOU regarding accessibility in a number of different areas by customers with disabilities. Instead of litigating these issues, the Applicants and Cfor AT have reached agreements on how these accessibility issues can best be addressed in the context of existing federal and state laws that protect the rights of people with disabilities. Since the MOU Settlement resolves these accessibility issues with the assistance of a group that represents the interests of persons with disabilities, and their witnesses who have the technical experience to recognize and resolve these accessibility barriers, we conclude that the MOU Settlement, as set forth in Attachment A of the February 24, 2012 Joint Motion, and which we incorporate into this decision by reference, is reasonable in light of the whole record, is consistent with the law, and is in the public interest. Accordingly, the Joint Motion to adopt the MOU Settlement is granted, and the terms set forth in the above-referenced MOU Settlement are adopted.

4. Procurement and Generation

4.1. Introduction

This section addresses the costs associated with electric procurement, gas procurement, and non-nuclear electric generation.

4.2. SDG&E Electric Procurement

4.2.1. Introduction

Electric procurement covers SDG&E's activities associated with the costs of procuring, managing, planning, and administering of SDG&E's electric and fuel supply for bundled customers.[11] The Electric Procurement Department and the Resource Planning Department are the two departments at SDG&E which are primarily responsible for these activities. These two departments "work closely to plan future electric and fuel requirements, administer and manage those resources to ensure SDG&E maintains customer rate stability and reasonableness." (Ex. 109 at 4.)

The "Electric Procurement Department is responsible for the following functions associated with purchasing electricity to meet SDG&E's bundled electric customer demands: Long term Procurement, Trading and Scheduling, and Middle- and Back-Office." (Ex. 109 at 4.) The Resource Planning Department is responsible for planning the long term electric generation needs of SDG&E's system and bundled customers, evaluating resource options, evaluating the impact of changes in state policies, and supporting the other functions related to meeting customers' needs.

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[11] The commodity expense for the fuel is recovered in the Electric Resource Recovery Account (ERRA) proceeding.

For the 2012 test year, SDG&E forecasts $10.442 million for the O&M costs associated with electric procurement activities. This is an increase of $2.153 million over the 2009 base year. SDG&E's O&M cost forecast of $10.442 million is composed of the following five cost functions: long term procurement ($2.511 million); trading and scheduling ($3.170 million); middle and back office ($3.445 million); resource planning ($938,000); and Assembly Bill (AB) 32 administrative fees ($378,000).

The long term procurement functions include the Procurement and Portfolio Design section, the Generation and Supply Project Management section, and the Vice President (VP) of Electric Procurement. Among the duties of the Procurement and Portfolio Design section is to solicit requests for offers, and to negotiate and execute agreements to meet SDG&E's long term energy and capacity requirements, and to manage the procurement of long term renewable and conventional resources. The Generation and Supply Project Management section is responsible for coordinating the electric procurement activities for new conventional and renewable generation, such as contract management, and monitoring the project schedule, design, and construction to ensure it meets the performance measures stated in the contract. The VP of Electric Procurement is responsible for the management and administration of all long term procurement, trading and scheduling, and the middle and back office functions.

The trading and scheduling functions are handled by the Energy Supply and Dispatch section, which is divided into three groups, Market Operations, Electric Trading, and Electric Fuels. The Energy Supply and Dispatch section handles short term planning, trading and scheduling activities, and manages the portfolio of assets to serve bundled customers.

The middle and back office functions include the Settlements and Systems section, and the Energy Risk section. According to SDG&E:

> The [Settlements and Systems section] is responsible for electric transaction counter-party settlements including confirmation of transactions, verifying and processing of invoices and billing requests for bilateral transactions, and preparing journal entries for recording expenses and revenues. Settlement activities with the CAISO [California Independent System Operator] include processing of daily settlement statements and invoices, validating settlements including, when appropriate, the filing of disputes of questionable charges and reporting of generation and load meter data. Proposed CAISO changes to its settlement process are reviewed and commented on including intervening at FERC [Federal Energy Regulatory Commission], if appropriate. (Ex. 109 at 16.)

The Energy Risk section performs middle office functions "such as identifying, managing, monitoring, and reporting on market, credit, financial and operational risks associated with Electric Procurement Department functions." (Ex. 109 at 17.)

The Resource Planning functions include planning for the long term electric generation needs of SDG&E's bundled customers, and evaluating future policy options. The staff supports SDG&E on various proceedings before the Commission and the California Energy Commission (CEC), and also produces the Long term Procurement Plan for the Commission.

The AB 32 administrative fees cover the administrative costs and fees associated with this legislation. Under the California Air Resources Board's (CARB) greenhouse gas (GHG) emissions fees regulations, electric generating units in California are required to pay annual fees for each megawatt-hour (MWh) of net power generated by combustion of natural gas. The CARB regulations also require electricity importers to pay administrative fees for each MWh of imported electricity if the electricity is from unspecified sources or the combustion of fossil fuels. Since these fees are likely to vary from year to year, SDG&E requests that these fees be recovered in the New Environmental Regulatory Balancing Account (NERBA).

4.2.2. Position of the Parties

4.2.2.1. DRA

DRA recommends that SDG&E's forecast of O&M costs for electric procurement be reduced by $2.153 million. DRA's recommended disallowance is based on the following:

- For long term procurement, DRA recommends $1.785 million, which is $726,000 less than SDG&E's estimate of $2.511 million.
- For trading and scheduling, DRA recommends $2.478 million, which is $692,000 less than SDG&E's estimate of $3.170 million.
- For middle and back office functions, DRA recommends $3.088 million, which is $357,000 less than SDG&E's estimate of $3.445 million.
- For AB 32 administrative fees, DRA recommends zero dollars, which is $378,000 less than SDG&E's estimate of $378,000.
- DRA does not take issue with SDG&E's estimate of $938,000 for resource planning.

On the long term procurement disallowance, DRA contends that SDG&E's request for seven additional personnel positions, and associated non-labor costs, is not needed. DRA presented data on the growth of renewable energy resources from 2003 through 2010 to demonstrate that the existing long term procurement staff are capable of handling the additional workload associated with SDG&E's growing renewable energy portfolio. DRA also contends that adding additional large renewable resources does not result in additional complexity for SDG&E's long term procurement, and that the additional work associated with replacing the power from once-through cooling power plants has been known and planned for as far back as 2005.

DRA's trading and scheduling disallowance is based on DRA's recommendation that additional personnel positions are not needed to handle the AB 32 administrative fees activities, and the costs associated with implementing the CAISO Market Redesign and Technology Upgrade (MRTU) initiatives. DRA recommends that the AB 32 administrative fees be handled elsewhere, and that the O&M costs associated with MRTU be booked to the MRTU memorandum account.

On DRA's middle and back office disallowance, DRA proposes to disallow four additional personnel positions that SDG&E requested. DRA contends that these positions are not needed because additional personnel are not needed to procure and manage the growth in renewables, and to handle the AB 32 related activities. Instead of adding additional positions, DRA contends that as older regulatory proceedings get resolved, the employees who worked on those issues can be shifted to take on new obligations.

On DRA's disallowance of all the AB 32 administrative fees, DRA contends that D.10-12-026 determined that the utilities cannot collect the AB 32 implementation costs in the GRC until the Commission determines in the next phase of A.10-08-002 that such costs are recoverable.

4.2.2.2. SDG&E

DRA's recommended disallowance of $726,000 for long term procurement is due to DRA's belief that the incremental personnel positions will not be needed. SDG&E contends that the additional positions are needed for the following reasons. In SDG&E's 2011 Renewable Portfolio Standard (RPS) solicitation, SDG&E received close to 1000 bids. Until the RPS requirement of 33% renewables is reached, SDG&E expects that there will be an increasing number of bids with each RPS solicitation. In addition, SDG&E contends that the reporting requirements for the RPS program, and data requests have increased significantly. SDG&E expects this trend to continue, and cites to D.11-12-052 in which SDG&E is required to provide hourly data for each of its proposed contracts. SDG&E also contends that the potential projects will need to be negotiated, and additional work will occur before the projects come on line. As for DRA's claim that no additional analytical work will need to be done, SDG&E contends that additional staff is needed to respond to the CAISO market which is changing and increasing in complexity, and that environmental changes will also place additional burdens. Regarding DRA's argument that the replacement of once-through cooling plants was known, SDG&E contends that the current regulations were not adopted until May 4, 2010, with an effective date of October 1, 2010, which represents an incremental need arising after the last GRC. In addition, planning for the retirement of such facilities is a complicated process, and that sufficient time is needed to carry out the procurement process.

SDG&E opposes DRA's recommended disallowance of the incremental personnel positions for trading and scheduling. SDG&E contends that additional staff is needed to participate and monitor the rules and regulations pertaining to the GHG Cap and Trade Program, and to perform analysis of the prices and products that are available to SDG&E to meet its obligations for GHG compliance. SDG&E contends that the four additional positions for the Real Time desk are needed in order to staff the desk on a 24 hour basis in order to manage the increase in CAISO requirements and the increased portfolio generation. On DRA's recommendation that no incremental personnel positions are needed to support the MRTU, SDG&E contends that the MRTU has been operating successfully for more than two years, and the MRTU memorandum account is no longer necessary and should be eliminated. SDG&E contends that the ongoing costs can and should be forecast and recovered in GRC rates.

DRA's middle and back office recommendation would disallow any new incremental personnel positions. SDG&E contends that the incremental positions are needed. One position is to perform the invoice and reporting associated with the GHG program. The systems administration position is needed to handle the complex CAISO settlements, new contracts, additional functions to comply with new programs, and to handle the system enhancements and upgrades. Due to new renewable and conventional projects, and the complexity of new contracts, two new positions are needed to handle the increased work in contract administration, billing functions, and CAISO settlements.

On DRA's recommended disallowance of the AB 32 administrative fees, SDG&E contends that DRA ignores that SDG&E is preparing for AB 32 compliance, and has already paid mandatory AB 32 administrative fees to CARB. Since these costs are being incurred, SDG&E contends that these costs should be included in its GRC request.

4.2.3. Discussion

4.2.3.1. Introduction

We have reviewed and considered the testimony and the arguments of SDG&E and DRA concerning the O&M electric procurement costs. This discussion of the O&M electric procurement costs is divided into the five following functions: long term procurement; trading and scheduling; middle and back office; resource planning; and AB 32 administrative fees.

4.2.3.2. Long term Procurement

The incremental increase in long term procurement O&M costs is due to the RPS program, and SDG&E's belief that more employees will be needed to prepare solicitations and to negotiate the renewable contracts in order to meet the 33% RPS by 2020. In addition, SDG&E contends the long term procurement staff will need to comply with GHG regulations, and the feed-in tariffs process.

DRA, on the other hand, contends that SDG&E has sufficient resources to handle the RPS-related work. DRA points out that in 2010, SDG&E had sufficient resources to procure 11.9% of renewable generation.

We agree with DRA's reasoning that SDG&E does not need as much staff as it has forecasted. We believe that these regulatory obligations can be handled by the existing long term procurement staff, and the addition of two additional positions. This reduction of five positions is reasonable because there were already 14.4 positions in long term procurement in 2009. With the addition of one new position to the Procurement and Portfolio Design section, and one additional position for Generation and Supply Project Management, the total positions in 2012 would be 16.4. It is our belief that these 16.4 positions are sufficient to handle the increased work. Accordingly, we reduce the funding for long term procurement from $2.511 million to $1.992 million, a reduction of $518,571.[12]

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[12] The $518,571 reduction is based on SDG&E's forecast of seven Full-Time Equivalents (FTE) at a total incremental cost of $726,000. The cost of each incremental FTE is approximately $103,714 and the cost of five FTEs is $518,571.

4.2.3.3. Trading and Scheduling

Next, we address DRA's recommended disallowance of $692,000 for the trading and scheduling functions. This recommended disallowance is associated with SDG&E's request for seven new positions for the trading and scheduling functions. DRA makes two arguments as to why its recommended disallowance should be adopted. First, DRA argues that all of the costs associated with MRTU should be booked in the MRTU memorandum account, instead of being recovered through the 2012 test year in this GRC. DRA's second argument is that SDG&E's request for an incremental position for the GHG cap and trade program should be disallowed because the AB 32 administrative fees that SDG&E seeks recovery of cannot be collected until the Commission decides in the next phase of the proceeding that such costs are recoverable.

We first address the MRTU argument. In Resolution E-4088, SDG&E was granted authority to establish its MRTU memorandum account (MRTUMA). The authority was granted because the Commission expected SDG&E and the other electric utilities "to be fully prepared for MRTU and to have the resources necessary to be able to participate in the new market design, [locational marginal pricing], and a day-ahead energy market," and to "meet this objective, the [investor-owned utilities] should be permitted to track incremental MRTU-related costs in a memorandum account." (Resolution E-4088 at 5.)

Although DRA believes that the MRTU-related costs should continue to be booked into the MRTU memorandum account, SDG&E states:

> SDG&E recently requested to recover the costs through December 2009 recorded in the MRTUMA in the ERRA [Energy Resource Recovery Account] 2009 proceeding. SDG&E will continue to request recovery of MRTUMA expenses in ERRA through the year 2011. After 2011, SDG&E

> plans to shift the O&M and capital from the MRTUMA to this 2012 GRC. (Ex. 109 at 7.)

DRA cites to SCE's last GRC decision as authority for why SDG&E should be required to continue to book all MTRU-related costs in the MRTUMA. In that proceeding, SCE requested that its forecast of MRTU-related O&M costs and capital expenditures for 2009-2011 be handled in its GRC proceeding. The Commission rejected SCE's request to include those expenses in SCE's GRC proceeding, and concluded that SCE should continue to record these costs in the MRTUMA, and denied SCE's request to terminate its MRTUMA. (D.09-03-025 at 290-292, 389, Conclusions of Law 203 and 204.)

We are not persuaded by DRA's argument that MRTU-related O&M costs and capital expenditures for SDG&E should continue to be recorded in SDG&E's MRTUMA. First, D.09-03-025 only applied to SCE's MRTU-related costs and the circumstances at that point in time. Part of the Commission's reasoning for concluding that SCE's MRTU-related costs should continue to be recorded in its MRTUMA is because the Phase 2 MRTU costs, and the costs of any subsequent phases, were "unknown at this time and the scope of the MRTU phases are changing and evolving." (D.09-03025 at 292.) Unlike what existed in the late 2008 and early 2009 timeframe, the implementation of MRTU is now complete and the MRTU structure has been in place and in operation since 2009. As SDG&E points out, there is no longer uncertainty about MRTU and its related costs. The second reason why we are not persuaded by DRA's argument is that after 2011, "SDG&E plans to shift the O&M and capital from the MRTUMA to this 2012 GRC." (Ex. 109 at 7.) SDG&E's MRTU O&M costs are no longer for the purpose of preparing for, and having the necessary resources, to participate in the new market design. Instead, as SDG&E points out, these are "on-going costs" that "can and should be forecast and recovered in GRC rates" for SDG&E. (Ex. 111 at 10.)

Accordingly, we do not adopt DRA's recommendation to shift consideration of SDG&E's incremental MRTU-related O&M costs for trading and scheduling from this GRC proceeding into its MRTUMA that is being considered in its ERRA proceeding in A.11-06-003 or into another future ERRA proceeding. With regard to SDG&E's request that its MRTUMA account should be terminated, that request should be addressed in A.11-06-003, where SDG&E is seeking recovery of its 2010 MTRU costs, or in a proceeding that covers any remaining MRTU-related costs that were recorded in 2011.

Next, we address DRA's argument that the incremental funding for one position to handle GHG cap and trade-related work should be disallowed. DRA's disallowance relies on the language in D.10-12-026 that AB 32 fees recorded to the memorandum account are to be addressed in a subsequent phase of A.10-08-002. Although SDG&E acknowledges that full implementation of AB 32 is still in progress, SDG&E seeks funding in this GRC because it needs to recruit and train an additional employee in order to be fully prepared for compliance with AB 32.

We have reviewed D.10-12-026 and SDG&E's AL 2218-E and AL 1997-G. D.10-12-026 authorized SDG&E to "establish a memorandum account to record its actual expenditures to comply with the Assembly Bill 32 Cost of Implementation Fee." In the discussion section of D.10-12-026, the Commission stated that it "will determine whether the Joint IOUs [investor-owned utilities] may recover expenses incurred <u>prior to the inclusion of estimated AB 32 Fees in each of the Joint IOUs' next general rate case</u>, and if approved, the appropriate mechanism for recovery." (D.10-12-026 at 4, emphasis added.) Then in

Conclusion of Law 2, the Commission stated that "Given the short time frame the Joint IOUs have to pay the AB 32 fee after issuance of the invoice by [CARB], it is reasonable to allow each of the Joint IOUs to establish a memorandum account to record its expenditures for complying with the AB 32 Fee before receipt of the first AB 32 Fee invoice." Those two statements suggest that the memorandum account is for the purpose of recording costs incurred before the first AB 32 invoice is received, and is not for the purpose of recording ongoing or future AB 32 O&M costs. Accordingly, SDG&E's funding request for one incremental position to handle AB 32-related work is properly before us in this GRC.

Since we do not adopt DRA's arguments that the MRTU costs, and the AB 32 administrative fees should be addressed elsewhere, the next issue to address is whether the seven new positions that SDG&E is requesting are reasonable. In 2009, SDG&E had 19 positions for trading and scheduling. SDG&E requests seven additional positions, which would increase the number of positions to 26. Given the number of existing positions that SDG&E already has, we do not believe that seven additional positions are needed to handle the additional work associated with the MRTU, and the work associated with complying with AB 32. It is reasonable under the circumstances to reduce the number of these new positions from seven to four positions. The reduced number of positions will reduce SDG&E's trading and scheduling O&M costs from $3.170 million to $2.873 million.

4.2.3.4. Middle and Back Office

SDG&E is requesting an incremental increase of $357,000 for O&M costs for middle and back office functions. This incremental increase is for the following four additional positions: one to perform the invoice and reporting associated with GHG compliance; one to perform systems administration related to the Allegro system due to the increased complexity of CAISO requirements, power purchase agreements, and system enhancements and upgrades; and two to perform settlements and contract administration due to the increase in the number of contracts.

DRA's recommended disallowance of $357,000 would disallow all four positions. DRA contends that the additional positions are not needed because the existing employees will be able to procure and manage all of the RPS contracts, these additional RPS contracts will reduce the need for AB 32 activities, and the completion of old regulatory proceedings should allow those employees to take on new obligations.

Based on the current number of positions (27.4) in the middle and back office, we agree with DRA that SDG&E's request for funding of four additional positions is too many. As mentioned earlier, it appears SDG&E has sufficient staff to handle the RPS work, and that the existing staff can undertake some of the new responsibilities. For those reasons, we believe that one additional position is warranted, instead of the four positions that SDG&E has requested. It is reasonable to reduce SDG&E's O&M funding request for middle and back office functions from $3.445 million to $3.177 million.

4.2.3.5. Resource Planning

SDG&E requests $938,000 for the O&M costs for resource planning functions in the 2012 test year. SDG&E has not requested any incremental increase over the 2009 level, and expects the workload to remain the same for resource planning over the next GRC cycle. DRA does not take issue with SDG&E's forecast of the O&M costs for resource planning.

4.2.3.6. AB 32 Administrative Fees

SDG&E is requesting that the AB 32 administrative fees of $378,000 for the 2012 test year be recovered in the NERBA. As SDG&E acknowledges, the AB 32 administrative fee is to pay the CARB fee for the combustion of fossil fuels from electric generating units.

DRA contends that these fees should be removed from this rate case, and should be addressed in A.10-08-002 once the Commission decides if such costs are recoverable.

Recently, in D.12-10-044, the Commission authorized SDG&E and SoCalGas to "recover the reasonable costs recorded in the memorandum account for Assembly Bill 32 Implementation Fees from ratepayers," and that they may "request to recover in rates any further fees expected to be incurred as a forecast cost in a general rate case proceeding." (D.12-10-044 at 14.) Since the CARB fee is expected to be incurred in test year 2012, the request by SDG&E for $378,000 is appropriate and should be included in SDG&E's test year 2012 electric procurement costs.

4.2.3.7. Conclusion

We have reviewed all of the testimony regarding the remaining electric procurement costs. Except for the adjustments discussed above, we conclude that the remaining O&M costs for electric procurement are reasonable and should be adopted. Accordingly, the cost of $9.358 million should be adopted as the 2012 test year O&M costs for SDG&E's electric procurement.

4.3. Gas Procurement

4.3.1. Introduction

This section addresses SoCalGas' O&M costs associated with the function of procuring natural gas for the core customers of SDG&E and SoCalGas. In accordance with D.07-12-019, the core gas portfolios of SDG&E and SoCalGas were consolidated into a single portfolio on April 1, 2008. SoCalGas' Gas Acquisition Department is responsible for managing this portfolio and procuring the gas for the core customers of both utilities.

The Gas Acquisition Department is responsible for the procurement of the natural gas commodity, arranging for the transport of that gas by using interstate and intrastate pipeline capacity, and the use of gas storage. This department also manages price and basis risk for the core portfolio, which includes the trading of financial instruments such as futures, options, and over-the-counter swaps. The personnel in this department include gas traders, risk management/financial traders, gas schedulers, analysts, and back office support staff. Among the duties of the back office support staff is to negotiate and administer all agreements, process settlements, account for the cost of gas and storage, compile financial and regulatory reports, provide information technology (IT) support, administer the gas management system, and maintain internal controls.

To get a sense of the scope and scale of work that the Gas Acquisition Department performs, from April 1, 2009 through March 31, 2010, over 10,000 gas purchases and sales transactions were entered into involving over 405 Bcf of net purchases, at a total cost of about $1.6 billion.

SoCalGas requests O&M costs of $3.639 million for the 2012 test year. This is composed of $3.113 million in labor costs, which is unchanged from the 2009 base year recorded costs. The Gas Acquisition Department expects to maintain the same level of staffing (30.4 positions) in the test year as in 2009. The non-labor costs for the 2012 test year are forecast at $526,000 which is based on the five-year average, and is an increase of $95,000 over the 2009 base year recorded expense.

4.3.2. Position of the Parties

4.3.2.1. DRA

DRA recommends that the $95,000 incremental increase be disallowed, and that the 2009 recorded non-labor costs be used. DRA contends that its review of SoCalGas' 2005-2009 recorded expenses, and the 2010 recorded expenses, do not support the $95,000 increase requested by SoCalGas. DRA contends that SoCalGas' use of the five-year average ($526,000) for the non-labor cost component is not justified because the data demonstrates that "the non-labor component has been declining steadily since 2006," although there "was a minimal non-labor increase in 2010 above the 2009 level." (Ex. 536 at 3.)

4.3.2.2. SoCalGas

SoCalGas contends that its 2012 test year forecast of the O&M costs for gas procurement is a conservative and reasonable forecast. Although SoCalGas is not requesting any labor-related increase, it believes that an increase could have been justified due to an increasingly complex and competitive gas market. Instead, SoCalGas elected to work within the same staffing level from 2009, with the "expectation that the additional workload would be offset by increased productivity for the use of technology, consultants and various on-line services." (Ex. 445 at 3.)

As for the non-labor costs, SoCalGas contends that this is due to the increased costs of "new software applications, publications and on-line services providing industry news and market intelligence." (Ex. 445 at 3.) The Gas Acquisition Department needs "these services to remain competitive in this fast-changing industry in order to secure the lowest possible gas costs for its core customers." (Ex. 445 at 3.) SoCalGas also contends that DRA selectively chose to ignore the fact that there was an increase in the non-labor component from 2005 to 2006, and from 2009 to 2010.

4.3.3. Discussion

We have reviewed the testimony and arguments of DRA and SoCalGas regarding the O&M costs for gas procurement.

We agree with SoCalGas that the use of the five-year average for the non-labor O&M costs of gas procurement is reasonable. DRA's analysis of the six years of recorded non-labor costs from 2005 through 2010 overlooks the fact that there was an increase in 2006 over 2005, and an increase in 2010 over 2009. In addition, the Gas Acquisition Department needs the non-labor materials and services that SoCalGas plans to obtain in the test year in order to compete successfully and efficiently in the natural gas market.

For all of the above reasons, SoCalGas' forecast of $3.639 million for the 2012 test year O&M costs for gas procurement is reasonable and should be adopted.

4.4. SDG&E Non-Nuclear Electric Generation

4.4.1. Introduction

This section covers SDG&E's O&M and capital expenditure costs associated with its non-nuclear electric generation activities. SDG&E's electric generation organization consists of three main groups: generation plant, renewable generation support, and generation administration.

The generation plant group operates three electric generation power plants.[13] These three power plants are the following: the original 46 MW combustion turbine at the Miramar Energy Facility; the second 46 MW combustion turbine at the Miramar Energy Facility; and a 555 MW combined cycle plant at the Palomar Energy Center.

The renewable generation support group is located in SDG&E's Electric Project Development and Business Planning Department. According to SDG&E, this department "provides support for solicitations, contract negotiations, and contract administration for renewable and conventional generation," "provides technical support to resource planning, regulatory affairs, and other internal departments," and "provides due diligence review of renewable energy bilateral offers as it pertains to technical or developmental viability." (Ex. 97 at 3.) This department also oversees SDG&E's 20% ownership share in the San Onofre Nuclear Generating Station (SONGs).

The generation administration group "provides managerial support, plant cost analysis, budgeting, engineering, and workforce administration for the Electric Generation organization." (Ex. 97 at 3.)

For the 2012 test year, SDG&E is requesting total O&M costs of $33.687 million. This is an incremental increase of $4.835 million over the 2009 recorded amount of $28.852 million. The incremental O&M increase is due

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[13] At the time SDG&E's application was filed, it had received approval from the Commission in D.07-11-046 to exercise its option to purchase the 480 megawatt (MW) combined cycle power plant in Boulder City, Nevada, from El Dorado Energy, LLC. SDG&E assumed ownership of the El Dorado power plant in October 2011. SDG&E's GRC request only addresses the electric generation activities and transition costs that are needed to integrate the El Dorado power plant into SDG&E's system.

primarily to SDG&E's request of nine additional positions for generation plant, and four additional positions in generation administration.

SDG&E is also requesting capital expenditures of $15 million. In contrast, the 2009 recorded capital expenditures were $26.780 million.

4.4.2. O&M Costs

4.4.2.1. Introduction

SDG&E is requesting total O&M costs of $33.687 million.

4.4.2.2. Position of the Parties

4.4.2.2.1. DRA

DRA recommends electric generation O&M costs of $30.183 million, which is $3.504 million less than what SDG&E recommends. DRA's recommendation would result in reductions in generation plant, renewable generation support, and generation administration.

For the Palomar Energy Center, DRA recommends that SDG&E's forecast of $29.608 million be reduced by $2.051 million. DRA's recommended O&M cost of $27.557 million for this facility is based on the use of the four-year average from 2006-2009.

DRA contends that the addition of nine new positions, as SDG&E has requested, is not needed because SDG&E acknowledges that the Miramar facility can be remotely operated from the Palomar Energy Center and during peak demand hours the Miramar facility is operated by one person. DRA also infers that the additional five maintenance technicians to maintain and repair the Palomar and Miramar facilities are not needed because SDG&E can use outside services instead.

Part of the costs of operating the Palomar Energy Center is due to the long term service agreement between General Electric Corporation (GE) and SDG&E.

This agreement provides for the maintenance of the major components of the facility, which were manufactured by GE, to be maintained by GE. This agreement covers such things as "engineering support, remote equipment monitoring by GE's Monitoring and Diagnostic Center, major component refurbishment and replacement, replacement parts, labor for major maintenance outages and inspections, as well as on-site administrative and technical support." (Ex. 97 at 10.) DRA disagrees with SDG&E's $9.783 million forecast for the GE agreement. DRA believes that the four-year average of 2006-2009 for this agreement should be used, which results in DRA's recommended cost of $8.723 million.

For the O&M costs for the Miramar Energy Facility, DRA recommends an amount of $928,000, which is $579,000 less than SDG&E's request of $1.507 million. DRA's $579,000 reduction is tied to its recommendation that SDG&E receive nothing in capital expenditures for the Miramar facility.

For the O&M costs for renewable generation support, DRA recommends an amount of $512,000, which is $450,000 less than SDG&E's request of $962,000. DRA recommends the reduction because it does not believe SDG&E needs to hire a consultant, at a cost of $250,000, to provide assistance to aid in the oversight of SONGS. DRA contends that such oversight was not contemplated in A.06-04-018, as SDG&E suggests. In addition, since SDG&E only has a 20% share in SONGS, the use of a consultant is excessive when "SCE already has experienced analysts with extensive knowledge of practices at other nuclear facilities that review SONGS operations at a high level." (Ex. 476 at 8.)

The other part of DRA's recommended reduction for renewable generation support is SDG&E's request for $200,000 in consulting costs to hire a renewable generation consultant to assess opportunities outside of the procurement process. DRA contends that this reduction is warranted because of the statement in D.10-12-026 that AB 32 implementation costs cannot be collected until the Commission decides that such costs are recoverable.

For the O&M costs for generation plant administration, DRA recommends an amount of $1.186 million, which is $424,000 less than SDG&E's request of $1.610 million. DRA's reduction is based on its proposed disallowance of the four incremental positions that SDG&E has requested. DRA contends that the costs associated with the El Dorado facility, which DRA calculates at $131,000, should be recorded in the Non-Fuel Generation Balancing Account (NGBA) and included in SDG&E's annual AL filing. DRA also contends that SDG&E's request for two compliance administrators ($195,000), and one additional engineer to assist with ongoing engineering efforts at the plants ($98,000), lack adequate support.

4.4.2.2.2. UCAN

UCAN makes two recommendations concerning SDG&E's electric generation O&M costs.

UCAN's first recommendation concerns the O&M costs at the Miramar facility. UCAN recommends an amount of $1.2 million, which is a $307,000 reduction to SDG&E's request of $1.507 million. UCAN's recommended amount is based on the recorded 2010 spending at Miramar, which UCAN contends includes the operation of both units for the entire year, and includes the increases in dispatch as suggested by SDG&E.

UCAN's second recommendation is for the O&M costs at the Palomar facility. UCAN recommends an amount of $23.436 million, which is a $6.172 million reduction to SDG&E's request of $29.608 million. UCAN calculated the non-labor costs using a three-year average of 2008-2010 as a starting point, and then made several adjustments to the average as discussed in Exhibit 558 at 11. Among UCAN's adjustments is to remove the 2008-2010 crane savings.

UCAN also concurs with DRA's argument that the addition of new employees at Palomar and Miramar are not needed. UCAN contends that between 2007 and 2011, SDG&E had between 28 and 33 staffers at Palomar and Miramar. For that reason, UCAN used the 2009 recorded amounts for the labor costs.

4.4.2.2.3. SDG&E

SDG&E disagrees with the reductions recommended by DRA and UCAN.

SDG&E contends that the additional positions it has requested are needed to operate and maintain its increased generation facilities, which have been placed into service since the last GRC.

SDG&E also contends that the O&M reductions recommended by DRA and UCAN do not take into account the increase in maintenance that is required for aging equipment, as well as the increased run times. Also, their recommendations do not account for the fact that the CAISO directs the dispatch of its generation units and the timing of when the plants are to undergo maintenance.

SDG&E also contends that DRA's recommendation to use a four-year average for the costs of the GE agreement is not based on the escalation factors contained in the contract. SDG&E further contends that DRA's recommendation to eliminate the requests for two consultants would be contrary to the Commission's directive to enhance oversight of SONGS, and to assist SDG&E in meeting its 33% renewables portfolio goal.

4.4.2.3. Discussion

We first address the recommendations of DRA and UCAN to reduce the O&M costs for the generation plant group at the Palomar Energy Center and Miramar Energy Facility.

SDG&E has requested that nine positions be added in the 2012 test year to the generation plant group. Three operations technicians will be added to add another shift of workers to the 12 who are currently employed. According to SDG&E, this will allow for a crew to be on-site at the Miramar facility, instead of it being operated remotely. Five maintenance technicians will be added to augment the existing maintenance staff to take care of the demand for maintenance and repairs at both Palomar and Miramar. SDG&E also requests that one plant manager be added due to the addition of the El Dorado facility. Both DRA and UCAN recommend that no additional positions be added during the 2012 test year.

We agree that some additional positions are needed to handle the four power plants that SDG&E owns and operates. Additional personnel are warranted due to the following: the addition of the El Dorado facility and the second Miramar turbine; the cycling of Palomar on a daily basis, as directed by the CAISO, instead of being used as a baseload plant; the increase in regulatory requirements due to grid stability and environmental compliance; the need for operators and maintenance staff at Miramar; and the need to maintain the power plant facilities to ensure the continued safe and reliable operation of the power plants. However, our review of SDG&E's request and its testimony leads us to conclude that adding three additional operator positions and five additional maintenance technicians is too many in light of the existing number of personnel.

For that reason, SDG&E's electric generation should be reduced by $564,318, or six positions.[14]

We have also reviewed the testimony concerning the methodologies that DRA and UCAN recommend be used to forecast the costs at Palomar and Miramar, including the GE agreement, and UCAN's forecast of the 2012 non-labor costs. We agree that SDG&E's use of a 2009 base year methodology yields a more reasonable forecast as opposed to the methodologies used by DRA and UCAN. DRA and UCAN used inconsistent methodologies for their respective forecasts of O&M costs for Palomar and Miramar. However, we agree with UCAN's argument that if the purchase of a gantry crane for the Palomar facility is adopted, that the O&M costs for crane rentals should be reduced. According to SDG&E's response to a UCAN data request, UCAN estimates that the crane rental savings will amount to $700,000. (*See* Ex. 558 at 11, 13; *See* 17 R.T. 1910-1912.) As discussed in the electric generation capital expenditures section below, since the purchase of the gantry crane is approved, it is reasonable to further reduce SDG&E's O&M costs for electric generation by $700,000 since a crane rental will no longer be necessary.

Next, we address the O&M costs for renewable generation support. DRA recommends that the $250,000 funding request for a consultant to assist in the oversight of SONGS, and a $200,000 request for a consultant to provide renewable leads, be disallowed.

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[14] The $564,318 is based on the labor amount for 2012 of $3.875 million (*see* Ex. 99 at 3) divided by 41.2 positions, which results in a per cost employee of $94,053, multiplied by six positions.

SDG&E contends that the request for a SONGS consultant is reasonable and is based on the Commission's directive in D.06-11-026 that SDG&E enhance its oversight of SONGS operations and costs. We have reviewed D.06-11-026, as well as the testimony and arguments of SDG&E and DRA concerning the funding request for the SONGS consultant. In D.06-11-026, the Commission expressed concern that the 100% balancing account recovery agreed to in the settlement between SDG&E, SCE, and DRA, which was adopted in D.06-11-026, might result in SDG&E having to pay more than it should, and whether SDG&E has "an incentive to minimize such costs." (D.06-11-026 at 12.) In the event SDG&E requests that this "two-way balancing account for SONGS operations and maintenance costs" be continued, the Commission directed SDG&E to "include in its filing an exhibit that addresses whether 100% recovery provides it with any incentive to minimize such costs." (D.06-11-026 at 18, Ordering Paragraph 4.) SDG&E contends that by hiring the SONGS consultant, who will have "knowledge of practices at other nuclear facilities," the consultant can provide SDG&E with a review of SONGS operations and to make recommendations as to whether SCE is minimizing costs. (Ex. 100 at 15.)

We are not persuaded by SDG&E's argument that the hiring of a SONGS consultant is necessary and reasonable. SDG&E also has at least one employee who is located at SONGS to monitor operations. D.06-11-026 focused on the SONGS steam generator replacement project. Given SDG&E's minority ownership of SONGS, the cost of the SONGS consultant, and the possible duplication of work that the consultant would be doing, we agree with DRA's recommendation that the SONGS consultant is not needed. Accordingly, SDG&E's O&M request for renewable generation support should be reduced by $250,000.

DRA's other recommendation concerning the O&M costs for the renewable generation support group is to disallow SDG&E's funding request of $200,000 for the renewable generation consultant. We agree with DRA that this funding request of $200,000 should be disallowed, but not for the reasons DRA has raised. SDG&E is requesting funds elsewhere in this GRC application to help it staff up to meet the 33% renewables goal, and to perform work that is similar to what the consultant would be doing, i.e., assisting "SDG&E in evaluating attributes of renewable opportunities outside of the formal RPS procurement process." (Ex. 100 at 18.) Since SDG&E's request for a consultant to aid in this effort is duplicative of the work of other SDG&E employees, this consultant is unnecessary. Accordingly, DRA's recommendation to disallow $200,000 for a renewable generation consultant is adopted.

Based on the above reductions, SDG&E's O&M funding request for renewable generation support of $962,000 should be reduced downward to $512,000.

The next item to discuss is DRA's recommended disallowance of $424,000 for all four incremental positions for the generation administration group. SDG&E requests that the following four positions be added to this group: one project engineer to assist with the existing engineer; one project manager to assist with the transition of new generation assets, and to oversee capital projects, projects related to infrastructure changes as a result of the North American Electric Reliability Corporation's (NERC) critical infrastructure protection (CIP) standards, and maintenance outage planning and execution; and two compliance administrators to ensure that all existing and future requirements are being met concerning NERC's cyber security and reliability standards.

One of the arguments that DRA makes is that the costs associated with the acquisition of the El Dorado plant should be recorded in the NGBA instead of in this GRC. We have reviewed D.07-11-046, which authorized SDG&E to record its O&M costs in the NGBA and to recover those costs in an AL filing. However, D.07-11-046 also stated that SDG&E should not be precluded from "requesting cost recovery for El Dorado through its general rate case process," and that it might be more "efficient to consider the revenue requirement for El Dorado along with that for SDG&E's other assets." (D.07-11-046 at 21.) Since the El Dorado plant was integrated into SDG&E's system in late 2011, it is appropriate to consider the ongoing O&M costs of that plant in this GRC.

We have reviewed DRA's testimony, and SDG&E's testimony regarding its current staffing of the generation administration group and why it believes the four additional positions are warranted. We agree with DRA that SDG&E's request for four additional positions is excessive. Instead of four positions, only two additional positions should be funded. Accordingly, it is reasonable to reduce the funding for the generation administration group from $1.610 million to $1.398 million.[15]

We have reviewed the testimony regarding all of the other costs included in SDG&E's O&M electric generation cost, and except for adjustments as discussed above, these other O&M costs are reasonable and should be adopted. Accordingly, funding for SDG&E's non-nuclear electric generation O&M costs should be $31.761 million.

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[15] This reduction is derived by dividing the incremental increase of $424,000 by the four positions that were requested, and reducing the funding request by $212,000.

4.4.3. Capital Expenditures

4.4.3.1. Introduction

SDG&E requests capital expenditures in the 2012 test year of $15 million, and $12 million in both 2010 and 2011. The capital expenditure projects for SDG&E's electric generation organization fall into the following budget categories: Miramar plant operational enhancements; Palomar plant operational enhancements; critical services engine; Escondido black start; and gas turbine compressor upgrade. According to SDG&E, all of the capital projects that are being considered will "increase the overall reliability, operability and safety of the plants." (Ex. 97 at 14.)

The capital expenditures for the Miramar plant operational enhancements are for the engineering and installation of a water treatment plant to serve both combustion turbines, and to upgrade the emissions monitoring system.

For the Palomar plant operational enhancements, the capital expenditure projects include the following projects: transformer breaker monitoring system; closed cooling water system upgrade; cooling water biocide upsize; security system upgrades to the turbine and process control systems; installing an elevator and a bridge where the generators are located; upgrade generator protection relays; purchase of a transformer in the event of a failure; purchase of a gantry crane for lifting work during minor and major outages; replacement of steam turbine last stage blades; and upgrade the instrument air purge system.

The critical services engine project is for the engineering, design, procurement, and installation of a natural gas fired reciprocating engine and generator package at the Palomar Energy Center. This project is to ensure that critical plant equipment is protected , and allows the facility to be ready for restart after the loss of the transmission system.

The Escondido black start project is to install a black start generator at the Escondido substation. This generator will enable the black start of the CalPeak Power Enterprise peaking power plant, which in turn will provide black start capability to the Palomar power plant.

The gas turbine compressor upgrade project is to correct known deficiencies in compressor design that could result in compressor failures and turbine damage, and to improve overall operating reliability.

4.4.3.2. Position of the Parties

4.4.3.2.1. DRA

DRA recommends that all of SDG&E's electric generation capital expenditures be disallowed except for the critical services engine project, which DRA recommends funding at $741,000.

On the Miramar plant operational enhancements, DRA suggests that since Miramar's two combustion turbines have only been on line since 2005 and 2009, that this project may not be needed. Regarding the project involving a water treatment plant, DRA contends that SDG&E has not justified why such a plant is needed and has not provided a cost-benefit analysis. DRA further contends that the upgrade of the continuous emissions monitoring system appears to be a software program, which should have been included as an IT capital expenditure request. DRA also contends that SDG&E has not justified why the continuous emissions monitoring system needs to be replaced, and has not demonstrated whether the upgrade is the least-cost solution. DRA also contends that SDG&E has not adequately explained why Miramar is expected to increase production, nor has SDG&E explained why the additional capital expenditure projects are needed. DRA also contends that the recorded amounts for 2010 amounted to $1.344 million, but it is unknown how this money was spent.

On DRA's recommended disallowance of the Palomar plant operational enhancements, DRA recommends that all of the capital expenditure projects be disallowed. DRA's reasoning for its recommended disallowances are set forth below.

SDG&E's proposed purchase of the transformer for Palomar is estimated at $4 million. Although SDG&E states that this backup transformer is needed in case of a failure, DRA contends that SDG&E did not explain whether it is standard practice to have a replacement transformer on hand as a backup, and whether there are cost effective alternatives to purchasing the transformer.

Regarding the proposed purchase of the gantry crane, DRA contends that SDG&E did not provide any workpapers to substantiate its claim that the purchase of a gantry crane will eliminate the need for a crane rental, or that the purchase of a crane will be more cost effective than renting a crane.

On the blade replacement, DRA contends that SDG&E has not demonstrated or provided any analysis that the turbine blades need to be replaced.

For the transformer breaker monitoring system, DRA contends that SDG&E has not described how this system can be used to extend the life of the equipment, and to avoid unanticipated and costly outages. DRA also contends that SDG&E did not identify how many transformers or breakers will be equipped with this technology, and that there was no cost-benefit analysis of whether such a system will prevent or mitigate outages, or defer capital replacement costs. DRA also contends that SDG&E did not explain how this monitoring system relates to SDG&E's smart grid investments.

On the cooling water biocide upsize, DRA contends that SDG&E has not demonstrated that the current cooling water system needs to be upgraded, and that SDG&E has not justified the costs of the project.

For the elevator and bridge, DRA contends that the primary reason for these improvements appear to be related to SDG&E's black start system restoration plan. However, DRA contends that SDG&E has not explained why such improvements are needed, and has not explained why the black start system restoration plan is necessary.

As for the remaining four capital expenditure projects at Palomar, DRA contends that SDG&E has not justified or explained why these projects are necessary.

DRA recommends that SDG&E's capital expenditure for the gas turbine compressor upgrade at Palomar be disallowed because SDG&E has not demonstrated the need for the compressor upgrade, and such an upgrade should not be necessary for a plant that has only been operational since 2006. DRA also contends that SDG&E has not provided detailed cost information about the upgrade costs and any alternatives that SDG&E may have considered.

For SDG&E's capital expenditure for the critical services engine project, DRA recommends funding at the recorded 2010 amount of $741,000 instead of SDG&E's recommendation of $2.500 million.

For SDG&E's capital expenditure for the Escondido black start project, DRA recommends no funding.

For both the critical services engine project, and the Escondido black start project, DRA contends that SDG&E did not demonstrated the benefits of the investments, and no cost benefit analyses were presented to demonstrate the reasonableness of these two projects.

4.4.3.2.2. UCAN

UCAN recommends that SDG&E's capital expenditures for non-nuclear electric generation be reduced by $6.680 million.

Under the Miramar plant operational enhancements, UCAN contends that SDG&E's funding request of $550,000 to install a water treatment plant should be disallowed because that plant will not be built before the end of the 2012 test year. According to a SDG&E response to a UCAN data request about this project, SDG&E admitted that "This project has not moved forward while other options have been explored," and "As a result, no on-line date for this project is set." (Ex. 558 at 13.)

On the proposed gantry crane project, UCAN believes that funding for this project should be authorized. In a response to a UCAN data request, SDG&E provided "information on the savings on past and future crane rentals," and that "the savings are very large relative to the cost of the crane ($1.5 million gross savings in the 2012 outage alone)." (Ex. 558 at 13.) UCAN contends that the gantry crane project will pay for itself in the GRC cycle. Since the purchase of the crane will result in crane rental savings, UCAN recommends that SDG&E's electric generation O&M costs be reduced by $700,000 as noted earlier.

For the cooling water biocide upsize, UCAN contends that the entire funding request of $680,000 should be disallowed for imprudence. According to a data response by SDG&E, the undersized water treatment tanks and pump skids at Palomar appear to have been the result of the "original engineers who underestimated the biocide injection rate as set forth in the requirements of the Palomar Cooling Tower Biocide Use, Biofilm Prevention and Legionella Monitoring Program." (Ex. 558 at 14.) UCAN contends that this undersized equipment was "caused by lax oversight of an affiliate transaction between

SDG&E and Sempra Energy." (Ex. 558 at 14.) UCAN contends that SDG&E's ratepayers should not have to pay for a project to remedy a problem that was caused by the original engineers or Sempra, and that SDG&E never corresponded with Sempra "during or subsequent to the construction of the plant." (Ex. 558 at 14.) UCAN believes that such a project should be borne by SDG&E's shareholders.

UCAN's rationale for its recommended disallowance of the cooling water biocide upsize also applies to the closed cooling water system upgrade project. This project involves the replacement of an underground cooling water system for both combustion turbines with an above-ground system, and to add isolation valves so that repairs and maintenance can be performed without shutting down the entire plant. According to SDG&E, the replacement project is needed because the "current underground system is prone to leaks and is difficult to repair." (Ex. 558 at 14-15; Ex. 97 at 16.) UCAN contends that Sempra, as the builder of the project, designed the project badly, and that SDG&E did not exercise any construction oversight. UCAN contends that SDG&E's ratepayers should not have to pay for bad affiliate transactions, and SDG&E's funding request of $450,000 should be disallowed.

UCAN recommends that $5 million of the $10 million that SDG&E has requested for the gas turbine compressor upgrades be disallowed. In May 2005, when the plant was still under construction, GE notified owners of the compressors in May 2005 that there were problems. Additional problems were identified in Technical Information letters that GE issued from June 2008 to December 2010. SDG&E did not file a claim with GE because the one-year warranty on these defective parts had expired. UCAN contends that it is appropriate to have SDG&E share in the cost of the project because SDG&E will continue to earn its 11% return on equity on both the replacement and defective parts, and had this been a power purchase agreement ratepayers would not have to pay any of these costs.

4.4.3.2.3 SDG&E

On DRA's recommended disallowances, SDG&E contends that contrary to DRA's claim, it "has provided more than sufficient detail and information behind the projects and the related costs, in direct testimony, the master data request, DRA's site visit to SDG&E facilities, and in follow-up data request responses." (Ex. 100 at 19.) The workpapers also contained a Capital Project Workpaper for the projects which described the business purpose, physical description, project justification, forecast methodology, and schedule. SDG&E also points out that "In the more than twelve months since serving its [Notice of Intent], SDG&E has received from DRA only one discovery request regarding Electric Generation Capital on May 6, 2011, containing 14 questions." (Ex. 100 at 20.) This is in contrast to DRA's testimony on Electric Generation Capital which posed 46 questions as to why the capital expenditure projects should not be funded, which DRA never requested SDG&E to provide answers to in discovery.

For the water treatment project at Miramar, SDG&E acknowledges that this project has been suspended.

Regarding DRA's recommendation to disallow the continuous emissions monitoring system at Miramar, this system includes hardware that is not controlled, serviced, or maintained by IT. The problems with this system were documented and provided to UCAN. SDG&E also points out that "Miramar has seen large increases in run time and starts," and that it is up to the CAISO to "determine when or how much Miramar runs." (Ex. 100 at 24.)

Regarding DRA's recommendation to disallow the transformer purchase at Palomar, SDG&E contends that having a spare transformer on hand is warranted, and will help ensure the availability of Palomar. This is based on SDG&E's experience with a December 2010 transformer outage, and SDG&E's efforts to find a suitable replacement,

For the gantry crane at Palomar, SDG&E estimates that crane service rentals for an outage will cost approximately $1.5 million, and that the steam turbine will require at least three major overhauls during its life.

Regarding DRA's recommendation to disallow the last stage blade replacement at Palomar, SDG&E contends that erosion during the last stage of steam turbines is common, and that Palomar's steam turbine will have 48,000 service hours when it is due for blade replacement. SDG&E contends that this is a reasonable and expected cost of maintaining a generating facility.

For the transformer breaker monitoring system, SDG&E contends that the on line monitors with built in diagnostics will be connected to SDG&E's communications network to allow monitoring. SDG&E contends that this monitoring is a form of reasonably priced insurance to minimize failures, which in turn benefits customers.

On the cooling water biocide upsize, SDG&E contends that the "Palomar Energy Center is a well-built facility that has performed admirably since beginning operations in 2006." (Ex. 100 at 29.) SDG&E contends that to disallow the upgrades because of UCAN's assertion that there was a lack of oversight or that the project was built by an affiliate would be incorrect. SDG&E asserts that every plant changes over time, and that hundreds of improvements have been made to Palomar's water treatment systems. SDG&E contends that the plant has outgrown the original system, and there is a need to increase the size of the biocide system because of "the current operating environment, water composition and 6 years of operating experience." (Ex. 100 at 30.)

On DRA's recommended disallowance of the elevator and bridge for Palomar, SDG&E contends that this will allow personnel to use an elevator instead of climbing six flights of stairs, often with tools. SDG&E contends that each boiler must be climbed at least twice a day by the roving operator.

On the closed cooling water system upgrade, SDG&E contends that it had no input into the design of Palomar, and that it bought the plant as-is. SDG&E contends that its closed cooling water system upgrade project should be funded based on its same reasoning as to why the cooling water biocide upgrade should be allowed.

Regarding the security upgrade at Palomar, SDG&E contends that the Palomar facility is obligated to comply with the NERC CIP standards due to cyber security concerns. Palomar's generation control system is based on a design that is over 10 years old, and moving to a new generation of control systems will provide full compliance with these cyber security standards.

SDG&E contends that the replacement of the digital generator protection relay at Palomar is justified because this relay design is about 20 years old, and does not perform as well as modern relays. The relay helps protect the generators and the electric grid in the event of an incident at the plant or on the grid.

SDG&E contends that the dry air purge system at the Palomar plant is needed to maintain a slight pressure on the bus ducts with dry, conditioned air, which will reduce the risk of failure of high voltage conductors from moisture or contamination.

SDG&E contends that the compressor upgrades at the Palomar Energy Center is part of the normal plant maintenance and equipment refurbishment. At the next major maintenance outage, the combustion turbines will have 48,000 operating hours and will be taken out of service and dismantled to inspect for wear and tear. For any 48,000-hour maintenance outage, several parts of the compressor section are likely to need refurbishment or replacement at a cost of about $10 million. According to SDG&E, the failure to fully address all worn or outdated design issues "would unnecessarily expose SDG&E and its customers to greater risk and potentially greater costs." (Ex. 100 at 34.) As for UCAN's argument that ratepayers would avoid this cost if it was a power purchase agreement, SDG&E states that it has some power purchase agreements "where the cost of plant equipment overhauls, major maintenance and capital additions are included." (Ex. 100 at 35.)

Regarding the critical services engine for Palomar, DRA recommends that only $741,000 of SDG&E's $2.500 million request be approved. SDG&E contends that the critical services engine is needed to avoid a plant going completely black and resulting in a plant being unavailable for several days.

For its Escondido black start project, SDG&E contends that the installation of an engine generator at the Escondido substation will allow a portion of the substation to be energized in the event of a system outage. In turn, the substation will then provide power to a local peaking plant, which could then start up and provide power to Palomar, which could then start up and provide support to the grid to restore the electric system. SDG&E views this as an effective method of increasing grid reliability and to improve restoration efforts.

4.4.3.3. Discussion

4.4.3.3.1. Miramar Plant Operational Enhancements

SDG&E is requesting total capital funding of $687,000 for the Miramar plant operational enhancements. Under this category, SDG&E plans to undertake various projects, including the two as described here. One project is to engineer and install a water treatment plant to serve both of the combustion turbines at the Miramar facility. Currently, the plant uses demineralized water that is brought in by a vendor, which is inefficient and costly. The second project is to upgrade the Continuous Emissions Monitoring System, which monitors the exhaust stack emissions and produces reports for submission to the local air district.

DRA and UCAN both oppose the water treatment plant project for different reasons. UCAN believes this project should be removed from SDG&E's GRC request because SDG&E acknowledges that this project "has been suspended while SDG&E explores other technologies and commercial arrangement…, " and that the "water treatment plant will not be installed at Miramar before the end of the test year." (Ex. 100 at 23; Ex. 101, SDG&E Response 05; 17 R.T. 1909.) Since the water treatment plant project for Miramar has been suspended, the funding request of $550,000 for this project shall be removed from SDG&E's Miramar plant operational enhancements budget for 2010 ($50,000) and 2011 ($500,000).

DRA recommends that SDG&E's request for funding of its Continuous Emissions Monitoring System be disallowed. SDG&E wants to upgrade this system because of problems in producing acceptable and accurate reports, and to match the system used at the Palomar facility. Documents supporting the problems with this system were provided to UCAN. Based on the need to correct the problems with the Continuous Emissions Monitoring System at Miramar, DRA's recommendation to disallow funding of this project is not adopted, and funding for this project in the amount of $137,000 should be approved for 2012.

Based on the above, capital funding for the category of Miramar plant operational enhancements shall be set at $137,000.

4.4.3.3.2. Palomar Plant Operational Enhancements

SDG&E is requesting total capital funding of $23.650 million for the Palomar plant operational enhancements. Under this category, SDG&E plans to undertake various projects, including the 10 projects described below and mentioned in the position of the parties.

SDG&E's first project is a transformer breaker monitoring system for Palomar at a cost of $1.500 million. This project is to include the purchase and installation of dynamic rating monitors on high voltage bushings at the Palomar facility. According to SDG&E, this will allow for the continuous monitoring of the bushings, to avoid a transformer failure. SDG&E is also installing these monitors on its other large transformers. DRA takes issue with this project, and contends that SDG&E has not described how this system can be used to extend the life of the equipment, and avoid unanticipated and costly outages. Without the monitors, SDG&E contends that it is unable to determine if the bushings are deteriorating. In deciding whether such a project should be funded, it is important to compare the cost of such a project with the benefits such a project. Due to its relatively low cost, we agree with SDG&E that this is "a form of reasonably priced insurance to help minimize the risk of an expensive failure." Accordingly, DRA's recommendation to disallow this project is not adopted, and funding of $1.500 million for this project should be approved.

SDG&E's second operational enhancement is for a closed cooling water system upgrade project at an estimated cost of $450,000. According to SDG&E, the current underground cooling water system is prone to leaks, is difficult to repair, and does not have enough isolation valves. This project would replace the current system with an above-ground system, and install isolation valves to allow for repairs and maintenance without shutting down the entire plant. SDG&E contends that "the plant has outgrown the original system and above-ground piping is now necessary." (Applicants' Opening Brief at 44.) Also, an above-ground system will "avoid any ground contamination or leaks into the ground that would require reclamation and clean-up efforts." (17 R.T. at 1915.)

DRA is opposed to this project, but did not provide a specific reason.

UCAN is opposed to the project because it believes the problem was caused by a bad design which Sempra did not catch, and which SDG&E should have caught had it provided construction oversight. UCAN's recommendation to disallow the closed cooling water system upgrade project is based on its argument that the Palomar cooling water system should have initially been built above-ground, or that the leak problems and lack of isolation valves was a design problem that should have been caught by SDG&E.

However, the testimony in this proceeding lacks evidence on the issue of whether SDG&E was responsible in some manner for the original design and construction of the Palomar facility. According to SDG&E's testimony, "SDG&E bought the plant as-is and had no say in its design." (Ex. 1000 at 31; *See* Ex. 101, SDG&E Responses 02, 04.) After operating the Palomar facility, SDG&E has uncovered leakage problems, and the lack of sufficient isolation valves. In order to correct those problems, SDG&E proposed this project. Under the circumstances, SDG&E's funding request of $450,000 is reasonable, and funding for this project should be approved.

SDG&E's third operational enhancement project is the cooling water biocide upsize project at a cost of $680,000. This project is to provide larger tanks and new pump skids to increase the capacity of the existing chemical tanks and pump skids that are used to treat Palomar's 1.3 million gallon cooling water system. DRA is opposed to the project because it does not believe SDG&E has demonstrated that the existing biocide system needs to be upgraded, and SDG&E has not justified the costs of the project. UCAN also opposes this project on the basis that the problem was caused by the original engineers who underestimated the biocide injection rate, which should have been caught by Sempra, or by SDG&E had it provided construction oversight. SDG&E contends that every plant changes over time, and that hundreds of improvements have been made to Palomar's water treatment systems. Among the needed changes is to increase the size of the biocide system.

We agree with SDG&E that plant and operating conditions change over time, which may result in modifications to the existing plant at a later time. The current biocide system was designed based on the assumptions made prior to 2006. Through SDG&E's operating experience with the plant, many different improvements have already been made. This cooling water biocide upsize is another modification that is needed based on the current operating conditions and challenges that SDG&E faces in operating the Palomar facility. Accordingly, the recommendations to disallow the cooling water biocide upsize project are not adopted. The project is reasonable under the circumstances, and SDG&E's funding request of $680,000 is reasonable and should be approved.

The fourth operational enhancement project is the Mark IV security system upgrade project, which will make changes to the plant control systems to comply with the NERC CIP standards. DRA is opposed to this project but did not cite any specific reason for its recommended disallowance. The CIP standards have been adopted by NERC to ensure that critical infrastructure protection functions are integrated into the planning and operation of the North American electric system. The NERC is the agency designated by the United States Department of Energy to coordinate the protection of this infrastructure. In order to meet these standards, the current plant control system, which design is over 10 years old, needs to be changed to meet these new cyber-security standards. Accordingly, DRA's recommended disallowance is not adopted, and SDG&E's request of $450,000 for this project is reasonable and should be approved.

The fifth operational enhancement is to install an elevator at one of the steam generators at the Palomar facility, and a foot bridge connecting the steam generators. SDG&E estimates the cost of this project at $500,000. DRA opposes the project because it does not believe SDG&E has justified the project. SDG&E's principal justification for this project is that without an elevator and bridge, plant personnel need to climb six flights of steps, often with tools. With an aging workforce, as well as safety concerns, SDG&E believes that the elevator and bridge is reasonable. We believe that the installation of the elevator and bridge will provide for easier maintenance access at the Palomar facility. Accordingly, DRA's recommended disallowance is not adopted, and SDG&E's request of $500,000 for this project is reasonable and should be approved.

SDG&E's sixth operational enhancement project is to upgrade the generator protection relays at a cost of $100,000. DRA is opposed to this project but did not cite a specific reason for its recommended disallowance. SDG&E

contends that the relay design is about 20 years old, and will not readily comply with the NERC and Western Electricity Coordinating Council regulations for testing, calibration, and certification without extra effort. Due to the age of the relays, and the regulations that these relays must comply with, it is reasonable for SDG&E to replace these relays with modern relays that meet these regulations. Accordingly, DRA's recommendation to disallow this project is not adopted, and SDG&E's request of $100,000 to replace the current relays is reasonable and should be adopted.

The seventh operational enhancement project is to purchase a backup transformer for the Palomar facility at a cost of $4 million. The Palomar facility relies on three large transformers, weighing about 300,000 to 400,000 pounds, to deliver power from its three generators. DRA recommends that this project be disallowed because SDG&E did not establish whether having a replacement transformer on hand is a typical industry practice, and has not explored whether there are cost effective alternatives to purchasing the transformer. Based on the evidence presented by SDG&E about the time it takes to procure a replacement transformer in the right configuration, as well as operational concerns, it is reasonable to have a backup transformer on hand. This backup transformer will limit the down time of the Palomar plant in the event of a transformer outage. Accordingly, DRA's recommendation to disallow the backup transformer is not adopted, and SDG&E's request of $4 million to acquire a backup transformer is reasonable and should be adopted.

The eighth operational enhancement project is the purchase of a gantry crane for the Palomar facility at a cost of $2 million. DRA opposes the project because of its belief that SDG&E has not justified that the crane purchase will be more cost effective than a crane rental. UCAN supports SDG&E's purchase of the gantry crane, but contends that the O&M costs for crane rentals should be reduced by $700,000.

Based on the testimony, it is apparent that the purchase of a gantry crane will be cost effective. During an outage, SDG&E estimates that a crane rental will cost approximately $1.5 million, and that the steam turbine at Palomar will require at least three major overhauls during its lifespan. As discussed in the O&M section on electric generation costs, we are also persuaded by UCAN's argument that if the purchase of the gantry crane is approved, that there should be a reduction in the cost of crane rental. Accordingly, DRA's recommendation to disallow the purchase of the gantry crane is not adopted, and SDG&E's request of $2 million to purchase the gantry crane is reasonable and should be adopted.

The ninth operational enhancement is to replace the last-stage blades on the steam turbine at Palomar due to the erosion of the blades caused by normal wear and tear. DRA opposes the project because it believes SDG&E has not demonstrated or provided any analysis that the last-stage blades need to be replaced. We agree with SDG&E that erosion of these last-stage blades can be expected when it has 48,000 service hours, and that it is reasonable to replace these blades in order to properly maintain a generating facility. Accordingly, DRA's recommendation to disallow the last-stage blade replacement project is not adopted, and SDG&E's request of $2 million for this project is reasonable and should be adopted.

The tenth operational enhancement project is for an instrument air purge system for the iso-phase bus ducts, which is estimated to cost $200,000. These ducts are used to enclose the 18,000 volt conductors that transport the power produced by each generator to the associated transformer. According to SDG&E,

these conductors must be maintained in a warm, dry, clean environment to prevent corrosion or arc flash incidents. The project will provide a constant supply of dry, instrument air to each iso-phase bus duct, which will displace contaminants from entering the duct. DRA is opposed to this project but does not cite any specific reason for its recommended disallowance. Based on the evidence presented, it is reasonable for SDG&E to proceed with this project to reduce possible problems with the conductors. Accordingly, DRA's recommendation to disallow the air purge system project is not adopted, and SDG&E's request of $200,000 for this project is reasonable and should be adopted.

The next category of capital expenditures is for the critical services engine project. The purpose of this project is to protect critical plant equipment at Palomar, and to allow the facility to be restarted after the loss of the transmission system. The Palomar facility depends on offsite power to keep its plant systems energized and operating when the plant is not generating power. If that offsite power goes down, critical systems without battery backup would be de-energized. This project was completed in 2011, which installed a natural gas powered engine and generator set at Palomar to provide power to critical systems in case the offsite power goes down. SDG&E estimates the cost of this project at $2.500 million. DRA recommends that only the $741,000 recorded in 2010 be approved.

Based on the testimony, this project to provide backup power to critical systems at the Palomar facility is reasonable as it will help protect critical systems in the event of an offsite outage, and will allow the Palomar facility to be ready for a restart after such an outage. Since the recorded costs in 2010 for this project were $741,000 and this project was completed in 2011, that suggests that the cost of this project has been overstated by SDG&E. Since the project was not completed until 2011, it is reasonable to assume that some additional costs were incurred in 2011 in connection with this project, which we estimate did not exceed $509,000. Instead of approving SDG&E's request of $2.500 million, we believe that total funding of $1.250 million for this project is reasonable under the circumstances and should be adopted.

The next category of capital expenditures is for the Escondido black start project, which SDG&E estimates will cost $2.200 million. The purpose of this project is to provide sufficient power to start up the Palomar facility. This would be accomplished by installing an engine and generator set at the Escondido substation. Providing power to the substation will enable power to be fed to the CalPeak peaking plant, which is adjacent to the Palomar facility. Once the CalPeak plant is able to operate, it can supply power back to the substation, which will then feed power over the 230 kilovolt (kV) system to Palomar, and provide sufficient power for startup. DRA recommends no funding for this project, and notes that although this project had an estimated in-service date of December 31, 2010, that there were no recorded costs for this project in 2010.

SDG&E acknowledges in its capital project workpaper for this project that the use of the Escondido black start engine and generator "may be infrequent," but it will be "a critical asset for SDG&E in the event of a blackout or other system emergency." (Ex. 98 at 6.) Although SDG&E estimated an in-service date of December 31, 2010 for this project in its capital workpapers, SDG&E did not provide an update in its October 2011 rebuttal testimony whether this project would even be built in the 2012 test year. Instead, SDG&E stated that the "Escondido Black Start project was delayed while alternatives to the configuration and actual location were further investigated." (Ex. 100 at 22, 36.)

Due to a lack of information as to whether this project will be pursued in the test year, and SDG&E's acknowledgement that even if this project is built, the use of such equipment may be infrequent, we do not approve SDG&E's funding request of $2.200 million for this project in 2010.

The final category of capital expenditures is for the gas turbine compressor upgrade at the Palomar facility. According to SDG&E, the turbine compressor was originally "designed and built using the state-of-the-art knowledge and techniques in order to achieve maximum efficiency and performance." (Ex. 98 at 7.) However, over time "several weaknesses and deficiencies were documented in the compressor, leading to re-design and improved manufacturing techniques," and these compressor improvements "are now available to be installed in the Palomar turbines." (Ex. 98 at 7.) SDG&E estimates the cost of this project at $10 million. DRA recommends that the gas turbine compressor upgrade project be disallowed, while UCAN recommends that $5 million of the $10 million that SDG&E has requested for the gas turbine compressor upgrades be disallowed.

We are persuaded by the arguments of DRA and TURN that shareholders should bear a portion of these capital expenditure costs. As DRA and TURN point out, the problems with the compressors began surfacing in 2005, sometime before the Palomar plant began operations in 2006. It appears that SDG&E could have pursued other courses of actions to remedy these problems and to reduce costs to ratepayers, but did not do so. Due to SDG&E's apparent knowledge of these compressor problems before the plant went into operation, it is reasonable under the circumstances for shareholders to bear a 50% share of the Palomar compressor upgrade project. Accordingly, it is reasonable to remove $5 million from SDG&E's capital expenditure request in 2012.

4.4.3.3.3. Summary of Capital Expenditures

Based on our review of the testimony and arguments of the parties, and our consideration of those adjustments, as discussed above, it is reasonable to adopt funding for SDG&E's electric generation capital expenditures as follows: $7.991 million in 2010; $12.009 million in 2011; and $10.037 million in 2012.

5. San Onofre Nuclear Generating Station (SONGS)

5.1. Introduction

SDG&E owns a 20% share of SONGS. This section addresses SDG&E's 20% share of the O&M costs (except for refueling outage O&M) and capital costs. SDG&E's 20% share of these costs is based on the SCE's forecast of costs that was submitted in its GRC filing in A.10-11-015, and the O&M and capital-related costs that SDG&E is presenting in this proceeding.[16]

SDG&E forecasts its total 2012 SONGS revenue requirement at $161.361 million, excluding the SONGS refueling outage O&M. As described in Exhibit 81, the majority of those costs will be established and addressed in SCE's GRC proceeding.[17] Of that amount, SDG&E is presenting testimony for $1.733 million in SONGS-related direct O&M costs in this proceeding. The $1.733 million is for SONGS Unit 1 spent fuel storage, the SONGS site easement, the SONGS industrial accident and litigation expense, and escalation of these

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[16] Other parts of this decision address SDG&E's request for other SONGS-related costs for insurance, labor for electric generation, and capital-related costs (i.e., return on rate base, depreciation, taxes, and franchise fees and uncollectible expense).

[17] The SCE GRC decision addressing the SONGS expenses was issued in November 2012 in D.12-11-051.

costs from 2009 dollars to 2012 dollars.[18] SDG&E is also requesting that its SONGS O&M two-way balancing account be continued.

For the SONGS-related costs to be established in SCE's GRC proceeding, SDG&E estimates that its 20% share of the test year 2012 O&M and overhead costs will be $123.189 million. SDG&E's expected share of the SONGS refueling outage O&M costs is $11.367 million. The refueling outage O&M costs are for the cost of performing maintenance and repairs on the systems and equipment that cannot be performed while the plant is operating. For the SONGS capital additions, SDG&E's 20% share is estimated at $45.687 million.

SDG&E requests that to ensure the proper and complete recovery of the SONGS-related costs, the Commission make a specific finding in this proceeding that SDG&E be allowed to update its revenue requirement for its SONGS-related O&M costs, capital additions, and escalation to reflect the Commission's final authorized amount established in SCE's [test year 2012] GRC and SDG&E's [test year 2012] GRC." (Ex. 81 at 12.) SDG&E plans to update the SONGS revenue requirement for its share of the authorized SONGS costs after a decision has issued in both SCE's GRC proceeding, and in this proceeding.

The following is a description of the other SONGS-related costs that SDG&E is requesting in this proceeding. The first is SDG&E's forecast of the SONGS Unit 1 spent fuel storage. This cost is for the storage of spent fuel assemblies that are stored in Illinois. SCE makes monthly payments for this storage, and then bills SDG&E for its 20% share. SDG&E estimated its test year

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[18] As discussed later, SDG&E has withdrawn its request for $710,000 for the industrial accident and litigation expense.

2012 expense to be $1.003 million. SDG&E also requests escalation for this cost from 2009 dollars to 2012 dollars.

The second SONGS-related cost that SDG&E has raised in this proceeding is for the SONGS site easement. SONGS is located on Camp Pendleton, which is owned by the United States Department of the Navy (Navy). Each of the owners of SONGS is billed separately by the Navy for their respective share of the easement fee. SDG&E estimates its annual site easement expense at $20,147.

The third SONGs-related cost is SDG&E's portion of the costs from industrial accident and litigation related to incidents that occurred at SONGS when the Master Insurance Program was in effect. The Master Insurance Program "insured the owners and all contractors and subcontractors under one insurance program for General Liability and Workers' Compensation insurance for all of SCE," and was started in 1972 and terminated in 1999. (Ex. 81 at 6.) SDG&E's estimated cost is $710,000 which represents SDG&E's share of the open claims from that period of time.

As mentioned earlier, SDG&E's testimony in this proceeding also requests that the SONGS two-way balancing account be continued. This balancing account was adopted as part of the settlement approved in D.06-11-026. This balancing account allows SDG&E to recover in rates the actual O&M costs billed to it by SCE, including the refueling outage O&M and contractual overheads.

5.2. Position of the Parties

5.2.1. DRA

DRA originally took issue with SDG&E's base O&M costs for SONGS, and with SDG&E's share of the SONGS capital expenses. However, the ALJ granted SDG&E's request to strike portions of DRA's testimony recommending these lower amounts because those issues were being litigated in SCE's GRC proceeding in A.10-11-015. Accordingly, those reductions are not at issue in this proceeding.

SDG&E is requesting $1.003 million for the expense billed to it by SCE for SDG&E's share of storing spent fuel assemblies from SONGS Unit 1 at a spent fuel storage facility located in Illinois. DRA reviewed SDG&E's testimony, workpapers, and discovery responses, and takes no issue with this amount.

As mentioned above, each owner of SONGS is billed by the Navy for its proportionate share of the easement fee. DRA takes no issue with the $20,147 that SDG&E pays to the Navy for this easement fee.

SDG&E requests recovery for the costs associated with the industrial accident and litigation that occurred at SONGS while the Master Insurance Program was in effect. DRA contends that because this insurance coverage "was terminated in 1999 and there are no longer premiums coming into the program, DRA recommends that these expenses should not be paid by ratepayers through higher rates." (Ex. 477 at 6.) DRA recommends disallowing this expense, and "suggests SDG&E should file an AL" if it expects to recover this additional expense. (*Ibid*.)

Although DRA took issue with the SONGS base O&M costs, that issue is not being addressed in this proceeding for the reason noted earlier. DRA acknowledges that a final forecast of these costs will be determined when a decision is issued in SCE's GRC proceeding.

DRA does not oppose SDG&E's request to continue the SONGS balancing account for O&M expenses.

DRA originally recommended that the capital costs for SONGS be reduced. However, as noted earlier, that issue was being litigated in the SCE GRC proceeding, and therefore will not be considered in this proceeding. DRA has raised an issue concerning SDG&E's loading of 4.49% of administrative and general (A&G) costs onto the capital amount that SDG&E receives from SCE. DRA contends that this additional loading of A&G expense does not appear to be consistent with D.09-03-025, and therefore recommends it be removed.

5.2.2. Joint Parties

The Joint Parties recommend that SDG&E undertake a community education or outreach program to educate the community about nuclear power and SONGS, as well as preparedness measures to take in the event of a nuclear-related incident. The Joint Parties also suggest that there be a community preparation campaign, which would involve groups involved in the California Alternative Rates for Energy program, as well as environmental groups, to assist SDG&E in providing community outreach and education. The Joint Parties advocate for this type of education because of the nuclear plant event in Japan, and because of the more recent problems and shutdown of SONGS.

The Joint Parties recommend that SDG&E spend on this education program an amount that is at least the same as "the costs that Sempra ratepayers will bear relating to assuring the Nuclear Regulatory Commission, the CPUC and…other state regulatory bodies of the future safety of the San Onofre plant" over the next three years. (Ex. 391 at 22.) For this community education program, the Joint Parties recommend that because this is a safety and community education issue, that ratepayers should bear 80% of the costs of such a program, and that Sempra shareholders bear 20% of the costs.

5.2.3. UCAN

In Exhibit 558, UCAN raised an argument concerning SDG&E's request for $710,000 for the SONGS Industrial Accident and Injury expense, which is also referred to as the Master Insurance Program. SDG&E claimed that the SCE rate cases did not allow SDG&E to recover those costs in the past, and therefore it needs to recover that cost in this proceeding. DRA recommended denying SDG&E this amount, and suggests that SDG&E file an AL to recover this cost.

UCAN agrees with DRA that separate funding for the Master Insurance Program should not be allowed in this rate case. However, UCAN disagrees with DRA and SDG&E that SDG&E should be allowed to recover this cost at all. As described in Exhibit 558, UCAN contends that the costs of the Master Insurance Program have been included in the last four SCE GRCs, and that the costs were "allocated to SDG&E and included in SDG&E's rates as part of the outcome of those [SCE] rate cases. " (Ex. 558 at 17.) UCAN contends that SCE forgot to bill SDG&E for this cost, but SDG&E continued to collect these costs in its own rates. UCAN contends that to allow SDG&E to recover this cost would result in a double recovery.

UCAN also contends that the property and liability insurance premium for SONGS should be reduced by $1.019 million. UCAN's reduction recommendation is based on past distributions that SDG&E has received from Nuclear Electric Insurance Limited (NEIL).

5.2.4. SDG&E

Regarding its request for the recovery of the Master Insurance Program expense, SDG&E agrees in Exhibit 84 with DRA and UCAN that this amount is not recoverable in this proceeding, and therefore withdraws its request for this expense. SDG&E plans to seek recovery of this in SCE's GRC.

On DRA's contention that SDG&E should not have added the 4.49% A&G loader onto the SONGS capital costs, SDG&E contends that this is an accepted and standard procedure, and is allowed by FERC's electric plant instructions.

SDG&E also contends that DRA's testimony on this issue is inconsistent with DRA's position regarding shared services billing, in which DRA did not take issue with SoCalGas' and SDG&E's allocation of shared services costs.

Regarding UCAN's recommendation that the SONGS nuclear insurance costs be reduced, SDG&E contends that UCAN's reduction is based on outdated 2010 information. SDG&E contends that its forecast is based on later information it received from its insurance broker that NEIL was not intending to make a distribution in 2012, and that its NEIL insurance premium is likely to increase.

SDG&E opposes the Joint Parties recommendation that it be ordered to conduct a community education or outreach program regarding nuclear power. SDG&E contends that SCE, as the majority owner, already conducts outreach programs and open houses in communities around SONGS, and that SDG&E's ratepayers already pay their share of these costs. SDG&E contends that it would be duplicative and an inefficient use of ratepayer funding if SDG&E was ordered to initiate its own program. SDG&E further contends that the Joint Parties should raise this issue in SCE's GRC proceeding.

5.3. Discussion

Two of the issues that parties have raised are addressed elsewhere in this decision. First, the Joint Parties request that Sempra be ordered to conduct a community education or outreach program regarding nuclear power. That issue is addressed in the Customer Service section of this decision. Second, UCAN's recommendation to reduce the SONGS nuclear property and nuclear liability insurance because of past distributions from NEIL is discussed in the Insurance section of this decision.

After the conclusion of the hearings in this proceeding, the SONGS facility was shut down in January 2012 due to premature wear on the tubes for the steam generators. These tubes were installed in 2010 and 2011. Due to the extended shutdown of SONGS, the Commission reconsidered the O&M and capital costs that were requested in the SCE GRC proceeding. The O&M and capital costs that SCE sought in its GRC were based on the assumption of normal operating conditions in 2012-2014. This shutdown of SONGS occurred after the evidentiary hearing was concluded in SCE's GRC proceeding, and after hearings had begun in this proceeding. As a result, no evidence was taken from the parties regarding the extended shutdown of SONGS.

In the Commission decision (D.12-11-051) regarding SCE's GRC, the Commission took into consideration the change in circumstances that had occurred at SONGS. Instead of disallowing the O&M costs and capital costs due to the shutdown, the Commission decided to authorize these costs, with some adjustments, as if SONGS was operating normally.[19] However, these costs were authorized "subject to review and refund in 2013." (D.12-11-051 at 28.) The Commission authorized SCE to establish a SONGS memorandum account to track the 2012 costs associated with O&M, cost savings from scheduled personnel reductions, maintenance and refueling outage expenses, and capital expenditures. SCE was also directed to file an application for a reasonableness review of the costs that are being tracked in this memorandum account. This reasonableness review is to be consolidated with I.12-10-013, and all "expenses disallowed by the reasonableness review will be refunded to ratepayers." (D.12-11-051 at 30.)

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[19] This approach was taken to avoid the future rate shock that could occur if the costs were disallowed for SONGS in 2012, but authorized again in the future. (*See* D.12-11-051 at 28.)

In that decision, the Commission also made SDG&E subject to the same conditional refund of SDG&E's share of the SONGS-related O&M and capital costs. (*See* D.12-11-051 at 40-41, Finding of Fact 36, Conclusions of Law 21 and 22, Ordering Paragraphs 10 and 11.) Since the Commission ordered SDG&E to comply with the same reasonableness and refund procedure in D.12-11-051, no further directives are needed in this proceeding about how the test year 2012 SONGS-related costs litigated in the SCE GRC proceeding will be treated.

DRA has raised the issue about the 4.49% A&G loader being added to the SONGS capital costs. We reviewed the testimony and arguments of SDG&E and DRA concerning this issue, and have also reviewed the federal regulation. We agree with SDG&E that the allocation of A&G costs to capital projects is permitted. Accordingly, DRA's recommendation to make a downward adjustment to capital costs is not adopted.

SDG&E has asked to continue the two-way SONGS balancing account. No one has objected to that request. We authorize SDG&E to continue that balancing account through this rate cycle. Since SDG&E is subject to this reasonableness and refund procedure, and because SDG&E's balancing account records the SONGS-related costs billed from SCE to SDG&E, it is not necessary to establish a separate memorandum account, as the Commission did for SCE, to track the 2012 SONGS costs and savings as described above.

Regarding the SONGS-related costs that SDG&E brought up in the context of this proceeding, SDG&E has withdrawn its request for $710,000 for the Master Insurance Program. Accordingly, SONGS-related costs shall reflect the removal of that amount.

No one objects to the amount that SDG&E is requesting for Unit 1 spent fuel storage, the escalation associated with the spent fuel storage, or the SONGS site easement fees. Accordingly, we adopt those amounts as reasonable for the SONGS-related costs.

Since D.12-11-051 decided SDG&E's 20% share of the SONGS O&M and capital costs, and the SONGS refueling outage O&M costs, SDG&E's test year 2012 revenue requirement shall include the amounts authorized for SDG&E in D.12-11-051, as well as the costs for Unit 1 spent fuel storage, the escalation associated with the spent fuel storage, and the SONGS site easement fees.

6. SDG&E Electric Distribution Operations

6.1. Introduction

This section addresses the forecasts of O&M expenses, and capital expenditures, associated with SDG&E's electric distribution system.

SDG&E's electric distribution system serves approximately three million persons using 1.4 million meters, and covers an area of more than 4,100 square miles from southern Orange County to the California-Mexico border. The terrain covers bay and coastal areas, inland valleys, and mountain and desert communities. According to SDG&E, its electric distribution system includes the following: "277 distribution substations, 995 distribution circuits, roughly 225,000 poles, 10,000 miles of underground system, 6,500 miles of overhead systems, and various other pieces of distribution equipment." (Ex. 61 at 2.) The primary distribution voltage is 12 kV, and some large areas have 4 kV.

SDG&E's distribution system is about 60% underground. SDG&E's overhead lines have approximately 400,000 trees located near those lines, which are maintained through SDG&E's vegetation management program. According to SDG&E, an "underground system is significantly more expensive to install as compared to an overhead system, has a shorter equipment life-expectancy, requires more time to troubleshoot problems, and takes longer to repair problems once found." (Ex. 61 at 3.) The aging overhead electric distribution system, which is found mostly in inland valleys and mountainous areas, are subject to winter rain, snow storms, and Santa Ana wind conditions, all of which affect the performance and safety of the overhead system.

SDG&E's customer mix is composed of about 1.230 million residential customers, 144,292 commercial and industrial customers, and 6,187 street light customers. These customers are located in both urban and rural communities consisting of 26 cities, two counties, and 15 major military facilities. There is an average of 1,350 customers per circuit.

SDG&E forecasts total O&M costs for test year 2012 of $126.103 million. SDG&E forecasts capital expenditures for electric distribution as follows: $246.075 million in 2010; $252.430 million in 2011; and $252.430 million in 2012.

6.2. O&M Costs

6.2.1. Introduction

SDG&E's O&M costs cover the operation, maintenance, supervision, and engineering functions of its electric distribution overhead and underground facilities, public affairs activities, and officer salaries. These O&M costs include the following activities:

- Routine maintenance and new construction;
- Dispatch and electric system control;
- Project planning and design;
- Skills training of the workforce;
- Development of standards, strategic planning, and distribution reliability functions;
- Management of contract construction forces;

- Public affairs communication and liaison activities with local, state and federal agencies; and
- Development, implementation, operation and maintenance of distribution system related IT systems.

SDG&E forecasts total O&M costs for the 2012 test year of $126.103 million. DRA recommends that O&M costs of $103.520 million be adopted.

The electric distribution O&M activities of SDG&E fall into 18 different categories as described in Exhibit 61. Each of the categories contain a description of the various O&M activities that SDG&E plans to perform. There are also three miscellaneous costs consisting of exempt materials, small tools, and department overhead pool. Due to the activities in each category, we address and discuss each of these 18 categories, and the miscellaneous costs, separately.

6.2.2. Electric Regional Operations (ERO)

6.2.2.1. Introduction

The first category of costs is ERO. ERO covers all of the electric distribution crews within six districts and eight operating centers. These crews provide coverage for all of SDG&E's electric distribution system throughout its service territory. The ERO group consists of electric lineman, apprentices, line assistants, dispatchers, office support personnel, and management supervision. Their primary job functions are to maintain the electric distribution system, restore service due to outages, and to fix service problems and other customer issues.

SDG&E forecasts the O&M costs for the ERO group at $41.923 million for the 2012 test year. This is a $7.730 million incremental change over the 2009 recorded amount of $34.193 million. DRA recommends that $34.273 million be adopted as the O&M costs for the ERO group, while UCAN recommends $32.940 million.

According to SDG&E, there are six drivers contributing to the incremental cost changes. These six drivers are the following:

- Maintain improved public and employee safety performance and reliability;
- Regulatory and environmental compliance;
- Fire preparedness;
- Work force development;
- System growth; and
- New technology.

The first driver of maintaining improved public and employee safety performance and reliability relies on several initiatives which focus on safety. These initiatives include the following: safety culture change; behavior based safety; overhead switch inspection and maintenance; and the overhead connector program.

The second driver is regulatory and environmental compliance. One activity is related to the United States Environmental Protection Agency's (EPA) advanced notice of proposed rulemaking into the reassessment of the use of liquid polychlorinated biphenyls (PCBs) in electric and non-electric equipment. According to SDG&E, this will result in SDG&E having to sample and test its electrical equipment for PCBs, remove or flush electrical equipment with PCB contamination, and dispose of all wastes generated by these activities. SDG&E requests that the costs associated with implementing this PCB phase-out be included in rates and subject to a two-way balancing account treatment in the NERBA.

Another regulatory and environmental compliance activity is inspection and maintenance of its electric distribution system to ensure the safety and reliability of the system and compliance with Commission general orders and

SDG&E construction and design standards. Environmental and nesting surveys are part of these ERO costs. Other activities include: the corrective maintenance program inspections to comply with the inspection cycles in General Order (GO) 165; annual patrols in fire zones; resources to comply with Rule 18 notifications and repair of safety hazards; quality control inspections of distribution poles in fire zones; and screening of ERO lineman for respiratory dysfunctions as required by the Federal Motor Carrier Safety Administration.

The third driver of the incremental cost changes is fire preparedness. These activities include the following: heightened response during red flag warnings of increased fire risk; mobilization of crews during elevated wind conditions; and the cost of safety patrols to restore service on a circuit after an outage.

The fourth driver is activities related to workforce development. These activities include line assistance and apprentice training, standby lineman training, and fault finding training.

The fifth driver is activities related to system growth. Among these activities are the additional costs associated with obtaining badges for SDG&E employees who work on a military base.

The sixth driver of the incremental costs for the ERO group is due to new technology. The introduction of new technology impacts several areas. One activity is the work associated with supporting customers, and the work on SDG&E's facilities, in order to accommodate the load created by plug-in electric vehicles (PEVs) during charging. Another impacted activity is the cost of operating and maintaining the smart grid infrastructure. The introduction of operational improvements due to the Operational Excellence 20/20 (OpEx) program will also impact the ERO group with new technology, new business processes, and training.[20] The deployment of smart meters will result in benefits associated with customer outage calls, automated outage analysis, crew deployment, and emergency/planned switching. Another activity that will be impacted is to revise the routes taken to inspect the poles, transformers, and other facilities to comply with the increased inspections and timing requirements in GO 165. The Area Resource Scheduling Organization (ARSO), a new department responsible for organizing, scheduling, and dispatching all gas and electric distribution work within SDG&E's system, will also be impacted.

6.2.2.2. Position of the Parties

6.2.2.2.1. DRA

As described in Exhibit 478, DRA makes a series of recommended disallowances for the cost drivers behind the ERO O&M costs.

One of the broad disallowances that DRA recommends relates to the fire hazard prevention costs incurred in complying with D.09-08-029. DRA contends that all of these fire hazard prevention costs should be recorded in the Fire Hazard Prevention Memorandum Account (FHPMA), which was established in that decision. DRA contends that SDG&E has not provided sufficient evidence to incorporate these costs into this GRC. DRA recommends the following disallowances for projects that DRA believes are related to fire hazard prevention: $125,000 for overhead switch inspection and maintenance; $200,000 for the overhead connector program; $177,000 for GO 165 annual patrols; $258,000 for Rule 18 notifications and repair of safety hazards;

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[20] The OpEx program was developed by SDG&E and SoCalGas under its former name of "Utility of the Future," and was "intended to make the Utilities more efficient and to help them meet future operational challenges." (Ex. 183 at 1; *See* D.08-07-046 at 81, footnote 54.)

$1.376 million for quality control inspections; $1.794 million for red flag warning operations; $122,140 for elevated wind conditions; and $1.646 million for outage patrolling during high fire risk periods.

DRA recommends that SDG&E's funding request of $160,000 for the safety culture change be disallowed because DRA believes that SDG&E's current standards are adequate.

DRA recommends that SDG&E's request to establish a two-way balancing account, called the NERBA, not be adopted. SDG&E requests that the NERBA be established to record the costs associated with implementing the PCB phase-out that the EPA announced in an Advanced Notice of Proposed Rulemaking. DRA contends that since the EPA is only contemplating such a rule, it is too early to determine whether the NERBA is appropriate, and that SDG&E should include this item in the next GRC rate cycle once a rule is adopted.

DRA recommends that SDG&E's funding request of $151,200 for climbing gear be disallowed because SDG&E did not provide any justification.

DRA recommends that SDG&E's funding request of $170,000 for the corrective maintenance program pathing increases be disallowed because DRA could not find any support for this in the OpEx testimony. According to SDG&E, the term "pathing" refers to the route or path that is "taken through the distribution system in order to systematically and repeatedly inspect the various poles, transformers and other facilities in compliance to the timing requirements of General Order 165." (Ex. 61.) Pathing allows for "the grouping of nearby facilities into the same inspection year in order to avoid returning to the same area every year." (Ex. 63 at 11.)

DRA recommends disallowance of $300,000 for the activity included in ERO that is labeled as "RIRAT" [Reliability Improvements in Rural Areas Team] and which appears in the O&M workpapers in Exhibit 62 at 21. DRA contends that there is no evidence or support for these O&M costs.

For the on-going support of the OpEx program, DRA recommends that all of the on-going O&M costs be disallowed. This includes the following funding requests: $20,000 for supervisor enablement; $153,000 for construction crew dispatch; and $100,000 for construction work scheduling. DRA's reasoning for its OpEx disallowances is that all of the OpEx projects for SDG&E will be completed by 2012, except for two, and that SDG&E did not provide support for these costs.

DRA recommends that the ARSO not receive any funding. DRA contends that is could not locate a discussion of the ARSO costs in the testimony or workpapers.

DRA recommends that SDG&E's funding request of $26,990 for PEVs be disallowed due to DRA's position that until there are more electric vehicles in SDG&E's service territory, ratepayer funds should not be used.

DRA recommends that the "O&C labor non-work (V&S)" of $4.892 million be removed because SDG&E did not provide any support for these O&M costs, nor could DRA find any reference to this in SDG&E's testimony.

For the smart grid O&M costs, DRA recommends that $456,000 in O&M costs be adopted, as compared to SDG&E's request of $3.643 million. DRA's recommended reduction is based on DRA's presentation and recommendations regarding the smart grid which is found in Exhibit 487.

6.2.2.2.2. UCAN

UCAN agrees with DRA that all of the O&M costs related to fire protection should be accounted for in the FHPMA, rather than being included in this GRC proceeding. UCAN recommends that a total of $14.6 million be removed from

SDG&E's forecast of fire protection costs, and that SDG&E be allowed to recover the reasonable actual costs through the FHPMA, subject to a reasonableness review. In the ERO group, UCAN contends that $5.313 million of the incremental increase is fire related.

UCAN's recommended O&M costs are also based on its analysis of recorded spending in 2009 and 2010, as compared to SDG&E's forecast. Although SDG&E forecast it would spend $38.580 million in 2010, UCAN notes that the recorded spending in 2010 was only $31.437 million, and $34.193 million in 2009. As described in Exhibit 558 at 25, UCAN used the two-year average of 2009-2010 as the basis of its forecast, and then added $608,000 for smart grid O&M spending, and then subtracted $483,000 in savings from the smart meters.

6.2.2.2.3. Coalition of California Utility Employees (CCUE)

The CCUE points out that DRA recommends a cap of $24 million if the fire hazard prevention activities are recovered through the FHPMA. CCUE is opposed to a cap on such activities.

6.2.2.2.4. SDG&E

DRA recommends that the funding request for SDG&E's safety culture change be disallowed. SDG&E's approach to safety uses education and training, enforcement of safety and standard practices, its safety culture change program, and its behavior based safety training. DRA did not recommend disallowing funding for the latter. While the behavior based safety training focuses on the individual, the safety culture change focuses on the way the group and organization view safety. SDG&E contends that all of these practices are needed to achieve improvements in SDG&E's safety performance.

DRA recommends that SDG&E's funding request to implement the PCB phase-out activities be disallowed. SDG&E contends that according to the EPA website as of October 2011, the EPA announced that it is committed to publish the proposed rule on PCBs in December 2012. Since the proposed rule is imminent, SDG&E requests funds "to begin the proactive screening of its older electrical equipment for PCBs and replacement of oil filled equipment with PCB levels greater than or equal to 50 parts per million PCBs." (Ex. 63 at 6.)

Contrary to UCAN's argument, SDG&E's fire-related costs are addressed in multiple areas due to the Commission's directive that a cost center approach be used in the GRC. SDG&E contends that since "fire, safety, and reliability activities are integrated into many areas of SDG&E's electric distribution operations," this "means that their costs are also spread over many areas." (Ex. 63 at 14.) As for UCAN's assertion that SDG&E did not spend money in 2010 on fire protection, SDG&E contends that those costs in 2010 were in the FHPMA.

Both DRA and UCAN recommend that all fire-related costs contained in SDG&E's testimony be disallowed, and be placed in the FHPMA.[21] SDG&E contends that these costs properly belong in this GRC as provided for in D.09-08-029 and D.12-01-032, and include the following costs that DRA recommended be placed in the FHPMA: overhead switch inspection and maintenance; overhead connector program; GO 165 annual patrols; OII quality control inspections; and the Rule 18 notifications and repair of safety hazards.

On DRA's recommendation to disallow funding for the corrective maintenance program pathing increases, SDG&E contends that it justified the

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21 DRA recommends that SDG&E's funding requests for the following be recovered through the FHPMA: GO 165 annual patrols in fire zones; OII quality control inspections; and Rule 18 notifications and repair of safety hazards.

pathing changes, and that there are anticipated savings which have been included as part of the OpEx implementation.

DRA recommends that all OpEx ongoing support costs be disallowed. SDG&E contends that since OpEx is a cost savings program that has long term benefits to customers, that DRA's recommended disallowance of the ongoing costs is in effect disallowing future savings.

SDG&E contends that DRA's recommendation to disallow the "O&C labor non-work (V&S)" should be rejected because these are O&M costs for vacation and sick leave. SDG&E contends that vacation and sick leave are major components of labor costs and should be approved. SDG&E notes that DRA did not disallow these vacation and sick leave costs for other SDG&E costs.

DRA recommends downward adjustments to the smart grid O&M costs. SDG&E contends that DRA's recommendation is inconsistent with California's energy goals, and that these smart grid projects are needed to meet the state's goals of promoting increased levels of renewable resources.

6.2.2.3. Discussion

6.2.2.3.1. Fire Hazard Prevention

We first discuss the recommendations of DRA and UCAN to remove the fire hazard prevention O&M costs from this proceeding, and to have those costs recorded in the FHPMA. If this recommendation is adopted, approximately $5.698 million in costs would be removed from the ERO O&M costs.

At the time the parties' testimony was prepared on the FHPMA, a decision on phase two of Order Instituting Rulemaking (R.) 08-11-005 had not yet been adopted.[22] When DRA and UCAN filed their opening briefs in April 2012, they continued to argue that these fire prevention hazard O&M costs should be accounted for in the FHPMA, and continued to press for this treatment in their reply briefs. DRA argues in its reply brief that since D.12-01-032 was issued near the time when the evidentiary hearings in this GRC had concluded, that the Commission clearly intended in D.12-01-032 that these fire hazard prevention costs be considered in a proceeding addressing the costs recorded in the FHPMA, rather than in this GRC. However, our review of D.12-01-032 leads us to agree with SDG&E that the fire hazard prevention O&M costs that SDG&E is requesting in the GRC, should be addressed in this proceeding.

D.12-01-032 clearly recognized that SDG&E and SoCalGas had "included forecasted costs from the Phase 1 Decision in their 2012 GRCs," and stated that "the only Phase 1 costs [that SDG&E and SoCalGas] may record in their FHPMAs are their actual costs to implement the Phase 1 Decision that are incurred prior to 2012." (D.12-01-032 at 152.) In Ordering Paragraph 14.i. of that decision, the Commission ordered that SDG&E and SoCalGas "shall record in their FHPMAs only those costs that are not being recovered elsewhere." These passages from D.12-01-032 make clear that SDG&E's request for fire hazard

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22 Following the October 2007 wildfires in southern California, the Commission issued R.08-11-005 to consider and adopt regulations to reduce the fire hazards associated with overhead power-line facilities and aerial communication facilities in close proximity to power lines. D.09-08-029 addressed the Phase One issues regarding fire prevention measures that could be adopted in time for the 2009 autumn fire season in southern California. The FHPMA was authorized by D.09-08-029. The Phase Two issues were to address and adopt regulations to reduce the fire hazards associated with overhead power line facilities, and aerial communication facilities located in close proximity to overhead power lines.

prevention O&M costs in this proceeding is entirely proper. Accordingly, we decline to adopt the recommendations of DRA and UCAN to remove these costs from consideration in this proceeding, and to consider them in a proceeding addressing the recovery of the costs in the FHPMA.

Having concluded that the fire hazard prevention O&M costs are properly before us, we review whether SDG&E's funding request for these O&M costs are reasonable. We first note that some of these fire hazard prevention activities may be duplicative of each other. For example, the overhead switch inspection and maintenance activity overlaps, or could be conducted in conjunction, with the overhead connector program, the GO 165 annual patrols, and the quality control inspections. Many of these devices and poles are likely to be located near each other, which should minimize having to make multiple trips to the same location. For those reasons, it is appropriate to reduce the O&M costs in each of these four activities by 25%.[23]

Second, SDG&E's funding request for red flag warning operations of $1.794 million, and for outage patrolling during high fire risk periods of $1.646 million, appear to be excessive as compared to the number of days that

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[23] The funding for overhead switch inspection and maintenance should be reduced from $125,000 to $93,750. The funding for the overhead connector program should be reduced from $200,000 to $150,000. The funding for the GO 165 annual patrols should be reduced from $177,000 to $132,750. The funding for the quality control inspections should be reduced from $1.376 million to $1.032 million.

red flag warnings and elevated wind conditions are called.[24] Accordingly, it is appropriate to reduce the O&M costs in each of these two activities by 25%.[25]

6.2.2.3.2. Safety Culture Change

DRA recommends that the funding of $160,000 for safety culture change be disallowed. SDG&E's testimony describes how the safety culture change is one component of SDG&E's approach to improving safety. In 2008, SDG&E experienced an electrical fatality. The safety culture change recognizes the role that the organization plays in promoting safety and accountability. For those reasons, DRA's recommendation to disallow this funding request is not adopted.

6.2.2.3.3. EPA and PCBs

DRA and UCAN recommend that since the EPA has not yet issued a proposed rule regarding the phase-out of PCBs in electrical equipment, that SDG&E' request to fund this effort, and to establish the NERBA and allow two-way balancing account treatment, not be adopted.

SDG&E noted in its rebuttal testimony that as of October 2011, the EPA had communicated "through their website that they are committed to publish the propos[ed] rule in December 2012." (Ex. 63 at 6.) However, SDG&E's response to a UCAN data request indicates that the notice of the proposed rulemaking will not be published in the Federal Register until April 2013. (Ex. 67, SDG&E Response to UCAN Data Request 83, Question 2;

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[24] In 2009, elevated wind conditions were declared four times. According to the SDG&E witness, in a typical year there are six red flag warning days.

[25] The funding for red flag warning operations should be reduced from $1.794 million to $1.346 million, and the funding for outage patrolling during high fire risk periods should be reduced from $1.646 million to $1.235 million.

15 R.T. 1653-1654.) It is apparent though that the EPA is likely to propose such a rule at some future date.

SDG&E proposes funding of $927,000 in O&M costs in the 2012 test year to begin assessing the PCBs it has in its electric distribution system, and that this be accounted for in the two-way NERBA balancing account. Since the EPA's proposed rule is unlikely to be issued before the end of 2012, we do not authorize any funding in the 2012 test year to allow SDG&E to begin to implement this expected proposed rule. Accordingly, SDG&E's funding request for ERO O&M costs should be reduced by $927,000.

Although we do not authorize any funds in the 2012 test year to implement the yet-to-be released rule, we recognize that the costs associated with implementing such a rule are likely to be substantial because of the widespread use of PCBs in electric distribution equipment. For that reason, we grant SDG&E's request to establish a two-way balancing account called the NERBA, and to record SDG&E's costs to the NERBA once the final rule on the phase-out of PCBs is issued by the EPA. SDG&E shall file a Tier 2 AL within 45 days of the effective date of this decision to establish the NERBA to record the costs associated with the EPA's final rule on the phase-out of PCBs.[26]

6.2.2.3.4. Climbing Gear

DRA recommends that $151,200 for climbing gear be disallowed. We are not persuaded that this funding request should be disallowed. Field personnel who perform work on overhead electric distribution equipment need safety equipment, such as climbing gear, in order to safely perform their work. With

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[26] We also address the applicability of the NERBA to the EPA's mandatory GHG reporting rule, and to AB 32, later in this decision.

the number of field personnel that SDG&E has, the funding request for this item is reasonable. DRA's recommendation to disallow this amount is not adopted.

6.2.2.3.5. OpEx Pathing Changes

DRA recommends that SDG&E's funding request of $170,000 for the corrective maintenance program pathing increases be disallowed. Due to the increase in the number of required inspections, one of SDG&E's OpEx initiatives is to use a new system to determine the order in which groups of poles should be inspected, and to "use a computer algorithm to efficiently route the inspection personnel." According to SDG&E, the changeover to this new system will result in a slight increase in "inspection activities over the first five year cycle of the program," but it is expected that as "all poles within the segments will be placed on the same schedule," that over the long term "this will result in reduced inspection costs." (Ex. 61 at 15-16.) SDG&E's funding request of $50,000 for pathing inspections, and $120,000 for pathing repairs, is reasonable. DRA's recommendation to disallow the funding request for the OpEx pathing changes is not adopted.

6.2.2.3.6. RIRAT

DRA recommends disallowance of $300,000 for the activity that is labeled as "RIRAT," and which appears in the O&M workpapers in Exhibit 62 at 21. DRA could not find any testimony or supporting documents to justify this funding request.

The only mention of RIRAT is in SDG&E's rebuttal testimony in Exhibit 63 in response to an argument raised by another party. SDG&E describes RIRAT as a "new team, called the Reliability Improvements in Rural Areas Team," which "is concentrating on developing operational concepts, designs and standards to improve the safety and reliability of circuits in rural locations and areas where fire risk is a significant concern to all." (Ex. 63 at 57.)

However, aside from a brief three line description in Exhibit 62 at 21, of "relay setting," "reduce SGF setting," and "reduce size of expulsion fuse," SDG&E fails to explain why the funding request for those non-labor items is justified. Although SDG&E has the burden of proving that its funding request is justified, it has failed to meet that burden by failing to respond to DRA's point in SDG&E's rebuttal to DRA in Exhibit 63, or to respond to DRA's point in SDG&E's reply brief. (*See* Ex. 63 at 5-15; DRA Opening Brief at 65; Applicants' Reply Brief at 46-48.) Accordingly, we agree with DRA that SDG&E has not justified its funding request for RIRAT in the ERO O&M costs, and SDG&E's O&M costs for ERO should be reduced by $300,000.

6.2.2.3.7. OpEx On-Going Support

DRA recommends that SDG&E's funding request of a total of $273,000 for OpEx on-going support be disallowed. SDG&E contends that the on-going O&M costs are needed to implement the operational improvements resulting from the OpEx programs. These O&M costs affect the ERO with new technology, business processes and training. The three ERO areas that will be most impacted are front line supervision, construction crew dispatch, and construction work scheduling. For front line supervision, $20,000 is being requested to equip supervisors with mobile data terminals, printers and software, so that they can "spend at least 60% of their work day in the field supervising crews, estimating work and serving customers." (Ex. 61 at 14.) $153,000 is being requested for construction crew dispatch, which will use the new ClickSchedule software to allow dispatchers to dispatch technicians and construction crews more efficiently. $100,000 is being requested for construction work scheduling, which will allow field crews to use the ClickMobile software on their mobile data terminals to process all work orders and to report their time. Training of personnel in ClickSchedule, ClickMobile, and other software will be needed.

We are not persuaded by DRA's argument that these on-going O&M costs are no longer needed. Although the OpEx projects have largely been implemented, there are still on-going costs associated with these OpEx projects, which we find are reasonable. Accordingly, we do not adopt DRA's recommendation to disallow the on-going O&M costs of $273,000.

6.2.2.3.8. Area Resource Scheduling Organization (ARSO)

The ARSO is a new group that was created under the OpEx initiatives. ARSO's responsibility is to organize, schedule, and dispatch all gas and electric distribution work within SDG&E using the ClickSoftware, which is a scheduling software application. The software will analyze available resources and match them up with the work that needs to be done. The ARSO group is led by one area resource manager. There are also two area resource dispatch supervisors who are responsible for the oversight of the dispatchers. There will also be five area resource scheduling advisors and analysts that will assist in the workflow and analyze the results of the work performed. A forecaster role is also expected to be added.

DRA contends that SDG&E's testimony and workpapers do not discuss the costs associated with ARSO. Due to this lack of support, DRA recommends that the O&M costs in ERO that are related to ARSO be disallowed.

We have reviewed the testimony and the briefs of the Applicants and DRA concerning the ARSO. It is clear that the ARSO plays an important role in the dispatch of SDG&E's field employees, and that the ClickSoftware that ARSO utilizes operates in tandem with the ClickSchedule and ClickMobile. Although SDG&E did not provide details of the ERO O&M costs related to ARSO, it is clear from SDG&E's ERO funding request of $41.923 million, that some part of that amount is related to ARSO. DRA could have also requested cost details about the ERO costs, but apparently chose not to do so. Similarly, SDG&E could have responded to DRA's recommended disallowance of the ARSO costs in its rebuttal testimony, but failed to do so.

Since ARSO is related to the roll out of ClickSchedule and ClickMobile, and is part of the OpEx initiatives that are supposed to result in work efficiencies over a period of time, we do not adopt DRA's recommendation to disallow all of the ERO O&M costs related to ARSO. Instead, we approve the ERO O&M costs for ARSO subject to a reduced funding amount. Due to SDG&E's failure to fully explain the cost details of its ERO O&M costs relating to ARSO, it is appropriate and reasonable to reduce the ERO O&M costs for ARSO by $3 million.

6.2.2.3.9. Impact of Plug-In Electric Vehicles (PEVs)

DRA recommends that SDG&E's funding request of $26,990 for PEVs be disallowed. We do not agree with DRA.

The O&M costs that SDG&E is requesting for ERO is related to the impacts that PEVs will have on the electric distribution system. The ERO activities include maintenance of the electric distribution system, and meeting customer needs, including those who have PEVs. There is no dispute that electric vehicle chargers will add additional load, which is likely to result in SDG&E having to make improvements to its distribution system in order to meet this load. For those reasons, the funding request of $26,990 is reasonable, and DRA's recommendation to disallow this amount is not adopted.

6.2.2.3.10. Vacation and Sick Leave

DRA recommends that the "O&C labor non-work (V&S)" of $4.892 million, which appears in Exhibit 62 at 21, be removed due to a lack of support. SDG&E's rebuttal testimony makes clear that this line item of its work papers refers to vacation and sick leave costs. These costs are part of SDG&E's reasonable labor costs. Accordingly, DRA's recommendation to disallow this amount from SDG&E's ERO O&M costs is not adopted.

6.2.2.3.11. Smart Grid

For the smart grid O&M costs, DRA recommends that $456,000 in O&M costs be adopted, as compared to SDG&E's request of $3.643 million. DRA's recommended disallowance is based on DRA's position regarding the smart grid, as described later in this section. SDG&E is opposed to DRA's position, and contends that the smart grid projects are needed to meet California's energy goals of promoting increased levels of renewable resources.

As we discuss in the smart grid sub-section, we have reduced or disallowed the funding of some of the smart grid projects that SDG&E has requested. These reductions occur primarily in the area of energy storage, devices to manage the growth in photovoltaic generation, PEVs, and reliability-related smart grid devices. Since we have reduced funding of these smart grid projects, it is reasonable and appropriate to reduce the O&M costs associated with the smart grid projects. Accordingly, the smart grid O&M costs should be reduced from SDG&E's request of $3.643 million to $1.500 million.

6.2.3. ERO (Troubleshooting/Engineering)

6.2.3.1. Introduction

This second category of costs for electric distribution O&M costs is headed up by the operations and engineering workgroup. This workgroup is responsible for ensuring safe and reliable electric service to SDG&E's customers. This workgroup covers six districts and two satellite locations within SDG&E's service territory. Each of these six districts has electric troubleshooters, engineers, a planner, technical assistants, and management supervision. The electric troubleshooters are the primary contact with customers who are experiencing service problems, and work closely with emergency response agencies to protect the public and SDG&E's employees from potentially hazardous conditions.

SDG&E forecasts the O&M costs for the ERO Troubleshooting/Engineering group at $7.851 million for the 2012 test year. This is a $631,000 incremental change over the 2009 recorded amount of $7.220 million. DRA recommends that O&M costs of $7.313 million be adopted. UCAN recommends that O&M costs of $7.020 million be adopted.

According to SDG&E, there are five drivers that are contributing to the incremental cost changes. These five drivers are the following:

- Regulatory and environmental compliance;
- Fire preparedness;
- System growth;
- New technology; and
- Work force development.

For the regulatory and environmental compliance driver, GO 165 will require SDG&E to increase its frequency of patrols in fire zones from two years to one year. The changes to Rule 12 will require SDG&E to patrol its own communication facilities attached to electric poles, and the changes to Rule 18 will require more detailed inspections of facilities.

Fire preparedness is also a driver of the incremental costs, which will require that electric troubleshooters to be positioned in areas of high fire danger during elevated wind conditions and red flag warning conditions.

System growth is another driver of the incremental costs for ERO Troubleshooting/Engineering. This will come from the growth in customer meters, which will lead to a greater number of customer related electrical events, and the growth in the use of electronic devices and appliances which results in the overloading of facilities.

New technology is another driver of increased costs. This includes the purchase of air cards for electric troubleshooters to access wireless functions, and GPS navigational devices.

Another driver is work force development, which SDG&E expects to result in an additional electric troubleshooter training class.

6.2.3.2. Position of the Parties

6.2.3.2.1. DRA

DRA's recommended disallowance of $538,000 is comprised of a disallowance of $418,000 for GO 165 annual patrols, and $120,000 for response to red flag warnings. DRA contends that due to D.09-08-029, these costs are related to fire hazard prevention and should be recorded in the FHPMA.

6.2.3.2.2. UCAN

UCAN's recommendation to adopt funding of $7.020 million is based on using a three-year average of 2008-2010, whereas SDG&E used the three-year average of 2007-2009 and then made incremental adjustments for load growth, red flag conditions, GO 165 inspections, and additional training.

UCAN recommends that the fire-related costs be recovered through the FHPMA. UCAN's methodology would eliminate SDG&E's increases for growth, GO 165, and training. UCAN contends that the increase proposed by SDG&E is not necessary because SDG&E forecasted spending of $7.769 million in 2010, but the 2010 recorded spending was only $6.982 million. UCAN also contends that SDG&E spent less money in 2010 than it did in 2009 for the GO 165 patrols, and that recent underground system growth has been less than 1%.

6.2.3.2.3. SDG&E

SDG&E contends that D.09-08-029 requires "electric utilities to increase the frequency of patrol inspections in rural areas from two years to one year within the 'Extreme and Very High Fire Threat Zones' in Southern California." (Ex. 63 at 16-17.) SDG&E contends that "there was an approximately 47% increase in patrol inspection costs from 2009 to 2010 and a 147% increase from 2009 to 2010 when the FHPMA costs are considered." (Ex. 63 at 17.)

SDG&E also contends that its funding request for elevated wind conditions and red flag warning conditions, and its funding request for the GO 165 patrols should be addressed in this GRC, rather than in the FHPMA.

As for UCAN's contention that system growth has slowed, SDG&E contends that system growth is continuing because of the addition of additional customers, added load demand per customer, and the conversion of overhead facilities to underground facilities. SDG&E also contends that this growth justifies the addition of more troubleshooter positions since the number of troubleshooters has remained unchanged over the last ten years.

6.2.3.3. Discussion

We first address the argument of DRA and UCAN that the fire hazard prevention activities, that are part of the O&M costs in this cost category, should be recovered in the FHPMA instead of in this GRC. As discussed in the ERO O&M section above, the GO 165 patrol costs, and the costs associated with elevated wind conditions and red flag warning conditions, are properly before us in this proceeding.

The next issue to address is what methodology should be used to develop the base O&M costs for ERO Engineering/Troubleshooting. Although UCAN's three-year average results in a higher base forecast ($7.020 million) as opposed to SDG&E's three-year average of $6.832 million, UCAN does not make any adjustments for system growth and training.

Based on the 2010 recorded costs, and the testimony about the slower growth in underground facilities, and the fewer GO 165 patrols, it is reasonable under the circumstances to reduce the O&M costs for ERO Engineering/ Troubleshooting by $600,000, which will reduce SDG&E's funding request of $7.851 million to $7.251 million.

6.2.4. Skills and Compliance Training

6.2.4.1. Introduction

This third category of costs for electric distribution O&M costs is the skills and compliance training organization. This organization is responsible for the development and training of the ERO workforce, which consists of electric field personnel, non-electrical support personnel, and supervisory staff. The core training provided by this organization consists of the following: electric linemen development using a three-year apprenticeship program; compliance training to meet federal, state, local safety, and environmental regulations; equipment operations and commercial drivers' training; and providing training support for other business units.

SDG&E forecasts the O&M costs for the skills and compliance training organization at $4.338 million for the 2012 test year. This is a $557,000 incremental change over the 2009 recorded amount of $3.781 million. DRA and UCAN recommend that $3.664 million be adopted as the O&M costs.

According to SDG&E, the three drivers that are contributing to the incremental cost changes are work force development, aging infrastructure, and regulatory and environmental compliance.

For the work force development driver, SDG&E expects to add additional electric troubleshooter training classes in 2011 and 2012 due to attrition and an aging workforce. A new training program for electric meter test technicians in advanced metering operations will be needed to offset workforce attrition. A training program is also being developed for the use of new fault finding equipment. A training program is also being developed for stand-by linemen. A training program for new instructors will also be developed. Training materials will be developed to support the training of equipment operators.

The aging electric distribution infrastructure is another driver of incremental costs. The training equipment that is used by the skills and compliance training organization needs replacement, and the current underground training facilities that were installed in 1980 need to be upgraded.

Under the regulatory and environmental compliance driver, SDG&E is seeking additional funds to ensure that its workforce is trained and certified in cardio pulmonary resuscitation, automated external defibrillator, and first aid training.

6.2.4.2. Position of the Parties

6.2.4.2.1.DRA

SDG&E developed its O&M forecast for the skills and compliance organization by using recorded 2009 data as the base year for labor costs, and a five-year average for non-labor costs. DRA takes no issue with SDG&E's

methodology for labor costs. However, DRA uses a four-year average of 2006-2009 to forecast non-labor costs. DRA contends that the 2005 data that SDG&E included in its five-year average was significantly higher than what was recorded for 2006-2009.

As described in Exhibit 478 at 30-38, DRA recommends disallowance of O&M in 11 areas. The main reasons for its recommended disallowances are that SDG&E offered no compelling reason or support for these costs, or that the costs are not related to skills or compliance training.

6.2.4.2.2. UCAN

UCAN agrees with DRA's O&M forecast of $3.664 million, but for a different reason. UCAN uses the three-year average of 2008-2010, which results in an average of $3.430 million. UCAN would then increase this amount by $243,000 which allows for growth, and reflects a mild improvement in the economy. UCAN does not agree with SDG&E's forecast of $4.338 million because it assumes a robust economy, which UCAN does not believe will occur. UCAN also points out that the recorded costs in 2010 was $2.952 million, as compared to SDG&E's 2010 forecast of $3.867 million.

6.2.4.2.3. SDG&E

SDG&E points out that it trains its workforce in a safe and controlled environment, and that this training is necessary to prepare its employees to recognize hazards and to safely work on and to maintain a complicated high voltage system. Ongoing training is also needed in a variety of other areas. In addition, many of the tools and systems at the current training facility have been in place for 30 years. These tools and systems need to be updated to reflect the current equipment that is in the field, including smart grid devices and other automated devices.

SDG&E also contends that DRA's recommended disallowance of the vacation and sick leave is inappropriate.

6.2.4.3. Discussion

We first address the methodology that should be used for the O&M costs for the skills and compliance training organization. UCAN believes that the three-year average of 2008-2010 should be used for both labor and non-labor costs. Both SDG&E and DRA use the recorded 2009 cost for labor costs. DRA then uses the four-year average of 2006-2009 for non-labor costs, while SDG&E uses the five-year average of 2005-2009.

We have reviewed the different methodologies used by SDG&E, DRA, and UCAN. Under the circumstances, we believe that DRA's method of using 2009 labor costs, and a four-year average of 2006-2009 for non-labor costs is an appropriate methodology to develop the base O&M costs. DRA's use of the four-average average for non-labor costs eliminates the 2005 recorded non-labor cost, which is the highest amount recorded from 2005-2010. The use of the 2009 recorded data for labor costs is appropriate because it reflects the labor costs in the 2008 -2009 timeframe, rather than incorporating the sudden decline in labor costs in 2010. Using DRA's methodology, we arrive at a base forecast of $3.664 million. SDG&E's methodology results in a base forecast of $3.733 million. UCAN's methodology results in a base forecast of $3.430 million.

SDG&E then makes incremental adjustments of $605,000 to its base forecast to arrive at its forecast of $4.338 million. These adjustments are due primarily to additional training of new apprentices which SDG&E expects to hire because of a brighter economic outlook, and other additional or new training programs, some of which are needed to meet new regulations or rules. Other miscellaneous costs, as noted by DRA, are then added to upgrade the current training infrastructure. Further, additional funding is sought to ensure the workforce is adequately trained and certified in cardiopulmonary resuscitation, automated external defibrillator, and first aid.

Having reviewed all of the testimony, we believe that DRA's base forecast of $3.664 million does not fully capture the training needs of new electric distribution workers who will need to be hired to replace an aging workforce during a period of slow economic growth. Accordingly, it is reasonable to adjust DRA's base forecast of $3.644 million upwards to a total funding of $3.800 million for the O&M costs for the skills and compliance training organization.[27]

6.2.5. Project Management

6.2.5.1. Introduction

The fourth category of costs for electric distribution O&M costs is the project management department. This department is responsible for the preparation of construction orders. The personnel in this department perform the design and engineering to develop the construction orders, from which additions and modifications to both the gas and electric distribution systems are constructed. These construction orders can range for services for an individual customer, to large distribution systems that serve subdivisions, commercial

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[27] We do not address DRA's individual disallowances item by item for several reasons. First, the total amount shown in the table which DRA reproduced in Exhibit 478 at 30, which is from SDG&E's workpaper in Exhibit 62 at 41, does not match the difference between SDG&E's base forecast of $3.733 million and its 2012 test year forecast of $4.338 million. Second, some of the requests are related to the replacement of aging infrastructure at the training facility, which due to its age, needs to be replaced. Third, the other items are related to training, which we believe are needed. And fourth, as mentioned earlier, vacation and sick leave costs should be included in the O&M costs.

centers, or high rise buildings. This department also prepares the construction orders to convert electric overhead lines to underground. Although the construction orders developed by this department represent capital projects, there is a small component of O&M costs which is addressed in this section.

SDG&E forecasts the O&M costs for the project management department at $1.521 million for the 2012 test year. This is a $1.091 million incremental change over the 2009 recorded amount of $431,000. DRA recommends that O&M costs of $603,000 be adopted. UCAN recommends O&M costs of $835,000.

According to SDG&E, there are four drivers that are contributing to the incremental cost changes.

The first driver is safety and environmental compliance training and employee skill development. The employees in this department must attend training in safety and environmental compliance, as well as other skill development classes.

The second driver is work force attrition, which requires the replacement of personnel who have transferred, retired or resigned.

The third driver is providing formal classroom training for new planners. SDG&E expects to hire and train 16 individuals in 2011 and to enroll them in the planner training class, which is expected to last 23 weeks. SDG&E also plans to hire and train an additional 16 planners in 2012. According to SDG&E, the hiring and training is needed to replace the skilled and aging workers who are retiring.

The fourth driver is to supplement the number of support staff as the number of planners increase. The project management department plans to add two project management assistants in 2012.

6.2.5.2. Position of the Parties

6.2.5.2.1. DRA

DRA's 2012 test year forecast is $603,000. DRA states that its forecast is based on recorded 2009 data, however, that 2009 recorded data is actually $431,000. (*See* Ex. 478 at 39.) According to DRA, it used the 2009 data because "it is most indicative of SDG&E's current spending." (Ex. 478 at 39.)

DRA is opposed to SDG&E's plan to add more planner positions, and the training associated with those positions. DRA contends that SDG&E did not provide support for these additional positions. DRA's forecast of $603,000 reflects 11.5 positions instead of the 19.5 employees that SDG&E has requested.

6.2.5.2.2. UCAN

UCAN notes that SDG&E's forecast for the 2012 test year of $1.521 million exceeds the recorded 2009 and 2010 costs of $431,000 and $340,000, respectively. Although SDG&E used as its base the five-year average of 2005-2009, that base forecast of $934,000 was well above the 2009 recorded amount of $431,000. To arrive at SDG&E's 2012 test year forecast, SDG&E then added an incremental amount of $587,000.

UCAN believes that there will be 36% fewer residential construction units in 2012 than SDG&E has forecasted. To reflect a weaker economy than what SDG&E has forecasted, UCAN would use the six-year average from 2005-2010 and no incremental increase. UCAN's methodology results in a 2012 test year forecast of $835,000. Although UCAN's forecast is slightly more than DRA's forecast of $603,000, this will allow SDG&E some flexibility to do some of the incremental work that SDG&E proposes, while recognizing the slowdown in the economy.

6.2.5.2.3. SDG&E

SDG&E developed its 2012 test year forecast by using the five-year average of 2005-2009 ($934,000), and then added incremental costs of $587,000.

SDG&E contends that DRA's use of the 2009 recorded data is not reflective of the O&M costs because 2009 was the only year during the 2005-2009 period that a planner/designer training class was not held. SDG&E asserts that its use of the five-year average is appropriate because two planner classes were held in 2005, and one class was held in each subsequent year except for 2009.[28] If the only cost data used is from 2009, this will fail to reflect any funding for the training class.

As for DRA's argument that SDG&E did not describe what this training class consists of, SDG&E asserts that this class is to teach the planners and designers how to do the design and engineering work that is needed to develop the construction orders. The training is also needed to ensure that SDG&E has the skilled workforce it needs to do its work, and to delay training until the economy improves would be irresponsible.

Regarding DRA's contention that the planners and designers are not useful to the utility, SDG&E contends that 10 of the planners and designers will remain in project management, and that the six others will be assigned to other areas within SDG&E where planners and designers are required.

Regarding UCAN's contention that its forecast is more reflective of the slowdown in the economy, SDG&E contends that new business work is not the only type of projects that project management handles. Project management also

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[28] SDG&E also notes that it did not conduct a training class in 2010, and argues that UCAN's inclusion of both the 2009 and 2010 data will result in lower O&M costs.

handles construction orders for corrective maintenance, to support capacity and reliability, and to convert overhead lines to underground.

6.2.5.3. Discussion

The first issue to address is the methodology that should be used to develop the forecast of the O&M costs for the project management department. The testimony shows that training classes were not held in 2009 and 2010. UCAN's six-year average methodology includes the 2009 and 2010 data. As a result, one-third of UCAN's forecast is affected by two years of no recorded training costs. If only the 2009 recorded data were used, no training costs would be included in that number. SDG&E's base forecast of $934,000 uses the five-year average of 2005-2009, and is only affected by one year of data (i.e., one-fifth) of no recorded training costs. Under the circumstances, SDG&E's five-year average methodology is appropriate to develop the base forecast of the O&M costs as it more fully reflects the costs of training.

The next issue is to decide whether SDG&E's incremental increase of $587,000 over its base forecast of $934,000 is warranted. UCAN contends that if its methodology and forecast is used, that its forecast of $835,000 allows SDG&E "to manage its workload to do some of the incremental work it proposes or to operate planner/designer classes if the economy improves somewhat…." (Ex.558 at 28.) The evidence demonstrates that additional hiring and training will be needed to replace an aging workforce, and that other types of construction orders besides new business require resources to address this work. When this evidence is considered, as well as comparing SDG&E's and UCAN's base forecasts to the historical data, some incremental increase is warranted. A reasonable incremental increase of $106,000 above SDG&E's base forecast of

$994,000 is warranted. This results in a funding amount of $1.100 million, which should be adopted as the O&M costs for the project management organization.

6.2.6. Service Order Team

6.2.6.1. Introduction

The fifth category of costs for electric distribution O&M costs is the service order team. This team is responsible for planning, overseeing and managing new additions and modifications to the electric and gas distribution systems, primarily related to services. The service order team acts as the SDG&E customer representative on these projects. The O&M costs associated with the service order team are for its support of construction operations storm recovery, construction maintenance programs, labor for training activities, and preparing orders to replace property.

SDG&E forecasts the O&M costs for the service order team at $270,000 for the 2012 test year. This is a decrease of $40,000 over the 2009 recorded amount of $310,000. DRA recommends that O&M costs of $258,000 be adopted.

According to SDG&E, there are three drivers that are contributing to the incremental cost changes. System growth is the first driver, as the service order team provides the assistance for projects that add new customers. With the improvement of the economy, SDG&E expects to increase staff so that the workload does not back up.

The second driver is work force development, which drives the need to train the service order team on new systems that are designed to better serve customer needs.

The third driver is regulatory and environmental compliance, which drives the need to train additional staff on the municipal, state, and federal regulations that affect the work of the service order team.

6.2.6.2. Position of the Parties

6.2.6.2.1. DRA

DRA recommends that funding of $258,000 be adopted, which is $12,000 less than SDG&E's funding request of $270,000. This difference is attributable to SDG&E's use of 2009 recorded data for its labor forecast, whereas DRA used a five-year average.

6.2.6.2.2. SDG&E

SDG&E contends that DRA's use of a five-year average for labor costs ignores the additional work that will be required as a result of the expansion of the Commission's GOs on construction and maintenance standards, municipal regulations in various jurisdictions concerning such things as storm water management, traffic control, backfill, and paving, and federal and state laws regarding safety and environmental concerns.

6.2.6.3. Discussion

We have reviewed the testimony of SDG&E and DRA, and agree with SDG&E's use of the 2009 recorded data for its labor costs. The 2009 labor cost data reflects the costs associated with recent rules and regulations that affect the work of the service order team. Accordingly, DRA's recommended reduction of $12,000 is not adopted, and SDG&E's forecast of $270,000 is reasonable and should be adopted as the funding amount for the O&M costs for the service order team.

6.2.7. Regional Public Affairs

6.2.7.1. Introduction

The sixth category of costs for electric distribution O&M costs is the regional public affairs group. According to SDG&E, this group "engages in activities that support communication with local and regional governments, community based organizations and customers on issues related to construction, operations and maintenance activities for SDG&E electric distribution." (Ex. 61 at 29.) Some of these activities include the following:

- Working with regional and local governments on issues regarding proposed regulations, permitting, and emergency preparedness and response;
- Educating officials at the county and city levels about SDG&E issues that could impact customers;
- Educating the community about SDG&E's operational activities, programs and services;
- Responding to customer and media inquiries;
- Resolving customer complaints; and
- Working with under-represented communities.

One of the programs that the regional public affairs group disseminates information about is SDG&E's Community Fire Safety Program. This program focuses on power line safety, and taking preventative measures and enhanced response to power line problems.

SDG&E forecasts the O&M costs for the regional public affairs group at $1.483 million for the 2012 test year. This is a decrease of $328,000 over the 2009 recorded amount of $1.811 million. DRA recommends that O&M costs of $1.006 million be adopted. UCAN opposes funding of the regional public affairs group on the grounds that this group is engaging "in activities in support of lobbying and corporate image enhancement." (Ex. 557 at 79.) However, if UCAN's recommendation to disallow funding on these grounds is not adopted, UCAN recommends that funding of $1.398 million be adopted.

According to SDG&E, there are four drivers of the cost changes. The first driver is customer education and stakeholder involvement, which results in SDG&E's participation in community events throughout its service territory about power line and fire safety, and emergency preparedness.

The second driver is new prevention measures, which means educating affected communities and agencies about replacing wood distribution poles with fire resistant steel poles, and installing new switching technology on the distribution system.

The third driver is response, communication and coordination. This is an important component of the Community Fire Safety Program, which results in coordination with fire agencies and the local communities about staging crews to respond to incidents.

The fourth driver is workforce development, which results in adding one additional public affairs manager, at a cost of $111,000, to address the increase in environmental regulations and outreach activities.

6.2.7.2. Position of the Parties

6.2.7.2.1. DRA

DRA's forecast of $1.006 million is $477,000 less than SDG&E's forecast of $1.483 million. DRA's lower forecast amount is due to the use of 2010 recorded data for its base forecast, as opposed to SDG&E's use of 2009 recorded data as SDG&E's base forecast. DRA's lower forecast also reflects the disallowance of one additional public affairs manager. DRA contends that this additional position is not needed in light of the current economy and because SDG&E has not justified the need.

6.2.7.2.2. UCAN

UCAN contends that in SDG&E's last GRC, the Commission put SDG&E on notice that if SDG&E wanted funding for regional public affairs, that it would have to provide "more detailed justification… for all public affairs and outreach expense to demonstrate genuine customer benefit that outweighs any incidental corporate image[ ] enhancement." (Ex. 557 at 79; D.08-07-046 at 75.) UCAN asserts that the activities that the regional public affairs group will be engaging in are "in support of lobbying and corporate image enhancement." (Ex. 557 at 79.)

UCAN contends that an example of SDG&E's lobbying and corporate enhancement is found in the responsibilities of the five regional public affairs managers, whose duties "include coordinating company relations with city councils and other elected and appointed officials, developing and promoting civic and community relations, and providing communications to key stakeholders on energy issues affecting customers and the region." (Ex. 557 at 79.)

In accordance with the statement in D.08-07-046 that requires "SDG&E and SoCalGas to maintain detailed contemporaneous documentation of the actual activities," UCAN requested SDG&E to provide such records. UCAN contends that SDG&E's response "acknowledged that it had not kept detailed, contemporaneous records of its Regional Public Affairs activities and that Public Affairs employees do not track their time by issue." (Ex. 557 at 80.) Since SDG&E did not provide any contemporaneous records to show how the costs of regional public affairs have historically been allocated between shareholder and ratepayer concerns, UCAN contends that ratepayer funding of the regional public affairs group should be disallowed.

In the event UCAN's disallowance of all of the funding for the regional public affairs group is not adopted, UCAN recommends that a funding amount of $1.398 million be adopted, which is based on the 2010 labor costs and the use of the two-year average of 2009-2010 for non-labor costs.

6.2.7.2.3. SDG&E

SDG&E points out that UCAN always raises the same issue about the funding of the regional public affairs group, and that UCAN mischaracterizes those activities as lobbying. For the reasons described below, SDG&E requests that UCAN's proposal be rejected.

SDG&E contends that the primary function of the regional public affairs group is to appear "before local governmental bodies regarding existing or proposed operations," and that this "does not involve lobbying or advocacy." (Ex. 63 at 28-29.) Without this group, the staff from the operations units would have to spend a large part of their time working with local governments and other stakeholders. Examples of some of the activities that the regional public affairs group has worked on are described in Exhibit 63 at 29 to 31, which include the following: franchise renewal and compliance; outreach to various groups about energy efficiency, the smart grid, smart meters, wood to steel projects; pipeline safety; vegetation management; substation relocations; coordinating emergency planning and response activities between SDG&E and the cities and counties; outreach on major construction projects; and outreach regarding customer programs and services.

On DRA's recommended disallowance of the public affairs manager position, SDG&E contends that the position is needed due to the increase in environmental regulations, and to conduct outreach about emergency preparedness, customer education, and permitting requirements.

6.2.7.3. Discussion

The first issue to address is UCAN's recommendation to disallow all of the funding for the regional public affairs group. UCAN's disallowance is based on its argument that the activities that this group participates in promote lobbying and enhances SDG&E's corporate image. SDG&E opposes UCAN's recommendation.

UCAN relies on the Commission's language in SDG&E's last GRC decision as to why SDG&E funding request should be rejected. In that decision, the Commission addressed DRA's recommendation to disallow "certain public affairs costs" that DRA believed was "directed primarily to corporate image enhancement rather than providing any specific service or value to ratepayers." (D.08-07-046 at 75.) Although the Commission did not adopt DRA's disallowance in that proceeding, the Commission stated the following:

> We will not adopt this disallowance (regardless of the test year settlement) because we believe there is ratepayer benefit from access to the company in an informal setting. But we will require SDG&E and SoCalGas to maintain detailed contemporaneous documentation of the actual activities, the service or information provided, including data on the numbers of customers who receive this service or information, as part of the documentation for the next GRC if the companies wish ratepayer funding for these activities. In effect, the companies are on notice that the bar has been raised and a more detailed justification is required for all public affairs and outreach expense to demonstrate genuine customer benefit that outweighs any incidental corporate image[ ] enhancement. (D.08-07-046 at 75.)

Based on the above passage, the Commission ordered the following:

> SDG&E and SoCalGas shall maintain detailed records on all public affairs outreach efforts for educational and other purposes. SDG&E and SoCalGas shall include this information in testimony and work papers in the next general rate cases. (D.08-07-046 at 107, Ordering Paragraph 28.)

As for how D.08-07-046 applies to UCAN's recommended disallowance, that issue requires a three-step analysis. First, it is clear that in the last GRC, DRA raised concerns about "certain" public affairs costs. However, D.08-07-046 did not explain which public affairs costs DRA was concerned with.[29] Based on Ordering Paragraph 28 of that decision, we surmise that the activities DRA was concerned about was "outreach efforts for educational and other purposes," such as perhaps conducting outreach at street fairs, appearing at schools, or sponsorship of certain events.

Second, in this proceeding, UCAN seeks to disallow all of the funding that SDG&E has requested for the regional public affairs group. UCAN did not specify which of the activities that the regional public affairs group engages in amount to lobbying or corporate enhancement. Based on the information provided by SDG&E in its direct (Exhibit 61) and rebuttal testimony (Exhibit 63), it is clear that the work that the regional public affairs group does is to meet with affected governments and other stakeholders to advise them of SDG&E's programs and services, construction activities, utility-related initiatives, emergency response, as well as other activities. Since UCAN seeks to disallow all funding of this group, we do not adopt UCAN's recommendation because, based on the information before us, the regional public affairs group engages in activities that benefits and informs customers and communities about SDG&E's programs, services, and initiatives.

The third step of our analysis is whether D.08-07-046 required SDG&E to maintain certain information and to include certain information in its testimony in this proceeding. Both the discussion and Ordering Paragraph 28 of D.08-07-046 make it evident that SDG&E has certain recordkeeping obligations,

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[29] To investigate which public affairs costs that DRA took issue with in SDG&E's last GRC would require further research of the evidentiary record in A.06-12-009, which we have not done.

as well as an obligation to provide certain information in its GRC filings. Reading the discussion that appears in D.08-07-046 at 75, together with Ordering Paragraph 28 of that decision, the "contemporaneous" and "detailed" recordkeeping appears to apply to those public affairs activities which DRA was concerned about in A.06-12-009, namely "outreach efforts for educational and other purposes." These recordkeeping obligations are triggered, along with including such documentation in its GRC filings, if SDG&E wants "ratepayer funding for these activities." (D.08-07-046 at 75.)

SDG&E's testimony in Exhibits 61 and 63 did not include any discussion of these types of outreach efforts, nor did it reference Ordering Paragraph 28 of D.08-07-046 in these two exhibits. That raises two possibilities. Either SDG&E is not requesting ratepayer funding for the type of activities that DRA took issue with in A.06-12-009, or such activities are part of its funding request but SDG&E failed to include the necessary documentation in its GRC filing. It does not appear to be the latter because DRA did not raise any issues in this proceeding, as it did in A.06-12-009, that the regional public affairs group's activities are "directed primarily to corporate image enhancement rather than providing any specific service or value to ratepayers." (D.08-07-046 at 75.) Also, we are not persuaded by UCAN's argument that since SDG&E "acknowledged that it had not kept detailed, contemporaneous records of its Regional Public Affairs activities," that this suggests that SDG&E "did not meet the burden of proof established by the Commission" in D.08-07-046 by not including such documentation in its GRC filing. (Ex. 557 at 80-81.)

Since no evidence has been presented in this proceeding to suggest that the funding request for regional public affairs involves activities that are of a lobbying nature, or to enhance the corporate image, we do not agree with

UCAN's suggestion that D.08-07-046 has not been complied with, or that SDG&E's funding request for this group should be disallowed entirely as a result of such documentation not being included in SDG&E's GRC filing.

That brings us then to the appropriate level of funding for the regional public affairs group. SDG&E's methodology results in a 2012 test year forecast of $1.483 million. DRA recommends funding of $1.006 million, while UCAN's alternative recommends funding of $1.398 million, respectively. Based on a review of the testimony of SDG&E, DRA, and UCAN, comparing the methodologies and adjustments they use to arrive at their respective forecasts, and considering the need for an additional public affairs manager given the state of the economy, it is reasonable to adopt $1.287 million in funding for the O&M costs for regional public affairs.

6.2.8. Grid Operations

6.2.8.1. Introduction

The seventh category of costs for electric distribution O&M costs is grid operations. Grid operations involve the work activities of electronic control technicians, and emergency control technicians. According to SDG&E, the electronic control technicians are responsible for the overall installation, testing, calibration, and maintenance of all supervisory, control and data acquisition (SCADA) equipment that interfaces with various systems. The emergency control technicians are responsible for ensuring the accuracy and availability of the SCADA system on a 24 hour basis.

SDG&E forecasts O&M costs for grid operations at $427,000 for the 2012 test year. This is an increase of $130,000 over the 2009 recorded amount of $297,000. DRA recommends that O&M costs of $327,000 be adopted. UCAN recommends that O&M costs of $267,000 be adopted.

According to SDG&E, the driver of the cost changes is equipment deployment growth. Due to many SDG&E initiatives, including OpEx and smart grid, SDG&E expects an increase in the number of SCADA remote terminal units that will be put into service. These new units and the existing units will increase the need for planned and unplanned maintenance. By 2012, grid operations anticipate the need to add one additional electronic control technician at an incremental cost of $100,000.

6.2.8.2. Position of the Parties

6.2.8.2.1. DRA

DRA recommends that a forecast of $327,000 be adopted. DRA's forecast is based on the three-year average of 2007-2009, which is what SDG&E used as its base forecast. DRA would disallow SDG&E's incremental increase of $100,000 to add one electronic control technician because of a lack of support for this additional position.

6.2.8.2.2. UCAN

UCAN recommends funding the O&M costs for grid operations at $267,000. UCAN's recommendation is based on the three-year average of 2008-2010 for labor, and a two-year average of 2009-2010 for non-labor costs.

UCAN points out that SDG&E's forecast of $427,000 is based on a three-year methodology of 2007-2009, and then an incremental amount of $100,000 is added for another SCADA system operator. UCAN contends that SDG&E's forecast appears inflated because 2008 had abnormally high non-labor costs, and the recorded costs in 2009 and 2010 were $297,000 and $240,000, respectively.

6.2.8.2.3. SDG&E

SDG&E's forecast of $427,000 is based on the three-year average of 2007-2009 ($327,000), and then an incremental increase of $100,000 is added.

SDG&E contends that DRA's recommended disallowance of $100,000 for the additional electronic control technician position is based on an incomplete review of SDG&E's OpEx program. SDG&E contends that it thoroughly described the OpEx program in Exhibit 183, and that its request for the additional position is reasonable and necessary.

Regarding UCAN's forecast, SDG&E contends that the time periods chosen by UCAN "appears to be an attempt to seek the lowest cost, while simultaneously ignoring the standard activities that occurred previously, and will remain part of this activity's responsibilities going forward." (Ex. 63 at 32.)

6.2.8.3. Discussion

We first address the two methodologies that were used to develop the base forecast of the O&M costs for grid operations. SDG&E and DRA both use the three-year average of 2007-2009 to develop their base forecasts. UCAN uses a three-year average of 2008-2010 for labor, and a two-year average of 2009-2010 for non-labor costs. We have reviewed the testimony and compared their methodologies to the recorded costs. UCAN's methodology will result in too low of a forecast since it uses the two years with the lowest non-labor costs, and its three-year average of labor costs incorporates one year of data with the lowest labor cost. The three-year average used by SDG&E and DRA to develop their base forecasts is more reflective of the expected costs. For those reasons, the $327,000 that SDG&E and DRA derived as their base forecasts is reasonable.

The second issue to address is whether the incremental cost of $100,000 to add the additional electronic control technician is reasonable. DRA opposes this incremental addition, while UCAN believes that its recommended funding could accommodate this additional position. We have reviewed and considered the testimony concerning grid operations, the relationship of the need to add one additional electronic control technician, and the lower smart grid funding. We have also balanced the need for this position with the costs that were experienced in 2009 of $297,000, and in 2010 of $240,000. Based on all those considerations, it is reasonable to adopt total O&M funding of $327,000 for grid operations.

6.2.9. Substation Construction and Maintenance

6.2.9.1. Introduction

The eighth category of costs for electric distribution O&M costs is the substation construction and maintenance section. This section is responsible for the installation and maintenance of 140 distribution substations on the SDG&E system. This section also installs and maintains the control functions of approximately 1300 overhead and underground distribution field devices.

SDG&E forecasts the O&M costs for the substation construction and maintenance section at $8.853 million for the 2012 test year. This is an increase of $529,000 over the 2009 recorded amount of $8.324 million. DRA recommends that O&M costs of $8.576 million be adopted. UCAN recommends that a funding level of $7.782 million be adopted.

According to SDG&E, the three drivers contributing to the incremental cost changes are fire preparedness, regulatory and environmental compliance, and training.

The fire preparedness driver results in the annual testing of 112 devices located in the backcountry that help mitigate hazards on the distribution system during elevated fire conditions. During elevated fire conditions and red flag warnings, personnel are positioned at substations in areas of high fire danger, to expedite a response to resolve an interruption of service or other electrical system problem caused by the weather.

For the regulatory and environmental compliance driver, SDG&E expects the Commission to adopt a new GO for electric utility substations by 2012, which will require substation inspection programs. As a result, SDG&E expects that support staff will have to be increased to comply with the inspection tracking and reporting process.

The training driver will result in training for new employees, and refresher training or new skills training for existing employees. In addition, new training courses are being developed for developing working foremen and journeyman, and for climbing.

6.2.9.2. Position of the Parties

6.2.9.2.1. DRA

DRA recommends that a forecast of $8.576 million be adopted.

DRA recommends that all of the fire hazard prevention costs be removed from this proceeding and recovered in the FHPMA. DRA's recommendation would disallow the $900,000 that SDG&E requests for red flag, elevated wind, and other fire related events, and the 10.5 new positions. In addition, DRA's FHPMA recommendation would also disallow $500,000 of the $1.079 million for helicopter utilization use.

DRA also recommends disallowance of $500,000 for aging infrastructure, but did not provide a reason for doing so. In addition, DRA recommends a disallowance of $50,000 for field crew laptop computers due to a lack of support. DRA also recommends the $1 million for vacation and sick leave be disallowed from SDG&E's funding request due to a lack of support.

Regarding the O&M costs related to the smart grid that are included in the substation construction and maintenance section, DRA recommends that $384,000 of the $1.646 million that SDG&E has requested be approved. DRA's reduction for the O&M costs is based on DRA's smart grid policy position. This affects O&M costs for the following: advanced energy storage, dynamic line ratings; smart transformers; fault circuit indicators; phasor measurement units; phase identification; SCADA capacitors; SCADA expansion; condition based maintenance; and public access charging facilities.

6.2.9.2.2. UCAN

UCAN recommends that a forecast of $7.782 million be adopted. UCAN's forecast uses a four-year average of 2007-2010 ($7.682 million), and then adds $100,000 to cover possible excess smart grid O&M expenses. UCAN points out that the 2009 recorded amount of $8.324 million was a peak spending year, and that the 2010 recorded amount of $6.944 million was considerably lower.

UCAN contends that SDG&E's workpapers for this account are not clear, and that the amount in the workpapers do not reconcile with the amount requested by SDG&E. UCAN also contends that SDG&E double counts the helicopter costs. For the fire hazard protection costs, UCAN recommends that those costs should be recovered through the FHPMA.

UCAN also contends that SDG&E's plan to add 15 additional positions from 2009-2012 appears to be inflated because of the state of the economy, and because the work to be performed will take less time than SDG&E has estimated.

6.2.9.2.3. SDG&E

SDG&E's forecast of $8.853 million was developed using a base forecast of $8.324 million, based on recorded 2009 labor and non-labor costs, and then making incremental adjustments.

SDG&E contends that the recommendation of DRA and UCAN to remove the O&M costs for red flag, elevated wind, and other fire related events from this GRC and to recover it in the FHPMA is wrong. SDG&E contends that the annual maintenance program that the substation construction and maintenance group performs does not qualify for inclusion in the FHPMA. Also, SDG&E contends that only a small portion of the helicopter costs relate to fire preparedness and prevention, and that the vast majority of the costs are related to the maintenance, restoration, patrols, and inspection of overhead lines.

On DRA's recommendation to disallow the vacation and sick leave costs, SDG&E contends the inclusion of vacation and sick leave is an appropriate expense.

SDG&E contends that UCAN's forecast of the funding amount needed is based on historical average spending, which does not reflect the costs of the incremental activities for fire prevention and protection, helicopter operations, and field crew laptop computers. SDG&E also contends that the laptops being requested are to allow the substation construction and maintenance crews to access information regarding the substations.

6.2.9.3. Discussion

The starting point for determining what the reasonable funding amount for the O&M costs for substation construction and maintenance is to first address UCAN's observation that SDG&E's workpapers on this issue, which are contained in Exhibit 62, "are not clear," and as a result "it is not easy to ascertain what SDG&E really wants and what is just included as fluff to make its smaller request look more reasonable." (Ex. 558 at 30.) This topic is relevant because it affects how DRA and UCAN developed their forecasts and recommendations,[30] and our view of the forecasts of SG&E, DRA, and UCAN and what the reasonable funding level should be.

UCAN contends that when one reviews the supplemental workpapers that appear in Exhibit 62 at 84 and 85, it is unclear whether the total amounts shown at those two pages are included in the workpapers that appear at 77 and 78 of Exhibit 62. UCAN also contends that the cost of helicopter services is double-counted since it appears in the workpapers at 80-82, as well as in the line item description at 84. (*See* Ex. 558 at 30.)

Although UCAN raised this issue in its opening testimony, SDG&E did not respond to this in its rebuttal testimony. (*See* Ex. 63 at 33-36.) SDG&E did, however, state in response to a UCAN data request that the "supplemental workpapers shown on pages 84 and 85 were intended to be illustrative of the types of activities and projects that are driving incremental costs," and are "illustrative placeholders and do not represent the figures used in the workpaper calculations," and that the "actual figures SDG&E used…are significantly lower and are properly represented in the formal workpapers." (Ex. 67, SDG&E Response to UCAN Data Request 83, Question 6, e.g.; 15 R.T. 1669.) SDG&E also attached a spreadsheet to its data response which reconcile SDG&E's incremental request. This also led to questioning of SDG&E's witness on the costs of the helicopter services, who acknowledged that helicopter costs were included in the account for substation construction and maintenance in 2005 through 2009, but

30 *See* Exhibit 478 at 46-54, and Exhibit 558 at 30-31.)

was also recommending an increase. (*See* 15 R.T. 1664-1666; Ex. 67, SDG&E Response to UCAN Data Request 83, Question 6, a-b.)

We agree with UCAN's observations that the O&M costs that are being requested for substation construction and maintenance could have been made clearer and easier to understand at the outset. Thus, with UCAN's observation in mind, our analysis begins with the recommendations concerning the FHPMA, and vacation and sick leave, followed by an examination of the methodologies used by the parties to develop their respective forecasts, and then an analysis of the clarifying spreadsheet as it relates to SDG&E's incremental request.

Both DRA and UCAN request that the fire hazard prevention activities be removed from this GRC and recovered through the FHPMA. As discussed earlier, the O&M costs related to fire hazard prevention activities are properly before us in this GRC and shall be included in SDG&E's funding request. Also, as previously discussed, since vacation and sick leave are a reasonable part of the labor costs, those costs shall be included as part of SDG&E's funding request, and DRA's recommendation to disallow the vacation and sick leave costs is not adopted.

On the methodologies used to develop their respective forecasts, UCAN's methodology uses a four-year average from 2007-2010, which results in a base forecast ($7.682 million) that uses three of the lowest years of recorded costs. UCAN then adds $100,000 to its base forecast to arrive at its recommended forecast of $7.782 million, which is at the low range. To develop SDG&E's base forecast of $8.324 million, SDG&E uses 2009 recorded costs for both labor and non-labor costs. The 2009 recorded cost is the highest recorded cost since the 2006 recorded cost of $8.918 million. SDG&E then makes incremental adjustments to its base forecast to arrive at its 2012 test year forecast of

$8.853 million. DRA recommends a funding level of $8.560 million, but does not describe how it calculated that amount. No one used the five-year average of 2005-2009, which results in an average of $8.177 million.

Although SDG&E infers that its use of 2009 recorded data to develop its base forecast better reflects recent cost drivers,[31] this is not supported by the recorded 2010 costs of $6.944 million, which is $1.761 million lower than SDG&E's 2010 forecast of these O&M costs, and $1.909 million lower than SDG&E's 2012 forecast. If recorded 2010 data was included in a six-year average of 2005-2010, this would result in an average of $7.971 million.

The above analysis of the different methodologies, as compared to the historical data, suggests that a reasonable base forecast is to use UCAN's four-year average of $7.782 million, instead of the base forecast suggested by SDG&E.

We now turn to the incremental costs that SDG&E contends are needed for the 2012 test year. The recommended reductions of both DRA and UCAN focused on the supplemental workpapers of SDG&E in Exhibit 62, which SDG&E admits were meant to be "illustrative placeholders." We have reviewed the testimony of the parties, including SDG&E's workpapers in Exhibit 62 and the corrected spreadsheet in Exhibit 67.

We agree with DRA and UCAN that there should be reductions in two areas to SDG&E's incremental request. The first reduction should be to SDG&E's incremental request for red flag, elevated wind, and fire-related events. As

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31 *See* Exhibit 61 at 34-37.

discussed earlier, we believe that SDG&E has overestimated this cost, based on the historical number of red flag and elevated wind conditions.

The second reduction should be to SDG&E's request for incremental smart grid costs. Both DRA and UCAN believe that all of SDG&E's funding for smart grid should be reduced. Our review of the testimony and the workpapers of the parties regarding the smart grid lead us to agree with DRA and UCAN that some reduction to the smart grid O&M costs is warranted. Based on the above, it is reasonable to adopt funding in the total amount of $8 million for the O&M substation construction and maintenance costs.

6.2.10. System Protection

6.2.10.1. Introduction

The ninth category of costs for electric distribution O&M costs is the system protection maintenance department. This department is responsible for maintaining and troubleshooting the protective relays and control systems within SDG&E's substations. This department also maintains other control systems for specialized equipment that SDG&E uses. The staffing for this department consists of relay technicians, electrical engineers, and a system analyst.

SDG&E forecasts the O&M costs for the system protection maintenance department at $702,000 for the 2012 test year. This is an increase of $51,000 over the 2009 recorded amount of $651,000. DRA recommends that O&M costs of $595,000 be adopted. UCAN recommends that O&M costs of $578,000 be adopted.

According to SDG&E, the drivers contributing to the incremental cost changes are fire preparedness, regulatory and environmental compliance, system growth, aging infrastructure, and new technology.

The fire preparedness driver results in this department supplying standby crews during high fire dangers. With the expected new GO regarding substations, more compliance and audit training will be required of staff. For the system growth driver, the additions and upgrades to distribution substations add to the number of devices that must be maintained, and the technical complexity of these devices require additional skills and training. With an aging infrastructure, more corrective maintenance is needed. The driver of new technology is that microprocessor-based protective relays and computer test equipment are replacing older technology, which requires additional skills and training.

6.2.10.2. Position of the Parties

6.2.10.2.1. DRA

DRA's recommended 2012 test year forecast amount is $595,000. DRA's forecast was arrived at using the four-year average of 2007-2010.

DRA recommends that SDG&E's incremental adjustment of $56,000 not be added to SDG&E's base forecast because it believes that SDG&E did not provide sufficient support to justify the incremental adjustment.

6.2.10.2.2. UCAN

UCAN uses the three-year average of 2008-2010 to develop its 2012 test year forecast of $578,000. UCAN did not make any incremental adjustment to its forecast. UCAN points out that in 2009 and 2010, the recorded O&M costs for system protection were $651,000 and $476,000, respectively.

6.2.10.2.3. SDG&E

SDG&E's 2012 test year forecast is based on the four-year average of 2006-2009, which developed a base forecast of $646,000. SDG&E then added incremental costs of $56,000 to arrive at its 2012 test year forecast of $702,000.

SDG&E contends that DRA's methodology use of the 2007-2010 is not representative of the true historical spend, and is an attempt to develop the lowest possible cost. SDG&E contends that its substations include old electromechanical relays that are being replaced with microprocessor based relays. SDG&E currently has about 1044 distribution microprocessor relays, and this number is increasing. Since these microprocessor relays require more technical expertise and skill to maintain, that results in more training, SDG&E contends that its forecast should be adopted without change.

SDG&E contends that UCAN's use of the three-average of 2008-2010 does not reflect the proper spend level for system protection O&M costs, and ignores the long term historical costs. SDG&E contends that its forecast, rather than UCAN's forecast, should be adopted for the same reasons that SDG&E referred to regarding DRA's forecast.

6.2.10.3. Discussion

None of the three parties explained why they did not use the 2005 recorded data, or why the five-year average of 2005-2009 should not be used. Based on a comparison to the historical costs from 2005-2009, the 2005 costs are comparable. If this five-year period is used, this results in an average of $641,000.

The forecasts of DRA and UCAN both use 2010 recorded data, which is the lowest recorded cost from 2005-2010. We agree with SDG&E that the incorporation of the 2010 data into the methodologies used by DRA and UCAN would skew the result.

Based on our analysis of the methodologies used by all three parties, and our comparison to the historical recorded cost for O&M system protection costs, we believe that a base forecast of $641,000 is reasonable, as opposed to the forecasts that SDG&E, DRA, and UCAN developed.

Using the five-year base forecast, the next issue is to decide whether any incremental adjustment should be made. SDG&E requests an incremental amount of $56,000, which is based on the increased maintenance costs for the older electromechanical relays, and the increase in training that is needed to improve the skill set to maintain and repair the growing use of microprocessor-based relays. Given the historical costs, we are not persuaded by SDG&E's argument that the incremental costs are warranted. Accordingly, it is reasonable to adopt a funding level of $641,000 for the O&M costs for system protection activities.

6.2.11. Electric Distribution Operations

6.2.11.1. Introduction

The tenth category of electric distribution O&M costs is the electric distribution operations group. This group is responsible for the Electric Distribution Operations Control Center, which directs the activities of electric troubleshooters, fault finding specialists, and crews throughout its service territory.

SDG&E forecasts the O&M costs for the electric distribution operations group at $10.475 million for the 2012 test year. This is an increase of $1.104 million over the 2009 recorded amount of $9.371 million. DRA recommends that O&M costs of $8.597 million be adopted. UCAN agrees with DRA's recommended funding level.

According to SDG&E, the following four drivers are contributing to the incremental cost changes: maintain improved safety performance and reliability; new technology; work force development; and fire preparedness. To maintain improved safety performance and reliability, and to provide sufficient coverage, SDG&E requests funding for one additional engineer, and an additional team lead for the distribution system operators. The new technology driver will result in an increase in SCADA devices, and the replacement of existing computers, monitors, and radios. For the work force development driver, there are costs associated with the two-year apprentice distribution system operator training program. For the fire preparedness driver, SDG&E expects to add another meteorologist to the one existing meteorologist, in order to provide real time support to understand changing weather conditions.

6.2.11.2. Position of the Parties

6.2.11.2.1. DRA

DRA recommends that the funding level for the O&M costs for electric distribution operations be set at $8.597 million. DRA's recommended funding level is based on the 2010 recorded data, which incorporates the incremental costs associated with "maintaining improved safety performance and reliability, new technology, work force development and fire preparedness." (Ex. 478 at 56-57.)

DRA recommends that the additional positions that SDG&E requests funding for not be allowed due to a lack of support of the need for these additional positions.

6.2.11.2.2. UCAN

UCAN agrees with DRA's forecast amount of $8.597 million, which is based on the 2010 recorded costs for electric distribution operations. UCAN points out that the 2009 recorded cost was $9.371 million. UCAN recommends an alternate funding level of $8.829 million (based on the three-year average of

2008-2010), in the event the Commission believes that some incremental spending is needed.

UCAN contends that the five-year average of 2005-2006 that SDG&E used to develop its base forecast, includes two high years of recorded data in 2005 and 2006. On top of that, SDG&E requests incremental funding to add additional positions. UCAN contends that it is unclear whether SDG&E needs these additional positions.

6.2.11.2.3. SDG&E

SDG&E recommends a 2012 test year forecast of $10.475 million. SDG&E's base forecast of $9.525 million uses the five-year average of 2005-2009. SDG&E then adds an incremental adjustment of $950,000 to its base forecast to arrive at its 2012 test year forecast of $10.475 million.

SDG&E contends that the recommendations of both DRA and UCAN to disallow all of the additional positions it requests ignore "the steady increase in electric system growth, replacement of aging infrastructure, requirements to comply with CPUC Standards, including GO 165 and GO 166, Fire Preparedness and increasing customer expectations for outage information." (Ex. 63 at 38, 40.) SDG&E also contends that the 2010 data was an anomaly because of "a relatively cool, damp summer with an abnormally low number of days where elevated wind, or Santa Ana conditions prevailed," and the "economic uncertainty during 2010 resulted in generally lower attrition rates among employees and a slowdown in the new business construction activities" which "influenced training and hiring decisions" for SDG&E's electric distribution operations. (Ex. 63 at 40; Ex. 67, SDG&E Response to UCAN Data Request 83, question 7.a and 7.b.)

6.2.11.3. Discussion

We have reviewed the testimony and the methodologies that the parties used to derive their various forecasts. We first note that the recommendation of DRA and UCAN to use the 2010 recorded data as the adopted forecast would result in using one of the lowest recorded amounts over the six-year period of 2005-2010. SDG&E's method, which uses the five-year average of 2005-2009 to derive its base forecast of $9.525 million, results in a base forecast that uses two years of data with the highest recorded costs. This results in an SDG&E base forecast which is overly generous. The methodologies used by all three parties skew their respective recommended forecasts.

If we ignore the two highest years of recorded costs, 2005 and 2006, a more reasonable base forecast can be derived. If a three-year average of 2007-2009 is used, the average is $8.793 million. If a four-year average of 2007-2010 is used, the average is 8.744 million. Based on our review of the different methodologies, as compared to the historical costs, a base forecast of $8.900 million is reasonable.

That brings us to SDG&E's request to make an incremental adjustment of $950,000 which DRA opposes, and which UCAN suggests a small portion may be warranted. We have reviewed the testimony of SDG&E, DRA, and UCAN concerning the additional positions that SDG&E has requested, and the other drivers for SDG&E's incremental request. Based on that testimony, it is reasonable to adjust the base forecast of $8.900 million by an additional $100,000. This results in a 2012 test year funding amount of $9 million for the O&M costs for electric distribution operations, which should be adopted. It is our belief that funding at this level will provide SDG&E with sufficient revenues to carry out its existing activities, as well as its planned incremental activities.

6.2.12. Distribution Operations/Electric Geographic Information Management

6.2.12.1. Introduction

The eleventh category of electric distribution O&M costs is distribution operations, which is responsible for electric geographic information management. This group is responsible for preparing accurate and timely maps.

SDG&E forecasts the O&M costs for this group at $1.548 million for the 2012 test year. This is an increase of $249,000 over the 2009 recorded amount of $1.299 million. DRA recommends that O&M costs of $1.340 million be adopted. UCAN agrees with DRA's recommended funding level.

The two drivers contributing to the incremental cost changes for this group are work force development and additional support personnel. With the roll-out of the new geographic information system (GIS) software, training will be required of existing staff. SDG&E also expects a backlog of work due to the training. SDGE plans to add two additional electric geographic information management coordinators to support the mapping and quality control function.

6.2.12.2. Position of the Parties

6.2.12.2.1. DRA

DRA's recommended forecast amount of $1.340 million was derived using the three-year average of 2008-2010, and the 2009 base year for personnel positions. DRA recommends against allowing adding any additional positions.

6.2.12.2.2. UCAN

UCAN agrees with DRA's recommended forecast of $1.340 million, and is in agreement with the methodology that DRA used. UCAN contends that the five-year average that SDG&E uses as its base forecast is inappropriate because costs are trending downward. UCAN also points out that the recorded costs in 2009 and 2010 were $1.299 million and $1.324 million, respectively.

6.2.12.2.3. SDG&E

SDG&E's 2012 test year forecast is derived based on the five-year average of 2005-2009, which results in an average of $1.508 million. To this, SDG&E adds an incremental amount of $40,000 to arrive at its 2012 forecast amount of $1.548 million.

SDG&E contends that its use of the five-year "represents all presented years and related volatility," and should be adopted. (Ex. 63 at 40-41.) SDG&E also contends that is provided support for the additional positions that it requested.

6.2.12.3. Discussion

SDG&E recommends a funding amount of $1.548 million, while DRA and UCAN recommend a funding level of $1.340 million.

We have reviewed the testimony and methodologies concerning the forecasts of O&M costs for the activities related to the electric GIS. UCAN points out that SDG&E's methodology uses two years of the highest recorded costs to develop its forecast. However, DRA's methodology suffers from the same affliction as it uses three years of data with the three lowest years of recorded costs over the 2005-2010 timeframe.

If a four-year average of 2007-2010 is used, that results in an average of $1.390 million. If a six-year average of 2005-2010 is used, that average is $1.478 million. Based on the information before us, including the 2009 and 2010 recorded costs, it is reasonable to adopt a funding amount of $1.400 million for the O&M costs for the activities related to the electric GIS.

6.2.13. Equipment Maintenance and Lab

6.2.13.1. Introduction

The twelfth category of electric distribution O&M costs is the Kearny equipment maintenance and lab. This facility includes the following five work groups:

- Tool repair: responsible for the maintenance, repair, and fabrication of tools, and to acquire new tools to support the needs of other groups.
- Apparatus: responsible for salvaging equipment removed from service.
- Transformer repair and high voltage test: this group is a North American Independent Lab certified high voltage test station, which performs tests to confirm the electrical condition of transformers, regulators, live line tools, and equipment, and to repair transformers, regulators, and street light controllers.
- Protective equipment testing laboratory: this group is a North American Independent Lab certified to inspect and test rubber goods used for electrical worker protection.
- Miramar material test lab: this group provides failure analysis of electrical underground cable and components, and electrical overhead components. This group also assists with categorizing the cause of failure of electrical equipment, and establishing trends and pinpointing areas where future problems may arise.

SDG&E forecasts the O&M costs for this lab at $2.080 million for the 2012 test year using a five-year linear method. This is an increase of $235,000 over the 2009 recorded amount of $1.845 million. DRA recommends that O&M

costs of $1.650 million be adopted.[32] UCAN recommends a funding amount of $1.769 million be adopted, which uses the three-year average of 2008-2010.

The four drivers contributing to the incremental cost changes for this lab are fire preparedness, regulatory and environmental compliance, system growth, aging infrastructure, and maintenance of improved safety performance and reliability. The fire preparedness driver results in the acquisition and maintenance of stand-by and fire response equipment. For the regulatory and environmental compliance drivers, additional rubber goods compliance training classes will be added, and additional lab work is anticipated to identify and remove PCBs. The system growth driver will result in increased load, which is expected to increase the replacement of overloaded transformers, and to increase transformer repair and scrapping operations. The aging infrastructure driver will result in an overloading of facilities, especially in older neighborhoods. Also, as demand grows on the distribution system, a greater number of facilities will require maintenance, repair, and disposal. To maintain improved safety performance and reliability, SDG&E expects an increase in live line tool testing and associated repair activities.

6.2.13.2. Position of the Parties

6.2.13.2.1. DRA

DRA recommends a funding amount of $1.650 million. DRA contends that SDG&E's use of a five-year linear forecasting methodology "overstates 2012

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[32] DRA's recommended funding level appears to be $1.650 million, which is the average using 2005-2009 recorded data. However, in DRA's testimony in Exhibit 478 at 61 and 62, DRA refers to its recommendation as $1.6 million and $1.550 million. UCAN's Exhibit 558 assumes DRA's recommended funding level is $1.650 million.

expense levels because it assumes that the historical trend in expense levels will continue into the future." (Ex. 478 at 61.)

DRA uses the five-year average of 2005-2009 to derive its recommended funding amount. DRA contends that its methodology reflects the fluctuations in incremental costs that are being forecasted.

6.2.13.2.2. UCAN

UCAN recommends that a funding amount of $1.769 million be adopted. UCAN's forecast is based on the three-year average of 2008-2010.

UCAN contends that SDG&E's five-year linear forecast failed to reflect the lower 2010 recorded costs of $1.685 million.

UCAN also contends that any incremental costs associated with the EPA's PCB phaseout, and the American Standards for Testing and Materials work on a new standard for personal grounds, should be disregarded as these activities are still a long ways off before they are adopted as a regulation or standard.

6.2.13.2.3. SDG&E

SDG&E's forecast of $2.080 million uses the five-year linear method.

SDG&E contends that the methodologies of DRA and UCAN will reduce the O&M costs for the equipment maintenance and lab without reflecting the increased work load, material expense and safety concerns. SDG&E points out that the labor funding for this organization accounts for the majority of the expense, and that the labor agreement contains agreed upon wage rate increases.

6.2.13.3. Discussion

SDG&E, DRA, and UCAN recommend different funding amounts. SDG&E recommends a funding amount of $2.080 million, while DRA and UCAN recommend $1.650 million and $1.769 million. Based on the testimony before us, and a comparison to the historical data of 2005-2010, we agree with DRA's recommendation because it represents the five-year average. SDG&E's methodology failed to reflect the lower 2009 costs. Under the circumstances, it is reasonable to adopt a funding amount of $1.650 million for SDG&E's activities related to equipment maintenance and lab.

6.2.14. Construction Services

6.2.14.1. Introduction

The thirteenth category of electric distribution O&M costs is the construction services group. This group is responsible for the oversight of all construction performed by contractors on electric distribution to ensure that the work is built in accordance with GOs 95 and 128 and SDG&E standards.

SDG&E forecasts the O&M costs for the construction services group at $5.532 million for the 2012 test year. This is a $58,000 incremental change over the 2009 recorded amount of $5.474 million. DRA recommends that a funding amount of $4.363 million be adopted, while UCAN recommends a funding amount of $3.841 million.

According to SDG&E, the two drivers contributing to the incremental cost changes are system growth, and fire preparedness. As SDG&E expects system growth to expand, additional staff will be needed for locate and mark services to minimize electric and gas interruptions. In addition, system growth will result in additional transformers and replacement of transformers to accommodate larger loads and to ensure system reliability. The fire preparedness driver will result in additional quality control inspections and repairs in rural areas to maintain reliability, safety, and to reduce incidents.

6.2.14.2. Position of the Parties

6.2.14.2.1. DRA

DRA recommends that a funding amount of $4.363 million be adopted. DRA's forecast is based on the four-year average of 2005-2008, with an upward adjustment of $406,000.

DRA recommends that $412,000 be removed from the funding amount because the costs are related to fire hazard prevention, which DRA believes should be recovered through the FHPMA.

6.2.14.2.2. UCAN

UCAN recommends a funding amount of $3.841 million be adopted. UCAN's recommended amount is based on the removal of $1.461 million of fire hazard prevention costs to the FHPMA, and a lower estimate of spending due to UCAN's view of the economy. UCAN points out that O&M costs in 2009 and 2010 were $5.474 million and $4.659 million, respectively.

6.2.14.2.3. SDG&E

SDG&E recommends a 2012 test year forecast of $5.532 million be adopted. SDG&E's forecast is based on a zero-based methodology. SDG&E contends its methodology addresses the "new pressures and accounts for activities that will be in this workgroup's base responsibilities going forward, making its methodology to most reasonable reflection of its costs for the test year 2012." (Ex. 63 at 43.)

Regarding the recommendation of DRA and UCAN to remove the fire hazard prevention activities and to consider the costs in the FHPMA, SDG&E contends that these costs should be considered in this GRC as it is part of the activities for this work group.

SDG&E contends that the methodologies that DRA and UCAN to derive their recommended forecasts are an "attempt to achieve the lowest cost through simple averaging (four years in DRA's case), or utilizing 2010 as the base year with a 50%…increment from SDG&E's proposed 2012 spend [in UCAN's case]." (Ex. 63 at 43.)

6.2.14.3. Discussion

We have reviewed the testimony of the parties and compared their methodologies to each other and to historical costs. Since construction services depend in large part on system growth, a major driver of the costs is the outlook for the economy. The other driver of costs is fire preparedness, which results in more inspections and repairs, as well as the hardening of facilities.

Both DRA and UCAN argue that the fire hazard prevention activities should be removed from this GRC and considered in the FHPMA. As previously discussed, the costs for the 2012 test year shall be included in this GRC. Accordingly, the recommendation of DRA and UCAN to remove those costs from this proceeding is not adopted. According to UCAN, those fire hazard prevention costs amount to about $1.461 million.

We now address which of the three methodologies is a better indicator of the 2012 test year costs. As stated above, the two primary drivers of costs for construction services are economic growth, and fire preparedness. Although DRA's methodology utilizes the four-year average of 2005-2008 as a base, it omits the 2009 recorded costs, which was the highest during the five years from 2005-2009. Also, DRA's method does not reflect the increase in fire preparedness costs. UCAN's methodology uses the 2010 recorded cost of $4.659 million as its base. For the reasons stated earlier, we do not agree with UCAN's removal of the fire hazard prevention costs from its base forecast. However, the use of the 2010 recorded data is a useful comparison to SDG&E's forecast.

We believe the recorded data from 2009 of $5.474 million, and the 2010 data of $4.659 million, are useful comparisons to SDG&E's forecast of $5.532 million because these two years reflect the effects of the economic downturn and a ramp-up of the fire preparedness costs. For 2012, the fire preparedness costs are likely to increase due to more inspections and repair of facilities in high fire zones. However, due to the slowdown in the economy, the need for construction services is likely to remain weak. Based on those considerations, it is reasonable to adopt a funding amount of $5 million for the O&M costs for construction services.

6.2.15. Vegetation Management

6.2.15.1. Introduction

The fourteenth category of electric distribution O&M costs is vegetation management. SDG&E's vegetation management program is responsible for inspecting and maintaining an inventory of approximately 400,000 trees that have the potential to encroach within the minimum required compliance distance between the overhead power lines and vegetation. This work consists of two separate activities, tree trimming, and pole brushing.

The vegetation management program is contained within the Construction Services department of the Electric Transmission and Distribution Operations organization. The staff for the vegetation management program includes the program manager, team leads, area foresters, contract administrators, quality assurance specialists, technical support and analyst, and customer service administrative staff.

6.2.15.2. Tree Trimming

6.2.15.2.1. Introduction

The tree trimming activity covers tree pruning, tree removal, and other vegetation management expenses. This activity occurs as a result of routine work involving annual cycle pruning and removal of trees, or work related to field memos and hazard tree work.

SDG&E forecasts the O&M costs for tree trimming at $27.419 million for the 2012 test year. This is a $2.176 million incremental change over the 2009 recorded amount of $25.243 million. DRA recommends that O&M costs of $23.504 million be adopted. UCAN agrees with DRA's forecast of the tree trimming costs. The FEA recommends a forecast of $24.263 million.

The primary cost drivers are complying with the rules and regulations that mandate a minimum clearance between the vegetation and SDG&E facilities.

According to SDG&E, tree trimming activity fluctuates from year to year due to two main factors: (1) the composition of fast, medium, and slow growing tree species in SDG&E's tree inventory, which determines the rate at which these trees will encroach on overhead lines; and (2) the impact of tree mortality and decline in overall tree health system-wide.

The tree trimming costs are currently treated under a one-way balancing account. SDG&E proposes a two-way balancing account treatment. SDG&E contends that a two-way balancing account is needed "due to the high variability and costs associated with the number of trees requiring line clearance pruning annually, combined with more stringent environmental factors, recent regulatory changes to G.O. 95[,] Rule 35 and increased inspection and removal of hazard trees in response to concerns expressed by the California Department of Forestry and Fire Protection…." (Ex. 61 at 48.) SDG&E contends that the two-way balancing account will "protect SDG&E customers from the regulatory uncertainty and the natural pattern of workload fluctuations from year to year." (Ex. 61 at 49.)

DRA, the FEA, and UCAN oppose SDG&E's proposal to have tree trimming costs accounted for in a two-way balancing account. DRA, the FEA, and UCAN recommend that the current one-way balancing account be retained.

6.2.15.2.2. Position of the Parties

6.2.15.2.2.1. DRA

DRA recommends a tree trimming forecast of $23.504 million. DRA's forecast uses SDG&E's zero-based methodology but excludes non-standard escalation items. DRA removed the non-standard escalation items from its forecast because SDG&E did not include these items in its forecast prior to this proceeding. DRA points out that SDG&E's forecast of $27.419 million is $2.176 million more than the 2009 recorded amount of $25.243 million.

DRA opposes SDG&E's request for a two-way balancing account for tree trimming costs. DRA recommends that the current treatment of tree trimming costs using a one-way balancing account be retained. The one-way balancing account allows SDG&E to recover what it spends on this activity, up to the spending cap. DRA contends that prior to 2009, tree trimming costs have never exceeded the spending cap. DRA also contends that in D.04-12-015, the Commission required SDG&E to continue this one-way balancing account treatment.

6.2.15.2.2.2. FEA

One of the explanations as to why SDG&E's 2012 test year forecast increased to $27.419 million is because of the additional insurance coverage for wildfires that SDG&E requires of its contractors, which SDG&E agrees to reimburse the contractors for. The FEA contends that this increase is not justified because SDG&E "has not presented any evidence that the contractors' negligence contributed to the wildfire damage, thus requiring this increase in coverage." (Ex. 577 at 43-44.)

The FEA recommends that the O&M funding amount for tree trimming be set at $24.263 million, which is based on the two-year average of the recorded costs for 2009 and 2010.

The FEA agrees with DRA's recommendation to keep the tree trimming costs in a one-way balancing account. The FEA contends that retention of the one-way balancing account will ensure that if SDG&E does not fully utilize the authorized tree trimming allowance, and that the funds will be returned to ratepayers.

6.2.15.2.2.3. UCAN

UCAN agrees with DRA's recommended forecast of $23.504 million. UCAN points out that the 2010 recorded costs for tree trimming was $23.300 million, which was lower than the $25.200 million that was spent in 2009.

UCAN also opposes SDG&E's request for a two-way balancing account for tree trimming costs. One of the reasons why SDG&E requests a two-way balancing account is because of the year-to-year fluctuation in the costs. UCAN contends that since" SDG&E is making progress on reducing the number of fast growing trees in its inventory," that reduces "the number of trees that need to be trimmed frequently," which will minimize this fluctuation. (Ex. 563 at 23.)

6.2.15.2.2.4. CCUE

CCUE contends that the Commission should not reduce the funding amount for tree trimming, while at the same time continuing the one-way balancing account. With the one-way balancing account, if SDG&E

over-forecasts its tree trimming expenses, ratepayers will be refunded the amount that has not been spent, with interest. If DRA's forecast of the tree trimming costs is adopted, CCUE favors the adoption of the two-way balancing account.

6.2.15.2.2.5. SDG&E

SDG&E's forecast of $27.419 million for tree trimming costs uses a zero-based methodology. SDG&E contends that the workload that took place in 2009 represents a realistic year for vegetation management. In addition, SDG&E explained and justified its costs, including an explanation of how the non-standard escalation items were treated. SDG&E also contends that it provided sufficient supporting information to the other parties that identified the "current and future upward pressures related to environmental requirements and changes in weather conditions that impact the growth and health of trees managed by SDG&E." (Ex. 63 at 45.)

SDG&E requests that tree trimming costs be allowed two-way balancing account treatment due to the uncertainties and fluctuations associated with the tree trimming costs. Although SDG&E has been able to manage its tree trimming costs within its approved budget in previous years, SDG&E contends it is now subject to more stringent environmental and regulatory requirements, and diseases and tree mortality has increased. SDG&E contends that the two-way balancing account treatment is needed "to adequately fund current and future vegetation management needs in order to remain in compliance, effectively mitigate hazardous trees, and provide a safe and reliable source of electricity to its customers." (Ex. 63 at 44.)

6.2.15.2.3. Discussion

SDG&E recommends a funding amount of $27.419 million for the O&M costs for the tree trimming costs. DRA and UCAN recommend a funding amount of $23.504 million, while the FEA recommends $24.263 million. The recorded spend in 2009 and 2010 was $25.243 million, and $23.300 million, respectively.

We have reviewed the testimony regarding the tree trimming costs, and have examined the parties' recommended forecasts in relationship to historical costs and to expected costs. The 2009 recorded cost is a good starting point as it is representative of the costs and workload experienced in the more recent years of 2009 and 2010, as tree trimming costs and activities have ramped up. The likelihood that these activities will continue to increase in the 2012 test year is supported by the increase in required inspections and clearances. In addition, the mixture of tree growth, tree mortality and diseases, and weather, will put upward pressure on costs. Although the FEA opposes including the cost of the additional liability insurance into the tree trimming costs, we believe that inclusion of that cost is needed to help control the costs of the contractors. Based on all of these factors, a funding amount of $25.500 million is reasonable, and should be adopted for the 2012 test year O&M costs for tree trimming.

Regarding SDG&E's request to treat tree trimming costs in a two-way balancing account, we do not grant that request. By continuing the one-way balancing account at the authorized funding amount, this will encourage SDG&E to perform the needed tree trimming activities, while containing costs. SDG&E can raise its request for two-way balancing account treatment in its next GRC.

6.2.15.3. Pole Brushing

6.2.15.3.1. Introduction

Pole brushing involves the inspection, and clearing of flammable brush and vegetation away from SDG&E's distribution poles in accordance with Public Resource Code § 4292.[33] There are more than 89,000 wood poles on the SDG&E distribution system that are located in high fire danger areas. In 2009, 33,000 poles required brush maintenance activities.

SDG&E forecasts the O&M costs for pole brushing at $5.354 million for the 2012 test year. This is a $1.551 million incremental change over the 2009 recorded amount of $3.803 million. DRA recommends a funding amount of $3.803 million be adopted. UCAN agrees with DRA's recommendation. The FEA recommends a funding amount of $3.852 million.

The pole brushing costs currently are not subject to a balancing account. SDG&E is proposing in this GRC to allow pole brushing expenses to be included in a two-way balancing account. DRA, FEA, and UCAN oppose SDG&E's proposal for a two-way balancing account, and recommend that the current treatment of no balancing account remain in effect.

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[33] Public Resource Code §4292 provides in pertinent part that the person who "owns, controls, operates, or maintains any electrical transmission or distribution line upon any mountainous land, or forest-covered land, brush-covered land, or grass-covered land shall…maintain around and adjacent to any pole or tower which supports a switch, fuse, transformer, lightning arrestor, line junction, or dead end or corner pole, a firebreak which consists of a clearing of not less than 10 feet in each direction from the outer circumference of such pole or tower."

6.2.15.3.2. Position of the Parties

6.2.15.3.2.1. DRA

DRA recommends a funding amount of $3.803 million for the O&M pole brushing costs. DRA's forecast is based on the 2009 recorded costs for labor and non-labor costs.

DRA contends that SDG&E's 2012 test year forecast should be reduced by the incremental non-labor costs because SDG&E did not provide support for these costs, and refused to provide the audit report regarding the 2010 and 2011 pole brushing costs.

DRA opposes SDG&E's request for a two-way balancing account for its pole brushing costs. DRA contends that the "historical data proves that SDG&E operates adequately without the use of a balancing account at all." (Ex. 478 at 70.) DRA recommends that the pole brushing costs continue without the use of a balancing account.

6.2.15.3.2.2. FEA

The FEA recommends a funding amount of $3.852 million. FEA's forecast is based on the two-year average of 2009 and 2010. FEA contends that the pole brushing costs for SDG&E have been fairly consistent from 2005 through 2011, and that the five-year average from 2006-2010 results in an average of $3.505 million. FEA contends that SDG&E has not substantiated its request for a funding amount of $5.354 million.

The FEA opposes SDG&E's recommendation to treat the pole brushing costs in a two-way balancing account. The FEA contends that the pole brushing costs have been fairly consistent, and that a two-way balancing account "would shift the risk of uncontrolled over-spending onto ratepayers…." (Ex. 577 at 53.)

6.2.15.3.2.3. UCAN

UCAN agrees with DRA's recommended funding amount of $3.803 million for the pole brushing costs. UCAN contends that the pole brushing costs do not need a balancing account.

6.2.15.3.2.4. SDG&E

SDG&E requests a funding amount of $5.354 million for the 2012 test year. SDG&E contends that this amount is warranted in light of having to comply with Public Resource Code § 4292, to revisit sites to inspect for regrowth and to clean up debris that has blown back around the poles and towers.

SDG&E requests that the pole brushing costs be afforded two-way balancing account treatment. SDG&E contends that the two-way balancing account is needed to address the uncertainty of these costs, and to provide "enough funding for the utility to administer the appropriate trimming activities, as needed, to ensure a safe and reliable system, while at the same time, ensuring that rate payers reap the rewards of efficiencies, savings, or favorable weather conditions." (Ex. 63 at 46.)

6.2.15.3.3. Discussion

SDG&E requests a funding amount of $5.354 million for the 2012 test year. This is in contrast to the DRA and UCAN recommendation of $3.803 million, and the FEA's recommendation of $3.852 million. In 2010, the recorded costs were $3.900 million.

We have reviewed the testimony on the pole brushing costs, and have compared the different recommendations and methodologies of the parties to the historical costs. Based on that review, the recorded data for 2009 and 2010 serve as a useful base for developing the 2012 test year forecast. The 2009 and 2010 costs incorporate the ramp up of the costs for the pole brushing activities required by the annual inspection requirement in Public Resource Code § 4292. We agree with SDG&E that an increase in the O&M costs are warranted, but not to the extent that SDG&E recommends. Under these circumstances, a funding amount of $4 million is reasonable, and should be adopted as the amount for the O&M costs for pole brushing.

SDG&E requests that the pole brushing costs be given two-way balancing account treatment. We do not grant SDG&E's request. We do not believe a two-way balancing account is needed, since the historical data indicates that these pole brushing costs have been fairly stable and do not fluctuate to a great degree. With today's authorized funding amount for these O&M costs, that should provide SDG&E with sufficient funding to carry out all of its pole brushing activities. SDG&E is free to request balancing account treatment in its next GRC.

6.2.16. Asset Management

6.2.16.1. Introduction

The fifteenth category of electric distribution O&M costs is asset management. Asset management "is a grouping of cost centers that perform a variety of administrative and technical activities related to the safe and efficient design, operation and maintenance of the electric distribution system." (Ex. 61 at 56.) Technical activities "include system capacity and operational analysis, reliability technical analysis, electric reliability reporting, as well as development of standard practices related to new technology, equipment, design and operations standards and work methods." (Ex. 61 at 56.) Other activities include the management of SDG&E's code compliance program and inspection and maintenance program.

SDG&E forecasts the O&M costs for asset management at $6.075 million for the 2012 test year. This is a $2.964 million incremental change over the 2009 recorded amount of $3.111 million. DRA recommends $2.212 million for the O&M costs for asset management. UCAN recommends a funding amount of $2.891 million.

SDG&E's total forecast of $6.075 million is composed of its funding requests in the four cost work groups described below.

The first work group is management, policy and oversight. This work group provides oversight over the technical areas, administers the associate engineer program, and provides support related to technology innovation and development. This work group also supports the emergency operations center and the construction and operations districts during major events and storm drills. SDG&E forecasts O&M costs for this work group at $344,000 for the 2012 test year. DRA does not take issue with SDG&E's O&M funding request for this work group. UCAN recommends a funding amount of $237,000.

The second work group is reliability and capacity analysis. This work group provides technical support services regarding the operations and maintenance of the electric distribution system. The two main groups providing these services are the technical analysis group, and the distribution planning group. SDG&E forecasts O&M costs for this work group at $1.167 million for the 2012 test year. DRA recommends that O&M costs of $824,000 be adopted, while UCAN recommends $659,000.

The third work group is compliance and asset management. This work group focuses on maintaining compliance with internal and external regulations, policies, and procedures as they relate to the operation and maintenance of the electric distribution system. SDG&E forecasts O&M costs for this work group at

$3.390 million for the 2012 test year. DRA recommends that O&M costs of $370,000 be adopted for this work group, while UCAN recommends $1.501 million.

The fourth work group is information management. This work group supports electric distribution by acting as a liaison for different groups in the electric distribution organization who are seeking software solutions and field hardware, with the information technology organization. This work group also provides hardware support for the mobile devices used in the field. SDG&E forecasts O&M costs for this work group at $1.174 million for the 2012 test year. DRA recommends that $674,000 be adopted, while UCAN recommends $494,000.

6.2.16.2. Position of the Parties

6.2.16.2.1. DRA

DRA's recommended funding amount for the asset management group is $2.212 million. DRA's recommendation is based on three reductions.

The first reduction is to the reliability and capacity analysis work group. DRA recommends a funding amount of $824,000, which is $343,000 less than SDG&E's request of $1.167 million. DRA's reduction would disallow $154,000 for a new engineering analyst position, $150,000 for a software application consultant, and $39,000 for three planners.

The second reduction is to the compliance and asset management work group. DRA recommends a funding amount of $370,000, which is $3.020 million less than SDG&E's request of $3.390 million. DRA's reduction removes all of the activities that it views as related to fire hazard prevention, which DRA contends should be recovered through the FHPMA.

DRA's third reduction is to the information management work group. DRA recommends a funding amount of $674,000, which is $500,000 less than

SDG&E's request of $1.174 million. DRA's reduction would disallow the two additional technical support assistant positions, and remove the funding for the item listed as "labor pressures" due to a lack of support.

6.2.16.2.2. UCAN

UCAN recommends that adjustments be made to all four work groups. All four of UCAN's adjustments would result in a funding amount of $2.891 million.

For the management, policy and oversight work group, UCAN recommends a funding amount of $237,000. UCAN's recommendation is based on the 2010 recorded costs of $217,000, to which it adds a $20,000 increment for activity related to the Electric Power Research Institute.

For the reliability and capacity analysis work group, UCAN recommends a funding amount of $659,000. This amount is based on 2010 recorded spending of $437,000, and then making an incremental adjustment as SDG&E suggested except for some of the costs associated with the sustainable communities program. UCAN points out that the actual spend in 2010 of $437,000 was below SDG&E's 2010 forecast of $749,000. UCAN reduced spending for the sustainable communities program because of its position that the program should wind down, and that O&M expenses should be reduced to the amount of funding that is necessary to keep the existing systems operating.

UCAN recommends a funding amount of $1.501 million for the compliance and asset management work group, as compared to SDG&E's 2012 test year forecast of $3.390 million. UCAN's recommended funding amount is made up of two reductions. First, UCAN removes $1.420 million from SDG&E's request because UCAN believes the activities are related to fire hazard prevention which should be recovered in the FHPMA. Second, UCAN removes

$200,000 from the wood pole inspection program because it believes the number of inspections is not increasing.

For the information management work group, UCAN recommends a funding amount of $494,000, which is the 2009 recorded spend. This is in contrast to SDG&E 2012 test year forecast of $1.174 million. UCAN's recommendation is based on the lack of detail from SDG&E about what the added workload will be, and because SDG&E only spent $300,000 in 2010 when it had forecasted $809,000.

6.2.16.2.3. SDG&E

SDG&E forecasts a total of $6.075 million for the O&M costs for asset management for the 2012 test year.

Regarding UCAN's recommendation to reduce the funding for the management, policy and oversight work group, SDG&E contends that UCAN's reduction of $107,000 is inappropriate. SDG&E contends that because of the reorganization that took place, SDG&E is not asking for increased funding for this work group.

DRA and UCAN have recommended reducing the funding for the reliability and capacity analysis work group. SDG&E contends that DRA's proposal to eliminate the engineering analyst position is illogical because this position is in support of the OpEx program, which DRA has not opposed. As for DRA's recommendation to remove the three distribution planner positions and have those costs considered in the FHPMA, SDG&E contends that such costs should be considered in this GRC. Regarding UCAN's recommendation to remove the funds for the sustainable communities program, SDG&E contends that such funds are justified based on its rebuttal testimony concerning the sustainable communities program.

Regarding DRA's recommendation to reduce the funding for the compliance and asset management group by $3.020 million, SDG&E contends that the activities related to fire hazard prevention are properly included in this GRC, and to consider those costs in the FHPMA would be contrary to D.12-01-032. SDG&E also contends that the increased funding is needed because of the additional workload created by GO 95's Rule 18. SDG&E also contends that the activities that SDG&E plans to carry out are in compliance with GO 165 and GO 95's Rule 44. On UCAN's recommendation to remove the increases for the wood pole inspections, SDG&E contends that those increases are justified because of the contract with the contractor which includes an automatic increase of about two percent each year.

On the recommendations of DRA and UCAN to reduce the funding for the information management work group, SDG&E contends that it has adequately supported its request for the two technical support assistant positions, and the eight GIS analysts. Regarding UCAN's reductions, SDG&E contends that the 2010 recorded spending was lower than forecast because positions were transferred temporarily to capital projects, which resulted in low O&M expenditures for 2010. As for UCAN's argument that SDG&E did not describe the details of the kind of work that the additional staff would be doing, SDG&E contends it provided thorough responses on the type of skills and responsibilities needed for these positions, as well as the specific work that was anticipated.

6.2.16.3. Discussion

SDG&E requests a total of $6.075 million for the asset management groups for the 2012 test year. DRA recommends a funding amount of $2.212 million, while UCAN recommends $2.891 million. As discussed below, the funding amount of $5.055 million should be adopted as the O&M costs for the asset management groups.

We first address UCAN's recommendation to reduce SDG&E's requested funding amount of $344,000 for the management, policy and oversight work group by $107,000. UCAN contends that its reduction is appropriate because the actual spending in 2010 was $217,000. However, as SDG&E points out, it underwent a reorganization in 2010, and as a result SDG&E is not requesting increased funding for this work group, and its requested funding amount is $141,000 lower than the 2009 recorded costs for this work group. Based on the testimony of the parties, SDG&E's funding amount of $344,000 is reasonable and should be adopted.

Next, we address the funding amount for the reliability and capacity analysis work group. SDG&E requests a funding amount of $1.167 million. DRA recommends a funding amount of $824,000, and UCAN recommends $659,000.

We have reviewed the testimony of SDG&E and DRA concerning the positions that DRA recommends be disallowed or removed. We do not adopt DRA's recommendation to disallow the $154,000 for the additional engineering analyst position. This position is part of the OpEx initiative and covers asset management using condition-based maintenance. The O&M costs associated with condition-based maintenance are described in the OpEx testimony, which DRA did not oppose. (*See* Ex. 183 at 6-7, A1.) On DRA's recommendation to remove $39,000 for the three planners because their work is related to fire hazard prevention, those costs will be considered in this GRC for the reasons stated earlier about the FHPMA. On DRA's recommendation to remove the software consultant cost of $150,000, that recommendation should be adopted since SDG&E did not provide a detailed breakdown of this cost.

On UCAN's recommendation to reduce the funding amount for the sustainable communities program, we do not agree with that recommendation. As discussed in SDG&E's electric distribution capital expenditures, the sustainable communities programs continues to provide benefits, and funding should continue through this GRC cycle.

Based on the above, the funding amount of $1.017 million for the O&M costs for the reliability and capacity analysis work group is reasonable and should be adopted.

For the compliance and asset management work group, SDG&E recommends a funding amount of $3.390 million. UCAN recommends a funding amount of $1.501 million, while DRA recommends $370,000. First of all, for the reasons discussed earlier, all of the fire hazard prevention activities for this work group will be considered in this GRC rather than through the FHPMA. Second, we have reviewed the testimony of the parties and considered the need for the four additional positions. However, given the historical costs for this workgroup, we do not believe that four additional positions are needed. Accordingly, $420,000 should be removed from this work group. Third, UCAN contends that the $1.600 million requested for the wood pole inspection program should be reduced by the $100,000 increases in 2011 and 2012. UCAN contends that these increases are not reasonable because the inspections under this program are not increasing. SDG&E opposes UCAN's recommendation and contends that the contracts include an automatic increase, as well as projections for other expenses. Although there is an increase adjustment clause in the contract for the pole inspection program, it is reasonable to reduce the funding amount for pole inspection by a total of $50,000 due to the uncertainty of the projection of other expenses. Based on the above, it is reasonable to set the funding amount for the O&M costs for the compliance and asset management work group at $2.920 million.

SDG&E recommends a 2012 test year funding amount of $1.174 million for the information management work group. DRA recommends a funding amount of $674,000 while UCAN recommends $494,000.

The difference between SDG&E's recommendation and the other parties is due to the 10 additional positions (two technical support assistants, and eight GIS analyst positions) that SDG&E plans to add by the 2012 test year. The recommendations of DRA and UCAN center around their belief that SDG&E did not provide sufficient information about the type of work that the additional personnel would be working on. We have reviewed the testimony of SDG&E, DRA, and UCAN regarding these additional positions. We agree with SDG&E, as shown in Attachment A to Exhibit 63, that SDG&E provided a description of the type of work and the expected workload that these additional positions would be doing. However, we do not agree with SDG&E that 10 positions are needed. In 2009, SDG&E had 5.1 full time equivalents (FTEs) in the information management work group.[34] Instead of adding 9.2 FTEs by 2012, we believe that this work can be handled by two additional positions. Accordingly, it is reasonable to reduce SDG&E's O&M funding for the information management work group by $400,000 to arrive at a funding amount of $774,000.

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[34] An FTE represents a single employee that works every business hour of a calendar year, and a number of less than one indicates that the employee will work a partial year or that the position had a vacancy during the year.

Based on all of the above adjustments, a funding amount of $5.055 million should be adopted for the O&M costs for the asset management work groups.

6.2.17. Distribution Engineering

6.2.17.1. Introduction

The sixteenth category of electric distribution O&M costs is distribution engineering. The distribution engineering work group is responsible for the development and maintenance of the construction standards that apply to electric distribution.

SDG&E forecasts the O&M costs for distribution engineering at $969,000 for the 2012 test year. This is a $157,000 incremental change over the 2009 recorded amount of $812,000. UCAN recommends that a funding amount of $909,000 be adopted. DRA does not take issue with SDG&E's forecast of the distribution engineering O&M costs.

According to SDG&E, the following five drivers are contributing to the incremental cost changes. First, new technology in the area of PEVs will require changes to the infrastructure as a result of the load created by the charging. Also, the use of smart transformers will result in the need to evaluate their performance, and to evaluate competing technologies. The second driver is that smart grid technologies will need to be evaluated and monitored. The third driver of fire preparedness will result in making overhead distribution lines more robust against fire, and expenses will be incurred to evaluate new products. The fourth driver is the need to meet improved efficiency standards for municipal streetlights. The fifth driver is that recruitment and training expenses are expected to increase as the aging work force nears retirement.

6.2.17.2. Position of the Parties

6.2.17.2.1. UCAN

UCAN recommends a funding amount of $909,000 for the O&M distribution engineering costs. UCAN's adjustment is based on spreading out the non-recurring cost of a bucket truck harness over the proposed four-year rate cycle.

6.2.17.2.2. SDG&E

SDG&E contends that UCAN's recommended reduction is inappropriate and shortsighted because the bucket truck harness is purchased every five years, and that the new five-year cycle begins in 2013, which requires this to be purchased in 2012.

6.2.17.3. Discussion

Instead of spreading the cost of the bucket truck harness over the four-year rate cycle, as UCAN suggests, we agree with SDG&E that the full $80,000 should be included in the 2012 test year forecast amount.

We have reviewed the testimony of the parties regarding the other O&M costs that are included in the distribution engineering costs and find those costs to be reasonable. The funding amount of $969,000 should be adopted for the O&M costs for distribution engineering.

6.2.18. Officer

The seventeenth category of costs for electric distribution O&M costs is the officer work group. The typical activities included in this work group include officer activities in support of electric distribution office supply expenses and officer travel expenses.

SDG&E forecasts the O&M costs for the officer work at $417,000 for the 2012 test year. This is a decrease of $16,000 over the 2009 recorded amount of $433,000. DRA and UCAN do not take issue with this forecast.

The testimony regarding the officer costs have been reviewed and we find those costs to be reasonable. The funding amount of $417,000 for the O&M costs for the officer work group should be adopted.

6.2.19. Administrative and Management

The eighteenth category of costs for electric distribution O&M costs is the administrative and management work group. This work group is responsible for supporting the financial system for the electric distribution organization.

SDG&E forecasts the O&M costs for the administrative and management work group at $150,000 for the 2012 test year. This is the same as the 2009 recorded amount. DRA and UCAN do not take issue with these O&M costs.

The testimony regarding the administrative and management work group has been reviewed and we find those costs to be reasonable. The funding amount of $150,000 for the O&M costs for the administrative and management work group should be adopted.

6.2.20. Miscellaneous Costs

The O&M costs for electric distribution also has indirect charges that are attributable to exempt materials, the purchase and repair of small tools, and pooled costs from the electric distribution department overhead. As described in Exhibit 61, the indirect costs are allocated to the appropriate gas and electric O&M accounts and capital expenditures, and the pooled costs are charged directly to the respective cost centers.

6.3. Capital Expenditures

6.3.1. Introduction

This section addresses SDG&E's estimated capital expenditures for its electric distribution utility plant for the period 2010 through 2012. This section also addresses the recommendation of the CCUE to impose a reliability incentive mechanism on SDG&E.

The electric distribution capital projects are the result of customer requests or to meet system needs. These capital projects include the following:

- Construction or modification of facilities to distribute electricity at 15,000 volts (15 kV) and below;
- Construction of modification of facilities that transform energy from transmission voltage levels to distribution voltage levels;
- Projects to improve system reliability; and
- Protective relaying, circuit breakers, substation switchgear, and associated equipment for distribution substations and for equipment on the 15 kV and below systems.

SDG&E's electric distribution capital projects are managed by project category. Within each project category are a number of different projects. According to SDG&E, the assignment of projects to project categories allows SDG&E to review "the various projects with a common understanding of their drivers and construction needs." (Ex. 69 at 24.) Project categories also allow for the reallocation of resources within common project types.

The six project categories are: (1) new business; (2) capacity; (3) reliability; (4) mandated; (5) franchise; and (6) fire hardening specific, and advanced metering infrastructure (AMI) projects. The following table is a summary of SDG&E's forecasted project costs by category:[35]

[35] SDG&E's forecast of the capital projects listed in the summary table are described in more detail in Exhibit 69.

($ 000)

Category	2010 GRC Forecast	2011 GRC Forecast	2012 GRC Forecast	Total
New Business	$61,604	$80,981	$89,977	$232,562
Capacity	$19,128	$47,080	$26,802	$93,010
Reliability	$55,876	$54,816	$65,634	$176,326
Mandated	$31,999	$35,987	$34,220	$102,206
Franchise	$19,060	$19,175	$18,318	$56,553
Fire Hardening & AMI	$ 2,656	$ 8,036	$17,479	$28,171
Total	$190,322	$246,075	$252,430	$688,828

In the sub-sections below, we address each project category separately.

Before we list each project category, it is useful to provide a description of each party's position on the electric distribution capital expenditures to get a sense of their concerns as we go through each project category.

6.3.1.1. Position of the Other Parties

6.3.1.1.1. DRA

DRA's overall position on the electric distribution capital expenditures is that the growth in capital expenditures should be at a more moderate pace than what SDG&E has recommended.

DRA recommends direct costs of $154.654 million for 2010, $152.488 million for 2011, and $158.382 million for 2012. DRA's total direct cost recommendation over the three years amounts to $465.524 million (as compared to SDG&E's total direct cost recommendation of $688.828 million).

DRA points out that if the indirect costs are added to the direct costs of the capital projects (as shown in the table above), SDG&E's total capital expenditures request for 2010, 2011 and 2012 would amount to $260 million, $332 million, and $343 million, respectively. SDG&E's total request over the three years amounts to almost $1 billion.

DRA's recommendations are based on the methodology it used, as well as consideration of the following factors: the state of the economy and that ratepayers should not have to shoulder an unfair burden to produce jobs or to pay for these increases; customers are scaling back their own capital spending and that SDG&E should do so as well; SDG&E's forecasts are too aggressive; and that SDG&E did not provide sufficient support for the capital projects, or that the information provided was difficult to understand or to trace. Due to the number of individual projects, and the tracing problems that DRA encountered in reviewing SDG&E's data, DRA used a "top down" approach of looking at the overall costs in each category instead of analyzing each particular project.

6.3.1.1.2. FEA

The FEA contends that the historical growth patterns do not support the increase that SDG&E is requesting for electric distribution capital expenditures. FEA points out that SDG&E forecasted a 12.5% increase in spending for 2010 over 2009 levels in these six categories, but the recorded 2010 data shows that SDG&E only spent about 4% more in 2010 than it did in 2009.

The FEA recommends a more modest increase in the electric distribution capital expenditures. As its starting point, the FEA uses the recorded 2010 capital expenditures instead of SDG&E's forecasted 2010 amount. The FEA then escalates the recorded 2010 amount by 6% each year for 2011 and 2012. As a result, the FEA recommends electric distribution capital expenditures in 2010 of $175.892 million, in 2011 of $186.446 million, and in 2012 of $197.632 million.[36]

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[36] For the PTY, the FEA recommends the use of the CPI for escalating the PTY capital expenditures.

FEA's total recommended capital expenditures over the three years amount to $559.970 million.

6.3.1.1.3. UCAN

UCAN analyzed SDG&E's capital expenditures request by using a "bottom up" approach of examining individual capital projects in the different categories. UCAN contends that its analysis supplements and supports the "top down" analysis of DRA.

UCAN contends that SDG&E's construction unit forecast is a critical component of SDG&E's forecast of capital expenditures for electric distribution, as well as gas distribution. SDG&E's original construction unit forecast of 9666 for 2012 is close to what was experienced in 2007 (10,471). If SDG&E's forecast was updated using Global Insight's July 2011 forecast of building permits, UCAN contends that the 2007 level of construction units would not be reached until 2014. UCAN also points out that SDG&E's original forecast estimated that there would be 20,607 residential construction units from 2010-2012, but using the July 2011 Global Insight forecast, there would only be 13,984 construction units in that same period. Since the economy has not been doing as well as SDG&E has projected, UCAN recommends that the Commission adopt a later and more realistic forecast of construction units because this will affect capital spending.

6.3.1.1.4. CCUE

CCUE contends that SDG&E's reliability performance "has declined steadily during the current GRC cycle with regard to both the standard SAIDI [system average interruption duration index] and SAIFI [system average interruption frequency index] metrics, as well as SDG&E's new SAIDET [system average interruption duration exceeding threshold] metric." (Ex. 591 at 1.) To provide SDG&E with an incentive to improve its system reliability, CCUE recommends that SDG&E be subject to "either a Reliability Investment Incentive Mechanism (RIIM)-type approach or a performance incentive approach to improving reliability." (Ex. 591 at 1.)

6.3.1.1.5. SDG&E

SDG&E contends that its forecast of capital expenditures for electric distribution should be adopted without the other parties' adjustments. SDG&E contends that its request is justified based on the detailed project summaries it presented for 114 different projects, as well as its responses to data requests. Contrary to DRA's assertion that it presented poor or confusing data, SDG&E contends it used "the most accurate methods for forecasting project costs in the format requested," as described in Exhibit 70 at 3-12. If SDG&E's capital projects are underfunded, it will be unable to fulfill all of its obligations.

SDG&E also contends that the approaches taken by DRA and FEA result "in a decreasing revenue requirement in spite of the strong trend showing otherwise." (Ex. 70 at 2.) Although UCAN took a more detailed approach to its analysis, SDG&E contends that UCAN makes "several false assumptions and fail to properly recognize changes in SDG&E's business environment." (Ex. 70 at 2.)

6.3.2. New Business Category

6.3.2.1. Introduction

The new business category of capital projects covers the construction of the facilities necessary to serve new customers. These facilities involve attachment of the existing distribution system to the customer's meter. The projects in this category also include converting existing overhead electric facilities to underground, and relocation, rearrangements, and removals of existing overhead and underground facilities in conjunction with customer upgrades in service or other customer requests.

For the new business category of projects, SDG&E recommends capital expenditures of $61.604 million for 2010, $80.981 million for 2011, and $89.977 million for 2012. These capital projects cover a wide variety of recurring capital work. Some of the projects are very specific and cover only one type of electric distribution work, while other projects cover a broad range of work.

The capital projects in the new business category were forecasted using different forecasting methodologies. According to SDG&E, historical expenditures were used for the capital projects that are related to new customer activity. For capital projects that are not related exclusively to connecting new customers, different methodologies were used depending on the considerations.

SDG&E has listed 15 projects under the new business category, which are listed in Exhibit 69 at 31-68. Each of the fifteen project categories consist of a variety of projects. The following is a brief description of each of the project categories.

Project 202 covers electric meters and regulators. This project is to purchase the distribution meters and regulators that are needed to operate and maintain the electric distribution system.

Project 204 covers electric distribution easements. This project covers the cost associated with obtaining electric distribution easements, including the costs for surveys, research of land rights, and environmental surveys.

Project 211 covers the conversion of overhead facilities to underground.

Project 214 covers the purchase of the distribution transformers that are needed to operate and maintain the electric distribution system.

Project 215 covers the extensions of the overhead electric distribution system to serve new residential customers.

Project 216 covers the extensions of the overhead electric distribution system to serve new non-residential customers.

Project 217 covers the extensions of the underground electric distribution system to new residential customers.

Project 218 covers the extensions of the underground electric distribution system to new non-residential customers.

Project 219 covers providing the facilities for new electric customers to be served from the overhead and underground distribution system.

Project 224 covers the costs associated with providing that portion of the overhead or underground utility system that runs from the point of connection to the distribution system to the customer's meter panel.

Project 225 covers the costs associated with replacing, relocating, rearranging, or removing existing electric distribution and service facilities as requested by customers.

Project 235 covers the costs of the work related to both new and existing customer installations, and the handling and salvage of scrapped distribution line equipment.

Project 2264 covers the costs of installing utility-owned renewable generation systems as part of the sustainable communities program.

Project 08265 covers the costs of installing conductors, hardware, and other infrastructure associated with primary circuit construction, to extend service to the San Onofre housing project on Camp Pendleton.

Project 09276 covers the costs of modifying the Cannon substation to provide service to the Poseidon desalination plant.

6.3.2.2. Position of the Parties

6.3.2.2.1. DRA

For the new business category of projects, DRA recommends capital expenditures of $43.729 million for 2010, $42.971 million for 2011, and $50.273 million for 2012.

Except for Project 2264 pertaining to sustainable communities, DRA's recommendations for the new business category are based on the use of the following methodology. For the 2010 level of capital expenditures, DRA used the recorded 2010 levels, even if the recorded amount was higher than SDG&E's forecast. DRA then developed the 2012 test year amount using the three-year average of the recorded amounts for 2008, 2009 and 2010. To determine the 2011 levels, DRA used the mid-point between the 2010 recorded and the 2012 test year amounts.

For the forecast of the capital expenditures for Project 2264, the sustainable community energy systems, DRA recommends that SDG&E only receive 50% of its request. DRA contends that the sustainable communities program, which has been in effect for three rate case cycles, no longer needs 100% ratepayer funding. DRA believes that the shareholders or individual customers should share in the cost of this effort. DRA further contends that SDG&E did not analyze or discuss the lessons learned from this program, or what ratepayers have gained from funding this program.

6.3.2.2.2. FEA

FEA recommends capital expenditures of $52.631 million for 2010, $55.789 million for 2011, and $59.136 million for 2012. FEA's recommendation uses the recorded 2010 amount, and annual increases of 6% each year for 2011 and 2012.

FEA contends that the recorded 2010 capital expenditures of $52.631 million was less than SDG&E's 2010 forecast of $61.604 million. SDG&E's 2010 forecast projected it would spend 12.5% more in 2010 over the recorded 2009 amount of $54.726 million. FEA contends that the historical growth patterns do not support the 29% increase in distribution plant additions that SDG&E is requesting. FEA also contends that "customer growth has been sluggish in recent years and may not reach the Company's projections in the attrition years." (Ex. 577 at 28.)

6.3.2.2.3. UCAN

For the seven capital projects that involve new construction, UCAN recommends capital expenditures of $9.943 million for 2010, $16.225 million for 2011, and $22.666 million for 2012.[37] These recommendations reflect UCAN's lower forecast of construction units.

UCAN also recommends that all capital expenditure funding for Project 2264, the Sustainable Community Energy Systems, be terminated.[38] For the 2012 test year, SDG&E is requesting $8.684 million for capital expenditures for this program. UCAN does not believe there is any justification to fund more capital projects. As discussed by UCAN in Exhibit 560, UCAN contends that other than installing additional generating capacity, SDG&E has not demonstrated how ratepayers have benefitted from these investments. UCAN

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[37] In contrast, SDG&E's forecast for these seven capital projects involving new construction is $19.558 million for 2010, $30.037 million for 2011, and $35.446 million for 2012.

[38] As mentioned earlier, UCAN also recommends that the O&M expenses for the sustainable communities program be reduced to the amount necessary to keep the existing systems operating.

also contends that since 2007, other programs such as the California Solar Initiative, has encouraged the development of renewable generation systems and has resulted in more renewable capacity than the sustainable communities program.

6.3.2.2.4. SDG&E

In Exhibit 70, SDG&E disputes DRA's allegations regarding the data and information that SDG&E provided to DRA in connection with the new business category of projects. SDG&E also disputes the interpretation of that data, and the forecasts that DRA and UCAN have recommended as a result of their respective review of that data.

Regarding the funding reductions that DRA and UCAN recommend for the sustainable communities program (Project 2264-Sustainable Community Energy Systems), SDG&E contends that the arguments of DRA and UCAN "are misleading, illogical and inconsistent with State goals." (Ex. 70 at 37.) SDG&E contends that this program "focuses on reducing energy demand and integrating clean energy systems while encouraging sustainable designed buildings," which is consistent with the 2008 update to California's Energy Action Plan which "recognizes it is essential to integrate and coordinate energy efficiency and distributed generation programs to allow customers to gain the largest benefit from their expenditures." (Ex. 70 at 37.) SDG&E also contends that although the primary goal of this program "is to support the development of clean distributed generation systems integrated into the distribution system, it also provides other important benefits by integrating energy efficiency, demand response, distributed renewable energy and sustainable building design." (*Id.* at 38.) SDG&E contends that the Sustainable Community Energy Systems helps "to advance the understanding of distributed generation in the electric distribution system and promote the benefits of energy efficiency, sustainability and distributed clean energy." (*Id*. at 40.) Since these are SDG&E controlled systems, it can control and monitor the systems to analyze distribution impacts and to test various solutions.

SDG&E also points out that under the current program, ratepayers own the Sustainable Community Energy Systems facilities, and receive 100% of the generation output. SDG&E contends that DRA's proposal that the property owner pay for 50% of the project would be not provide a sufficient incentive to the property owner under the current program since all generation output goes to the ratepayers. If shareholders were to pay for 50% of the program costs, SDG&E shareholders would end up co-owning a portion of these facilities with ratepayers. SDG&E also contends that it has complied with the directives in D.04-12-015 by identifying the list of potential projects, and the criteria of how these programs will be selected.

6.3.2.3. Discussion

SDG&E is critical of DRA's recommended reduction to the funding of the new business category of projects because it uses a top down approach instead of a project by project analysis. SDG&E asserts that such a method ignores the specific cost circumstances of certain projects, and understates the amount of capital funding that is required.

Although the top down approach does not analyze each specific project, that same type of an approach is used in many settlements that come before us when the settling parties agree to an overall amount for certain category of costs. In those kinds of settlements, the settling parties need to consider whether, from their viewpoint, the total amount that is agreed upon is fair and reasonable, and if it will provide the utility with sufficient funds to carry out the activities it plans to undertake. In deciding whether a prospective settlement should be adopted or not, the Commission considers whether the settlement is reasonable in light of the whole record, consistent with the law, and in the public interest. (*See* Rules of Practice and Procedure, Rule 12.1(c).) Although there is no settlement in this proceeding, we consider DRA's top down approach using the same kind of analysis, i.e., whether the amount recommended by DRA is fair and reasonable in light of the whole record, and if DRA's amount or some other amount will provide SDG&E with sufficient funds to carry out its planned activities. Thus, we do not reject DRA's recommendation solely on the basis that it uses a top down approach.

The other factor that we need to consider in deciding how much capital funding there should be for the new business category of projects, is customer growth. DRA, FEA, and UCAN all recommend lower funding amounts due in part to the economic downturn and slower customer growth. Although "SDG&E acknowledges that economic conditions have improved more slowly than originally forecast," SDG&E recommends against making isolated updates in the GRC. (Ex. 70 at 36.)

We have reviewed the testimony of all the parties concerning the new business category of projects. Instead of discussing each of the 15 projects that are in the new business category, we also take a top down approach to what an appropriate and reasonable level of capital funding should be.

Based on our review of the projects, the parties' recommendations, and the slow down in customer growth, it is reasonable to adopt capital funding of $52.631 million in 2010, $61 million in 2011, and $71 million in 2012. Our reasons for adopting those levels of funding are described below.

The starting point for capital funding of the new business category of projects is the recorded 2010 data of $52.631 million. Although SDG&E opposes the use of the 2010 data, its use is appropriate under the circumstances as it provides the actual level of spend during that year.

For 2011 and 2012, we have considered the factor of less customer growth, which reduces the number of activities and equipment purchases in the various projects. We have also reviewed and considered the level of activity pertaining to overhead conversions, the undergrounding of distribution systems to serve new customers, and the level of new business infrastructure. All of those projects have been affected by the downturn in the economy, which should result in less activity for those project activities.

In addition, we have considered the parties' recommendations for their requested levels of funding in deciding the level of capital funding that should be adopted for the new business category of projects. DRA's recommendation, when viewed in light of the historical data is too low. The FEA's recommendation of using the 2010 recorded amount is a good starting point, but the incremental growth does not appear to reflect all of the project activities that are being contemplated. UCAN's approach, which focused on the seven capital projects involving new construction, approximate our adopted level of funding for 2011 and 2012.[39]

[39] If UCAN's reductions for the seven capital projects is subtracted from SDG&E's recommendations for 2011 and 2012 (and capital funding for the sustainable communities program is retained), UCAN's 2011 recommendation would amount to $67.169 million, and its 2012 recommendation would amount to $77.191 million.

Our adopted capital funding for 2011 and 2012 also includes reduced funding for the sustainable community energy systems project. Although UCAN and DRA believe that the time is ripe to discontinue funding of new projects, we believe that some funding of these projects should continue through this GRC cycle.

We agree with DRA and UCAN that the sustainable community energy systems project should be wound down, and that future funding of new projects should end after this GRC cycle is completed. By the end of this GRC cycle, the sustainable communities program will have been in existence for about 12 years. Through past funding, and funding in this GRC, the objectives of the sustainable community energy systems as envisioned in D.04-12-015 will have been met. That is, the objectives of "ensuring environmentally sensitive energy solutions, stimulating the distributed generation industry, supporting and partnering with interested developers, and promoting energy and demand savings" will have been fulfilled. (D.04-12-015 at 36.) As UCAN points out, there are other programs that encourage the growth of renewable distributed generation without ratepayer funding. With more customers electing to purchase renewable generation systems, there will no longer be a need for ratepayers to fund additional new projects. By the end of this GRC cycle, SDG&E will have sufficient operational experience and data from this program to draw conclusions about how such systems affect the electric grid, and how such systems can be integrated into the electric grid.

Accordingly, it is reasonable to taper off the funding for new community energy systems for this GRC cycle. SDG&E must begin to plan for the conclusion of the sustainable community energy systems projects as this GRC cycle ends. Since there will still be operational existing community energy systems at the end of this GRC cycle, we will review future O&M expenses for these operational systems in the next GRC filing.

Based on the above discussion of our top down approach to the capital expenditure funding of the new business category, it is reasonable to adopt capital funding of $52.631 million in 2010, $61 million in 2011, and $71 million in 2012.

6.3.3. Capacity Category

6.3.3.1. Introduction

The capacity category covers projects that are required for capacity and substation additions. The capacity projects consist of load transfers, re-conductors, circuit extensions, and new circuits. The substation projects include projects that are required to support the expansion of existing substations, i.e., substation additions, or to construct new substations.

For the capacity category of projects, SDG&E recommends capital expenditures of $19.128 million for 2010, $47.080 million for 2011, and $26.802 million for 2012.

SDG&E has listed 41projects under the capacity category, which are listed in Exhibit 69 at 69-129. These project activities include the following: installation of overhead and pad-mounted shunt capacitors and controls on the electric distribution circuits; immediate corrective action to respond to primary distribution system overload and voltage related issues in which individual jobs cost less than $500,000; site preparation and installation of equipment and other infrastructure associated with distribution substation construction or primary circuit construction; addition of transformers and/or new circuits at various substations or other locations; transfer of load from the Wabash substation by reconfiguring circuits and installing stepdown transformers; installation of new or replacement substation 12 kV capacitors; modification of the Cabrillo circuit 483 in compliance with United States Navy requirements; replacement of copper wire on circuit 520 with a new conductor; and distribution system capacity improvements that cost less than $500,000.

6.3.3.2. Position of the Parties

6.3.3.2.1. DRA

Instead of performing an analysis on each of the 41 projects, DRA reviewed the cost category as a whole and proposes dollar amounts for the entire capacity category, i.e., a top down approach. DRA used the methodology described earlier for deriving its recommendations. For the capacity category of projects, DRA recommends capital expenditures of $25.270 million for 2010, $24.236 million for 2011, and $23.202 million for 2012.

6.3.3.2.2. FEA

FEA recommends capital expenditures of $21.458 million for 2010, $22.745 million for 2011, and $24.110 million for 2012. FEA's recommended funding level for 2010 is based on the 2010 recorded amount for the capacity category of projects, and the 2011 and 2012 funding level reflects annual increases of 6%.

6.3.3.2.3. SDG&E

DRA did not directly rebut specific capacity projects, but instead recommends reductions that are based on a "formula using costs from years 2008-2010." (Ex. 70 at 24-25.) SDG&E contends that DRA's method ignores SDG&E's project specific estimates. SDG&E also points out that the capacity category of projects include the construction of three new substations, and the rebuilding of five other substations.

Regarding DRA's concern that there is a lack of unit data to project costs for substation construction, SDG&E contends that most substation construction costs are site-specific and vary widely due to the type of work that is needed. The cost of the equipment which is placed in the substation is more uniform.

6.3.3.2.4. Discussion

SDG&E has 41projects under the capacity category of projects. The purpose behind these projects is to have a reliable system which can meet current and future customer needs. A review of these projects reveals that circuits need to be added to take the load off circuits which are close to or are already overloaded, and that new substations are being added or existing substations are being rebuilt to meet growth in the area. As described in Exhibit 69, the planning process for these projects takes a long period of time, and many different sources of information and data are considered and analyzed before SDG&E decides which projects are needed.

A major reason for the large increase in the 2012 test year over the 2010 recorded amount is because of the construction of new substations and the rebuilding of existing substations. According to SDG&E, these facilities are needed to serve customer growth and load growth.

We have reviewed all of the testimony regarding the capacity category of projects, and have considered the arguments of the parties. We have also reviewed the 41 projects in the context of the current economy. Based on that review, it is reasonable to adopt a funding level for $19.128 million for 2010. This amount reflects what SDG&E has requested, even though the recorded actual expenditure in 2010 was higher. For 2011 and the 2012 test year, it is reasonable to adopt a funding level of $38 million, and $22 million, respectively. The adopted funding levels for 2011 and 2012 represent a modest reduction from what SDG&E has requested, and reflects the economic downturn experienced during that time period. The adopted funding levels for 2010, 2011, and the 2012 test year all reflect that capital expenditures are needed to ensure the safety and reliability of SDG&E's distribution system, and to meet the capacity needs of its customers.

In footnote 144 of the Applicants' reply brief, SDG&E notes that Project 02252, the Mira Sorrento substation, was to have an in service date of December 31, 2012. SDG&E notes that the in service date was delayed to 2013, and that it would be reasonable to reflect the delay in the in service date of the Mira Sorrento substation to 2013. Based on that, the results of operations (RO) model will reflect the delay in the in service date of this substation to 2013.

6.3.4. Reliability Category

6.3.4.1. Introduction

The reliability category of capital expenditures covers projects which SDG&E believes are needed to maintain or improve the quality and reliability of electric service to its customers. For this category of projects, SDG&E recommends capital expenditures of $55.876 million for 2010, $54.816 million for 2011, and $65.634 million for 2012.

SDG&E's recommended funding would cover 34 capital projects. Among other things, these projects include replacing cable, reconfiguring circuits, improving power quality, installing system automation equipment, rebuilding of existing substations, replacing obsolete distribution substation equipment, and restoring service. These 34 projects are described in Exhibit 69 at 141-195.

6.3.4.2. Position of the Parties

6.3.4.2.1. DRA

For the reliability category of projects, DRA recommends capital expenditures of $49.094 million for 2010, $47.640 million for 2011, and $46.186 million for 2012.

6.3.4.2.2. FEA

The FEA recommends capital expenditures of $50.565 million for 2010, $53.599 million for 2011, and $56.815 million for 2012.

6.3.4.2.3. UCAN

UCAN provided an analysis of various reliability projects, which it described in Exhibit 563. The following is a summary of UCAN's recommendations for these projects.

UCAN analyzed information from SDG&E about the reliability of SDG&E's electrical circuits and concludes that many of SDG&E's "electrical circuits have very poor reliability." (Ex. 563 at 3.) UCAN contends that this information also highlights that there is a "prevalence of underground cable failures," and suggests that instead of replacing the underground cable after it has failed, it "may be more cost effective for ratepayers to replace cable proactively especially on circuits where the [underground] failures are more frequent than normal." (Ex. 563 at 5.) UCAN also points out that several types and vintages of underground cable are more prone to failure, especially unjacketed cable. In light of this cable reliability issue, UCAN agrees that SDG&E's capital expenditure request for the replacement of underground cable in Project 230 is reasonable. For this project, SDG&E requests $10.3 million in 2011, and $11.1 million in 2012. However, UCAN recommends that SDG&E

should proactively replace the worst performing circuits first in order to achieve the greatest reliability benefit for the investment.

For Project 226, which is a blanket project for the management of overhead distribution, UCAN recommends a net capital expenditure budget of $6.300 million in 2011, and $4.200 million in 2012. This is in contrast to SDG&E's net request of $6.671 in 2011, and $5.652 million in 2012. UCAN's recommended amounts are based on its review of the additional costs that SDG&E is requesting in 2011 and 2012 as described in UCAN's Exhibit 563 at 8-9.

UCAN reviewed Project 93240, which is the blanket project covering distribution circuit reliability construction. UCAN recommends $5.9 million in 2011, and $3.6 million in 2012. UCAN notes that Project 93240 consists of expenditures for base reliability, and fire preparedness activities on overhead lines. For the base reliability capital expenditures, UCAN recommends a reduction of $5 million in 2011, and $5.2 million in 2012. UCAN contends that these reductions are warranted because SDG&E's actual expenditures on base reliability averaged $5.735 million during the 2007-2010 period, whereas SDG&E used the 2007-2009 three year average of $8.461 million to derive its base reliability estimate. Regarding fire preparedness reliability activities, UCAN recommends deferring the $13.8 million in fire preparedness projects in 2012 until lower cost alternatives to fire hardening in the Mount Laguna area are considered, such as the building of a microgrid.

6.3.4.2.4. CCUE

CCUE contends that the replacement of wood poles should be at a much faster rate than SDG&E is proposing. CCUE points out that both DRA and UCAN are proposing much lower pole replacement rates than SDG&E. CCUE believes that at least 2,200 wood pole replacements should take place each year, instead of the 1,400 pole replacements that would occur under SDG&E's forecast. To achieve the 2,200 replacements, CCUE recommends that the pole replacement budget be increased to $23.443 million.

CCUE contends that DRA's methodology "ignores reliability data, and focuses solely on historical expenditures," and that DRA's recommendation "would cut the reliability capital expenditures in 2011 and 2012 to less than SDG&E actually spent in 2010." (Ex. 592 at 4.) Although reliability costs trended upwards in 2008-2010, DRA's recommendation results in a downward trend in 2010-2012. CCUE recommends that DRA's recommendation be rejected.

CCUE also opposes DRA's recommended decrease in funding that is associated with unjacketed branch cable. CCUE contends that this type of cable is the cause of about 25% of SDG&E's outages. Although SDG&E has 2,253 miles of this type of cable, in 2009 SDG&E replaced only about 33 miles of this cable. CCUE points out that UCAN accepts SDG&E's proposed expenditure of $10 to $11 million per year for the Project 230 cable replacement. CCUE recommends that the replacement of the unjacketed branch cable be increased to at least 65.4 miles per year, and that the funding for cable replacement be increased from the $10.503 million average to $13.750 million.

CCUE also recommends that the Commission adopt a performance incentive or reliability incentive to ensure that SDG&E does not divert planned reliability investments to shareholders. This issue is discussed under the "Reliability Incentives" section.

6.3.4.2.5. SDG&E

SDG&E points out that DRA's testimony does not contain any substantive discussion of the projects in the reliability category, and that DRA has not justified why DRA's forecasting method is appropriate for this category of projects.

Regarding UCAN's testimony about SDG&E's electrical circuits and outages, SDG&E contends that UCAN's interpretation of this data is misleading and portrays SDG&E's system as unreliable. As for UCAN's recommendation that SDG&E prioritize its cable replacement based on worst performing circuits, SDG&E contends that it already does that based on several criteria as described in Exhibit 70 at 28. SDG&E also contends that UCAN's use of averaging to develop the base reliability estimate of capital expenditures would result in an underfunding of SDG&E's reliability projects.

SDG&E contends that the amount spent on reliability projects have been relatively level, and that the increased request in 2012 is because of Project 93240. A large part of the increase for Project 93240 is due to fire preparedness. UCAN recommends that the spending for Project 93240 should only be $3.600 million, which SDG&E contends is about 40% less than what SDG&E has spent on this project in the past five years.

6.3.4.3. Discussion

The reliability category of capital expenditures covers projects which SDG&E believes are needed to maintain or improve the quality and reliability of electric service to its customers. The 34 capital projects under this category cover projects such as the rebuilding of existing substations, replacement of obsolete distribution substation equipment, cable replacement, reconfiguration of circuits, power quality improvement, system automation through the deployment of SCADA, and restoring service.

We have reviewed the testimony and arguments of the parties regarding the reliability category of capital expenditures. SDG&E's electric distribution system contains a lot of equipment which is more than 30 years old. This equipment requires maintenance or replacement in order to ensure continuing reliability. Some of the substations are also being removed due to the old legacy systems that require high levels of maintenance and skill sets to continue operating. We have also considered the impact on ratepayers if the wood poles were replaced at a higher rate as suggested by CCUE, as well as the fairly level amounts of historical spending in the reliability category of projects. Based on all of these considerations, it is reasonable to adopt funding levels for the reliability category of capital expenditures in 2010 of $50.565 million, in 2011 of $49 million, and in 2012 of $58 million. Funding at these levels should ensure that SDG&E's electric distribution system will continue to operate reliably into the future.

6.3.5. Mandated Category

6.3.5.1. Introduction

The mandated category covers projects that are required to ensure compliance with programs that have been mandated by the Commission and other regulatory agencies.

For the mandated category of projects, SDG&E recommends capital expenditures of $31.999 million for 2010, $35.987 million for 2011, and $34.220 million for 2012.

SDG&E has listed seven projects under the mandated category, which are listed in Exhibit 69 at 196-212. The following is a brief description of each of those projects.

Project 229 covers the activities required to implement SDG&E's corrective maintenance program. This project includes correcting GO 95 and GO 128 infractions in accordance with GO 165 and SDG&E's filed compliance plan.

Project 289 covers the replacement of oil and gas switches, which are inspected and maintained in accordance with GO 165 and SDG&E's filed compliance plan. In addition, this project covers repairs to substructures that are structurally unsound.

Project 1295 covers the cost of sampling and maintaining the data for load research, dynamic load profile, and the CEC study sample.

Project 06247 covers the replacement of live energized front equipment with dead front equipment whenever these facilities are encountered during other work.

Project 09168 addresses voltage deviations at four substations by installing stepped capacitor banks.

Project 10265 covers the installation of protective equipment, or reconfiguration of SDG&E poles, in certain areas to prevent avian wildlife from coming into contact with more than one unprotected overhead wire simultaneously, which can cause an outage and damage the distribution system.

Project 87232 covers pole replacement or reinforcement in accordance with GO 165 and SDG&E's approved compliance plan.

6.3.5.2. Position of the Parties

6.3.5.2.1. DRA

For the mandated category of projects, DRA recommends capital expenditures of $29.294 million for 2010, $26.428 million for 2011, and $23.562 million for 2012.

6.3.5.2.2. FEA

The FEA recommends capital expenditures of $31.153 million for 2010, $33.022 million for 2011, and $35.004 million for 2012.

6.3.5.2.3. UCAN

UCAN recommends capital expenditures for the mandated category of $28.613 million for 2011, and $29.099 million for 2012. UCAN's recommendation is based on its analysis of three projects as described in Exhibit 563 at 11-17.

The first mandated category project that UCAN reviewed was Project 229, which covers the corrective maintenance program. Regular inspections take place as a result of the corrective maintenance program, and replacement equipment is installed if infractions are noted during the inspection. The costs for this project are based on the historical number of infractions found per inspection. UCAN contends that SDG&E used too high of a ratio (1.20) which does not match the historical data. UCAN calculates that the historical ratio is 1.15 infractions per inspection, and notes that the ratio has been declining from 2005-2009, and the 2010 ratio was 1.05. The use of a higher ratio results in higher costs. UCAN recommends that a ratio of no higher than 1.15 be used. UCAN also contends that SDG&E has overforecasted the number of inspections that will be needed. Instead of using SDG&E's number of inspections (73,748), UCAN believes that 65,746 inspections should be used. Based on UCAN's recommended ratio and inspections, UCAN recommends a budget of $7.8 million for 2011and 2012, a 15% reduction of SDG&E's request for Project 229.

The second project that UCAN analyzed was Project 06247, which covers the replacement of live front equipment. UCAN points out that the 2010 recorded spending for this project was $654,000, which was similar to the 2009 amount of $644,059. However, SDG&E is requesting $1.275 million for this project in the 2012 test year. UCAN does not believe SDG&E has substantiated its request for an increase, and as a result UCAN recommends that this project be funded at the historical level of $654,000 in 2011 and 2012.

The third project that UCAN analyzed is Project 87232 which addresses the corrective maintenance program for poles. UCAN does not believe SDG&E has substantiated its request for increased pole replacements. UCAN contends that it is reasonable to expect a workload of 1150 replacement poles and 600 reinforced poles per year. Based on that expected workload, UCAN recommends a budget for this project of $12 million for 2011 and for 2012.

6.3.5.2.4. SDG&E

SDG&E contends that DRA's methodology of averaging the mandated category costs, instead of reviewing each individual project, results in an amount that "does not account for historical trends and completely disregards changes in SDG&E's business environment." (Ex. 70 at 16.)

SDG&E also contends that DRA's assertion that there is no basis for increased inspection levels on Project 229 (Corrective Maintenance Program) ignores that SDG&E is transitioning from one inspection system to another as a result of OpEx, which will result in increased inspections over the next two to three years. In addition, SDG&E contends that more quality control inspections of distribution poles in high risk fire areas are required as a result of D.10-04-047, as well as increased inspections and assessments as required by D.09-08-029.

On UCAN's point that SDG&E has overestimated the number of inspections, SDG&E contends that its forecasted inspections for 2011 and 2012 accurately reflect the work that was performed in prior years.

6.3.5.3. Discussion

The mandated category of capital expenditures addresses the costs of seven projects to comply with programs that are required by the Commission and other regulatory agencies.

We have reviewed the testimony and arguments of the parties concerning the mandated category of capital expenditures. In deciding what the reasonable level of funding should be, we have considered the inspection programs that are required, and what SDG&E plans to do in order to comply with those requirements. We have also considered the contentions of DRA and UCAN that a lower number of inspections should be utilized. Based on all of those considerations, it is reasonable to adopt funding levels for the mandated category of capital expenditures in 2010 of $31.153 million, in 2011 of $32 million, and in 2012 of $30 million.

6.3.6. Franchise Category

6.3.6.1. Introduction

The franchise category covers the projects that are devoted to the conversion of overhead distribution systems to underground, and street or highway relocations, in accordance with SDG&E's franchise agreements.

For the franchise category of projects, SDG&E recommends capital expenditures of $19.060 million for 2010, $19.175 million for 2011, and $18.318 million for 2012.

SDG&E has listed three projects under the franchise category, which are listed in Exhibit 69 at 213-221. Project 205 covers the costs of relocating existing distribution facilities in the streets or highways due to municipal improvements. Project 210 covers the costs of converting existing overhead facilities to underground facilities in accordance with Rule 20A. Project 213 covers the costs of converting existing overhead facilities to underground facilities within the City of San Diego.

6.3.6.2. Position of the Parties

6.3.6.2.1. DRA

For the franchise category of projects, DRA recommends capital expenditures of $6.749 million for 2010, $10.809 million for 2011, and $14.868 million for 2012.

6.3.6.2.2. FEA

The FEA recommends capital expenditures of $18.214 million for 2010, $19.307 million for 2011, and $20.465 million for 2012.

6.3.6.2.3. UCAN

The majority of SDG&E's request for the franchise category of projects is for Project 210, the conversion of overhead lines to underground pursuant to tariff Rule 20A. UCAN recommends a budget of $11.7 million for 2011 and 2012.

UCAN contends that the expenditures for this project have been decreasing from 2005-2010. In contrast, SDG&E is requesting over $14 million for this project for each year in 2010-2012. Although SDG&E forecasts $14.6 million for this project in 2010, the recorded 2010 spending was only $11.7 million.

6.3.6.2.4. SDG&E

SDG&E contends that spending in the franchise category "has been very consistent throughout recent years." (Ex. 70 at 12.) SDG&E contends that DRA's testimony overlooks certain franchise category projects, while UCAN's approach fails to recognize certain changes affecting SDG&E's franchise category costs. SDG&E contends that DRA's recommendation of $32.400 million, and UCAN's recommendation of $50.800 million, for franchise category costs over the three years, will result in SDG&E having very little funding to meet all of its obligations to convert overhead facilities to underground facilities.

6.3.6.2.5. Discussion

The franchise category of capital projects is to address the undergrounding of overhead facilities, or the relocation of facilities, pursuant to SDG&E's franchise agreements.

We have reviewed the testimony and arguments of the parties concerning the franchise category projects. We have also compared the parties' forecasts to the historical costs. DRA's method results in a recommendation that is too low in light of the recorded spend in 2009 and 2010. Based on these considerations, it is reasonable to adopt funding levels for the franchise category of capital expenditures in 2010 of $18.214 million, in 2011 of $17.750 million, and in 2012 of $16.750 million.

6.3.7. Fire Hardening Specifics and AMI Category

6.3.7.1. Introduction

This category covers the projects which do not fall into the other five categories, and are related to fire hardening projects or AMI. These project activities include transferring existing electric distribution conductors from the existing wooden transmission pole to a new steel transmission pole.

For the fire hardening specifics and AMI category of projects, SDG&E recommends capital expenditures of $2.656 million for 2010, $8.036 million for 2011, and $17.479 million for 2012.

SDG&E has listed 14 projects under the fire hardening specifics and AMI category, which are listed in Exhibit 69 at 222-252. Ten of the projects address the rebuild of different tie lines by replacing wood poles with steel poles, transferring the distribution conductors from the existing poles to the new poles, and replacing the distribution conductors as needed. Two of the projects cover the distribution work associated with the replacement of transmission poles, which consist of moving the existing distribution facilities to the new transmission poles. One project is to replace existing overhead distribution in areas of high fire risk by undergrounding the distribution lines. The last project addresses the expansion of SDG&E's test meter farm at Miramar by adding additional meters, and the wiring, framing, and meter sockets to support the meters. The meter farm allows SDG&E's advanced metering operations group to test meter-related hardware and firmware changes for possible impacts.

6.3.7.2. Position of the Parties

6.3.7.2.1. DRA

For the fire hardening specifics and AMI category of projects, DRA recommends capital expenditures of $518,000 for 2010, $346,000 for 2011, and $173,000 for 2012.

Based on its review, DRA contends that SDG&E is proposing a very aggressive schedule for replacing the wood poles with steel poles. DRA notes that SDG&E is requesting a threefold increase over its request in A.06-12-009. DRA's recommendation reflects a more moderate increase for the replacement of these poles.

6.3.7.2.2. FEA

The FEA recommends capital expenditures of $1.871 million for 2010, $1.983 million for 2011, and $2.102 million for 2012.

6.3.7.2.3. UCAN

UCAN points out that DRA recommends that the additional fire hardening projects be deferred until the economy recovers. In addition to that reason, UCAN contends there are three other reasons as to why these fire hardening projects do not warrant funding.

The first reason is UCAN's contention that SDG&E admits that not all of its fire preparedness projects are in the high fire threat zone. One example of this is Project 09139, which UCAN contends is a reliability project rather than a fire hardening project. For that reason, UCAN recommends disallowing the distribution capital expenditure of $206,000 in 2010 for this project.

The second reason as to why fire hardening costs should be less is UCAN's contention that SDG&E has overestimated the actual project costs for both overhead and undergrounding.

UCAN's third reason is its contention that SDG&E has not substantiated its $12.9 million request of Project 10263, which provides for undergrounding in fire threat zones. UCAN contends that there is no estimate of the miles to be undergrounded, the cost per mile, the cost effectiveness of this project, or an analysis of alternatives to undergrounding such as an off grid system. UCAN recommends a budget of $1 million in 2011 and in 2012.

6.3.7.2.4. SDG&E

DRA seeks to reduce funding for Project 87232. SDG&E contends that DRA's recommendation would result in inadequate funding to allow SDG&E to transfer existing distribution conductors to the new steel transmission poles. SDG&E notes that the vast majority of poles that are being replaced in the fire hardening category are transmission poles that use money recovered through transmission rates that are regulated by the FERC.

UCAN has recommended that projects outside of the fire threat zone not be funded. SDG&E contends that the projects outside of the zone have equipment which protects the downstream equipment that is located within the fire zone, and therefore should be funded as part of fire preparedness.

On UCAN's recommendation that SDG&E should consider whether customers should be taken off the grid instead of spending large sums for capital projects, SDG&E contends it has considered using photovoltaic arrays and energy storage systems, but it is not feasible as compared to traditional methods of providing service.

6.3.7.3. Discussion

There are 14 projects under the category of fire hardening specifics and AMI. The recommendations for funding of this category of projects vary greatly from what SDG&E has recommended, and what DRA, FEA, and UCAN have recommended. The differences are due primarily to whether or not SDG&E should fire harden their distribution system by moving distribution equipment onto steel poles, and whether SDG&E should underground overhead facilities in high fire zones.

We have reviewed the testimony and arguments of the parties concerning this category of projects. In addition, we have also considered the fire safety aspects of SDG&E taking proactive steps to harden its distribution system in order to minimize the fire danger in high fire zones, while balancing the cost impact on ratepayers in the current economic environment. We have also considered whether an off-grid system would be more cost effective, but are not persuaded that it would be. Although the costs associated with fire hardening are high, such projects will ultimately benefit those who live and work in those communities when wires and cables are transferred onto steel poles, or the overhead facilities are placed underground. Based on all these considerations, it is reasonable to adopt funding levels for the fire hardening and advanced metering infrastructure category in 2010 of $1.871 million, in 2011 of $6 million, and in 2012 of $14 million.

6.3.8. Reliability Incentives

6.3.8.1. CCUE Proposal

CCUE recommends that the Commission adopt in this GRC a performance incentive approach, or a RIIM to improve SDG&E's reliability of providing service to its customers.

As described in Exhibit 591, CCUE contends that monetary reliability incentives work based on its analysis of the performance of SDG&E and Pacific Gas and Electric Company (PG&E) without performance incentives. CCUE contends that over the period of 2008-2010, "SDG&E's frequency and duration of outages has gotten steadily worse" without performance incentives. (Ex. 591 at 14.)

The issue of incentives for reliability performance was previously addressed by the Commission in D.08-07-046. In that decision, the Commission authorized a reliability incentive using four different performance incentives. The first performance incentive is the SAIDI. The SAIDI measures the minutes of sustained outages over five minutes long per customer per year. The second performance incentive is the SAIDET. The SAIDET represents the SAIDI minutes experienced by customers for outage durations beyond an annual interruption minute threshold. The third performance incentive is the SAIFI, which measures the number of sustained outages per year. The fourth performance incentive is the Estimated Restoration Time (ERT). The ERT provides affected customers with an estimated time of service restoration that is within one hour of the actual restoration time.

SDG&E was allowed in D.08-07-046 to accept or decline the authorized incentive mechanisms. SDG&E declined to have the incentive mechanisms apply to it.

CCUE recommends that SDG&E should be subject to the performance incentives that were adopted in D.08-07-046, using the targets that would have been in effect in 2010. The following are CCUE's recommended reliability performance incentives.

	SAIDI	SAIFI	SAIDET
Target	61.4	0.55	30.7
Deadband	+/- 2	+/- 0.02	+/- 2
Increment	1	0.01	1
Units	minutes	outages	minutes
$/increment	$250,000	$250,000	$175,000
Maximum Award	$2,000,000	$3,750,000	$1,750,000
Annual Improvement	5%	0.03	5%

Alternatively, CCUE recommends that a RIIM-type mechanism be adopted for SDG&E. CCUE notes that in D.06-05-016, the Commission approved a stipulation which created a RIIM for SCE. That RIIM was subsequently modified and updated as a result of a stipulation that was adopted in D.09-03-025.

CCUE proposes a RIIM mechanism that is similar to what was adopted for SCE. The mechanism would identify and "approve the categories of capital investments for infrastructure replacement and the like that are considered electric and gas safety and reliability-related." (Ex. 591 at 19-20.) These categories of capital investments would be similar to the categories that were identified for SCE's RIIM as Category A. In addition, SDG&E's RIIM would approve the categories of capital expenditures that are considered obligatory and not under the direct control of SDG&E, similar to SCE's Category B.

CCUE recommends that the Commission require SDG&E to file an AL in which SDG&E would identify the Category A and Category B expenses. The expenditure levels that the Commission adopts would then be used to quantify the Category A and Category B amounts. The RIIM would then be implemented over the full GRC cycle "to allow SDG&E time to identify over- or under-expenditures in Category B, and adjust its Category A expenditures accordingly." (Ex. 591 at 20.) Any under spending by SDG&E of the RIIM targets would be rebated to ratepayers.

CCUE also proposes that the RIIM for SDG&E should also "identify a required number of net new hires for the job categories relevant to reliability, and a penalty rate for any shortfalls." (Ex. 591 at 20.) CCUE also "proposes that the new hire target for represented electrical and gas workers be 40 per year for each year of the GRC, while the overall RIIM employee target would be 40 per year minus the number of retirements." (Ex. 591 at 20-21.)

CCUE contends that imposing a RIIM on SDG&E will solve the problem of SDG&E overestimating its costs. If a RIIM is adopted and authorized funding is at or near SDG&E's recommended level of funding, any money that SDG&E does not spend on reliability will be returned to ratepayers. If a lower level of funding is adopted than what SDG&E recommended, and this amount is insufficient to carry out the reliability projects, then SDG&E will have to make up the shortfall from shareholders' profits or by diverting monies from other categories.

6.3.8.2. Position of the Other Parties

6.3.8.2.1. UCAN

As part of SDG&E's incentive compensation plan, UCAN recommends that the metric of reliability be included as part of the reliability performance measure. UCAN recommends that the SAIDI and SAIFI scores be used. For SAIDI, UCAN recommends 59.46 minutes, and for SAIFI, UCAN recommends 0.52 outages. CCUE contends that these two UCAN numbers could be substituted for the targets used in CCUE's reliability incentive described above if the Commission approves increased spending in reliability-related areas.

6.3.8.2.2. SDG&E

SDG&E agrees with CCUE's overall position that SDG&E needs "the proper resources available to safely and reliably operate and maintain the electric system," and that it has and continues to invest significant financial and human resources to achieve reliability. (Ex. 63 at 56.) Even though the performance based ratemaking incentives ended in 2007, SDG&E contends that this has not slowed down its reliability efforts. SDG&E points out that one example of this effort was the creation of a group called the RIRAT, which concentrates on the development of concepts, designs, and standards to improve the safety and reliability of circuits in rural areas and in high fire zone areas.

SDG&E contends that it has embraced balanced incentive mechanisms in the past, and is willing to consider them again in the future. However, SDG&E does not agree with CCUE's proposal to use a reliability incentive metric that was developed in the past, or a RIIM-type mechanism. SDG&E contends that the RIIM was designed for SCE which had problems that SDG&E does not have. In addition, SDG&E contends that no reliability incentives are needed at this time because it is proposing in this GRC "to continue to devote significant amounts of funding toward reliability as demonstrated by its current actions and by its reliability related requests in this current GRC." (Ex. 63 at 57.)

6.3.8.3. Discussion

Based on the data supplied by SDG&E, using the reliability metrics that were developed in D.08-07-046, CCUE contends that SDG&E's reliability has gone down during the time performance incentives have not been in place. To rectify that situation, CCUE proposes that the reliability incentive that was developed in SDG&E's prior GRC be adopted for use in this proceeding, or in the alternative, that the Commission adopt a RIIM-type mechanism for SDG&E.

In deciding whether these incentive mechanisms should be adopted at this time, we address whether there is a need for such a mechanism. Based on the testimony that was presented, there are two arguments as to why an incentive mechanism should be considered. The first argument for adopting an incentive mechanism is that SDG&E acknowledges in its testimony "that it has experienced a slight decrease in reliability performance over the last three years even though it devoted significant resources and investment toward reliability during that period." (Ex. 63 at 56.) That statement suggests that either SDG&E is not doing enough to ensure the reliability of its system, or that there were other factors which caused the reliability metrics to worsen. SDG&E's rebuttal testimony suggests that the decrease in reliability may be due to the "unpredictable weather and aging infrastructure," or that it may be due to inadequate resources and funding. (Ex. 63 at 56.)

The second argument for adopting an incentive mechanism is that the data from the reliability measures which CCUE analyzed in Exhibit 591 suggests that reliability has declined when no performance incentives have been in place.

However, aside from seeking increased funding for certain capital expenditure projects, neither CCUE nor SDG&E provided any other information as to why they believe reliability performance declined during 2008-2010. Nor has CCUE or any other party suggested that other types of tools or additional oversight are needed to ensure that the necessary reliability measures are being carried out.

CCUE recommends that the Commission "should simply reinstate for 2012 the performance incentives" and parameters that were developed in SDG&E's prior GRC in D.08-07-046. (Ex. 591 at 17.) Under CCUE's recommendation, the targets for SAIDI, SAIFI, and SAIDET would be updated to those that would have been in effect in 2010 under D.08-07-046. According to CCUE, leaving the targets at the 2010 levels are "doubly generous" to SDG&E, and leaving "the maximum award and penalty unchanged is also conservative." (Ex. 591 at 18.) This statement suggests that the performance incentives may need to be updated before the Commission imposes a performance incentive on SDG&E, as evidenced by SDG&E's statement that it is opposed to the performance incentive adopted in D.08-07-046 because it is uses "outdated reliability incentive metrics of the past." (Ex. 63 at 57.)

CCUE's alternative recommendation is for the Commission to adopt a RIIM-type mechanism for SDG&E. This mechanism would be modeled after the RIIM mechanism that was originally adopted for SCE in D.06-05-016 and revised in D.09-03-025. SCE's RIIM identifies certain categories of capital expenditures that are related to long term electric service reliability. SCE's RIIM also contains a staffing component whereby SCE must hire a certain number of field people, with a penalty if this requirement is not met. The RIIM commits SCE to spending the Commission authorized funding for these categories of projects, and any under-spending of the RIIM is to be refunded to ratepayers with interest at the end of the GRC cycle. CCUE proposes that the details of which categories of projects should be the subject of the RIIM should be left to an AL filing. For SDG&E's staffing component of the RIIM, CCUE recommends "that the new hire target for represented electrical and gas workers be 40 per year for each year of the GRC, while the overall RIIM exployee target would be 40 per year minus the number of retirements." (Ex. 591 at 20-21.)

Based on the information that is before us, we do not adopt CCUE's recommendation to impose performance incentives or a RIIM-type mechanism on SDG&E. The primary reason why we do not adopt CCUE's recommendation is because none of the parties have demonstrated that either of these two mechanisms will help solve the decline in reliability that was measured from 2008-2010. There is insufficient evidence before us to determine what caused the reliability measures to decline. The decline in reliability could have been due to a number of different reasons, such as weather-related factors, inadequate levels of authorized funding, prioritization of projects, or because the monies for reliability-related projects were not used for that purpose.[40] To adopt and impose a mechanism on SDG&E for the apparent purpose of improving reliability is not warranted at this time without an understanding of what caused the reliability measures to decline.

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[40] As described by SDG&E in Exhibits 69 and 222, all proposed capital projects undergo an extensive review process, including a review of how the projects can improve system reliability and performance. If reliability measures continue to decline, the capital project review process might need to be evaluated to determine if the process for reviewing reliability needs to be revised.

Another reason for not adopting CCUE's recommendation at this time is because we have authorized reliability-related funding at levels close to what SDG&E has requested. This is consistent with our review of the projects and the activities that SDG&E plans to carry out to enhance reliability, and well as our obligation to ensure that the utilities provide safe and reliable utility service. Over the course of the 2012 test year rate cycle, the reliability measures can track whether the authorized level of funding helps to improve or to worsen the reliability measures. In addition, steps can be taken by SDG&E to determine what other factors may be causing the reliability measures to worsen or to improve. Analyzing the causes behind the lack of reliability can assist the Commission in developing better tools or mechanisms to improve reliability. Accordingly, we do not adopt CCUE's recommendation to adopt and impose performance incentives or a RIIM-type mechanism on SDG&E in this GRC.

However, we will require SDG&E to continue collecting the SAIDA, SAIFI, SAIDET, and ERT data over the course of this rate cycle. This will provide the data on the number of, and length of, the outages, and the time it takes to restore service. In addition, SDG&E shall also be required to keep a record of the cause of the outages.[41] In its next GRC filing, SDG&E shall be required to include a discussion and a summary of the reliability measures, with a comparison to the data from the two prior GRC cycles. Also, a summary of the cause of the outages shall be included in the next GRC filing, along with a discussion of the trends that were observed. SDG&E shall also be required to include in that filing whether an incentive-type mechanism should be adopted during that GRC cycle

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[41] We assume that SDG&E already tracks this type of information as to the cause of each outage.

to help improve reliability. If so, SDG&E shall describe how such a mechanism will help to improve reliability, and the details of how such a mechanism should operate. Other parties can then respond to SDG&E's proposal or offer their own proposals based on SDG&E's data and discussion.

Even though we do not adopt an incentive mechanism for reliability in this proceeding, we remind SDG&E that it has a continuing obligation under Pub. Util. Code § 451 to provide safe and reliable service.

6.4. Smart Grid

6.4.1. Introduction

As part of its electric distribution operations, SDG&E plans to invest in smart grid capital projects. This sub-section addresses SDG&E's request for funding of the capital projects related to the smart grid, as well as the O&M costs associated with the smart grid team.[42] For the capital-related smart grid costs in test year 2012, SDG&E estimates funding of $55.252 million.[43] For the O&M costs for the smart grid team, SDG&E forecasts $1.003 million in test year 2012.

6.4.1.1. O&M Costs

The smart grid team is responsible for SDG&E's smart grid strategy and policy across all of SDG&E's operations, and for coordinating the adoption and implementation of the smart grid technologies. The smart grid team consists of a director and five other employees. Since its formation in 2009, this unit has been

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[42] Other smart grid-related costs, such as information technology and upgrading of voltage infrastructure, are discussed elsewhere in this decision.

[43] The $55.252 million excludes the funding for the expansion of condition-based maintenance, which SDG&E withdrew. For 2011 and 2012, SDG&E's total estimated funding for the capital projects listed in this sub-section is $91.820 million.

developing SDG&E's smart grid strategy and policy, and providing assistance and support for Commission proceedings relating to the smart grid.

Funding in the amount of $1.003 million is requested in test year 2012 for the O&M costs related to the smart grid team.

6.4.1.2. Capital Projects

As renewable generation and PEVs increase in relationship to the local load on the system, SDG&E expects that these events will impact its electric system operations and reliability. To mitigate these impacts, SDG&E plans to undertake projects which incorporate smart grid technologies into the electric system infrastructure. The goal of using these smart grid technologies is to maintain and/or improve system performance and operational flexibility and reliability.

Some of the capital projects are also being integrated with the work that is being done to harden SDG&E's overhead electric system in high fire threat zones. According to SDG&E, the smart grid sensor technology, and advanced system monitoring and control features, can be used to provide more operational flexibility, improve reliability, and reduce the fire risk.

The smart grid capital projects are grouped into the following four categories: renewable growth, electric vehicle growth, reliability, and smart grid development. SDG&E's estimated capital expenditures for these capital projects are shown in the table below.

(Thousands of 2009 dollars)[44]

Project	2010	2011	2012	Total
Energy Storage	$0	$25,193	$29,790	$54,983
Dynamic Line Ratings	$0	$1,963	$1,963	$3,926
Phasor Measurement Units	$0	$1,475	$2,581	$4,056
Capacitor SCADA	$0	$2,902	$2,902	$5,804
SCADA Expansion	$0	$0	$4,699	$4,699
PEVs	$0	$0	$0	$0
Smart Transformers	$0	$2,047	$521	$2,568
Public Access Charging Facilities	$0	$0	$5,230	$5,230
Wireless Faulted Circuit Indicators	$0	$1,302	$2,199	$3,501
Phase Identification	$0	$1,184	$4,027	$5,211
Integrated Test Facility	$0	$502	$1,340	$1,842
Total	$0	$36,568	$55,252	$91,820

The following is a brief description of each of these capital projects.[45] The energy storage project is to assist in addressing the intermittency issues created by variable renewable generation. Two types of energy storage will be used. Community energy storage devices will be used in "circuits where the penetration of PV is 20% or more of the circuit load at times of high photovoltaic system output and low circuit loads…." (Ex. 122 at 20-21.) Substation energy storage "will be installed to mitigate the effects of utility scale (up to 2 MW) PV projects that will be installed in various locations." (Ex. 122 at 21.)

44 The condition-based maintenance expansion capital project is not reflected in this table because SDG&E withdrew this project. The cost associated with the PEVs is shown as zero because the proposed upgrade of the primary and secondary voltage infrastructure is reflected in the electric distribution capital projects.

45 Each of these capital projects are described in more detail in Exhibit 122.

The project for dynamic line ratings is to install dynamic line rating technologies on 10 distribution circuits per year. Dynamic line ratings "compare the weather-adjusted, thermal rating of a conductor against the static design rating," which along with other sensors, allows the utility "to calculate the amount of current that can be transmitted in real time." (Ex. 122 at 21-22.)

The phasor measurement units technology uses high speed, time-synchronized measurement devices at substations and at key points on the distribution system to identify "changes in PV output and enable the dispatch of energy storage devices to counter act the effects of the PV output fluctuation." (Ex. 122 at 23.) SDG&E plans to install this equipment on four distribution circuits in 2011, and seven circuits in 2012, where there is a high concentration of PV systems.

The capacitor SCADA project is to install SCADA devices on capacitor controllers. According to SDG&E, these "SCADA controlled capacitor banks will provide local and remote control, failure prediction and detection, reduced operating cost, and should enhance distribution system performance through improved voltage and reactive power control." (Ex. 122 at 24.) SDG&E has about 1400 capacitors out in the field. SDG&E plans to add SCADA devices on all of these capacitors over a seven year period.

The SCADA expansion project is to install more devices to allow for the remote operability and automated operation of SCADA capable switches. According to SDG&E, this will provide "faster isolation of faulted electric distribution circuits and branches, resulting in faster load restoration and isolation of system disturbances." (Ex. 122 at 25.) SDG&E estimates that this project "will require installation of SCADA at 13 substations serving 76 circuits, and 281 SCADA switches on circuits that lack SCADA line or SCADA tie switches." (Ex. 122 at 26.)

The PEV capital project is to upgrade the primary and secondary voltage infrastructure to accommodate the use of PEVs in SDG&E's service territory. SDG&E plans to evaluate the voltage infrastructure of customers who have PEVs to determine if there is adequate capacity. If upgrades are needed, that upgrade would be covered under this project. The cost of these upgrades is included in the electric distribution capital projects.

The smart transformers project is to install "sensors and technology on distribution transformers so that they can monitor and report loading, and the state of the transformers." (Ex. 122 at 27.) According to SDG&E, this project will allow for the monitoring of the load and condition of transformers feeding PEVs, provide information about the state and condition of the transformer, and facilitate dynamic ratings of the transformers. Under this project, SDG&E will install monitoring devices on all the transformers serving customers with PEVs.

The project for public access charging facilities is to install utility-owned, public access charging facilities for PEVs in under-served areas. According to SDG&E, this project will "provide PEV charging facilities in locations that are not necessarily commercially or economically desirable, but needed to serve the broader and growing PEV charging needs of the public." (Ex. 122 at 28-29.) Persons using these charging facilities would pay an applicable PEV tariff that would be developed.

The wireless faulted circuit indicators allows for remote monitoring of faulty circuits, and "is expected to provide rapid identification and location of faulted distribution circuits resulting in reduced outage and repair times." (Ex. 122 at 31.) Under this project, SDG&E plans to install these devices on all non-SCADA switches and all cable poles with switches in the distribution system over a five year-period (2011-2015).

The phase identification project is designed to accurately identify the phase of the new distribution operating system. This project will identify the phase to which each transformer is connected, and the phase of each conductor. SDG&E anticipates that this project will provide for improved worker safety, more accurate selection of fuses, impose the sizing of circuit capacity, and reduce system losses. The majority of this work is anticipated for 2012 and 2013.

The integrated test facility project is to build a facility and to purchase equipment for the "testing of the integration of multiple complex hardware and software systems comprising Smart Grid technologies." (Ex. 122 at 35.)

6.4.2. Position of the Parties

6.4.2.1. DRA

DRA recommends that $20.149 million be adopted for the funding of SDG&E's smart grid projects.

DRA acknowledges the need to improve and upgrade the existing electric delivery system, but disagrees with SDG&E about how to create the optimal result. Instead of spending the monies to move ahead with SDG&E's aggressive smart grid projects, DRA takes a more cautious approach of evaluating what is being done already, and how SDG&E can be better organized before large ratepayer-funded smart grid expenditures are undertaken. DRA believes that before ratepayer money is spent on smart grid projects, that one must ensure that the money is being "spent appropriately and effectively to realize the true value of the investment being made." (Ex. 487 at 2.) Given the current economic conditions, DRA contends that "the Commission must use restraint and mindfulness when setting revenue requirements." (*Ibid*.)

DRA points out that the Commission has an ongoing smart grid proceeding in R.08-012-009, and that the California utilities have received federal monies to modernize the electric grid. According to DRA, the smart grid technical solutions and policy guidelines are still being formed. Instead of speeding ahead, and before large sums of money are authorized for the smart grid, DRA believes that the following steps are necessary: (1) learn from the many smart grid pilot programs that are currently underway; (2) utilize one-way balancing accounts for the pilot programs that are approved; (3) create a meaningful message about the smart grid for customers; and (4) refrain from signing blank checks to the utilities because the smart grid is considered to be the solution. (*See* Ex. 487 at 7.)

SDG&E filed its Smart Grid Deployment Plan in A.11-06-006 in June 2011. DRA notes that SDG&E's estimated cost of the smart grid deployments is $3.5 billion over the period of 2006-2020, and that SDG&E has already spent monies on smart meters and OpEx.

The energy storage capital projects make up the majority of the funding costs of SDG&E's smart grid projects. SDG&E requests $25.193 million in 2011, and $29.790 million in 2012. DRA recommends funding of $4.500 million in 2011, and $6.200 million in 2012. DRA acknowledges that "storage is an important contributor to the electric system," and that the Commission opened R.10-12-007 analyze the opportunities to develop and deploy energy storage technologies in California's electric system. (Ex. 487 at 10.) DRA also notes that there are 16 projects nationwide that have received funding for studying and testing of various energy storage technologies. Due to the ongoing energy storage rulemaking and these projects, DRA recommends scaling back the size of SDG&E's energy storage capital projects.

For the dynamic line ratings, DRA recommends funding of $392,600 in 2011, and in 2012, instead of SDG&E's recommendation of $1.963 million in each year. Instead of SDG&E's proposal to install dynamic line rating technology on 10 distribution circuits per year, DRA recommends that only two circuits per year be done. DRA contends that there are existing projects that are looking into reducing system losses, improving system reliability, and optimizing grid operations.

For the phasor measurement units project, DRA recommends funding of $368,750 in 2011, and in 2012. DRA contends that there are 10 transmission projects that received funding that is related to the installation or increased use of phasor measurement devices, and that these projects "are aimed at finding ways to improve monitoring, improve critical decision making on the grid operations, reducing congestion and integrating renewables." Instead of SDG&E's deployment of 11 of these devices over two years, DRA recommends that only two devices be installed.

For the two SCADA-related projects, DRA recommends a slower rollout than what SDG&E proposes. DRA also notes that SDG&E's transmission system is 95% controlled by SCADA, and that SDG&E has requested funding in the past to expand its distribution SCADA. DRA recommends funding of $1.450 million in 2011, and in 2012, for the capacitor SCADA project. For the SCADA expansion, DRA recommends funding of $2.980 million in 2012.

For the smart transformers related to PEVs, DRA contends that the rollout of PEVs will be more modest than SDG&E has predicted. DRA recommends funding of $521,000 in 2011, and in 2012.

For the public access charging facilities, DRA recommends zero funding for this project. DRA contends that it cannot support the use of ratepayer funds for such a project until larger volumes of PEVs are located in SDG&E's service territory, and more information concerning PEVs can be obtained.

For SDG&E's wireless fault indicators, DRA recommends zero funding for this project. DRA contends that this is not a "must have" technology, and should not be pursued in the current economic environment.

DRA recommends zero funding the phase identification project. DRA's disallowance is based on the limited information that SDG&E provided about this project. DRA is uncertain about what needs to be done, what will be installed, and the number of places where this will be done.

For the integrated test facility project, DRA acknowledges the need to have a facility to test smart grid-related products. However, with the delay in reaching national standards, DRA contends that such an effort should be slowed down. DRA recommends funding of $500,000 in 2011 and in 2012.

DRA also recommends that customers need to be made aware and educated about the smart grid projects that are being undertaken, and that concerns about privacy, personal information, and security need to be addressed.

6.4.2.2. FEA

FEA is concerned that a large portion of the total projected costs of the smart grid projects, as described in SDG&E's Smart Grid Deployment plan, are being requested in this proceeding. FEA contends that SDG&E's smart grid proposals "are too aggressive at this point in time," and recommends that these projects be pursued "in a separate proceeding when more direction from the Commission regarding specific initiatives has been formalized and such costs are more definitive and fully supported." (Ex. 577 at 40.)

The FEA also contends that SDG&E "has acknowledged that the costs and benefits [of the smart grid projects] are difficult to project at this point," and that instead of "rushing into billions of dollars of spending on unproven technology, the Commission and the utilities should proceed with Smart Grid investment at a more steady and cautious pace to assure that money on Smart Grid charged to ratepayers is spent reasonably." (Ex. 577 at 36, 39.) FEA also points to other state decisions where smart grid costs were rejected or reduced.

6.4.2.3. UCAN

UCAN recommends that SDG&E's smart grid request be reduced from a total of $91.820 million to $19.929 million. As discussed in the PTY ratemaking section of this decision, UCAN also recommends that SDG&E's smart grid proposals be reduced by $120.497 million in 2013, 2014, and 2015.

UCAN contends that it "has long championed the deployment of a Smart Grid in San Diego." (Ex. 568 at 4.) However, UCAN became concerned about SDG&E's "large and seemingly underutilized investments" in the smart grid over the past five years, and retained a consultant "to evaluate SDG&E's methodology by which it makes 'Smart Grid' investments in the context of this GRC application." (Ex. 568 at 5.) UCAN's consultant concluded that "SDG&E has not applied a reasonable process by which it decides to make Smart Grid investments and has not presented sufficient support for any of its proposed 2012-2015 Smart Grid investments." (*Ibid*.)

UCAN contends that SDG&E's approach and methodology for evaluating whether a smart grid investment should be made is deficient. Before smart grid investments are undertaken and funded by ratepayers, UCAN believes that SDG&E should adhere to the following considerations.

UCAN contends that SDG&E's approach did not identify the benefits and goals of making such an investment, and that without a "complete understanding of what technology is available and what it can accomplish, utilities deploy equipment that severely restricts what can be accomplished within a 'Smart Grid' design." (Ex. 568 at 7.) SDG&E also contends that without targeted goals and measurable metrics, there is insufficient justification for ratepayers to fund such projects. UCAN cites to D.07-04-043 as an example of how SDG&E's advanced metering infrastructure project could have been leveraged to provide "improvements to overall systems operation," such as a voltage management, and other data that smart meters can provide. (Ex. 568 at 9.) UCAN also contends that SDG&E is still in a position to take advantage of the smart meter data, but SDG&E "has not yet developed the analytics to actually make use of this valuable information…." (Ex. 568 at 17.) Before additional costs are paid for by ratepayers, UCAN contends that SDG&E should assess how the data from the smart meters can be used by SDG&E to assist utility operations.

UCAN also contends that SDG&E did not attempt to quantify the cost effectiveness of the smart grid projects. An example of this is SDG&E's proposal to install recharging stations for PEVs. UCAN contends that SDG&E did not provide "any evidence that the demand currently or is expected to exist." (Ex. 568 at 11.) UCAN suggests that these stations are unnecessary because most charging can be done at home since the "average daily mileage driven by San Diego residents is 23.7 miles…." (*Ibid*.) UCAN also points out that ECOtality received a grant to deploy over 1,400 public charging stations in SDG&E's service area, and that Costco recently decided to remove its charging stations due to limited usage by owners of PEVs. With the trend toward plug-in hybrid electric vehicles, UCAN contends that this will further reduce the need for public charging stations since owners of such vehicles can rely on a gas engine for backup power.

UCAN believes that this cost effectiveness approach should also be used for SDG&E's proposal for smart transformers for electric vehicles. Instead of spending money on transformer upgrades, UCAN contends it is more cost effective to use smart meter data and load analysis to determine whether a transformer serving a PEV needs to be upgraded.

UCAN suggests that pilot programs could be undertaken before full funding of a smart grid project is authorized. However, before a pilot program is authorized, there should be plans for the pilot program, measurable goals or metrics to measure the success of the pilot, and a methodology or plan by which SDG&E will assess the pilot program and whether such a technology or product should be fully deployed.

UCAN agrees with SDG&E that the growth in renewable generation must be planned for and managed so that it does not negatively affect the grid. However, UCAN contends that SDG&E has created a sense of urgency that the issues related to distributed generation, especially photovoltaics, must be addressed immediately. Instead of SDG&E's use of energy storage, dynamic line ratings, phasor measurement units, capacitor SCADA, and SCADA expansion to manage the growth of renewable generation, UCAN suggests a different approach. First, SDG&E should perform an impact study to determine to what extent photovoltaic installations are causing system stability and reliability issues. UCAN believes that such a study will provide the baseline to establish the current state of SDG&E's system. UCAN points out that residential photovoltaic generation is less likely to cause system reliability problems than commercial or utility generation since residential customers are likely to use the energy within their own homes. UCAN also recommends that "SDG&E evaluate integrated control systems to accommodate renewable generation before investing heavily in other projects," and to review the technology, software, and approaches that are being used in Germany and Spain to manage and control the high usage of photovoltaic generation. (Ex. 568 at 26.)

Second, UCAN contends that SDG&E should use "their SCADA enabled line switches and SCADA capacitor banks" to regulate voltage, which can help manage the potential intermittency problems associated with photovoltaic generation. UCAN contends this will enable SDG&E to "track the operation of the electrical system in real-time and can be used to control aspects of the electric system through functions such as voltage adjustment, line switching, and demand management." (Ex. 568 at 24.)

As described in more detail in Exhibit 568, UCAN recommends partial funding for some of the smart grid projects, subject to SDG&E performing the impact study and meeting other conditions as outlined in the considerations mentioned above. UCAN recommends total funding of the smart grid projects in the amount of $19.929 million, which consists of the following: (1) $12.137 million for a limited energy storage pilot project to test the energy storage project; (2) $1.770 million for a limited pilot project involving phasor measurement units; (3) $58,040 for a limited capacitor SCADA pilot project; and (4) zero funding for the dynamic line ratings project, the voltage infrastructure upgrades related to PEVs, the smart transformers associated with the PEVs, the public access charging facilities, the wireless fault indicators, phase identification, and the integrated test facility.

Regarding SDG&E's PTY smart grid expenses, UCAN recommends that SDG&E's PTY request of $141.7 million be reduced by $120.5 million.

6.4.2.4. SDG&E

SDG&E contends that there are four drivers behind its smart grid proposals.

The first driver is the growth in renewables. When SDG&E first drafted its testimony, the photovoltaic generation owned by customers was approximately 65 MW. At the time SDG&E' rebuttal testimony was prepared around September 2011, that generation grew to 110 MW. According to SDG&E, this growth exceeds what the CEC had forecasted. Since that time, SDG&E also notes that Senate Bill 32 was signed into law which created a feed-in tariff program for photovoltaic generation up to three MW in size, and that in D.10-12-048 the Commission approved a renewable auction mechanism for photovoltaic generation of 1 to 20 MW. As a result of the higher penetration of photovoltaic generation, SDG&E contends that this impacts the voltage, and has a negative impact on operations and customer.

The second driver behind SDG&E's smart grid projects is the growth in PEVs. As of September 30, 2011, there were about 820 Nissan Leafs in SDG&E's service territory, 549 installed residential chargers, and 23 installed public chargers. By the end of 2012, SDG&E expects 57 models of PEVs to be available.

The third driver of SDG&E's smart grid projects is its obligation to provide reliable service to its customers. SDG&E contends that intermittent renewable resources and electric vehicles will affect the reliability of its electric service. SDG&E also contends that it has an aging infrastructure, and a need to improve its fire preparedness.

The fourth driver of its smart grid projects is that there is a need "to test the function of new consumer focused technologies on the installed smart meters and associated systems to enable Smart Grid characteristics." (Ex. 125 at 2.)

SDG&E contends that smart grid technologies, solutions, and standards are rapidly evolving, and that it needs a "test facility to address equipment standards, integration and interoperability challenges for these technologies." (Ex. 125 at 9.)

SDG&E contends that its approach to the smart grid is based on engineering judgment and undisputed facts, and that these projects should proceed ahead instead of being slowed down. Although there are Commission proceedings and grant-funded projects going on, SDG&E contends that its customers are going ahead with the adoption of distributed energy resources and renewable generation, and the purchasing of PEVs. Due to the growth in renewables and PEVs, voltage and other problems may result and impact service quality if these projects are not addressed and pursued.

As for the grant-funded projects, SDG&E contends that more than half of this funding is supporting smart meter projects, and only about 9% of these projects have a connection to SDG&E's smart grid projects. SDG&E also contends that many of these grant-funded projects looking into energy storage and dynamic line ratings, are taking place outside California and may not be relevant to SDG&E's system. Also, SDG&E contends that due to the growth in photovoltaic generation, it "cannot wait for the results and lessons learned by other utilities." (Ex. 125 at 18.)

As for DRA's concern over a lack of standards, SDG&E contends that waiting "for consensus standards to be developed and adopted is counter-productive and will impact SDG&E's ability to maintain a reliable grid in the face of the challenges presented by implementing California's energy policy goals." (Ex. 125 at 12.)

DRA also suggests that SDG&E's smart grid projects should not proceed until SDG&E's Smart Grid Deployment Plan has been approved. However, SDG&E contends that in D.10-06-047, the Commission allowed for the review of infrastructure projects in this GRC proceeding.

As for DRA's concern over privacy and security concerns, SDG&E notes that D.11-07-056 adopted rules to protect the privacy and security of electric usage data, and that its smart grid projects comply with that decision.

SDG&E also responded to UCAN's arguments in Exhibit 125. SDG&E contends that it did go through a decision making process, a cost benefit analysis, and that it performed several studies. Regarding UCAN's suggestions that SDG&E can rely on the data from its smart meters to accomplish some of the same things that the smart grid projects are designed to do, SDG&E contends that such functions would come at an additional cost and would still have to be developed. SDG&E also points out that UCAN should know the limitations of SDG&E's smart meters since UCAN was a technical advisory panel member to SDG&E. As for UCAN's suggestion that SDG&E should learn from the Germany and Spain about how they respond to photovoltaic generation, SDG&E contends that there are significant differences between their system designs and SDG&E.

6.4.3. Discussion

In this sub-section, we address the reasonableness of the costs of SDG&E's smart grid capital projects, and whether such projects should be funded. In doing so, we are guided by several applicable Pub. Util. Code sections.

The starting point for examining the costs related to the smart grid is Pub. Util. Code § 8360, in which it was declared that it is the policy of this state "to modernize the state's electrical transmission and distribution system to maintain safe, reliable, efficient, and secure electrical service, with infrastructure that can meet future growth in demand and achieve" the items set forth in subdivision (a) through (j) of that code section. It is also important to note that Pub. Util. Code § 8366 states that "Smart grid technology may be deployed in a manner to maximize the benefit and minimize the cost to ratepayers and to achieve the benefits of smart grid technology." As discussed below, there are also code sections applicable to SDG&E's proposals regarding energy storage and PEVs.

SDG&E is anxious to roll out its smart grid projects because it believes its customers are rapidly adopting photovoltaic generation, and using PEVs. Due to those developments, SDG&E favors installing different kinds of devices to counter the possible problems that can result. DRA, FEA, and UCAN are generally in favor of deploying the smart grid projects but believe that it should occur at a slower pace, or that studies should be undertaken and some funding be allowed for pilot projects. In our discussion below, we have taken those concerns into consideration, as well as the financial impact that these projects will have on ratepayers, and the code sections that apply.

It is also appropriate to note that for the PTY, SDG&E is requesting additional smart grid investments. Assuming that SDG&E's PTY proposal is granted as requested, the additional revenue requirement impact from these smart grid projects would amount to $50 million in 2013, $72 million in 2014, and $96 million in 2015. SDG&E's PTY request is discussed later in this decision.

No one takes issue with SDG&E's request of $1.003 million in O&M costs for the smart grid team. Based on our review of these costs, SDG&E's forecast of this cost is reasonable and should be adopted.

SDG&E's energy storage capital project makes up the bulk of its capital funding request. In 2011 and 2012, SDG&E requests a total of $54.983 million.

DRA recommends total funding of $10.700 million, while UCAN recommends total funding of $12.100 million. DRA's reasoning for reduced funding is due to the ongoing energy storage rulemaking (R.10-12-007), and to the energy storage demonstration and research projects that are taking place. UCAN's reasoning for reduced funding is because it believes SDG&E should only pursue a limited pilot project at this point, and that such a project should only be undertaken after SDG&E has performed a study to determine the impact that photovoltaic generation may have on system stability and reliability.

In deciding whether it is reasonable to have ratepayers fund SDG&E's energy storage project, we rely on the code sections that were added to the Pub. Util. Code as a result of AB 2514 (Stats. 2010, Ch. 469, Sec. 2.). AB 2514 added Chapter 7.7 to the Pub. Util. Code to address energy storage systems. In § 2836, the Commission was directed to "open a proceeding to determine appropriate targets, if any, for each load-serving entity to procure viable and cost-effective energy storage systems to be achieved by December 31, 2015, and December 31, 2020." The Commission opened R.10-12-007 for that purpose. As a result, the Commission issued D.12-08-016, which in phase one, adopted a framework for analyzing energy storage needs. Phase two is currently underway, and is studying how energy storage should be evaluated and incorporated into existing procurement portfolios. The major issue in phase two is to determine whether procurement targets for energy storage are appropriate, and if so, how much should be procured. In deciding whether procurement targets should be adopted, § 2836.2(a) requires the Commission to "Consider existing operational data and results of testing and trial pilot projects from existing energy storage facilities." In addition, § 2836.2(d) requires the Commission to "Ensure that the energy storage system procurement targets and policies that are established are technologically viable and cost effective."Based on the Commission's ongoing rulemaking to carry out AB 2514, and the considerations that the Commission must first take into account before any energy storage procurement targets are adopted, we agree with DRA and UCAN that the funding for SDG&E's energy storage projects should be reduced or eliminated. At the present time, the Commission is still going through the process of evaluating information to decide what kind of energy storage policies should be adopted, to determine how to evaluate the cost effectiveness of energy storage systems, and to review the results of other energy storage projects. (*See* D.12-08-016 at 26-27; R.10-12-007, January 18, 2013 ALJ Ruling.) Since the Commission has not yet adopted the energy storage policies and targets as required by AB 2514, it would be unreasonable and premature to invest heavily into energy storage projects that have not been evaluated for technological viability and cost effectiveness. Accordingly, we do not authorize any capital expenditure funding in this GRC for energy storage in 2011 and 2012. Instead, if SDG&E desires funding for its energy storage projects, it should do so by filing an application. That application should include a proposal for the funding of energy storage projects using a competitive solicitation process, consistent with the Commission's guidance on generation procurement adopted in D.12-04-046. We believe that a competitive solicitation process will result in more cost-effective energy storage projects, instead of authorizing funds in this GRC.

SDG&E's dynamic line ratings project is to install sensor devices on its distribution circuits "to monitor the line conductor tension and determine ground clearances and weather conditions to calculate the amount of current that can be transmitted in real time." (Ex. 122 at 21-22.) SDG&E also plans to develop an interface to assist system operators in managing this information. According to SDG&E, the system operators and engineers can then use this information to compare the design rating, increase capacity, and operate the grid at higher efficiencies. DRA recommends total funding of $785,200, while UCAN recommends zero funding.

We have reviewed and considered the testimony and arguments of the parties concerning the dynamic line ratings project. Although UCAN points to possible overheating and safety issues that could be caused by using such devices, we agree with SDG&E that UCAN's perspective overlooks the fact that SDG&E has built and maintained its distribution system in accordance with GO 95 and 128. DRA believes that SDG&E should review the results of other similar projects before full funding is allowed, while SDG&E contends that these out-of-state projects are not relevant to SDG&E's situation. Based on all of these considerations, it is reasonable to allow reduced funding of $1.463 million in 2011, and $1.463 million in 2012. This will provide SDG&E with sufficient funding to install some of these devices to help develop a smarter way of managing its electric grid.

The phasor measurement units project is to install syncrophasors on the distribution system. According to SDG&E, using these devices will allow it to analyze the changes in output of photovoltaic generation systems, and allow SDG&E to dispatch energy storage devices to counter the effects of this output fluctuation. Under SDG&E's proposal, this equipment will be placed on four circuits in 2011 and seven circuits in 2012. DRA's reduced funding of $368,750 per year would allow for one circuit installation per year. UCAN recommends total funding of $1.770 million for a pilot project to evaluate the effectiveness of this kind of technology, and that the pilot involve circuits that involve an energy storage project.

We have considered the need for the phasor measurement units project. With the growing adoption of photovoltaic generation in SDG&E's service territory, we believe that this project can help SDG&E to better manage its grid to respond to the variable output. However, since these devices will be used in conjunction with energy storage, and because we have eliminated the funding for the energy storage projects, it is appropriate to reduce the funding for this project as well. Instead of reducing it to the amounts suggested by DRA and UCAN, it is reasonable to authorize capital expenditure funding of $900,000 in 2011, and 2012 funding of $1.500 million.

The capacitor SCADA project is to implement SCADA control of all capacitors on SDG&E's distribution system. According to SDG&E, this will result in better voltage control, reduced maintenance, and better system diagnostics. DRA recommends reducing the funding in 2011 and 2012 to $1.450 million in each year. UCAN recommends funding of $58,040 for a pilot project only.

We have considered the benefits of installing SCADA control on SDG&E's capacitors and believe that such a project will allow SDG&E to better manage its electric distribution system in a smart grid fashion. However, we are concerned at the pace and cost of such a rollout given the current economic circumstances. Based on those considerations, it is reasonable to adopt a reduced level of capital expenditure funding of this project in the amount of $1.802 million in 2011, and $1.802 million in 2012.

SDG&E's SCADA expansion project is to install, upgrade, and expand its SCADA system at substations, and on distribution circuits. According to SDG&E, this will allow it to expand its remote operations of SCADA capable switches, and provide for faster responses to outages and system disturbances.

DRA recommends reducing the funding from $4.699 million to $2.980 million. UCAN recommends adopting SDG&E's funding amount.

We have considered the benefits of SDG&E expanding SCADA controls to other parts of its distribution system. We agree with SDG&E and UCAN that such a project will lead to better management of SDG&E's electric system, and that it will reduce the time it takes to locate and to repair problems. However, we are concerned with the impact that full roll-out of this project, as requested by SDG&E, will have on ratepayers given the current economy. Accordingly, it is reasonable to reduce the 2012 capital expenditure funding from $4.699 million to $2.250 million.

SDG&E requests funding for its smart transformers project. This project consists of installing sensors and technology on distribution transformers to monitor "the load and condition of transformers feeding" PEVs. (Ex. 122 at 27.) DRA recommends that funding for this project be reduced, while UCAN recommends that all funding for this project be disallowed. We have considered the need for these types of sensors and devices. We agree with SDG&E that the smart meter data cannot provide all the information that it needs concerning the transformers. We also agree with DRA's contention that this project does not need to be rolled out as quickly as SDG&E proposes. As these sensors and devices are installed, SDG&E will gain a better understanding of the additional load that PEVs create, and can take the necessary steps to meets such challenges. It is reasonable under the circumstances to reduce the capital expenditure funding for the smart transformers in 2011 from $2.047 million to $1.300 million, and to allow funding of $521,000 in 2012.

Due to the number of PEVs in SDG&E's service territory, and its belief that adoption of PEVs is growing, SDG&E requests $5.230 million in 2012 to deploy public access charging facilities. DRA and UCAN oppose funding for this project because of what they believe is more modest growth of PEVs, the number of charging stations that already exist and are being planned, and because of the short distances driven by owners of PEVs.

In addition to reviewing the testimony and argument of the parties about the public access charging facilities, we have also reviewed D.11-07-029 and Pub. Util. Code § 740.2. D.11-07-029 developed the policies to address this code section's requirement for the Commission "to develop infrastructure sufficient to overcome any barriers to the widespread deployment and use of plug-in hybrid and electric vehicles." In that decision, the Commission prohibited electric utilities from owning electric vehicle service equipment, such as charging stations, except for their own use. However, that decision allowed SDG&E to request funds in this proceeding for its public access charging facilities as long as it provides "convincing evidence that our prohibiting SDG&E ownership of electric vehicle service equipment at this early stage of Electric Vehicle market development would result in underserved markets or market failures in areas where non-utility entities fail to properly serve all markets." (D.11-07-029 at 50.)

Based on the record in this proceeding, SDG&E has not provided convincing evidence that if it is not allowed to deploy public access charging facilities that this will result in an underserved market or a market failure. As SDG&E points out, there is already a widespread deployment of charging stations for PEVs, and more are expected to be installed. SDG&E also notes that a number of different businesses are considering installing recharging stations as well. DRA and UCAN also point to the slowing growth in the adoption of PEVs. All of these factors persuade us to adopt the positions of DRA and UCAN that there should be no ratepayer funding of SDG&E's proposal to deploy public access charging facilities.

DRA and UCAN both recommend disallowing the funding for the wireless fault circuit indicators. They question the need for these devices when there are already circuit indicators in place, and suggest that the smart meter data can be leveraged to help troubleshoot circuit problems. We are not persuaded by the arguments of DRA and UCAN. As SDG&E points out, the data from the smart meter will only be useful if the outage is at a single transformer, at a single service, or at a feeder or branch service. Although there are circuit indicators out in the field already, this type of technology will enable SDG&E to monitor its circuits remotely, and reduce the time it takes to pinpoint the source of a circuit problem. However, we are concerned with the cost impact of such a project given the current economy. For those reasons, we approve a reduced level of capital expenditure funding for this project in the amount of $1.202 million in 2011, and $1.199 million in 2012.

On SDG&E's request for funding for its phase identification project, we agree with UCAN that this project should not be funded. Ensuring that SDG&E and its workers know the phase of the equipment it is connected to is a safety-related issue. However, UCAN correctly points out that this is something that SDG&E should have been doing all along as part of its normal course of business. SDG&E acknowledges that it "marks or identifies much of its equipment in the field…." (Ex. 125 at 23.) SDG&E goes on to state that "mapping each of the three phases (Phase A, B, C) that exist in most distribution circuits to the individual pieces of line equipment to which they are connected into a geographic information system, GIS, has not been accurately completed." (*Ibid*.) SDG&E also states that while it "does mark phases in the field, the accurate transfer of the phase information to databases has not always occurred." (Ex. 125 at 44.) UCAN also points to electrical safety codes which require the "identification of circuits, phases and conductors…to keep employees, contract employees, and the public safe." (Ex. 568 at 76-77.) Based on those considerations, ratepayers should not have to pay twice for something that SDG&E should have been doing in the past. Accordingly, no funding of the phase identification project is adopted.

Regarding SDG&E's request for funding for an integrated test facility, we acknowledge that interoperability is needed to ensure that the smart grid can operate as envisioned. Although SDG&E agrees that there is still a lack of consensus standards, SDG&E at the same time requests authorization and funding to proceed with the projects and technologies that it believes will address all of the potential problems it has identified. Due to SDG&E's desire to press forward with its smart grid projects before standards have been fully resolved, it is reasonable to require SDG&E to bear some of the costs of an integrated test facility. Accordingly, we adopt DRA's funding recommendation of $250,000 in 2011, and $250,000 in 2012 for the integrated test facility.

As noted by SDG&E, the Commission has already addressed the privacy and security concerns that DRA raised concerning the use of electricity data. (*See* D.11-07-056.)

7. Gas Distribution

7.1. Introduction

This section addresses the O&M costs and the capital expenditures associated with the natural gas distribution operations of SDG&E and SoCalGas. The primary function of the gas distribution system is to deliver natural gas from the transmission system to the customers in their respective service territories.

These operations include the use of gas distribution main lines and service lines, measurement and regulator stations, customer meters, pressure regulators, and electronic equipment. In addition, the gas distribution operations involve engineering, supervision, and technical support.[46]

Both utilities perform work to: maintain the daily operation of the distribution system; connect new customers; ensure there is sufficient capacity; replace damaged or deteriorating facilities; and relocate facilities as needed. This work is performed by a workforce that consists of construction crews, technical planners, and engineers.

Regarding their capital expenditures, SDG&E and SoCalGas are "committed to continued long term investment in its pipeline infrastructure to ensure the integrity of its distribution system and comply with applicable local, state and federal laws and regulations." (Ex. 22 at 4; Ex. 26 at 4.) Both utilities also state that they actively evaluate "the condition of its pipeline system through its maintenance and operations activities, and replaces pipeline segments to preserve the safe and reliable system customers have come to expect." (*Ibid*.)

To meet the needs of a growing customer base, both utilities install new main lines, service lines, and meter set assemblies. To ensure reliability and safety, both companies make "a variety of other capital improvements, including pressure betterment projects to improve areas of low pressure, pipeline renewals to replace deteriorated pipelines or obsolete equipment, installations and replacement of [cathodic protection] systems, and the purchase of electronic

[46] For SoCalGas, the cost of its regional public affairs support is also included.

pressure monitoring devices for pressure tracking." (Ex. 22 at 53; Ex. 26 at 60.) In addition, both utilities relocate pipelines as necessary.

7.2. SDG&E

7.2.1. Introduction

SDG&E's gas distribution system consists of about 14,640 miles of gas main lines and service lines. These lines are constructed of both steel and plastic materials, and consist of varying sizes. The main lines transport natural gas from the transmission lines, and operate at either high or medium pressure. The main lines are then connected to a series of service lines, which are connected to each customer's meter set assembly, and then to the customer's gas pipeline. SDG&E serves about 845,000 gas customers in a geographic area covering more than 1400 square miles.

SDG&E has about 340 distribution employees located at five operating bases and one technical office in its service territory.

SDG&E requests O&M costs of $19.900 million for the 2012 test year, and capital expenditures for 2010, 2011 and 2012 of $75.072 million, $42.176 million, and $30.657 million, respectively.

DRA recommends O&M costs of $14.840 million for the 2012 test year, and capital expenditures for 2010, 2011 and 2012 of $64.976 million, $34.136 million, and $19.982 million, respectively.

UCAN recommends O&M costs of $15.262 million.

7.2.2. O&M Costs

7.2.2.1. Introduction

SDG&E requests that its forecast of O&M costs of $19.900 million for the 2012 test year be adopted. This amount consists of $19.812 million for non-shared activities, and $88,000 for shared service activities. The $19.900 million amount is a $4.313 million increase over the 2009 recorded amount.

According to SDG&E, the O&M activities include "leakage surveys, leak repairs, maintenance on mains and services, application of corrosion control measures, valve maintenance, regulator station maintenance, monitoring meter accuracy, checking for odorant, and locating and marking buried pipes to avoid damage caused from digging by others." (Ex. 22 at 11.) In addition, there is a variety of support work that needs to be done to complete the field O&M activities, such as "maintaining pipeline maps and related gas system location information, administering and implementing city permitting and traffic control requirements, and maintenance of engineering models of system flows and pressures." (*Ibid*.)

7.2.2.2. O&M Non-Shared Services

7.2.2.2.1. Introduction

The O&M costs for gas distribution are categorized by SDG&E into the following three categories: field operations and maintenance; asset management; and operations management and training. In the sub-sections below, we discuss each of these three categories separately.

7.2.2.2.2. Field Operations and Maintenance

7.2.2.2.2.1. Introduction

SDG&E forecasts $15.572 million for the non-shared O&M costs for field operations and maintenance.

This category of costs covers the O&M activities that address the physical condition of the gas distribution system. According to SDG&E, these activities are preventative, corrective, or supportive in nature. The preventative work is generally performed on a scheduled basis. Corrective work reacts to a situation or facility condition. The supportive work consists of activities that are necessary for completing the work assignments.

The field operations and maintenance category consists of nine workgroups.[47] These nine workgroups are: leak survey; locate and mark; main maintenance; service maintenance; supervision and training; tools, materials, fittings; electric support; other services; and measurement and regulation.

The first workgroup is leak survey. SDG&E's forecasts O&M costs of $1.259 million for the leak survey workgroup. This workgroup records the labor and non-labor expenses associated with the federal pipeline safety regulation regarding leakage surveys. According to SDG&E, its pipelines are leak surveyed at one year and five year intervals. This workgroup also records the cost associated with the clearing of right-of-way in order to perform the leakage surveys. SDG&E used the 2009 recorded amount as its base amount, and then added incremental amounts for wireless fees for mobile data terminals, increased leak survey due to system growth, and for weed abatement.[48]

The second workgroup is locate and mark. SDG&E's forecast of locate and mark costs are $2.775 million. The purpose of the locate and mark activity is to avoid damage to the underground gas infrastructure by third-party excavators. This process is initiated by the excavator's call to Underground Service Alert,

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[47] The workgroups consist of activities that represent similar functions, and/or have similar cost drivers.

[48] In its testimony on gas distribution O&M costs, UCAN notes that in response to a UCAN data request, SDGE withdrew its request of $50,000 for weed abatement. As a result, SDG&E's O&M request for the leak survey workgroup is $1.209 million. (*See* Ex. 558 at 45.)

who then notifies the owner of the underground facilities to mark the location of its facilities where the planned excavation is to take place. SDG&E used the 2009 recorded amount as its base amount, and then added incremental amounts for the costs of promoting three field employees to supervisory positions, and to reflect the recovery of construction activity.

The third workgroup is for main maintenance, which SDG&E has forecast at $1.175 million. This workgroup records the costs associated with investigating and repairing leaks in distribution mains, and moving, lowering, and raising short sections of gas distribution mains, vaults, and related structures. SDG&E used the 2009 recorded amount as its base amount, and then made incremental adjustments to reflect the recovery of construction activity, and to upgrade bridge and span supports due to the deteriorating condition of the bridge support infrastructure.

The fourth workgroup is for service maintenance, which SDG&E has forecast at $1.399 million. This workgroup records the costs associated with investigating and repairing leaks in gas distribution services, as well as the costs of moving, lowering, and raising shorter sections of distribution services, vaults, and related structures. The investigation and repair of leaks includes excavation, changing service valves, testing service pipe for leaks, inspection and testing service pipe after repairs have been made, installing, maintaining, and removing temporary supply sources, and the repair of service risers. SDG&E used the 2009 recorded amount as its base amount, and then made an incremental adjustment to reflect increased maintenance of services due to system growth.

The fifth workgroup is the supervision and training workgroup. SDG&E forecasts $2.632 million for this workgroup. This workgroup records the costs for employee field skills training, field supervision and management, and miscellaneous expenses related to SDG&E's gas operations. The 2009 recorded amount of $2.262 million was selected as the base amount. Incremental costs were then added, which consist of the following: formal training for leak survey personnel; support training on the new GIS that will contain gas distribution asset records; support training for new technologies such as the field scheduling and dispatch of maintenance and inspection activities using the mobile data terminals; a new management training program for working foreman; training of field employees on pressurized pipelines under controlled conditions; and training of new gas technicians and welders on gas pipelines.

The sixth workgroup is the tools, materials and fittings workgroup, which SDG&E forecasts $502,000 in costs. This workgroup records the costs for small tools, pipe materials and associated installation materials, pipe fittings, and work clothing. The 2009 recorded amount was used for the 2012 test year forecast.

The seventh workgroup is the electric support workgroup, which SDG&E forecasts costs of $588,000. This workgroup records the costs incurred by the gas distribution crews that have been trained to provide traffic control services for electric distribution crews during inspections under the corrective maintenance program. The forecast for the 2012 test year is based on a three year linear trend.

The eighth workgroup is the other services workgroup, which SDG&E forecast costs at $2.344 million. This workgroup records the miscellaneous costs that are associated with gas distribution field operations that have not been captured in other major workgroups. These activities include leak investigations of customers' house lines, leak surveys of transmission mains, paving and street repair, and support of the installation of cathodic test stations for high pressure main evaluation. A five-year average (2005-2009) was selected as the base forecast ($209,000), which was adjusted upwards by the new environmental regulations, which SDG&E proposes be recovered in a two-way balancing account called the NERBA.

SDG&E proposes that the NERBA be adopted to record the costs associated with the proposed environmental reporting rules that will require SDG&E to annually report "methane emissions from natural gas distributions systems; annually inventory components; annually survey for leaks, and conduct other new activities." (Ex. 22 at 28.) Data collection may begin in January 2011, and the first report may be due in March 2012. SDG&E estimates that the other services workgroup will incur costs of $2.136 million in the 2012 test year over the base forecast. Since there is uncertainty about the specific compliance requirements, SDG&E proposes that these costs be recovered in a two-way balancing account called the NERBA.

The ninth workgroup is the measurement and regulation workgroup. SDG&E forecasts $2.898 million in costs for this workgroup. This workgroup records the costs for the inspection and maintenance of distribution regulator stations, valve maintenance and meter set inspections, maintenance of electronic instruments, and meter removals for accuracy checks. The 2009 recorded amount was selected as the base amount. Incremental costs were then added for the following as described in Exhibit 22: periodic maintenance of pipeline tapping and plugging equipment; regulator station lid replacement program; lead paint removal for distribution regulator stations; formal training for regulator technician group; growth in regulator station inspection and maintenance; support training for GIS; support training for new technologies; wireless fees for mobile data terminals; increased need for traffic control; electronic corrector replacement program; and smart meter module ongoing maintenance.

7.2.2.2.2.2. Position of the Parties

7.2.2.2.2.2.1. DRA

DRA recommends a series of reductions to SDG&E's gas distribution O&M costs as described in Exhibit 503.

For the leak survey workgroup, DRA recommends O&M costs of $1.025 million for the 2012 test year, a reduction of $234,000 from SDG&E's recommendation of $1.259 million. DRA's recommendation is based on the five-year average of 2006-2010.

For the locate and mark workgroup, DRA recommends O&M costs of $2.290 million, which is a $485,000 reduction from SDG&E's recommendation of $2.775 million. DRA's recommendation uses the two-year average of 2009 and 2010.

For the main maintenance workgroup, DRA recommends O&M costs of $1.083 million, which is a reduction of $92,000 from SDG&E's recommendation of $1.175 million. DRA's recommendation uses the five-year average of 2006-2010.

DRA accepts SDG&E's forecast of the O&M costs for the service maintenance workgroup.

For the supervision and training workgroup, DRA recommends $2.105 million as the O&M costs, a reduction of $527,000 from SDG&E's recommendation of $2.632 million. DRA's recommendation is based on the five-year average of 2006-2010.

DRA accepts SDG&E's O&M forecast for the tools, materials and fittings workgroup, as well as SDG&E's O&M forecast for the electric support workgroup.

DRA recommends $190,000 for the O&M costs for the other services workgroup. DRA's recommendation is based on the five-year average of 2006-2010, and removal of the NERBA amount of $2.154 million.

For the measurement and regulation workgroup, DRA recommends an O&M forecast of $2.262 million, instead of SDG&E's recommendation of $2.898 million. DRA's recommendation uses the five-year average of 2006-2010.

7.2.2.2.2.2.2. UCAN

UCAN's general observation of SDG&E's gas distribution O&M expenses is that SDG&E's 2010 forecast of $16 million was above the recorded 2010 amount of $13.7 million. SDG&E's 2012 test year forecast represents a 29% increase over the 2010 recorded amount, which UCAN asserts lacks credibility regarding the need for work, and the quick ramp up of costs from 2010 to 2012. Due to the reduction in gas distribution spending in 2010, UCAN reduced SDG&E's expected level of spending in 2012.

For the leak survey workgroup, UCAN recommends $1.084 million as the O&M forecast. UCAN's recommendation is based on the three-year average of 2008-2010. UCAN contends that its forecast is consistent with the amount of square miles that were surveyed in recent years, and is based on the three years with the highest unit costs per square mile. UCAN also contends that since the 2010 recorded amount was the lowest since 2006, and below the 2009 recorded costs of $1.181 million, that SDG&E's minor adjustments for growth and cell phone fees make no sense and should not be adopted as part of the forecast.

For the locate and mark workgroup, UCAN recommends an O&M forecast of $2.523 million as opposed to SDG&E's forecast of $2.775 million. UCAN contends that SDG&E's forecast is deficient because the activity level was low in 2010 and 2011. Also, SDG&E forecast 8979 construction units in its GRC filing, but the 2012 forecast is for 6538 construction units. UCAN's forecast also excluded the additional supervisors that SDG&E included in its forecast because the actual 2010 labor spending was below SDG&E's forecast. UCAN contends that means "either the supervisors were added and other costs were reduced, or the supervisors were not needed because labor hours are continuing to be low." (Ex. 558 at 47.)

UCAN agrees with SDG&E's base forecast ($1.065 million) for the main maintenance workgroup, but opposes SDG&E's incremental costs for the recovery of new construction, and the upgrade of bridge and span supports.

UCAN recommends that the O&M forecast for service maintenance should be $1.196 million, and is opposed to SDG&E's incremental costs for system growth. UCAN's recommendation of $1.196 million is based on the three-year average of 2008-2010.

For the supervision and training workgroup, UCAN recommends O&M costs of $2.262 million, as opposed to SDG&E's recommendation of $2.632 million. UCAN's forecast is lower because it does not believe the 2012 economy will be as robust as SDG&E's forecast, and because UCAN does not believe SDG&E will need to hire as many employees as SDG&E has projected.

UCAN accepts SDG&E's labor forecast for the tools, materials and fittings workgroup, which is based on the 2009 labor costs. However, UCAN proposes using the three-year average of 2008-2010 for non-labor costs. UCAN contends that this adjustment reflects the lower spending during that three year period. This results in a UCAN recommendation of $449,000 in O&M costs for the tool, materials and fittings workgroup.

Regarding the other services workgroup, UCAN agrees with DRA that the NERBA should be rejected. By rejecting the NERBA, this reduces the O&M costs for this workgroup by $2.179 million. For the remaining O&M costs in the other services workgroup, UCAN recommends $165,000 which is based on the three-year average of 2008-2010.

For the measurement and regulation workgroup, UCAN recommends an O&M forecast of $2.536 million, instead of SDG&E's forecast of $2.898 million. UCAN's forecast uses the "two-year average of 2009-2010 plus 2012 adjustments minus 2010 adjustments for all the maintenance programs…." (Ex. 558 at 53.) UCAN contends its forecast is justified because SDG&E spent only $2.236 million in 2010, which was 15% less than what SDG&E had forecast in 2010.

7.2.2.2.2.2.3. SDG&E

SDG&E presented testimony in rebuttal to the positions of DRA and UCAN on gas distribution O&M costs.

On the leak survey workgroup, SDG&E contends that DRA's method ignores the changes that have affected the leak survey group over the past five years. In addition, SDG&E contends that DRA's method does not address the new work requirements in this area.

With respect to UCAN's recommendation for the leak survey workgroup, SDG&E contends that UCAN's forecast is inaccurate because: it does not capture the actual footage to be surveyed; it does not account for the growth experienced by SDG&E or the wireless fees; and does not include funding for new supervisors. SDG&E also contends that UCAN's method is flawed because UCAN's forecast is based on new construction, when that work should be based on the existing underground structures.

For the locate and mark workgroup, SDG&E contends that DRA's recommendation is based on data from the two lowest years, which ignores an economic recovery, and additional supervisors. SDG&E points out that DRA's own witness presented a forecast of residential building permits that increases through 2012.

On the recommendations of DRA and UCAN concerning the main maintenance workgroup, SDG&E contends that including the cost of maintaining bridge and span pipe supports is needed to ensure safety and reliability, and that the appropriate five-year average is for the period of 2005-2009, and not the 2006-2010 period that DRA used.

Regarding UCAN's recommendation for service maintenance, SDG&E contends that the incremental cost for system growth should be included due to the improving economy. As the economy approves, SDG&E contends that this will result in more alterations to SDG&E's distribution services.

For the supervision and training workgroup, SDG&E contends that the recommendations of DRA and UCAN should be rejected because both of those recommendations ignore the incremental costs for training that is needed to enhance worker effectiveness and safety.

UCAN recommends that a three-year average should be used for the non-labor costs for the tool, materials and fittings workgroup. SDG&E opposes UCAN's non-labor method, and contends that SDG&E's method best reflects the anticipated non-labor costs.

On the recommendations of DRA and UCAN to reduce the O&M expenses for the other services workgroup, SDG&E contends that its five-year average should be used instead of UCAN's three-year average, and DRA's five-year average which used the 2006-2010 data. SDG&E argues that its five-year average is a more appropriate forecast method because it reflects the variability of costs in this workgroup.

Regarding the need for the NERBA, SDG&E contends that the mandatory GHG reporting rule will require SDG&E to annually report fugitive and vented methane emissions from its gas distribution system. Due to this incremental environmental compliance cost, and because of the uncertainty of how this rule will impact SDG&E's operations and costs, SDG&E requests that the two-way balancing account in the form of the NERBA, be adopted. With the two-way balancing account, SDG&E states that "should SDG&E find that such expenditures are less than forecasted, excess revenues will be credited back to ratepayers." (Ex. 25 at 10.)

On the recommendation of DRA to reduce the O&M expenses for the measurement and regulation workgroup, SDG&E contends that DRA's forecast does not reflect the current operational conditions, and ignores incremental safety enhancements and training activities. SDG&E contends that UCAN's recommendation uses 2010 data, which is too low, and "does not capture the operating realities of managing a gas distribution system." (Ex. 25 at 32.)

7.2.2.2.2.3. Discussion

We have reviewed the testimony and arguments of the parties regarding the category of costs for field operations and maintenance. We have also considered the different forecasts of the parties and the incremental additions that SDG&E is requesting, and compared those forecasts to the historical costs. Based on all those considerations, and as discussed below, it is reasonable to adopt a total O&M forecast of $11.578 million for the field operations and maintenance category. In contrast, SDG&E requested $15.572 million for this category of costs.

The first workgroup is for leak survey. The main driver of this O&M cost is the federal pipeline safety regulations concerning leak surveys. In order to have an adequate sized workforce to carry out the leak surveys, to utilize the mobile data terminals, to account for a moderate growth in the amount of pipelines that need to be leak surveyed, and to remove the weed abatement costs as noted by UCAN, it is reasonable to adopt an O&M forecast of $1.100 million for the leak survey workgroup.

The second workgroup is locate and mark. The locate and mark activity depends on the amount of construction and the state of the economy. Based on the historical costs, the economic slowdown and the gradual economic recovery, the staff needed to handle this activity, and the incremental additions that SDG&E is requesting, it is reasonable to adopt DRA's O&M forecast of $2.290 million for the locate and mark workgroup.

The third workgroup is main maintenance. The factors which influence these O&M costs are the aging main lines and bridge support infrastructure, and the economy and the gradual construction recovery. These factors have also been considered in light of the historical costs. Based on all these considerations, it is reasonable to adopt DRA's O&M forecast of $1.083 million.

The fourth workgroup is for service maintenance. The O&M costs in this workgroup are influenced by the aging service lines and infrastructure, municipal improvements, and system growth. Based on these considerations, as well as a comparison to recorded costs, it is reasonable to adopt UCAN's O&M recommendation of $1.196 million.

The fifth workgroup is for supervision and training. The majority of the costs in this workgroup are due to field skills training. In reviewing the forecasts of SDG&E, DRA, and UCAN, the four years of 2005 to 2009 provide a useful range for developing the base forecast. As described in Exhibit 22, SDG&E then adds in the costs of incremental training in various areas. DRA and UCAN do not believe the incremental costs are warranted. Based on our review of SDG&E's request for incremental training, as well as the historical costs for this workgroup, it is reasonable to adopt DRA's O&M forecast of $2.105 million.

The sixth workgroup is for tools, materials, and fittings. SDG&E recommends O&M costs of $502,000 which is based on the 2009 recorded amount. UCAN recommends $449,000 as the O&M forecast, which uses the three-year average for non-labor costs from 2008-2010. Based on the historical costs experienced for this workgroup, we are not persuaded that UCAN's methodology should be used. Instead, it is reasonable to adopt SDG&E's forecast of $502,000 for the tools, materials, and fittings workgroup.

The seventh workgroup is for electric support. None of the other parties dispute SDG&E's recommendation of $588,000 as the O&M costs for the electric support workgroup. However, a review of these historical costs suggests that the 2012 test year cost will be less than what SDG&E and DRA have forecasted. Based on the historical costs, it is reasonable to adopt an O&M forecast of $540,000 for the electric support workgroup.

The eighth workgroup is for other services. SDG&E's other services workgroup is composed of the costs which it has incurred historically, and the estimated costs of complying with the mandatory GHG reporting rule.

For the historical costs, SDG&E used the five-year average of 2005-2009 to derive its forecast of $208,000. DRA used the five-year average of 2006-2010 to derive its base forecast of $190,000. UCAN used the three-year average of 2008-2010 to derive its base forecast of $165,000. We have compared the different forecasts to the historical data for 2005-2010. Based on that comparison, it is reasonable to adopt an O&M amount of $200,000 for the other services workgroup, which does not include the cost of complying with the mandatory GHG reporting rule.

Regarding the issue of whether this GRC should include funding for the mandatory GHG reporting rule, we conclude that it should, but not at the funding level that SDG&E recommends. The mandatory GHG reporting rule went into effect on December 30, 2010, shortly after the Applicants filed their GRC application. As a natural gas distribution system, SDG&E is required under Subpart W of Part 98 of Title 40 of the Code of Federal Regulations (CFR) to monitor and report its GHG emissions to the EPA. With deadlines to begin the monitoring and reporting of GHGs, it is clear that SDG&E will incur O&M expenses in order to comply with this rule. DRA and UCAN have not offered any compelling reasons as to why this GRC should not include funding to comply with this rule.

SDG&E requests that the Commission authorize the NERBA as a two-way balancing account to record the costs associated with complying with the mandatory GHG reporting rule. DRA, FEA, and UCAN oppose the NERBA and related funding for O&M costs. The reason why SDG&E requests a two-way balancing account is because of the uncertainty over how much it will cost to comply with this rule. The testimony of the Applicants, as well as other exhibits, make it clear that depending on how the rule is interpreted, a large number of facilities might have to be inspected and monitored. SDG&E has been working with the American Gas Association to clarify Subpart W. At the time when SDG&E served its rebuttal testimony, the EPA had "issued a second revision of technical corrections which again changed areas of consideration involved in determining source requirements for leak testing." (Ex. 327 at 16.) As noted by

SDG&E, these changes have the potential to impact the "scope and costs for compliance activities." (*Ibid*; *See* Ex. 337.)

Based on the uncertainty of the costs of complying with the mandatory GHG reporting rule, it is reasonable to authorize SDG&E to file an AL to establish the NERBA as a two-way balancing account to record SDG&E's O&M costs that are associated with complying with the mandatory GHG reporting rule that is set forth in Subpart W of Part 98 of Title 40 of the CFR. SDG&E shall file a Tier 2 AL within 45 days from the effective date of this decision to establish the NERBA for that purpose.

Since SDG&E is likely to incur O&M costs related to the mandatory GHG reporting rule, it is reasonable to adopt additional O&M costs of $300,000 for the other services workgroup for the 2012 test year. This amount is reasonable because SDG&E acknowledges that these O&M costs related to the GHG reporting rule are uncertain. Since such costs will be subject to the two-way balancing account, if today's level of funding is too low, SDG&E will be able to request recovery of the difference in the NERBA at a later date. Accordingly, the total O&M amount for the other services workgroup is $500,000.

The ninth workgroup is for the measurement and regulation workgroup. SDG&E forecasts $2.898 million in costs for this workgroup. DRA recommends $2.262 million, while UCAN recommends $2.536 million. SDG&E contends that the base forecast for this workgroup should be the 2009 recorded amount of $2.486 million since that amount includes the addition of a supervisor position. SDG&E proposes $412,000 in incremental costs, as described in Exhibit 22, to arrive at its forecast of $2.988 million. We have examined the differing forecasts and compared them to the historical costs. In addition, we have considered the incremental activities which SDG&E plans to pursue in the test year. Based on our analysis of all of these considerations, it is reasonable to adopt DRA's recommendation of $2.262 million as the 2012 test year O&M amount for the measurement and regulation workgroup.

7.2.2.2.3. Asset Management

7.2.2.2.3.1. Introduction

SDG&E forecasts $2.726 million for the non-shared O&M costs for asset management.

This category of costs covers the O&M activities that evaluate the condition of the gas distribution system. These activities include such things as the maintenance of asset records, the identification of corrective maintenance solutions, and coordination with field personnel on completion and recording of O&M activities. The asset management category consists of the following two workgroups: pipeline O&M planning; and cathodic protection.

The first workgroup is the pipeline O&M planning workgroup. SDG&E forecasts O&M costs of $1.828 million for this workgroup. This workgroup records the costs for the pipeline maintenance technical planning office personnel, regional engineering, pipeline mapping personnel, mapping of pipeline facilities, various analytical and administrative support positions, and associated supervision. SDG&E's technical planning office provides many of the technical and administrative services to carry out and complete the O&M activities. In addition, the technical planning office coordinates the emergency response efforts by managing the gas emergency center. The gas emergency center is activated when there is a significant event, and provides support for the field operations with engineering, pipeline planning, mapping, logistics, and office resources.

SDG&E used the 2009 recorded amount as its base amount, and then added incremental amounts for the following: support training for the GIS; a rotation program for engineers; to provide support for construction design estimating due to the development of the graphic work design process; and to make the staff adjustments for drafting support.

The second workgroup is cathodic protection. SDG&E forecasts O&M costs of $898,000 for this workgroup. This workgroup records the costs associated with the inspection and evaluation of the cathodic protection system on SDG&E's steel distribution pipelines. SDG&E used a three-year average as its base amount, and then added incremental amounts for the following: formal training for the cathodic protection workforce; support training for the new GIS; support training for new technologies; and wireless fees for mobile data terminals.

7.2.2.2.3.2. Position of the Parties

7.2.2.2.3.2.1. DRA

For the pipeline O&M planning workgroup, DRA recommends O&M costs of $1.473 million, which is $355,000 less than SDG&E's recommendation of $1.828 million. DRA's recommendation is based on the two-year average of 2009-2010.

For the cathodic protection workgroup, DRA recommends O&M costs of $824,000, which is a reduction of $74,000 from SDG&E's recommendation of $898,000. DRA's recommendation uses the five-year average of 2006-2010.

7.2.2.2.3.2.2. UCAN

For the pipeline O&M planning workgroup, UCAN recommends O&M costs of $1.581 million. UCAN's recommendation is based on the three-year average of 2008-2010 for labor, and a two-year average of 2009-2010 for non-labor.

UCAN recommends an O&M forecast of $848,000 for the cathodic protection workgroup. UCAN's recommendation uses the four-year average of 2007-2010, and does not include any of the adjustments that SDG&E used.

7.2.2.2.3.2.3. SDG&E

SDG&E contends that DRA's recommendation, as well as UCAN's recommendation, fail to reflect the "necessary expenditures for training employees in the new GIS system; the pressing need for new engineers hired into the Engineering Rotation Program to provide necessary engineering for the safety sensitive positions to which they are assigned; additional staffing requirements to support the rollout of the Graphic Work Design…for the OpEx 20/20 project for construction cost estimating; and the full year's effect for two vacancies that were filled in 2009 for drafting support." (Ex. 25 at 34.) SDG&E contends that DRA's "shortfall in funding would not be sufficient to adequately train personnel responsible for accurately mapping gas pipelines on the GIS system, to adequately prepare engineering personnel to respond to gas emergencies, to develop accurate construction cost estimates for customers, and to maintain the level of drafting personnel that were on staff at year end 2009." (Ex. 25 at 34-35.) SDG&E also criticizes UCAN's methodology because it relied on 2010 data.

On the recommendation of DRA regarding cathodic protection, SDG&E contends that DRA's inclusion of the 2006 data into its five-year average fails to reflect the organizational changes that took place, and are not representative of the current group structure. Also, DRA ignored the incremental costs for a formalized training program, for training personnel on the new GIS platform and graphic work design applications, and the wireless fees for the mobile data terminals.

Regarding UCAN's recommendation for cathodic protection, SDG&E disagrees with UCAN's inclusion of the 2010 data, and believes that the 2007-2009 period is more appropriate. UCAN's recommendation also did not include the incremental costs, which SDG&E contends are necessary for training, and to connect the mobile data terminals.

7.2.2.2.3.3. Discussion

We have reviewed the testimony and arguments of the parties regarding the asset management category of costs. We have also compared SDG&E's forecast and the incremental additions it is requesting, and the forecasts of DRA and UCAN to the historical costs.

Based on those considerations, it is reasonable to adopt UCAN's O&M forecast of $1.581 million for the pipeline O&M planning workgroup.

Based on the above considerations, it is reasonable to adopt UCAN's O&M forecast of $848,000 for the cathodic protection workgroup.

7.2.2.2.4. Operations Management and Training

7.2.2.2.4.1. Introduction

SDG&E forecasts $1.514 million for the non-shared O&M costs for operations management and training. Operations management and training is the only workgroup within this category.

This category of costs covers the O&M activities that represent the leadership and operations support to the organization responsible for gas distribution. Included within this category are the costs associated with the following: developing and maintaining distribution construction standards; evaluating new field technologies; assisting with field training; training distribution welders; providing code-required welder testing; providing welding inspection; managing the welding school; and the management and administrative and support positions at the gas technical services.

SDG&E used the 2009 recorded amount as the base, and then added incremental amounts for the following: increased cost of welder training materials; staffing adjustment for manager and advisor position; instructional designer for skills field training; and support of new technology and process improvement.

7.2.2.2.4.2. Position of the Parties

7.2.2.2.4.2.1. DRA

DRA recommends $1.099 million for the operations management and training workgroup, which is $415,000 less than SDG&E's forecasted expenses of $1.514 million. DRA's recommendation is based on the two-year average of 2009-2010. DRA points out that since 2006, the expense for this workgroup has been decreasing.

7.2.2.2.4.2.2. UCAN

For the operations management and training workgroup, UCAN recommends O&M costs of $1.193 million for the 2012 test year, instead of SDG&E's recommendation of $1.514 million. UCAN's forecast is lower because it does not believe the 2012 economy will be as robust as SDG&E's forecast, and because UCAN does not believe SDG&E will need to hire as many employees as SDG&E has projected.

7.2.2.2.4.2.3. SDG&E

SDG&E contends that DRA's two-year average methodology "fails to acknowledge the need to fund incremental work elements above the base level necessary to adequately fund" this workgroup. SDG&E contends that the incremental additions are needed for the course materials for welder training, funding to represent the full year effect of filling vacancies to ensure adequate management oversight and support, staffing for a full time instructional designer to ensure that training remains current, and staffing to support new technologies and work process improvements.

Regarding UCAN's recommendation, SDG&E contends that UCAN's methodology is flawed because UCAN assumes incorrectly that the entire cost is a training expense, and contains math errors. In addition, UCAN does not include the incremental addition for new training, which is not included in the historical base.

7.2.2.2.4.3. Discussion

We have reviewed the testimony and arguments of the parties regarding the category of costs for operations and management and training. We have also compared SDG&E's forecast and the incremental additions it is requesting, and the forecasts of DRA and UCAN, to the historical costs. Based on all those considerations, it is reasonable to adopt DRA's O&M forecast of $1.099 million for operations management and training.

7.2.2.3. O&M Shared Services

SDG&E's forecast of the gas distribution O&M expense for shared services for test year 2012 is $88,000. These O&M expenses are to support the following business functions of SDG&E: operations leadership; and operations technical support.

The operations leadership function covers the costs of the VP, administrative support, and miscellaneous non-labor expenses in support of the organization. The operations technical support function covers the costs of two SDG&E employees who are engaged in field support to SoCalGas' inland region.

The estimated total expenses for operations leadership is $114,000 and $169,000 for operations technical support. Of these totals, SDG&E retained $20,000 of the operations leadership costs, but none of operations technical support costs. SDG&E was billed $68,000 from SoCalGas for services from the office of the VP representing administrative support services.

UCAN recommends that operations leadership amount be reduced to $98,000 instead of the $114,000 that SDG&E used. For operations technical support, UCAN recommends that the amount be reduced to $149,000 instead of the $169,000 that SDG&E used. UCAN's reduced amounts are because the 2010 spending was less than 2009 by a considerable amount.

UCAN proposes to reduce the shared costs because of the lower 2010 costs. We have reviewed the testimony and arguments of SDG&E and UCAN regarding the O&M shared services, and the impact on SDG&E and SoCalGas if UCAN's reductions were adopted. We have also considered UCAN's argument in light of the economic downturn in 2010 and the forecast for 2012. However, we are not persuaded by UCAN that the operations leadership amount and the operations technical support should be reduced. Accordingly, it is reasonable to adopt SDG&E's forecast of $88,000 as the total booked cost for gas distribution shared service.

7.2.3. Capital Expenditures

7.2.3.1. Introduction

This section addresses SDG&E's estimated capital expenditures for its gas distribution utility plant for the period 2010 through 2012.

The gas distribution capital projects are the result of customer requests or to meet system needs. SDG&E's gas distribution capital projects are managed by project category. Within each project category are a number of different projects.

SDG&E has 14 project categories of capital expenditures. The following table is a summary of SDG&E's forecasted project costs by category:[49]

($ 000)

Category	2010 GRC Forecast	2011 GRC Forecast	2012 GRC Forecast	Total
New Business	$2,085	$3,514	$4,898	$10,497
System Minor Add/Reloc./Retire	$754	$754	$754	$2,262
Meter & Regulator Materials	$6,349	$6,631	$7,526	$20,506
Pressure Betterment	$2,209	$3,121	$3,704	$9,044
Distribution Easements	$30	$30	$30	$90
Pipe Relocation – Franchise & Freeway	$4,047	$3,970	$3,825	$11,842
Tools & Equipment	$313	$446	$446	$1,205
NERBA	$0	$1,400	$0	$1,400
Code Compliance	$547	$349	$441	$1,337
Replacement of Mains & Services	$1,549	$1,528	$1,487	$4,564
Cathodic Protection	$581	$646	$711	$1,938
Regulator Station Improvements	$614	$1,332	$721	$2,667
Local Engineering	$5,083	$5,742	$6,114	$16,939
Camp Pendleton – San Onofre 1	$439	$0	$0	$439
Sub Total	$24,600	$29,463	$30,657	$84,720
Smart Meter Project	$50,472	$12,713	$0	$63,185
Total Capital	$75,072	$42,176	$30,657	$147,905

In the sub-sections below, we address each project category separately.

[49] SDG&E's forecast of the capital projects listed in the summary table are described in more detail in Exhibit 22. SDG&E's rebuttal in Exhibit 25 at 43 shows a comparison to the capital expenditures that DRA and UCAN are requesting.

7.2.3.2. New Business

7.2.3.2.1. Introduction

The new business category of capital projects covers the changes and additions to the existing gas distribution system to serve new customers. These capital projects include the installation of gas main lines and service lines, meter set assemblies, and regulator stations.

For the new business category of projects SDG&E forecasts capital expenditures of $2.085 million for 2010, $3.514 million for 2011, and $4.898 million for 2012. These capital expenditures are based on SDG&E's projection of new meter sets added to the gas distribution system, multiplied by the cost per meter set. SDG&E anticipates that in 2012, the growth in new meter sets will return to the 2006 level.

7.2.3.2.2. Position of the Parties

7.2.3.2.2.1. DRA

DRA recommends that capital expenditures be authorized as follows for the new business budget code: for 2010, the recorded amount of $2.011 million; $2.499 million for 2011; and $2.499 million for 2012. DRA's capital expenditures for 2011 and 2012 are based on the three-year average of 2008-2010. DRA also notes that the capital expenditures for new business have declined from 2005 to 2010.

7.2.3.2.2.2. UCAN

UCAN recommends that capital expenditures be authorized as follows for the new business budget code: $2.623 million for 2010; $2.138 million for 2011; and $3.144 million for 2012. UCAN's capital expenditure forecasts are based on lower gas construction units than what SDG&E used.

7.2.3.2.2.3. SDG&E

SDG&E contends that DRA's use of the three-year average to derive the capital expenditures for 2011 and 2012 "implies that new business activity will remain stagnant at a level that represents the lowest level of spending over the last five years." (Ex. 25 at 45.) SDG&E points out, however, that DRA does not dispute SDG&E's forecast of future units of construction, and DRA's forecast of active customers is similar to SDG&E's forecast of growth, "which is consistent with some rebound in construction unit growth." (Ex. 25 at 45.) SDG&E contends that its forecast for each of the three years was based on independent estimates of construction units and the cost per unit.

With regard to UCAN's forecast, SDG&E points out that UCAN derived its 2011 and 2012 forecast by "developing its own construction unit forecast," and then "determined the percentage reduction between UCAN's and SDG&E's construction unit forecast, [and] then reduced SDG&E's 2011 and 2012 forecasted expenditures by this same percentage difference between the two." (Ex. 25 at 46.) Although SDG&E "acknowledges that economic conditions have improved more slowly than originally forecast, it would be inappropriate to make isolated updates to the general rate case" for the following reasons:

> First, selective updating ignores the fact that while certain costs may be lower than expected, other costs may be higher than expected and there is no provision to update those instances of higher costs. Second, the Rate Case Plan is very prescriptive regarding the types of information that may be updated in a general rate case and the proposal by UCAN contravenes this intent. Third, the revenue requirement associated with new business should reflect the level of activity that SDG&E expects to occur over the rate case period. …[In addition,] UCAN's forecast for 2011 is $455,000 less than 2010 recorded expenditures, yet UCAN's forecast of

construction units is 29% higher in 2011 than it was in 2010.
(Ex. 25 at 46-47.)

7.2.3.2.3. Discussion

We have reviewed the testimony and the argument of the parties concerning the capital expenditures regarding new business, the forecast of new customers, and construction units. We have also compared the forecasts of capital expenditures to the historical spending. At the time SDG&E's opening testimony was prepared, it relied on the IHS Global Insight Winter 2009 regional forecast for San Diego County to develop its estimate of customers. SDG&E's estimate of customers is derived from the permit and employment assumptions contained in the IHS Global Insight forecast. That forecast is also used by SDG&E to shed light on the direction of the economy, and to validate its forecast methodology. The estimate of customers is important because it is a factor which affects a lot of the costs in this GRC.

In their rebuttal testimony, some parties mentioned the more recent July 2011 IHS Global Insight forecast for San Diego County. (*See* Ex. 29 at 16-17; Ex. 558 at 57-58.) This later forecast shows a more moderate growth of construction units than was originally forecasted in the Winter 2009 IHS Global Insight forecast. According to UCAN, the later forecast shows that "the 2007 level of construction units is not expected to be seen until 2014." (Ex. 558 at 58.) SDG&E also "acknowledges that economic conditions have improved more slowly than originally forecast…." (Ex. 25 at 46.) SDG&E's witness on customer growth also acknowledged that the Federal Reserve, and IHS Global Insight reduced their growth projections for 2011 and 2012. (23 R.T. 2962.)

Based on all these considerations, we agree that the economic outlook is not as optimistic as SDG&E originally forecast it would be. We believe that the capital expenditure forecasts for new business will reflect the forecasts of DRA and UCAN, instead of SDG&E's forecast. Accordingly, it is reasonable to adopt the following forecast of capital expenditures for new business: $2.011 million for 2010; $2.250 million for 2011; and $2.900 million for 2012.

7.2.3.3. System Minor Additions, Relocations and Retirements

7.2.3.3.1. Introduction

The category of system minor additions, relocations, and retirements covers the costs that are not covered in other work categories. These costs include abandonment of main and service lines, and service relocations due to customer requests.

For this category, SDG&E forecasts capital expenditures of $754,000 annually in 2010, 2011, and 2012. These capital expenditures were based on SDG&E's use of the five-year average of 2005-2009 for the labor component, and the five-year average of 2005-2009 was used for the non-labor components of materials and services, and contribution in aid of construction (CIAC) credits.

7.2.3.3.2. Position of the Parties

7.2.3.3.2.1. DRA

DRA recommends that capital expenditures be authorized as follows for the system minor adds, relocations, and retirements budget code: for 2010, the recorded amount of $313,000; and for 2011 and 2012, DRA accepts SDG&E's forecasts of $754,000 in each year.

7.2.3.3.2.2. SDG&E

SDG&E contends that DRA's recommendation for the 2010 level of capital expenditures is incorrect because it "included portions of collectible monies from customers that should be excluded from the forecast," and [h]ad the appropriate treatment of the collectible monies been performed, a value of $604,000 would have been obtained for 2010 recorded expenditures." (Ex. 25 at 49.)

7.2.3.3.3. Discussion

Based on our review of the parties' testimony and arguments, and a comparison of the forecasts to historical spending, it is reasonable to adopt the following forecast of capital expenditures for system minor additions, relocations, and retirements: $604,000 for 2010; $754,000 for 2011; and $754,000 for 2012.

7.2.3.4. Meter and Regulator Materials

7.2.3.4.1. Introduction

The meter and regulator materials category of capital projects covers the cost of purchasing new gas meters and pressure regulators for use by new customers or for replacements.[50]

For this category, SDG&E forecasts capital expenditures of $6.349 million for 2010, $6.631 million for 2011, and $7.526 million for 2012. These capital expenditures are based on SDG&E's projection of new business, the trend in routine replacements, and program replacement.

7.2.3.4.2. Position of the Parties

7.2.3.4.2.1. DRA

For the meter and regulator materials budget code, DRA recommends that capital expenditures be authorized as follows: for 2010, the recorded amount of $6.083 million; and for 2011 and 2012, annual expenditures of $4.665 million. DRA's forecast for 2011 and 2012 is based on the five-year average of 2006-2010.

7.2.3.4.2.2. UCAN

UCAN recommends the following capital expenditures: for 2010, the recorded amount of $6.083 million; $6.344 million for 2011; and $7.062 million for

[50] The cost of installation is covered by other applicable budget categories such as new business or code compliance.

2012. UCAN's forecast for 2011 and 2012 is tied to its forecast of construction units, which is less than what SDG&E believes will occur.

7.2.3.4.2.3. SDG&E

SDG&E contends that DRA's forecast of the capital expenditures ignores the expenditures for the smart meter modules that attach to the gas meters. The smart meter modules included in SDG&E's forecast is to cover the costs of purchasing these modules for meter replacements that are used in routine or planned meter changes.

SDG&E objects to UCAN's forecast because it relies on UCAN's forecast of construction units, which SDG&E believes understates the rebound in construction. SDG&E also takes issue with UCAN's assumption that all the meters and regulators cost the same. SoCalGas contends that this is not the case, and that the cost depends on the size of the meters and its use.

7.2.3.4.3. Discussion

We have reviewed the parties' testimony and arguments concerning the capital expenditures for meters and regulators. We have also compared the parties' forecasts to historical spending. We have also taken into consideration the more moderate growth in the number of future customers given the state of the economy, and the need for the smart meter modules that are used in the replacement gas meters. Based on those considerations, it is reasonable to adopt DRA's recommendations regarding the capital expenditures for meters and regulators as follows: $6.083 million for 2010; $4.665 million for 2011; and $4.665 million for 2012.

7.2.3.5. Pressure Betterment

7.2.3.5.1. Introduction

The pressure betterment category of capital projects covers the costs of projects to improve pressure in areas where there is insufficient capacity or pressure to meet load growth. Typical pressure betterment projects include the installation of new main lines, and if necessary, regulator stations, or upgrading existing main lines and regulator stations to a higher pressure.

For the pressure betterment category of projects, SDG&E forecasts capital expenditures of $2.209 million for 2010, $3.121 million for 2011, and $3.704 million for 2012. These capital expenditures were based on known specific projects that were identified by SDG&E. According to SDG&E, the costs of these projects were "estimated by identifying the type, size and length of pipe and whether or not a regulator or limiting station would be involved, and multiplying by the unit cost for these materials." (Ex. 22 at 62.)

7.2.3.5.2. Position of the Parties

7.2.3.5.2.1. DRA

For the pressure betterment budget codes, DRA recommends the following capital expenditures: for 2010, the recorded amount of $852,000; and for 2011 and 2012, annual expenditures of $1.700 million.

7.2.3.5.2.2. SDG&E

SDG&E contends that DRA's forecast is deficient because DRA did not consider the pressure betterment work that was reported in budget code 545 for 2010 of $1.120 million, and did not account for this in 2011 and 2012. In addition, SDG&E contends that its forecast of capital expenditures were based on projects that have been identified as needed work to improve system pressure.

7.2.3.5.3. Discussion

We have reviewed and considered the testimony and arguments of SDG&E and DRA concerning the pressure betterment capital expenditures, and compared the forecasts to historical costs. We have also taken into account the pressure betterment work that is recorded in budget code 545. Based on those considerations, it is reasonable to adopt the following forecast of capital expenditures for pressure betterment: $1.972 million for 2010; $2 million for 2011; and $2.500 million for 2012.

7.2.3.6. Distribution Easements

7.2.3.6.1. Introduction

The distribution easements category of capital projects covers the costs of obtaining gas distribution easements. This work usually consists of survey and mapping, document research, document preparation, and negotiations for the acquisition of easements.

For this category, SDG&E forecasts annual expenditures of $30,000 in 2010, 2011, and 2012. These capital expenditures are based on the five-year average of 2005-2009.

7.2.3.2.6. Position of the Parties

7.2.3.2.6.1. DRA

DRA recommends that capital expenditures be authorized as follows for the distribution easements budget code: for 2010, the recorded amount of $11,000; and DRA accepts SDG&E's forecast of annual expenditures of $30,000 in 2011 and 2012.

7.2.3.6.2.2. SDG&E

SDG&E opposes DRA's forecast of the 2010 capital expenditures because it is based on the use of 2010 data.

7.2.3.6.3. Discussion

We have reviewed the testimony and argument of the parties concerning distribution easements, and have also compared the forecasts to historical costs. Based on those considerations, it is reasonable to adopt the following forecast of capital expenditures for distribution easements: $11,000 for 2010; $30,000 for 2011; and $30,000 for 2012.

7.2.3.7. Pipe Relocation – Franchise and Freeway

7.2.3.7.1. Introduction

The category of pipe relocation – franchise and freeway covers the costs of relocating existing gas facilities when they conflict with public improvements by local or state agencies.

For this category of projects, SDG&E forecasts capital expenditures of $4.047 million for 2010, $3.970 million for 2011, and $3.825 million for 2012. These capital expenditures are based on construction forecasts for 2010 that were provided to SDG&E by the cities, San Diego County, and the California Department of Transportation (CALTRANS).

7.2.3.7.2. Position of the Parties

7.2.3.7.2.1. DRA

DRA recommends that capital expenditures be authorized as follows for the pipe relocations – franchise and freeway budget code: for 2010, the recorded amount of $3.652 million; and for 2011 and 2012, annual expenditures of $2.398 million.[51]

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[51] Although DRA refers to the 2010 recorded amount as $3.652 million, the correct 2010 recorded amount appears to be $3.672 million as corrected in 12 R.T. 1127.

7.2.3.7.2.2. UCAN

UCAN recommends the following capital expenditures for this budget code: for 2010, the amount of $2.753; $2.544 million for 2011; and $2.466 million for 2012.[52]

7.2.3.7.2.3. SDG&E

SDG&E is opposed to DRA's forecast because DRA failed to explain why it used the five-year average of 2006-2010 to derive its 2011 and 2012 forecast. SDG&E also contends that its forecast of capital expenditures for 2010-2012 is based on the construction forecasts provided by the cities, San Diego County, and the CALTRANS. SDG&E expects that construction activities will return to the levels that occurred before the economic slowdown.

SDG&E is opposed to UCAN's forecast of capital expenditures because UCAN's methodology relies on the incorrect 2010 amount. SDG&E contends that the actual 2010 costs support SDG&E's 2011 and 2012 forecast.

7.2.3.7.3. Discussion

We have reviewed the testimony and arguments of the parties concerning the pipe relocations due to franchise and freeway. We have also compared the forecasts to the historical costs, and considered the economic conditions which affect these kinds of projects. Based on those considerations, it is reasonable to adopt the following forecast of capital expenditures for pipeline relocations due to franchise and freeway: $3.672 million for 2010; $2.400 million for 2011; and $2.900 million for 2012.

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[52] UCAN states in Exhibit 558 at 64 that its 2010 forecast of capital expenditures is based on the 2010 recorded amount. However, as SDG&E points out in Exhibit 25, the 2010 recorded amount appears to be $3.672 million.

7.2.3.8. Tools & Equipment

7.2.3.8.1. Introduction

The tools and equipment category of capital projects covers the costs of new tools and equipment that field personnel use to construct, operate, and maintain the gas distribution system. The new tools and equipment are purchased due to failure or age, advances in technology, and to improve safety.

For the tools and equipment category of projects, SDG&E forecasts capital expenditures of $313,000 for 2010, $446,000 for 2011, and $446,000 for 2012. These capital expenditures are based on the five-year average of 2005-2009 excluding historical expenditures of large, non-typical purchases. To this base forecast, SDG&E added the expenses necessary to design and construct the training facility for distribution operations field personnel, and to purchase optical methane scanners at a cost of $1.400 million in 2011.

SDG&E contends that the optical methane scanners are needed because of the mandatory GHG reporting rule. This rule requires SDG&E to annually report "methane emissions from natural gas distributions systems; annually inventory components; annually survey for leaks, and conduct other new activities." (Ex. 22 at 65.) According to SDG&E, since there is uncertainty about the specific compliance requirements, SDG&E proposes that the two-way balancing account, called the NERBA, be adopted to record the expenses that are incurred in complying with this rule.

7.2.3.8.2. Position of the Parties

7.2.3.8.2.1. DRA

For the tools and equipment budget code, DRA recommends the following: the recorded amount of $143,000 for 2010; $1.798 million for 2011; and $398,000 for 2012.

7.2.3.8.2.2. SDG&E

SDG&E contends that DRA's forecast does not reflect all of the incremental increases that SDG&E has requested. DRA's forecast does not include the costs associated with constructing a training facility "to provide enhanced training to gas distribution personnel." (Ex. 25 at 59-60.)

7.2.3.8.3. Discussion

We have reviewed the testimony and arguments of the parties concerning the capital expenditures for tools and equipment. We have also considered the need for the training facility to train gas distribution field personnel, and the costs of the tools that will be used to comply with Subpart W. As noted earlier, Subpart W requires monitoring and reporting of GHG emissions. Based on all those considerations, it is reasonable to adopt the following forecast of capital expenditures: the actual recorded cost of $143,000 for 2010; $1.846 million for 2011; and $446,000 for 2012.

As previously discussed, we also adopt the NERBA two-way balancing account to record the costs associated with complying with Subpart W. The cost of the methane scanners, which will be used to comply with Subpart W, are reflected in the adopted forecast of capital expenditures.

7.2.3.9. Code Compliance

7.2.3.9.1. Introduction

The code compliance category of capital projects covers the cost of upgrades or addition to facilities to ensure compliance with minimum federal safety standards for gas pipelines. The four main components of these capital projects are for regulator replacement programs, installation of barricades to protect meter set assemblies from vehicular traffic, installation of distribution system electronic pressure monitoring devices, and isolation valves for the safe operation of the gas distribution system.

For the code compliance category, SDG&E forecasts capital expenditures of $547,000 for 2010, $349,000 for 2011, and $441,000 for 2012. These capital expenditures were developed based on an examination of the four main components of capital projects.

7.2.3.9.2. Position of the Parties

7.2.3.9.2.1. DRA

For the code compliance budget code, DRA recommends the following capital expenditures: for 2010, the recorded amount of $441,000; and for 2011 and 2012, annual capital expenditures of $256,000.

7.2.3.9.2.2. SDG&E

SDG&E contends that DRA's forecast is not reasonable because it underestimates the capital expenditures that have historically been incurred, and did not include incremental costs.

7.2.3.9.3. Discussion

We have reviewed the testimony and arguments of the parties, and compared their forecasts to the historical costs. Based on those considerations, DRA's forecast appears to be too low because it did not account for all of the costs that are included in the code compliance budget code. It is reasonable to adopt the following forecast of capital expenditures for code compliance: $441,000 for 2010; $349,000 for 2011; and $441,000 for 2012.

7.2.3.9.10. Replacement of Mains & Services

7.2.3.9.10.1. Introduction

The category of replacement of mains and services covers the costs of replacing deteriorated gas distribution pipelines. These replacements can range from minor repairs to more complex projects. Most of the minor repairs are completed in association with leak investigation and repair work, while more extensive projects are based on evaluation criteria such as the "observed condition of the pipe, coating deterioration, leak history, age of the pipe, construction methods originally used, and location relative to places of gathering." (Ex. 22 at 68.)

For this category, SDG&E forecasts capital expenditures of $1.549 million for 2010, $1.528 million for 2011, and $1.487 million for 2012. These capital expenditures are based on the five-year average of 2005-2009.

7.2.3.10.2. Position of the Parties

7.2.3.10.2.1. DRA

For the replacement of mains and services budget code, DRA recommends the following capital expenditures: for 2010, the recorded amount of $1.233 million; and SDG&E's forecasts of $1.528 million for 2011, and $1.487 million for 2012.

7.2.3.10.2.2. SDG&E

SDG&E opposes DRA's 2010 forecast because it is based on the use of 2010 recorded data. SDG&E contends that using "2010 cost data without an overall evaluation of operating conditions ignores fundamental cost drivers that affect operations throughout the system." (Ex. 25 at 62.)

7.2.3.10.3. Discussion

Based on our review of the testimony and arguments of the parties, and comparing the forecasts to historical costs, it is reasonable to adopt the following forecast of capital expenditures for the replacements of mains and services: $1.233 million for 2010; $1.528 million for 2011; and $1.487 million for 2012.

7.2.3.11. Cathodic Protection

7.2.3.11.1. Introduction

The cathodic protection category of capital projects covers the cost of installing new and replacement cathodic protection systems and equipment to comply with state and federal pipeline corrosion control standards. Cathodic protection combats corrosion on steel pipelines by imposing an electric current flow toward the surface of the pipeline, which keeps the pipeline negatively charged with respect to the surrounding soil.

For the cathodic protection budget code, SDG&E forecasts capital expenditures of $581,000 for 2010, $646,000 for 2011, and $711,000 for 2012. These capital expenditures were developed using the five-year trend of 2005-2009.

7.2.3.11.2. Position of the Parties

7.2.3.11.2.1. DRA

For the cathodic protection budget code, DRA recommends the following capital expenditures: for 2010, the recorded amount of $364,000; and annual capital expenditures of $412,000 for 2011 and 2012.

7.2.3.11.2.2. UCAN

UCAN recommends the following capital expenditures for this budget code: $364,000 for 2010; and for 2011 and 2012, annual capital expenditures of $458,000.

UCAN contends that SDG&E's forecast for this budget code is based on a linear trend. However, UCAN contends that SDG&E's use of the linear trend "is not statistically significant," and that the "2010 spending ($364,000) was considerably less than in 2009 ($506,000) and even farther below SDG&E's forecast of $581,000, showing that there really isn't any trend at all." (Ex. 558 at 64-65.)

7.2.3.11.2.3. SDG&E

SDG&E is opposed to the forecasts of DRA and UCAN. SDG&E contends that the use of the five-year average by DRA, and the three-year average by UCAN, does not reflect the trend for this budget code. According to SDG&E, this increasing trend is due to the aging of the cathodic protection infrastructure, and increasing construction costs.

7.2.3.11.2.4. Discussion

We have reviewed the testimony and arguments of the parties concerning the capital expenditures for cathodic protection. We have also compared the forecasts to the historical costs. We are not persuaded by SDG&E's argument that the five-year increasing trend justifies its forecast. The historical data shows that costs generally increased from 2005 to 2009, with the exception of 2007. Then in 2010, as UCAN points out, the costs went down from the higher amounts that were recorded in 2006, 2008 and 2009. Based on all of those considerations, it is reasonable to adopt UCAN's recommended forecasts of capital expenditures for cathodic protection as follows: $364,000 for 2010; $458,000 for 2011; and $458,000 for 2012.

7.2.3.12. Regulator Station Improvements

7.2.3.12.1 Introduction

The category of regulator station improvements covers the costs of small capital projects that are not covered under other budget codes. These projects "typically involve upgrades to distribution piping associated with regulator stations, relocating regulator stations out of traffic due to growth and other safety improvements to distribution facilities." (Ex. 22 at 70.) Also included in this category are expenditures related to the reliability and capacity improvement of SDG&E's compressed natural gas (CNG) vehicle refueling stations.

For this category of capital projects, SDG&E forecasts capital expenditures of $614,000 for 2010, $1.332 million for 2011, and $721,000 for 2012. These capital expenditures are based on the five-year average of 2005-2009, and the addition of the SDG&E's CNG vehicle refueling stations.

Position of the Parties

7.2.3.12.2.1. DRA

For the regulator station improvements and other budget code, DRA recommends the following capital expenditures: for 2010, the recorded amount of $461,000; and annual expenditures of $484,000 in 2011 and 2012. DRA's 2011 and 2012 forecast is based on the five-year average of 2006-2010.

7.2.3.12.2.2. SDG&E

SDG&E is opposed to DRA's forecast because it utilizes 2010 data, and because DRA did not consider the incremental costs for the CNG project.

7.2.3.12.3. Discussion

The major difference between the forecasts of SDG&E and DRA is due to the incremental costs for the CNG project. According to SDG&E, this project is to improve the existing infrastructure at SDG&E's CNG vehicle refueling stations. This project consists of replacing aging dispenser controllers, adding slow-fill dispensers, and adding additional capacity. The incremental costs for this project are $93,000 in 2010, $810,000 in 2011, and $200,000 in 2012.

We have reviewed the testimony and argument of the parties, and have also compared their forecasts to the historical costs. We have also considered the need to improve SDG&E's CNG vehicle refueling stations. Based on those considerations, it is reasonable to adopt the following forecast of capital expenditures for this budget code: $461,000 for 2010; $1.050 million for 2011; and $600,000 for 2012.

7.2.3.13. Local Engineering

7.2.3.13.1. Introduction

The local engineering category covers the capital costs of a broad range of services to support gas distribution capital construction. These support service activities consist of technical planning and project management support, and engineering activities. The technical planning and project management activities include the following: planning the project; producing project drawings; acquiring and managing third party services; and estimating work order costs. The engineering activities include such activities as gas network analysis, developing construction designs and pressure control specifications, and conducting assessments of construction impacts on the reliability of the gas distribution system.

For the local engineering category, SDG&E forecasts capital expenditures of $5.083 million for 2010, $5.742 million for 2011, and $6.114 million for 2012. These capital expenditures were developed based on the ratio of the relationship of the percentage of local engineering to total direct capital expenditures, and then applied to the forecasted total capital expenditures.

7.2.3.13.2. Position of the Parties

7.2.3.13.2.1. DRA

For the local engineering budget code, DRA recommends the following capital expenditures: DRA accepts SDG&E's 2010 forecast of $5.083 million; and for 2011 and 2012, DRA recommends annual expenditures of $4.902 million. To derive its forecast for 2011 and 2012, DRA used the five-year average of 2005-2009.

7.2.3.13.2.2. UCAN

UCAN recommends the following capital expenditures for the local engineering budget code: $4.560 million for 2010; $4.497 million for 2011; and $4.687 million for 2012. UCAN's forecasts used the same method as SDG&E, but used UCAN's own estimates of the amount of capital expenditures.

7.2.3.13.2.3. SDG&E

SDG&E contends that DRA did not explain why it used a five-year average, and DRA did not recognize the relationship of local engineering to the other construction activities.

Regarding UCAN's recommendations, SDG&E takes issue with UCAN's forecast of construction activity. Since UCAN agrees with SDG&E's ratio of local engineering to construction activity, if SDG&E's estimates are adopted, the Commission should also adopt SDG&E's local engineering forecast.

7.2.3.13.3. Discussion

We have reviewed the testimony and arguments of the parties concerning the local engineering budget code. We have also compared the local engineering forecasts of the parties to their forecasts of gas distribution capital expenditures. Based on those considerations, it is reasonable to adopt the following forecast of capital expenditures for this budget code: $4.590 million for 2010; $4.900 million for 2011; and $5.100 million for 2012.

7.2.3.14. Camp Pendleton – San Onofre 1

7.2.3.14.1. Introduction

The Camp Pendleton-San Onofre 1 budget code covers the cost of replacing the master metered gas distribution system with an individually metered gas distribution system in the area known as San Onofre 1 at Camp Pendleton. This project is expected to be completed by the end of 2010.

SDG&E forecasts capital expenditures of $439,000 in 2010, and no costs in 2011 and 2012.

DRA accepts SDG&E's forecast of the capital expenditures for this budget code.

Based on the evidence presented, it is reasonable to adopt SDG&E's forecast of $439,000 in 2010 as the capital expenditure for this budget code.

7.2.3.15. Smart Meter Project

7.2.3.15.1. Introduction

The category of smart meter gas modules and installations covers the cost of the purchase and installation of the smart meter gas meter modules, the replacement of meters due to smart meter module incompatibility, and related equipment required to program the module.

The costs recorded in this category end in 2011 with the conclusion of the roll-out of the smart meter project. Starting in 2012, the costs of the purchase of the meters and associated smart meter modules are included under the meter and regulator materials category. SDG&E forecasts capital expenditures of $50.472 million for 2010, $12.713 million for 2011, and zero for 2012.

Position of the Parties

8.2.3.15.2.1. DRA

DRA recommends that the 2010 recorded amount of $43.890 million be used for 2010. DRA does not take issue with SDG&E's capital expenditure recommendations for 2011 and 2012.

8.2.3.15.2.2. SDG&E

SDG&E opposes DRA's recommendation to use the 2010 recorded amount. SDG&E contends that its total smart meter project estimate of $63.185 million from 2010-2012 has not changed, and that only the timing of the expenditures has changed due to the roll-out schedule. If DRA's recommendation is adopted, SDG&E contends that this would leave SDG&E underfunded for this project.

7.2.3.15.3. Discussion

We have considered the testimony and arguments of SDG&E and DRA concerning the smart meter project. Although the amount of money spent on capital expenditures in 2010 by SDG&E was $43.890 million, we agree with SDG&E that it still has a total project cost of $63.185 million over the three-year period of 2010-2012. SDG&E represents that the timing of the expenditures has changed because of a change in the roll-out schedule. Based on those considerations, it is reasonable to adopt capital expenditures for the smart meter project in 2010 of $50.472 million. However, we believe that SDG&E's request for funding in 2011 of $12.713 million is too high, given that the roll-out of smart gas meters has just begun. Accordingly, it is reasonable to authorize capital expenditure funding of $4 million in 2011, and zero funding in 2012.

7.3. SoCalGas

7.3.1. Introduction

SoCalGas' gas distribution system consists of about 97,400 miles of gas main lines and service lines. These lines are made of both steel and plastic materials in varying sizes. The main lines transport gas from SoCalGas' transmission lines. The main lines then connect to various service lines, which in turn connect to each individual customer's meter set assembly.

SoCalGas serves about 5.5 million gas customers over a geographic area of about 20,000 square miles. SoCalGas has about 1600 gas distribution employees who are located at four operating regional headquarters, and at 51 operating bases throughout its service territory.

SoCalGas requests O&M costs of $132.337 million for the 2012 test year, and capital expenditures for 2010, 2011 and 2012 of $187.825 million, $224.217 million, and $212.576 million, respectively.

7.3.2. O&M Costs

7.3.2.1. Introduction

SoCalGas requests that its O&M forecast of $132.337 million for the 2012 test year be adopted. This amount consists of $131.182 million for non-shared activities, and $1.155 million for shared service activities. The $132.337 million is a $38.904 million increase over the 2009 recorded amount. In contrast, DRA recommends gas distribution O&M costs of $92.829 million.

According to SoCalGas, the O&M activities include "leakage surveys, leak repairs, maintenance on mains and services, application of corrosion control measures, valve maintenance, regulator station maintenance, monitoring meter accuracy, checking for odorant, and locating and marking buried pipes to avoid damage caused from digging by others." (Ex. 26 at 11.) In addition, there is a variety of support work that needs to be done to complete the field O&M activities, such as "maintaining pipeline maps and related gas system location information, administering and implementing city permitting and traffic control requirements, and the maintenance of engineering models of system flows and pressures." (*Ibid*.)

The sections below first discuss the O&M non-shared services, followed by a discussion of the O&M shared services.

7.3.2.2. O&M Non-Shared Services

7.3.2.2.1. Introduction

SoCalGas' forecast of the non-shared O&M costs is $131.182 million.

The O&M non-shared costs for gas distribution are categorized by SoCalGas into the following categories: field operations and maintenance; asset management; operations management and training; and regional public affairs. In the sub-sections below, we discuss each of these four categories separately.

7.3.2.2.2. Field Operations and Maintenance

7.3.2.2.2.1. Introduction

SoCalGas forecasts $100.934 million for the non-shared O&M costs for field operations and maintenance.

This category of costs covers the O&M activities that address the physical condition of the gas distribution system. According to SoCalGas, these activities are preventative, corrective, or supportive in nature. The preventative work is generally performed on a scheduled basis. Corrective work reacts to a situation or facility condition. The supportive work consists of activities that are necessary for completing the work assignments.

The field operations and maintenance category consists of eight workgroups. These eight workgroups are: locate and mark; leak survey; measurement and regulation; cathodic protection field; main maintenance; service maintenance; field support; and tools, fittings and materials.

The first workgroup is locate and mark. SoCalGas forecasts these O&M costs at $10.557 million. This activity is to avoid possible damage to SoCalGas' underground gas infrastructure by third-party excavators. This process is initiated by a call to Underground Service Alert, who then notifies the owner of the underground facilities to mark the location of its facilities where the planned excavation is to take place. SoCalGas used the five-year average of 2005-2009 as its base amount, and then added incremental amounts for the following: federal stimulus funding; the installation of the Los Osos sewer system; removal of paint markings; and increased city and municipality requirements.

The second workgroup is for leak survey. SoCalGas forecasts O&M costs of $4.145 million. This workgroup records the labor and non-labor expenses associated with the federal pipeline safety regulation regarding leakage surveys. According to SoCalGas, its pipelines are leak surveyed at intervals of one, three, or five years. SoCalGas has about 97,400 miles of main and service pipeline that require leak survey. SoCalGas used the five-year average of 2005-2009 as its base amount, and then added an incremental amount for growth in its system.

The third workgroup is the measurement and regulation workgroup. SoCalGas forecasts $35.725 million in costs for this workgroup. This workgroup records the costs for the operation and maintenance of regulator stations, medium and large meter set assemblies, and associated components. The five-year average of 2005-2009 was selected as the base amount. Incremental costs were then added for the following as described in Exhibit 26: replacement of aging medium and large meter set assemblies; replacement of aging regulators at regulator stations; regulatory requirements to conduct customer load surveys; increased city and municipality requirements; regulator station lid and vault maintenance; pedestrian access at construction sites; incremental odorization testing; and to survey facilities as part of its compliance with the mandatory GHG reporting rule, which SoCalGas proposes be recorded to the NERBA.

The fourth workgroup is the cathodic protection field. SDG&E forecasts $2.946 million in O&M costs. This workgroup records the costs associated with maintaining the cathodic protection field that is used to protect buried steel pipelines from corroding. SoCalGas used the five-year average of 2005-2009 as its base amount, and then added incremental amounts for the following: federal stimulus funding; pedestrian access at construction sites; and increased city and municipality requirements.

The fifth workgroup is for main maintenance, which SoCalGas has forecast at $7.931 million. This workgroup records the costs associated with investigating and repairing leaks in distribution mains, and relocating or altering the SoCalGas distribution facilities if they conflict with a municipal project. SoCalGas used the five-year average of 2005-2009 as its base amount, and then made incremental adjustments to reflect the following: federal stimulus funding; pedestrian access at construction sites; the installation of the Los Osos sewer system; and increased city and municipality requirements.

The sixth workgroup is for service maintenance, which SoCalGas forecasts at $10.876 million. This workgroup records the costs associated with investigating and repairing leaks in the service pipelines, as well as the cost of altering the gas service lines. SoCalGas used the five-year average of 2005-2009 recorded amount for its base amount, and then made incremental adjustments for the following: federal stimulus funding; pedestrian access at construction sites; the installation of the Los Osos sewer system; increased city and municipality requirements; and replacing aging and obsolete regulators.

The seventh workgroup is field support, which SoCalGas forecasts at $18.609 million. This workgroup records the costs associated with a variety of support services to complete the daily O&M activities that take place within gas distribution operations. These support services include field supervision, clerical support, dispatch operations, off production time, and materials support. SoCalGas used the five-year average of 2005-2009 recorded amount for its base amount, and then made incremental adjustments for the following: ARSO; wireless fees for mobile data terminals; miscellaneous increased support requirements; pedestrian access at construction sites; and support training for new technology.

The eighth workgroup is for the tool, materials and fittings workgroup, which SoCalGas forecasts $10.145 million. This workgroup records the costs for small tools, pipe materials and associated installation materials, pipe fittings, and work clothing. SoCalGas used the five-year average of 2005-2009 to develop its base amount, and then added an incremental adjustment for the replacement of safety vests.

7.3.2.2.2.2. Position of the Parties

7.3.2.2.2.2.1. DRA

As described in Exhibit 533, DRA recommends reductions to all eight workgroups in the field operations and maintenance category.

For the locate and mark workgroup, DRA recommends $9.487 million, which is lower than SoCalGas' recommendation of $10.557 million. DRA's recommendation is lower because it does not believe that economic conditions will improve as rapidly as SoCalGas projects it will, and because the locate and mark activity has declined since 2005 with the exception of 2007. On the incremental costs, DRA contends that SoCalGas did not provide adequate support, except for the work associated with the Los Osos sewer system. Accordingly, DRA recommends that the 2010 recorded amount of $9.400 million be used as the base, and that an incremental increase of $60,000 for the Los Osos project be allowed.

For the leak survey workgroup, DRA does not oppose SoCalGas' forecast of $4.145 million.

For the measurement and regulation workgroup, DRA recommends $10.858 million, as opposed to SoCalGas' recommendation of $35.725 million.

This large difference is due to SoCalGas' inclusion of the NERBA for activities related to the mandatory GHG reporting rule. Without the NERBA costs, SoCalGas' forecast would amount to $12.283 million. DRA's recommendation of $10.857 million is based on the five-year average of 2005-2009 ($10.830 million), and an additional $27,000 for NERBA-related activities.

As discussed in Exhibit 533, DRA contends that SoCalGas did not provide sufficient support to justify the incremental costs that SoCalGas is requesting for the measurement and regulation workgroup. DRA further contends that some of these incremental costs are already reflected in the base forecast which reflects the historical costs of performing these same activities.

Included within the measurement and regulation workgroup is the NERBA and SoCalGas' request to fund activities related to the mandatory GHG reporting rule. DRA opposes the request for funding of activities related to the mandatory GHG reporting rule at the level SoCalGas has requested, and opposes the use of the NERBA to record such costs. DRA contends that if the NERBA is authorized, that there will be no incentive for SoCalGas to keep costs down. In addition, SoCalGas has not proposed any review of these expenses once the money has been spent. DRA also points out that the mandatory GHG reporting rule requires far less inspections than the number of sites SoCalGas included in its request for NERBA funding, and for that reason recommends that only $27,000 be authorized.

For the cathodic protection field workgroup, DRA recommends $2.102 million as opposed to SoCalGas' forecast of $2.947 million. The forecasts of both DRA and SoCalGas use the five-year average of 2005-2009. However, DRA's recommendation does not include the incremental increase of $845,000 that SoCalGas requests. DRA did not increase its forecast because it contends that SoCalGas did not provide sufficient support to justify the incremental costs.

For the main maintenance workgroup, DRA recommends $6.836 million, as opposed to SoCalGas' recommendation of $7.932 million. DRA's recommendation uses the same five – year average of 2005-2009 ($6.662 million) that SoCalGas used. DRA then added $174,000 to its forecast for the Los Osos sewer system project, instead of the $523,000 that SoCalGas had requested. DRA is opposed to the other incremental costs that SoCalGas has requested because DRA believes that SoCalGas did not provide sufficient support to justify the incremental costs.

For the service maintenance workgroup, DRA recommends $9.644 million as opposed to SoCalGas' forecast of $10.876 million. DRA and SoCalGas both used the five-year average of 2005-2009 to develop their base forecast. However, DRA only added incremental costs of $84,000 for the Los Osos sewer system project and did not adopt the other incremental costs that SoCalGas included in its forecast. DRA did not incorporate these other incremental costs because of its belief that SoCalGas did not provide sufficient support to justify the incremental costs. DRA also contends that some of these incremental activities may already be reflected in the base forecast, which incorporates the historical costs of performing these same activities.

For the field support workgroup, DRA recommends $14.688 million.[53] In contrast, SoCalGas requests $18.609 million. DRA's recommendation is based on the 2009 recorded amount ($14.411 million), whereas SoCalGas used the

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[53] The text in DRA's Exhibit 533 at 44 regarding SoCalGas' recommended forecast is inconsistent with what is shown in DRA's table at that same page.

five-year average of 2005-2009 to develop its base forecast. DRA then added incremental costs of $277,000 for support training for new technology to its 2009 base forecast. SoCalGas added a total of $3.511 million in incremental costs to its base forecast. Due to the more recent forecast of employment levels, DRA contends that its 2009 base forecast is more appropriate to use because employment levels are not projected to "return to the 2005-2006 levels until at least the 2015-2017 timeframe and not before then." (Ex. 533 at 43.) Regarding the other incremental costs that DRA did not incorporate into its forecast, DRA contends that SoCalGas did not provide sufficient support to justify the incremental costs, and that many of these costs are unnecessary or have already been paid for.

For the tools, materials, and fittings workgroup, DRA recommends $8.215 million, as opposed to SoCalGas' forecast of $10.145 million. DRA's recommendation uses the 2010 recorded amount for this workgroup. DRA contends that the 2010 recorded amount should be used because the historical spending from 2005-2010 has shown "a steady decline in the annual expenses for this work group," and because the latest forecast of economic growth only indicates a "very slight improvement in the economy" for the test year. (Ex. 533 at 50.)

7.3.2.2.2.2.2. TURN

For the leak survey workgroup, TURN recommends $4.048 million, as opposed to SoCalGas' recommendation of $4.145 million. TURN's recommendation is based on the trend of 2005-2010, as compared to the 2006-2010 trend of $3.980 million. TURN chose to use the $4.048 million amount over the $3.980 million amount "[b]ecause of the importance of leak survey work." (Ex. 545 at 4.)

For the measurement and regulation workgroup, TURN recommends $10.423 million, as opposed to SoCalGas' recommendation of $35.725 million. TURN points out that SoCalGas' 2010 spending for this workgroup was $9.900 million. For TURN's recommendation, it used the 2006-2010 five-year average as its base forecast, and then subtracted $226,000 to reflect fewer paper charts as a result of the installation of more electronic pressure monitors.

For the cathodic protection field workgroup, TURN agrees with DRA recommendation of $2.102 million. TURN contends that SoCalGas' 2010 recorded amount of $1.810 million was below SoCalGas' 2010 forecast of $2.646 million, and below the five-year average spending level of $2.102 million. TURN contends that the 2010 data shows that SoCalGas' incremental requests "for permitting, paving, traffic, pedestrians, restricted working hours, stimulus, and overtime for all new work are suspect." (Ex. 545 at 6.)

For the service maintenance workgroup, TURN recommends $9.288 million as opposed to SoCalGas' forecast of $10.876 million. TURN's recommendation is based on the five-year average of 2006-2010, and then adds an incremental amount for the Los Osos sewer system. TURN points out that the 2010 recording spending of $9.022 million was $1.219 million less than SoCalGas' 2010 forecast of $10.241 million. TURN contends that the 2010 recorded data demonstrates that SoCalGas' incremental adjustments make no sense, and that the 2010 data supports a lower amount for this workgroup.

For the field support workgroup, TURN recommends $14.903 million, as opposed to SoCalGas' forecast of $18.609 million. TURN's recommendation is based on the three-year average of 2008-2010, plus the incremental addition of $277,000 for support of new technology that DRA had added. TURN contends that its forecast is appropriate because TURN's forecast of building permits is

49% below SoCalGas' forecast, and because the 2010 recorded spending of $14.949 million was below SoCalGas' 2010 forecast of $17.222 million.

7.3.2.2.2.2.3. SoCalGas

On the locate and mark workgroup, SoCalGas disagrees with DRA's lower forecast of O&M costs for this workgroup for the reasons described in Exhibit 29. SoCalGas contends that the IHS Global Insight forecast that it referenced in its testimony, and the later IHS Global Insight forecast that DRA used, should only be used to "assess the general direction of the economy," and should not be used "to draw a one-to-one correlation between unemployment levels and locate and mark spending." (Ex. 29 at 16.) SoCalGas also points out that the more recent IHS Global Insight forecast, which DRA referenced, "continues to show positive growth and therefore continues to support [SoCalGas'] assumption of an overall upward direction for the economy." (Ex. 29 at 16-17.) SoCalGas also asserts that DRA's reliance on the number of tickets, which reflect the number of locate and mark projects, does not reflect the scope of work that may be required of each ticket. SoCalGas also contends that the time to complete each ticket is also increasing.

In rebuttal to DRA's opposition to the incremental additions that SoCalGas made to its locate and mark forecast, SoCalGas contends that: it provided DRA with "substantial evidence" to support the need for incremental funding; the timing of its requests for funding are realistic and should be adopted by the Commission; and although SoCalGas may not track historical spending on each task, that the assessment of future needs and costs by the field supervisors should not be ignored.

Regarding TURN's lower O&M forecast for the leak survey workgroup, SoCalGas contends that the 2010 data should not be used for the reasons stated earlier. SoCalGas recommends that its forecast be adopted because the 2005-2009 data shows that the leak survey activity has trended upward, which DRA and TURN both acknowledge.

DRA opposes the funding request for the replacement of the medium and large meter set assemblies that SoCalGas included for the measurement and regulation workgroup. SoCalGas contends that the cost of replacing these meter set assemblies is not reflected in the historical spending for this workgroup, and that it provided DRA with data which shows that the average age of the meters being replaced are 21.1 to 25.5 years.

In the measurement and regulation workgroup, DRA opposed SoCalGas' incremental funding request to replace aging regulators. SoCalGas contends that the information it provided to DRA establishes that there is a need to replace certain obsolete regulator models because those regulator models have been discontinued, and the parts and continuing maintenance for those regulators are expensive. Although the historical spending include the expenses for general maintenance of regulators, and for immediate replacements, the historical spending does not reflect the need to replace the 1668 regulators that SoCalGas has identified as obsolete. SoCalGas contends that the "proactive and systematic replacement of these regulators will remove obsolete equipment increasingly prone to failure from the system." (Ex. 29 at 33.)

DRA opposes the incremental request for the rebuilding of 800 customer meter set assemblies. SoCalGas points out that the five-year average does not fully reflect the number of annual rebuilds. In three of the five years, there were about 250 rebuilds per year, and in 2008 and 2009 there were annual rebuilds of about 860. SoCalGas contends that the number of rebuilds is now occurring at a higher rate, and that the historical spending levels do not support the higher levels of maintenance work.

DRA is also opposed to the incremental funding for city and municipality requirements. SoCalGas contends that it has provided substantial evidence to support its incremental funding request. The field supervisors have knowledge of these requirements, and SoCalGas included examples of different cities increasing their requirements, which impact SoCalGas' costs.

On DRA's recommendation to remove all funding to comply with the mandatory GHG reporting rule, SoCalGas contends that this rule still needs to be clarified before it "can assess the operational impacts of this final rule." (Ex. 29 at 36.) Due to the continuing uncertainty over the scope of this rule, SoCalGas contends its original estimate is reasonable, and with "the two-way [NERBA] account, should [SoCalGas] ultimately find that such expenditures are not required, the costs will be credited back to ratepayers." (Ex. 29 at 37.)

Regarding DRA's opposition to the incremental funding for regulator station lids and vaults, SoCalGas has identified 52 regulator stations where field personnel have observed that the vault or lids need repair.

On DRA's opposition to incremental funding for pedestrian access at construction sites, SoCalGas contends that it was not until late 2009 that these procedures and practices were put into practice, and that the incremental costs incurred by SoCalGas were not included in the 2005-2009 historical average or the base year. According to SoCalGas, the incremental costs are for the set-up and dismantling of the pedestrian access equipment and annual review training.

DRA also opposes SoCalGas' incremental funding request for odorant testing during the installation of meter set assemblies. Since this new operating procedure was not introduced until late 2010, there is no historical cost data for this new procedure.

On TURN's opposition to the incremental funding requests, SoCalGas contends that the 2010 data should not be used, and that TURN's summary of the 2010 spending was understated by more than $500,000, which impacts TURN's five-year average forecast (2005-2010) proposal.

On TURN's proposed reductions to the incremental costs for the measurement and regulation workgroup, SoCalGas contends that its evidence justified the need for the overtime pay, and was not an attempt to inflate SoCalGas' forecast. Regarding TURN's reduction of the paper chart pressure records, SoCalGas contends that "while maintenance costs associated with paper charts are decreasing, there are also increases in O&M expenses associated with the installation" of electronic pressure monitors." (Ex. 29 at 44-45.)

DRA and TURN oppose the incremental funding for cathodic protection. SoCalGas contends that it provided substantial evidence to support the need for incremental funding as a result of federal stimulus-related construction work. SoCalGas further contends that the incremental funding for pedestrian access at construction sites, as well as the increased city and municipality requirements will impact the cathodic protection work. For the reasons mentioned earlier, SoCalGas contends that these requests for incremental funding should be approved, and the reductions proposed by DRA and UCAN should not be adopted.

DRA opposes incremental funding for main maintenance. SoCalGas contends that the same reasons it mentioned earlier about federal stimulus spending on transportation projects, pedestrian access at construction sites, and increased city and municipality requirements, apply equally to why incremental funding for main maintenance should be approved. On the Los Osos sewer project, SoCalGas contends that all of the incremental funding it requested should be approved. SoCalGas contends that DRA fails to recognize that SoCalGas' work must begin before the city's construction activities take place, and that DRA incorrectly normalized the costs of the Los Osos sewer project.

DRA and TURN oppose the incremental funding for service maintenance. SoCalGas contends that the same reasons it mentioned earlier about the use of 2010 data, federal stimulus spending on transportation projects, pedestrian access at construction sites, increased city and municipality requirements, and the Los Osos sewer project, apply equally to why incremental funding for service maintenance should be approved. Regarding DRA's opposition to incremental funding to replace obsolete regulators that have internal relief capabilities, SoCalGas contends "that this is an incremental activity to proactively manage the replacement of service regulators." (Ex. 29 at 66.)

DRA and TURN oppose incremental funding for the field support workgroup. On DRA's use of the 2009 recorded amount as DRA's base forecast, SoCalGas contends that this is an unrealistic base forecast because the 2009 data is the lowest point over the five-year period of 2005-2009. In addition, SoCalGas contends that DRA's use of the 2009 data as its base forecast "does not address the potential for future growth, but rather assumes stagnant future economic activity." (Ex. 29 at 70.)

On DRA's opposition to incremental funding for the new ARSO, SoCalGas contends that a centralized system and process to schedule and dispatch distribution inspection and maintenance orders was not previously in place. SoCalGas has worked with consultants to estimate the level of on-going support that is needed, which is estimated at 14 scheduling advisors. Full deployment of this system was completed in 2011. SoCalGas contends that its request for six scheduling advisors is reasonable. SoCalGas also contends that the scheduling and dispatch work activities cannot be carried out by the same 60 supervisors who performed the scheduling and dispatch work, and instead will be handled by a centralized organization. As a result of the centralized scheduling and dispatch, there will be OpEx benefits. SoCalGas contends that DRA is willing to accept the OpEx benefits, but not the ongoing expenses to support the OpEx technologies and tools to achieve these benefits.

Regarding DRA's opposition to the wireless fees, SoCalGas contends that the wireless fees are needed to connect the mobile data terminals, and to use the systems and applications that have been installed.

On the incremental funding for miscellaneous support activities, SoCalGas contends that its testimony validates the increase in work for miscellaneous support activities. Regarding the incremental funding to support new technology, SoCalGas contends that its full request for incremental funding should be adopted so that the full OpEx benefits can be realized by training the employees in the use of these systems and applications. With regard to DRA's opposition to incremental funding of pedestrian access at construction sites, SoCalGas contends that this request is for annual review training, which is not included within SoCalGas' base forecast request.

On TURN's proposed reductions to the field support workgroup, SoCalGas is opposed to TURN's use of 2010 data for the reasons stated earlier. SoCalGas also contends that the incremental funding request are due to requirements by others, or because of OpEx or other business decisions, and are not directly connected to economic conditions.

SoCalGas is opposed to DRA's reductions to the tools, fittings, and materials workgroup. SoCalGas contends that DRA's reliance on a single year of spending does not reflect future expectations and changes in requirements. The single year of data that DRA relies on also reflects stagnant economic activity. SoCalGas asserts that its forecast is more reflective of the future because it uses a forecast from the IHS Global Insight which projects there will be an economic recovery.

SoCalGas also contends that the $33,000 in incremental costs for safety vests, which DRA did not allow for in its forecast, are needed in order to meet the revised standard for high visibility safety apparel. Since SoCalGas workers work in gaseous atmospheres, the safety vests must be made of materials that do not generate static electricity. SoCalGas contends that DRA's use of the 2010 recorded amount does not reflect the incremental expenditures that are needed to meet the revised standard.

7.3.2.2.2.3. Discussion

The field operations and maintenance category of activities includes eight workgroups. We address each workgroup below. For each workgroup, we reviewed the testimony and arguments of the parties for each workgroup, and compared each parties' forecasts to the historical data. Based on the below discussion, it is reasonable to adopt a forecast of $69.857 million for the field operations and maintenance category.

The first workgroup is for locate and mark. SoCalGas recommends $10.557 million, and DRA recommends $9.487 million. We agree with SoCalGas that the use of more data points for this workgroup is better than just relying on the 2010 data as DRA has done to develop its base forecast. The historical data suggests that a base forecast for the locate and mark workgroup should be between $9.800 million and $9.867 million. In reviewing the incremental costs, and the respective arguments and evidence concerning these incremental costs, we agree with DRA that economic growth will not be as robust as SoCalGas has forecasted, and that the incremental costs will not be as large as SoCalGas believes it will be. Based on those considerations, it is reasonable to adopt a forecast of $9.807 million as the O&M costs for the locate and mark workgroup.

The second workgroup is for leak survey. SoCalGas recommends $4.145 million, while TURN recommends $4.048 million. We have compared the forecasts of SoCalGas and TURN to the historical data, and have considered the regular inspections that are needed for the leak surveys of SoCalGas' distribution system. In addition, we have considered SoCalGas' adjustment for incremental growth, as compared to the 2010 data which reflects less footage surveyed in 2010 than in 2009. Based on those considerations, it is reasonable to adopt TURN's forecast of $4.048 million as the O&M costs for the leak survey workgroup.

The third workgroup is for measurement and regulation. SoCalGas recommends $35.725 million. DRA recommends $10.858 million, while TURN recommends $10.423 million.

The biggest difference for the measurement and regulation workgroup is due to SoCalGas' proposed survey of its gas pipeline facilities to comply with the mandatory GHG reporting rule. SoCalGas estimates its incremental cost of complying with this rule will be $23.442 million. As discussed earlier, and which no one disputes, Subpart W of Part 98 of Title 40 of the CFR requires SoCalGas to monitor and report its GHG emissions to the EPA. SoCalGas' estimate of how much work will be required is based on a broad interpretation of what type of facilities it will be required to monitor and report. SoCalGas is working with an industry group to clarify the extent to which facilities must be monitored. Due to this uncertainty, SoCalGas recommends that the NERBA be established as a two-way balancing account to record the costs of complying with Subpart W.

DRA and TURN seek to remove all funding for the costs of complying with Subpart W. DRA pointed out in its testimony that Subpart W only requires data collection at certain sites, which should result in a substantial downward revision to SoCalGas' estimate of $23.442 million. Since there is still uncertainty about exactly which facilities need to be monitored under Subpart W, SoCalGas did not provide an updated forecast of its Subpart W costs to DRA. DRA estimates that SoCalGas will incur $27,000 in costs to comply with Subpart W.

We have considered the amounts that SoCalGas and DRA have recommended, the obligations imposed by Subpart W, and the impact on ratepayers. Based on those considerations, it is reasonable to adopt initial funding of $2.000 million to allow SoCalGas to carry out O&M activities to comply with Subpart W.[54] All costs incurred by SoCalGas to comply with Subpart W shall be recorded to the NERBA, which is the two-way balancing account that SoCalGas has requested. As we did for SDG&E, SoCalGas is authorized to file a Tier 2 AL within 45 days of the effective date of this decision to establish a two-way balancing account to record the costs of complying with Subpart W.

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[54] One of the concerns raised by DRA is that the actual costs of complying with Subpart W may not be scrutinized if the NERBA is adopted to record these costs. Since compliance with Subpart W is a continuing obligation, DRA is free to scrutinize and raise concerns about the Subpart W spending in SoCalGas' next GRC application, or when review of the over-recovery or under-recovery of the NERBA takes place.

We have also reviewed the other incremental costs for the measurement and regulation workgroup, and considered the evidence and the arguments of the parties. Based on these considerations it is appropriate to allow a portion of the incremental costs that SoCalGas has requested. Not counting the Subpart W funding of $2 million, it is reasonable to adopt a remaining forecast of $10.500 million for the measurement and regulation workgroup. Accordingly, it is reasonable to adopt a total forecast of $12.500 million for the O&M costs for the measurement and regulation workgroup.

The fourth workgroup is for the cathodic protection field. SoCalGas recommends $2.946 million. DRA and TURN recommend $2.102 million. The difference between SoCalGas' forecast and the forecast of DRA and TURN is that DRA and TURN exclude the incremental costs that SoCalGas has requested. The largest part of SoCalGas' incremental request is for $725,000 for the increase in city and municipality requirements. We have reviewed the testimony and argument of the parties, and compared the forecasts to the historical data. Based on those considerations, the incremental increase for city and municipality requirements is too high, and it is reasonable to adopt $2.102 million as the O&M costs for the cathodic protection field workgroup.

The fifth workgroup is for main maintenance. SoCalGas recommends $7.931 million, while DRA recommends $6.836 million. The two largest incremental costs that SoCalGas requests are due to the Los Osos sewer project ($523,000) and the increase in city and municipality requirements ($648,000). We have reviewed the testimony and arguments of the parties, including their views of the outlook for city and municipality requirements and our view that economic growth will be more moderate than what SoCalGas has forecasts. We have also considered the status of the Los Osos sewer project, which started construction in 2012, and is expected to be completed in late 2014. We have also compared the parties' forecasts to the historical costs and to the five-year average. Based on these considerations, it is reasonable to adopt $6.950 million as the O&M costs for the main maintenance workgroup.

The sixth workgroup is for service maintenance. SoCalGas recommends $10.867 million. DRA recommends $9.644 million, and TURN recommends $9.288 million. We have reviewed the testimony and the arguments of the parties, and compared their forecasts to the historical costs, including the 2010 costs, and to the incremental costs that SoCalGas has requested. Based on those considerations, it is reasonable to adopt $9.750 million as the O&M costs for the service maintenance workgroup.

The seventh workgroup is for field support. SoCalGas recommends $18.609 million. DRA recommends $14.688 million, and TURN recommends $14.903 million. The primary difference between these three forecasts is due to the incremental costs that SoCalGas is requesting for this workgroup. The major components which make up this incremental increase are the following: supporting new technology ($2.731 million); the addition of six scheduling advisors for the new ARSO ($459,000); and wireless fees ($290,000) for the mobile data terminals to be installed on 730 vehicles. We have reviewed the testimony and the arguments of the parties concerning the field service workgroup. We have also compared all three forecasts to the historical costs, and to the incremental costs that SoCalGas is requesting. Based on those considerations, it is reasonable to adopt $15.100 million as the O&M costs for the field support workgroup.

The eighth workgroup is for tools, materials, and fittings. SoCalGas recommends $10.145 million, while DRA recommends $8.215 million. The main difference between the two forecasts is due to the methodologies that SoCalGas and DRA used. SoCalGas relied on the five-year average of 2005-2009 to derive its base forecast of $10.139 million. SoCalGas then added an incremental $33,000 for new safety vests. DRA used the 2010 recorded amount of $8.215 million as its test year forecast, and did not include any incremental funding for the safety vests. DRA used the 2010 recorded amount as its forecast because of the downward trend in recorded costs. We have reviewed the testimony and arguments of SoCalGas and DRA, and have compared their forecasts to the historical costs for different five-year periods. Based on those considerations, it is reasonable to adopt $9.600 million as the O&M costs for the tools, materials, and fittings workgroup.

7.3.2.2.3. Asset Management

7.3.2.2.3.1. Introduction

SoCalGas forecasts $14.190 million for the non-shared O&M costs for asset management.

The asset management category of costs covers the O&M activities that address the physical condition of the gas distribution system. These activities include the maintenance of asset records, the identification of corrective maintenance solutions, and coordination with field personnel on the completion and recording of O&M activities. The asset management category consists of the pipeline O&M planning workgroup, and the cathodic protection workgroup.

The first workgroup is the pipeline O&M planning workgroup. SoCalGas forecasts O&M costs of $7.123 million for this workgroup. This workgroup records the costs for the services provided by the technical planning office. These activities include the following: identifying construction design requirements; evaluating pressure specifications; conducting pipeline planning;

providing project drawings; identifying material selection; preparing work order estimates; acquiring third party contract services; and obtaining permits for construction. The technical planning office also coordinates the emergency response efforts by managing the gas emergency center. The gas emergency center is activated when there is a significant event, and provides support for the field operations with engineering, pipeline planning, mapping, logistics, and office resources.

For the O&M planning workgroup, SoCalGas used the 2009 recorded amount as its base amount, and then added an incremental amount for the addition of four field environmental compliance specialists.

The second workgroup is cathodic protection. SoCalGas forecasts O&M costs of $7.067 million for this workgroup. This workgroup records the costs associated with the inspection and evaluation of the cathodic protection system on SoCalGas' steel distribution pipelines. SoCalGas used the five-year average of 2005-2009 as its 2012 test year forecast.

7.3.2.2.3.2. Position of the Parties

7.3.2.2.3.2.1. DRA

DRA recommends $6.900 million for the pipeline O&M workgroup. DRA does not take issue with SoCalGas' use of the 2009 recorded amount of $6.777 million as SoCalGas' base forecast. However, DRA disagrees with SoCalGas' incremental request for four compliance specialists at a total cost of $346,000. DRA believes that only two compliance specialists are warranted because of the delay beyond the test year of "many of the data collection and reporting requirements," and because one compliance specialist for each of the four regions is unnecessary. (Ex. 533 at 54.)

For the cathodic protection workgroup, DRA agrees that SoCalGas' forecast of $7.067 million is reasonable.

7.3.2.2.3.2.2. TURN

For the pipeline O&M workgroup, TURN recommends $6.712 million as opposed to SoCalGas' forecast of $7.123 million. TURN's recommendation is based on the three-year average of 2008-2010 ($6.539 million), and the additional incremental costs of $173,000 for the two compliance specialists as recommended by DRA. TURN also points out that in 2010, SoCalGas only spent $6.272 million for this workgroup, which was less than SoCalGas' 2010 forecast of $6.777 million.

7.3.2.2.3.2.2.1. SoCalGas

The recommendations of DRA and TURN for the pipeline O&M workgroup only includes the cost of two compliance specialists, instead of the four that SoCalGas requested. SoCalGas contends that four compliance specialists are needed to perform work related to the mandatory GHG reporting rule, "stormwater discharge, and foreseeable modifications to other existing regulations." (Ex. 29 at 83.) In discussing the need for the compliance specialists, DRA talked about the cap and trade program. However, SoCalGas contends that DRA's discussion about using the compliance specialists to perform work relating to the cap and trade program is irrelevant because SoCalGas did not mention this program in its testimony about the type of work the compliance specialists would be doing. DRA also mentioned that some of the implementation dates had been delayed, which in DRA's view, justifies the hiring of only two compliance specialists. SoCalGas contends that only the mandatory GHG reporting rule was delayed, and the other new environmental regulatory requirements have not gone away. SoCalGas also contends that environmental compliance needs have increased over time, which is why four compliance specialists are needed. SoCalGas also questioned TURN's base forecast, which used the three-year average of 2008-2010. SoCalGas contends that 2010 data should not be used, and a workforce at the 2009 level is needed "to ensure it can provide the appropriate level of service to field operations." (Ex. 29 at 85.)

7.3.2.2.3.3. Discussion

For the asset management category of costs, SoCalGas recommends a total of $14.190 million. SoCalGas' recommendation consists of its recommendation of $7.123 million for the pipeline O&M planning workgroup, and $7.067 million for the cathodic protection workgroup.

DRA and TURN only take issue with SoCalGas' forecast for the pipeline O&M planning workgroup. DRA recommends $6.900 million for this workgroup, while TURN recommends $6.712 million. The difference between SoCalGas' forecast, and the forecasts of DRA and TURN, are due to how their respective base forecasts were calculated, and the allowance for two compliance specialist positions instead of the four that SoCalGas has requested.

We have reviewed the testimony and arguments of the parties concerning the asset management category of costs. We have also compared the parties' forecasts of the pipeline O&M planning costs to the historical costs, including the 2010 costs, and considered the need for compliance specialists in light of the increase in environmental regulations. Based on those considerations, it is reasonable to adopt $6.750 million as the O&M costs for the pipeline O&M planning workgroup, and $7.067 million as the O&M costs for the cathodic protection workgroup. Accordingly, the total adopted amount for the O&M costs for asset management is $13.817 million.

7.3.2.2.4. Operations Management and Training

7.3.2.2.4.1. Introduction

SoCalGas forecasts $12.151 million for the non-shared O&M costs for operations management and training. This category of costs covers the O&M activities associated with operations leadership, field management, operations support, and field technical skills training.

SoCalGas used the five-year average of 2005-2009 to develop its base amount, and then added incremental costs as described in Exhibit 26 for the following: gas operations services; engineering rotation program; technical services field management; formal field instructional materials; educational aids and equipment for field technical skills training; and video embedded system instruction.

7.3.2.2.4.2. Position of the Parties

7.3.2.2.4.2.1. DRA

For the operations management and training category of costs, DRA recommends O&M costs of $8.928 million, as opposed to SoCalGas' forecast of $12.151 million. As shown in the table in Exhibit 533 at 56, DRA's recommendation uses the 2009 recorded amount as its base forecast, and then adds incremental costs of $1.156 million for certain items that SoCalGas had requested.[55] DRA did not adopt all of SoCalGas' incremental costs because of DRA's position that: the historical costs in the base forecast already include funds for what SoCalGas is requesting as incremental costs; SoCalGas has not

[55] The text in DRA's Exhibit 533 at 56, conflicts with DRA's table at that same page. DRA states that its incremental increases total to $617,300 instead of the $1.156 million as shown in that table under DRA's forecast.

provided sufficient support for the incremental costs; and the incremental costs are excessive.

7.3.2.2.4.2.2. SoCalGas

For the base forecast, both SoCalGas and DRA use the 2009 recorded amount for labor costs. However, for non-labor costs, SoCalGas used the five-year average of 2005-2009, while DRA used the 2009 recorded amount. SoCalGas contends that the 2009 recorded amount for non-labor costs should not be used because non-labor costs are expected to exceed the lower levels of non-labor costs that were experienced in recent years. For that reason, SoCalGas used the five-year average for non-labor costs. SoCalGas also contends that DRA's use of the 2009 recorded amount for non-labor costs "does not capture the fluctuating services provided by this workgroup from year to year as well as the fluctuating non-labor levels associated with the number of employees in the workgroup." (Ex. 29 at 88.)

With regard to DRA's reductions to the incremental costs that SoCalGas is requesting, SoCalGas contends that DRA is mistaken when it asserts that the historical costs already includes the costs of employees who are moving from the OpEx program back to gas operations. SoCalGas contends that the employees of gas operations who were redeployed to the OpEx program since 2007 were charged to the OpEx program, and therefore did not show up in the historical costs for operations management and training. The OpEx employees who are being redeployed back to gas operations in 2012 are not included in the OpEx costs for the 2012 test year because the OpEx forecast is a zero-based forecast, and is not based on the historical recorded data of the OpEx program. Since there is no double counting, SoCalGas contends that this incremental funding should be approved.

On SoCalGas' request for incremental costs to support new technologies and the associated business processes that were implemented by OpEx, SoCalGas contends that the 16 incremental positions are needed "to fully support the integration of the OpEx 20/20 Program tools, technologies, and associated business process as they are rolled out." (Ex. 29 at 92.) SoCalGas also contends that the need for these 16 positions were based on the recommendations of staff who had the best understanding of the OpEx program support needs, and that SoCalGas explained how the forecasted expenses were determined. As for DRA's contention that SoCalGas did not explain how the requested positions will be utilized to integrate the OpEx applications into the business environment, SoCalGas contends that it provided such an explanation to DRA as set forth in Ex. 29 at 94.

DRA did not include incremental funding for the engineering rotation program due to a lack of support, that specific needs were not identified, and that the funding for these positions are already embedded in historical costs. SoCalGas contends that it provided substantial support as to why new engineers need to be hired, and why this program is needed. Since these new engineers will start their employment in this program, the funding request is incremental and is not embedded in historical costs.

DRA recommends that only $82,500 of the incremental funding request of $536,000 be authorized for formal field instructional materials. SoCalGas contends that all of the incremental funding should be authorized because revisions to the gas standards need to be updated in a formal manner.[56]

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[56] The gas standards refer to the many gas maintenance and construction field procedures that SoCalGas has.

Beginning in October 2009, SoCalGas began formally tracking and modifying training materials. Prior to that time, the process of revising training materials was done informally. These revisions will be performed by instructional design workers who will incorporate the revisions into the formal field training materials. These revisions will then be tracked through the use of a "centralized system which improves the monitoring and coordination of both the review of revised Gas Standards and the integration of any changes into training material. (Ex. 29 at 100.)

On the incremental need for video embedded system instruction, SoCalGas contends that its incremental funding request should be adopted so that videos of work processes can be produced, which will allow field workers to access these videos on their mobile data terminals to remind them, and to enhance their training, of how to properly and safely perform a task.

7.3.2.2.4.3. Discussion

For the category of operations, management, and training, SoCalGas forecasts $12.151 million, while DRA forecasts $8.928 million. The primary difference between the two forecasts is due to the different non-labor costs, and the amount of incremental costs that SoCalGas and DRA have incorporated into their respective forecasts. SoCalGas has included $4.148 million in incremental costs into its forecast, while DRA has included $1.094 million in incremental costs. We have reviewed the testimony and arguments of the parties, and have compared their forecasts to the historical costs. Based on all those considerations, it is reasonable to adopt $9.450 million as the O&M costs for the operations, management, and training category of costs.

7.3.2.2.5. Regional Public Affairs

7.3.2.2.5.1. Introduction

SoCalGas forecasts $3.907 million for the non-shared O&M costs for regional public affairs.

As described in Exhibit 26, this category of costs covers the O&M activities associated with regional public affairs which works with governmental entities regarding proposed regulations, permitting, franchises, emergency preparedness and response, and informing them about SoCalGas issues that could affect customers. Regional public affairs also serves as a point of contact about SoCalGas construction activities, customer programs and service offerings, responding to customer and media inquiries, and resolving customer complaints.

SoCalGas used the 2009 recorded costs for the 2012 test year. DRA does not take issue with SoCalGas' forecast of the O&M costs for regional public affairs.

7.3.2.2.5.2. Position of the Parties

7.3.2.2.5.2.1. TURN

For the category of regional public affairs, TURN recommends that no funding be allowed. TURN's recommendation is based on UCAN's recommended disallowance of these costs for SDG&E, and because TURN does not believe that SoCalGas has documented and justified its regional public affairs costs.

7.3.2.2.5.2.2. SoCalGas

SoCalGas contends that D.08-07-046 was not clear as to the definition of "public affairs," and that based on the record of that decision, SoCalGas interpreted this to mean activities relating to community relations. Based on that interpretation, SoCalGas provided information on its outreach activities in Exhibit 232. SoCalGas also contends that the focus of its regional public affairs is to support regional field operations "through its work with regional and local governments on issues regarding proposed regulations, permitting, franchises and emergency preparedness and response," and is not for the purpose of providing outreach to enhance its corporate image. (Ex. 29 at 108-109.) SoCalGas also provided numerous examples of the interactions that regional public affairs has with local governments in Exhibit 29.

7.3.2.2.5.3. Discussion

Earlier in this decision we addressed and rejected UCAN's contention that there should be no funding for SDG&E's regional public affairs. We have also reviewed the testimony that SoCalGas and TURN presented regarding SoCalGas' regional public affairs.

For the same reasons that we mentioned earlier as to why UCAN's contention should be rejected, those same reasons also apply to TURN's argument. We are not persuaded by TURN's argument that SoCalGas did not comply with D.08-07-046. A review of D.08-07-046 indicates that the activities with which the Commission expressed concerns about had to do with "corporate image enhancement." SoCalGas presented materials about its community outreach activities in Exhibit 232. SoCalGas also provided examples in Exhibit 29 of the type of work that its regional public affairs group performs in support of SoCalGas' field activities. The types of activities that SoCalGas described are not done to enhance SoCalGas' corporate image, but rather affect the gas distribution work activities that SoCalGas is engaged in. For those reasons, we do not adopt TURN's argument to disallow all funding for SoCalGas' regional public affairs. Instead, it is reasonable to adopt SoCalGas' forecast of $3.907 million for the O&M costs for the regional public affairs group.

7.3.2.3. O&M Shared Services

SoCalGas' forecast of the gas distribution O&M expense for shared services for test year 2012 is $1.155 million. These O&M expenses are to support the following business functions of SoCalGas: operations leadership; and operations technical support.

The operations leadership function covers the costs of the VP, administrative support, and miscellaneous non-labor expenses in support of the organization. The operations technical support function covers the costs associated with developing, reviewing, and enhancing gas distribution field operations, maintenance, and pipeline installation practices and procedures. The estimated total expenses for operations leadership is $349,000 and $611,000 for operations technical support. Of these totals, SoCalGas has retained $892,000 of these costs, and $263,000 was billed in from SDG&E for services from the office of the VP representing administrative support services, and the cost of two SDG&E employees who provide support for paving inspection and environmental compliance.

None of the other parties raised concerns about SoCalGas' shared O&M costs.[57]

Based on our review of the testimony concerning shared O&M services for SoCalGas, it is reasonable to adopt SoCalGas' forecast of $1.155 million for the O&M shared services for gas distribution.

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[57] To the extent a party wants to argue that SoCalGas' shared O&M costs are affected by UCAN's contention that SDG&E's shared O&M costs need to be adjusted, we have rejected UCAN's argument as discussed earlier.

7.3.3. Capital Expenditures

7.3.1.1. Introduction

This section addresses SoCalGas' estimated capital expenditures for its gas distribution utility plant for the period 2010 through 2012. SoCalGas requests $187.825 million in 2010, $224.217 million in 2011, and $212.576 in 2012.

The gas distribution capital projects are the result of customer requests or to meet system needs. SoCalGas' gas distribution capital projects are managed by project category. Within each project category are a number of different projects. SoCalGas has 15 project categories of capital expenditures. The following table is a summary of SoCalGas 'forecasted project costs by category:[58]

($ 000)

Category	2010 GRC Forecast	2011 GRC Forecast	2012 GRC Forecast	Total
New Business	31,395	37,945	43,854	113,194
NB: 29 Palms	2,800	10,200	4,800	17,800
Pressure Betterment Projects	10,936	13,306	13,200	37,442
Supply Line Replacements	3,180	3,164	3,139	9,483
Main Replacements	32,063	31,873	31,598	95,534
Service Replacements	11,639	11,529	11,408	34,576
Main & Service Abandonments	4,022	4,022	4,022	12,066
Regulator Station Projects	6,319	7,186	7,424	20,929
Cathodic Protection	4,192	4,328	4,464	12,984

[58] SoCalGas' forecast of the capital projects listed in the above summary table is described in more detail in Exhibit 26.

Category	2010 GRC Forecast	2011 GRC Forecast	2012 GRC Forecast	Total
Pipeline Relocations - Freeway	2,207	2,196	2,179	6,582
Pipeline Relocations - Franchise	9,260	9,477	9,660	28,397
Mobile Home Parks	67	67	67	201
Other Distribution Capital Projects	3,448	3,448	3,448	10,344
Meter Guard Installations	984	1,097	1,210	3,291
Meters and Regulators	24,797	26,219	31,016	82,032
Equipment/Tools	2,193	2,253	1,393	5,839
NERBA	0	15,700	0	15,700
Field Capital Support	38,323	40,207	39,694	118,224
Total	$187,825	$224,217	$212,576	$624,618

In the sub-sections below, we address each project category separately.

7.3.3.2. New Business

7.3.3.2.1. Introduction

The new business category of capital projects covers the changes and additions to the existing gas distribution system to serve new customers. These capital projects include the installations of gas main lines and service lines, meter set assemblies, and regulator stations. Included in the new business category is a separate capital project for the Twenty-nine Palms Marine Base.

For the new business category of projects unrelated to the Twenty-nine Palms Marine Base, SoCalGas recommends capital expenditures of $31.395 million for 2010, $37.945 million for 2011, and $43.854 million for 2012. These capital expenditures were based on SoCalGas' projection of new meter sets added to the gas distribution system, multiplied by the cost per meter set.

Included under the new business category is the capital project for the Twenty-nine Palms Marine Base. This project involves the installation of mains and services on the base. SoCalGas anticipates spending $2.800 million, $10.200 million, and $4.800 million in 2010, 2011, and 2012, respectively. Of this estimated spending, $11.500 million will be collected from the customer.

7.3.3.2.2. Position of the Parties

7.3.3.2.2.1. DRA

For the Twenty-nine Palms project, DRA does not dispute the costs of that new business project because the majority of the costs for this project will be recovered from the customer.

For the remainder of the new business category, DRA accepts SoCalGas' proposed expenditures of $31.195 million for 2010. For 2011, DRA recommends $15.178 million instead of SoCalGas' recommendation of $37.945 million. For 2012, DRA recommends $17.546 million instead of SoCalGas' recommendation of $43.854 million.

Although DRA accepts SoCalGas' 2010 recommended capital expenditures, DRA contends that SoCalGas was overly optimistic in the forecast of new business meter set installations. DRA also points out that SoCalGas projected new business meter set installations of 45,526 in 2010, but the actual new meter installations for 2010 was only 26,585. Also, trench reimbursement for new customers who provide their own trench was down by about 79%. The 2010 recorded capital expenditures was $12.350 million, as compared to SoCalGas' 2010 projection of $31.195 million.

DRA developed its 2011 and 2012 estimates by considering SoCalGas' acknowledgement of "the overall lower new business activity," and the lower recorded costs in 2008-2010. DRA then "applied the ratio of actual recorded expenditures to [SoCalGas'] estimates for 2010, which is 0.4, to [SoCalGas'] estimates for 2011 and 2012," which results in DRA's estimates of $15.178 million for 2011 and $17.546 million for 2012. (Ex. 535 at 7.)

7.3.3.2.2.2. TURN

TURN recommends that adjustments be made to six budget codes which are growth-related. Three of these budget codes are included in the new business category. The first budget code under new business is for main new business account. SoCalGas forecasts spending of $103.786 million in 2010-2012 to install 166,000 new meter sets at a cost of $626 per unit (based on the five-year average cost of 2005-2009). TURN forecasts that only 83,000 meter sets will be installed during that period at a cost of $438 per unit. Based on TURN's forecast, it recommends capital expenditures for this budget code of $11.631 million in 2010, $11.123 million in 2011, and $15.795 million in 2012. TURN's forecast amounts to a total of $38.549 million over the three years, as compared to SoCalGas' forecast of $103.786 million for that period.

TURN's second budget code under the new business category is for trench reimbursements. When a new customer provides the trench for new gas service, SoCalGas is required to reimburse the customer. SoCalGas has forecast these costs over the three years at $11.945 million. TURN recommends a total of $3.274 million, which is based on the following forecasts: $719,000 for 2010, $1.056 million for 2011, and $1.499 million for 2012. TURN's forecast is based on 2010 actual spending, and for 2011-2012, TURN used the three-year average of 2008-2010.

TURN's third budget code that it reviewed under new business is for new business forfeitures. New business forfeitures are customer advances for construction that are no longer deemed refundable, which reimburse the utility for the cost of unused and/or underutilized facilities that were constructed at the request of new business customers. TURN contends that SoCalGas experienced relatively stable refunds from 2005 to 2008, and that there was a small increase in 2009, and another increase in 2010. TURN contends that refunds can be expected to increase in 2009 to 2010 because the line extension allowances were reduced in 1998, which increased the amount that developers had to advance in later years. For those reasons, TURN opposes SoCalGas' use of a five-year average. TURN recommends that the 2010 actual forfeitures be used, and that the 2011-2012 forecast be based on the three-year average of 2008-2010. Instead of the $4.856 million that SoCalGas recommended in 2010 through 2012, TURN recommends $6.230 million in 2010, and $5.657 million is 2011 and in 2012.

TURN contends that a SoCalGas response to a data request indicates that the construction at the Twenty-nine Palms Marine base has been delayed, "with large amounts of spending pushed beyond the test year." (Ex. 545 at 25.) TURN recommends 2010 funding of $400,000, 2011 funding of $4.600 million, and zero funding in 2012. TURN recommends deferring $3.500 million in capital expenditures to a later date.

7.3.3.2.2.3. SoCalGas

SoCalGas contends that DRA's use of single ratio for its 2011 and 2012 forecast assumes that SoCalGas' "projections of 2011 and 2012 expenditures are overstated by the same relationship as the 2010 experience," and that reducing SoCalGas' future capital expenditures as recommended by DRA "would not recognize [SoCalGas'] need to respond to future customer needs. (Ex. 29 at 121.) SoCalGas contends that its estimates of new construction are consistent with its forecasts of customer growth, which is similar to the testimony of DRA's own witness.

TURN proposed reductions to SoCalGas' capital expenditures for new business. TURN's reductions were based on its separate analysis of construction costs and trench reimbursements. TURN's forecast of construction costs was based on TURN's forecast of meter installations and unit cost, which is much lower than what SoCalGas has proposed. For TURN's unit costs, it used the 2008-2010 average cost per meter, which was the period when new business activity was at its lowest. For trench reimbursements, TURN also relied on the average expense in the three lowest years to determine its 2011 and 2012 forecasts. Although SoCalGas "recognizes that the growth in the new housing market has been less than anticipated, " SoCalGas contends that the 2010 data should not be relied upon since it did not have an opportunity under the rate case plan to update its showing. (Ex. 29 at 122.)

TURN also proposed an increase to new business forfeitures. New business forfeitures reimburse SoCalGas for the cost of unused and/or underutilized facilities that were constructed at the request of a new business customer. According to SoCalGas, the data regarding new business forfeitures is a component of the rate base calculation, and was not displayed in the capital summary tables in SoCalGas' direct testimony on capital expenditures in Exhibit 26. The new business forfeiture amounts are dependent on customer gas throughput levels incurred over a three to ten year period. Due to the complexity of tracking each customer construction job, SoCalGas forecasted the forfeitures based on the five-year average of 2005-2009 which captures "years of high as well as years with low forfeiture amounts." (Ex. 29 at 124.) SoCalGas forecasts annual forfeiture credits of $4.856 million for 2010, 2011 and 2012. As described in Exhibit 226, SoCalGas contends that TURN's use of the 2010 data was not comparable to the 2005-2009 data, and that the 2010 data that TURN used is not reliable.

Regarding the Twenty-nine Palms Marine base project, SoCalGas acknowledges that it provided TURN with the most recent construction schedule. Based on this schedule, SoCalGas does not oppose TURN's recommended reductions for this project.

7.3.3.2.3. Discussion

For the new business category, we have reviewed the testimony and argument of the parties, including the new business forfeitures. We have also compared the parties' outlook on new meter set installations to the historical data, and to the economic outlook. Based on all those considerations, as well as the recorded 2010 costs and the number of new business meter installations in 2010, it is reasonable to adopt the following capital expenditures for new business (excluding the Twenty-nine Palms Marine base project): for 2010, the recorded amount of $12.350 million; for 2011, $17.415 million; and for 2012, $21.650 million. The adopted amounts for 2011 and 2012 are based on our view of a moderate recovery of the economy, and a comparison to what was experienced in 2008 through 2010.

For the Twenty-nine Palms Marine base project, the original construction schedule that was part of SoCalGas' original forecast of these capital expenditures has now been pushed back. Due to the delay in this project, SoCalGas does not oppose TURN's recommended funding of this project. Based on the testimony of the parties, it is reasonable to adopt capital expenditures for the Twenty-nine Palms Marine base of $400,000 for 2010, $4.600 million for 2011, and zero funding in 2012.

7.3.3.3. Pressure Betterment Projects

7.3.3.3.1. Introduction

The pressure betterment category records the costs of the gas distribution pressure betterment capital projects. These capital projects are carried out in areas where there is insufficient capacity or pressure to meet load growth. According to SoCalGas, as the load increases over time due to population expansion, increased density, or larger businesses, the existing pressure decreases which reduces the available capacity for customers. If this pressure decrease is not addressed, gas service to customers could be interrupted. These projects typically involve the installation of new main lines, and if necessary, regulator stations or upgrading of existing main lines to higher pressure lines.

For this category, SoCalGas recommends capital expenditures of $10.936 million for 2010, $13.306 million for 2011, and $13.200 million for 2012. SoCalGas' estimated expenditures for 2011 and 2012 are based on the five-year average from 2005-2009, which SoCalGas contends captures the yearly variations in system pressure betterment requirements. The 2011 and 2012 forecasts were then adjusted upwards due to the permit required by the State Water Resources Control Board for storm water discharges associated with construction activity. The forecasts were then adjusted downwards to reflect operational efficiencies from the introduction of new technology and changes in business processes.

7.3.3.3.1. Position of the Parties

7.3.3.3.1.1. DRA

DRA does not take issue with SoCalGas' forecast of capital expenditures for pressure betterment.

7.3.3.3.1.2. TURN

Based on TURN's observation of the 2005-2010 spending on pressure betterment, TURN contends it "stands to reason that more pressure betterment projects are needed when load is growing rapidly and new customers are being added." (Ex. 545 at 26.) TURN recommends that the 2010 forecast use the 2010 recorded amount of $9.341 million, and that the three-year average of 2007-2009 be used as the base forecast for a 2011 amount of $11.720 million, and a 2012 amount of $11.636 million.

7.3.3.3.1.3. SoCalGas

SoCalGas contends that "with continual changes in customer load, it is difficult to identify and estimate specific betterment projects more than a year into the future." (Ex. 29 at 125.) For 2010, SoCalGas identified some of the projects, and determined that there would not be an incremental increase over the 2009 recorded amount. For 2011 and 2012, SoCalGas' forecasts were based on the five-year average of 2005-2009 ($12.657 million), which captures the high and low levels of spending. SoCalGas then added $777,000 for a permit from the State Water Resources Control Board for storm water discharge, and reduced the forecasts for operating efficiencies.

With regard to TURN's lower amounts for the pressure betterment capital expenditures, SoCalGas contends that TURN erroneously assumes that these capital projects are needed only when load is growing rapidly. Although pressure betterment capital projects are often necessary when new load is added to the system, SoCalGas contends that "the number of projects and level of spending is much more dependent on where the load is being added." (Ex. 29 at 126.) SoCalGas further contends that if the new load is being added to the system in an area with available capacity, no new pressure betterments are needed. However, if the new load is being added in an area that has limited capacity available, pressure betterment is likely to be required. SoCalGas also points to a graph in Exhibit 29 which shows that from 2006 to 2009, new business spending and new meter sets were declining, but pressure betterment spending did not decline. SoCalGas also contends that TURN's use of a three-year average, which excludes the years with higher pressure betterment spending, would result in underfunding.

7.3.3.3.4. Discussion

Based on our review of the testimony and arguments of the parties, and a comparison of their forecasts and methodologies to the historical costs from 2005 to 2010, it is reasonable to adopt the following forecasts of the pressure betterment capital expenditures: for 2010, the recorded amount of $9.341 million; $11.720 million for 2011; and $11.930 million for 2012. These adopted amounts are in line with the pressure betterment costs that have been experienced in recent years, as well as providing sufficient funds for the permit for storm water discharges.

7.3.3.4. Supply Line Replacements

7.3.3.4.3. Introduction

The supply line replacements category of capital projects records the costs associated with replacing high pressure distribution pipelines. These supply lines normally operate at pressures higher than 60 pounds per square inch gauge.

The condition of the supply lines are typically evaluated through SoCalGas' O&M activities involving excavations, leakage surveys, and damage repairs. If a supply line is found to have deteriorating conditions, SoCalGas conducts an engineering evaluation of the supply line to determine whether it should be replaced or abandoned.

Spending for supply line replacements vary from year to year. SoCalGas has identified eight projects that need replacement of the supply lines. The timing of these projects is "still dependent on a timely review of operating conditions, detailed planning requirements, acquiring the required permits, and coordination of scheduling." (Ex. 26 at 67.) Due to this uncertainty, SoCalGas estimated capital expenditures for 2010 through 2012 based on the five-year average of 2005-2009. SoCalGas recommends capital expenditures of $3.180 million for 2010, $3.164 million for 2011, and $3.139 million for 2012. The forecasts were then adjusted downwards to reflect operational efficiencies.

7.3.3.4.2. Position of the Parties

7.3.3.4.2.1. DRA

DRA does not take issue with SoCalGas' forecast of capital expenditures for supply line replacements.

7.3.3.4.2.2. TURN

TURN recommends the following capital expenditures for supply line replacements: $1.237 million for 2010; $2.612 million for 2011; and $2.592 million for 2012. TURN's forecast is based on the five-year average of 2006-2010.

7.3.3.4.2.3. SoCalGas

SoCalGas opposes the use of 2010 data by TURN. Although SoCalGas did not spend as much on supply line replacements in 2010, it "still expects to need at least as much as was forecasted for the combined years, and supply line spending in 2011 and 2012 is expected to exceed the original forecasted level for those years." (Ex. 29 at 130.) SoCalGas' updated list of supply line projects are estimated to total to $13.8 million instead of the total of $9.483 million that SoCalGas originally forecasted. SoCalGas contends that to maintain the safety and reliability of this replacement work, SoCalGas' forecast should be adopted instead of TURN's lower forecast.

7.3.3.4.3. Discussion

We have reviewed the testimony and argument of the parties concerning the supply line replacements. We have also compared the forecasts and methodologies of SoCalGas and TURN to the historical data. Based on the recent historical spending, and the supply line replacement projects that SoCalGas plans to undertake, it is reasonable to adopt the following capital expenditures for supply line replacements: for 2010, the recorded amount of $1.237 million; $2.612 million for 2011; and $2.592 million for 2012.

7.3.3.5. Main Replacements

7.3.3.5.1. Introduction

The main replacements category of capital projects records the costs associated with replacing the main lines that support the delivery of gas to SoCalGas' customers, as well as the costs of replacing the service lines as part of the replacement of the main lines.

The condition of the main lines is evaluated based on various O&M activities and field observations. The pipeline segments that require replacement are then prioritized.

SoCalGas used the five-year average of 2005-2009 to develop its forecast of capital expenditures. The forecasts were then adjusted downwards to reflect operational efficiencies. SoCalGas recommends capital expenditures of $32.063 million for 2010, $31.873 million for 2011, and $31.598 million for 2012.

7.3.3.5.2. Position of the Parties

7.3.3.5.2.1. DRA

DRA does not dispute SoCalGas' forecasts of the capital expenditures for main replacements.

7.3.3.5.2.2. TURN

For the 2010 forecast of capital expenditures, TURN recommends that the actual 2010 recorded amount of $43.982 million be used. TURN did not dispute SoCalGas' forecasts for 2011 and 2012.

7.3.3.5.2.3. SoCalGas

For the reasons mentioned earlier, SoCalGas opposes the use of the 2010 data. SoCalGas recommends that its 2010 forecast of $32.063 million be used instead of TURN's recommendation of $43.982 million.

7.3.3.5.3. Discussion

Based on a review of the testimony and arguments of the parties, it is reasonable to adopt the following capital expenditures for main replacements: $32.063 million for 2010; $29.873 million for 2011; and $29.598 million for 2012. We do not adopt TURN's 2010 forecast because TURN's recommended amounts over the three year period would provide more money than what SoCalGas forecasted will be needed. With respect to the reductions in capital expenditures for 2011 and 2012, those reductions are warranted given the size of those expenditures in each of those years, and the cost burden on ratepayers due to current economic circumstances.

7.3.3.6. Service Replacements

7.3.3.6.1. Introduction

The service replacements category of capital projects records the costs associated with replacing the service lines that support the delivery of gas to SoCalGas' customers. This replacement work usually occurs as a result of leaks. According to SoCalGas, most of the leaks are found on steel service lines that do not have cathodic protection. Sometimes SoCalGas replaces the entire service line, instead of repairing the leak and installing and maintaining cathodic protection on the existing service line.

SoCalGas used the five-year average of 2005-2009 to develop its forecast of capital expenditures. This five-year average was used by SoCalGas because "this category of spending has remained fairly constant over time." (Ex. 26 at 69.) The forecasts were then adjusted downwards to reflect operational efficiencies. SoCalGas recommends capital expenditures of $11.639 million for 2010, $11.529 million for 2011, and $11.408 million for 2012.

7.3.3.6.2. Position of the Parties

7.3.3.6.2.1. DRA

DRA does not dispute SoCalGas' forecasts of the capital expenditures for service replacements.

7.3.3.6.2.2. TURN

For the 2010 forecast of capital expenditures, TURN recommends that the actual 2010 recorded amount of $11.458 million be used. TURN did not dispute SoCalGas' forecasts for 2011 and 2012.

7.3.3.6.2.3. SoCalGas

For the reasons mentioned earlier, SoCalGas opposes the use of the 2010 data. SoCalGas recommends that its 2010 forecast of $11.639 million be used instead of TURN's recommendation of $11.458 million.

7.3.3.6.3. Discussion

We have reviewed the testimony and arguments of the parties concerning the capital expenditures for service replacements. We have also taken into account the historical data, and SoCalGas' acknowledgement that this category of costs has remained fairly stable. Based on these considerations, it is reasonable to adopt the following capital expenditures for service replacements: for 2010, the recorded amount of $11.458 million; $11.029 million for 2011; and $11.000 million for 2012. Although DRA and TURN did not contest the capital expenditures for 2011 and 2012, those costs are a large and recurring expense.

Due to the current economic conditions, slight reductions to those costs are warranted to alleviate the burden on ratepayers.

7.3.3.7. Main and Service Abandonments

7.3.3.7.3. Introduction

The main and service abandonments category of capital projects records the costs associated with the abandonment of distribution main lines and service lines without installing replacement pipeline. The abandonment usually occurs when the pipeline is no longer needed for current system operations, and it is not expected to be needed in the future. The abandonment of main lines and service lines render the lines inactive.

SoCalGas used the five-year average of 2005-2009 to develop its forecast of capital expenditures. SoCalGas recommends annual capital expenditures of $4.022 million for 2010, 2011, and 2012.

7.3.3.7.2. Position of the Parties

7.3.3.7.2.1. DRA

DRA does not take issue with SoCalGas' forecasts of the capital expenditures for main and service abandonments.

7.3.3.7.2.2. TURN

TURN contends that the 2010 recorded amount of $2.515 million was well below SoCalGas' forecast of $4.022 million. Instead of using SoCalGas' five-year average of 2005-2009, TURN recommends using the 2010 recorded amount of $2.515 million for 2010, and the three-year average of 2008-2010 ($3.013 million) for 2011 and 2012.

7.3.3.7.2.3. SoCalGas

SoCalGas contends that the five-year average of 2005-2009 was used due "to the unscheduled and unpredictable nature of this work." (Ex. 29 at 131.) TURN opposes the use of the earlier historical data. SoCalGas contends that the costs were higher in the earlier years because it was "driven by increased work elements, timing of projects, other field construction requirements, job skills requirements, complexity of jobs, and/or job locations." (Ex. 29 at 132.) Since the expenditures for this category of costs varies, SoCalGas contends that its use of the longer five-year average is appropriate.

7.3.3.7.4. Discussion

We have reviewed the testimony and arguments of SoCalGas and TURN. We have also compared their respective forecasts and methodologies to the historical data from 2005-2010. Based on the recorded data in recent years, and state of the economy, it is reasonable to adopt the following forecasts as the capital expenditures for main and service abandonments: for 2010, the recorded amount of $2.515 million; and for 2011 and 2012, TURN's recommendation of $3.013 million for each year.

7.3.3.8. Regulator Station Projects

7.3.3.8.3. Introduction

The regulator station projects record the costs associated with the upgrade, relocation, and replacement of regulator stations. The regulator stations lower the pressure of the gas that comes from the high pressure pipelines as it enters the distribution system. These stations consist of valves and regulators, and in many cases are located in underground vaults. SoCalGas operates and maintains approximately 2000 regulator stations. According to SoCalGas, 700 of these stations are over 35 years old, which is the average life expectancy of a regulator station. Historically, between 11 and 24 stations are addressed in any one year. According to SoCalGas, the failure of a regulator station could result in over-pressurization of the gas distribution system, which may result in reduced service to customers, and could jeopardize the safety of the public.

SoCalGas proposes to address 21, 24, and 25 stations over the three years. SoCalGas recommends annual capital expenditures of $6.319 million, $7.186 million, and $7.424 million in 2010, 2011, and 2012, respectively. SoCalGas' recommendations are based on the five-year average of 2005-2009.

7.3.3.8.2. Position of the Parties

7.3.3.8.2.1. DRA

DRA does not take issue with SoCalGas' forecasts of the capital expenditures for regulator station projects.

7.3.3.8.2.2. TURN

TURN contends that SoCalGas has overstated the average unit cost per station. Instead of the $302,620 per station that SoCalGas calculated, TURN contends that the average cost per station was $278,185 for the period 2005-2009.

TURN also contends that the 2010 recorded amount for this category of costs was $3.831 million, as opposed to SoCalGas' 2010 forecast of $6.355 million. According to SoCalGas' response to a TURN data request, the 2010 costs paid for 19 stations (instead of the 21 that SoCalGas had forecasted) at a unit cost of $201,630.

TURN recommends that for 2010, the actual recorded amount of $3.831 million be used. For 2011 and 2012, TURN used SoCalGas' forecast of the number of stations per year that SoCalGas plans to replace, and multiplied that by a per unit cost of $250,000 per station. That results in a forecast of $6.000 million for 2011, and $6.250 million for 2012.

7.3.3.8.2.3. SoCalGas

SoCalGas contends that the "type of regulators installed per year vary in size and complexity so that, in some years, the complexity of regulator station installations is greater than in other years, which causes the variation in unit cost per regulator station in any give[n] year." (Ex. 29 at 134.) For that reason, SoCalGas used the five-year average of 2005-2009 to forecast the costs of the regulator stations.

SoCalGas does not object to TURN's averaging methodology to calculate the unit cost for the regulator station replacements, but insists that the appropriate averaging period to use is 2005-2009, instead of including the 2010 data.

SoCalGas also points out that TURN made an error in its calculation of the proposed average cost per unit. Instead of $250,000 per unit that TURN calculated, the per unit cost should be $264,000.

7.3.3.8.3. Discussion

We have reviewed the testimony and arguments of the parties concerning the capital expenditures for the regulator station projects. We have also taken into consideration the type of work that may be needed at each individual regulator station, and reviewed the historical cost data and the methodologies that the parties used. Based on those considerations, we adopt the following capital expenditures for regulator station projects: for 2010, the recorded amount of $3.831 million; $6.000 million for 2011; and $6.250 million for 2012.

7.3.3.9. Cathodic Protection

7.3.3.9.1. Introduction

The cathodic protection category of capital projects records the costs associated with the installation and replacement of cathodic protection systems and equipment. Cathodic protection is one form of mitigating external corrosion on steel pipelines by sending an electric current flow toward the surface of the pipeline. Federal regulations set forth the standards for pipeline corrosion work.

SoCalGas used the five-year average of 2005-2009 to develop its forecast of capital expenditures for cathodic protection. SoCalGas recommends annual capital expenditures of $4.192 million, $4.328 million, and $4.464 million for 2010, 2011, and 2012, respectively.

7.3.3.9.2. Position of the Parties

7.3.3.9.2.1. DRA

DRA reviewed the recorded costs for the five-year period from 2005-2009. Based on that review, DRA believes there is only an insignificant upward trend, and that the five-year average of 2005-2009 should be used instead. DRA recommends capital expenditures of $4.192 million in 2010, and $3.782 million per year for 2011 and 2012.

7.3.3.9.2.2. TURN

TURN takes issue with SoCalGas' reliance on the five-year trend. TURN contends that the data "is not statistically significant and most of the difference is explained because of a large jump in spending between 2005 and 2006," and was not due to an ongoing trend. (Ex. 545 at 28.) TURN also points out that the 2010 capital spending of $3.362 million, which was the lowest since 2005, is not consistent with an upward trend. Due to the absence of a trend, and because the 2010 data is relatively low, TURN recommends that the five-year average of 2006-2010 ($3.788 million) be used for 2011 and 2012, and that the actual 2010 amount of $3.362 million be used for 2010.

7.3.3.9.2.3. SoCalGas

SoCalGas used the trend of 2005-2009 because of the continuing increases it has experienced for deep well drilling, and its aging infrastructure. SoCalGas contends that DRA failed to address the effects of contractor rates and infrastructure age when DRA was analyzing whether an upward trend exists.

According to SoCalGas, it "has experienced a 17% real increase in contractor costs for deep well drilling over the period 2005 to 2009," and that the average cost of a well drilled in 2005 was $31,700, and that in 2009 the average cost had risen to $37,100. (Ex. 26 at 73; Ex. 29 at 136.)

SoCalGas opposes TURN's forecast of the capital expenditures for cathodic protection. SoCalGas contends that TURN's analysis of the 2010 data ignores the higher contractor costs, and that the 2010 data should not be used.

7.3.3.9.3. Discussion

We have reviewed the testimony and the arguments of the parties concerning the capital expenditures for cathodic protection. We have also compared the methodologies and forecasts of the parties to the historical costs, and considered the higher contractor costs and the aging infrastructure. Based on these considerations, it is reasonable to adopt the following amounts: for 2010, the recorded amount of $3.362 million; for 2011, $3.782 million; and for 2012, $3.800 million.

7.3.3.10. Pipeline Relocations - Freeway

7.3.3.10.1. Introduction

The pipeline relocations-freeway category of capital projects records the costs associated with the relocation or alteration of SoCalGas' facilities due to the planned construction or reconstruction of freeways. Since this work is performed at the request of external agencies, the timing and number of freeway pipeline projects is largely outside the control of SoCalGas.

SoCalGas used the 2009 recorded costs to develop its base forecast of capital expenditures, which was then reduced because of new technology and changes in business processes that are anticipated to improve operating efficiencies. SoCalGas recommends capital expenditures of $2.207 million, $2.196 million, and $2.179 million for 2010, 2011, and 2012, respectively.

7.3.3.10.2. Position of the Parties

DRA does not take issue with SoCalGas' forecast of capital expenditures for pipeline relocations due to freeway construction. TURN recommends that for 2010, the actual recorded amount of $1.740 million be used. TURN does not oppose the 2011 and 2012 forecasts. SoCalGas opposes TURN's use of the 2010 data.

7.3.3.10.3. Discussion

We have reviewed the testimony and argument of the parties concerning the capital expenditures related to freeway pipeline relocations. Based on those considerations, it is reasonable to adopt the following capital expenditures as follows: for 2010, the recorded amount of $1.740 million; $2.196 million for 2011; and $2.179 million for 2012.

7.3.3.11. Pipeline Relocations-Franchise

7.3.3.11.1. Introduction

The pipeline relocations-franchise category of capital projects records the costs associated with the relocation or alteration of SoCalGas' facilities due to the construction or reconstruction of roads or railway systems. Since this work is driven by external agencies, SoCalGas cannot accurately predict when these projects will be carried out.

SoCalGas used a trend of the five-year period of 2005-2009 to develop its forecast of capital expenditures, which was then reduced because of new technology and changes in business processes that are anticipated to improve operating efficiencies. SoCalGas recommends capital expenditures of

$9.260 million, $9.477 million, and $9.660 million for 2010, 2011, and 2012, respectively.

7.3.3.11.2. Position of the Parties

7.3.3.11.2.1. DRA

DRA reviewed the expenditures for the five year period from 2005 to 2009. DRA contends that this historical data fluctuated, and that there was an insignificant upward trend. Instead of using a trend, DRA used the five-year average of 2005-2009 to derive its forecast of $8.516 million for 2011 and for 2012. DRA does not take issue with SoCalGas' 2010 forecast of $9.260 million.

7.3.3.11.2.2. TURN

TURN recommends that the recorded amount of $11.016 million be used for 2011, and does not appear to take issue with SoCalGas' 2011 and 2012 forecasts.[59]

7.3.3.11.2.3. SoCalGas

SoCalGas contends that DRA's proposal to use the five-year average is not appropriate because "this category of spending is driven by the expected actions of external third parties." (Ex. 29 at 138.) SoCalGas expects to see a growth in requests for relocations due to an improving economy, the availability of federal funding for municipalities, population growth and density, and the age of the infrastructure. SoCalGas contends that DRA failed to address these drivers.

7.3.3.11.3. Discussion

We have reviewed the testimony and argument of the parties, and compared the parties' forecasts and methodologies to the historical costs. Based

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[59] The $11.016 million amount appears in Exhibit 29 at 118, which reflects SoCalGas' adjustment of TURN's amount of $10.209 million or $10.247 million as shown in Exhibit 545 at 33 and in the footnotes to Exhibit 29 at 118.

on those considerations, recent historical costs, and the slow down in the economy, it is reasonable to adopt the following capital expenditures for pipeline relocations due to franchise agreements: for 2010, the recorded amount of $11.016 million; $8.800 million for 2011; and $8.900 million for 2012.

7.3.3.12. Mobile Home Parks

The mobile home park category of capital projects records the costs associated with the purchase of existing natural gas distribution systems that are located at mobile home parks. Pub. Util. Code § 2791 requires the gas utilities to work with mobile home park owners, upon written request, to transfer ownership of their gas distribution systems.

SoCalGas used the five-year average of 2005-2009 to derive its forecast of capital expenditures. SoCalGas recommends annual capital expenditures of $67,000 for 2010, 2011, and 2012. No one opposed SoCalGas' forecasts.

Based on our review of the testimony, and Pub. Util. Code § 2791, it is reasonable to adopt annual capital expenditures of $67,000 for 2010, 2011, and 2012 for the mobile home park category.

7.3.3.13. Other Distribution Capital Projects

7.3.3.13.1. Introduction

The other distribution capital projects category records the costs of other activities that are not specifically included in other categories of work. Some examples include the following: replacement, alteration, or abandonment of such things as valves, vaults, roads and fences; raising, lowering or relocating mains due to interference with other companies' pipeline facilities; conversion of high pressure main to medium pressure; and changes to SoCalGas' facilities due to a customer request.

SoCalGas used the five-year average of 2005-2009 to develop its forecast of capital expenditures. SoCalGas recommends annual capital expenditures of $3.448 million for 2010, 2011, and 2012.

Also included in the category for other distribution capital projects is the cost of meter guard installations. The meter guard installations are installed at certain locations to protect the meter set assemblies from vehicle traffic. SoCalGas used the five-year average of 2005-2009 to develop its base forecast of capital expenditures, and expects an annual growth in spending of 19%. SoCalGas recommends capital expenditures of $984,000, $1.097 million, and $1.210 million for 2010, 2011, and 2012, respectively, for the meter guard installations.

7.3.3.13.2. Position of the Parties

7.3.3.13.2.1. DRA

DRA does not take issue with SoCalGas' forecasts of the capital expenditures for other distribution, or for the meter guard installations.

7.3.3.13.2.2. TURN

For the other distribution projects, TURN contends that SoCalGas' use of the five-year average includes the 2005 to 2007 period, when the economy was doing well. TURN believes that during the economic growth period of 2005 to 2007, there were many customers who requested relocation of facilities. Due to the economic slowdown, TURN used the three-year average of 2008-2010 to derive its forecasts. TURN recommends that the recorded amount of $2.653 million be used for 2010, and that the amount of $3.073 million be used for 2011 and for 2012.

For the meter guard installations, TURN recommends that the recorded amount of $1.227 million be used for the 2010 forecast, as shown in

Exhibit 545 at 33, and in Exhibit 29 at 118. TURN does not dispute SoCalGas' forecasts for the 2011 and 2012 capital expenditures.

7.3.3.13.2.3. SoCalGas

SoCalGas used the five-year average of 2005-2009 to derive its forecast for the category of other distribution capital. It used this average to "capture the variability of work elements and reflect the anticipated improvement in economic conditions…." (Ex. 29 at 139-140.)

SoCalGas is opposed to TURN's forecast because it includes the use of 2010 data. SoCalGas also contends that the five-year average is a directional indicator, rather than a reflection of an economic boom as TURN has characterized the 2005-2007 data. SoCalGas also contends that TURN's forecast did not consider the variability of the work elements.

For the meter guard installations, SoCalGas notes that TURN used the recorded amount for TURN's 2010 forecast.

7.3.3.13.3. Discussion

For the other distribution capital projects (excluding the meter guard installations), we have reviewed the testimony and arguments of SoCalGas and TURN. We have also reviewed their respective forecasts and compared them to the historical data. We have also taken into consideration the state of the economy and the variability of the work elements. Based on those considerations, it is reasonable to adopt the following amounts for the other distribution capital expenditures: for 2010, the recorded amount of $2.653 million; and $3.073 million for 2011 and for 2012.

For the capital expenditures related to meter guard installations, we have reviewed the testimony and arguments of SoCalGas and TURN. Based on that review, it is reasonable to adopt the following capital expenditures for meter guard installations: for 2010, the recorded amount of $1.227 million; $1.097 million for 2011; and $1.210 million for 2012.

7.3.3.14. Meters and Regulators

7.3.3.14.1. Introduction

The meters and regulators category records the costs for the purchase of gas meters, pressure regulators, electronic pressure and temperature correction equipment, and electronic pressure monitors.

SoCalGas has requested funding of $24.797 million, $26.219 million, and $31.016 million for 2010, 2011, and 2012, respectively. SoCalGas' forecasts are based on the forecasted purchases of all four of the above types of equipment. The forecasts for each type of the equipment used different methodologies.

For the purchase of meters, SoCalGas based the labor costs "on the 2009 average labor cost per unit for warehouse handling, technical evaluations, and quality assurance multiplied by the number of forecasted meter units purchased." The non-labor costs were "based on a blended rate of the meter contract prices multiplied by the new business installation and replacement requirements." (Ex. 26 at 80.) Due to the number of meters to be purchased, SoCalGas negotiated a three year contract for the period January 1, 2010 through December 31, 2012.

Due to the high number of pressure regulators to be purchased, SoCalGas also negotiated a three year contract for the period January 1, 2010 through December 31, 2012. The methodology that SoCalGas "used to calculate the required funding for regulator purchases was based on a blended rate of the regulator contract prices multiplied by the new business installation and replacement requirements." (Ex. 26 at 81.)

For the purchase of volumetric correctors, SoCalGas notes that the costs for these instruments range from $500 to $200,000 each, which can result in a wide variation in average cost between years.

For the purchase of electronic pressure monitors, SoCalGas used the 2009 unit cost multiplied by the forecasted number of electronic pressure monitor purchases.

7.3.3.14.2. Position of the Parties

7.3.3.14.2.1. DRA

DRA contends that SoCalGas' forecast of new meter purchase is too optimistic. SoCalGas forecasted 234,506 new meter purchases for 2010 at a cost of $19.351 million. However, DRA points out that only 198,341 new meters were purchased in 2010 at a cost of $15.937 million.

DRA also points out that the 2010 total recorded capital expenditures for the meters and regulators category was $20.501 million, as compared to SoCalGas' 2010 forecast of $24.797 million. DRA contends that this 2010 recorded amount is in line with the 2008 amount of $21.798 million, and the 2009 amount of $20.413 million.

As described in Exhibit 535, DRA developed its forecasts for 2011 and 2012 by taking into account the current level of new business activity, and the lower recorded expenditures in 2008 to 2010. DRA made a downward adjustment to the estimates for meters and gauges, but did not reduce SoCalGas' plan to buy 100,000 additional regulators to replace the aging regulators. DRA recommends the following capital expenditures for meters and regulators: $24.797 million for 2010; $22.791 million for 2011; and $27.461 million for 2012.

7.3.3.14.2.2. TURN

TURN recommends the following forecasts for the meter and regulators capital expenditures: for 2010, the actual recorded amount of $20.501 million; $22.815 million for 2011; and $24.697 million for 2012.

For TURN's forecast of the 2011 and 2012 spending for meters, TURN proportionally reduced SoCalGas' spending level down to TURN's estimate of the meter requirements.

TURN reduced SoCalGas' forecast for the spending on regulators. TURN reduced the number of regulators because of its belief that there will be less growth than what SoCalGas has forecasted. TURN also reduced the spending for regulators because of TURN's belief that 100,000 regulators will not be purchased in the last quarter of 2012, and if they are, they should be deemed to be purchased in 2013 since SoCalGas "admits that the meters are specifically not needed in 2012 at all." (Ex. 545 at 23.)

TURN also reduced the spending for electronic pressure correctors because of TURN's lower forecast regarding meter growth.

7.3.3.14.2.3. SoCalGas

SoCalGas takes issue with DRA's forecast because DRA's method extrapolates the 2011 and 2012 activity based on the 2010 activity. SoCalGas contends that DRA did not explain the relationship of the 2010 data to its 2011 and 2012 projections. SoCalGas also contends that DRA's forecast ignores SoCalGas' forecast of future units of new construction, SoCalGas' planned meter change outs, and its inventory requirements. SoCalGas contends that the "meter inventories must remain at a level which can support operational logistics and minor supply chain interruptions." (Ex. 29 at 144.)

SoCalGas takes issue with the adjustments that TURN has recommended. Although SoCalGas acknowledges "that the growth in the new housing market has been less than anticipated," "the forecast needs to be sufficient to meet customer needs." SoCalGas points out that TURN's forecast of the meter sets is 49% lower per year than the level SoCalGas has forecasted. SoCalGas also contends that TURN's forecast does not recognize the need to have an inventory of meters. SoCalGas contends it needs to maintain a reserve inventory of meters in case of interruptions in its supply chain, and to reduce the inventory by using what is in stock is not practical.

Regarding TURN's reduction to the regulator purchases, SoCalGas contends that TURN's reference to the 2010 actual purchases was understated by $196,000. SoCalGas also contends that SoCalGas' purchase of the extra regulators will be installed at the time of meter changes that have already been planned for the year, or in conjunction with the module installations for the gas smart meters. The purchase of the extra regulators is to obtain a sufficient inventory before the change-outs take place.

SoCalGas is also opposed to TURN's adjustments to the electronic pressure correctors because it contends that TURN's forecast for new meter growth is too low, which reduces the amount that TURN has forecasted.

7.3.3.14.3. Discussion

We have reviewed the testimony and arguments of the parties, and have reviewed the historical data regarding the number of meters, regulators, and pressure correctors that have been purchased in the past. We have also considered the state of the economy, the parties' outlook for economic growth, the need to maintain inventory, and the purchases planned by SoCalGas. Based on all those considerations, and consistent with our view that there will be moderate economic growth, it is reasonable to adopt the following capital expenditures for the meters and regulators: for 2010, the recorded amount of $20.501 million; $23.310 million for 2011; and $28.025 million for 2012.

7.3.3.15. Equipment/Tools

7.3.3.15.1. Introduction

The equipment/tools category of capital projects records the costs associated with the purchase of capital tools and equipment used by field personnel for the maintenance and repair of the gas distribution system. These capital expenditures include routine purchases to replace broken or obsolete tools and equipment on an as-needed basis, as well as small purchases of technologically advanced tools and equipment. In 2009, SoCalGas began to replace its existing leak and carbon monoxide detection equipment with a single instrument. SoCalGas also plans to purchase 100 remote laser leak detectors to allow it to leak survey in locations that are difficult to access. The capital expenditures for equipment and tools are $2.193 million, $2.253 million, and $1.393 million in 2010, 2011, and 2012, respectively.

SoCalGas has also included costs that it requests be recovered in the NERBA, which it listed under the equipment/tools category. Proposed environmental reporting rules will require SoCalGas to annually report "methane emissions from natural gas distributions systems; annually inventory components; annually survey for leaks, and conduct other new activities." (Ex. 26 at 86.) According to SoCalGas, data collection may begin in January 2011, and the first report may be due in March 2012. In order to comply with the data collection requirements, SoCalGas plans to purchase optical scanning equipment at an estimated cost of $15.700 million in 2011.[60] SoCalGas contends that since there is uncertainty about the specific compliance requirements, it proposes that the NERBA be established as a two-way balancing account, to record the expenses incurred.

7.3.3.15.2. Position of the Parties

7.3.3.15.2.1. DRA

DRA recommends the following capital expenditures for the equipment/tools category: $2.193 million for 2010; $7.253 million for 2011; and $1.393 million for 2012.

DRA contends that $15.700 million of the $17.953 million that SoCalGas has requested for 2011 is for the purchase of optical scanners for surveying leaks pursuant to Subpart W of the mandatory GHG reporting rule. The preliminary version of this rule appeared to require widespread monitoring. According to DRA, when the final version of this rule was adopted, the number of sites that require monitoring has been greatly reduced. As a result, DRA contends that fewer optical scanners are needed. Instead of purchasing "approximately three units per district for a total of 157 units at $100,000 each…DRA recommends about one unit per district for a total of 50 units at $5 million, resulting in a reduction of $10.7 million." (Ex. 535 at 10.)

7.3.3.15.2.2. TURN

TURN contends that SoCalGas' response to a TURN data request shows that SoCalGas "has spent and is budgeting to spend less on multi-gas detectors than it forecast in the GRC…." (Ex. 545 at 31.) TURN's recommendation has the

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[60] The optical scanning equipment raises the 2011 forecast of capital expenditures to a total of $17.953 million.

effect of reducing the 2010 and 2011 costs for the multi-gas detectors by $234,000 and $105,000, respectively.

For the total equipment and tools category, TURN recommends that the recorded amount of $2.401 million be used for 2010, $17.848 million be used for 2011, and $1.393 million be used for 2012.

7.3.3.15.2.3. SoCalGas

SoCalGas acknowledges the issuance of the final Subpart W rule. However, SoCalGas contends that until there is further clarification of the definitions contained in that rule, SoCalGas cannot assess the final impact on its operations. SoCalGas further contends that due to this continuing uncertainty, that this reinforces the need for the two-way NERBA, and that its original estimate of complying with this rule is reasonable and should be adopted. SoCalGas recognizes that if the two-way balancing account is adopted, and the capital expenditures it has requested are too high, that "the under spent costs will be refunded back to ratepayers." (Ex. 29 at 150.)

Regarding TURN's adjustment for the multi-gas detectors, SoCalGas does not oppose TURN's recommendations to reduce the costs for these detectors.

7.3.3.15.3. Discussion

We have reviewed the testimony and arguments of the parties concerning the capital expenditures for the equipment and tools category. We have also reviewed Subpart W and considered the impact of that rule on SoCalGas' operations.

As discussed earlier, we adopt and authorize SoCalGas to establish the NERBA, as a two-way balancing account to record the costs associated with complying with Subpart W. However, based on our review of Subpart W, and DRA's interpretation that less monitoring will be needed, we will reduce the amount of capital expenditures in 2011 for the purchase of optical scanners. Instead of allowing funds for the purchase of 157 optical scanners, it is reasonable under the circumstances to allow funds for the purchase of 50 optical scanners. Based on all these considerations, it is reasonable to adopt the following capital expenditures for equipment and tools: for 2010, the actual recorded amount of $2.401 million; $7.253 million for 2011; and $1.393 million for 2012.

7.3.3.16. Field Capital Support

7.3.3.16.1. Introduction

The field capital support category records the costs associated with the broad range of services that support gas distribution field capital asset construction. These services "include project planning, local engineering, clerical support and field dispatch, field management and supervision, and off-production time for support personnel and field crews…." (Ex. 26 at 87.)

SoCalGas forecasts capital expenditures for the field capital support category at $38.323 million, $40.207 million, and $39.694 million for 2010, 2011, and 2012, respectively. Since field capital support varies with the level of capital construction activity, SoCalGas applied a percentage of 30% to the five-year average of construction costs to derive its base forecast. To that base, SoCalGas added the costs to support the new scheduling and dispatch organization. The 2012 forecast was then reduced due to the operational efficiencies associated with the introduction of new technology and changes in business processes.

7.3.3.16.2. Position of the Parties

7.3.3.16.2.1. DRA

DRA applied the same percentages that SoCalGas used to derive its forecasts of the field capital support costs. DRA applied these percentages to the adjustments that DRA has recommended.

DRA recommends the following capital expenditures: $38.323 million for 2010; $31.101 million for 2011; and $29.469 million for 2012.

7.3.3.16.2.2. TURN

Since TURN's forecast of the other gas distribution capital costs are lower than SoCalGas' forecast, TURN's forecast of the field capital support costs is also lower.

TURN recommends the following capital expenditures: $34.649 million for 2010; $30.740 million for 2011; and $30.366 million for 2012.

7.3.3.16.2.3. SoCalGas

SoCalGas contends that DRA's forecast of the 2011 and 2012 costs for field capital support contain calculation errors. According to SoCalGas, if these errors were corrected, DRA's corrected forecast for 2011 and 2012 would be $33.247 million and $31.791 million, respectively.

Since TURN's forecast of the field capital support costs is based on TURN's forecast of other costs, SoCalGas contends that TURN's forecast is unreasonable.

7.3.3.17.3. Discussion

We have considered and reviewed the testimony and the arguments of the parties concerning the forecasts of the field capital support costs. We have also reviewed the amounts that we have adopted for gas distribution construction costs, in relationship to the forecast of field capital support. Based on those considerations, it is reasonable to adopt the following capital expenditures for field capital support: for 2010, the recorded amount of $34.649 million; $32.500 million for 2011; and $32 million for 2012.

8. Gas Transmission

8.1. Introduction

This gas transmission section addresses the O&M costs for the gas transmission operations of SDG&E and SoCalGas.[61]

For the gas transmission O&M costs, SDG&E requests a total of $3.916 million. This is an increase of $222,000 over the 2009 adjusted recorded costs.

For the gas transmission O&M costs of SoCalGas, it requests a total of $32.357 million.

8.2. SDG&E

8.2.1. Introduction

SDG&E's gas transmission system consists of about 168 miles of high pressure pipelines and two compressor stations. SDG&E receives its gas from the interconnection points at Rainbow, bordering the counties of San Diego and Riverside, and at the San Onofre receipt point. SDG&E's system is also designed to receive re-gasified liquefied natural gas supplies at the Otay Mesa interconnection.

According to SDG&E, the "daily operation and maintenance of the SDG&E gas transmission pipeline and compressor station systems is performed by SDG&E employees, while support functions are performed by SDG&E's gas transmission Technical Services organization." (Ex. 87 at 3.) The managerial

[61] The capital expenditures for the gas transmission operations of SDG&E and SoCalGas are discussed under the topic of gas engineering.

leadership of SDG&E's gas transmission organization, and O&M activities is provided by SoCalGas' gas transmission organization. The cost of the services provided by SoCalGas is billed to SDG&E. SDG&E's gas transmission organization does not provide any billable services to SoCalGas.

SDG&E's gas transmission organization consists of the following five operations: pipeline operations; gas compression operations; technical services; gas system operations and planning; and gas scheduling. The last two operations are provided by SoCalGas.

SDG&E's pipeline operations function covers the day-to-day O&M of its gas transmission pipeline facilities and infrastructure. According to SDG&E, this "includes operating and maintaining equipment at pipeline receipt points, valve control stations, major customer delivery custody-transfer points, all associated monitoring, metering, and control facilities, odorization equipment, and real-time operating data telemetry communications between gas facilities and SoCalGas' – Gas System Operations organization." (Ex. 87 at 3.) Pipeline operations also performs the annual leak surveys, operates and maintains the cathodic protection systems, monitors third-party construction activities, and performs locate and mark services. Other functions of pipeline operations are described in Exhibit 87 at 4.

The gas compression operations cover the day-to-day O&M of the two compressor station facilities and the associated infrastructure. According to SDG&E, this "includes operating and maintaining 14 compressor engines and ancillary equipment, all associated monitoring, metering, and control facilities, odorization equipment, filtration vessels, cooling equipment, and real-time operating data telemetry communications between compression facilities and SoCalGas' Gas System Operations organization." (Ex. 87 at 4.) This group also does leakage inspections, and maintains the piping of the cathodic protection systems. The other responsibilities of this group are described in Exhibit 87 at 4.

The technical services function "includes the activities of design engineering, instrumentation and control, project support, and environmental services in support of the day-to-day operations and maintenance of the gas transmission system." (Ex. 87 at 5.) This group also provides on-site technical expertise to the pipeline and gas compression operations field personnel, and also troubleshoots technical issues for O&M and capital projects.

The gas system operations and planning is performed by SoCalGas, and consists of two departments, the gas control and SCADA (supervisory control and data acquisition system) department, and the gas transmission planning department. Gas control operates and manages the real-time operation and control of gas flow through the pipeline system. The SCADA group manages the SCADA equipment, which allows for the "remote monitoring and operation of valves, compressors, pressure regulation equipment, and gas flow across the system." (Ex. 87 at 5.) The gas transmission planning department is responsible for the long term planning and design of the gas transmission systems for SDG&E and SoCalGas.

The gas scheduling function is performed by SoCalGas. This function consists of managing "the day-to-day system and operations for nominations, allocations and scheduled volumes for approximately 955 of SoCalGas' non-core meter customers and 125 of SDG&E's non-core meter customers." (Ex. 87 at 5.) As part of the scheduling process, this group "manages transportation nominations for on-system and off-system deliveries based on priority rights, confirms nominations to interstate and intrastate suppliers, reports scheduled quantities to customers, tracks storage accounts, tracks and clears shipper imbalances and administers the imbalance trading process." (Ex. 87 at 6.)

8.2.2. Gas Transmission O&M Costs

8.2.2.1. Introduction

SDG&E requests a total of $3.916 million for its gas transmission O&M expense. This O&M expense is comprised of $3.303 million for non-shared costs, and $613,000 for shared service costs.

8.2.2.2. Non-Shared O&M Costs

8.2.2.2.1. Introduction

SDG&E's non-shared O&M costs total $3.303 million. These costs are divided into the following three categories: pipeline O&M; compressor station O&M; and transmission technical services.

To develop its test year 2012 forecasts, SDG&E applied annual incremental changes to the 2009 base year adjusted recorded expenditures. SDG&E used the 2009 base year adjusted costs because it believes they are "a reasonable indicator of future costs as reflecting recent and representative operational conditions." (Ex. 87 at 8.)

We separately discuss each of these three categories below.

8.2.2.2.2. Pipeline O&M

SDG&E forecasts $969,000 for the test year 2012 pipeline O&M costs. This is an incremental increase of $33,000 over the 2009 amount.

The 2009 base year amount of $886,000 is for the performance of annual pipeline O&M activities. SDG&E is not forecasting any increase for these activities. The incremental increase of $33,000 that SDG&E is proposing is due to the user fee for the pipeline safety program activities that are administered by the Pipeline and Hazardous Materials Safety Administration (PHMSA) of the United States Department of Transportation (DOT). SDG&E calculated the increase based on non-standard escalation inflation indexing as described in Exhibit 87.

None of the other parties have taken issue with SDG&E's forecast of the test year 2012 costs for pipeline O&M costs. Based on a review of the testimony of SDG&E and DRA concerning these costs, it is reasonable to adopt SDG&E's forecast of $969,000 for the pipeline O&M costs.

8.2.2.3. Compressor Station O&M

8.2.2.2.3.1. Introduction

SDG&E forecasts $2.226 million for the test year 2012 compressor station O&M costs. This is an incremental increase of $131,000 over the 2009 amount.

The 2009 base year amount of $2.095 million is for the performance of annual gas compression O&M activities. SDG&E is not forecasting any increase for these activities. The incremental increase of $131,000 is attributable to three rules or regulations. $57,000 of the $131,000 is for the cost of complying with AB 32, which is codified in Health and Safety Code § 38500 and following. According to SDG&E, AB 32 "will result in increased regulatory compliance requirements relative to minute releases of methane gas into the atmosphere." (Ex. 87 at 9.)

The second incremental increase is in the amount of $19,000 and is to comply with the National Emissions Standards for Hazardous Air Pollutants (NESHAP) for reciprocating internal combustion engines (RICE), and with Rule 1110.2 of the South Coast Air Quality Management District (SCAQMD). SDG&E anticipates that the NESHAP rule for spark ignition engines will require SDG&E to install improved catalysts on such engines to reduce formaldehyde and carbon monoxide emissions. SDG&E anticipates that the revision to

SCAQMD's Rule 1110.2 "will require SDG&E to meet new emission limits and monitoring requirements for the Moreno Compressor Station." (Ex. 87 at 10.)

The third incremental increase is in the amount of $55,000. This incremental increase is to pay for the Clean Air Act non-attainment fees of the Moreno Compressor Station, which is administered by the CARB.

8.2.2.2.3.2. Position of the Parties

8.2.2.2.3.2.1. DRA

DRA recommends test year 2012 O&M costs of $2.120 million. DRA's recommendation is based on the five-year average of 2006-2010.

8.2.2.2.3.2.2. SDG&E

SDG&E contends that DRA's use of the five-year average of 2006-2010 will not provide SDG&E enough funding for the new compliance program requirements. SDG&E contends that DRA's use of the five-year average fails to capture the incremental cost pressures resulting from the rules and regulations described above.

8.2.2.2.3.3. Discussion

We have reviewed the testimony and arguments of SDG&E and DRA concerning the compressor station O&M costs. We have also compared their forecasts to the historical costs. Based on all those considerations, it is reasonable to adopt DRA's forecast of $2.120 million for the test year 2012 compressor station O&M costs.

8.2.2.2.4. Transmission Technical Services

8.2.2.2.4.1. Introduction

SDG&E forecasts $108,000 for the test year 2012 transmission technical services O&M costs. This amount is the same as the 2009 base year adjusted amount.

DRA reviewed and accepted SDG&E's forecast of the technical services O&M costs. None of the other parties have taken issue with SDG&E's forecasted amount.

Based on our review of the testimony and arguments of SDG&E and DRA, it is reasonable to adopt SDG&E's forecast of $108,000 for the technical services O&M costs for test year 2012.

8.2.2.3. Shared O&M Costs

The shared O&M costs addresses the expenditures for the support management of the operations and support staff services that relate to SDG&E's gas transmission operations. SDG&E's gas transmission operations, and SoCalGas' gas transmission operations, are managed and supported in part by SoCalGas' employees.

SDG&E's forecast of the test year O&M shared services is $613,000. All of these O&M shared services costs are billed in from SoCalGas. The details of the costs that are billed to SDG&E from SoCalGas' gas transmission shared services are described in Exhibit 87.

None of the other parties take issue with SDG&E's forecast of the gas transmission shared services O&M costs.

We have reviewed the testimony regarding the shared services O&M costs for gas transmission. Based on that review, it is reasonable to adopt SDG&E's forecast of $613,000 for its shared services O&M costs for test year 2012.

8.3. SoCalGas

8.3.1. Introduction

SoCalGas' gas transmission system consists of about 3989 miles of high pressure pipelines, and 11 compressor stations. The gas transmission system covers the geographic area from the California and Arizona border to the

Pacific Ocean, and from Fresno County south to the California-Mexico border. SoCalGas receives gas from interstate pipelines, and various California offshore and onshore production sources. This natural gas is then delivered from the gas transmission system directly to SoCalGas' distribution system, gas storage fields, and to some non-core customers**.**

The SoCalGas transmission system is designed to receive, on a firm basis, 3.875 billion cubic feet per day (Bcf/d) of interstate and intrastate gas supplies. With the combination of gas pipeline receipts, and gas storage withdrawals, the SoCalGas system can send out 6 Bcf/d to customers.

SoCalGas' gas transmission organization consists of the following five operations: pipeline operations; gas compression operations; technical services; gas system operations and planning; and gas scheduling.

SoCalGas' pipeline operations function covers the day-to-day O&M of its gas transmission pipeline facilities and infrastructure. According to SoCalGas, this "includes operating and maintaining equipment at pipeline receipt points, valve control stations, major customer delivery custody-transfer points, all associated monitoring, metering, and control facilities, odorization equipment, and real-time operating data telemetry communications between gas facilities and SoCalGas' Gas Control Operation department." (Ex. 90 at 4.) Pipeline operations also perform the annual leak surveys, operate and maintain the cathodic protection systems, monitor third-party construction activities, and perform locate and mark services. Other functions of pipeline operations are described in Exhibit 90 at 4.

The gas compression operations cover the day-to-day O&M of the 11 compressor station facilities and the associated infrastructure. According to SoCalGas, this "includes operating and maintaining 42 compressor engines and ancillary equipment, all associated monitoring, metering, and control facilities, odorization equipment, filtration vessels, cooling equipment, and real-time operating data telemetry communications between compression facilities and the Gas System Operations department." (Ex. 90 at 5.) This group also does leakage inspections, and maintains the piping of the cathodic protection systems. The other responsibilities of this group are described in Exhibit 90 at 5.

The technical services function "includes the activities of design engineering, instrumentation and control, project support, and environmental services in support of the day-to-day operations and maintenance of the gas transmission system." (Ex. 90 at 5.) This group also provides right-of-way maintenance, on-site technical expertise to the pipeline and gas compression operations field personnel, and troubleshoots technical issues for O&M and capital projects.

The gas system operations and planning consists of two departments, the gas control and SCADA department, and the gas transmission planning department. Gas control operates and manages the real-time operation and control of gas flow through the pipeline system. The SCADA group manages the SCADA equipment, which allows for the "remote monitoring and operation of valves, compressors, pressure regulation equipment, and gas flow across the system." (Ex. 90 at 6.) The gas transmission planning department is responsible for the long term planning and design of the gas transmission systems for SDG&E and SoCalGas.

The gas scheduling function consists of managing "the day-to-day system and operations for nominations, allocations and scheduled volumes for approximately 955 of SoCalGas' non-core meter customers and 125 of SDG&E's non-core meter customers." (Ex. 90 at 6.) As part of the scheduling process, this group "manages transportation nominations for on-system and off-system deliveries based on priority rights, confirms nominations to interstate and intrastate suppliers, reports scheduled quantities to customers, tracks storage accounts, tracks and clears shipper imbalances and administers the imbalance trading process." (Ex. 90 at 6.)

8.3.2. Gas Transmission O&M Costs

8.3.2.1. Introduction

SoCalGas requests a total of $32.357 million for its gas transmission O&M expense. This O&M expense is comprised of $28.205 million for non-shared costs, and $4.152 million for shared service costs.

8.3.2.2. Non-Shared O&M Costs

SoCalGas' non-shared O&M costs total to $28.205 million. These costs are divided into the following three categories: pipeline O&M; compressor station O&M; and technical services.

To develop its test year 2012 forecasts, SoCalGas applied annual incremental changes to the 2009 base year adjusted recorded expenditures. SoCalGas used the 2009 base year adjusted costs because it believes they are "a reasonable indicator of future costs as reflecting recent and representative operational conditions." (Ex. 90 at 9.)

We separately discuss each of these three categories below.

8.3.2.2.1. Pipeline O&M

8.3.2.2.1.1. Introduction

SoCalGas forecasts $17.727 million for the test year 2012 pipeline O&M costs. This is an incremental increase of $1.372 million over the 2009 amount.

The 2009 base year amount of $10.889 million is for the performance of annual pipeline O&M activities. SoCalGas is not forecasting any increase for these activities.

There are four incremental increases to SoCalGas' pipeline O&M costs. The first incremental increase is in the amount of $1.354 million, which is for the user fee to fund the pipeline safety program activities that is administered by the PHMSA. SoCalGas calculated the increase based on non-standard escalation inflation indexing as described in Exhibit 90.

The second incremental increase is in the amount of $4.717 million. This increase is due to the lease agreement contract with the city of Long Beach.

The third incremental increase is in the amount of $750,000 for the removal of previously abandoned pipelines. According to SoCalGas, this increase is for "unanticipated additional costs beyond the original abandonment removal costs that occurred many years ago." (Ex. 90 at 10.) This usually occurs when the abandoned pipe interferes with the property owner's desire to develop the property, or because the property owner wants to have SoCalGas convey the unused easement back to the landowner.

The fourth incremental increase is in the amount of $17,000 for electric system pole inspections for SoCalGas' overhead electric supply systems. This program is to improve the protection of its electric system poles against fire risks.

8.3.2.2.1.2. Position of the Parties

8.3.2.2.1.2.1. DRA

DRA reviewed SoCalGas' pipeline O&M costs in Exhibit 533. DRA accepts all of the incremental increases except for the increase related to removal of previously abandoned pipelines.

DRA contends that SoCalGas did not adequately justify its forecast of $750,000 for the removal of previously abandoned pipelines. DRA contends that SoCalGas' forecast of this incremental cost was not based on any actual expenses for pipeline removal. Instead, the forecast was based on a cost per foot estimate.

DRA also points out that SoCalGas did not record any expense in 2005 to 2008 for the removal of previously abandoned pipelines, and in 2009 one project was done at a cost of $91,087. Although SoCalGas states that its forecast is based on eight known projects, DRA contends there is no indication that these projects must be completed in test year 2012.

DRA recommends funding of $250,000 for the removal of abandoned pipelines.

8.3.2.2.1.2.2. TURN

TURN recommends several adjustments to SoCalGas' forecast of the pipeline O&M costs.

First, TURN recommends that instead of using the 2009 base year amount of $10.889 million, which SoCalGas used, TURN recommends that the six-year average of $10.911 be used as the base from which to add incremental expenses. TURN recommends the use of its six-year average because SoCalGas' 2010 recorded expense was less than SoCalGas's forecasted 2010 amount, and because the recorded expenses fluctuated from year to year from 2005 through 2010 with no apparent trend.

The second adjustment pertains to the removal of previously abandoned pipeline. TURN recommends funding of $200,000 instead of the $750,000 that SoCalGas has recommended. Although SoCalGas removed pipeline in 2009 at a cost of $91,000, and in 2010 at a cost of $493,000, TURN contends that these appear to be one-time discrete events. In support of that argument, TURN points out that no abandoned pipe was removed between 2000 and 2008. As for the eight projects that SoCalGas cited, TURN contends that SoCalGas has reached agreement with two of the eight owners, and that the abandoned pipeline will remain in place.

TURN's third adjustment is to the electric system pole inspections. Although TURN does not take issue with the need to undertake this program, TURN points out that the 2010 recorded expense was under what SoCalGas had forecasted for 2010, and that this minor expense "should be subsumed into the base forecasts."

8.3.2.2.1.2.3. SoCalGas

On the recommended reductions of DRA and TURN to the removal of abandoned pipelines, SoCalGas contends that its forecast is based on "specific line item details as to locations and lengths of pipelines known to potentially impact [test year 2012] expenses." (Ex. 92 at 4.) SoCalGas also points out that in 2010, it recorded $493,000 in removal costs. For those reasons, SoCalGas recommends that its forecast of $750,000 should be adopted over the lower forecasts of DRA and TURN.

On TURN's recommendation to use $10.911 million as the base year forecast, SoCalGas notes that the 2009 amount of $10.889 million is most representative of the expected test year 2012 O&M costs. SoCalGas also notes the five-year average of 2005-2009 is $10.943 million.

On TURN's recommendation to remove the electric pole inspection O&M costs, SoCalGas contends that this is a new activity which is not reflected in the 2009 base amount, or in TURN's six-year average. These costs are the result of D.09-08-029, which made SoCalGas' own electric lines and poles subject to GO 95.

8.3.2.2.1.3. Discussion

We have reviewed the testimony and arguments of SoCalGas, DRA, and TURN concerning the pipeline O&M costs. We have also compared their forecasts to the historical costs, and have considered the need for the incremental increases that SoCalGas requested. Based on those considerations, it is reasonable to use the 2009 adjusted recorded amount as the base year expenses for pipeline O&M costs. It is also reasonable to fund the removal of abandoned pipelines at $250,000 as recommended by DRA. It is also reasonable to allow the incremental increase of $17,000 for electric pole inspection. Accordingly, the funding amount of $17.227 million should be adopted for the test year 2012 pipeline O&M costs.

8.3.2.2.2. Compressor Station O&M

8.3.2.2.2.1. Introduction

SoCalGas forecasts $8.099 million for the test year 2012 compressor station O&M costs. This is an incremental increase of $806,000 over the 2009 amount.

The 2009 base year amount of $7.176 million is for the performance of annual gas compression O&M activities. SoCalGas is not forecasting any increase for these activities.

The incremental increase of $806,000 is due to three rules or regulations, and a change in the odorant policy.

The first incremental increase is in the amount of $229,000 and is for the cost of complying with AB 32. According to SoCalGas, AB 32 "will result in increased regulatory compliance requirements relative to minute releases of methane gas into the atmosphere." (Ex. 90 at 12.)

The second incremental increase is in the amount of $114,000 and is to comply with the NESHAP for reciprocating internal combustion engines, and the revision to Rule 1160 of the Mojave Desert Air Quality Management District (MDAQMD). SoCalGas anticipates that the NESHAP rule for spark ignition engines will require SoCalGas to install improved catalysts on such engines to reduce formaldehyde and carbon monoxide emissions. SoCalGas anticipates that the revision to MDAQMD's Rule 1160 "will require SoCalGas to meet new emission limits and monitoring requirements at the North Needles, South Needles and Newberry Compressor Stations." (Ex. 90 at 13.)

The third incremental increase is in the amount of $179,000. This incremental increase is to pay for the fees to partially fund the CARB's Stationary Source Program, as a result of AB 10X.

The fourth incremental increase is in the amount of $400,000. This increase is for the cost of adding a supplemental odorant at two receipt points beginning in 2011. This supplemental odorant will "provide greater consistency in the odorant blend throughout the service territory and within California," and will allow employees and customers to "recognize the same odor should there be a gas leak at any point along all of California's utility-operated natural gas systems." (Ex. 90 at 14.)

8.3.2.2.2.2. Position of the Parties

8.3.2.2.2.2.1. DRA

DRA does not take issue with SoCalGas' incremental increase of $400,000 for the supplemental odorant. However, DRA does take issue with the incremental increases to comply with the additional rules and regulations.

Regarding SoCalGas' incremental increase of $229,000 for AB 32 compliance, DRA recommends no increase. DRA contends that "it is unlikely that [SoCalGas] will be required to address any new regulations until 2016 because of the delay in the implementation date." (Ex. 533 at 99.)

On SoCalGas' incremental request of $114,000 for compliance with NESHAP, DRA points out that SoCalGas acknowledges that the final NESHAP rule will impact fewer locations and engines than SoCalGas had originally forecasted. Also, DRA contends that there is no evidence that the MDAQMD will revise its Rule 1160 by 2012. DRA recommends no incremental increase.

On SoCalGas' incremental request of $62,000 to address AB 10X, DRA contends that SoCalGas' request is unsupported and unjustified. DRA contends that the actual fees that SoCalGas paid from 2004-2009 have not exceeded $118,051, and that SoCalGas has not offered any evidence to demonstrate that the fees will increase in test year 2012. DRA recommends that the incremental increase of $62,000 not be allowed.

8.3.2.2.2.2.2. SoCalGas

For the incremental funding of $229,000 for AB 32, SoCalGas contends that it "is required to manage the monitoring, recordkeeping and reporting requirements for AB 32's and EPA's Mandatory Reporting requirements for its large compressor stations," and that the first mandatory reports were due in September 2011. SoCalGas contends that it will be incurring costs in the test year 2012 GRC period "to manage compliance obligations under the AB 32 and EPA Mandatory Reporting." (Ex. 330 at 9.) According to SoCalGas, these "new compliance activities have generated additional work scheduling and tracking requirements, along with an increased volume of data to be collected, analyzed, reported and stored." (Ex. 330 at 10.) As shown in Exhibit 330, SoCalGas also points out that it has paid the mandatory AB 32 administrative fees to CARB for 2010 to 2011, and 2011 to 2012, and that such fees have amounted so far to more than $11 million.

Regarding the 2016 date that DRA referenced, SoCalGas contends that is the second compliance period for the AB 32 cap and trade allowances, which does not affect the administrative fees that SoCalGas has already been paying.

On the $114,000 incremental increase for NESHAP compliance, SoCalGas contends that this request is justified because these costs are to comply with NESHAP and the proposal to revise Rule 1160 of the MDAQMD. SoCalGas contends that other local air districts have already published specific rules that require significant reduction of emission levels that the current Rule 1160 of the MDAQMD, and that it is reasonable to expect the MDAQMD to adopt a similar rule. SoCalGas is working on an engine pilot study with the MDAQMD to finalize Rule 1160, and is currently incurring costs related to Rule 1160 compliance.

On DRA's recommendation to disallow the incremental increase for the AB 10X fee assessments, SoCalGas described in Exhibit 92 why it expects the fees to increase in test year 2012. SoCalGas also included copies of its 2010 and 2011 recorded fee assessments for the three stations that are subject to the assessment of fees. In 2010, the invoice for two of the three stations was $144,260. In 2011, the invoiced total for three stations was $222,238, which is in excess of the test year 2012 forecast of $179,000.

8.3.2.2.2.3. Discussion

We have reviewed the testimony and arguments of SoCalGas and DRA concerning the compressor station O&M costs. Based on the evidence presented by SoCalGas, it is clear that SoCalGas will incur incremental costs in test year 2012 to comply with AB 32 and AB 10X. DRA has also reviewed the incremental increase for the supplemental odorant, and the base year O&M expenses, and does not oppose those costs. However, given current economic conditions, SoCalGas must exercise spending restraint in this area, and cannot expect full O&M funding when other parties do not object. On the incremental costs to comply with NESHAP and MDAQMD regarding reciprocating engines, we decline to adopt the $114,000 incremental increase because the MDAQMD has not finalized the revision to Rule 1160, and is unlikely to do so before the end of test year 2012. Based on all those considerations, it is reasonable to adopt $7.685 million for the test year 2012 compressor station O&M costs.

8.3.2.2.3. Technical Services

8.3.2.2.3.1. Introduction

SoCalGas forecasts $2.379 million for the test year 2012 technical services O&M costs. This amount consists of two incremental increases over the base amount of $989,000.

The test year 2012 base amount is forecast at $989,000, which is the same as the 2009 adjusted recorded amount. SoCalGas is not forecasting any increase in the base technical services O&M costs.

The first incremental increase is in the amount of $1.185 million. This incremental increase is related to SoCalGas' management of its right-of-way, and includes "vegetation removal, storm damage mitigation, access roadway resurfacing, right of access and pipeline placement signage repairs and replacement, and exposed pipeline rust mitigation." (Ex. 90 at 14.) According to SoCalGas, these maintenance costs are increasing due to stricter habitat preservation guidelines and the use of environmental protection inspectors.

The second incremental increase is in the amount of $205,000. This incremental increase is for technical services support staffing. According to SoCalGas, this "staff is responsible for developing operational process changes in response to continuous and ever-changing business needs," and this is affected by "the implementation of new technologies which are applicable to both field and administrative functions." (Ex. 90 at 15.)

8.3.2.2.3.2. Position of the Parties

8.3.2.2.3.2.1. DRA

DRA recommends that SoCalGas' incremental increase of $500,000 for right-of-way management be disallowed. DRA contends that SoCalGas has not justified the increase request, and that the historical expenses do not support SoCalGas' claim that "stricter guidelines and restrictions are driving expenses in this area." (Ex. 533 at 102.) DRA also contends that SoCalGas did not identify the guidelines or restrictions that are supposedly driving the increase in SoCalGas' forecast. DRA points out that the recorded costs have fluctuated, and that in 2008, SoCalGas spent $1.519 million, $685,055 in 2009, and $1.185 million in 2010.

DRA does not oppose SoCalGas' incremental increase of $205,000 for two FTEs for the technical services support staffing.

8.3.2.2.3.2.2. SoCalGas

SoCalGas contends that its workpapers in Exhibit 91 provided a substantive explanation, and the cost calculation factors, for its forecast of the right-of-way management O&M costs. The workpapers list the maintenance work activities that are awaiting scheduling. The cost of these work activities are estimated to cost about $4.075 million. SoCalGas' request of $1.185 million is lower than the total cost because all of "this work cannot be scheduled for completion within any single year and therefore is prorated over a period of years." (Ex. 92 at 7.) Regarding DRA's claim that SoCalGas did not identify the guidelines or restrictions that affect the right-of-way management costs, SoCalGas provided an overview of these legislative and regulatory actions in Exhibit 92 and 330.

8.3.2.2.3.3. Discussion

We have reviewed the testimony and arguments of SoCalGas and DRA concerning the technical services O&M costs. Based on our review of the planned right-of-way management activities, the applicable rules and regulations which affect these O&M costs, the historical costs for the right-of-way O&M costs, and the incremental increase requests, it is reasonable to adopt the amount of $1.950 million as the technical services O&M costs for test year 2012.

8.3.2.3. Shared O&M Costs

SoCalGas forecasts $4.152 million for the test year 2012 shared services pipeline O&M costs. This is an incremental increase of $169,000 over the 2009 amount.

All of the shared service activities are performed by SoCalGas, as described in Exhibit 90. SoCalGas forecasts that it will bill SDG&E $613,000 in shared services O&M costs in test year 2012, and that SoCalGas will retain $4.152 million in shared services O&M costs.

None of the other parties have taken issue with SoCalGas' forecast of the shared services O&M costs. Based on our review of the uncontested shared services costs, it is reasonable to adopt $4.152 million as the shared services O&M costs for SoCalGas.

9. Gas Storage and Engineering

9.1. Introduction

This section addresses the O&M costs and capital expenditures associated with the gas storage operations of SoCalGas, and the gas engineering operations of SDG&E and SoCalGas.

The gas storage section addresses the O&M costs and the capital expenditures of SoCalGas.

For gas engineering, the O&M costs cover activities in support of the gas distribution and transmission operations of SDG&E and SoCalGas, including pipeline integrity requirements. The gas engineering capital expenditures address the capital projects related to the gas transmission and engineering operations of SDG&E and SoCalGas.

9.2. Gas Storage

9.2.1. Introduction

The gas storage operations pertain only to SoCalGas. SoCalGas owns and operates four underground storage fields, which it uses to store natural gas. These storage fields are integrated into SoCalGas' gas delivery system. These gas storage fields cover large areas of land, and require compressors, regulators, and monitoring equipment to operate the storage fields. The four storage fields have a working inventory capacity of about 134 Bcf.

SoCalGas uses the storage fields to meet the seasonal needs of its customers, as well as to meet daily gas balancing requirements. These storage fields are generally used to store natural gas during seasonal periods when gas consumption is typically low, usually during the summer months. The gas is then typically withdrawn when gas consumption is high, usually during the colder winter months. According to SoCalGas, at the beginning of the withdrawal season, "the combined storage capacity of the four storage fields is enough to completely supply all of SoCalGas' customers for approximately six weeks." (Ex. 466 at 5.)

SoCalGas forecasts O&M costs of $28.939 million for test year 2012, and $30.596 million in capital expenditures.

9.2.2. Gas Storage O&M Costs

9.2.2.1. Introduction

SoCalGas forecasts $28.939 million in gas storage O&M costs for 2012. SoCalGas' base forecast amount of $27.231 million uses the 2009 recorded labor costs, and the five-year average of 2005-2009 for the non-labor costs. As described below, SoCalGas requests incremental increases which raise SoCalGas' test year 2012 forecast to $28.939 million.

The gas storage operations consist of about 150 employees, who perform operational and support work. The storage fields are staffed with crews that allow the fields to be operated on a continuous 24 hour basis.

There are general functions and basic activities that are performed at all four storage fields, as well as general work functions performed by support personnel. According to SoCalGas, all of these functions and activities make up the bulk of the historical expenses.

As described in Exhibit 466, these work functions and activities consist of the following gas storage operations: operation supervision and engineering; wells, lines, and compressor stations; equipment operation and maintenance; structural improvements, rents and royalties; maps and records; compressor station fuel and power, and gas losses; and other storage expenses.

The incremental funding request over the 2009 adjusted recorded amount is $1.942 million. The incremental request is composed of seven items.

The first incremental request is in the amount of $304,000 and pertains to the addition of four additional positions to manage the mandatory GHG reporting rule, and the related surveying, monitoring, and reporting activities. This funding would be subject to the NERBA.

The second incremental request is in the amount of $754,000 to pay for the non-attainment fees, pursuant to Rule 317 of the SCAQMD, for stationary sources that emit nitrous oxide and/or volatile organic compounds. Three of the storage fields are subject to Rule 317.

The third incremental adjustment is in the amount of $245,000 for ensuring that SoCalGas' electric poles and overhead wiring are in compliance with GO 95. SoCalGas owns more than 500 poles and associated wire and transformers that it uses in its own operations.

The fourth incremental adjustment is in the amount of $50,000 which is for a permit from Santa Barbara County to manage the vegetation at the La Goleta storage field.

The fifth incremental adjustment is in the amount of $100,000 to comply with Rule 333 of the Santa Barbara Area Pollution Control District.

The sixth incremental adjustment is in the amount $80,000 for adding one employee to operate the dehydration equipment at the Playa del Rey storage field.

The seventh incremental adjustment is in the amount of $95,000 for the addition of a project manager to evaluate and integrate new technology and procedures into SoCalGas' storage operations.

The remainder of the increase over the 2009 adjusted recorded amount is due to the increase in non-labor expense as a result of SoCalGas using the five-year average of 2005-2009, instead of the 2009 recorded expense for non-labor costs.

9.2.2.2. Position of the Parties

9.2.2.2.1. DRA

DRA disagrees with SoCalGas' use of the five-year average for non-labor expenses, and with SoCalGas' use of the 2009 recorded labor cost, to derive the base year amount. SoCalGas used the five-year average for non-labor O&M costs because of fluctuating costs, as compared to the labor O&M costs. DRA contends that SoCalGas' argument is contrary to the historical data for 2005-2009, which shows that both the labor and non-labor costs fluctuated during that period. DRA also disagrees with SoCalGas' use of the 2009 labor cost because that was the highest labor expense during the 2005-2009 period. DRA recommends that 2009 recorded labor and non-labor expenses be used as the base forecast instead. As a result, DRA recommends a base amount of $26.997 million for gas storage O&M costs.[62]

SoCalGas requests an incremental increase of $304,000 for activities related to the mandatory GHG reporting rule. As described in Exhibit 533, DRA believes that the scope of activities to comply with this rule will be less than what SoCalGas had originally forecasted. Due to this reduced activity, DRA recommends that only two additional FTEs be funded at a cost of $152,000, instead of the four that SoCalGas had requested. On the incremental increase of $754,000 for the SCAQMD non-attainment fee, DRA believes that the fee equivalent approach adopted in SCAQMD's Rule 317 will mean that SoCalGas

[62] The $26.997 million reflects SoCalGas' upward adjustment of DRA's base amount. DRA's base amount was developed using an earlier version of SoCalGas' testimony. (*See* Ex.470 at 4; Ex. 533 at 105.)

will no longer be required to pay a fee, and that funding for this amount is unnecessary.

On the incremental increase of $245,000 to allow SoCalGas to comply with GO 95, DRA recommends that no funding should be allowed. DRA contends that SoCalGas provided inconsistent data, and has not adequately justified its incremental request. DRA also notes that ratepayers are already funding four red flag events per year.

On the incremental increase of $100,000 for activities to comply with Rule 333 of the Santa Barbara Area Pollution Control District, DRA contends that the rule does "not appear to warrant significant changes in [SoCalGas'] monitoring requirements for the engines at the La Goleta storage field." (Ex. 533 at 111.) In addition, this rule has required SoCalGas to be in compliance since 2008. DRA recommends no incremental funding due to SoCalGas' lack of support for such an increase.

DRA also recommends disallowing $200,000 in other incremental increases, which are reflected in DRA's table in Exhibit 533 at 105 under the "miscellaneous" category. DRA did not discuss its reasons for disallowing those miscellaneous incremental requests.

9.2.2.3. SoCalGas

SoCalGas contends that DRA's base year amount does not reflect the different trends for labor and non-labor costs. SoCalGas states that there are "fundamental differences between labor and non-labor expenses," and therefore it is "appropriate to forecast each differently." (Ex. 470 at 5.) As shown in the graph in Exhibit 470 at 5, SoCalGas contends that labor expenses have been trending up, while the non-labor expenses reflect historical fluctuations. Due to those differences, SoCalGas recommends that its base forecast amount of $27.231 million be used.

On the $304,000 incremental increase to add four additional FTEs to comply with the mandatory GHG reporting rule, SoCalGas contends that its request is appropriate given the monitoring, recordkeeping, and reporting requirements. SoCalGas contends that the timing of these requirements fall within the test year 2012 period, and that it will be incurring costs to manage its compliance obligations. As for DRA's argument that fewer facilities will need to be monitored than SoCalGas had originally anticipated, SoCalGas contends that there are still a number of other compliance activities that need to be monitored and reported, and that these activities apply to distribution, transmission, and storage.

SoCalGas disagrees with DRA's recommendation to disallow the incremental increase of $754,000 for the non-attainment fee under Rule 317 of the SCAQMD. As set forth in Exhibit 330, SoCalGas described why the fee equivalency methodology will still result in SoCalGas having to pay the non-attainment fee required under Rule 317.

SoCalGas also disagrees with DRA's recommendation to disallow the incremental increase of $245,000 to allow SoCalGas to comply with GO 95. SoCalGas contends that it provided a response to DRA which reported that SoCalGas had spent $325,000 on compliance inspection activity in 2009. Although this number was inconsistent with the $200,000 SoCalGas had referenced in its workpapers, SoCalGas contends that this "should not be grounds for dismissing the original 2010 forecasted value of $200,000, particularly since it is only about 60% of what SoCalGas actually spent on this activity." (Ex. 470 at 9.)

As for DRA's argument that there were no historical costs for engineering support for GO 95 activities, SoCalGas contends that SoCalGas was not impacted by GO 95 until D.09-08-029 was issued on August 20, 2009. The incremental costs for this engineering support were estimated from SoCalGas' prior work on its electrical system.

On the $75,000 incremental increase for maintenance and contractor inspection costs associated with wildfire prevention and GO 95, SoCalGas contends that its forecast of five Red Flag days is reasonable. This allows SoCalGas to be prepared in the event a devastating wildfire affects SoCalGas' electrical system.

SoCalGas disagrees with DRA's recommended disallowance of the incremental increase of $100,000 to comply with Rule 333 of the Santa Barbara Area Pollution Control District. SoCalGas contends that this rule increased the monitoring testing from quarterly to monthly if the engine fails to meet the requirements, and that this revised rule became effective on June 19, 2010. In addition to the testing, SoCalGas may have to perform extensive tuning to optimize engine performance and to ensure that engine performance remains within the required limits. SoCalGas also contends that a mobile emission laboratory is needed because portable analyzers can be damaged if they are sampling for long periods of time.

9.2.2.3.1. Discussion

We have reviewed the testimony and the arguments of SoCalGas and DRA concerning the gas storage O&M costs. We have also compared their forecasts to the historical costs, and reviewed the various rules and regulations which affect SoCalGas' incremental increases.

Regarding the base forecast amount, we have compared the forecasts that SoCalGas and DRA have recommended to the historical costs. We agree with SoCalGas that the base forecast amount should use the 2009 recorded labor costs because the historical data shows an upward trend for labor costs. We also agree with SoCalGas that the five-year average of 2005-2009 is appropriate to use for the non-labor costs due to the fluctuating costs. Accordingly, SoCalGas' base forecast amount of $27.231 million should be used to form the basis of the test year 2012 gas storage O&M costs.

We have also considered the incremental increases that SoCalGas requested, and the base forecast of the O&M costs, in light of the current economy. O&M costs have remained fairly steady over the period from 2005 through 2009. To limit passing on the incremental costs to ratepayers, SoCalGas must also take active steps to control its O&M storage costs. Based on all those considerations, it is reasonable to adopt the amount of $27.607 million as the gas storage O&M costs for test year 2012.

9.2.3. Gas Storage Capital Expenditures

9.2.3.1. Introduction

SoCalGas forecasts the following capital expenditures for gas storage: $27.660 million for 2010; $31.605 million for 2011; and $30.596 million for 2012.

The capital projects that SoCalGas plans to undertake consists of five categories of projects. The first category cover capital projects related to the compressor stations. The second category covers capital projects related to the existing wells, and the drilling of replacement wells. The third category covers capital projects related to the pipelines. The fourth category covers capital projects related to purification. The fifth category of capital projects is related to work on auxiliary equipment.

In the subsections below, we address each of the five categories separately.

9.2.3.2.Compressor Stations

9.2.3.2.1. Introduction

SoCalGas forecasts the following capital expenditures for the compressor stations: $4.430 million for 2010; $6.851 million for 2011; and $6.851 million for 2012. These capital expenditures are for the maintenance, replacement, and upgrades at the different storage field compressor stations.

SoCalGas' base forecast for 2010 is based on fifteen specific projects. Its forecasts for 2011 and 2012 are based on "the difference between known specific projects and the average of five years of recorded costs in this budget category between years 2005 and 2009." (Ex. 468.) Added to the base forecast are two other capital projects. The first is the overhaul of the main unit #5 engine and compressor at the Honor Rancho storage field. The second capital project is to make upgrades to the turbine-driven compressors located at Aliso Canyon.

9.2.3.2.2. Position of the Parties

9.2.3.2.2.1. DRA

DRA accepts SoCalGas' 2010 capital expenditure forecast of $4.430 million for compressor station capital projects. For the 2011 and 2012 compressor station capital expenditures, DRA recommends $5.413 million for each year.

DRA's recommendation for 2011 and 2012 is based on the five-year average of recorded capital expenditures from 2005 to 2009. DRA contends that its use of the five-year average captures "any addition of new projects and subtraction of expired projects, and therefore by definition, the yearly average number has already accounted for new projects added." (Ex. 535 at 13.) DRA further contends that SoCalGas' addition of $1.438 million each year for compressor overhauls is unnecessary and should be removed.

9.2.3.2.2.2. SoCalGas

SoCalGas contends that the $1.438 million in 2011 and 2012 is necessary because these were incremental costs due to the overhaul of two compressor overhauls. SoCalGas contends that such overhauls are infrequent occurrences and costly, and were not reflected in the five-year average. SoCalGas contends that the compressor overhauls are needed due to the delay in the issuance of an amended certificate of public convenience and necessity (CPCN) to allow the replacement of the turbines at the Aliso Canyon storage field.

9.2.3.2.3. Discussion

We have reviewed the testimony and arguments of SoCalGas and DRA concerning the capital expenditures for the compressor stations.

We also take official notice of A.09-09-020, in which SoCalGas seeks to amend its CPCN to allow the replacement of the compressors at Aliso Canyon. SoCalGas filed A.09-09-020 in September 2009. A motion to adopt a proposed settlement was filed on November 27, 2012, but no action regarding the proposed settlement has been taken yet. As a result, the Commission has not yet acted on SoCalGas' request to replace the existing compressors.

Due to the circumstances concerning the compressors at Aliso Canyon, and the overhaul of the compressor at Honor Rancho, it is reasonable to make some incremental adjustments to the capital expenditures for 2011 and 2012. The following forecasts for the compressor stations capital expenditures should be adopted: $4.430 million for 2010; $5.851 million for 2011; and $5.851 million for 2012.

9.2.3.3. Wells

SoCalGas forecasts the following capital expenditures for wells: $11.055 million for 2010; $7.616 million for 2011; and $7.616 million for 2012.

According to SoCalGas, these capital expenditures include the "costs associated with replacing failed components on existing wells and drilling replacement wells for the injection and withdrawal of natural gas from underground storage facilities, including wells used for observation." (Ex. 466 at 21.)

SoCalGas' forecast for 2010 was based on the capital project for eight specific projects. To this base forecast, SoCalGas added three additional projects. The first capital project is for leaking wellhead replacements and upgrades, which has the effect of adding $1.141 million in 2010. The second capital project is to drill two replacement storage wells per year to replace "existing aging, mechanically unsound, high operating cost injection/withdrawal wells." (Ex. 468 at 7.) This has the effect of adding $7.019 million each year in 2010, 2011, and 2012. The third capital project is for the replacement of tubing to prevent gas and oil leaks. This has the effect of adding $901,000 in 2010.

None of the other parties have taken issue with SoCalGas' forecasts of the capital expenditures for wells.

Based on our review of the testimony and arguments of SoCalGas and DRA concerning the capital expenditures for wells, it is reasonable to adopt the following: $11.055 million for 2010; $7.616 million for 2011; and $7.616 million for 2012.

8.1.1.1. Pipelines

8.1.1.1.1. Introduction

SoCalGas forecasts the following capital expenditures for pipelines: $4.222 million for 2010; $3.493 million for 2011; and $3.493 million for 2012.

These capital expenditures are for "necessary pipeline maintenance, replacements, relocations, and upgrades at the various storage fields to ensure safety, maintain or improve reliability, and to meet the required capacities of the various piping systems." (Ex. 466 at 23.) These pipelines are used to transport the gas from transmission or field lines into the storage injection wells, and to withdraw the gas from the withdrawal wells to where the gas enters the transmission or distribution system.

The base forecast of the 2010 capital expenditures was developed from the budget categories for 2010. The base forecast for 2011 and 2012 was based on the five-year average. Three large projects then increased the base forecasts. The first project is to replace various leaking valves at Aliso Canyon. This has the effect of adding $898,000 in each year to 2010, 2011, and 2012. The second project is to install a high pressure pipeline at the Honor Rancho storage field to replace an existing line that was de-rated due to corrosion. This second project has the effect of adding $2.415 million to 2010. The third project is to install a new pipe bridge and pipes to remove existing pipes from a ravine with an active landslide and extensive soil erosion. This third project adds $1.218 million each year in 2011 and 2012.

8.1.1.1.2. Position of the Parties

8.1.1.1.2.1. DRA

DRA accepts SoCalGas' forecast of the 2010 capital expenditures for pipelines. DRA recommends capital expenditures of $2.275 million for 2011, and for 2012. DRA's recommendation for 2011 and 2012 is based on the five-year average of recorded capital expenditures from 2005 to 2009. DRA contends that its use of the five-year average captures "any addition of new projects and subtraction of expired projects, and therefore by definition, the yearly average number has already accounted for new projects added." (Ex. 535 at 14.) DRA further contends that SoCalGas' addition of $1.218 million each year for replacement of the pipeline span support at Aliso Canyon is inappropriate, and should be removed for both 2011 and 2012.

8.1.1.1.2.2. SoCalGas

SoCalGas contends that the funding request for the pipeline span support is reasonable because the project is to replace a badly eroded pipe bridge. SoCalGas further contends that this is a high cost project, and that this is not reflected in the historical data that was used in the five-year average.

8.1.1.1.3. Discussion

We have reviewed the testimony and argument of SoCalGas and DRA concerning the capital expenditures for pipelines. We have also compared their forecasts of capital expenditures to the historical data, and considered the need for the various projects that SoCalGas has described. Based on those considerations, and the recorded costs of $4.303 million in 2009 and $4.974 million in 2010, it is reasonable to adopt SoCalGas' forecasts of the capital expenditures for pipelines as follows: $4.222 million for 2010; $3.093 million for 2011; and $3.093 million for 2012.

8.1.1.2. Purification

SoCalGas forecasts the following capital expenditures for purification: $2.031 million for 2010; $4.191 million for 2011; and $4.191 million for 2012.

According to SoCalGas, these capital expenditures are for the "costs associated with equipment used primarily for the removal of impurities from, or the conditioning of, natural gas withdrawn from underground storage fields." (Ex. 466 at 24.)

SoCalGas' forecast for 2010 was based on the capital budget for six specific projects. To the base 2010 forecast, SoCalGas added $897,000 in 2010 for the Playa del Rey dehydration unit, which began construction in 2009 and was completed in 2010.

None of the other parties have taken issue with SoCalGas' forecasts of the capital expenditures for wells.

Based on our review of the testimony and arguments of SoCalGas and DRA concerning the capital expenditures for purification, it is reasonable to adopt the following: $2.031 million for 2010; $4.191 million for 2011; and $4.191 million for 2012.

8.1.1.3. Auxiliary Equipment

8.1.1.3.1. Introduction

SoCalGas forecasts the following capital expenditures for auxiliary equipment: $5.923 million for 2010; $9.454 million for 2011; and $8.445 million for 2012.

These capital expenditures are for "work on various types of field equipment not captured in other budget codes such as instrumentation, measurement, controls, electrical, drainage, infrastructure, transportation, safety, and communications systems." (Ex. 466 at 25.)

The base forecast of the 2010 capital expenditures was derived from the capital budget for 25 projects that range in cost from $51,000 to $3.600 million. The base forecast for 2011 and 2012 was based on the five-year average of 2005-2009. Two projects were then added to the base forecasts. The first project is to bring the Aliso Canyon utility poles and overhead wiring up to compliance with GO 95. This project has the effect of adding $1.800 million in 2011, and in 2012. The second project is upgrade three motor control centers at Aliso Canyon to improve the short circuit rating. This second project has the effect of adding $1.009 million in 2011.

8.1.1.3.2. Position of the Parties

8.1.1.3.2.1. DRA

DRA accepts SoCalGas' 2010 forecast of the capital expenditures. DRA's recommends capital expenditures of $6.645 million for 2011, and in 2012. DRA's 2011 and 2012 forecast is based on the five-year average of 2005-2009. DRA contends that since the five-year average captures the addition and subtraction of projects, that SoCalGas' incremental addition of $1.8 million for electrical system upgrades each year, and $1.009 million for the motor control centers is unnecessary.

8.1.1.3.2.2. SoCalGas

SoCalGas opposes DRA's reductions to the 2011 and 2012 capital expenditures. SoCalGas contends that these incremental projects are necessary, very costly, and are not reflected in the five-year average. SoCalGas also points out that GO 95 did not apply to SoCalGas' electric poles and overhead lines during the 2005-2009 period that was used for averaging. SoCalGas also contends that the 2010 recorded costs were higher than the 2010 forecasted amount by $2.200 million, which the Commission should consider when evaluating DRA's proposed reductions.

8.1.1.3.3. Discussion

We have reviewed the testimony and argument of SoCalGas and DRA concerning the capital expenditures for auxiliary equipment. We have also compared their forecasts of capital expenditures to the historical data, and considered the need for the various projects that SoCalGas has described. Based on those considerations, and the recorded cost of $8.103 million in 2010, it is reasonable to adopt SoCalGas' forecasts of the capital expenditures for auxiliary equipment as follows: $5.923 million for 2010; $7.454 million for 2011; and $6.645 million for 2012.

8.2. Gas Engineering

8.2.1. Introduction

Gas engineering provides the engineering and technical services that support the gas distribution and transmission operations of SDG&E and SoCalGas. This section addresses the O&M expenditures for gas engineering, and the capital expenditures for gas transmission, and gas engineering.

SDG&E requests that $13.750 million be adopted as its test year 2012 O&M costs for gas engineering. For capital expenditures, SDG&E requests $10.216 million for 2010, $12.281 million for 2011, and $12.406 million for 2012.

SoCalGas requests that $94.452 million be adopted as its test year 2012 O&M costs for gas engineering. For capital expenditures, SoCalGas requests $94.790 million for 2010, $114.333 million for 2011, and $158.306 million for 2012.

In the sub-sections below, we first address SDG&E's gas engineering, followed by SoCalGas' gas engineering.

8.2.2. SDG&E Gas Engineering

8.2.2.1. Introduction

SDG&E operates 169 miles of transmission pipeline. Using the DOT's definition of "transmission pipeline," SDG&E's gas distribution and gas transmission operating units operate approximately 246 miles of DOT transmission pipeline.

SDG&E's gas distribution system consists of about 8345 miles of mains, about 593,000 services, and 840,000 meters.

In order to provide safe and reliable gas service, SDG&E needs to undertake continuous O&M activities, as well as carrying out capital projects. Many of the costs described in this section "are in direct response to mandated federal pipeline safety regulations including, but not limited to, requirements associated with Subpart O, 'Gas Transmission Pipeline Integrity Management' (herein referred to as the Transmission Integrity Management Program, or TIMP), and Subpart P, 'Gas Distribution Pipeline Integrity Management' (herein referred to as the Distribution Integrity Management Program, or DIMP)."[63] (Ex. 51 at 4.)

[63] The TIMP was established as the result of the Pipeline Safety Improvement Act of 2002 and the enactment of 49 CFR Part 192 Subpart O (Subpart O). Pursuant to Subpart O, "operators of gas transmission pipelines are required to identify the threats to their pipelines in High Consequence Areas…, analyze the risk posed by these threats, collect information about the physical condition of their pipelines, and take actions to address applicable threats and integrity concerns before pipeline failures occur." (Ex. 51 at 4-5.) The DIMP was established as the result of the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006 and the enactment of 49 CFR Part 192 Subpart P (Subpart P). DIMP requires the operators of DOT-defined distribution pipe, by August 2, 2011, to "develop and implement an integrity management program that includes a written integrity management plan…." (49 CFR § 192.1005.)

8.2.2.2. O&M Costs

8.2.2.2.1. Introduction

SDG&E's test year 2012 O&M costs are composed of non-shared O&M costs of $11.869 million, and shared O&M costs of $1.881 million. Together, these O&M costs total to $13.750 million.

8.2.2.2.2. Non-Shared O&M Costs

8.2.2.2.2.1. Introduction

SDG&E's test year 2012 forecast of its non-shared O&M costs amount to $11.869 million. These non-shared O&M costs are divided into the following four cost categories: gas engineering; transmission pipeline integrity management program; distribution pipeline integrity management; and public awareness. We discuss each of these cost categories separately.

8.2.2.2.2.2. Gas Engineering

Under the cost category of gas engineering, SDG&E estimates test year 2012 O&M costs of $700,000. This amount is an incremental increase of $491,000 over the 2009 recorded amount of $209,000.

The incremental increase is due to two activities. The first activity is for an additional $20,000 for asset and data management. This includes " computer-based work-management systems, mapping products, geographic information system development, and technical computing support," as well as additional training on new programs such as GIS. (Ex. 51 at 11.)

The second activity is associated with the cost of complying with two of the environmental requirements in AB 32. AB 32 requires a program administration fee to be paid for each therm of gas delivered to any end user, excluding wholesale customer and electric generating units. This fee commenced in 2010. SDG&E forecasts this fee at $471,000 for test year 2012, and believes it will increase over time. The second requirement of compliance and reporting is discussed in the shared O&M costs.

The only other party who commented on the gas engineering costs was DRA. DRA examined the historical trend from 2005-2010 for the gas engineering costs. DRA accepts SDG&E's test year 2010 forecast "because the expense has been increasing over the last five years…." (Ex. 505 at 3.)

Based on a review of the testimony and arguments of the parties, as well as the historical costs, it is reasonable to adopt funding of $700,000 for the gas engineering category of costs.

8.2.2.2.2.3. Transmission Pipeline Integrity

8.2.2.2.2.3.

Under the cost category of transmission pipeline integrity, SDG&E estimates test year 2012 O&M costs of $7.339 million. This amount is an incremental increase of $6.592 million over the 2009 recorded amount of $747,000. SDG&E's forecast is based on a zero-based approach. A historical approach was not used because the level of work that is forecasted was not reflected in the historical costs.

This cost category includes TIMP-related costs. Pursuant to Subpart O, SDG&E and SoCalGas developed their Baseline Assessment Plan. This plan "contains the goals and schedule for how and when the TIMP assessments will be performed." (Ex. 51 at 13.) The TIMP requires the operators of gas transmission systems to conduct their baseline assessments of all high consequence areas that were in existence on December 2002 by December 2012. After the completion of this baseline assessment, the operator must reassess that same segment within seven years of the last assessment. For the smaller diameter pipelines, the TIMP baseline assessment schedule calls for these pipes to be inspected in 2008-2012. According to SDG&E, the "total cost to assess these comparatively shorter-length, smaller-diameter pipeline segments in the second five-year period is greater than the cost to assess the larger-diameter, longer-length segments completed during the first five-year period of the program." (Ex. 51 at 15.)

Three primary methods are used to carry out an assessment of the pipelines. These methods are: external corrosion direct assessment, in-line inspection, and pressure testing. The external corrosion direct assessment method uses a combination of operating data, interviews with operations personnel, and above ground surveys. Once areas of corrosion have been identified, excavation of prioritized sites to evaluate the pipe surface will be done. The in-line inspection method uses specialty inspection tools, sometimes referred to as "smart pigs," to inspect the interior of the pipelines through various measurements. This inspection method does not work in all pipelines because of the inability to the tools to pass through certain valves, bends, or obstructions. The pressure test method involves allowing water into the pipeline at a pressure greater than the maximum allowable operating pressure for a fixed period of time.

In addition to these assessment methods, TIMP activities "also include internal and external corrosion control, metallurgical assessment, damage prevention, integrity assessment, inspection, excavation for verification, pipeline-related quality control, evaluating susceptibility to external factors such as seismic activity, and the development and implementation of remediation plans." (Ex. 51 at 15.) The TIMP support activities consist of "procurement, quality control, deployment, and operations and maintenance of the pipeline assets." (*Ibid*.)

As a result of Chapter 523 of the Statutes of 2012, § 969 was added to the Pub. Util. Code, with an effective date of January 1, 2012. That code section provides that the costs relating to Subpart O of Part 192 of Title 49 of the United States Code, are to be recovered through a balancing account established for that purpose. That code section also provides that "Nothing in this section is intended to interfere with the commission's discretion to establish a two-way balancing account." (Pub. Util. Code § 969.) DRA, TURN, and UCAN have proposed in these consolidated proceedings that the TIMP-related O&M costs and capital expenditures be subject to a one-way balancing account. SDG&E

proposes that it should be a two-way balancing account, and that any year-end balance be carried forward into the following year.

8.2.2.2.2.3.

10.3.2.2.2.3.2.1. DRA

DRA recommends that the Commission adopt a test year 2012 forecast of $1.082 million. DRA's forecast is based on increasing the 2010 recorded amount $1.067 million by 0.7% per year.

10.3.2.2.2.3.2.2. TURN and UCAN

TURN and UCAN recognize the interest in ensuring gas pipeline safety. To ensure that the amounts authorized by the Commission are being used for pipeline safety, TURN and UCAN "recommend that the Commission adopt safeguards to ensure that whatever expenditures the Commission authorizes for pipeline safety are spent for that purpose and can be closely tracked by the

Commission." (Ex. 547 at 1.) One of the safeguards that TURN and UCAN propose is for the Commission to adopt a one-way balancing account for SDG&E's TIMP-related O&M costs and capital expenditures. TURN and UCAN propose that any "authorized amounts for these activities that are unspent at the end of the GRC cycle, plus interest, should be returned to ratepayers in the next GRC." (Ex. 547 at 5.) TURN and UCAN contend that the one-way balancing account treatment will prevent SDG&E from using the authorized funds for a different purpose.

10.3.2.2.2.3.2.3. Southern California Generation Coalition

The Southern California Generation Coalition (SCGC) raised the argument that SoCalGas should be prevented from including capital expenditures in the NERBA. Although SCGC raised this in the context of SoCalGas' application, that same issue arises in connection with SDG&E's NERBA. SCGC contends that balancing accounts have only "traditionally covered expenses that deviate from projected levels," and that SoCalGas has not provided any justification for including capital costs in the NERBA. (Ex. 319 at 17.)

10.3.2.2.2.3.2.4. SDG&E

SDG&E contends that DRA's recommendation ignores SDG&E's analysis of its TIMP's funding requirements, and did not acknowledge any of the cost drivers behind SDG&E's request. SDG&E contends that its forecast is "based on a number of specific projects that are required by law to be completed by December 17, 2012." (Ex. 54 at 4.)

With regard to the TIMP balancing account, SDG&E recommends that this be a two-way balancing account. SDG&E contends that the "two-way balancing account is in the best interest of all stakeholders," because any "under-spending would be returned to ratepayers, but if SDG&E finds that the prudent application of additional expenses is warranted for pipeline safety, it is reasonable to expect SDG&E to incur those expenses and recover them in rates." (Ex. 54 at 7.)

8.2.2.2.2.3.

We have reviewed the testimony and the arguments of the parties concerning the transmission pipeline integrity category of costs. We have also reviewed Subpart O and the type of work that is required, and have also reviewed Pub. Util. Code § 969.

Based on those considerations, we adopt the following. First, in accordance with Pub. Util. Code § 969, we adopt a two-way balancing account to recover the TIMP-related O&M costs and capital expenditures of complying with Subpart O. Due to the costs of complying with the TIMP, as well as DIMP, and the changing requirements, we are not persuaded by SCGC's argument that capital expenditures should not be included in the NERBA. We will also allow the year-end balance in that two-way balancing account to be carried forward into the following year. A two-way balancing account is appropriate due the costs of complying with Subpart O and possible changes in pipeline inspection requirements in the future. A two-way balancing account will ensure that SDG&E has sufficient funds to carry out all the necessary TIMP-related work to ensure that its gas transmission system remains safe and reliable. Accordingly, SDG&E is authorized to file a Tier 2 AL within 45 days of the effective date of this decision to establish this two-way balancing account. As noted by SDG&E in Exhibit 54, the parties will have an opportunity to review the reasonableness of these TIMP-related expenses in this balancing account when those expenses are reported in the Annual Regulatory Account Balance Update.

Second, we have reviewed SDG&E's workpapers regarding its forecast for the transmission pipeline integrity costs, and compared it to the historical data and to DRA's forecast. Based on the work that Subpart O requires, and the type of work that is needed to perform the assessments of the pipelines, DRA's forecast is too low. Since we have adopted a balancing account for these TIMP-related costs, it is reasonable to adopt a test year 2012 forecast of $5.339 million. Should this test year forecast for TIMP-related costs be understated, SDG&E will have an opportunity to recover the difference from its customers through the two-way balancing account.

8.2.2.2.2.4. Distribution Pipeline Integrity

8.2.2.2.2.4.

Under the cost category of distribution pipeline integrity, SDG&E estimates test year 2012 O&M costs of $3.373 million. This amount is an incremental increase of $2.214 million over the 2009 recorded amount of $1.159 million. SDG&E's forecast used a zero-based approach "because this is a new activity and there is no history of this activity in prior years." (Ex. 51 at 23.)

This cost category covers the costs of complying with the DIMP regulations in Subpart P, and affects over 8300 miles of main lines, and 6300 miles of service lines. These DIMP costs are in addition to the gas distribution O&M costs and capital expenditures discussed earlier.

SDG&E's DIMP-related costs are driven by the following eight activities: (1) work relating to GIS; (2) distribution risk evaluation and monitoring system; (3) DIMP driven monitoring; (4) anodeless riser program; (5) vehicular damage; (6) sewer lateral initiative; (7) damage prevention; and (8) cathodic protection program enhancement. The costs of all of these activities add up to SDG&E's test year request of $3.373 million.

GIS allows SDG&E to integrate its existing data and maps about its distribution system into a single electronic repository, and to present that information in a graphical display. SDG&E forecasts $155,000 for contract support in the test year.

The distribution risk evaluation and monitoring system is a computational model that supports SDG&E's DIMP mitigation strategy. This model helps to evaluate and risk-rank pipeline threats associated with leakage on a pipeline segment. Although no additional funding for this model has been requested, SDG&E notes that this model does affect pipeline replacement costs.

The DIMP driven monitoring supplements the ranking of the risks through the distribution risk evaluation and monitoring system. Due to various construction or permitting issues, a high ranked risk may not be immediately replaced. If a high ranked risk cannot be replaced, SDG&E will monitor the pipe segment on a more frequent basis for accelerated deterioration. SDG&E forecasts $4000 for this activity in the test year.

The anodeless riser program is a program to replace or to service anodeless risers, which "are service line components that have shown a propensity to fail before the end of their useful lives." (Ex. 51 at 33.) Due to the large number of these risers, SDG&E plans that this program will take over 13 years, beginning in 2010 and concluding in 2023. SDG&E forecasts $1.804 million in funding for this activity for the test year.

The vehicular damage pertains to protecting above-ground distribution facilities from vehicle damage. SDG&E forecasts $300,000 for this new activity during the test year.

The sewer lateral initiative program is to protect distribution pipelines from damages associated with sewer laterals when trenchless technology is used to install gas pipelines. The problem occurs when the gas pipeline and sewer line cross paths, which may lead to a leak of the gas pipeline. To alleviate this problem, locate and mark, and depth checks are done before trenching. In addition, SDG&E will inspect potential problem areas using cameras to visually verify potential conflicts. For this new project, SDG&E forecasts funding of $878,000.

Damage prevention relates to activities to prevent damage to distribution pipelines by third parties. SDG&E is forecasting two additional FTEs to enhance the existing damage prevention program at a cost of $200,000.

The cathodic protection program enhancement involves collecting and organizing information and data for each cathodic protection station or area, which will provide baseline information. SDG&E requests $32,000 for 0.5 FTE.

TURN and UCAN propose that the DIMP-related O&M costs and capital expenditures be subject to a one-way balancing account. SDG&E proposes that a two-way balancing account be adopted for the DIMP-related costs, and that any balance at year-end be carried forward into the next year.

SDG&E requests that the current Distribution Integrity Management Program Account (DIMPBA) be closed out. The DIMPBA is a one-way balancing account that was adopted as part of the settlement in SDG&E's last GRC. The DIMPA records "the difference between actual and authorized operating and maintenance costs associated with SDG&E's [DIMP] pursuant to [D.] 08-07-046." (Ex. 262 at 4.) As of December 31, 2011, the DIMPBA was overcollected by $70,084. According to footnote 8 of Exhibit 596, this amount represents the balancing account interest. SDG&E proposes to amortize this balance in gas transportation customers' rates upon the implementation of SDG&E's 2012 GRC revenue requirement, and to transfer any remaining balance in the DIMPBA to the Core Fixed Cost Account/Noncore Fixed Cost Account, and that the DIMPBA be eliminated if the Commission includes the DIMP costs in base margin.

8.2.2.2.2.4.

10.3.2.2.2.4.2.1. DRA

DRA recommends that the Commission adopt a test year 2012 forecast of $2.179 million. DRA's forecast is based on increasing the 2010 recorded amount $2.149 million by 0.7% per year. DRA contends that its "forecast methodology is more reasonable than SDG&E's method because it utilizes the more recent 2010 recorded data." (Ex. 505 at 4-5.)

10.3.2.2.2.4.2.2. TURN and UCAN

For the DIMP-related O&M costs and capital expenditures, TURN and UCAN make the same recommendation as it did for SDG&E's TIMP-related O&M costs and capital expenditures. TURN and UCAN propose that a one-way balancing account be created for SDG&E's DIMP-related O&M costs and capital expenditures. TURN and UCAN propose that any "authorized amounts for these activities that are unspent at the end of the GRC cycle, plus interest, should be returned to ratepayers in the next GRC." (Ex. 547 at 5.) TURN and UCAN contends that the one-way balancing account treatment will prevent SDG&E from using the authorized funds for a different purpose.

10.3.2.2.2.4.2.3. SDG&E

SDG&E contends that DRA's forecast is too simplistic, and ignores SDG&E's description of the DIMP activities that are expected to ramp up in test year 2012. Although SDG&E's 2010 recorded expenses for DIMP were less than what it had forecasted, the reason for this was because SDG&E was not required to submit and implement its DIMP until August 2, 2011. SDG&E also contends that based "on the current spending rates, it is estimated that the 2011 expense will exceed the forecast amounts." (Ex. 54 at 13.)

Regarding the proposal to recover DIMP-related costs through a balancing account, SDG&E takes the position that a two-way balancing account should be adopted. SDG&E contends that "one-way balancing account treatment creates incentives that are inconsistent with a maximum focus on pipeline safety…." (Ex. 54 at 13.) SDG&E further contends that "a two-way balancing account is in the best interest of all stakeholders," because any "underspending would be returned to ratepayers, but if SDG&E finds that the prudent application of additional expenses is warranted for pipeline safety, it is reasonable to expect SDG&E to incur those expenses and recover them in rates." (Ex. 54 at 14.) SDG&E also contends that another reason for the two-way balancing account is because there may be additional requirements that will cause additional safety measures to be taken for the distribution pipeline system.

8.2.2.2.2.4.

We have reviewed the testimony and the arguments of the parties concerning the distribution pipeline integrity category of costs, and have reviewed Subpart P.

Based on those considerations, we adopt the following. First, we adopt a two-way balancing account to recover the DIMP-related O&M costs and capital expenditures of complying with Subpart P, and to allow SDG&E to carry forward any year-end balance to the following year. A two-way balancing account is appropriate due the costs of complying with Subpart P and possible changes in requirements. A two-way balancing account will also ensure that SDG&E carries out the necessary work to ensure that its gas distribution system remains safe and reliable. Accordingly, SDG&E is authorized to file a Tier 2 AL within 45 days of the effective date of this decision to establish this two-way balancing account. As noted by SDG&E in Exhibit 54, the parties will have an opportunity to review the reasonableness of these DIMP-related expenses in this balancing account when those expenses are reported in the Annual Regulatory Account Balance Update.

Second, SDG&E has requested that the current one-way balancing account, the DIMPBA, be closed out. Since we have adopted the two-way balancing account for these DIMP-related costs, SDG&E is authorized to close out its current DIMP balancing account by filing a Tier 2 AL within 45 days of the effective date of this decision. Any balance remaining in the DIMPBA shall be amortized in gas transportation customers' rates on an equal percent of authorized margin basis.

Third, we have reviewed SDG&E's workpapers regarding its forecast for the distribution pipeline integrity costs, and compared it to the historical data and to DRA's forecast. Based on the work that Subpart P requires, and the type of work that SDG&E plans to carry out, it is reasonable to adopt SDG&E's test year 2012 forecast of $3.373 million. Since we have adopted a balancing account for these DIMP-related costs, should SDG&E's test year forecast be overstated, any excess will be refunded to SDG&E's customers.

8.2.2.2.2.5. Public Awareness

8.2.2.2.2.5.

Under the cost category of public awareness, SDG&E estimates test year 2012 O&M costs of $457,000. This amount is an incremental increase of $384,000 over the 2009 recorded amount of $73,000. SDG&E's forecast used the base year plus incremental additions.

The public awareness cost category covers the costs of complying with the public awareness program set forth in 49 CFR §192.616. Under that regulation, SDG&E must develop and implement a public education program to educate the public, government organizations, and persons engaged in excavation about procedures to follow involving pipeline excavations, and how to identify gas leaks. That regulation also requires SDG&E to notify municipalities, school districts, businesses, and residents of pipeline locations.

According to SDG&E, a large driver of the incremental costs is measuring the impact of the public awareness messages, which necessitates that more frequent safety messages be targeted to affected stakeholders.

8.2.2.2.2.5.

10.3.2.2.2.5.2.1. DRA

DRA recommends that the Commission adopt a test year 2012 forecast of $121,000. DRA's forecast is based on increasing the 2010 recorded amount $119,000 by 0.7% per year. DRA contends that its "forecast methodology is more reasonable than SDG&E's method because it utilizes the more recent 2010 recorded data." (Ex. 505 at 5.)

10.3.2.2.2.5.2.2. SDG&E

SDG&E contends that DRA's recommendation made no attempt to refute the merits of SDG&E's proposal. SDG&E contends that the funds it requested are necessary so it can "implement new or enhanced activities, refine its program, and create a tailored approach to segments of the affected stakeholders to communicate safety messages geared for them." (Ex. 54 at 16.) In addition, the funds are needed to conduct "periodic evaluation and assessment to determine the effectiveness of the communications to their target audiences." (*Ibid*.)

8.2.2.2.2.5.

We have reviewed the testimony and arguments of SDG&E and DRA, and compared their forecasts to the 2009 and 2010 costs. We have also considered the need to periodically evaluate the effectiveness of the public awareness program, as incorporated into the requirements of 49 CFR §192.616. Based on those considerations, it is reasonable to adopt $200,000 for the O&M costs for public awareness in test year 2012.

8.2.2.2.3. Shared O&M Costs

SDG&E forecasts $1.881 million for the test year 2012 shared services general engineering O&M costs. This is an incremental increase of $524,000 over the 2009 amount of $1.357 million.

There are two cost centers that comprise the shared services O&M costs for general engineering. The cost centers are codes and standards, and operations technology. These two cost centers, and the billed-in amount from SoCalGas, total to SDG&E's forecast of $1.881 million.

The codes and standards "supports the development and integration of gas standards for both SoCalGas and SDG&E." (Ex. 51 at 32.) SDG&E has retained $11,000 for this activity, and billed-out $64,000 to SoCalGas.

Operations technology "provides operations technology application and field hardware support for the benefit of the Gas Distribution and Gas Transmission organizations at both SoCalGas and SDG&E." (Ex. 51 at 33.) SDG&E has retained $11,000 for this activity, and billed-out $70,000 to SoCalGas.

SDG&E has billed in costs of $1.859 million from SoCalGas. These costs represent "the expense associated with the shared-service support received by SDG&E from SoCalGas." (Ex. 51 at 34.)

None of the other parties have taken issue with SDG&E's forecast of the shared services O&M costs.

Based on our review of the uncontested shared services costs, it is reasonable to adopt $1.881 million as the shared services O&M costs for SDG&E.

8.2.2.3. Capital Expenditures

8.2.2.3.1. Introduction

This section addresses the estimated capital expenditures for SDG&E's gas transmission, engineering, and pipeline integrity operations. SDG&E forecasts the following capital expenditures: $10.216 million for 2010; $12.281 million for 2011; and $12.406 million for 2012.

SDG&E's capital expenditures for this rate cycle cover the following 11 capital projects, which are categorized as follows: (1) gas transmission – new additions; (2) gas transmission – pipeline replacements; (3) gas transmission – pipeline relocations – freeway; (4) gas transmission – compressor stations; (5) gas transmission – cathodic protection; (6) gas transmission – LNG support; (7) gas transmission – meter and regulator stations; (8) gas transmission – pipeline integrity – projects for distribution; (9) gas transmission – capital tools; (10) gas transmission – direct supervision and engineering overheads; and (11) distribution integrity management program.

As described in Exhibits 51 and 54, each of these categories consists of one or more budget codes, which record the costs of these capital projects.[64] We separately discuss each of these capital projects below.

[64] The "budget code" is also referred to as "budget category."

8.2.2.3.2. New Additions

8.2.2.3.2.1. Introduction

The new additions covers the "costs associated with the design and installation of new transmission pipelines to serve new customer loads and/or to improve the ability to move natural gas to points of critical need at adequate pressure." (Ex. 51 at 36.)

SDG&E estimates annual expenditures of $1.267 million in 2010, 2011, and 2012. SDG&E's estimate is based on the five-year average of 2005-2009.

8.2.2.3.2.2. Position of the Parties

8.2.2.3.2.2.

DRA contends that the recorded 2009 amount was $111,000 and that the 2010 recorded amount was $56,000. Based on the recorded data, DRA recommends that an annual amount of $56,000 be adopted for 2010, 2011, and 2012.

8.2.2.3.2.2.

SDG&E contends that DRA failed to mention that the 2005 recorded amount for new additions was $3.026 million, and that SDG&E's forecasts were based on the five-year average of 2005-2009. SDG&E points out that DRA did not object to SDG&E's use of the five-year average in SDG&E's other transmission capital expenditures, but objected to SDG&E's use in this instance. SDG&E also contends that the new additions capital projects are customer-driven, and vary considerably from year to year.

8.2.2.3.2.3. Discussion

We have reviewed the testimony and arguments of SDG&E and DRA concerning gas transmission new additions. We have also compared the forecasts of SDG&E and DRA to the historical costs from 2005 to 2010, and considered the slower growth in the economy.

Based on those considerations, it is reasonable to adopt the following capital expenditures for new additions: the recorded amount of $256,000 for 2010; and an annual amount of $500,000 in 2011 and for 2012.

8.2.2.3.3. Pipeline Replacements

8.2.2.3.3.1. Introduction

The gas transmission – pipeline replacements covers the cost of replacing gas transmission pipelines, or pipeline sections that have reached the end of their service lives. SDG&E contends that since 2002, these costs "have been heavily influenced by the new federal pipeline integrity rules…." (Ex. 51 at 37.) As a result, the capital costs in 2009 are lower than what SDG&E has forecasted in

2012 because more replacements and retrofits will occur as a result of the earlier assessments of transmission pipeline.

SDG&E estimates the following capital expenditures: $575,000 in 2010; $2.011 million in 2011; and $617,000 in 2012.

8.2.2.3.3.2. Position of the Parties

8.2.2.3.3.2.

DRA contends "that there were no costs associated with pipeline replacement in 2009 and 2010." (Ex. 504 at 7.) DRA contends that the historical trend for this account "shows that the expenses of this account have drastically declined from 2007 to 2010." (*Ibid.*) DRA recommends zero in capital expenditures for 2010, and does not oppose SDG&E's requests of $2.011 million for 2011, and $617,000 for 2012.

8.2.2.3.3.2.

SDG&E notes that it "generally opposes the use of actual 2010 costs rather than forecasted costs…." (Ex. 54 at 19.)

8.2.2.3.3.2.

We have reviewed the testimony and arguments of SDG&E and DRA concerning pipeline replacements for gas transmission. We have also compared the forecasts of SDG&E and DRA to the historical costs from 2005 to 2010.

Based on those considerations, it is reasonable to adopt the following capital expenditures for pipeline replacements: zero as the recorded amount for 2010; $1.500 million for 2011; and $617,000 for 2012.

8.2.2.3.3.2.

8.2.2.3.3.3. Introduction

The gas transmission – pipeline relocations cover the cost of relocating gas transmission pipelines due to the needs of CALTRANS.

SDG&E estimates annual capital expenditures of $212,000 in 2010, 2011, and 2012.

8.2.2.3.3.4. Position of the Parties

8.2.2.3.3.4.

SDG&E supplied DRA with the recorded costs for freeway pipe relocations for 2005 through 2010. DRA notes that there were no costs for this account in 2009, and that the 2010 recorded cost was $88,000.

DRA recommends the recorded amount of $88,000 for 2010, and does not oppose SDG&E's forecast of $212,000 for 2011, and for 2012.

8.2.2.3.3.4.

SDG&E contends that these freeway pipe relocation costs are difficult to forecast because it depends on the projects that CALTRANS is planning, and that these costs can vary widely from year to year.

8.2.2.3.3.5. Discussion

We have reviewed the testimony and arguments of SDG&E and DRA concerning the capital expenditures associated with freeway pipe relocations. We have also compared the forecasts of SDG&E and DRA to the historical costs from 2005 to 2010.

Based on those considerations, it is reasonable to adopt the following capital expenditures for pipeline replacements: the recorded amount of $88,000 for 2010; and SDG&E's forecast of $212,000 for 2011, and for 2012.

8.2.2.3.4. Compressor Stations

8.2.2.3.4.1. Introduction

The gas transmission – compressor stations cover the cost of installing and replacing compressor station equipment.

SDG&E estimates the following capital expenditures: $4.961 million in 2010; $2.486 million in 2011; and $2.610 million in 2012.

8.2.2.3.4.2. Position of the Parties

8.2.2.3.4.2.

SDG&E supplied DRA with the recorded costs for the compressor stations for 2005 through 2010. DRA notes that the 2010 recorded cost was $3.288 million.

DRA recommends the recorded amount of $3.288 million for 2010, and does not oppose SDG&E's forecast of $2.486 million for 2011, and $2.610 million for 2012.

8.2.2.3.4.2.

In Exhibit 54, SDG&E notes that the correct recorded 2010 amount should have been $4.048 million instead of the $3.288 million referenced by DRA. According to SDG&E, this difference is attributable to a calculation error by DRA, and because of SDG&E's failure to reference an account.

8.2.2.3.4.2.

We have reviewed the testimony and arguments of SDG&E and DRA concerning the capital expenditures associated with the compressor stations. We have also compared the forecasts of SDG&E and DRA to the historical costs from 2005 to 2010.

Based on those considerations, it is reasonable to adopt the following capital expenditures for the compressor stations: the recorded amount of $4.048 million for 2010; and SDG&E's forecast of $2.486 million for 2011, and $2.610 million for 2012.

8.2.2.3.4.2.

8.2.2.3.4.3. Introduction

The cathodic protection capital expenditures cover the costs "associated with the installation and replacement of cathodic protection…equipment used to protect transmission pipelines against corrosion." (Ex. 51 at 39.)

SDG&E estimates the following capital expenditures: $281,000 in 2010; and $94,000 in 2011, and in 2012.

8.2.2.3.4.4. Position of the Parties

8.2.2.3.4.4.

DRA obtained the 2005-2010 recorded costs for cathodic protection. DRA notes that the 2010 recorded cost was $49,000.

DRA recommends the recorded amount of $49,000 for 2010, and does not oppose SDG&E's forecast of $94,000 for 2011, and for 2012.

8.2.2.3.4.4.

SDG&E notes that it "generally opposes the use of actual 2010 costs rather than forecasted costs…." (Ex. 54 at 19.)

8.2.2.3.4.5. Discussion

We have reviewed the testimony and arguments of SDG&E and DRA concerning the capital expenditures for cathodic protection. We have also compared the forecasts of SDG&E and DRA to the historical costs from 2005 to 2010.

Based on those considerations, it is reasonable to adopt the following capital expenditures for cathodic protection: the recorded amount of $49,000 for 2010; and SDG&E's forecast of $94,000 for 2011, and for 2012.

8.2.2.3.5. LNG Support

SDG&E does not expect any capital expenditures for LNG support for 2010, 2011, or 2012. No capital expenditures have been included in SDG&E's request.

8.2.2.3.6. Meter and Regulator Stations

8.2.2.3.6.1. Introduction

The meter and regulator stations cover "the capital cost of installing and rebuilding large meter set assemblies … for transmission-served customers." (Ex. 51 at 40.)

SDG&E estimates the following capital expenditures: $60,000 in 2010; and $444,000 in 2011, and in 2012.

8.2.2.3.6.2. Position of the Parties

8.2.2.3.6.2.

DRA does not oppose SDG&E's forecasts.

8.2.2.3.6.2.

SDG&E contends that for the other capital expenditures, DRA recommended that the Commission adopt SDG&E's recorded costs. However, DRA failed to recommend that the 2010 recorded costs of $579,000 for the meters and regulators stations be used, which is inconsistent with what DRA had done for the other capital expenditures. SoCalGas contends that "if the Commission uses actual 2010 costs for some capital accounts it should do so for all of them." (Ex. 54 at 21.)

8.2.2.3.6.3. Discussion

We have reviewed the testimony and arguments of SDG&E and DRA concerning the capital expenditures for the meters and regulator stations. We have also compared the forecasts of SDG&E and DRA to the historical costs and to the 2010 recorded costs.

Based on those considerations, it is reasonable to adopt the following capital expenditures for the meters and regulator stations: $60,000 for 2010; and SDG&E's forecast of $444,000 for 2011, and for 2012.

8.2.2.3.7. Projects for Distribution

The "projects for distribution" records the cost of complying with some of the new pipeline integrity requirements. According to Exhibit 52 at 14, this budget code captures the "DOT transmission pipeline work generated to address these regulatory requirements…."

SDG&E estimates the following capital expenditures: $2.626 million in 2010; $2.698 million in 2011; and $920,000 in 2012.

None of the other parties take issue with SDG&E's forecast.

Based on our review of the testimony and arguments of the parties, it is reasonable to adopt SDG&E's forecast of the capital expenditures for the projects for distribution as follows: $2.626 million in 2010; $2.698 million in 2011; and $920,000 in 2012.

8.2.2.3.8. Capital Tools

The budget code for capital tools records the "costs associated with the purchase and replacement of capital tools used by the Gas Transmission operating and engineering departments," and includes such tools as "specialized welding equipment, leakage detection, and GPS receivers used for land surveys." (Ex. 51 at 41.)

SDG&E estimates the following capital expenditures: $14,000 in 2010; $20,000 in 2011; and $20,000 in 2012.

None of the other parties take issue with SDG&E's forecast.

Based on our review of the testimony and arguments of the parties, it is reasonable to adopt SDG&E's forecast of the capital expenditures for capital tools as follows: $14,000 in 2010; $20,000 in 2011; and $20,000 in 2012.

8.2.2.3.9. Direct Overheads

The budget code for direct overheads covers the cost of the supervision and engineering overhead, which are then reassigned to the various capital budget codes.

SDG&E estimates annual capital expenditures of $220,000 in 2010, 2011, and 2012.

None of the other parties take issue with SDG&E's forecast.

Based on our review of the testimony and arguments of the parties, it is reasonable to adopt SDG&E's forecast of annual capital expenditures for direct overheads of $220,000 in 2010, 2011, and 2012.

8.2.2.3.10. DIMP

The budget code for DIMP covers the costs of "DIMP-driven activities for accelerated replacements or new installations of identified and targeted components of the system." (Ex. 51 at 42.)

SDG&E estimates capital expenditures of $2.829 million in 2011, and $6.002 million in 2012.

None of the other parties take issue with SDG&E's forecast.

Although no one disputes SDG&E's forecast of these capital expenditures, we are concerned that the request for 2012 is excessive in comparison to no recorded costs in 2010, and the capital projects that are expected in 2012. Based on those considerations, it is reasonable to adopt capital expenditures of $2.829 million in 2011, and $4.500 million in 2012.

8.2.3. SoCalGas Gas Engineering

8.2.3.1. Introduction

SoCalGas operates 2830 miles of transmission pipeline, and 11 compressor stations. Using the DOT definition of "transmission pipeline," SoCalGas' gas distribution, gas transmission, and gas storage operating units operate approximately 3989 miles of DOT transmission pipeline.

SoCalGas' gas distribution system consists of about 47,600 miles of mains, about 4.350 million services, and 5.700 million meters. SoCalGas also operates four underground gas storage fields, with a working inventory capacity of about 134 Bcf. In order to provide safe and reliable gas service, SoCalGas needs to undertake continuous O&M activities, as well as performing capital projects. Many of the costs described in this section are in direct response to the federal pipeline safety regulations which include TIMP and DIMP.

8.2.3.2. O&M Costs

8.2.3.2.1. Introduction

SoCalGas' test year 2012 O&M costs are composed of non-shared O&M costs of $78.399 million, and shared O&M costs of $16.053 million. Together, these O&M costs total to $94.452 million.

8.2.3.2.2. Non-Shared O&M Costs

SoCalGas' test year 2012 forecast of its non-shared O&M costs amount to $78.399 million. These non-shared O&M costs are divided into the following four cost categories: gas engineering; transmission pipeline integrity management; distribution pipeline integrity management; and public awareness. We discuss each of these cost categories separately.

8.2.3.2.2.1. Gas Engineering

SoCalGas forecasts test year 2012 O&M costs of $21.383 million for the cost category of gas engineering. This amount is an incremental increase of $11.194 million over the 2009 recorded amount of $10.189 million.

Gas engineering covers many different engineering activities that are performed to ensure that the SoCalGas system is safe and reliable. These engineering activities have been divided into the following seven sub-workgroups by SoCalGas: (1) gas measurement, control and pressure regulation; (2) engineering analysis center; (3) engineering design and support; (4) asset and data management; (5) planning and analysis; (6) gas infrastructure project management and construction; and (7) Sustainable SoCal Program. For most of these work groups, the costs were forecasted based on the five-year average, and then incremental costs were added.

For gas measurement, control, and pressure regulation, these activities include the following: "the maintenance and operation of 22 SoCalGas Natural Gas Vehicle (NGV) fueling stations used for public and operational fleet fueling, limited support for customers' NGV fueling stations, electrical maintenance/basic electrician services to support SoCalGas' multitude of operational and office facilities, and the maintenance of gasoline station Underground Storage Tank … control and monitoring systems."
(Ex. 55 at 14.)

The activities of the engineering analysis center cover a variety of engineering and technical services support work. Since the engineering analysis center is responsible for compressor equipment standards, the assessment of new compressor technology, and compressor design, and because the compressors are geographically dispersed, the center provides support on air quality compliance. The work activity regarding air quality compliance is driven by compliance with AB 32, the mandatory GHG reporting rule, and changes to MDAQMD Rule 1160.

The activities for engineering design and support cover pipeline and gas facilities engineering design, and include such work as the following: "evaluation, specification, and/or modification of major compressor station and storage facility plant equipment such as heat exchangers, cooling towers, pressure vessels, compressors, generators, and gas treatment apparatus; drafting; engineering drawing management; strategic planning; and field support."
(Ex. 55 at 15.)

The asset and data management activity includes the use of " computer-based work management systems, mapping products, geographic information system development, and technical computing management and support." (Ex. 55 at 16.) Part of the activity is maintaining and upgrading software applications that are used for engineering-specific activities. Due to a shift to the work and processes that this group is responsible for, SoCalGas forecasts a shift of 13 positions.

Planning and analysis covers the cost of resources "to analyze and forecast near-term and long term system requirements for SoCalGas operations…." (Ex. 55 at 20.) Planning and analysis also covers "the resources required to optimize the use of transmission and storage capacity in conjunction with market analysis, open seasons, customer surveys, and to support the execution of supplier and customer contracts." (*Ibid.*) A large driver of these costs are the program administrative fee for AB 32, and the cap and trade costs. In addition, there are compliance and reporting requirements.

The gas infrastructure project management and construction covers the "functional and technical expertise and resources needed to perform technical development consultation, planning, permitting, detailed design, material specifications and management, infrastructure facility construction, and the commissioning and general project management of major gas facility infrastructure projects…." (Ex. 55 at 22.)

The Sustainable SoCal Program involves the installation of four biogas conditioning systems at certain customer sites. These systems would capture the raw biogas, process it to meet pipeline quality gas specifications, and inject the gas into the SoCalGas pipeline system.

8.2.3.2.2.1.

10.2.2.3.3.1.2.1. DRA

DRA recommends that $10.889 million be adopted as the gas engineering O&M costs for test year 2012, as opposed to SoCalGas' request of $21.383 million. DRA has raised several objections to SoCalGas' gas engineering O&M costs.

DRA objects to SoCalGas' use of the five-year average of 2005-2009. DRA contends that the annual expenses for gas engineering have decreased slightly from 2006 to 2009. DRA recommends that the 2009 recorded expenses of $10.189 million be used as the base forecast.

For the engineering analysis center, SoCalGas requested an increase of $180,000 above the base year to handle the impact of increased environmental regulations. DRA recommends that none of this increase be allowed. DRA contends that the EPA has only announced an advance notice of proposed rulemaking regarding PCBs, and that a final rule may take years before a final rule is adopted.[65] Regarding the MDAQMD, DRA contends that there is no indication that Rule 1160 of the MDAQMD will be finalized by 2012, or any indication that an amendment will be made to that rule. For AB 32, DRA contends that the compliance date for SoCal Gas will not start until at least 2016.

DRA also objects to SoCalGas' incremental increase of $9.542 million for planning and analysis. Of this amount, SoCalGas estimates that about $4.500 million will be needed for the program administrative fee assessed by the CARB, and $5 million for the emission credits to offset GHG emissions. DRA contends that SoCalGas' request for both fees "is premature because the costs used to estimate the fees are still in the proposal stage at this time," and "because the Commission has not decided whether or not ratepayers should be responsible for any of the AB 32 fees," citing D.10-12-026. (Ex. 533 at 72.) DRA further contends that under the cap and trade program, SoCalGas will not have to begin any compliance action until 2015.

DRA is also opposed to SoCalGas' incremental increase of $606,000 for the O&M costs associated with the Sustainable SoCal Program. DRA contends that: it is the responsibility of the gas producing entity to ensure that the gas is of pipeline quality; gas production is unregulated, and there is no legislation or policy that requires SoCalGas to undertake gas production or treatment activity;

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[65] It appears that DRA's argument concerning the EPA's proposal about a rulemaking involving PCBs may be misplaced. According to Exhibit 55 at 15, the activities of the engineering analysis center appear to be impacted by the mandatory GHG reporting rule of the EPA. (*See* Ex. 330 at 8-9.)

and SoCalGas has not demonstrated why ratepayers should have to pay for the expenses of capturing and conditioning raw biogas.

10.3.3.2.2.1.2.2. SCGC

SCGC contends that the CARB administrative fee should not be collected through the gas transmission O&M expenses. SCGC contends that the inclusion of such a fee will result in electric generators and wholesale customers having to pay twice for this fee. SCGC recommends that the CARB administrative fee be recovered through the NERBA instead. To prevent SoCalGas from recovering the CARB administrative fee from customers that pay the administrative fee directly to the CARB, SCGC recommends that the NERBA should include language that excludes those who are directly billed by the CARB.

With respect to the cap and trade allowances, SCGC contends that SoCalGas' forecast of $5 million should not be included in the 2012 base rates. SCGC contends that this amount should not be included in the 2012 base rates because of the delay of the auction until later in 2012, and because it is difficult to estimate the allowance cost accurately. SCGC recommends that on a going forward basis, that the cap and trade allowance costs should be recovered through the NERBA.

Regarding the cost of monitoring and reporting of GHG emissions to the CARB, SCGC recommends that these costs should be excluded from the NERBA and left in base rates. SCGC's rationale for excluding this cost from the NERBA is because SoCalGas has not demonstrated that the monitoring and reporting costs will rise significantly.

10.3.3.2.2.1.2.3. SoCalGas

SoCalGas contends that DRA's reliance on the 2009 data ignores that the difference between the 2005 and 2009 recorded data was less than one percent, and that the 2009 data was "essentially the lowest value from the entire dataset" of 2006-2009 that DRA used. (Ex. 58 at 8.) SoCalGas also contends that DRA "ignored the 2010 data that validates SoCalGas' forecast." (*Ibid*.)

On DRA's opposition to the incremental increase for the engineering analysis center, SoCalGas contends that the center is incurring costs through its involvement "in a pilot program with the MDAQMD to demonstrate emission control technology to help with development of Rule 1160," and that a technical advisor "oversees the troubleshooting, tuning, and testing efforts associated with this project." (Ex. 58 at 9-10.) SoCalGas also points out that other local air districts have recently amended their rules which "have lower emissions limits than the current MDAQMD Rule 1160," and that it "is reasonable to expect lower emission limits in the revised MDAQMD Rule 1160 to be in line with the other local air districts." (Ex. 330 at 18.)

Regarding DRA's opposition to the CARB administrative fee, SoCalGas contends that it already "paid mandatory AB 32 administrative fees to CARB for the agency's fiscal budgets 2010/2011 and 2011/2012,"which "total more than $11 million and will be on-going on an annual basis." (Ex. 330 at 10.) SoCalGas also notes that a memorandum account was authorized in D.10-12-026 to record any fees to comply with AB 32.

SCGC also opposes SoCalGas' incremental increase for the AB 32 administrative fees on the grounds that the administrative fees would be recovered twice from wholesale and electric generation customers. SoCalGas contends that its calculation of the CARB administrative fee already excluded the throughput of wholesale and electric generation customers, and that the future rate design proceedings "can ensure that the AB 32 fee component is excluded from their tariffed rates." (Ex. 330 at 11.)

SCGC also recommends that the AB 32 fees should be included in the NERBA. SoCalGas agrees with SCGC, and SoCalGas has proposed that the cost recovery for the AB 32 administrative fee expense be recovered through the NERBA as described in Exhibits 55, 58, and 262. SoCalGas also contends that the "costs for the administrative fees will only be collected from customers that do not pay them directly to CARB." (Ex. 58 at 12.)

Regarding DRA's opposition to the $5 million that SoCalGas has requested for emission credits, SoCalGas points out that the first cap and trade auction that was originally scheduled for February 2012 was delayed to later in 2012, and that SoCalGas plans to participate in the auction.

On DRA's opposition to the Sustainable SoCal Program, SoCalGas contends that the program is not subsidizing unregulated gas producers. Instead, SoCalGas will lease space from wastewater treatment plants to install conditioning equipment owned by SoCalGas that is paid for by ratepayers to capture and process the biomethane which SoCalGas would own. That processed biomethane would then be used in SoCalGas' facilities and fleet vehicles.

Although there is no explicit state policy for SoCalGas to procure biomethane, SoCalGas contends that biogas and biomethane do "comply with the state's Renewable Portfolio Standard for electric utilities, the [CARB's] Cap and Trade Program and the Low Carbon Fuel Standard…to reduce GHG emissions." (Ex. 419 at 59.) According to SoCalGas, it is proposing the Sustainable SoCal Program "because the bioenergy market has not developed…," and it "is well positioned to undertake this effort at a cost lower than other entities…." (Ex. 419 at 60.) SoCalGas further contends that this program "is similar to other Commission clean energy policies, where all or the majority of ratepayers pay to support technologies like solar water heating, energy efficiency, and distributed generation, with the ultimate goal of accelerating adoption and reducing costs for these technologies." (Ex. 419 at 59.)

SoCalGas also contends that the biomethane from this program, when used to fuel its NGV fleet, will have value under the low carbon fuel standard, and that it will have the option of retaining those low carbon fuel standard credits without expiration.

SoCalGas also contends that contrary to DRA's assertion that this is a new technology or a research and development type project, this type of technology is "commercially available and is widely in operation in various countries throughout the world." (Ex. 419 at 60.)

10.3.3.2.2.1.3. Discussion

The starting point for addressing which of the gas engineering costs should be included in the test year 2012 revenue requirement begins with the appropriate base forecast. DRA relies on the 2009 recorded costs for its base forecast, while SoCalGas uses the five-year average of 2005-2009. We have reviewed the recorded costs and compared the forecasts of DRA and SoCalGas to the historical costs. Although the 2009 recorded cost was the second lowest recorded cost for the period from 2005-2009, it is within the range experienced during the period from 2005-2009. Based on our review, it is reasonable to adopt the five-year average of 2005-2009 ($10.417 million) as the base forecast for SoCalGas' gas engineering O&M costs.

In examining the base gas engineering O&M costs, these costs have remained fairly steady for the period from 2005 through 2009. We are concerned, however, with the impact of the incremental increases that SoCalGas has requested for this cost. SoCalGas' test year 2012 O&M request is an increase of

$11.194 million over the 2009 recorded amount of $10.189 million. In deciding the appropriate level of gas engineering O&M costs, it is important to weigh and to balance this consideration.

As part of its objections to SoCalGas' incremental increase to the gas engineering O&M costs, DRA objects to the $180,000 in incremental costs related to the engineering analysis center. SoCalGas requests this amount to support compliance of SoCalGas' compressors with AB 32's monitoring and reporting requirements, and with the EPA's mandatory GHG reporting rule. It is also anticipated that the compressors used by SoCalGas in the Mojave Desert will need to comply with a stricter version of the MDAQMD's Rule 1160 in the near future. DRA objects to this incremental increase because it believes that SoCalGas is not required to immediately comply with these regulations.

We have reviewed the testimony and arguments of SoCalGas and DRA concerning when SoCalGas will be required to comply with these three regulations, and have also reviewed the current versions of those regulations. Some of these monitoring and reporting requirements have gone into effect, while other rules have not yet been revised.

SocalGas has also requested incremental costs of $9.542 million for planning and analysis. It is clear from the evidence that SoCalGas has been paying the CARB administrative fees. SCGC raised the concern that electric generators and wholesale customers, who already pay this administrative fee directly to the CARB, should not be charged by SoCalGas for this fee. According to the SoCalGas witnesses, the calculation of the CARB administrative fees excluded the gas throughput of the electric generators and wholesale customers.

In addition, the NERBA will ensure that the CARB administrative fee excludes the throughput of the electric generators and wholesale customers.[66] To ensure that these customers are not charged twice for this fee, that issue can be raised in SoCalGas' rate design application. [67]

Part of the incremental increase of $9.542 million for planning and analysis has to do with the cap and trade emission credits. Both DRA and SCGC contend that the funding for the emission credits should be removed from the test year 2012 base rates because of the initial delay in the cap and trade auction, and the uncertainty of this cost. The CARB's cap and trade auction was held on November 14, 2012. According to the CARB's website of the auction results of the Quarterly

Auction 1, SoCalGas was not listed as a bidder for that first auction. Consequently, that means that the $5 million that SoCalGas requested for test year 2012 will not be needed. Accordingly, we agree with DRA and SCGC that the O&M costs for planning and analysis activities should be reduced.. Since we have adopted the NERBA, as discussed earlier, SoCalGas has a mechanism in place to recover the costs of any emission credits.

DRA also objects to the incremental increase of $606,000 for the Sustainable SoCal Program. For the reasons set forth later in this decision, in which we remove all of the costs of the Sustainable SoCal Program from this proceeding,

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[66] As mentioned earlier, we have adopted the NERBA to recover the cost of complying with the AB 32 CARB administrative fee.

[67] We note that D.10-12-026 authorized SoCalGas to establish a memorandum account to record the costs of the AB 32 implementation fee, and in D.12-10-044 SoCalGas was authorized to recover those costs from ratepayers, and to recover any further fees in its GRC proceeding.

we agree with DRA that the O&M costs should be removed from the O&M costs for gas engineering.

Based on the above discussion and adjustments, and the balancing of these competing concerns, it is reasonable to adopt gas engineering O&M costs of $12.567 million for test year 2012.

8.2.3.2.2.2. Transmission Pipeline Integrity Management

8.2.3.2.2.2.

Under the cost category of transmission pipeline integrity, SoCalGas estimates test year 2012 O&M costs of $24.760 million. This amount is an incremental increase of $13.799 million over the 2009 recorded amount of $10.961 million. SoCalGas' forecast uses a zero-based approach. According to SoCalGas, a historical approach was not used because the level of work that is forecasted was not reflected in the historical costs.

This cost category includes TIMP-related costs. Pursuant to Subpart O, SDG&E and SoCalGas developed their Baseline Assessment Plan. This plan "contains the goals and schedule for how and when the TIMP assessments will be performed." (Ex. 55 at 13.) The TIMP requires the operators of gas transmission systems to conduct their baseline assessments of all high consequence areas that were in existence on December 2002 by December 2012.[68] After the completion of this baseline assessment, the operator must reassess that same segment within seven years of the last assessment. For the smaller

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[68] According to SoCalGas, it "ranks 22nd among the nation's DOT Transmission pipeline operators with 3,989 transmission pipeline miles," but it "ranks as the highest operator of [high consequence area] miles in the nation with 1,149 miles." (Ex. 55 at 31.)

diameter pipelines, the TIMP baseline assessment schedule calls for these pipes to be inspected in 2008-2012. According to SoCalGas, the "total cost to assess these comparatively shorter-length, smaller-diameter pipeline segments in the second five-year period is greater than the cost to assess the larger-diameter, longer-length segments completed during the first five-year period of the program." (Ex. 55 at 30.)

SoCalGas uses three primary methods to carry out an assessment of its transmission lines. These methods are: external corrosion direct assessment, in-line inspection, and pressure testing. A summary of these methods was described in the gas engineering section for SDG&E.

In addition to these assessment methods, SoCalGas' TIMP activities "also include internal and external corrosion control, metallurgical assessment, damage prevention, integrity assessment, inspection and excavation for verification, pipeline-related quality control, evaluating susceptibility to external factors such as seismic activity, and the development and implementation of remediation plans." (Ex. 55 at 29.) The TIMP support activities consist of "procurement, quality control, deployment, and operations and maintenance of the pipeline assets." (*Ibid*.)

As a result of Chapter 523 of the Statutes of 2012, § 969 was added to the Pub. Util. Code, with an effective date of January 1, 2012. That code section provides that the costs relating to Subpart O of Part 192 of Title 49 of the United States Code are to be recovered through a balancing account established for that purpose. That code section also provides that "Nothing in this section is intended to interfere with the commission's discretion to establish a two-way balancing account." (Pub. Util. Code § 969.) DRA, TURN, and UCAN have proposed in these consolidated proceedings that the TIMP-related O&M costs and capital expenditures be subject to a balancing account. SoCalGas proposes that this balancing account should be a two-way balancing account, and that any year-end balance be carried forward into the following year.

8.2.3.2.2.2.

10.3.3.2.2.2.2.1. DRA

DRA recommends that the Commission adopt a test year 2012 forecast of $11.100 million, instead of SoCalGas' forecast of $24.760 million.

DRA contends that SoCalGas' forecast is unsupported. Since SoCalGas only has 2.38 miles of cased mains, SoCalGas' claim that it cannot rely on average expense as a basis for its forecasted mains for the first time is not convincing. DRA further contends that since SoCalGas has been assessing its transmission pipelines for about 10 years, that SoCalGas' "historical work level and historical expenses are the best indicators of how much of the system has been assessed and how much more needs to be done, and at what cost." (Ex. 533 at 77.)

Based on the data that DRA reviewed, SoCalGas is now in the reassessment phase of the TIMP. Due to the reassessments, DRA contends that the five-year average of 2006-2010 should be used to forecast the test year 2012 expenses. DRA contends that this five-year average "represents actual pipeline assessment expenses in recent years and even includes the most recent spending in 2010, and reflects all the assessments performed – the easy and difficult segments in [SoCalGas'] system," and that this "amount should be sufficient for [SoCalGas]…given the fact that [SoCalGas] has been performing transmission pipeline assessment work activities for almost 10 years," and "there should be some savings achieved with experience and work efficiency." (Ex. 533 at 78.)

DRA also recommends that there should be a one-way balancing account for the TIMP-related costs.

10.3.3.2.2.2.2.2. TURN and UCAN

TURN and UCAN recognize the interest in ensuring gas pipeline safety. To ensure that the amounts the Commission authorizes are being spent on pipeline safety, TURN and UCAN propose that a one-way balancing account be created for SoCalGas' TIMP-related O&M costs and capital expenditures. TURN and UCAN propose that any "authorized amounts for these activities that are unspent at the end of the GRC cycle, plus interest, should be returned to ratepayers in the next GRC." (Ex. 547 at 5.) TURN and UCAN contends that the one-way balancing account treatment will prevent SoCalGas from using the authorized funds for a different purpose.

10.3.3.2.2.2.2.3. SCGC

As noted earlier in SDG&E' TIMP-related capital expenditure, SCGC raised the argument that SoCalGas should be prevented from including capital expenditures in the NERBA.

10.3.3.2.2.2.2.4. SoCalGas

SoCalGas contends that DRA's recommended amount of $11.100 million "would fall well short of the resources needed to complete the baseline assessments and reassessments required under 49 CFR Subpart 'O,'" and that DRA's recommendation is based on a misinterpretation of SoCalGas' information. (Ex. 58 at 14.)

Contrary to DRA's belief, SoCalGas contends that it is scheduled to complete the baseline assessments by December 17, 2012. According to SoCalGas' Baseline Assessment Plan, SoCalGas has 271 pipeline segments scheduled for baseline assessment in 2012, which total to 61.57 miles. SoCalGas also contends that "many of the remaining assessments will be more costly than previously experienced because they are more complex and the ability to use traditional smart pigging technology is very limited." (Ex. 58 at 15.)

SoCalGas also acknowledges that it has "already begun to reassess pipelines that were baseline assessed early in the program." (Ex. 58 at 14.) The reassessments have started because of the requirement that "pipelines must be re-assessed within seven years of their prior assessment." (*Ibid*.)

SoCalGas contends that due to the miles of baseline assessments to be performed in test year 2012, the higher costs associated with the remaining shorter pipeline segments, and because of the ongoing reassessments, the historical costs are not a good indicator of the future costs.

SoCalGas recommends that the TIMP-related costs be recovered through a two-way balancing account, and that it be allowed to carry the year-end balance forward into the following year. SoCalGas contends that the "two-way balancing account is in the best interest of all stakeholders" because any " under-spending would be returned to ratepayers, but if SoCalGas finds that the prudent application of additional expenses is warranted for pipeline safety, it is reasonable to expect SoCalGas to incur those expenses and recover them in rates." (Ex. 58 at 22.) SoCalGas contends that a two-way balancing account will achieve the common goal of pipeline safety, "while providing flexibility to manage safety concerns and fiscal oversight." (Ex. 58 at 23.)

8.2.3.2.2.2.

We have reviewed the testimony and the arguments of the parties concerning the transmission pipeline integrity category of costs. We have also reviewed Subpart O and the type of work that is required, and have also reviewed Pub. Util. Code § 969.

Based on those considerations, we adopt the following. In accordance with Pub. Util. Code § 969, we adopt a two-way balancing account to recover the TIMP-related O&M costs and capital expenditures of complying with Subpart O. However, this balancing account shall be subject to the following. Any costs in excess of the O&M costs authorized for these TIMP costs shall be subject to recovery through a Tier 2 advice letter process. Such a restriction on this two-way balancing account will ensure that the TIMP-related costs are reasonable and necessary. We will also allow the year-end balance in that two-way balancing account to be carried forward into the following year. A two-way balancing account is appropriate due the costs of complying with Subpart O and possible changes in pipeline inspection requirements in the future. A two-way balancing account will also ensure that SoCalGas has sufficient funds to carry out all the necessary TIMP-related work to ensure that its gas transmission system remains safe and reliable, while the AL process will ensure that costs in excess of what has been authorized will be subject to review. Accordingly, SoCalGas is authorized to file a Tier 2 AL within 45 days of the effective date of this decision to establish this two-way balancing account. As noted by SoCalGas in Exhibit 58, the parties will have an opportunity to review the reasonableness of these TIMP-related expenses in this balancing account when those expenses are reported in the Annual Regulatory Account Balance Update, as well as through the AL process if costs exceed the authorized level.

Next, we decide the level of authorized O&M costs for TIMP. We have reviewed SoCalGas' testimony regarding its forecast for the transmission pipeline integrity costs, and compared it to the historical data and to DRA's forecast. Based on the work that Subpart O requires, and the type of work that is needed to perform the baseline assessments, as well as the reassessments, DRA's forecast is too low. However, SoCalGas' incremental request of $13.799 million appears excessive in light of the TIMP-required work that has already been performed. Accordingly, it is reasonable to adopt a test year 2012 forecast of $20.760 million. Should SoCalGas' test year forecast be overstated, any excess will be refunded to SoCalGas' customers. If this amount is insufficient, SoCalGas can pursue the AL process.

8.2.3.2.2.3. Distribution Pipeline Integrity Management

8.2.3.2.2.3.

Under the cost category of distribution pipeline integrity, SoCalGas estimates test year 2012 O&M costs of $31.097 million. This amount is an incremental increase of $24.527 million over the 2009 recorded amount of $6.570 million. SoCalGas used a zero-based forecast approach "because historical trending or averaging is not appropriate." (Ex. 55 at 49.)

This cost category covers the costs of complying with the DIMP regulations in Subpart P, and affects over 47,650 miles of main lines, and 48,640 miles of service lines. These DIMP costs are in addition to the gas distribution O&M costs and capital expenditures discussed earlier.

SoCalGas notes that its DIMP O&M costs are significant, which is due to the size of its distribution system, and its higher than industry average installation costs.

SoCalGas' DIMP-related costs are driven by the following seven activities: (1) work relating to GIS; (2) distribution risk evaluation and monitoring system; (3) DIMP driven monitoring; (4) anodeless riser program; (5) vehicular damage; (6) sewer lateral initiative; and (7) damage prevention. The costs of all of these activities add up to SoCalGas' test year request of $31.097 million.

GIS allows SoCalGas to integrate and convert its existing data and maps about its distribution system into a single electronic repository, and to present that information in a graphical display. SDG&E forecasts $4.285 million for GIS activities in the test year.

The distribution risk evaluation and monitoring system is a computational model that supports SoCalGas' DIMP mitigation strategy. This model helps to evaluate and risk-rank pipeline threats associated with leakage on a pipeline segment. No additional non-shared funding for this model has been requested. However, SoCalGas notes that this model does affect pipeline replacement costs.

The DIMP driven monitoring supplements the ranking of the risks through the distribution risk evaluation and monitoring system. Due to various construction or permitting issues, a high ranked risk may not be immediately replaced. If a high ranked risk cannot be replaced, SoCalGas will monitor the pipe segment on a more frequent basis for accelerated deterioration. SoCalGas forecasts $574,410 for this activity in the test year.

The anodeless riser program is a program to replace or to service anodeless risers, which is "a service line component that has shown a propensity to fail before the end of their useful lives." (Ex. 55 at 42.) SoCalGas estimates that there are about 2.600 million risers "that have the potential to be an integrity threat due to premature failure." (*Ibid*.) Due to the large number of these risers, SoCalGas plans that this program will take place over 6 years. SoCalGas forecasts $15.033 million in funding for this activity for the test year.

The vehicular damage pertains to protecting above-ground distribution facilities from vehicle damage. SoCalGas forecasts $2.252 million for this activity during the test year.

The sewer lateral initiative program is to protect distribution pipelines from damages associated with sewer laterals when trenchless technology is used to install gas pipelines. The problem occurs when the gas pipeline and sewer line cross paths, which may lead to a leak of the gas pipeline. To alleviate this problem, locate and mark, and depth checks are done before trenching. For this activity, SoCalGas forecasts funding of $7.504 million.

Damage prevention relates to activities to prevent damage to distribution pipelines by third parties. SoCalGas is forecasting six additional FTEs to enhance the existing damage prevention program at a cost of $450,000. In addition, SoCalGas plans to do the following: obtain and train its employees on the latest pipeline locating equipment at an estimated cost of $240,000; perform annual leakage survey activities of distribution mains that do not meet the definition of a DOT transmission line at an estimated cost of $170,000; install pipeline markers on high pressure pipelines where such markers are not currently required and record the locations, at an estimated cost of $283,000; and increase the frequency of leakage surveys of medium pressure distribution mains without cathodic protection located in business districts at an estimated cost of $312,000.

TURN and UCAN propose that the DIMP-related O&M costs and capital expenditures be subject to a one-way balancing account. SoCalGas requests two-way balancing account treatment for these costs.

SoCalGas requests that the current DIMPBA be closed out. The DIMPBA is a one-way balancing account that was adopted as part of the settlement in SoCalGas' last GRC. The DIMPA records "the difference between actual and authorized operating and maintenance…costs associated with SoCalGas' [DIMP] pursuant to [D.] 08-07-046." (Ex. 264 at 2-3.) As of December 31, 2011, the DIMPBA was overcollected by $2.186 million. SoCalGas proposes to amortize this overcollection balance to gas customers' rates on an equal percent of authorized margin basis upon the implementation of SoCalGas' 2012 GRC revenue requirement, and to transfer any remaining balance in the DIMPBA to the Core Fixed Cost Account and Noncore Fixed Cost Account, and to eliminate the DIMPBA if the Commission includes the DIMP-related costs in base margin.

8.2.3.2.2.3.

DRA recommends that the Commission adopt a test year 2012 forecast of $7.151 million, as opposed to SoCalGas' forecast of $31.097 million.

DRA takes issues with the amounts that SoCalGas has requested for the anodeless riser program, vehicular damage, the sewer lateral inspection program, and damage prevention.

Regarding its reduction for the anodeless riser program, DRA contends that SoCalGas provided data for this kind of work in 2009. That recorded 2009 data shows SoCalGas inspected and repaired 43,524 risers at a cost of $380,176 and had riser replacement costs of $2.500 million. This 2009 cost was part of the gas distribution costs. In 2010, SoCalGas spent $2.800 million for the inspection, repair, and replacement of the risers as part of its gas distribution costs. SoCalGas also spent an additional $515,000 in 2010 for this kind of work, which was included in its DIMP-related costs. The number of anodeless risers that SoCalGas had forecasted to inspect in 2010, fell far short of the actual number of risers that were actually inspected in 2010. DRA contends that SoCalGas has not offered convincing evidence to support SoCalGas' acceleration of its inspection and repair of the anodeless risers. Based on the number of inspections of the anodeless risers under the DIMP-related costs, DRA recommends funding of $515,000.

For vehicular damage, DRA recommends that SoCalGas not receive any of the $2.252 million that it has requested. DRA contends that SoCalGas only "appears to be in the process of identifying the facilities at risk in its territory, and assessing the risk levels at these facilities, as opposed to having completed such a process and having identified and assessed the risks." (Ex. 533 at 86.) DRA also contends that there "does not appear to be a spike in the number of incidents or any other influencing factors that would warrant immediate increased action by [SoCalGas]." (*Ibid*.) For those reasons, DRA believes that the level of funding SoCalGas receives for this type of work as part of its gas distribution O&M costs is sufficient.

Regarding the sewer lateral inspection program, DRA recommends a funding level of $622,000 instead of SoCalGas' forecast of $7.504 million. DRA's recommendation of $622,000 is based on the 2010 recorded expense. DRA states that it does not oppose the concept of this program, but contends that SoCalGas "has not presented adequate evidence, analysis, and engineering studies to demonstrate why this program must be carried out in five years." (Ex. 533 at 87.) DRA also contends that SoCalGas already makes sewer lateral repairs as part of its routine field operations, and that a cross-bore situation is a low probability issue. DRA also takes issue with SoCalGas' methodology for forecasting the number of potential sewer lateral conflicts, which DRA contends was not based on a review of SoCalGas' own records or field inspections.

DRA also takes issue with SoCalGas' forecast of the damage prevention O&M costs. Instead of SoCalGas' forecast of $1.455 million, DRA recommends a funding amount of $1.200 million. DRA's difference is due to the six FTEs that SoCalGas has requested. DRA contends that SoCalGas did not adequately explain why a new FTE is needed in each of the four regions as requested by SoCalGas, and did not justify the need for an additional FTE in the claims department. Based on the data that DRA received from SoCalGas, "the number of third-party damage incidents on its system has been decreasing since 2006." (Ex. 533 at 91.) Instead of six FTEs, DRA recommends funding only two FTEs.

10.3.3.2.2.3.2.2. TURN and UCAN

For the DIMP-related O&M costs and capital expenditures, TURN and UCAN make the same recommendation as it did for the TIMP-related O&M costs and capital expenditures. TURN and UCAN propose that a one-way balancing account be created for SoCalGas' DIMP-related O&M costs and capital expenditures. TURN and UCAN propose that any "authorized amounts for these activities that are unspent at the end of the GRC cycle, plus interest, should be returned to ratepayers in the next GRC." (Ex. 547 at 5.) TURN and UCAN contends that the one-way balancing account treatment will prevent SoCalGas from using the authorized funds for a different purpose.

10.3.3.2.2.3.2.3. SoCalGas

With regard to DRA's objection to the anodeless riser program, SoCalGas acknowledges that the threat of leakage from these risers is not a new threat. However, SoCalGas contends this is not a reason for not aggressively addressing this leakage problem. SoCalGas points out that it provided DRA with a comprehensive engineering analysis report, which was also included as part of Exhibit 58. SoCalGas contends that this report and SoCalGas' data response demonstrate "that SoCalGas can expect an [anodeless riser] failure rate of 15%, requiring the replacement of over 300,000 [anodeless risers]." (Ex. 58 at 29.) SoCalGas also points out that the Commission should recognize that DRA's reliance on the 2010 recorded amount of $515,000 for this program was during an early stage of this program.

On DRA's objection to SoCalGas' request for $2.252 million for vehicular damage, SoCalGas contends that it developed a "more comprehensive and analytical study" to support its program to protect above-ground distribution equipment from vehicular damage. (Ex. 58 at 36.) This program is now known as the Gas Infrastructure Protection Program. It is estimated that 26,500 meter set assemblies will be mitigated under this program, and that these mitigation efforts will "include below-ground relocations of above-ground facilities, installation of protective barriers, and potential installation of High Pressure Excess Flow Valves…and protective barriers." (Ex. 58 at 37.) According to SoCalGas, this program will address the DIMP objective of addressing "threats that could have low probability and high consequences." (Ex. 58 at 39.)

Regarding DRA's objection to SoCalGas' sewer lateral inspection program, SoCalGas points out that there were 175 claims from 2000-2010 for damaged sewer laterals. Although these claims did not cause any explosions, fires, or injuries, these cross-bore incidents pose a serious safety issue and can result in a catastrophe. SoCalGas also contends that it completed its own internal assessment, and its "review of thousands of field and video inspections in 2010 determined that more than 3,400 conflicts are likely to exist within the system." (Ex. 58 at 42.)

On DRA's reduction to the damage prevention activities, SoCalGas contends that these activities will require dedicated resources, and that six FTEs are needed given SoCalGas' "size and its large and diverse service territory." (Ex. 58 at 45.)

SoCalGas notes that it is currently recording DIMP-related activities into a one-way balancing account. For the test year 2012 GRC cycle, TURN and UCAN have proposed to continue this one-way balancing account treatment. SoCalGas opposes the request of TURN and UCAN for one-way balancing, and recommends two-way balancing account treatment. SoCalGas contends that the "one-way balancing account treatment creates incentives that are inconsistent with a maximum focus on pipeline safety, as the Commission's Independent Panel Review found." (Ex. 58 at 45.) SoCalGas also contends that with two-way balancing account treatment, any "underspending would be returned to ratepayers, but if SoCalGas finds that the prudent application of additional expenses is warranted for pipeline safety, it is reasonable to expect SoCalGas to incur those expenses and recover them in rates." (Ex. 58 at 46.) SoCalGas also notes that the other parties will have the opportunity to review those expenses for reasonableness when those expenses are reported in the Annual Regulatory Account Balance Update. SoCalGas also contends that two-way balancing account treatment is warranted because additional safety measures may be adopted in the future.

8.2.3.2.2.3.

We have reviewed the testimony and the arguments of the parties concerning the distribution pipeline integrity category of costs, and have reviewed Subpart P.

Based on those considerations, we adopt the following. First, we adopt a two-way balancing account to recover the DIMP-related O&M costs and capital expenditures of complying with Subpart P, and to allow SoCalGas to carry forward any year-end balance to the following year. This two-way balancing account shall be subject to the following. Any costs in excess of the O&M costs authorized for these DIMP costs shall be subject to recovery through a Tier 2 advice letter process. Such a restriction on this two-way balancing account will ensure that the DIMP-related costs are reasonable and necessary. A two-way balancing account is appropriate due to the costs of complying with Subpart P and possible changes in future requirements. A two-way balancing account will also ensure that SoCalGas carries out the necessary work to ensure that its gas distribution system remains safe and reliable, while the AL process will ensure that costs in excess of what has been authorized will be subject to review. Accordingly, SoCalGas is authorized to file a Tier 2 AL within 45 days of the effective date of this decision to establish this two-way balancing account. As noted by SoCalGas in Exhibit 58, the parties will have an opportunity to review the reasonableness of these DIMP-related expenses in this balancing account when those expenses are reported in the Annual Regulatory Account Balance Update, as well as through the AL process if costs exceed the authorized level.

Second, SoCalGas has requested that the current one-way balancing account, the DIMPBA, be closed out. Since we have adopted the two-way balancing account for these DIMP-related costs, SoCalGas is authorized to close out its current DIMP balancing account by filing a Tier 2 AL within 45 days of the effective date of this decision. Any overcollection remaining in the DIMPBA shall be amortized in gas transportation customers' rates on an equal percent of authorized margin basis.

Third, we have reviewed SoCalGas' testimony regarding its forecast for the distribution pipeline integrity costs, and compared it to the historical data and to DRA's recommendations. Based on the work that Subpart P requires, the type of work that SoCalGas plans to carry out, the objections that DRA has raised with regard to the anodeless risers and the number of FTEs that are needed for the damage prevention activities, and the DIMP-related work that has been done before, it is reasonable to adopt an authorized funding amount of $24.947 million for the DIMP-related O&M costs.

8.2.3.2.2.4. Public Awareness

8.2.3.2.2.4.

Under the cost category of public awareness, SoCalGas estimates test year 2012 O&M costs of $1.159 million. This amount is an incremental increase of $852,000 over the 2009 recorded amount of $307,000. SoCalGas' forecast used a zero-based methodology plus incremental activities.

The public awareness cost category covers the costs of complying with the public awareness program as set forth in 49 CFR § 192.616. Under that regulation, SoCalGas must develop and implement a public education program to educate the public, government organizations, and persons engaged in excavation about procedures to follow involving pipeline excavations, and how to identify gas leaks. That regulation also requires SoCalGas to notify municipalities, school districts, businesses, and residents of pipeline locations.

According to SoCalGas, a large driver of the incremental costs is measuring the impact of the public awareness messages, which necessitates that more frequent safety messages be targeted to affected stakeholders.

8.2.3.2.2.4.

10.3.3.2.2.4.2.1. DRA

DRA recommends that the funding amount from public awareness O&M costs be set at $307,000 as opposed to SoCalGas' recommendation of $1.159 million. DRA notes that between 2006 and 2009, SoCalGas spent an average of $314,000 on the public awareness program, and that the annual expenses did not fluctuate. DRA contends that SoCalGas has not provided sufficient evidence to demonstrate why the costs for the public awareness program will increase dramatically in test year 2012.

10.3.3.2.2.4.2.2. SoCalGas

SoCalGas acknowledges that 49 CFR §192.616 does not impose any new requirements on it. However, SoCalGas contends that its incremental increase is driven by the federal government's goal of: (1) reviewing and evaluating results; (2) identifying gaps; and (3) continually improving the program through completed surveys. SoCalGas also contends that these incremental funds will be used "to continuously improve gas pipeline public awareness and safety-related customer communications in an ever-evolving landscape of pipeline safety regulations." (Ex. 58 at 49.)

8.2.3.2.2.4.

We have reviewed and considered the testimony and arguments of SoCalGas and DRA concerning the public awareness O&M costs. We have also compared the activities that SoCalGas plans to undertake, and have compared the forecasts of SoCalGas and DRA to the historical costs. We have also taken into account the goal of 49 CFR § 192.616 of educating the public about pipeline hazards and safety.

Based on all those considerations, DRA's recommended forecast is too low in light of the activities that SoCalGas plans to undertake in order to effectively reach the public. Under the circumstances, it is reasonable to adopt SoCalGas' forecast of $600,000 for the public awareness O&M costs.

8.2.3.2.3. Shared O&M Costs

SoCalGas forecasts $16.053 million for the test year 2012 shared services general engineering O&M costs. This is an incremental increase of $3.676 million over the 2009 amount of $12.377 million.

There are four cost centers that comprise the shared services O&M costs for gas engineering. These cost centers are as follows: general engineering; pipeline integrity; distribution integrity management; and pipeline design and gas standards. These four cost centers, and the billed-in amount from SDG&E, total to SoCalGas' forecast of $16.053 million.

The general engineering costs retained by SoCalGas amount to $9.206 million, as described in Exhibit 55. These cover a number of engineering-related activities such as the following: engineering design; gas measurement, regulation and pressure control; engineering analysis center; asset and data management; and management planning and analysis.

The pipeline integrity costs covers the engineering and technical services associated with the TIMP and corrosion management activities. SoCalGas has retained costs of $5.700 million.

For the distribution integrity management costs, SoCalGas has retained costs of $343,000. The activities in this cost center support the DIMP efforts.

The pipeline design and gas standards covers the costs of ensuring that those individuals who are responsible for gas standards are informed of regulatory changes, and that the procedures they manage are in compliance. SoCalGas has retained costs of $670,000.

The amount billed in from SDG&E amounts to $134,000. This amount covers the support services for codes and standards, and for mobile data terminals.

None of the other parties have taken issue with SoCalGas' forecast of the shared services O&M costs. Based on our review of the uncontested shared services costs, it is reasonable to adopt $16.053 million as the shared services O&M costs for SoCalGas.

8.2.3.3. Capital Expenditures

8.2.3.3.1. Introduction

This section addresses the estimated capital expenditures for SoCalGas' transmission, engineering, and pipeline integrity operations. SoCalGas forecasts the following capital expenditures: $94.790 million for 2010; $114.333 million for 2011; and $158.306 million for 2012.

SoCalGas' capital expenditures for this rate cycle cover the following 17 capital projects, which are categorized as follows: (1) pipeline integrity – distribution; (2) DIMP; (3) transmission pipelines – new additions; (4) transmission pipelines – replacements and pipeline integrity program; (5) transmission pipeline - relocations – freeway; (6) transmission pipeline relocations – franchise/private; (7) gas transmission – compressor stations; (8) gas transmission pipelines – cathodic protection; (9) gas transmission – meter and regulator; (10) gas transmission – auxiliary equipment; (11) gas transmission- pipeline land rights; (12) gas transmission – laboratory equipment; (13) gas transmission & storage – capital tools; (14) gas storage – supervision and engineering direct overheads; (15) gas transmission – supervision and engineering direct overheads;

(16) gas transmission – Coastal Region Conservation Program; and
(17) Sustainable SoCal Program.

As described in Exhibits 55 and 58, each of these categories consists of one or more budget codes, which record the costs of these capital projects. We separately discuss each of these capital projects below.

8.2.3.3.2. Pipeline Integrity – Distribution

The pipeline integrity – distribution budget code records the costs of complying with part of the TIMP requirements in Subpart O. Most of this activity consists of retrofits to the pipelines to accommodate inspection tools, and repair of pipelines.

SoCalGas estimates annual expenditures of $14.405 million in 2010, $22.902 million in 2011, and $20.762 million in 2012.

None of the other parties take issue with SoCalGas' forecast.

Based on our review of the testimony and arguments of the parties, it is reasonable to adopt SoCalGas' forecast of the capital expenditures for pipeline integrity – distribution as follows: $14.405 million in 2010; $22.902 million in 2011; and $20.762 million in 2012.

8.2.3.3.3. DIMP

The DIMP budget code records the costs of complying with part of the DIMP requirements in Subpart P. The capital expenditures are primarily for "pipeline replacement work that is incremental to routine replacement work and required to maintain system integrity, along with compliance with new DIMP regulatory requirements." (Ex. 55 at 72.)

SoCalGas estimates annual expenditures of $14.262 million in 2011, and $30.224 million in 2012.

None of the other parties take issue with SoCalGas' forecast.

Based on our review of the testimony and arguments of the parties, it is reasonable to adopt SoCalGas' forecast of the capital expenditures for DIMP as follows: $14.262 million in 2011; and $30.224 million in 2012.

8.2.3.3.4. New Additions

8.2.3.3.4.1. Introduction

The budget codes for new additions include the "costs associated with the design and installation of new transmission pipelines to serve new customer loads and/or to improve the ability to move natural gas to points of critical need at adequate pressure." (Ex. 55 at 72.) The projects included in SoCalGas' forecast include the City of Palmdale utility electric generating plant, the Anaheim utility electric generating plant, a hydrogen energy plant, and Line 6916 for the north/south interconnect.

SoCalGas estimates annual expenditures of $9.519 million in 2010, $11.197 million in 2011, and $19.292 million in 2012.

8.2.3.3.4.2. Position of the Parties

8.2.3.3.4.2.

DRA contends that it is uncertain whether the projects for the City of Palmdale, the SCE Mandalay peaker plant, and the hydrogen energy plant, will be built, and that it is speculative as to when construction can begin. Due to these uncertainties about the feasibility and timing of these projects, DRA recommends removing all of the expenditures for these projects. As a result, DRA recommends zero in capital expenditures for 2011, and $5.928 million for 2012.

8.2.3.3.4.2.

SoCalGas contends that DRA did not challenge SoCalGas' 2010 forecast of $9.519 million. SoCalGas also notes that the 2010 recorded amount was $12.727 million. SoCalGas also notes that in other parts of DRA's testimony, DRA recommended the adoption of the actual 2010 costs when it was lower than the forecast amount, and recommended the adoption of the forecast amount when it was lower than the actual 2010 cost.

SoCalGas contends that DRA's recommendation is based on a single response by SoCalGas as to the status of three 2011 projects that were on the active list in spring 2010. In that response, SoCalGas had reported that all three projects had been delayed. SoCalGas contends that it "should have noted in its response that it is routine for projects to become delayed and that when that happens, other needed projects inevitably arise." (Ex. 58 at 52.) SoCalGas also contends that the "project lists and priorities are reviewed and adjusted monthly, and that it expects four projects in 2011, and six projects in 2012. SoCalGas also notes that it has no record of ever spending zero dollars in these budget codes, that the five-year average for 2005-2009 was $19.292 million, and that the 2010 recorded spending was $3 million greater than what SoCalGas had forecasted.

8.2.3.3.4.2.

We have reviewed the testimony and arguments of SoCalGas and DRA. We have also compared the forecasts of SoCalGas and DRA to the historical costs and trends, and taken into consideration the delay in the different projects that SoCalGas included in its forecast of capital expenditures.

Based on those considerations, DRA's forecast is too low, while SoCalGas' forecast of expenditures is too high given the delay of some of these projects. It is reasonable under the circumstances to adopt the following capital expenditures for new additions: $9.519 million in 2010; $2.801 million for 2011; and $9.269 million in 2012.

8.2.3.3.4.2.

8.2.3.3.4.3. Introduction

The budget codes for replacements and the pipeline integrity program include the "cost of replacing Transmission pipelines or pipeline sections found to have reached the end of their effective service lives through a combination of age, condition, or external threat such as landslides and/or natural disaster." (Ex. 55 at 73.)

SoCalGas estimates annual expenditures of $42.766 million in 2010, $35.227 million in 2011, and $25.917 million in 2012.

8.2.3.3.4.4. Position of the Parties

8.2.3.3.4.4.

DRA recommends capital expenditures of $33.747 million for 2011, and $25.547 million in 2012. DRA's capital expenditures are lower because it believes that SoCalGas can save money by reusing some or all of the launcher/receiver assemblies that are used for the in line inspection tests.

8.2.3.3.4.4.

SoCalGas contends that DRA's recommended reductions are based on how many launcher/receiver assemblies should be temporary or permanent. SoCalGas contends that its forecast was based "on site-specific reviews of project conditions and gas operations requirements which dictate what sites lend themselves to temporary or permanent lauchers/receivers." (Ex. 58 at 54.) Since SoCalGas is in a position to make those kinds of determinations, SoCalGas contends that the Commission should adopt SoCalGas' original forecasts.

8.2.3.3.4.5. Discussion

We have reviewed the testimony and arguments of SoCalGas and DRA for the replacement and pipeline integrity program budget codes. We have also compared the forecasts of SoCalGas and DRA to the historical costs, and considered whose forecast is likely to be more accurate.

Based on those considerations, it is reasonable to adopt the forecast of SoCalGas for the replacement and pipeline integrity program capital expenditures as follows: $42.766 million in 2010; $35.227 million in 2011; and $25.917 million in 2012.

8.2.3.3.5. Relocations – Freeway

The budget codes for relocations – freeway records the costs associated with pipeline relocations as a result of a CALTRANS' request.

SoCalGas estimates annual expenditures of $1.019 million in 2010, and $2.010 million in 2011, and in 2012.

None of the other parties take issue with SoCalGas' forecast.

Based on our review of the testimony and arguments of the parties, it is reasonable to adopt SoCalGas' forecast of the capital expenditures for relocations – freeway as follows: $1.019 million in 2010; and $2.010 million for 2011, and in 2012.

8.2.3.3.6. Relocations – Franchise/Private

The budget codes for relocations – franchise/private records the costs of "relocating transmission pipelines to accommodate planned private property development, street improvement projects other than freeways, and other work required due to right-of-way agreements and franchise requirements." (Ex. 55 at 75.)

SoCalGas estimates capital expenditures of $10.104 million in 2010, $8.128 million in 2011, and $11.105 million in 2012.

None of the other parties take issue with SoCalGas' forecast.

Based on our review of the testimony and arguments of the parties, it is reasonable to adopt SoCalGas' forecast of the capital expenditures for relocations – franchise/private as follows: $10.104 million for 2010; $8.128 million for 2011; and $11.105 million for 2012.

8.2.3.3.7. Compressor Stations

8.2.3.3.7.1. Introduction

The budget codes for the compressor stations records the costs of "installing and replacing compressor station equipment used in connection with SoCalGas' transmission system operations." (Ex. 55 at 76.)

SoCalGas estimates capital expenditures of $2.303 million in 2010; $5.407 million in 2011; and $19.257 million in 2012.

8.2.3.3.7.2. Position of the Parties

DRA recommends capital expenditures of $4.460 million for 2011, and $9.781 million for 2012. DRA's recommended reductions are due to two reasons. First, DRA contends that the costs in 2012 should go down because the EPA finalized its RICE/NESHAP Subpart ZZZZ on August 20, 2010, which lowered the estimated costs that SoCalGas had forecasted from $3.588 million to $1.707 million. DRA's second reduction is because Rule 1160 of the MDAQMD has not yet been revised, as SoCalGas had originally anticipated. DRA therefore reduced the 2011 capital expenditures by $947,000, and the 2012 capital expenditures by $7.595 million.

8.2.3.3.7.2.

SoCalGas agrees with DRA's recommendation to use the latest estimated costs as a result of the finalized RICE/NESHAP rule.

DRA's second reduction is because the MDAQMD's Rule 1160 has not yet been revised. SoCalGas contends that DRA's reduction should not be adopted because SoCalGas is incurring costs and is partnering with the MDAQMD to do a pilot study to finalize Rule 1160. SoCalGas also points out that other local air districts have already amended their rules to require significant reduction of the emission levels from internal combustion engines.

8.2.3.3.7.3. Discussion

We have reviewed the testimony and arguments of SoCalGas and DRA concerning the compressor station capital expenditures, and the final RICE/NESHAP rule. We have also considered the delay in finalizing Rule 1160 of the MDAQMD. Although Rule 1160 has not been revised yet, SoCalGas is incurring some costs for activities related to this rule. For that reason, we believe that some capital funding for this capital project is warranted.

Based on those considerations, it is reasonable to adopt the following capital expenditure for the compressor stations: $2.303 million for 2010; $4.450 million for 2011; and $11.300 million for 2012.

8.2.3.3.8. Cathodic Protection

The budget codes for cathodic protection records the costs "associated with the installation and replacement of Cathodic Protection…equipment used to protect transmission pipelines against corrosion." (Ex. 55 at 77.)

SoCalGas estimates capital expenditures of $2.413 million in 2010, and $1.793 million in 2011, and in 2012.

None of the other parties take issue with SoCalGas' forecast.

Based on our review of the testimony and arguments of the parties, it is reasonable to adopt SoCalGas' forecast of the capital expenditures for cathodic protection as follows: $2.413 million for 2010; and $1.793 million in 2011, and in 2012.

8.2.3.3.9. Meter and Regulator

The budget codes for meter and regulator are for the "capital cost of installing and rebuilding large meter set assemblies…for transmission-served customers." (Ex. 55 at 77.)

SoCalGas estimates capital expenditures of $8.777 million in 2010, and $4.526 million in 2011, and in 2012.

None of the other parties take issue with SoCalGas' forecast.

Based on our review of the testimony and arguments of the parties, it is reasonable to adopt SoCalGas' forecast of the capital expenditures for meter and regulator as follows: $8.777 million for 2010; and $4.526 million for 2011, and for 2012.

8.2.3.3.10. Auxiliary Equipment

The budget codes for auxiliary equipment are for "the costs of equipment installed to support transmission system operations that are not captured in other [budget codes]." (Ex. 55 at 78.)

SoCalGas estimates capital expenditures of $882,000 in 2010, and $1.651 million in 2011, and in 2012.

None of the other parties take issue with SoCalGas' forecast.

Based on our review of the testimony and arguments of the parties, it is reasonable to adopt SoCalGas' forecast of the capital expenditures for auxiliary equipment as follows: $882,000 for 2010; and $1.651 million for 2011, and for 2012.

8.2.3.3.11. Pipeline Land Rights

8.2.3.3.11.1. Introduction

The budget code for pipeline land rights includes the "costs associated with the acquisition of land and land rights necessary to conduct natural gas transmission activities." (Ex. 55 at 79.) SoCalGas plans two land purchases. The first is to purchase land adjacent to its compressor stations at North Needles, Newberry Springs, and Blythe due to the expected impact of new emission regulations. The second purchase is to buy land in exchange for special permits that SoCalGas needs for pipeline construction and maintenance activities in lands covered by the Endangered Species Act.

SoCalGas estimates capital expenditures of zero in 2010, $4.000 million in 2011, and $8.300 million in 2012.

8.2.3.3.11.2. Position of the Parties

8.2.3.3.11.2

DRA contends that it is speculative on SoCalGas' part as to whether the North Needles, Newberry Springs, and Blythe compressor stations will be impacted by the new emission regulations. SoCalGas also contends that purchasing the adjacent land as a mitigation measure may not be cost effective, and that SoCalGas has not presented any detailed analyses to support the proposed land purchases. For those reasons, DRA recommends the removal of $4.000 million in 2011, and $2.000 million in 2012.

DRA is also opposed to SoCalGas' plan to purchase land in exchange for special permits under the provisions of the Endangered Species Act. DRA contends that SoCalGas has not provided any detailed analysis to justify the need for the special permits. DRA recommends the removal of $6.300 million in 2012.

Under DRA's recommendations, there would be zero capital expenditures for pipeline land rights in 2011 and 2012.

8.2.3.3.11.2

Contrary to DRA's claim, SoCalGas contends that the Federal Clean Air Act, and the California emission regulations found in § 93300.5 of Title 17 of the California Code of Regulations, apply to North Needles, Newberry Springs, and Blythe. SoCalGas also contends that it provided a response to DRA which detailed why the land purchases are necessary, as opposed to having to spend even more money for EPA-ordered emissions mitigation if the adjacent lands are not purchased and people then move into the area. If that occurred, under a worst case scenario, the air quality board "could require the sites to be converted from reciprocating-engine-driven compressors to electric-motor-driven compressors" at a potential cost of up to $33 million at each site. (Ex. 58 at 56.) SoCalGas contends that the "purchase of buffer lands around these critical sites is a prudent and timely business and economic decision that is essential for continued operation of these critical facilities." (Ex. 58 at 57.)

With respect to the purchase of mitigation lands in exchange for special permits, SoCalGas contends that § 10 of the Endangered Species Act and Fish and Game Code § 2081 are not speculative, as DRA claims. SoCalGas contends that its "[O&M] and construction activities in the affected lands are subject to these laws," and an applicant for an Incidental Take Permit "is required to demonstrate how they intend to mitigate their 'take' impacts and how they will pay for such mitigation." (Ex. 330 at 14.) SoCalGas explained how the purchase of the mitigation lands would work in a data response to DRA, a copy of which was attached in Appendix E of Exhibit 330.

8.2.3.3.11.3. Discussion

We have reviewed the testimony and arguments of SoCalGas and DRA, and have also reviewed the applicable laws and regulations. We have also considered the possible consequences if SoCalGas does not purchase the lands adjacent to the three compressor stations, and if it does not purchase the other lands in exchange for the Incidental Take Permits.

Based on all those considerations, it is reasonable to adopt the following capital expenditures for pipeline land rights as follows:
$4.000 million for 2011; and $7.300 million for 2012.

8.2.3.3.12. Laboratory Equipment

8.2.3.3.12.1. Introduction

The budget code for laboratory equipment covers the costs of acquiring and replacing tools and equipment for the Gas Engineering Analysis Center located in Pico Rivera.

SoCalGas estimates capital expenditures of $265,000 in 2010, $935,000 in 2011, and $295,000 in 2012.

8.2.3.3.12.2. Position of the Parties

8.2.3.3.12.2

DRA contends that the mandatory GHG reporting rule is less stringent than SoCalGas had expected, and as a result the number of optical imaging devices and high volume samplers that SoCalGas proposed be purchased, should be reduced. DRA recommends capital expenditures of $455,000 in 2011, and $295,000 in 2012.

8.2.3.3.12.2

SoCalGas contends that the mandatory GHG reporting rule applies to "custody transfer gas stations," which are transmission facilities. Since the transmission and storage functions are unaffected by the changes to the mandatory GHG reporting rules, the request for tools in 2011 should not be reduced. SoCalGas' Exhibit 330 also describes the compliance activities that it needs to undertake with respect to its transmission and storage operations, as well as its distribution operations. These compliance activities have not been changed as a result of the mandatory GHG reporting rule.

8.2.3.3.12.3. Discussion

We have reviewed the testimony and arguments of SoCalGas and DRA concerning the laboratory equipment. In addition, we have considered the compliance activities that SoCalGas is required to undertake of its transmission and storage operations as a result of the mandatory GHG reporting rule.

Based on those considerations, it is reasonable to adopt DRA's recommendation of capital expenditures for laboratory equipment as follows: $265,000 for 2010; $455,000 for 2011; and $295,000 for 2012.

8.2.3.3.13. Capital Tools

The budget code for capital tools covers the cost of purchasing and replacing capital tools that are used by the transmission and storage operating departments. These tools include specialized welding equipment, and global positioning receivers that are used for land surveys.

SoCalGas forecasts annual capital expenditures of $307,000 in 2010, 2011, and 2012.

None of the other parties take issue with SoCalGas' forecast.

Based on our review of the testimony and arguments of the parties, it is reasonable to adopt SoCalGas' forecast of the capital expenditures for the capital tools as follows: annual amounts of $307,000 for 2010, 2011, and 2012.

8.2.3.3.14. Gas Storage – Supervision & Engineering Di

rect Overheads

The budget code for gas storage – supervision and engineering direct overheads covers the funding of supervision and engineering overheads that are allocated over the capital budget codes.

SoCalGas forecasts capital expenditures of $240,000 in 2010, $278,000 in 2011, and $335,000 in 2012.

None of the other parties take issue with SoCalGas' forecast.

Based on our review of the testimony and arguments of the parties, it is reasonable to adopt SoCalGas' forecast of the capital expenditures for the gas storage – supervision and engineering direct overheads as follows: $240,000 in 2010; $278,000 in 2011; and $335,000 in 2012.

8.2.3.3.15. Gas Transmission – Supervision & Engineeri

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The budget code for gas transmission – supervision and engineering direct overheads covers the funding of supervision and engineering overheads that are allocated over the capital budget codes.

SoCalGas forecasts capital expenditures of $904,000 in 2010, $1.046 million in 2011, and $1.260 million in 2012.

None of the other parties take issue with SoCalGas' forecast.

Based on our review of the testimony and arguments of the parties, it is reasonable to adopt SoCalGas' forecast of the capital expenditures for the gas transmission – supervision and engineering direct overheads as follows: $904,000 in 2010; $1.046 million in 2011; and $1.260 million in 2012.

8.2.3.3.16. Coastal Region Conservation Program

The budget code for the Coastal Region Conservation Program covers "the cost of developing a programmatic permitting approach to obtain federal and state approval under the [Endangered Species Act] to conduct routine SoCalGas operations and maintenance in the Counties of San Luis Obispo, Santa Barbara, Ventura, Los Angeles, Orange, San Bernardino, and Riverside." The planning area covered by this program encompasses 8.657 million acres.

SoCalGas forecasts capital expenditures of $886,000 in 2010, $664,000 in 2011, and zero in in 2012.

None of the other parties take issue with SoCalGas' forecast.

Based on our review of the testimony and arguments of the parties, it is reasonable to adopt SoCalGas' forecast of the capital expenditures for the Coastal Region Conservation Program as follows: $886,000 in 2010; $664,000 in 2011; and zero in 2012.

8.2.3.3.17. Sustainable SoCal Program

8.2.3.3.17.1. Introduction

The budget code for the Sustainable SoCal Program covers the cost of installing "four BioEnergy units at certain customer sites for the purpose of capturing raw biogas and upgrading it to pipeline quality biogas (biomethane)."

(Ex. 55 at 82.) SoCalGas plans to install two of the units in the third quarter of 2012, and two units after test year 2012. Each unit installation is estimated to cost about $5.600 million.

SoCalGas forecasts capital expenditures of $11.272 million in 2012.

8.2.3.3.17.2. Position of the Parties

8.2.3.3.17.2

DRA contends that SoCalGas is not in the business of producing gas, and that "is the responsibility of gas producers, whose prices are not regulated." (Ex. 535 at 22.) DRA also contends that AB 32 and Executive Order S.06-06 "did not authorize the subsidization by ratepayers of private producers of natural gas to improve the quality of their gas so it meets pipeline specifications," and that

SoCalGas has not provided any "cost-benefit analysis of how the cost of the project compared to the potential benefits of removing emissions." (*Ibid*.) DRA contends that SoCalGas' shareholders should pay for this project.

8.2.3.3.17.2

SoCalGas contends that the Sustainable SoCal Program "will advance the market development efforts associated with producing pipeline quality biogas from digested raw biogas generated from wastewater treatment plants, dairies, and food processing plants." (Ex. 55 at 82.) SoCalGas further contends that "[b]ecause of its expertise and corporate values, SoCalGas is positioned to play a leadership role in advancing the use of biogas while supporting the objectives of both AB 32 and Executive Order S.06-06 by providing California and its ratepayers with significant environmental and economic benefits by helping to reduce GHG emissions." (Ex. 55 at 83.) Under this program, SoCalGas will design, install, own and operate the biogas conditioning systems at these biogas producer sites. SoCalGas will lease a small space from the host facility "to house the required gas conditioning system and pipeline interconnection facilities onsite." (Ex. 419 at 52-53.)

SoCalGas contends that its "proposal supports Commission and state policies, is well-timed to advance a valuable resources for the region and for [SoCalGas'] customers, and its cost is in the range of other renewable technologies." (Ex. 419 at 52.)

SoCalGas contends that SoCalGas will not be subsidizing the owners of the facilities where the biogas is produced because they will not own the biogas. The only benefit the facility owners would receive is the lease payments for allowing SoCalGas to locate the units at those facilities. SoCalGas also contends that the premium to produce biomethane under the Sustainable SoCal program is comparable to the cost of photovoltaic thin film and "with other solar technologies, and is within the range of the premiums for other renewable technologies," such as wind, geothermal, and biomass. (Ex. 419 at 58-59.)

Although there is no explicit mandate that requires SoCalGas to procure biomethane, SoCalGas contends that "biogas and biomethane comply with the state's Renewable Portfolio Standard for electric utilities, the [CARB's] Cap and Trade Program and the Low Carbon Fuel Standard…to reduce GHG emissions." (Ex. 419 at 59.) SoCalGas further contends that the Sustainable SoCal Program "is similar to other Commission clean energy policies, where all or the majority of ratepayers pay to support technologies like solar water heating, energy efficiency, and distributed generation, with the ultimate goal of accelerating adoption and reducing costs for these technologies." (Ex. 419 at 59.)

8.2.3.3.17.3. Discussion

Later in this decision we discuss the reasons for rejecting SoCalGas' request to fund the Sustainable SoCal Program. Those same reasons also apply to this section regarding the capital expenditures related to gas transmission for the Sustainable SoCal Program. Accordingly, we adopt DRA's recommendation that there should be zero funding for capital expenditures relating to the Sustainable SoCal program.

9. SDG&E and SoCalGas Gas Safety Reporting

9.1. Introduction

In D.11-04-031, the Commission ordered PG&E to provide a semi-annual "Gas Transmission and Storage Safety Report," and in D.11-05-018, the Commission ordered PG&E to provide semi-annual "Gas Distribution Pipeline Safety Reports." TURN and UCAN recommend that similar semi-annual reporting requirements be imposed on SDG&E and SoCalGas.

In 2011, Pub. Util. Code § 958.5 was enacted into law with an effective date of January 1, 2012. That code section imposed a gas transmission and storage safety report on the natural gas utilities.

9.2. Position of the Parties

9.2.1. TURN and UCAN

TURN and UCAN recognize the interest in ensuring gas pipeline safety. As part of its recommended "safeguards to ensure that whatever expenditures the Commission authorizes for pipeline safety are spent for that purpose and can be closely tracked by the Commission," TURN and UCAN recommend that the Commission "require semi-annual Pipeline Safety Reports akin to the reports ordered for [PG&E] in D.11-04-031…and D.11-05-018…." (Ex. 547 at 1.)

TURN and UCAN contend that these reports will "provide essential information to allow the Commission and the parties to monitor and better understand how the utilities are carrying out their pipeline safety responsibilities between rate cases." (Ex. 547 at 5.) According to TURN and UCAN, these reports will provide important information on the following: an explanation of the utility's strategic planning approach to the ranking of safety projects; the utility's most recent "Risk Management Top 100" report; updates regarding the status and amount spent for safety projects and maintenance activities; whether projects targeting identified high risks have been carried out or postponed; and the utility's rationale for any reprioritization of a projects.

9.2.2. SDG&E and SoCalGas

SDG&E and SoCalGas are opposed to the proposal of TURN and UCAN to impose on them similar kinds of reporting requirements. SDG&E and SoCalGas, however, are open to a reporting requirement that is "meaningful, suited for the purpose intended, and not duplicative." (Ex. 54 at 10; Ex. 58 at 5.)

SDG&E and SoCalGas make three arguments as to why similar reporting requirements should not be imposed on it. First, they argue that the reporting requirements imposed on PG&E were a direct result of PG&E's handling of the September 9, 2010 San Bruno fire explosion and fire, and the December 24, 2008 Rancho Cordova explosion and fire. Since the reporting requirements in D.11-04-031 and D.11-05-018 were operator-specific to PG&E, the Applicants contend it would be inappropriate to apply similar reporting requirements to them because it extends well beyond issues involving pipeline integrity. The Applicants also argue that instead of imposing reporting requirements on them, TURN and UCAN "should support the Commission's efforts to acquire the resources needed to review and analyze the existing reports to further assure public safety, which was identified by the Independent Panel Review." (Ex. 54 at 11; Ex. 58 at 26.)

Second, the Applicants argue that TURN and UCAN deferred to DRA on pipeline safety issues, but none of the DRA witnesses mentioned or recommended any need for additional reporting for the Applicants' transmission and distribution operations. The Applicants further argue that TURN and UCAN should have raised this reporting issue in other proceedings addressing pipeline safety.

The third argument of the Applicants is that the type of information that TURN and UCAN seek to impose on the Applicants is duplicative of the pipeline integrity management information that is already being supplied to the Commission's Safety and Enforcement Division.[69] SDG&E asserts that the PHMSA report provides details on the high consequence area miles of pipeline that have been assessed and reassessed in a given year, and the assessment method that was used for such tests. In addition, the Applicants state that it provided DRA with a copy of its Baseline Assessment Plan, which provides a roadmap of specific actions for each pipeline covered under the federal TIMP and DIMP. For spending information regarding the pipelines, the Applicants contend that such information would be provided in the NERBA.

9.3. Discussion

In our analysis of the reporting recommendation of TURN and UCAN, it is important to recognize that Pub. Util. Code § 958.5 was recently enacted into law with an effective date of January 1, 2012. That code section provides in pertinent part:

> (a) Twice a year, or as determined by the commission, each gas corporation shall file with the commission's consumer protection safety division a gas transmission and storage safety report. The consumer protection safety division shall review the reports to monitor each gas corporation's storage and pipeline-related activities to assess whether the

[69] The Safety and Enforcement Division was formerly known as the Consumer Protection and Safety Division.

projects that have been identified as high risk are being carried out, and to track whether the gas corporation is spending its allocated funds on these storage and pipeline-related safety, reliability, and integrity activities for which they have received approval from the commission.

(b) The gas transmission and storage safety report shall include a thorough description and explanation of the strategic planning and decision-making approach used to determine and rank the gas storage projects, intrastate transmission line safety, integrity, and reliability, operation and maintenance activities, and inspections of its intrastate transmission lines. If there has been no change in the gas corporation's approach for determining and ranking which projects and activities are prioritized since the previous gas transmission and storage safety report, the subsequent report may reference the immediately preceding report.

The positions taken by both SDG&E and SoCalGas overlook Pub. Util. Code § 958.5. Since SDG&E and SoCalGas are a "gas corporation," as used in Pub. Util. Code § 958.5, this code section applies to the gas transmission operations of both companies, and to the gas storage operations of SoCalGas. Accordingly, SDG&E is required under this code section to provide a gas transmission safety report containing the applicable transmission information set forth in subsection (b) of Pub. Util. Code § 958.5, and as set forth in Attachment **C** of this decision. SoCalGas as the operator of both gas transmission and gas storage operations, is required to provide a gas transmission and storage safety report containing the information set forth in subsection (b) of that code section, and as set forth in Attachment C of this decision.

As to whether SDG&E and SoCalGas should be required to provide semi-annual reports containing information about their gas distribution operations, such reports are not covered under Pub. Util. Code § 958.5.

However, the applications of SDG&E and SoCalGas in these consolidated proceedings cover their natural gas operations during the 2012 through 2014 or 2015 rate cycle.[70] In conducting their gas operations, both companies are obligated under Pub. Util. Code § 451 to "furnish and maintain such adequate, efficient, just, and reasonable service, instrumentalities, equipment and facilities…as are necessary to promote the safety, health, comfort, and convenience of its patrons, employees, and the public."

To ensure compliance with Pub. Util. Code § 451, the Commission has the authority under several code sections to order a public utility to provide reports. In particular, Pub. Util. Code § 584 provides in part that:

> Every public utility shall furnish such reports to the commission at such time and in such form as the commission may require in which the utility shall specifically answer all questions propounded by the commission. The commission may require any public utility to file monthly reports of earnings and expenses, and to file periodical or special reports, or both, concerning any matter about which the commission is authorized by any law to inquire or to keep itself informed, or which it is required to enforce.

Section 581 requires a utility to "furnish to the commission in such form and detail as the commission prescribes all tabulations, computations, and all other information required by it to carry into effect any of the provisions of this part, and shall make specific answers to all questions submitted by the commission." In addition, Pub. Util. Code § 582 requires each utility to "deliver to the commission copies of any or all…reports, books, accounts, papers, and

[70] The issue of whether the rate cycle should be three or four years is discussed later in this decision.

records in its possession or in any way relating to its property or affecting its business, and also a complete inventory of all its property in such form as the commission may direct."

We are not persuaded by the Applicants' argument that since similar information is already being supplied to the PHMSA, that no additional reporting is needed. In order to ensure that the Commission has information about the gas distribution operations of SDG&E and SoCalGas, to provide the Safety and Enforcement Division with the tools needed to oversee the safety and reliability of the gas distribution operations of SDG&E and SoCalGas, and to ensure that pipeline integrity management efforts are being carried out, the Commission shall require SDG&E and SoCalGas to submit a semi-annual gas distribution safety report, similar to what was imposed on PG&E. This gas distribution safety report shall be incorporated into a combined gas transmission and gas distribution safety report for SDG&E, and a combined gas transmission, gas storage, and gas distribution safety report for SoCalGas. The information to be supplied in these safety reports shall be in the format as described in Attachment C of this decision. We will require SDG&E and SoCalGas to serve their respective semi-annual safety report beginning July 1, 2013 to the directors of the Safety and Enforcement Division and Energy Division. These initial safety reports shall cover the one year period from January 1, 2012 through December 31, 2012. Each subsequent report shall cover each subsequent six-month period, and the second semi-annual safety report shall be served on September 1, 2013, and on each March 1 and September 1 thereafter until further notice.

Pursuant to Pub. Util. Code § 958.5(c), the Safety and Enforcement Division shall review SDG&E's gas transmission and distribution projects and activities, and SoCalGas' gas transmission and distribution and gas storage projects and activities, to assess whether the projects and activities are being carried out, and to track whether SDG&E and SoCalGas are spending their allocated funds on projects and activities that ensure the safety and reliability of their respective gas transmission, gas distribution, and gas storage operations. Should the Safety and Enforcement Division detect any problems with the way in which SDG&E or SoCalGas prioritize or carry out their capital expenditure projects and O&M activities, the Safety and Enforcement Division shall bring these problems to the Commission's attention immediately. The Energy Division shall provide the Safety and Enforcement Division with the necessary assistance to review and monitor these reports.

10. Customer Service

10.1. Introduction

This section addresses the O&M expenses and capital expenditures for the activities of SDG&E and SoCalGas that are related to customer service. These activities cover the customer service-related activities that take place out in the field, at the call centers, and at the branch offices. It also covers customer service-related activities that occur at the offices of SDG&E and SoCalGas, which include billing services, credit and collections, remittance processing, and technology support. Customer service also includes activities that support and promote customer service programs and products.

In the sub-sections below, we provide a brief background of the customer service-related activities, followed by a discussion of the SDG&E customer service issues, and the SoCalGas customer service issues.

10.2. Field, Call Center and Branch Offices

10.2.1. Introduction

The Applicants have requested funding of their O&M expenses for customer service field, and customer contact activities. These activities include fulfillment of the service orders by utility personnel in the field, the call centers that answer telephone calls from customers, and the costs of in-person bill payment services at branch offices and authorized payment locations. SoCalGas has also requested O&M expenses for meter reading.

SDG&E is requesting total shared and non-shared O&M expenses of $35.361 million. SoCalGas is requesting total shared and non-shared O&M estimated expenses of $230.306 million.

The customer service field activities include providing service at customer locations by field technicians who perform such work as turn-ons, appliance inspections and safety service checks, and meter and regulator replacements. The factors which impact this work include meter growth as a result of new customers, customer turnover, and meter and regulator replacements. For SDG&E, this work is also impacted by the deployment of smart meters.

SDG&E's customer services field operations are located at five bases. In 2009, SDG&E's customer service field personnel completed over 1.1 million orders. SoCalGas' customer service field operations are located at 51 bases, and in 2009 SoCalGas' field personnel completed over 4.3 million orders.

Customer contact refers to the call center operations of SDG&E and SoCalGas in which telephone calls are handled by customer service representatives. Incoming calls are first routed to an interactive voice response system with menu choices. If the customer cannot resolve the issue using the voice response system or needs further assistance, the call is then queued to be answered by a customer service representative. Calls involving emergency and hazardous conditions go to the front of the queue.

SDG&E has two call centers with about 200 customer service representatives. The SDG&E call centers handle over 3 million calls per year. SoCalGas has two call centers and about 600 customer service representatives. The call centers of SoCalGas handle more than 7 million calls per year.

The branch offices and authorized payment locations provide in-person bill payment services. SDG&E has seven branch offices and more than 50 authorized payment locations. Together, they processed more than 1.2 million bill payments in 2009. SoCalGas has 47 branch offices and more than 200 authorized payment locations. The SoCalGas branch offices and authorized payment locations processed about 7 million bill payments in 2009.

For SoCalGas, meter reading remains a part of its customer services, and its estimated expenses for customer service field and customer contact are based on a continuation of the current analog gas meters without AMI deployment.[71] SoCalGas completes about 5.6 million meter reads per month.

For SDG&E, its advanced metering infrastructure (smart meters) impacts its customer service field and customer contact operations. At the start of 2012, SDG&E had deployed about 99% of its smart meters. The use of smart meters is expected to result in a net reduction of about 23% of customer service field orders because of the remote read and connect and disconnect capabilities, and a reduction in bill inquiries at the call center.

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[71] SoCalGas was authorized in D.10-04-027 to deploy smart meters to 6 million customers over a period of seven years. SoCalGas does not expect to complete the deployment of smart meters until 2017.

SDG&E and SoCalGas also request funding for customer services-related capital expenditures. SDG&E requests $6.286 million for 2011, and $17.900 million for 2012. SoCalGas requests $12.424 million for 2010, $11.968 million for 2011, and $15.567 million for 2012.

SDG&E's capital expenditures include funding forecasts for: customer service representative online customer helpdesk support tools; the upgrade project for the Service Order Routing Technology (SORT) application; Home Area Network (HAN) implementation, infrastructure, integration, and facilities; and the Distributed Energy Resource Management Systems (DERMS).

SoCalGas' capital expenditures include funding forecasts for: call recording replacement; customer service field operating efficiency; forecasting and scheduling; customer service field mobile data terminals; PACER[72] refresh; replacement of meter reading handheld devices; and planned and routine meter replacements.

SDG&E and SoCalGas also request approval of their forecasts of miscellaneous revenues from customer service fees which are associated with customer service field and customer contact activities.[73]

SDG&E estimates miscellaneous revenues of $5.507 million for electric, and $2.498 million for gas. These miscellaneous revenues include service establishment charges, and collection charges.

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[72] PACER refers to the service order scheduling and routing system.

[73] According to the Applicants, "Miscellaneous revenues are comprised of fees and revenues collected by the utility from non-rate sources for the provision of specific products or services." (Ex. 452 at 1; See Ex. 450 at 1.)

SoCalGas estimates miscellaneous revenues for test year 2012 of $32.938 million. These miscellaneous revenues include the following: service establishment charge; reconnection charge; residential and commercial parts programs; connect appliance services; timed appointments; seismic services; and general restore service.

Several parties seek to reduce the forecasted expenses of SDG&E and SoCalGas concerning their customer services. The primary cause of the reduction in the forecasted expenses is due to the different methodologies that the Applicants and the other parties use to derive their test year 2012 cost forecasts.

Below, we address the customer field, call center, and branch offices issues pertaining to SDG&E, followed by issues pertaining to SoCalGas.

10.2.2. SDG&E Field, Call Center and Branch Offices

10.2.2.1. Introduction

SDG&E is requesting test year 2012 total shared and non-shared O&M estimated expenses of $35.361 million for customer service field and customer contact operations. This is a decrease of $2.669 million over the 2009 base year adjusted recorded expenses.

Since SDG&E 's deployment of its advanced metering infrastructure (smart meter) is essentially complete, the test year 2012 forecasts of customer service field and customer contact activities have integrated the effects of that program into SDG&E's forecasts. SDG&E is also continuing and expanding its activities concerning HAN, which works in conjunction with SDG&E's smart meter network.[74]

SDG&E's capital expenditures that are related to customer service field and customer contact activities are also addressed in this section. The test year 2012 forecast of these capital expenditures amount to $17.9 million.

DRA, UCAN, and CCUE have raised issues concerning SDG&E's customer service field and customer contact operations, and have recommended that adjustments be made to the test year 2012 forecast of O&M expenses for customer service field activities. CCUE raised the workforce issue of how many gas workers SDG&E has available to respond to, and to restore service after an earthquake. In the sections below, we address the issues that were raised in the customer services field, call center, and branch offices area. The issue raised by CCUE is separately discussed following the SDG&E capital expenditures section.

No one has raised any issues about SDG&E's forecast of its shared services O&M expenses ($788,000) for its customer service field and customer contact activities. Based on the evidence, we adopt SDG&E's forecast of O&M shared services in the amount of $788,000 as reasonable.

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[74] The HAN infrastructure allows smart appliances and devices to communicate with each other through a communications network on the customer's premise.

10.2.2.2. Customer Services Field

10.2.2.2.1. Introduction

SDG&E's test year 2012 forecast of non-shared O&M expenses for customer service field activities is $20.389 million. This forecast is a net reduction of $3.219 million from the 2009 adjusted recorded level of $23.608 million. To arrive at this forecast, SDG&E used its five year average methodology of the customer service field order volumes by order type. SDG&E then applied the benefits from the smart meter program to this forecast.

SDG&E's test year 2012 forecast of its shared O&M expenses for customer service field activities is $131,000.

10.2.2.2.2. Position of the Parties

10.2.2.2.2.1. DRA

DRA has proposed reductions to SDG&E's forecasted expenses for customer services field non-shared services. DRA's recommended reduction of $250,000 is composed of $150,000 in increased drive time, and $100,000 for the forecasted increase in carbon monoxide alarm orders. The $150,000 in increased drive time is the result of SDG&E's proposal to increase the average drive time for each customer service field order by 1%. DRA contends that the increase in drive time has not been justified by SDG&E, and because of its belief that there should be less traffic congestion due to the slowdown in the economy and high unemployment.

With respect to the carbon monoxide alarm orders, DRA contends that the number of alarm orders that were forecasted by SDG&E for 2010 and 2011 were higher than the actual number of alarm orders that were completed for the one-year period from June 1, 2010 to May 31, 2011. DRA contends that SDG&E's request of $138,000 for the increase in alarm orders should be reduced by $100,000.

10.2.2.2.2.2. UCAN

UCAN proposes that in addition to DRA's reduction, that there be an additional reduction of $1.212 million. UCAN's recommended reduction is based on the different methodologies that it used, in contrast to methodologies used by SDG&E. UCAN's principal methodology was to reduce by 1% the volume of most service orders because of slower customer growth. For certain other service orders, as described in Exhibit 558, UCAN proposed different methodologies to derive the forecasts of those service orders.

10.2.2.2.2.3. SDG&E

SDG&E contends that increasing the average drive time for each customer service field order by 1% is justified because the data from 2010 and 2011 shows that the average drive time increased by more than 1% over the 2009 level.

SDG&E contends that its five-year average methodology should be used because it accounts for the various factors that have affected service order volumes in recent years. SDG&E further contends that UCAN's various forecasting methodologies are inconsistent and selective, and are designed to highlight UCAN's position of reducing costs. In addition, SDG&E contends that UCAN's use of 2010 data is flawed because the 2010 data already includes lower service order volumes due to the effects of the smart meter benefits.

10.2.2.2.2.4. Discussion

Based on our review of all of the evidence, and as discussed below, we adopt a test year 2012 forecast of $19.639 million for the O&M expenses for customer service field related activities and functions.

The first issue to address is DRA's recommendation to reduce SDG&E's costs by $150,000 due to SDG&E's proposal to increase drive time by 1% for each customer service field order.

SDG&E justifies the 1% increase in drive time because of the Global Insights Regional Forecast of August 2011, which estimates that employment will grow in 2011 and 2012 in the San Diego area, and is higher than the employment growth in 2009. SDG&E contends that increased employment and positive customer growth will mean more vehicle trips and increased traffic congestion. SDG&E also relies on 2010 and 2011 data for average drive time for customer service field orders which show that average drive time increased over the 2009 level.[75]

We do not agree with SDG&E's contention that the average drive time has increased over the average drive time for 2009, and that the forecasted employment growth will be higher than 2009. Given the slow down in the economy, we agree with DRA that there should not be an allowance for increased drive time.

The second issue to address is DRA's recommendation to reduce SDG&E's funding request for carbon monoxide alarm orders by $100,000. For this recommendation, DRA relies on the period of June 1, 2010 through May 31, 2011 to justify its reduction. During that period, there were 2283 carbon monoxide alarm orders. SDG&E forecasted 4398 carbon monoxide alarm orders for 2011, and 3,287 alarm orders for 2010. SDG&E points out that the time period DRA relied on to justify the reduction for carbon monoxide alarm orders was before the effective date of Senate Bill (SB) 183. SB 183, which is partially codified in Health and Safety Code section 17926, requires the installation of a carbon monoxide alarm in single family dwellings effective July 1, 2011.

The time period that DRA relies on to justify a lower number of alarm orders was before the date of July 1, 2011, when single family dwellings are required to have a carbon monoxide alarm. Given this new statute, it is reasonable to assume that the number of service orders related to carbon

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[75] This is an example of the Applicants' use of more recent data to justify their forecasts. As we noted earlier, the use of more recent data may be appropriate depending on the circumstances surrounding its use.

monoxide alarms will go up in test year 2012. Accordingly, we adopt SDG&E's test year 2012 forecast of the carbon monoxide alarm orders.

DRA raised a third issue about SDG&E's forecasted expenses for enhancements to the advanced metering infrastructure. DRA contends that these "new expenses suggest that the expenses in the [advanced metering infrastructure] business case were understated." (Ex. 506 at 3.) SDG&E points out that the operational benefits from the smart meters ($5.257 million in customer service field and $82,000 of customer contact benefits) were identified in Exhibit 138 as factors that reduce the test year O&M expenses. SDG&E also points that the advanced metering infrastructure application specifically identified the incremental costs that would be incurred after the deployment of the smart meters.

DRA has not recommended that the smart meter costs of $646,000, that are included in the test year 2012 forecast of customer service field expenses, be disallowed. In addition, we do not find any merit in DRA's contention that additional smart meter related costs were never contemplated when SDG&E's advanced metering infrastructure application was approved. Accordingly, no adjustment to the customer service field costs are warranted based on DRA's contention regarding the smart meter costs.

We now turn to the reductions recommended by UCAN. UCAN's recommended reductions are based on the methodologies it used to arrive at the forecasts of customer service field orders, which are lower than SDG&E's forecast of customer service field orders.

SDG&E used the five-year average methodology for 60 different order types, and applied assumed meter growth for 2010-2012. For collection orders, SDG&E used a three-year average due to a lack of recorded data.

UCAN used three different methodologies for its forecasts. For customer service field activities, UCAN reduced the service order volumes by one percent. For customer service field dispatch and support functions, UCAN used a five-year average of 2005-2009 reduced by 10% to reflect the reduction in workforce. For customer service field supervision, UCAN used a two-year average of 2009-2010 reduced by SDG&E's forecasted 2010-2012 incremental reduction.

We are persuaded by UCAN's arguments and testimony that the volume of customer service-related activities will be lower than what SDG&E has forecasted. Accordingly, it is reasonable to reduce the customer services field O&M costs by $750,000 to reflect the arguments of DRA and UCAN that there will less O&M costs than what SDG&E has forecasted. Based on that reduction, it is reasonable to adopt a forecast of $19.639 million for the non-shared O&M expenses for SDG&E's customer services field activities.

10.2.2.3. SDG&E Call Center

10.2.2.3.1. Introduction

SDG&E is requesting $12.284 million for non-shared call center O&M expenses, and $627,000 in shared services O&M expenses. SDGE refers to the call center as the customer contact center.

10.2.2.3.1.1. Position of the Parties

10.2.2.3.1.2. DRA

DRA recommends that SDG&E's forecast of customer contact expenses be reduced by $856,000. DRA's reductions are in three areas. DRA proposes to disallow $181,000 for the expenses associated with additional customer service representatives because SDG&E did not account for the OpEx benefits. DRA recommends disallowance of $106,000 for an OpEx analyst because SDG&E did not justify the need for the analyst. The remaining $569,000 disallowance of DRA is for software license and maintenance agreements which SDG&E did not explain the need for.

10.2.2.3.1.3. UC

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UCAN recommends a reduction of $638,000 in call center costs, of which $181,000 overlaps with DRA's recommendation. UCAN also recommends a 10% reduction ($1.096 million) in SDG&E's customer contact expenses due to UCAN's recommendation that SDG&E's customer contact activities should move toward internet-based services.

10.2.2.3.1.4. SDG&E

SDG&E contends that DRA's recommended disallowance of $856,000 should not be adopted. SDG&E contends that if DRA's proposed disallowance of $181,000 for customer service representative positions were adopted, that this would result in a double count of the OpEx benefits associated with the increasing use of SDG&E's customers with the interactive self-service options when calls are made to the call centers. On DRA's recommended disallowance of $106,000 for the OpEx analyst, SDG&E contends that this position will allow that person to use the software tools that will help "improve the customer experience, increase [customer service representative] productivity and achieve the OpEx self-service goals." (Ex. 140 at 33.) According to SDG&E, this software, and the person to operate the software, are needed to achieve the OpEx annual benefits. Regarding DRA's disallowance of $569,000 for the software license and maintenance agreements, SDG&E contends this is needed to maintain and update the current software. SDG&E argues that since DRA has accepted the benefits from OpEx, that the expenses associated with OpEx should be funded in order to achieve the benefits of OpEx.

SDG&E contends that UCAN's proposed adjustment of $638,000 is flawed because UCAN uses a two-year average of 2009-2010 to forecast answered call volumes. SDG&E contends that the 2010 call volumes already include the OpEx benefits of interactive self-service calls in the 2010 answered call volumes.

10.2.2.3.2. Discussion

We first address DRA's recommendation to reduce the customer contact O&M expenses by $856,000. DRA's recommended disallowances are based on SDG&E's perceived failure to take into account OpEx benefits, to explain why the OpEx analyst is necessary, and to explain why the annual maintenance fees for the software are needed. SDG&E has demonstrated in its testimony that the OpEx benefits have been accounted for, and explained the need for the OpEx analyst and the fees for the software. Accordingly, DRA's recommended reduction of $856,000 for these customer contact O&M expenses is not adopted.

Next, we address UCAN's proposed reduction of customer contact O&M expenses by $638,000. SDG&E's UCAN contends that despite a trend of declining costs, SDG&E is forecasting an increase in call center costs.

To derive its forecast of customer service representative answered calls, SDG&E uses its five-year average methodology multiplied by its forecast of meters. SDG&E's methodology results in answered calls of about 2.548 million calls. SDG&E's cost per call for test year 2012 is $3.741.

Due to the declining number of calls answered by customer service representatives, and the increasing number of calls handled by the interactive voice response system, UCAN recommends that the forecast of answered calls be based on the two-year average of 2009 and 2010 data.[76] UCAN's methodology results in answered calls of about 2.412 million. UCAN's cost per call of $3.673 is based on the two-year average of 2009 and 2010 costs for labor costs, and the non-labor costs is based on a five-year average of non-labor costs from 2006-2010.

Our review of the evidence and the competing methodologies of UCAN and SDG&E lead us to conclude that UCAN's method will result in a more accurate reflection of the call center costs for the test year. This will result in a reduction to the call center costs, as described at the end of this discussion.

The other issue that UCAN raised is a proposed 10% reduction in customer contact test year 2012 estimated expenses ($1.096 million). UCAN refers to this reduction as a "productivity factor" adjustment in its reply brief. UCAN proposes this reduction because it believes that SDG&E has been slow to adopt internet based services for its customers, and that cost effectiveness must be considered when making infrastructure investments.

UCAN's 10% proposed reduction is mentioned in Exhibit 558, and states that the $1.096 million "reduction is comprised of $903,000 in call center operations and $193,000 in call center support costs…." (Ex. 558 at 74.) There is no other explanation in UCAN's testimony of how these proposed dollar amount reductions were arrived at, but states that the testimony of UCAN's other witness in Exhibit 555 "identifies a technological shift that could reduce call

[76] UCAN's methodology would adjust the 2009 data for five missing days of data as described in footnote 26 of Exhibit 558.

center costs even further by moving toward internet-based services, and proposes a further ratemaking adjustment of 10% of call center costs or $1,096,000." (Ex. 558 at 74.)

Exhibit 555 describes UCAN's view of how SDG&E has been reluctant to adopt new internet-based services for its customers, and how the monies that SDG&E received in its last GRC could have been used to develop new web-based services for its customers, but did not. UCAN then describes why SDG&E's call center should be transformed into a contact center in which SDG&E can develop "a plan to utilize the efficiencies of the Web to improve the customer experience while gaining operational efficiencies."(Ex. 555 at 34.) In the absence of SDG&E having a comprehensive vision of how the internet will be integrated into its customer contact operations, UCAN believes that the Commission should refrain from approving certain expenditures that only benefit a subset of SDG&E customers who have established a "My Account" with SDG&E. UCAN believes such projects and expenditures should benefit all customers who use the internet.[77]

We note that SDG&E did provide information about its current internet-based services for on-line transactions and the initiatives it is taking in offering such services. SDG&E also recognizes that some customers prefer to utilize internet-based and social media services, while other customer segments continue to utilize the existing call centers and branch offices.

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[77] UCAN agrees with DRA that the funding of social media and messaging should not be funded unless SDG&E can show "that customer adoption of social media will enhance its customer service and reduce its customer outreach costs…." (Ex. 555 at 44-45.)

UCAN raises some valid points regarding the increasing use of the internet to obtain information or to transact business. However, UCAN's concerns must be also be balanced with the type of services that SDG&E offers, that is, the provisioning of natural gas and electricity to its customers. If either of these services are not received by SDG&E's customers, or if a hazardous condition exists, it is more likely that customers will call SDG&E's call center first to make SDG&E aware of the problem, rather than to use the internet to log a complaint. Thus, call centers will continue to remain an integral part of a utility's operations. In addition, certain customers may prefer to pay their bill over the internet, while others may choose to send in their payment or pay their bill at a convenient location. That being said, the internet can provide a depositary of information to SDG&E's customers, as well as integrating certain transactions over the internet and providing information over the internet using "chat" operators or other technology. However, SDG&E still needs to provide continuing customer contact information through traditional methods to other customer segments.

Since UCAN has not specified where the 10% reductions should be made, and the reasons for making the reductions,[78] we decline to adopt UCAN's proposal to reduce customer contact O&M costs by 10%.

SDG&E is directed to provide in its next GRC filing a description of all of its internet-related and social media functions that are available to its customers or that it is planning, the reasons for providing those functions and their cost effectiveness, and how the call centers have been or will be integrated or utilized

[78] This is in contrast to UCAN's other proposals to make specific adjustments to SDG&E's revenue requirement request in this proceeding.

to provide those functions. The Commission will examine in SDG&E's next GRC application whether SDG&E should be doing more in these areas, or if it has achieved an appropriate balance in providing its customers with a variety of tools and information.

Based on the evidence presented and as discussed above, it is reasonable to adopt $11.784 million as the non-shared call center O&M cost, and $627,000 as the shared services call center O&M cost.

12.2.2.4. SDG&E Branch Offices and Authorized Payment Location

12.2.2.4.1. Introduction

SDG&E requests test year 2012 O&M costs of $1.900 million for activities associated with branch offices and authorized payment locations. SDG&E operates five dedicated branch office locations, two shared branch office facilities, and about 51 authorized payment locations.

Disability Rights Advocates originally raised the issue of SDG&E's compliance of its branch offices and authorized payment locations with the American with Disabilities Act. That issue is addressed by the settlement with Cfor AT.

12.2.2.4.2. Position of the Parties

12.2.2.4.2.1. DRA

DRA recommends that the expenses for branch offices and authorized payment locations remain at the 2009 recorded expense level of $1.793 million. DRA contends that in-person payment transactions have been declining significantly, and therefore SDG&E's three-year average should not be used. DRA believes that keeping the expense level at the 2009 recorded level will account for the decline in in-person payments, and allow for minor maintenance and costs related to the American with Disabilities Act.

12.2.2.4.2.2. UCAN

UCAN recommends a funding level of $1.752 million for the branch offices and authorized payment locations, which is based on a two-year average of 2009-2010. UCAN contends that SDG&E's "spending on branch offices has been declining over the six years from 2005-2010," and that the 2010 spending of $1.711 million "was even lower than 2009 spending" of $1.793 million. (Ex. 558 at 79.)

12.2.2.4.2.3. SDG&E

SDG&E closed and consolidated branch offices in 2005 and 2006. However, SDG&E is not planning to close additional branch offices at this time. With the closing of those branch offices in 2005 and 2006, SDG&E contends it is appropriate to use its 3-year average methodology of 2007-2009. SDG&E also contends that this 3-year methodology reflects the decline in authorized payment locations in 2007-2009, and the increase in the number of authorized payment locations in 2011.

12.2.2.4.3. Discussion

Based on our review of the evidence and the arguments of the parties, we believe that SDG&E's methodology and forecast of the O&M expenses for SDG&E's branch offices and authorized payment locations should be adopted. The methodologies that DRA and UCAN propose be used do not reflect the additional authorized payment locations that were added in 2011. SDG&E had 49 authorized payment locations in 2009, and this expanded to 76 locations in 2011. The 3-year average methodology of SDG&E reflects the decline of in-person payments, while at the same time accommodates the costs of the additional authorized payment locations that were added in 2011. Adopting the methodology of DRA or UCAN is likely to underestimate the O&M costs. Accordingly, SDG&E's methodology and forecast of the O&M expenses for SDG&E's branch offices and authorized payment locations are reasonable, and its forecast of $1.900 million should be adopted.

12.2.2.5. SDG&E Customer Satisfaction

12.2.2.5.1. Introduction

UCAN contends that SDG&E has experienced an increasing number of customer complaints, even though SDG&E has continued to spend monies on customer service field and customer contact activities during 2005 to 2009. In the 2008 GRC of SDG&E, UCAN pointed out that the customer service complaints had increased from 55 in 1999 to 88 complaints in 2005 and 126 complaints in 2006. In 2007, 2008, and 2009 these complaints were 100, 188, and 161, respectively. UCAN points out that there is a similar trend for field service complaints, with 12 complaints in 1999 to a high of 91 complaints in 2009. UCAN also points to the number of informal complaints that were filed with the Commission's Consumer Affairs Branch against SDG&E. In 2007 and 2008, there were over 200 informal complaints each year, and in 2009 the number rose to 310 complaints. UCAN also points to SDG&E's customer comment tracking system to support the trend in the number of complaints. Despite these trends, UCAN contends that SDG&E has not undertaken any analysis to explain the increase in the number of customer complaints.

Although SDG&E continues to spend monies on its interactive voice response system to handle some of the call center transactions, UCAN contends that SDG&E is unable to produce data regarding customer satisfaction with the interactive voice response system versus calls that are answered by customer service representatives. UCAN contends that SDG&E should be required to maintain data to measure the quality of the interactive voice response experience, as well as tracking the time to complete a customer service representative call and an interactive voice response call. UCAN suggests that some customers might prefer to use an internet-based customer contact service instead of, or in addition to, the interactive voice response system and the call center, and that the increased deployment of such internet services may reverse these trends.

UCAN also contends that SDG&E failed to provide UCAN with data regarding SDG&E's Service Guarantee, which pays a customer between $15 to $50 if SDG&E misses a scheduled appointment. UCAN proposes that SDG&E be penalized for the failure to provide "any statistics on payouts or number of customers who availed themselves of the program," by ordering SDG&E to "split the costs of the program with shareholders until the next GRC… at which time, if it provides details of these costs, the program might, once again, be fully funded by ratepayers." (Ex. 555 at 66.)

12.2.2.5.2. Position of SDG&E

SDG&E points out that its customer comment tracking system maintains a log of every customer complaint, and that each complaint is assigned to an appropriate supervisor for disposition and follow-up with the customer. In addition, the calls answered by SDG&E's customer service representatives are randomly selected for quality assurance review. Each customer service representative has about 30 to 40 calls reviewed each year by the quality assurance analyst, and an additional set of calls is reviewed by the supervisor of the customer service representative.

SDG&E further contends that the total level of customer complaints is small. SDG&E cites as an example that in the highest complaint year of 2010, there were a total of 1292 complaints (including complaints about the smart meters), which is less than 1% of the residential customer base. In a customer satisfaction survey conducted of randomly selected SDG&E customers who interacted with SDG&E's customer service representatives, those customers rated high levels of satisfaction in 2009 and 2010, as compared to 2005-2008. SDG&E also contends that customer satisfaction with customer service field workers remained high as well, and was steady from 2005-2010. SDG&E contends that these results are also supported by the 2009-2010 JD Power Associates rankings, and the study of SDG&E's interactive voice response system.

Regarding SDG&E's alleged failure to provide Service Guarantee data to UCAN, SDG&E contends that UCAN is misrepresenting the facts because it provided a data response with an Excel file to UCAN that contained a "complete history of SDG&E service guarantee pay-outs." (Ex. 140 at 67.) SDG&E's response and the Excel file were even attached to UCAN's own testimony in Exhibit 555 at 117-118. The data that SDG&E provided to UCAN shows that missed appointments have declined since the Service Guarantee program was launched in July 1999, and that missed appointments were at their lowest in 2009 and 2010.

12.2.2.5.3. Discussion

We are not persuaded by UCAN's arguments that customer satisfaction with SDG&E's workers in the field or at the call centers is on the decline, and that SDG&E is not taking these types of complaints seriously. First of all, as pointed out by SDG&E, SDG&E maintains a tracking system of complaints from its customers. Whether these complaints involve workers in the field or on the telephone, these complaints are followed up by the appropriate supervisors. SDG&E also conducts quality assurance monitoring of calls answered by the customer service representatives, and conducts surveys of customers whose premises were visited by a customer service field worker. Second, the customer satisfaction surveys and report continue to give high marks to SDG&E and to customers' interactions with SDG&E's voice response system. And third, when the number of customer complaints is measured against the volume of calls that SDG&E receives, and the volume of service orders that its workers complete, these complaints account for only a very small percentage of calls and service orders.

UCAN recommends that SDG&E be required to track customer satisfaction with the interactive voice response system, and to keep data of the time it takes to complete interactive voice response calls and calls answered by a customer service representative. Since the report on the interactive voice response system was completed in 2010, and because SDG&E maintains data on the time is takes to complete telephone calls to the call center, we do not impose any additional data record keeping requirements on SDG&E.

We also find that there is no merit in UCAN's allegation that SDG&E failed to provide data to UCAN regarding the Service Guarantee program, or that the cost of such a program should be shared with SDG&E's shareholders for such failure. UCAN's own testimony includes the Service Guarantee data that SDG&E supplied to UCAN.

12.2.2.6. SDG&E Capital Expenditures

12.2.2.6.1. Introduction

SDG&E's test year 2012 request for capital expenditures includes seven capital projects related to customer service field and customer contact activities. These seven capital projects are for the following:

Description $ (000)	2010 Estimate	2011 Estimate	Test Year 2012 Estimate
Helpdesk Support	$0	$0	$1,551
SORT Upgrade	$0	$1,304	$2,985
HAN DRCA Implementation	$0	$1,856	$3,126
HAN Infrastructure	$0	$1,770	$1,990
HAN Systems Integration	$0	$1,356	$2,463
HAN Laboratory	$0	$0	$700
DERMS	$0	$0	$5,085
Total	$0	$6,286	$17,900

The capital project involving Helpdesk Support is for an on-line tool to enable customer service representatives to provide assistance to customers who are using SDG&E's My Account and other internet services. This Helpdesk Support project will allow customer service representatives to see a customer's online screen or actions and allow the representative to provide the customer with "co-browsing" help. The estimated completion date for this project is mid-2013, with capital expenses in 2012 of $1.551 million, and total project expenses of $2.143 million.

The SORT Upgrade is to upgrade SDG&E's Service Order Routing Technology (SORT) software so that it is compatible with SDG&E's move to a Windows 7 operating system platform. The SORT software is used by SDG&E to schedule, route, and dispatch the service orders it receives on a daily basis. These service orders include emergency response to gas leaks or other hazardous conditions, electric outages, high bill investigations, requests for appliance inspections and adjustments, service activation, and account closures. The SORT software currently runs using the Windows XP operating system. Support for the XP operating system ends in April 2014, and the SORT vendor will no longer support the current SORT version which uses the XP operating system. The estimated capital expenses for the SORT Upgrade is $4.289 million through 2012, and total project expenses of $5.489 million.

The HAN DRCA Implementation capital project is to implement HAN demand response control application (DRCA), which is the software that controls and allows the HAN to operate and to support the management of two way communication with HAN devices within the home. The estimated capital expenses for the HAN DRCA are $4.982 million through 2012, and total project expenses of $14.150 million.

The HAN Infrastructure capital project is to implement the hardware infrastructure that is needed to support the DRCA application. The estimated capital expenses for the HAN Infrastructure are $3.760 million through 2012, and total project expenses of $5.148 million.

The HAN Systems Integration capital project defines the business processes and use situations which will be implemented by the information technology system integration and legacy teams. The estimated capital expenses for the HAN Systems Integration are $3.820 million through 2012, and total project expenses of $6.639 million.

The HAN Laboratory capital project is for a facility to test the compatibility of HAN devices with SDG&E's smart meter system. The estimated capital expense for the HAN laboratory is $700,000 in 2012.

The DERMS capital project is for the distributed energy resource management system (DERMS) software. This software allows SDG&E to optimize energy resources in response to system operational events, environmental, and equipment conditions. The estimated capital expenses for this project are $5.085 million.

12.2.2.6.2. Position of the Parties

12.2.2.6.2.1. DRA

DRA recommends disallowing all capital projects related to customer service field and customer contact activities except for the Helpdesk Support project.

DRA recommends disallowing the SORT upgrade for two reasons. First, since SDG&E was planning to upgrade to Windows 7 in 2008, DRA believes that the earlier SORT upgrade should have implemented an upgrade compatible with Windows 7 instead of the XP operating system. DRA's second reason is SDG&E did not present any evidence to show that the current SORT application is incompatible with Windows 7 or that technical support cannot be obtained elsewhere. Unless SDG&E can demonstrate that the SORT software will not work with Windows 7, DRA contends that that no funding should be allowed.

DRA objects to the funding of the four HAN-related projects for several reasons. First, DRA contends that SDG&E's request is premature because the underlying technology and interactive appliances are still being developed, time of use or dynamic pricing is not in widespread use, that benefits are speculative, and the Smart Grid Deployment Plan in A.11-06-006 has not been evaluated.

Second, DRA does not believe the HAN-related projects will provide tangible benefits. Without dynamic pricing in effect, which DRA recommends be on a voluntary basis, DRA does not expect HAN projects to be cost effective. DRA also contends that the benefits of HAN are unlikely to outweigh the additional cost at this time. As SDG&E implements its Smart Grid deployment plan, it should demonstrate that the benefits of the HAN infrastructure will exceed the costs of deploying it before the Commission approves the funding for such projects.

DRA's third reason for disallowing the HAN-related projects is because of the developing competitive market for HAN products and services, and that ratepayers will have the choice of whether or not to purchase these technologies.

12.2.2.6.2.2. UCAN

UCAN objects to the Helpdesk Support project because UCAN believes that this project will only be available to those customers who have a "My Account" profile with SDG&E. UCAN contends that these types of functions should be available to all SDG&E customers.

UCAN also recommends that the HAN Laboratory capital project be disallowed because SDG&E has not justified the need for it, and that it is an inefficient use of ratepayer funds. UCAN also suggests that the cost of such a facility could be shared with the other electric utilities.

12.2.2.6.2.3. SDG&E

SDG&E contends that Helpdesk Support is not limited to My Account users. SDG&E contends that the co-browsing tool in the Helpdesk Support allows those who are on-line with SDG&E's website or on SDG&E's My Account to request assistance from a customer service representative to help with website navigation or transaction issues.

On DRA's recommended disallowance of the SORT upgrade project, SDG&E contends that the project is needed because Microsoft will discontinue supporting the XP operating system in 2014, which will require SDG&E to move to a Windows 7 operating system before that time. In addition, the SORT vendor "will not support the current version of the SORT application on the Windows 7 Operating System, making an upgrade necessary so that ultimate compatibility with Windows 7 is maintained in 2014." (Ex. 140 at 71.) If the current SORT application is run on an XP operating system after Microsoft ends support, this could expose SDG&E to security issues such as unauthorized access, as well as the risk of declining reliability and performance which could impact the safety of employees and customers.

On DRA's recommended disallowances for HAN-related projects, SDG&E contends that DRA's recommended disallowances are contrary to the Commission's policy and direction as set forth in the decision on SDG&E's advanced metering infrastructure in D.07-04-043 and the Commission's decision in D.11-07-056, which among other things, ordered SDG&E and the other electric utilities to file an AL to develop HAN implementation plans.

Regarding the HAN laboratory, SDG&E contends that it is needed in order to test HAN devices and system compatibility with SDG&E's systems. Since many of the systems that SDG&E uses are proprietary, sharing the costs of the laboratory with the other electric utilities would not be practical.

On DRA's proposed disallowance of the DERMS project, SDG&E contends that DRA did not explain why this project should be disallowed. SDG&E contends that the DERMS software is a mathematical modeling tool that is needed to balance system supplies and demand as more distributed energy resources become available.

12.2.2.6.3. Discussion

The first capital project that we address is the Helpdesk Support project. Contrary to UCAN's contention, this project is not limited to customers who have an SDG&E My Account profile. The co-browsing function will allow SDG&E's customer service representatives to assist all users who access the SDG&E website, as well as its customers who are using the information available in their My Account profile. SDG&E's funding request for the Helpdesk Support project is reasonable and should be adopted.

The next capital project that we address is the SORT upgrade. The current version of the SORT software runs on the XP operating system. The XP operating system is over 10 years old, and Microsoft's Windows 7 operating system is now in use. The Windows 8 operating system just became available. SORT is an integral component of SDG&E's customer service field and customer contact activities as it allows SDG&E to schedule, route, and dispatch all of the service orders it receives on a daily basis. The customer service representatives use it to enter service orders from customers, and the workers in the field are dispatched using this system to fulfill the order. Since the current SORT software uses the XP operating system, it will not work on the Windows 7 operating system, and the current SORT software will not be supported by the SORT vendor. In order to keep up with technological change, SDG&E is switching its operating system platform to Windows 7. If the SORT Upgrade is not funded, SDG&E will be using an outdated scheduling and dispatch software application that will no longer be supported by the vendor. Although DRA suggests that other consultants could be used to maintain the SORT software and the XP operating system, we do not believe these are viable or cost effective solutions. Based on our review of the capital expenditure funding request for the SORT upgrade, it appears that the funding request for 2012 is excessive. Accordingly, it is reasonable to authorize $1.304 million in 2011, and $2.485 million in 2012.

The next capital project that we address is the DERMS capital project, for which SDG&E requests $5.085 million in 2012. Although DRA recommends that this project be disallowed, it did not provide a reason for its disallowance. According to SDG&E, the DERMS capital project will optimize the utilization of energy resources in response to events and conditions that might occur. To achieve this, the DERMS software "incorporates advanced optimization algorithms to dispatch demand and supply side resources." (Ex. 138 at 59.) Based on our review, SDG&E's funding request for this project is too high, given the work that needs to be done. Under the circumstances, it is reasonable to authorize capital expenditure funding of $4.550 million in 2012 for this project.

We now turn to the funding request for the HAN-related capital projects. DRA recommends that all of the HAN-related capital projects be disallowed because it believes such projects are premature because the technology is still being developed, that no smart appliances are on the market, that time of use or dynamic pricing is not widespread, that the benefits of HAN-related investments are speculative, and that SDG&E's Smart Grid Deployment Plan has not yet been evaluated by the Commission. UCAN recommends disallowing funding of the HAN laboratory.

DRA's objections to the HAN-related capital projects raise important overarching issues about whether the Commission should take a wait and see approach on how the HAN market and standards develop, and whether SDG&E is putting the cart before the horse with its HAN-related infrastructure investments.

We first note that DRA's objections to the HAN-related capital projects overlook what the Commission has already embarked upon concerning the deployment of SDG&E's advanced metering infrastructure that was approved in D.07-04-043, and the history behind the development of SDG&E's Smart Grid Deployment Plan as set forth in D.11-07-056.

In D.07-04-043, the Commission adopted the settlement regarding the deployment of an advanced metering infrastructure for SDG&E. In the summary of D.07-04-043, the Commission described the purpose of SDG&E's advanced metering infrastructure as follows:

> This decision is part of our effort to transform California's investor-owned utility distribution network into an intelligent, integrated network enabled by modern information and control system technologies …From 2008 through 2010, SDG&E will install approximately 1.4 million new, AMI-enabled, solid state electric meters and 900,000 AMI enabled gas modules that can, among other things, measure energy usage on a time-differentiated basis. The deployment will improve customer service by providing customer premise endpoint information, assist in gas leak and electric systems outage detection, transform the meter reading process and provide real near-term usage information to customers. AMI will also support such technological advances as in-house messaging displays and smart thermostat controls."
> (D.07-04-043 at 2.)

In the settlement agreement adopted by D.07-04-043, the project costs for SDG&E's AMI was increased to a total of $572 million to accommodate the additional cost of adding HAN functionalities to SDG&E's AMI. These additional functions include a HAN "communication system, based on an open standard capability for residential and [commercial and industrial] customers, which should be compatible with the HAN choice of other major California utilities." (D.07-04-043, App. A at 3.) The Commission also stated that these additional functionalities will promote the "vision…that all customers, over time, will have more access to information, increasingly be able to interact with the utility to better customize services, and have greater ability to work with their own selected suppliers and technologies to manage their environments." (D.07-04-043 at 82.)

In D.11-07-056, the Commission adopted rules to protect the privacy and security of data generated by smart meters. In that decision, the Commission ordered SDG&E and the other electric utilities to submit their respective Smart Meter HAN implementation plans through a Tier 3 AL. Ordering Paragraph 11 of D.11-07-056 states in pertinent part:

> Each implementation plan should include an estimated rollout implementation strategy, including a timetable, for making HAN functionality and benefits generally accessible to customers in a manner similar across all three companies. The implementation plans shall include an initial phase with a rollout of up to 5,000 HAN 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 standard issues. The implementation strategy for HAN activation should discuss key issues, such as costs, expanded data access and data granularity, current and evolving national standards & security risk mitigation and best practices, responsibilities for secure HAN connection, outcomes from working on HAN device interoperability, security testing and certification methodologies developed in collaboration with interested third parties…, customer needs and preferences, a strategy for learning from the initial rollout, and provisions for accommodating customers' efforts to utilize HAN functionality independent of the utility. The full rollout shall require smart meters to transmit energy usage data to the home so that can be received by an HAN device of the consumer's choice." (D.11-07-056 at 166-167.)

It is clear from D.07-04-043 and D.11-07-056 that the Commission wants the advanced metering infrastructure of SDG&E to provide its customers with HAN functions, and that an initial phase for early adopters is envisioned even though technology and standard issues may not yet be settled. DRA takes a more cautious approach and does not believe any of the HAN-related projects should be funded until the standards are finalized, smart appliances are being developed or marketed, and demonstrable benefits can be shown. DRA warns that to do otherwise, monies may be spent on projects that may require significant modification later on.

In balancing the policy and direction that the Commission set forth in D.07-04-043 and D.11-07-056, with DRA's cautionary approach, we believe that some funding of the HAN-related projects is appropriate at this time. In order to have interoperability between SDG&E's smart meters and the available HAN devices, and to roll out an initial phase for early adopters of HAN devices, it is reasonable to fund the HAN DRCA, HAN Infrastructure, and HAN Systems Integration projects at 75% for its 2011 funding request, and at 50% of SDG&E's proposed funding for test year 2012. We believe that funding at these levels will provide SDG&E with the necessary funds to obtain the hardware and software it needs, and the expertise to integrate these investments with the capabilities of its advanced metering infrastructure. If funding for these capital projects was disallowed, as DRA recommends, there would be no hardware and software to allow the HAN devices to interact with SDG&E's smart meters. This would be contrary to what the Commission envisioned in D.11-07-056 about having HAN functionalities available to early adopters of such technology.

We do not adopt SDG&E's request for test year 2012 funding of its HAN laboratory. Until more HAN devices are developed and available for testing, funding of a laboratory dedicated to such activities is premature.

Based on the above discussion, it is reasonable to adopt the following capital expenditures for SDG&E's customer service field and customer contact activities: $5.041 million in 2011; and $12.376 million in 2012.

12.2.2.7. CCUE Staffing Issue

12.2.2.7.1. Introduction

The CCUE raised an issue about the size of SDG&E's customer service field workforce.[79] CCUE questions whether SDG&E has a sufficient number of electric and gas workers available to respond to, and to restore service, in the event of a major event such as an earthquake or a widespread outage. CCUE contends that this issue about staffing plays an important role in the reliability of the electric and gas distribution system. According to CCUE, with more staffing, the electric and gas distribution system can be better maintained and preventative measures can be taken that reduces the number of outages that can occur. These maintenance and preventative measures will also affect the number of repairs that need to be made following a major event, and the higher staffing levels will affect how many workers can respond to a major event, and how fast repairs can be made. CCUE also points out that the reliability of the system is a function of the level of capital investment.

According to information provided by SDG&E to CCUE, SDG&E has 352 workers who can respond to restore electrical power after an outage. Since 53 of the 352 are in pre-apprentice or apprentice positions, CCUE contends that SDG&E has only about 300 electrical workers who are fully trained and available

[79] CCUE also raised issues about the safety and reliability of SDG&E's electricity and gas operations, and that certain O&M and capital expenditures should not be reduced as suggested by DRA and UCAN. CCUE recommends that the Commission adopt a reliability incentive or a performance incentive mechanism to incent SDG&E to address safety and reliability issues, and to provide for sufficient staffing. That issue is discussed separately, and CCUE's concerns about the reductions proposed by other parties are addressed in the respective O&M or capital expenditures sections of this decision.

to work to restore electrical power after an outage. CCUE suggests that this low level of staff may have contributed to how long it took SDG&E to restore power after the system-wide blackout that occurred on September 8, 2011.

According to information supplied to CCUE by SDG&E, SDG&E has about 521 workers who can work in the field to check and restore gas service after a major earthquake.

CCUE contends that the number of available workers to respond to a major event is shrinking in proportion to the number of SDG&E customers. In addition, due to the aging of the workforce, SDG&E faces an increasing number of potential retirements, and too small of a pool of new trainees to replace SDG&E's aging workforce.

12.2.2.7.2. Position of SDG&E

SDG&E recognizes that with the deployment of its advanced metering infrastructure, that it will have fewer customer service field workers who can respond in the event of a major event that disrupts utility service. However, SDG&E contends it cannot increase its customer service field workforce to anticipate and respond to a major outage event because this "high level of staffing for a low frequency event (low probability but high impact) would generate excess workforce capacity under normal or average year conditions." (Ex. 140 at 96.) SDG&E also points out that it has mutual assistance agreements in place to request help from other utilities in the event of a large-scale natural disaster.

12.2.2.7.3. Discussion

The issue that CCUE raises about having a sufficient workforce on hand to respond to a major event relates to what the optimal size of SDG&E's workforce should be. To have the workforce sized optimally involves a balancing of the number of workers needed to handle average or day-to-day activities, and the number of workers needed to respond to a major event. If SDG&E hires more workers than it needs to handle the average amount of work, the additional workers may be idle for a large percentage of time. This will result in the underutilization of the workforce, and in unnecessary and additional costs.

We also note, as SDG&E has pointed out, that it has mutual assistance agreements with other utilities, which can provide skilled workers to assist SDG&E if there is a major event which requires additional resources to restore gas or electric service.

Having enough workers on hand to safely and reliably operate a utility's gas facilities and operations is an issue identified in Pub. Util. Code § 961. That code section requires a gas utility to develop a plan for the safe and reliable operation of its gas operations. This plan and subsequent updates, which are to be approved by the Commission, are to include information about ensuring that the utility has "an adequately sized, qualified, and properly trained gas corporation workforce to carry out the plan." (Pub. Util. Code § 961(d)(10).) In addition, subdivision (d)(6) and (d)(8) of that code section require a timely response to reports of gas "leaks and other hazardous conditions and emergency events, including disconnection, reconnection, and pilot-lighting procedures," and for the gas utility to prepare for, "or minimize damage from, and respond to, earthquakes and other major events," respectively.

SDG&E filed its draft Natural Gas System Operator Safety Plan on June 29, 2012 in R.11-02-019. Comments on the safety plans were filed on September 7, 2012. Since R.11-02-019 is addressing the workforce issues identified in Pub. Util. Code § 961, we refrain from deciding in this proceeding what the adequate size of SDG&E's gas workforce should be.

For the reasons noted above, we do not adopt the suggestion of CCUE to require SDG&E to have a specified number of employees on its workforce to respond to and to restore service in the event of a major event.

12.2.3. SoCalGas Field, Call Center and Branch Offices

12.2.3.1. Introduction

SoCalGas is requesting test year 2012 total shared and non-shared O&M estimated expenses of $230.306 million for customer service field and customer contact operations. This is an increase of $18.334 million over the 2009 base year adjusted recorded expenses. According to SoCalGas, its O&M test year 2012 forecast is consistent with the decision regarding SoCalGas' AMI program (D.10-04-027) because the test year 2012 forecast and D.10-04-027 assume continuation of meter reading related activities through 2017 as more smart meters are installed.

SoCalGas' request for these test year 2012 O&M expenses includes the operational benefits from SoCalGas' OpEx project. According to SoCalGas, the OpEx benefits or cost reductions total about $7 million per year. This is attributable to $5.6 million in reductions in the call centers because of increased self-service transactions, and $1.4 million in customer service field productivity gains. Another $990,000 reduction in O&M is expected from increased efficiencies in the customer service field cost centers from improvements in forecasting and scheduling and operating automation.

DRA and TURN recommend that a number of customer service field and customer contact costs be disallowed or reduced. UWUA recommends that steps be taken to reduce the time it takes in the field to complete a service order, and to reduce the time it takes to answer a call at the call centers. UWUA also recommends that the Commission require specific safety training of all of

SoCalGas' employees, and that existing procedures for addressing safety incidents and hazards be improved.

In the sections below, we address the issues that were raised in the customer services field, customer contact, branch office, meter reading, and capital expenditures areas. Following that, we discuss the issues raised by UWUA.

12.2.3.2. Customer Services Field

12.2.3.2.1. Introduction

SoCalGas is requesting $134.5 million for customer services field O&M expenses. This represents a $9.9 million increase over the 2009 adjusted recorded level of $124.6 million.

DRA and TURN have recommended that adjustments be made to SoCalGas' forecast of the test year 2012 O&M expenses for customer services field activities.

12.2.3.2.2. Position of the Parties

12.2.3.2.2.1. DRA

DRA recommends that SoCalGas' request be reduced by $3.148 million. DRA's recommended disallowances are based on SoCalGas' proposed increases in average drive time, industrial service technician activities concerning air quality, and associated supervision.

SoCalGas has proposed an annual 1% increase in average drive time per customer service field order, resulting in an increase of $1.245 million in test year 2012 expenses. DRA contends that the increase in drive time is not warranted because traffic congestion is less due to the current state of the economy and high unemployment.

12.2.3.2.2.2. TURN

TURN contends that SoCalGas over forecasted its customer service field activities, and that SoCalGas' forecasts for 2010, and 2006-2008, were higher than the recorded expenses for those years. TURN recommends that the test year 2012 forecast of customer service field activities be reduced. Instead of using SoCalGas' five-year average methodology, TURN proposes to use the 2010 recorded expenses as the basis for its test year 2012 forecast, without any adjustment for escalation or customer growth. TURN's proposal would result in a reduction to SoCalGas' O&M expenses for customer service field activities by $8.993 million. TURN contends its methodology results in an amount higher than what was recorded in 2009, and is consistent with SoCalGas' spending in recent years.

TURN also recommends that the 2010 recorded expenses be used to forecast the dispatch, supervision, and support functions associated with the customer service field activities. TURN contends that SoCalGas' use of the five-year average methodology results in a 2010 forecast for these costs which is about $1 million higher than the 2010 recorded costs.

12.2.3.2.2.3. SoCalGas

SoCalGas contends that DRA's proposed disallowance is arbitrary because DRA did not provide a specific analysis to justify its proposed disallowance. Although DRA relies on economic conditions to justify its recommended disallowance, SoCalGas contends that traffic congestion in its service territory has increased, and that the average drive time of its customer service field personnel has increased in excess of the 1% assumed annual increase.

Regarding TURN's forecast of customer service field activities, SoCalGas contends that TURN selectively used 2010 recorded costs to estimate the test year

2012 forecast. SoCalGas contends that the 2010 data is not representative of the average expected activity levels from the previous years, and was one of the lowest activity years on record. SoCalGas also contends that TURN did not include any factor for customer growth, and that TURN used an entirely different methodology for SDG&E. SoCalGas contends that its forecast of customer service field costs should be adopted because it is based on the five-year average methodology, it includes incremental customer service field activities from forecasted meter growth, and includes the new requirements regarding carbon monoxide detectors and SCAQMD requirements. SoCalGas contends that its test year 2012 forecast of customer service field activities represents the average year for all customer service field order types. In addition, SoCalGas contends that the five year average of 2005-2009 is very similar to the 10 year average (2001-2010) for total orders per meter as shown in Table 9 in Exhibit 145.

Regarding the industrial service activities, SoCalGas proposes to increase funding of incremental industrial service technicians by $1.753 million in test year 2012 due to anticipated increases in industrial service orders as a result of changes to the SCAQMD emission rules. DRA opposes the incremental increase to industrial service activities because it believes SoCalGas is subsidizing large customer air quality compliance costs by performing equipment inspections and tune-ups for large customers.

SoCalGas contends that it provides the same kind of gas equipment inspection and tune up services for its residential and small business customers. SoCalGas contends it has performed these services for all customers as a long established service, and to exclude industrial customers from receiving these types of services would be inequitable.

SoCalGas contends that TURN's suggestion to reduce wages ignores the fact that its wages for represented customer service field personnel are established through a collective bargaining agreement, and therefore cannot be unilaterally reduced. SoCalGas also contends that the 2011 industrial service technician orders in SCAQMD's service territory are almost twice the level of the 2010 orders. SoCalGas also contends that TURN's reliance on the 2010 data is not representative of the average year.

12.2.3.2.3. Discussion

We first address the methodologies used by SoCalGas and TURN to estimate the test year 2012 O&M expenses for customer service field activities, and for customer service field dispatch, supervision and support functions. TURN's methodology for these two functions is limited to one year of recorded data for 2010. We do not adopt TURN's methodology. This one year of data is not representative of the historical data for customer service field activities, and for the dispatch, supervision and support functions associated with customer service field activities. In addition, the 2010 recorded data does not reflect the recent requirements to install carbon monoxide detectors, or the changes to the SCAQMD's emission rules.

In contrast, SoCalGas' test year 2012 forecast of its customer service field activities, and the associated dispatch, supervision, and support functions, is based on a five-year average. However, in analyzing that data, as TURN points out, SoCalGas' forecast is too high relative to the historical spending which took place from 2005-2010. We have taken that into consideration in determining what the O&M costs should be.

Next, we address DRA's recommendation to reduce SoCalGas' costs by $1.245 million due to SoCalGas' proposal to increase drive time by 1%. We agree with DRA's recommendation that SoCalGas' proposal to increase customer service field drive time by 1% should be eliminated. SoCalGas' witness acknowledges that "traffic congestion, was 9.7% in 2010, up 11% from 2009, but still 27% off the 2007 peak." (Ex. 145 at 13.) The table at that page supports that statement, and shows that in four areas of SoCalGas' service territory, the traffic congestion in 2008 through 2010 was still lower than the traffic congestion in 2006 and 2007. DRA also points out that the high unemployment rate and lower customer growth suggests that fewer vehicle trips are occurring. For those reasons, we adopt DRA's recommendation to eliminate SoCalGas' proposal to increase the customer service field drive time by 1%, which results in a reduction of $1.245 million to SoCalGas' forecasts of the O&M costs.

We now turn to DRA's recommendation to disallow SoCalGas' incremental funding of industrial service technicians by $1.753 million. SoCalGas proposes to increase the funding because of anticipated increases in industrial service orders resulting from changes to the emission rules of the SCAQMD. DRA's disallowance is based on its argument that SoCalGas should not be subsidizing its large commercial customers' air quality compliance costs by performing equipment inspections and tune ups for these customers. We do not adopt DRA's recommended disallowance.[80] The equipment inspections and tune up activities are part of the services that SoCalGas offers to all of its customers to ensure that customers' gas appliances and equipment are in

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80 DRA recommends disallowing 1.5 FTEs for a customer service field manager due to its recommended disallowance of the incremental funding for industrial service technicians. Since we do not adopt DRA's recommendation on the industrial service technicians, DRA's recommendation to reduce the manager position is not adopted.

working order and operating safely. SoCalGas has also demonstrated that the SCAQMD emission rules have led to more industrial service orders, which justifies the incremental funding of the industrial service technicians.

TURN recommends that the proposed increase in the number of industrial service technicians be funded with cost reductions in other areas of customer service field activities, including a reduction in wages. Since the wages of SoCalGas' represented employees are set in collective bargaining agreements, TURN's recommendation to reduce the wages of SoCalGas' employees is not adopted.

Based on the evidence presented, the adjustment for drive time as noted above, and the comparison to historical costs, we find SoCalGas's test year 2012 forecast in the amount of $129.500 million for O&M expenses for customer service field, and customer service field dispatch, supervision and support functions, to be reasonable.

12.2.3.3. SoCalGas Call Center

12.2.3.3.1. Introduction

SoCalGas is requesting $46.424 million for its call center expenses, which it refers to as its customer contact center. According to SoCalGas, the benefits from OpEx led to a reduction of $5.628 million in test year 2012 for customer contact center estimated expenses. As a result, there is a net increase of $99,000 for customer contact center expenses over 2009 levels.

12.2.3.3.2. Position of the Parties

12.2.3.3.2.1. DRA

DRA recommends that SoCalGas' request for customer contact center expenses be reduced by $801,000. DRA's proposed reduction of $801,000 would disallow $106,000 for an OpEx analyst, and $695,000 for OpEx software/hardware license and maintenance fees. DRA contends that SoCalGas did not provide an explanation of why these expenses are needed.

12.2.3.3.2.2. TURN

TURN agrees with DRA's recommended disallowances, but recommends further reductions due to TURN's lower forecast of expected calls, the disparity between how much SoCalGas pays its customer service representatives as compared to what SDG&E pays its customer service representatives, and because of SoCalGas' telecommunication bill. TURN's total recommended reduction amounts to $4.952 million.

TURN contends that SoCalGas' forecast, which used the five-year average, assumes an increase in calls per meter and average call time, which is premised on SoCalGas' customer growth figures. TURN's forecast is based on 7.5 million expected calls at a unit labor cost of $4.33 per call and non-labor costs equal to 1.04% of labor costs. TURN's forecast of expected calls is about 500,000 fewer calls than what SoCalGas forecasted (7.995 million calls).

TURN also proposes a further reduction of 2% in SoCalGas' labor costs because of SDG&E's lower labor costs. TURN contends that this is not a proposal to change the wages of SoCalGas' customer service representatives. Instead, this proposed reduction is to recognize that there should be slower growth in the wages of SoCalGas' customer service representatives as compared to the growth of wages for other SoCalGas employees.

TURN also recommends a reduction of $104,000 in SoCalGas' telecommunications bill. This reduction is based primarily on the estimate of the number of phone calls that will be made, and to TURN's lower forecast of the abandoned call rate.

12.2.3.3.2.3. SoCalGas

SoCalGas contends that the two items that DRA seeks to disallow are part of the continuing costs of OpEx. In order to achieve the benefits of OpEx, which DRA accepts, these ongoing expenses for OpEx are needed. SoCalGas contends that adopting DRA's recommendations without understanding the impact on the OpEx benefits does not make sense, and that this is an example of DRA's bias in proposing reductions without considering the impact.

SoCalGas contends that TURN's recommendations are flawed for four reasons. First, SoCalGas points out that the customer service representatives at SoCalGas are union members whose wages are set by the collective bargaining agreement, and therefore cannot be reduced. Second, SoCalGas contends that TURN's use of 2009-2010 call volumes and the assumption of 1.35 calls per meter for its volume forecast are flawed because the recorded 2010 calls already include substantial OpEx benefits in the form of reductions in customer service representative answered calls, which TURN accepts. Third, SoCalGas points out that TURN's witness used a completely different methodology to estimate SDG&E's customer service representative answered call volume, as compared to the methodology that TURN used for SoCalGas. And fourth, SoCalGas did not use substandard call center performance in 2009-2010 as TURN suggests.

12.2.3.3.3. Discussion

We first address DRA's recommendation to reduce the customer contact O&M expenses by $801,000. DRA's recommended disallowances are based on SoCalGas' perceived failure to explain what the OpEx analyst would be doing, and why the annual maintenance fees for hardware and software are needed. However, the information about the need for an OpEx analyst, and for the annual maintenance fees was set forth in SoCalGas' revised direct testimony. In addition, SoCalGas responded to a DRA data request, in which SoCalGas explained the benefits of the three software applications which are part of the annual maintenance fees that were requested by SoCalGas. The need for the annual maintenance fees was also set forth in SoCalGas' rebuttal testimony. SoCalGas also points out that in order to reap the benefits of the OpEx program, which DRA acknowledges, these additional expenses are warranted. For all of those reasons, DRA's recommendation (and TURN's concurrence with DRA's recommendation) to disallow the customer contact O&M costs by $801,000 is not adopted.

Next, we address the different methodologies that TURN and SoCalGas used to derive their forecasts of the cost to handle the call center calls. TURN's method used the adjusted cost per call in 2009, whereas SoCalGas used the five-year averaging methodology, which relies on the 2005-2009 data. Both TURN and SoCalGas disregard the 2010 recorded data, although TURN points out that SoCalGas' 2010 forecast is higher than the 2010 recorded call center costs by about $2.5 million.[81] TURN also contends that it did not use the same methodology for SDGE because SoCalGas experienced more problems with the handling of call center calls in 2009 and 2010 than SDG&E.

We reject TURN's methodology and adopt SoCalGas' methodology for developing the forecast of the call center costs. TURN acknowledges that there

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[81] We are not persuaded that we should always check to see whether the forecasts for a particular year match the recorded costs for that year. This is especially difficult to do in a GRC, where the forecasts need to be developed ahead of time with the data that the utility has on hand at the time the forecasts are being prepared. However, the parties may include in their testimony, as parties have done in this GRC, a comparison between what the utility forecasted and the recorded costs for those forecasted years.

were fluctuations in the 2009 and 2010 data for SoCalGas. The 2009 data is also the lowest call volume since 2002. If we adopt the TURN methodology, we would essentially be limited to one year of recorded costs during a period of fluctuating costs and call center calls. By adopting SoCalGas' methodology, we believe this better reflects the call center costs over a period of time.

We also reject TURN's proposal for a 2% reduction due to the disparity between what SoCalGas and SDG&E pay their respective customer service representatives. As SoCalGas points out, the higher wage that it pays to its customer service representatives is due to the collective bargaining agreement with these employees.

Next, we address TURN's recommended reduction for SoCalGas' telecommunications bill. Since we adopt the SoCalGas methodology for the forecast of the call center costs and number of calls, the telecommunications bill that SoCalGas forecasted will remain unchanged. Accordingly, TURN's recommendation to reduce the telecommunications bill, based on TURN's lower forecast of the number of calls, is not adopted. However, there is the issue of whether the telecommunications bill should be adjusted due to the estimate of the number of abandoned calls. SoCalGas estimated a 4.2% abandoned call rate, while TURN originally estimated a 3.3% abandoned call rate. SoCalGas then pointed out in its rebuttal testimony a time period discrepancy in TURN's abandoned call rate, which SoCalGas states should result in a rate of 3.6% instead of the 3.3%. Having reviewed the evidence, we adopt an abandoned call rate of

3.6% instead of SoCalGas' abandoned call rate of 4.2%. This will lower SoCalGas' call center support expenses by about $10,850.[82]

Based on the evidence presented, we find SoCalGas' test year 2012 forecast of the O&M expenses for customer contact to be reasonable, as adjusted in the manner described above. The adjusted O&M funding amount is $46.413 million.

12.2.3.4. SoCalGas Branch Offices and Authorized Payment Locations

12.2.3.4.1. Introduction

SoCalGas requests test year 2012 estimated non-shared expenses of $11.135 million for activities associated with branch offices and authorized payment locations.

TURN originally recommended a funding level of $10.4 million, while DRA recommends that the expenses be maintained at the 2009 recorded expense of $10.137 million. UWUA recommends increasing the funding level to a total of $13.635 million as a result of its recommendation to add personnel at the branch offices.

12.2.3.4.2. Position of the Parties

12.2.3.4.2.1. DRA

DRA recommends that the expenses for branch offices be reduced because SoCalGas is planning to file an application to reduce the number of branch offices. DRA recommends using the 2009 recorded expense level because of the decline of in-person payments. DRA believes the 2009 amount is appropriate because it will allow SoCalGas to comply with the requirements of the Fair and

[82] The modeling of the RO model should reflect the 3.6% abandoned call rate.

Accurate Credit Transactions Act (FACTA), as well as reflecting further declines of in-person payments.[83]

12.2.3.4.2.2. TURN

TURN agrees with DRA's forecast, and provides additional support as to why it believes SoCalGas overestimated its costs. TURN contends that SoCalGas' forecast of labor costs and the incremental cost of implementing FACTA were higher than the recorded expenses. In addition, implementation of FACTA at authorized payment locations has been postponed indefinitely. Based on this information, TURN recommends a test year 2012 forecast of $10.619 million.[84] TURN's recommended forecast assumes that all offices remain open, and if branch offices are closed or hours are curtailed, the forecast should be reduced to 2009 levels or even lower.

12.2.3.4.2.3. SoCalGas

SoCalGas acknowledges that its plans to file an application to propose closing selected branch offices. However, until the Commission authorizes such a closure, all of the branch offices remain operational and continue to incur ongoing expenses. SoCalGas also points to the additional authorized payment locations that have been added, and that the numbers of transactions at these authorized payment locations have increased. SoCalGas contends that the effect of DRA's recommendation is it will prevent SoCalGas from increasing expenses

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83 FACTA requires the Applicants to verify the identities of its customers to prevent identity theft.

84 TURN originally recommended a test year 2012 forecast of $10.4 million. TURN then revised its forecast upwards to $10.619 million by dropping its challenge to the implementation of FACTA procedures at the authorized payment locations.

for the six additional security guards it added in 2010, and for complying with FACTA.

SoCalGas contends that it decided not to implement FACTA screening at authorized payment locations due to customer privacy concerns. However, SoCalGas is proceeding with alternative solutions to satisfy FACTA customer verification requirements, and the incremental expenses for FACTA implementation at the authorized payment locations are being redirected to these alternative solutions.

12.2.3.4.3. Discussion

DRA's recommendation to use the 2009 recorded level of costs for SoCalGas' test year 2012 forecast of the expenses for branch offices and authorized payment locations is not adopted. Although SoCalGas is contemplating filing an application for authority to close some of its branch offices, such an application has not been filed. Thus, SoCalGas will continue to incur expenses for all of its branch offices during the test year. In addition, DRA's use of the 2009 data does not account for the six security guards that were added in 2010 or the FACTA implementation activities. Accordingly, the use of the 2009 data, as suggested by DRA, would not reflect the continuing operation of all the branch offices, the six security guards, and the FACTA implementation costs.

We believe that TURN's recommendation to use the adjusted 2010 recorded data is a better indicator of the test year 2012 costs since it includes the six security guards and the FACTA implementation costs. SoCalGas acknowledges that in-person payments at branch offices are declining, while transactions at authorized payment locations are increasing. Also, the number of security guards that have been hired has not been as much as originally forecasted, and other costs have been less than recorded. Although SoCalGas' methodology is based on the five-year average, we do not believe it represents the recent trend in the decline of in-person payments at the branch locations, and that actual costs have been lower than anticipated costs. TURN's methodology reflects some of the increase in the number of authorized payment locations, as well as the continuing operation of the branch offices. Based on those reasons, and under the circumstances described in this discussion, we adopt as reasonable TURN's recommended forecast of $10.619 million for the branch offices and authorized payment locations.

As for Utility Workers Union of America's recommendation to add more staffing at the branch offices, that is discussed in the section addressing the UWUA concerns.

12.2.3.5. SoCalGas Meter Reading

12.2.3.5.1. Introduction

SoCalGas' test year 2012 forecast of non-shared meter reading expenses is $32.917 million, which is an increase of $1.260 million over the adjusted recorded 2009 expense of $31.657 million.

12.2.3.5.2. Position of the Parties

12.2.3.5.2.1. DRA

DRA proposes to reduce SoCalGas' test year 2012 request for meter reading by $1.076 million through disallowance of $440,000 in the area of supervisor, training and programs, and $636,000 for meter route analysts and advisors.

DRA's proposed disallowances are based on the argument that SoCalGas received funding for these positions in its last GRC, and that savings would accrue to ratepayers once SoCalGas' advanced metering infrastructure is deployed. Since SoCalGas chose not to fill these positions, DRA contends that SoCalGas will receive a double recovery for the positions it has not filled.

12.2.3.5.2.1. SoCalGas

SoCalGas contends that if DRA's proposed disallowances are adopted, SoCalGas' revenue requirement will be reduced twice for the same meter reading benefits. First, it will be reduced in the Advanced Metering Infrastructure Balancing Account because of the meter reading benefits that were assumed in D.10-04-027. Second, by disallowing the positions for test year 2012, SoCalGas will receive a reduced revenue requirement in 2012.

12.2.3.5.2.2. Discussion

We agree with SoCalGas' position on the test year 2012 forecasts of the meter reading costs, and that DRA's recommended disallowances should not be adopted. As SoCalGas' witness explained in Exhibit 143, the test year 2012 forecast of metering reading expenses do not include the SoCalGas advanced metering infrastructures costs or benefits. D.10-04-027 includes the meter reading benefits which reflect the increases requested and authorized in SoCalGas' test year 2008 GRC. "To remain consistent with the benefits approved and authorized in…D.10-04-027," SoCalGas included the expenses authorized in SoCalGas' 2008 GRC in the test year 2012 forecast. (Ex. 143 at 45.) As explained by SoCalGas:

> To ensure that neither SCG nor ratepayers are disadvantaged from the TY 2012 authorization for estimated operational expenses, SCG will reconcile the final TY 2012 GRC authorization with the SCG AMI operating benefits assumed in D.10-04-027. SCG will then adjust the SCG AMI operating benefits multiplier factor accordingly in an updated SCG AMI revenue requirements AL to reflect the outcome of the TY 2012 GRC. (Ex. 143 at 46.)

If we adopt the two disallowances recommended by DRA, this will result in a double reduction to SoCalGas' revenue requirement. Since the DRA disallowances are part of the operating benefits in SoCalGas' advanced metering infrastructure program, the adjustment process described above will ensure that ratepayers are not disadvantaged by having these costs included in the test year 2012 forecast. Accordingly, DRA's recommendation to disallow the $440,000 for additional management personnel, and $636,000 for meter reading staff, is not adopted.

Based on all of the evidence, we find SoCalGas' forecast of meter reading expenses in the amount of $32.917 million to be reasonable.

12.2.3.6. SoCalGas Capital Expenditures

12.2.3.6.1. Introduction

SoCalGas is requesting recovery for six capital expenditure projects, and for meter replacements. The estimated capital expenditures for SoCalGas' customer service field and customer contact activities for test year 2012 are forecasted at $20.506 million, which includes planned and routine meter replacements of $9.777 million. SoCalGas also requests funding for capital expenditures in the amount of $12.424 million for 2010, and $11.968 million for 2011.

The first capital project is for additional mobile data terminals that are installed in the customer service field vehicles. These mobile data terminals are computer devices that are used by the field technicians and supervisors for receiving, recording, and completing service orders. According to SoCalGas, these new mobile data terminals are needed due to the additional personnel to handle the expected growth of the industrial service orders which are due in part because of the new SCAQMD emission rules. The project cost for these mobile data terminals cover the 2010-2012 timeframe.

The second capital project is for customer service field operating efficiency. This project is for a software application that generates reports, and tracks and stores all services provided to industrial customers. This software will create the various service order types associated with industrial service technician orders, and interface with SoCalGas' customer information system (CIS), and service order scheduling and routing system (PACER) applications to provide the order status. This capital project was completed and put into service in the first quarter of 2010.

The third capital project is a forecasting and scheduling project that provides enhancements to the PACER applications. The enhancements will redesign the routing process to improve the management of the order completion deferment schedule, and the workforce scheduling. These enhancements are intended to reduce overtime, and to gain efficiencies by automating the order completion deferment schedule. This capital project was expected to be put into service by December 2011.

The fourth capital project is for the call recording replacement project, which provides a software upgrade to the current version of the customer contact center call recording system. This recording system records all customer calls for quality assurance and follow up. The current version of the call recording system is no longer supported by the vendor. This capital project was put into service in September 2010.

The fifth capital project is to purchase a new meter reading handheld system, which is to replace the current meter reading handheld computers. The vendor no longer supports the current handheld computers, and the current devices have reached the end of their useful life. The project involves the purchasing of about 1000 handheld devices and related hardware and set up. The other component of the project is to integrate the new system software with the CIS. The software integration began in 2011, and is expected to be completed in 2012. The acquisition and deployment of the handheld devices is expected to be completed by December 2012.

The sixth capital project is labeled as the "PACER Refresh," which is to replace the 1,600 mobile data terminals and related equipment that are currently be used by field personnel. The current mobile data terminals are over five years old and are reaching the end of their useful life. The limited memory and processing capabilities of the current mobile data terminals limit the ability to add new applications such as global positioning, and to interface with the upgraded operating system and upgraded PACER application software. This capital project is expected to be put into service beginning in 2012, and fully deployed in all operating bases in the fourth quarter of 2013.

SoCalGas' planned capital expenditures also include the purchase of meters to be used for planned or routine replacement of meters. SoCalGas estimates $9.777 million per year for 2010, 2011, and test year 2012.

12.2.3.6.2. Position of the Parties

12.2.3.6.2.1. DRA

DRA supports capital projects that increase SoCalGas' operating efficiency, and to replace equipment whose continued use would create problems. However, DRA objects to projects that upgrade functional technology, and to projects that will not produce tangible benefits to ratepayers. DRA believes that three of the capital expenditure projects fall into this category: the costs associated with the additional mobile data terminals that are used in the field;

the meter reading handheld system replacement; and the mobile data terminal refresh.

The first capital project that DRA objects to is to the additional customer service field mobile data terminals that SoCalGas is requesting. DRA's objection to this project is tied to its argument that SoCalGas should not be hiring new employees to provide air quality-related services to large commercial and industrial customers. DRA contends that these large customers of SoCalGas should pay for their own costs to bring their gas-fired equipment into compliance with the air quality regulations.

The second capital project that DRA objects to is the funding of new meter reading handheld devices. DRA contends that SoCalGas failed to describe why the current handheld computers are inadequate, and did not explain why the new handheld devices are needed and how they will produce tangible ratepayer benefits. DRA contends that as long as the current handheld computers allow field personnel to complete their work and service quality can be maintained, no replacements of the current handheld devices are needed.

The third capital project that DRA objects to is for the funding of the PACER mobile data terminal refresh. DRA contends that SoCalGas has presented no evidence that the continued use of the current mobile data terminals would impair operations. In addition, DRA contends that SoCalGas has not justified the benefits of adding the Windows operating system and new applications, nor has SoCalGas explained how adding the global positioning application would reduce drive times. DRA contends that in an era of massive budget cuts at all levels of government, it would be irresponsible to allow utilities to invest in projects that are not mission critical.

12.2.3.6.2.2. SoCalGas

DRA's recommended disallowance of the additional mobile data terminals is related to its argument that SoCalGas should not be providing air quality-related services to its large customers. SoCalGas contends that the services it provides to its large customers are no different from the services provided before the new SCAQMD emission rules were adopted, and are no different from services provided to other customers. As a result of these new emission rules, SoCalGas has received more requests for these industrial customer services.

SoCalGas points out that only $137,000 of the $915,000 requested for the mobile data terminals is for additional technicians related to the growth in service orders as a result of the SCAQMD emission rules. If the $137,000 is not approved, SoCalGas contends that the remaining $778,000 should be allowed because DRA did not object to the test year 2012 forecast of the customer service field order volumes.

DRA's second recommendation is to disallow the funding for new meter reading handheld system and devices. SoCalGas contends that the current meter reading handheld devices were originally purchased and installed in 1996. These devices now have a median age of 15 years and are past their depreciable book life. In addition, the vendor of the current devices is no longer supporting the current devices and replacing them with similar models is no longer possible. Also, the current devices are failing or requiring repair at a rate of 350 to 400 per year. Since SoCalGas has about 1000 meter readers, the failure rate of the devices is significant, and impacts its operations.

The third proposed disallowance of DRA is for the PACER refresh project, which involves replacement of the existing mobile data terminals that are in the customer service field vehicles. SoCalGas contends that the replacement of the mobile data terminals is needed because of SoCalGas' conversion to the Microsoft Windows 7 operating system. According to SoCalGas, Microsoft will no longer provide support or upgrades to the Windows XP operating system that SoCalGas is currently using. The mobile data terminals do not have the capacity to run Windows 7, and will need to be upgraded to work with SoCalGas' PACER system which runs on Windows 7. In addition, SoCalGas contends that the mobile data terminals have exceeded their three year warranty and their depreciation life of five years, and show an increasing need for repair. In order to take advantage of the evolving technology to serve its customers, as well as for operational and security purposes, the replacement of the mobile data terminals are needed.

12.2.3.6.3. Discussion

The first recommended disallowance that we address is for the additional mobile data terminals. SoCalGas points out that these additional mobile data terminals are needed for two reasons. First, there is projected increase in industrial service orders due to the SCAQMD emission rules, which will require additional positions. Second, the additional mobile data terminals are needed because of the higher service order volume forecast. As discussed earlier, we did not adopt DRA's proposed disallowance for customer service field O&M expenses related to the growth in industrial service orders as a result of the SCAQMD emission rules. DRA's argument as to why the additional mobile data terminals are not needed is unconvincing. The growth in service orders as a result of the SCAQMD emission rules will result in additional personnel, who will need the mobile data terminals so they can perform their job responsibilities. In addition, the growth in service order volume will also require additional personnel, who will also need mobile data terminals. Thus, DRA's proposed disallowance of $915,000 for this capital expenditure project is not adopted, although we will make reductions for the reasons set forth at the end of this discussion.

Next, we address DRA's proposed disallowance of $6.917 million for the replacement of the current meter reading handheld system. SoCalGas has demonstrated that the current handheld devices are past their useful life and are failing at a high rate. If the current meter reading handheld devices are not replaced with new handheld devices, it is likely that the older handheld devices will disrupt SoCalGas' operations by taking more time to complete the meter reading and providing that data to SoCalGas' billing system. For those reasons, we do not adopt DRA's proposed disallowance for the replacement of the current meter reading handheld system, but we will make an overall reduction for the reasons which follow.

The third disallowance proposed by DRA is in the amount of $3.908 million to replace the current mobile data terminals with new computer terminals. DRA justifies its proposed disallowance because the current mobile data terminals continue to operate, and that money should not be spent on equipment that still functions. If adopted, DRA's proposed disallowance would result in older computer terminals being used in field vehicles to respond to the dispatch of service orders. With SoCalGas' planned changeover to the Windows 7 operating system, and to the upgraded PACER system running on Windows 7, these existing mobile data terminals will not be able to interface with the updated systems and new software applications. The likely result is that it will take longer to dispatch SoCalGas' field personnel, and for these personnel to complete the service orders. Having updated mobile data terminals in the service vehicles out in the field is important to allow field personnel to respond quickly to unsafe situations and to complete their service orders in a timely manner. For all of those reasons, DRA's proposed disallowance of this entire project is not adopted.

We are concerned, however, that the purchase of mobile data terminals for fulfilling the increase in industrial service orders, may overlap or be duplicative of the replacement of the existing mobile data terminals with new mobile data terminals that can run on Windows 7. It also appears that SoCalGas can take steps to reduce the overall number of terminals that are needed for both projects.

On a similar note, the replacement of all of the current meter reading handheld devices with new devices may not be needed since SoCalGas will be replacing its analog meters with digital meters in the near future. This reduces the need to acquire a full complement of new handheld meter reading devices, as the need for these new devices will decline as more digital meters are installed.

Based on the evidence presented, and the concerns that we have expressed about these projects, it is reasonable to adopt the following capital expenditure amounts: $12.224 million for 2010; $10.968 million for 2011; and $19.506 million for 2012.

12.2.3.7. UWUA Recommendations

12.2.3.7.1. Introduction

The Utility Workers Union of America (UWUA) has made several recommendations in this proceeding concerning SoCalGas' customer service field and customer contact activities.[85] Among the UWUA recommendations is

[85] Local 132 of the UWUA represents about 3800 members who work at SoCalGas, and most of those UWUA members are also customers of SoCalGas.

to improve customer service and safety at SoCalGas by restoring the levels and standards for safety related services that were previously in place at SoCalGas.[86] UWUA contends that its members have experienced declining service at SoCalGas over the years. UWUA recommends that specific improvements be made to customer service in the field, and to customer service at the call centers and payment offices.

For improvements in the field, UWUA recommends the following: (1) 100% timely response to the most serious customer leak reports, which are classified by SoCalGas as A1, and involve the smell of gas or the sound of escaping gas inside a building or a confined area;[87] (2) two day order completion for non-leak service orders involving gas turn-ons, opening and closing accounts including meter reads and safety checks, high bill investigations, appliance malfunctions, and other transactions where SoCalGas is the sole or primary provider of the service;[88] and (3) improving after meter services for residential customers, including expanding the SoCalGas program to eliminate brass appliance connectors.

For the improvements to customer services at SoCalGas' call center and branch offices, UWUA recommends the following: (1) that 90% of incoming calls to the call centers be answered within one minute after cut-over from the interactive voice response telephone system; (2) that the customer service

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[86] The issues that UWUA raises concerning improving the safety culture at SoCalGas is discussed later in this decision.

[87] An A2 leak is an outdoor gas odor, and is responded to by SoCalGas within four hours.

[88] These types of non-leak orders are categorized by SoCalGas as B, C, and D orders, and have a lower priority than A orders that involve a gas leak and gas odor.

representatives be allowed a longer time to process customer calls in order to resolve issues and place service orders; and (3) restore the ability of customer service field offices to schedule customer service orders and to resolve billing and other disputes. UWUA's level of service recommendation of 90% is based on its contention that SoCalGas' interactive voice response system can take several minutes to navigate before the call is directed to the call queue that is answered by a customer service representative.

UWUA contends that the primary obstacle to improving service quality and safety is due to a chronic shortage of employees in key positions that involve customer service and safety. To meet the UWUA recommended improvements and standards, UWUA recommends that there be a staffing increase, which UWUA estimates will cost $27.350 million.[89] Although UWUA is not recommending that the Commission order SoCalGas to hire more workers at this time, UWUA does recommend that the Commission authorize additional revenues so that SoCalGas can meet the UWUA recommended service standards. In addition, UWUA recommends that SoCalGas be directed to work with its employees to meet the UWUA standards, including consideration of the staffing increases. UWUA also recommends that a working relationship be established among Commission staff, UWUA representatives, and SoCalGas management to monitor progress on meeting the standards, including expenditures of additional funds that may be authorized.

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[89] UWUA's proposals involve increasing the staffing for the following: various positions in the field that service residential customers; the customer service representative positions at the call centers; and customer contact representatives at the branch offices.

12.2.3.7.2. SoCalGas Position

SoCalGas acknowledges the efforts of the UWUA in providing its insight and perspective on providing safe and a high level of reliable service. However, SoCalGas points out that to achieve higher customer service levels, these needs to be balanced with the incremental cost of doing so. The following is a summary of SoCalGas' description of what UWUA recommends and what SoCalGas is currently doing in that area.

UWUA recommends a 100% response to an A1 leak call. An A1 leak call is when a customer calls the SoCalGas call center and states that gas is smelled inside a building.[90] According to SoCalGas, an A1 leak call is given the highest priority by SoCalGas, and is responded to immediately by an energy technician residential (ETR). During SoCalGas' regular business hours of Mondays through Saturdays 7 am to 5 pm, SoCalGas has an established goal of responding to an A1 leak call within 30 minutes of the customer request. During non-business hours, SoCalGas has an established goal of responding to such a leak within 45 minutes. According to SoCalGas, the percentage of A1 leak orders that did not meet the 30 minutes or 45 minutes response times in 2009 and 2010 were 4.8% and 8.3%.[91] As a result of the San Bruno gas pipeline explosion and fire in September 2010, the number of A1 leak calls has increased. Despite the increase

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[90] If the customer reports that the smell of gas is outside, that leak order is classified as A2, and the response time is a bit longer. For a leak on a gas distribution line, SoCalGas classifies the leak by Code 1, 2, and 3. A Code 1 leak is responded to immediately as well.

[91] SoCalGas also presented data on the percentage of calls that were not responded to within the 30 and 45 minute standard immediately after the San Bruno explosion. The percentage of calls that were not responded to within the standard rose to about 10.4% in October and November 2010, and to 11.28% for December 2010.

in the number of A1 leak calls, the average response time to an A1 leak call in 2010 was 22 minutes, which is only a two minute increase over the 2009 average response time of 20 minutes.

SoCalGas states that it "is committed to a continuous effort to improve safety performance by building a safety oriented culture." (Ex. 145 at 66.) SoCalGas contends, however, that it is virtually impossible to achieve a 100% response to A1 leak calls because of geographic, logistical, and random circumstances. Even if the staffing for ETRs are increased, there will still be situations where it will take the closest ETR some time to arrive at the customer's location. SoCalGas also states that even with the increase in A1 leak calls, its response time was well within its goal, and it knows of "no incident nor of any evidence that the increase in average A1 response time of approximately 2 minutes (between 2010 and 2009) led to a customer safety incident that was not addressed in a safe and timely manner." (Ex. 145 at 67.)

UWUA recommends that SoCalGas achieve an average two-day order completion schedule for all customer orders, and that at least 120 ETRs be hired as part of that recommendation. SoCalGas contends that although the UWUA witnesses estimated that 120 new employees will be needed to meet a two-day order completion schedule, those witnesses do not have a formal background in forecasting of workforce requirements. In order to meet a two-day order completion schedule, SoCalGas estimates it will need 539 additional ETRs with an incremental annual expense of $40.7 million, and $4.3 million in additional supervision costs. SoCalGas contends its GRC requests funding for staffing that will allow it to complete non-leak orders in a timely manner that is consistent with its 2009 order completion schedules.

UWUA recommends that when a qualified SoCalGas employee is at a customer's premise, that the employee check all gas appliances for brass and copper connectors, and to replace the connectors at a cost. UWUA also recommends that for customers enrolled in the California Alternate Rates for Energy (CARE) program, the connector change be performed without the $62 charge. SoCalGas contends that its policy already requires personnel to inspect the appliance connector to ensure that the connector is acceptable. If the employee discovers an unacceptable two-piece or copper connector on an appliance, the policy requires an inspection of all gas connectors at the premises. The policy also requires the employee to notify the supervisor for follow-up action when an unacceptable two-piece or copper connector is encountered in a tract or multiple dwelling and similar connectors are thought to exist in other units. SoCalGas also contends that UWUA's recommendation would require its employees to look for unsatisfactory connectors and not just unacceptable two-piece or copper connectors, which could lead to unnecessary and costly inspections.

For SoCalGas' call center, UWUA recommends that the level of service be increased so that 90% of inbound call center calls are answered within 60 seconds, and that customer service representatives be allowed an average of 270 seconds to answer a call. In this GRC, SoCalGas is targeting a level of service of 76% of total calls being answered within 60 seconds, and that the average call handling time take 231 seconds. According to SoCalGas, to achieve a 90% level of service would be unprecedented, and even under performance based regulation, the highest level of service achieved was 83.2% in 2007. SoCalGas also contends that the level of customer satisfaction is not negatively impacted when the level of service is between 70% to 83%.

Regarding the recommendation for average handling time, SoCalGas contends that increasing the average handling time means that the customer service representatives at the call center will be less efficient, and it will take them another 40 seconds to complete a customer call. SoCalGas contends that there is no evidence to suggest that the mix of customer calls has changed to justify a longer average handling time. SoCalGas also estimates that to achieve at 90% level of service will require 88 additional customer service representatives, nine lead customer service representatives, and six supervisors, at an approximate cost of $6.6 million. In addition, SoCalGas contends that raising the level of service to 90% for answering calls will not improve the response time to A1 leak calls since those calls are automatically moved to the front of the call center telephone queue. SoCalGas already targets that 90% of emergency calls be answered within 20 seconds.

UWUA recommends that for each of the 47 SoCalGas branch offices, that there be at least one customer contact representative for each office so that other transactions can take place. SoCalGas contends that since about 97% of all branch office transactions involve payment transactions, there is no need to staff all the branch offices with a higher pay job classification to handle one to three percent of the transactions. SoCalGas also points out that branch office transactions are declining, which no one has disputed. SoCalGas further contends that if a customer has an emergency gas issue, that the customer will call SoCalGas, instead of going to a branch office to report it.

12.2.3.7.3. Discussion

As a preface to our discussion of UWUA's recommendations, UWUA has cited to Pub. Util. Code § 961 as authority for the Commission to adopt and implement UWUA's recommendations. Subdivision (b) of that code section requires a gas utility to "develop a plan for the safe and reliable operation of its commission-regulated gas pipeline facility," and that the Commission is to review and accept, modify, or reject the plan by December 31, 2012. To the extent SoCalGas has addressed gas safety and reliability issues in its plan submitted pursuant to Pub. Util. Code §§ 961 and 963, those issues will be addressed in the Gas Safety Rulemaking.[92]

The first UWUA recommendation that we address is its recommendation that 100% of the A1 leak calls be responded to within the 30 minutes and 45 minutes. We agree with SoCalGas that there are logistical and geographical conditions that may prevent a response to an A1 leak call within that timeframe goal. Even if additional ETRs are added, in a geographic area as large as SoCalGas' service territory, it is virtually impossible to have the ETRs positioned in the right place at the right time in order to respond to an A1 leak call within the 30 minutes or 45 minutes. The benefit of achieving a 100% response within the timeframe would require a huge increase in the number of ETRs throughout its service territory, as well as cost, and a lot of non-productive time waiting to respond to A1 leak calls. To achieve a 100% response within the timeframe for responding to A1 leak calls is outweighed by the cost of such undertaking. Adding additional personnel to meet the 100% response will likely result in a number of extra employees who can fulfill the 100% response, but will also result

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[92] The plan that is submitted to the Commission is required to address, among other things, how the gas utility will respond to "customer and employee reports of leaks and other hazardous conditions and emergency events, including disconnection, reconnection, and pilot-lighting procedures," and how the gas utility will ensure that there is an "adequately sized, qualified, and properly trained" workforce. (Pub. Util. Code § 961(d)(6) and (d)(10).)

in a number of idle personnel when service orders taper off. Accordingly, UWUA's recommendation for a 100% response within 30 minutes and 45 minutes for an A1 leak call is not adopted.

The data that SoCalGas presented regarding the response time to A1 leak calls is of interest, and we will continue to monitor that data. The data that SoCalGas presented regarding the "missed window" and percentage missed right after the San Bruno explosion and fire shows that the percentage of calls that have not been responded to within the timeframe has been rising.[93] For example, for December 2010, 1357 calls out of 12,033 A1 leak calls were not responded to within the 30 minutes and 45 minutes. However, the average response time was still 23.44 minutes. (*See* Ex. 145 at 66.) This "missed window" of response time is a source of concern given the heightened awareness of ensuring the safety of the natural gas delivery infrastructure. Both SoCalGas and SDG&E shall be required to compile the same type of monthly and annual data as shown on pages 65 and 66 of Exhibit 145, and to supply that information in its next GRC filing as well as upon demand by Commission staff. SoCalGas and SDG&E shall also explain in its next GRC filing what efforts it has taken to minimize delays in responding to A1 leak calls.

The second UWUA recommendation to address is its recommendation that there be an average two-day order completion for non-leak customer orders. These customer orders would cover such things as customer turn ons and turn offs, non-payment turn ons and shutoffs, high bill investigations, and meter reading and verification. UWUA contends that completing these types of orders

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[93] One possible reason why the response time went up is because of the increased number of calls that were experienced following the San Bruno explosion and fire.

in a timely manner is important because it can help to detect gas leaks, and results in more accurate closing bills for departing customers. UWUA recommends that additional ETRs be added because the time to respond to customer orders is taking longer.

Both UWUA and SoCalGas recognize that in order to decrease the time it takes to respond to and fulfill a non-leak customer order depends on increasing the number of employees. In order to achieve a two-day order completion, UWUA estimates that 120 more ETRs will be required at an annual cost of $14.1 million. SoCalGas estimates that to meet UWUA's recommendation, 539 additional ETRs will be needed at an annual cost of $40.7 million.

Reducing the time it takes to complete a non-leak order has a direct relationship to the number of employees who can respond to those situations and to the cost of those additional employees. At the same time, we need to consider the impact on ratepayers of having to pay more to have additional employees on hand to reduce the time it takes to complete a customer order. Although UWUA's testimony implies that health and safety problems can arise if non-leak customer orders are not completed in a timely manner, UWUA did not present any evidence that the longer response times to complete these types of orders has created actual problems, or that it will reduce customer safety. In weighing and balancing the issues of safety, the cost of adding additional employees to meet UWUA's recommendation, and the cost impact to ratepayers, we do not adopt UWUA's recommendation that additional funds be authorized to hire additional staff to reduce the time it takes to complete non-leak customer calls.

The third recommendation that we address is UWUA's recommendation to identify and remove dangerous connectors at a customer's premise. The unacceptable connectors include the two piece brass connectors and copper connectors.

UWUA contends that the SoCalGas workers are supposed to focus on the cause of the customer's service request when visiting the customer's premise, which may limit their ability to inspect other appliances for gas-related issues. UWUA also contends that the time allowances for completion of various types of work orders is too limited. SoCalGas already has a policy in place for a trained employee to inspect for acceptable gas connectors when making a call at a customer's premise. In addition, the policy allows the employee to check other appliances on the customer's premise for gas-related issues at the customer's request, and thus the employee is not limited just to inspection of the original service call. Since SoCalGas has a policy in place to inspect for acceptable connectors, and to expand the inspection when unacceptable brass or copper connectors are found or at a customer's request, we do not adopt UWUA's recommendation to check the connectors on every appliance. Regarding the time allowances to complete work orders, that is an issue that should be left to SoCalGas to decide as it is familiar with the time needed to complete various tasks and procedures.

Fourth, we address UWUA's recommendation to have SoCalGas' call center achieve a 90% level of service in answering calls within 60 seconds, and to increase the average handling time of each call to 270 seconds. This is in contrast to SoCalGas' test year 2012 target of 76% of calls being answered within 60 seconds, and an average handle time of 231 seconds.

The data that SoCalGas has in its testimony demonstrates that from 2005 through August 2011, SoCalGas' call center was able to answer a call within 60 seconds for 70% to 83% of the time. The results of the customer satisfaction survey with the handling of the calls during this seven year period remain high. UWUA has not demonstrated that SoCalGas' customers are dissatisfied with the time it takes for a customer service representative to talk to them.

To achieve a 90% level of service to answer all calls within 60 seconds is estimated by SoCalGas to require 103 additional personnel at an approximate cost of $6.6 million per year. UWUA estimates that 120 additional customer service representatives will be needed. In view of the level of service that the call center is able to achieve with the current staffing, and the cost to achieve a 90% level of service, it is not cost effective to have incoming calls answered more readily. We note that calls regarding gas leaks are not affected, since such calls are given top priority and go to the top of the telephone queue to be answered. Accordingly, we do not adopt UWUA's recommendation that incoming call center calls be answered within 60 seconds 90% of the time.

On the average handle time for a call to SoCalGas' call center, we will not require SoCalGas to increase the average handle time. The issue of deciding how much time is required to handle each incoming call is something that should be left to SoCalGas to determine. The time it takes to complete a task, and the ability to follow policies and procedures, are two of the factors used to evaluate an employee's performance. SoCalGas is in the best position to decide how to best staff its call center, and to decide what procedures need to be in place in order to minimize the time required to handle each call in a satisfactory manner.

Accordingly, UWUA's recommendation to increase the average handle time of each call to 270 seconds is not adopted.[94]

The fifth recommendation concerns the staffing of SoCalGas' branch offices. UWUA recommends that each of the 47 branch offices be staffed with a customer contact representative that can provide the same type of service that a call center's customer service representative can handle. That is, instead of a branch office employee handling bill payments only, UWUA recommends they also handle other issues such as payment arrangements and scheduling of work orders.

We do not adopt UWUA's recommendation for three reasons. First, as SoCalGas points out, almost all of the transactions at branch offices involve payment transactions. Second, the numbers of branch transactions are declining. And third, a telephone is available at the branch office to connect to SoCalGas' call center in the event the staff at the branch office cannot assist the customer. To upgrade the positions at the branch offices, when most of the transactions can be handled by the existing branch office staff, does not make sense. Thus, UWUA's recommendation to add additional positions at all of the SoCalGas branch offices is not adopted.

10.3. Customer Service Office Operations

10.3.1. Introduction

As part of the Applicants' customer service, each utility has office operations. The Applicants' office operations have cost centers which provide

[94] UWUA contends that the SoCalGas field workers are not allotted sufficient average times to complete their tasks. Our rationale for not lengthening the average times applies to those field workers as well.

the following kinds of customer service related activities: billing services, office credit and collections, uncollectibles, remittance processing, postage, customer service technology support, and other customer service staff operations. The activities of SoCalGas also include measurement data operations. The O&M expenses and the capital expenditures associated with these activities are discussed in this section.

For SDG&E, the test year 2012 O&M expenses for office operations is forecasted at $22.383 million. For SoCalGas, the test year 2012 O&M expenses for office operations is forecasted at $52.677 million.

For capital expenditures related to customer service office operations, zero expenditures are forecasted for the Applicants in test year 2012. For 2010 and 2011, SDG&E estimates capital expenditures of $1.336 million and $456,000, respectively, and SoCalGas estimates capital expenditures of $1.061 million for 2010.

For SDG&E's forecast of miscellaneous revenues generated by its office operations, SDG&E 's forecasts $611,000 for test year 2012. For SoCalGas, the forecast of miscellaneous revenues for test year 2012 is $1.236 million.[95]

To derive the Applicants' forecasts of their respective O&M costs for office operations, the Applicants in most instances used the five-year average methodology when historical data was available. The Applicants also made adjustments to the averages for various reasons, such as the following: to account for partial year staffing; new safety, regulatory, or other government compliance activities that affect customer service activities; and for certain programs and

[95] The discussion concerning miscellaneous revenues is discussed later in this decision.

initiatives of the Applicants to increase support services in the area of billing, customer information systems, project management, and process improvement. Other things such as customer growth, productivity improvements, and the use of different bill payment channels, may also result in adjustments to the methodology used by the Applicants.

In the subsections below, we first address the office operations of SDG&E, followed by the office operations of SoCalGas.

10.3.2. SDG&E Office Operations

10.3.2.1. Introduction

SDG&E's test year 2012 forecast of O&M non-shared ($17.720 million) and shared services ($4.663 million) total to $22.383 million. This is $3.271 million more than the 2009 adjusted recorded expenses of $19.112 million.

The office operations of SDG&E provide customer service to about 1.4 million electric customers and more than 840,000 gas customers. We first discuss the O&M non-shared services, followed by the O&M shared services.

10.3.2.2. O&M Non-Shared Services

10.3.2.2.1. Introduction

SDG&E's forecast of O&M expense for non-shared services for test year 2012 is $17.720 million. These O&M expenses are to support the following business functions of SDG&E: billing services; office credit and collections; bill delivery; postage; customer service technology support; and other customer service operations. The estimated expenses for these six billing functions for test year 2012 are as follows:

($000 of 2009 Dollars)

Function	**2009 Recorded**	**2012 Estimated**
Billing Services	$4,142	$5,115
Office Credit & Collections	$2,331	$2,776
Bill Delivery	$930	$890
Postage	$5,561	$5,409
Customer Services Technology Support	$1,071	$1,048
Customer Service Operations-Other	$1,623	$2,482
Total	$15,658	$17,720

We discuss each of these six billing functions separately.

10.3.2.2.2. Billing Services

10.3.2.2.2.1. Background

The billing services function covers the cost of calculating customers' bills and maintaining customer account information. This customer billing function at SDG&E consists of the following four organizations: residential and small commercial customers; large commercial and industrial customers; operations support; and contracts and compliance. SDG&E estimates $5.115 million for billing services in test year 2012.

10.3.2.2.2.2. Position of the Parties

10.3.2.2.2.2

DRA recommends that almost all of the billing services costs that are related to smart meters be disallowed. Although the smart meters are supposed to result in cost savings, DRA contends that SDG&E is adding new expenses due to more complex billing exceptions, and to "configure and test the interval data systems that capture Smart Meter data." (Ex. 509 at 4.)

DRA also recommends that an additional $199,500 be disallowed from SDG&E's estimate of billing services. DRA's recommendation would disallow the following: project analyst regarding job training; one position to support the limited re-opening of the direct access proceeding; and compliance advisor.

DRA contends that the project analyst for job training is not needed because this involves management functions and should not require an additional position. Regarding the two positions to support the limited reopening of the direct access proceeding, DRA contends that SDG&E did not justify the need for two additional positions, and recommends that one position be disallowed. DRA contends that the proposed compliance advisor is not needed because that should be part of the existing staff duties with management guidance. DRA does not oppose funding at the 2009 staffing level for one manager, two customer service analysts, and one special investigator.

10.3.2.2.2.2

SDG&E contends that DRA's recommendation to disallow the smart meter-related billing costs is contrary to Commission decisions and policy, and that it ignores "the realities of what is necessary to make the smart meter program work for customers." (Ex. 134 at 3.) SDG&E contends that these smart meter-related billing costs are needed to support the smart meter program and to achieve the smart meter benefits. The additional costs are needed for the systems and support to process the additional customer usage data generated by the smart meters, and to provide the usage data to SDG&E's customers. If DRA's recommendations are adopted, SDG&E contends that it would be denied the "necessary resources to fulfill its billing services obligations, and improperly reduce SDG&E funding for projected benefits without providing the associated funds expressly tied to and needed to achieve such benefits." (Ex. 134 at 10.) According to SDG&E, DRA accepts the benefits from the smart meters but "inconsistently recommends a discontinuation of the resources necessary to

continue the smart meter program and achieve associated benefits."
(Ex. 134 at 7.)

With regard to DRA's recommended disallowance of $199,500, SDG&E contends that the positions for the project analyst for job training and the compliance advisor are needed. The project analyst position develops, maintains, and trains billing staff on new billing procedures. According to SDG&E, the filling of this position has improved the accuracy of customer bills. As for the compliance advisor position, SDG&E contends that this position is needed due to the "growing complexity of rates and rate options, and the growth of specialized segments, such as electric vehicles, which will require additional analysis," and to "assist with analyzing, participating, and implementing changes coming from regulatory proceedings that impact billing."
(Ex. 134 at 11.)

10.3.2.2.2.3. Discussion

SDG&E forecasts $5.115 million for billing services in test year 2012. This is an increase of $1.208 million over the five-year average for billing services of $3.907 million.

DRA makes two recommendations. DRA's first recommendation is to disallow the billing services costs that are related to smart meters. DRA's recommendation is based on its concern that the communications technology for smart meters is still under development, and that the purported savings from the deployment of smart meters is being nullified by SDG&E's request for smart meter-related expenses. The smart meter expenses make up $527,000 of the $1.208 million increase that SDG&E is proposing.

SDG&E argues that DRA's recommendation to disallow the smart meter-related billing costs is contrary to the Commission's decisions and policy regarding smart meters.

In the earlier section on SDG&E's capital projects for customer service field activities, we discussed the development of SDG&E's AMI program. In D.07-04-043, the Commission adopted the settlement regarding the AMI deployment for SDG&E. In that settlement, the parties clearly contemplated that the AMI would result in benefits, while at the same time incurring costs to bring about these benefits.

As part of that adopted settlement, SDG&E, DRA, and UCAN agreed to a risk contingency and sharing proposal for the costs of the AMI program. For costs incurred of up to $622 million, no after-the-fact reasonableness review is required. (*See* D.07-04-043, App. A at 6-7.) DRA has not alleged that these forecasted smart meter-related expenses of $527,000 exceed the $622 million threshold that would require a reasonableness review. To disallow the smart-meter related expenses of $527,000 at this point in time would be premature and contrary to the settlement adopted in D.07-04-043. For those reasons, DRA's recommendation to disallow $527,000 in smart meter-related expenses that are included in the test year 2012 forecast of billing services costs, is not adopted.

DRA's second recommendation is to disallow an additional $199,500 from SDG&E's estimate of billing services for the following job positions: $60,000 for project analyst that develops, maintains, and trains billing staff on new billing procedures; $49,500 for one position to support the limited re-opening of the direct access proceeding; and $90,000 for the compliance advisor to support additional regulatory requirements that impact billing. SDG&E presented testimony regarding all of the job positions, but did not present any responsive testimony to DRA's rebuttal regarding DRA's recommended disallowance for the position supporting the direct access proceeding.

Based on our review of the testimony of SDG&E and DRA, we do not believe that these additional positions are needed given SDG&E's current staffing. Accordingly, DRA's recommendation to disallow $199.500 for these positions is reasonable, and the total funding for billing services in the amount of $4.916 million should be adopted.

10.3.2.2.3. Office Credit & Collections

10.3.2.2.3.1. Background

The office credit and collections function includes the following kinds of activities: skip tracing; bill collection; management of small commercial customer accounts; and bankruptcy processing, analysis, and reporting. These activities help to assess risk exposure and manage bad debt exposure on active and final accounts. SDG&E estimates $2.776 million for office credit and collections for test year 2012.

10.3.2.2.3.2. Position of the Parties

10.3.2.2.3.2

DRA recommends disallowing SDG&E's funding request of $188,000 for additional meter revenue protection investigators. DRA contends that the additional investigators are not needed because there is the equal likelihood that theft investigations will go down, instead of up, with smart meters.

10.3.2.2.3.2

SDG&E contends that since the installation of the smart meters, the number of leads for potential cases of energy theft have risen because of the ability of the smart meters to communicate with SDG&E on a daily basis. In the past, most leads of potential energy theft were reported by meter readers. SDG&E also contends that the two additional investigator positions are consistent with the costs that were contemplated and acknowledged in the Joint Settlement in SDG&E's AMI proceeding that was adopted in D.07-04-043.

10.3.2.2.3.3. Discussion

SDG&E estimates $2.776 million for office credit and collections for test year 2012.

DRA recommends disallowing SDG&E's funding request of $188,000 for two additional meter revenue protection investigators. SDG&E argues that these two additional positions are consistent with the costs that were contemplated and acknowledged in the settlement of SDG&E's advanced metering infrastructure proceeding that was adopted in D.07-04-043.

We have reviewed Exhibit 135, and Exhibit 136 which is the confidential version of SDG&E's workpapers, and have confirmed SDG&E's contention that SDG&E's AMI settlement contemplated the need for two additional meter revenue protection investigators in 2012. Since DRA and SDG&E acknowledged in the AMI settlement that it considered "all positions advanced in all the testimony sponsored in the proceeding by all parties," that suggests DRA was aware that additional investigators would be requested. For those reasons, DRA's recommendation to disallow $188,000 for the two additional investigators is not adopted.

Based on our review of the testimony and arguments regarding office credit and collections, it is reasonable to adopt O&M costs of $2.776 million for office credit and collections.

10.3.2.2.4. Bill Delivery

10.3.2.2.4.1. Background

The bill delivery function includes the costs for paper and envelopes for sending bills to customers. SDG&E estimates $890,000 for test year 2012.

SDG&E's test year 2012 estimate is $40,000 lower than the 2009 recorded costs of $930,000.

10.3.2.2.4.2. Position of the Parties

10.3.2.2.4.2

UCAN recommends that the bill delivery forecast be reduced by $358,000 to reflect the savings from the increasing number of customers who choose the paperless billing option. According to UCAN, as more customers choose paperless billing, SDG&E should see more cost savings. UCAN forecasts a paperless adoption rate of 41.47% in 2012 and uses an adjusted 40.27% to reduce SDG&E's bill delivery costs. SDG&E forecasts a paperless adoption rate in 2012 at 35.15%. UCAN's forecast of the paperless adoption rate "uses the ratio 2010 recorded adoption rates to SDG&E's forecast in 2010 to adjust forecast years 2011 and 2012 accordingly." (Ex. 561 at 12.) UCAN also contends that SDG&E did not account at all for paperless billing in its forecast of 2012 bill delivery costs.

10.3.2.2.4.2

SDG&E contends that its use of the five-year average methodology is reasonable to forecast the bill delivery costs. UCAN's recommendation relies on the 2010 actual paperless adoption rate, and then extrapolates and adjusts that result to derive its forecasts of the paperless adoption rates for 2011 and 2012. SDG&E contends that UCAN's selective updating ignores that some cost drivers may be higher or lower than expected.

SDG&E also contends that UCAN's recommendation to apply the 40.27% reduction to SDG&E's forecast of $890,000 is inappropriate. According to SDG&E, it is inappropriate because UCAN only uses the variable of the paperless adoption rate and fails to take into account the other fixed and variable costs that drive bill delivery costs. In addition, SDG&E contends that UCAN's application of its reduction to SDG&E's forecast is erroneous because SDG&E's forecast of the paperless adoption rate is already embedded in its 2012 bill delivery cost of $890,000.

10.3.2.2.4.3. Discussion

SDG&E estimates $890,000 for test year 2012 for bill delivery costs. UCAN recommends that the bill delivery forecast be reduced by $358,000 to reflect the increasing number of customers who choose the paperless billing option.

The principal difference between the forecast of SDG&E and UCAN's recommended reduction is based on the rate at which SDG&E's customers will adopt paperless billing. UCAN points out that in 2010, 52,849 of SDG&E's customers chose paperless billing, which is an adoption rate of 4.8%. SDG&E's forecast in this application of the 2010 paperless adoption rate was that 21,960 customers would choose paperless billing, or an adoption rate of 2%. Based on the 2010 recorded adoption rate, UCAN then adjusted the forecast of the paperless adoption rate for 2011 and 2012 and derived a cumulative paperless adoption rate of 40.27%, as opposed to SDG&E's cumulative paperless adoption rate of 35.15%.

Although SDG&E objects to UCAN's use of the 2010 recorded paperless adoption rate to justify UCAN's adjustment, we believe that the use of the 2010 data is appropriate under the circumstances because the 2010 data shows that the paperless adoption rate is tapering off. Accordingly, UCAN's forecast of the paperless adoption rate for 2012 should be used to derive the O&M forecast.

That brings us to the next issue as to what the appropriate adjustment should be for the bill delivery costs. UCAN applies the adjusted paperless adoption rate of 40.27% to SDG&E's 2012 test year forecast of $890,000 in bill delivery costs, and derives a forecast of $532,000. SDG&E contends that since its paperless adoption rate of 35.15% is already embedded in its 2012 test year forecast of $890,000, that UCAN should have used the difference of 5.12% (40.27%-35.15%), instead of the 40.27%, to calculate its recommended reduction. We agree with SDG&E that since the billing delivery costs already include the effects of the paperless adoption rate over the last several years, that the correct calculation of the reduction for bill delivery costs should only be $45,568 ($890,000 x 5.12%). Accordingly, although we adopt UCAN's adjusted paperless adoption rate of 40.27%, we do not adopt UCAN's calculation of how UCAN's higher paperless adoption rate will reduce the bill delivery costs. Instead, we adopt the calculation that SDG&E suggests should be used if the Commission agrees with UCAN's position on the paperless adoption rate. That is, SDG&E's 2012 test year forecast of $890,000 in bill delivery costs should be reduced by $45,568 instead of UCAN's recommended reduction of $358,000. That results in an adjusted amount of $844,000, which should be adopted as the O&M costs for bill delivery.

10.3.2.2.5. Postage Expense

10.3.2.2.5.1. Background

SDG&E's forecast of the postage expense function reflects the most recent rate increase of the United States Postal Service. SDG&E estimates postage expense of $5.409 million for test year 2012. This $5.409 million is made up of approximately $4.527 million in postage, and $882,000 in prefunded postage.[96]

[96] The revised test year 2012 forecast of SDG&E for postage expense is $5.409 million. (*See* Ex. 596 at 8.) UCAN's objections to SDG&E's postage forecast were based on SDG&E's original postage forecast of $5.656 million.

10.3.2.2.5.2. Position of the Parties

10.3.2.2.5.2

UCAN recommends that two adjustments be made to SDG&E's estimate of the postage expense. UCAN's first adjustment is to reduce postage costs by $740,821 to reflect the savings from customers that adopt a paperless billing option, while also reflecting meter growth.[97] UCAN contends that SDG&E's

[97] As stated in the preceding footnote, UCAN's reduction of $740,821 is based on SDG&E's original forecast of $5.656 million. Using SDG&E's revised forecast of $5.409 million, the revised prefunded postage of $484,000, and UCAN's methodology, we estimate UCAN's proposed reduction would amount to about $765,840.

growth in postage cost is inconsistent with SDG&E's desire to convert all new customers to paperless billing.

UCAN's second adjustment is to remove $882,000 in prefunded postage from the postage cost estimate.[98] UCAN contends that the prefunding costs should be booked to SDG&E's cash working capital account (FERC #165 – Prepayments), instead of including it in the customer service office operations expenses.

10.3.2.2.5.2

SDG&E disagrees with UCAN's forecast of the paperless adoption rate, and its application to SDG&E's postage costs. SDG&E contends that there are other variables that impact postage expense, and are not limited to just the paperless adoption and customer growth rates. One variable is that there are still 400,000 non-residential bills that cannot use the paperless billing option, and bills need to be generated for these customers. Another variable is that the postage costs include the cost of mailing bills, as well as the cost of mailing other notices to customers.

Regarding UCAN's contention that the prefunded postage of $484,000 should be treated as a prepaid asset and not expensed every year, SDG&E contends that this is inconsistent with SDG&E's practice which dates back to

[98] In response to a UCAN data request and questioning during the evidentiary hearing, SDG&E reduced the prefunded postage from $882,000 to $484,000.

1998. SDG&E expenses funds that are used to replenish the prefund postage account that is required by the United States Post Office.

10.3.2.2.5.3. Discussion

SDG&E's estimate of the postage expense for the 2012 test year is $5.409 million, and if the prefunded postage of $484,000 is excluded, that leaves an amount of $4.925 million.

The first adjustment that UCAN recommends is to reduce SDG&E's forecasted postage costs by about $765,840 to reflect UCAN's higher paperless adoption rate. We have reviewed the testimony and the arguments of SDG&E and UCAN concerning the paperless adoption rate, and the methods used by SDG&E and UCAN to forecast postage costs. As stated in the bill delivery discussion, we adopt UCAN's paperless adoption rate. However, UCAN and SDG&E differ over the method of how to apply the paperless adoption rate to SDG&E's forecast of the postage amount of $4.925 million. We agree with SDG&E that instead of using UCAN's method to come up with a proposed reduction of about $765,840, that the correct method of accounting for the higher paperless adoption rate of UCAN and to arrive at the proper reduction amount, is to use the 5.12% difference between the paperless adoption rates of UCAN and SDG&E. By multiplying the 5.12% difference and the net postage forecast of $4.925 million, that results in a reduction of $252,000.

The second adjustment that UCAN recommends is to remove the prefunded postage amount of $484,000 from SDG&E's postage expense forecast, and to book that amount to SDG&E's cash working capital account. SDG&E contends that it has consistently included prefunded postage as part of its postage expense since 1998. UCAN contends that treating prefunded postage as an expense is inappropriate and violates the FERC Uniform System of Accounts (USOA). As discussed in SoCalGas' postage discussion, although SoCalGas agreed with TURN that its prefunded postage should be booked to a prepaid account, SoCalGas and SDG&E do not agree with UCAN's recommendation to book prefunded postage into a prepaid account rather than to expense it.

We have considered the testimony of SDG&E, UCAN, SoCalGas and TURN on the issue of how prefunded postage should be accounted for by SDG&E. FERC Account #165 for electric utilities states as follows:

> This account shall include amounts representing prepayments of insurance, rents, taxes, interest and miscellaneous items, and shall be kept or supported in such manner as to disclose the amount of each class of prepayment.

It is our view that prefunded postage must be accounted for by SDG&E in its FERC Account #165 instead of being included as part of postage expense. The prefunded postage is required by the United States Post Office in an amount sufficient to cover anticipated postage costs. As such, the prefunding of anticipated postage is money that is paid prior to the period to which it is applied, and therefore a prepayment. Although the prefunded postage amount may vary over time, we agree with UCAN that this prepayment of postage is required under the FERC USOA to be booked to Account #165 instead of as an O&M expense.

Even though SDG&E has consistently included prefunded postage as an O&M expense in the past, SDG&E did not directly respond to UCAN's argument that the FERC USOA requires prepayments to be booked to a cash working capital account such as Account #165. Instead, SDG&E argues that "it is operationally more efficient to expense the replenishment of the prefund postage account instead of creating additional administrative activity to account for the actual postage each month." (Applicants Opening Brief at 251.)

As discussed later, SoCalGas agreed with TURN that it should not have included prefunded postage as an O&M expense in its GRC request, and that the prefunded postage properly belongs in a prepaid account. The same type of accounting treatment should apply to SDG&E. Accordingly, we agree with UCAN that it is reasonable to require SDG&E to remove the prefunded postage amount of $484,000 from the O&M postage expense forecast, and to book the prefunded postage into a cash working capital account.

Based on the above, it is reasonable to adopt O&M costs of $4.673 million for postage.

10.3.2.2.6. Customer Service Technology Support

10.3.2.2.6.1. Background

The customer service technology support function is composed of staff who have "experience in customer service technologies and specialized knowledge of the customer service operating functions and activities." (Ex. 131 at 23.) These employees provide the support for the major customer service information technology applications such as SDG&E's service order routing technology system, and interface with those who work in the information technology system area who develop, and maintain such systems and programs. SDG&E estimates $1.048 million as the O&M costs for test year 2012.

10.3.2.2.6.2. Position of the Parties

UCAN disagrees with how SDG&E developed its forecast of costs for customer service technology support. According to UCAN, SDG&E's forecast was based on the five-year average methodology and adjusted downward by $694,000 for 2010 and then an incremental increase of $354,000 was applied for forecast years 2011 and 2012. UCAN contends that because the costs in this account did not vary by large amounts, with the exception of 2009, that the five-year average should be used with no adjustments. UCAN's recommended forecast of customer service technology support costs is $722,000.

10.3.2.2.6.2

SDG&E disagrees with UCAN's use of a five-year average methodology without any adjustment. SDG&E contends that the adjustments it made to the five-year average are appropriate because it resolves the volatility in spending in 2009 and 2010 that resulted from some lease payments that were made in 2009, and the incremental adjustment is warranted because two additional positions are needed to support the projects and technology described in Exhibit 131.

10.3.2.2.6.3. Discussion

SDG&E estimates $1.048 million in expenses for customer service technology support for test year 2012.

We have reviewed the testimony and arguments of SDG&E and UCAN concerning the forecast of the costs for customer service technology support. SDG&E's 2012 test year forecast of $1.048 million is higher by $328,000 as compared to the five-year average methodology result of $720,000. UCAN disagrees with the $328,000 increase because the costs for this account have not varied except for 2009.

We are not persuaded by SDG&E's reasoning that the $328,000 increase is justified. Accordingly, it is reasonable to adopt O&M costs of $900,000 for test year 2012 for customer service technology support.

10.3.2.2.7. Other Customer Service Operations

10.3.2.2.7.1. Introduction

The other customer service operations are comprised of the Customer Service VP, Planning and Budgets organization, and Market Services. The Customer Service VP was previously a shared organization with SoCalGas, but as a result of the restructuring, this position is now non-shared and resides at SDG&E. The responsibilities of this VP include responsibility for all customer-related activities for SDG&E. The Planning and Budgets organization performs data collection, creates consolidated reports, analyzes monthly results, and provides special project support. The Market Services organization focuses primarily on residential customers, and manages and coordinates a variety of programs and services developed for the residential market, as well as providing data analysis, and working with operational and regulatory groups within SDG&E.

SDG&E estimates $2.482 million for the other customer service operations for test year 2012.

10.3.2.2.7.2. Position of the Parties

10.3.2.2.7.2

UCAN opposes SDG&E's request and believes that the forecast is inflated relative to recorded costs. The largest cost increase for the other customer service activities appears to be related to SDG&E's efforts regarding HAN technologies. UCAN agrees with DRA that ratepayers should not be funding these kinds of HAN activities. UCAN contends that if these HAN-related costs are removed, that this eliminates SDG&E's justification for increasing 2012 test year costs over the 2010 recorded costs. UCAN recommends that the forecast for other customer service technology be limited to $1.449 million, which is the average derived from the five-year average methodology.

10.3.2.2.7.2

SDG&E disagrees with UCAN's recommendation to remove all the HAN-related costs. SDG&E's opposition is based on the same arguments it made regarding DRA's recommendation to remove the HAN-related costs.

10.3.2.2.7.3. Discussion

Earlier in this decision, we addressed the opposition to SDG&E's capital projects in the areas of customer service and customer contact. One of DRA's objections to SDG&E's capital projects was based on the argument that the HAN-related capital projects were not needed because HAN technology is still being developed, that no smart appliances are on the market, that time of use or dynamic pricing is not widespread, and the benefits of HAN-related investments are speculative. DRA and UCAN oppose funding of the HAN-related costs, which amount to about $1 million of SDG&E's forecast of $2.482 million.

Based on the earlier reduction of the HAN-related capital expenditures, it is reasonable to reduce the HAN-related costs for the other customer service operations costs. As a result, $1.735 million should be adopted as the O&M costs for the other customer service operations costs.

10.3.2.3. O&M Shared Services

10.3.2.3.1. Introduction

SDG&E forecasts $4.663 million in O&M shared customer service office operations costs for test year 2012. This forecast of shared costs is made up of SDG&E's costs that are retained by SDG&E ($3.154 million) and the costs that SoCalGas bills to SDG&E ($1.509 million).

These O&M shared costs come from the following four categories of services: Sarbanes-Oxley project management; customer service technology support; business planning and budgets; and market services. A description of the four categories of services and the costs associated with them are described in Exhibit 131.

10.3.2.3.2. Position of the Parties

10.3.2.3.2.1. DRA

DRA recommends that the shared services for customer service technology support be increased by only 15% above the five-year average, which amounts to $322,000. This is in contrast to SDG&E's forecast of an increase of $1.151 million. DRA contends that SDG&E's request overstates the staffing needs for the work associated with smart meters, and the support needed to maintain additional systems and the increased complexity of existing systems.

10.3.2.3.2.2. SDG&E

SDG&E contends that as additional functions are added to existing systems, or new systems are developed, that there is also a need for additional resources to manage those systems. SDG&E contends that DRA provided no justification for its 15% increase recommendation above the five-year average, and that DRA's recommendation is unsupported by the evidence.

10.3.2.3.3. Discussion

We have reviewed the testimony of SDG&E and DRA regarding the forecast of the shared costs for customers services technology support. The incremental increase of $1.151 million that SDG&E is requesting is too high in light of the historical costs, the work activities that this increase is to be used for, and the current staffing. We are persuaded by DRA that a reduction to these shared costs is warranted. Based on those considerations, it is reasonable to adopt $4.220 million for the O&M shared customer service office operations costs.

10.3.2.4. Conclusion

Based on our review of the evidence, and except for the adjustments as discussed above, we find SDG&E's forecasts of the costs of O&M nonshared activities and shared activities for customer service operations to be reasonable and those forecasts should be adopted and adjusted as described. SDG&E is also directed to remove its prefunded postage from O&M expense and book it into a cash working capital account as a prepayment item.

10.3.2.5. Office Operations Capital Expenditures

10.3.2.5.1. Introduction

For capital expenditures related to SDG&E's customer service office operations, SDG&E is requesting a total of $1.336 million for 2010, and $456,000 for 2011. In 2010, the capital projects consist of its billing regulatory project ($165,000), and the bill redesign project ($1.171 million). The billing regulatory project enhances the billing, financial, and reporting functions that are needed to support legislation and regulatory mandates. The bill redesign project is to redesign SDG&E's paper and electronic bills to improve and enhance the bill format, and to provide customers with more usable information in formats that customers want. In 2011, the capital project consists of an upgrade to SDG&E's computer assisted collections system ($456,000), which is used by SDG&E to manage delinquent final bills and to interface with collection agencies. No capital projects were planned for 2012.

10.3.2.5.2. Position of the Parties

10.3.2.5.2.1. DRA

DRA recommends that the bill redesign project be limited to the actual 2010 expenditure of $848,000. With that adjustment, DRA's recommended total forecast of the capital expenditures for SDG&E's customer service office operations amounts to $1.469 million.

10.3.2.5.2.2. SDG&E

SDG&E contends that it is inappropriate to use the 2010 actual data because it amounts to selective updating, and that the Rate Case Plan restricts the type of information that can be updated.

10.3.2.5.3. Discussion

Since the bill redesign project was completed and recorded actual costs of $848,000 in 2010, it is appropriate under the circumstances to reflect that actual amount into SDG&E's request. Accordingly, the forecast for SDG&E's 2010 bill redesign project should be reduced from $1.171 million to $848,000. With that adjustment, and based on our review of the testimony concerning the capital expenditures for SDG&E's customer service office operations, we find SDG&E's remaining forecast of the capital expenditures for 2010 and 2011 to be reasonable. Accordingly, the following capital expenditures for customer service office operations should be adopted: $1.013 million for 2010; and $456,000 for 2011.

10.3.3. SoCalGas Office Operations

10.3.3.1. Introduction

SoCalGas' test year 2012 forecast of O&M non-shared ($45.383 million) and shared services ($6.793 million) total to $52.176 million. This is $3.355 million more than the 2009 adjusted recorded expenses of $48.821 million.

The office operations of SoCalGas provide customer service to almost 5.5 million customers.

In the sub-sections below, we discuss SoCalGas' O&M non-shared services, the O&M shared services, and the capital expenditures for the office operations.

10.3.3.2. O&M Non-Shared Service

10.3.3.2.1. Background and Positions

SoCalGas' forecast of O&M expense for non-shared services for test year 2012 is $45.383 million.[99] These O&M expenses are to support the following business functions of SDG&E: billing services, measurement data operations, office credit and collections, bill delivery; postage; customer service technology support; and other customer service operations. The estimated expenses for these seven billing functions for test year 2012 are as follows:

[99] This total reflects SoCalGas' revised postage amount of $20.629 million, instead of SoCalGas' original forecasted amount.

($000 of 2009 Dollars)

Function	**2009 Recorded**	**2012 Estimated**
Billing Services	$7,378	$7,512
Measurement Data Operations	$1,036	$1,223
Office Credit & Collections	$5,333	$5,760
Bill Delivery	$5,855	$5,491
Postage	$20,424	$20,629
Customer Services Technology Support	$2,304	$3,133
Customer Service Operations-Other	$1,103	$1,635
Total	$43,433	$45,383

The billing services function covers the cost of calculating customers' bills and maintaining customer account information. This function consists of two organizations, one which provides billing activities for residential, and small commercial and industrial customers, and another organization that provides billing activities for large commercial and industrial customers. SoCalGas estimates $7.512 million for billing services in test year 2012. No one objects to SoCalGas' estimate of the expenses for the billing services function.

The business functions of the measurement data operations provide monitoring of, and maintaining accurate and timely measurement reporting for the 1405 large gas volume meters that are equipped with electronic measurement devices. The data from these electronic measurement devices is collected by SoCalGas' measurement collection system. SoCalGas estimates $1.223 million for measurement data operations in test year 2012. No one objects to SoCalGas' estimate of the expenses for measurement data operations function.

The office credit and collections function includes the following kinds of activities: turn on service investigations; bill collection; management of residential customer accounts, meter revenue protection; and bankruptcy processing, analysis, and reporting. These activities help to assess risk exposure and manage bad debt exposure on active and final accounts. SoCalGas estimates $5.760 million for office credit and collections for test year 2012.

Part of the costs of the office credit and collections function is due to the FACTA, which was signed into law on December 2, 2003, and requires full compliance by December 31, 2010. FACTA requires SoCalGas to take certain measures to verify a residential customer's identity and to prevent identity theft. Also related to the office credit and collections function is the uncollectible rate, which SoCalGas forecasts at 0.278%.

DRA recommends disallowance of the incremental FACTA expenses of $396,000 due to SoCalGas' alleged delay in requesting funding for this expense. DRA contends that FACTA became law in 2003, and SoCalGas had until December 31, 2010 to achieve compliance and to request the necessary funds but did not do so. DRA contends that SoCalGas should not be rewarded for its delay in requesting the funds needed for FACTA.

SoCalGas contends that it was not impacted by FACTA as enacted. SoCalGas was not aware until June 2008, that FACTA would apply to them, and that it would have until December 31, 2010 to comply. In August 2009, SoCalGas began training its employees regarding FACTA compliance, and it was implemented in September to November of 2009. SoCalGas points out, that aside from this timing issue, DRA does not object to the requested staff and associated expenses to comply with FACTA. SoCalGas also contends that DRA did not cite to any Commission precedent to support its disallowance that is based on an alleged delay in requesting funding.

The bill delivery function consists of the costs related to printing and inserting services for customer bills, notices, letters, and customer correspondences. SoCalGas estimates $5.491 million for test year 2012.

TURN recommends that the bill delivery expense forecast be reduced to $4.334 million. TURN's recommendation is based on its expectation that more customers will take advantage of the paperless billing option. TURN contends that although paperless billing began in 2006, it was not reflected until 2007. Since SoCalGas used the five-year average methodology of 2005-2009, TURN contends that SoCalGas' methodology only reflects three years of paperless billing and therefore does not account for the increase in paperless billing during the test year. Since SoCalGas forecasts 1.298 million customers on paperless billing in 2012 (24.46% of customers), and the data from 2007-2009 reflects only 1.025 million customers on paperless billing, TURN recommends that SoCalGas' forecast of bill delivery costs be prorated downward by 24.46%.

SoCalGas contends that TURN's recommendation to apply the 24.96% reduction to all bill delivery costs is inappropriate. TURN's percentage reduction is inappropriate because it reflects TURN's expectation of the expected residential customers who will participate in the paperless billing program. SoCalGas points out that a number of the bill delivery costs are fixed by contract, and that machine maintenance costs do not vary because of less throughput. SoCalGas also contends that its request for bill delivery costs takes into account the increase in more residential customers choosing the paperless billing option.

SoCalGas' forecast of the postage expense function reflects the most recent rate increase of the United States Postal Service, as well as an adjustment related to prefunded postage costs. SoCalGas estimates $20.629 million for test year 2012.

TURN originally objected to SoCalGas' original forecast of $21.131 million for postage. One of the reasons why TURN objected to the original forecast was because it believes that prefunded postage costs should be accounted for as cash working capital in SoCalGas' FERC Account #165, instead of being included in postage as an expense. SoCalGas researched and verified TURN's accounting-related objection, and as a result reduced its postage funding request to $20.629 million as shown in the comparison exhibit in Exhibit 599 at 279. According to Exhibit 415, the prefunded postage is accounted for in SoCalGas' FERC Account # 154 which covers prepaid materials and supplies. TURN accepts SoCalGas' revised postage forecast of $20.629 million.

The customer services technology function provides the employees who have the experience in customer service technologies and knowledge of the customer service operating functions and activities. These employees provide the support for the major customer service information technology applications, and interface with those who work in information technology system application development, maintenance, and enhancement. SoCalGas estimates $3.133 million for test year 2012.

DRA recommends that SoCalGas' incremental increase of $917,000 for the customer services technology function be reduced by $742,000. DRA contends that SoCalGas' forecast overstates self-service options, customer data collection, and regulatory compliance. In addition, SoCalGas is requesting seven business analysts to support software and collect customer data, which DRA contends are unnecessary. DRA believes that good software should provide tangible benefits that exceed their costs. DRA contends that its recommendation for an incremental increase of $175,000 will allow SoCalGas to add 2.3 FTEs while keeping non-essential expenses out of rates.

TURN recommends a reduction of $914,400 to reflect the five year average without any adjustments. Although SoCalGas used its five-year average methodology, TURN points out that SoCalGas adjusted the average by over 41%

to account for fluctuations in the data. TURN contends the adjustment is not needed because the costs show little fluctuation as reflected by TURN's comparison of the 2010 recorded costs to the five-year average, which differs by only $17,000.

SoCalGas contends that DRA's recommendations fail to consider certain key facts and lack support. SoCalGas contends that DRA's recommended reduction of 5.7 FTEs for the customer services technology function does not accurately represent the activities that will be performed by that staff, and that DRA does not understand what activities this group will be supporting. SoCalGas contends that the additional staff is needed to support a new single view of the customer database, that allows customer service representatives to view a customer's recent contact history, and to collect data from its customers that will be used to increase self-service, and to understand and modify customer service behavior. In addition, additional workload was added by enhancements to the on-line features in a customer's My Account profile and to SoCalGas' website. With changes in technology, the anticipated growth for more self-service options, and ensuring the security of customer information, SoCalGas contends that this additional staff support is needed. SoCalGas further contends that DRA has not demonstrated why DRA's recommendation to support only 2.3 FTEs is justified. As for DRA's contention that good software does not require significant maintenance and should provide tangible benefits that exceed costs, SoCalGas contends that this statement is not supported by any analysis or evidence.

Regarding TURN's recommendation to reduce SoCalGas' office operations by $917,000, SoCalGas acknowledges that the expenses for customer service technology using the five-year average methodology were relatively flat.

However, SoCalGas contends that TURN's disallowance fails to recognize the facts that additional projects were approved that support an adjustment to the five-year average methodology.

The other customer service operations are comprised of the Customer Operations VP, and Market Services. The VP is a new position that is being added as a result of the recent customer services reorganization. The responsibilities of this VP include managing of Customer Operations. Market Services, among other things, provides consulting and project management services across customer services, and provides analytical support to the call center and for attaining field and customer satisfaction objectives. SoCalGas estimates $1.635 million for other customer service operations for test year 2012.

DRA recommends disallowing the full request for the VP position, and for the costs of an additional industrial engineer. DRA contends that SoCalGas has not explained why the existing senior engineer is unable to complete the tasks, and why an additional engineer is needed. DRA recommends disallowing the engineer position, but allow $45,000 for two interns that can support the existing senior engineer. DRA also recommends disallowing the entire amount for the VP position because SoCalGas did not justify why a separate VP is needed, and the benefits that this position will provide.

TURN recommends a reduction of $388,000 for the other customer service operations. TURN proposes to use the 2010 recorded costs to estimate these expenses because the 2010 recorded costs were lower than what SoCalGas estimated in this GRC for the 2010 expenses. Although SoCalGas used the five-year average methodology, it was adjusted upwards by 55%. TURN contends that SoCalGas' adjustment to the average is inflated, and that SoCalGas' forecast for 2010 was higher than what was recorded in 2010. TURN contends that the recorded 2010 data is a more accurate proxy for the 2012 costs than SoCalGas' adjusted five-year average.

SoCalGas contends that the additional industrial engineer is needed to provide support to the senior industrial engineer in the areas of logistics, communications, and data analysis. The additional engineer is needed for an engineering study that is being undertaken to develop data in all 51 service districts about the time it takes to complete order types, and whether the field workers are following all of the appropriate procedures and policies. As for the new VP position, this was created as a result of the reorganization of Sempra, which established separate senior management teams at each utility. This new position is responsible for the operations of the call center, meter reading, billing, credit and collections, and remittance processing and bill delivery. In addition, this position oversees the benefits from SoCalGas' implementation of the OpEx program and the advanced metering infrastructure program, and for ensuring that the technology is in place to provide better customer service while reducing costs.

SoCalGas contends that TURN's proposed reduction of $388,000 is inappropriate because TURN relies on more recent data to support its reduction. SoCalGas contends that this amounts to a selective use of more recent data, the use of more recent data is contrary to the Rate Case Plan, and TURN's proposal is not consistent with the funding needs because it does not reflect the level of activity SoCalGas expects to occur over the 2012-2015 period.

10.3.3.2.2. Discussion

This discussion section addresses all of the O&M non-shared costs for SoCalGas' office operations.

No one has objected to SoCalGas' forecasts of the O&M costs for billing services and measurement data operations. Regarding the postage expense, SoCalGas reduced its postage O&M costs to $20.629 million as a result of TURN's objection to prefunded postage. Based on the evidence and the arguments regarding SoCalGas' billing services, measurement data operations, and postage expense, we find SoCalGas' forecasts of these costs for test year 2012 to be reasonable, and the forecasts for these three business functions should be adopted.

We now turn to SoCalGas' forecast of expenses for office credit and collections. We first note that SoCalGas has demonstrated that its request for an uncollectible rate of 0.278% is reasonable and should be adopted.

Second, DRA recommends that SoCalGas' forecast of expenses for office credit and collections for test year 2012 be reduced by $396,000. DRA's reduction is based on its argument that FACTA was signed into law in December 2003 and that SoCalGas had plenty of time to request funding for FACTA but was late in doing so. We have reviewed the timeline for the implementation of FACTA as described by SoCalGas. We agree with SoCalGas that it began to implement FACTA in 2009 after SoCalGas became aware that the utilities would be subject to this legislation. Contrary to DRA's assertion, SoCalGas was not late in delaying its funding request to implement FACTA. Accordingly, we do not adopt DRA's recommendation to reduce SoCalGas' estimate of the test year 2012 costs for office credit and collections by $396,000. However, it is appropriate to reduce these O&M costs by $200,000 since we do not believe the cost of implementing FACTA will be as high as SoCalGas has forecasted. Accordingly, it is reasonable to adopt O&M costs of $5.560 million for office credit and collections.

The next issue to address is the forecast of the bill delivery costs. TURN recommends that SoCalGas' forecast of $5.491 million for bill delivery costs be reduced to $4.334 million. This involves another disagreement as to whether SoCalGas' use of the five-year average methodology is appropriate.

SoCalGas used the five-year average methodology of 2005-2009 to develop its estimate of the test year bill delivery costs. SoCalGas' use of the five-year average reflects three years of data when paperless billing was adopted by SoCalGas' residential customers. Since SoCalGas' forecast already incorporates three years of data that includes the effect of paperless billing, it is not appropriate to reduce SoCalGas' five-year average forecast of costs by TURN's recommended 24.46% as that method assumes five years of paperless billing. TURN's 24.46% reduction would result in an underestimate of the bill delivery costs. We agree with TURN, however, that a reduction of SoCalGas' forecast is warranted because the average that SoCalGas uses does not include the effects of paperless billing for two out of the five years. Accordingly, we adopt a reduction of $500,000 to SoCalGas' test year 2012 forecast of $5.491 million, which results in an adopted forecast of $4.991 million. This $500,000 reduction results in approximately the average between what TURN and SoCalGas have recommended, which we believe is reasonable under the circumstances because it reflects the rising trend in the number of customers who choose paperless billing and appropriately balances the fixed costs and variable costs arguments of SoCalGas and TURN.

Next, we address SoCalGas' forecast of the costs for customer services technology. DRA and TURN recommend that SoCalGas' forecast of $3.133 million be reduced respectively by $742,000 and $914,400.

The recommended reductions of both DRA and TURN assume, in large part, that SoCalGas costs for customer service technology will remain stable in test year 2012 or that the benefits from the customer service technology will keep costs steady. We do not agree with the positions of DRA and TURN. Although the unadjusted five-year average is almost the same as the 2010 recorded costs, TURN's method and DRA's method do not reflect the additional work that customer service technology personnel will be undertaking. In order to provide its customers with a better experience using SoCalGas' website, and to provide its customers with more self-service options, SoCalGas needs knowledgeable workers in customer service who can assist in the development of these kinds of activities that utilize technology. For those reasons, SoCalGas' forecast of the customer service technology costs for test year 2012 is reasonable and should be adopted.

The last issue regarding SoCalGas' office operations is SoCalGas' forecast of the costs for other customer service operations. DRA and TURN recommend reductions to SoCalGas' forecast for different reasons.

We first address DRA's recommendation to disallow the entire request for the VP position for customer service. DRA contends that SoCalGas did not justify why this VP position is needed. SoCalGas contends that this position was created as a result of the restructuring of SoCalGas and SDG&E. Instead of having a centralized management for both utilities, it was decided to have separate utility management for both companies due to the different work activities and environments that face the two companies. We agree with SoCalGas regarding the creation and funding of this position for VP of consumer service. Accordingly, SoCalGas' funding request for this position of VP of customer services is reasonable, and SoCalGas' forecast of the test year 2012 costs for this position should be adopted instead of DRA's recommended disallowance of this position.

Next, we address DRA's recommendation to disallow the cost of the additional industrial engineer, and to allow the cost of two interns to support the existing senior engineer. DRA make its recommendation because it believes that SoCalGas did not explain why the additional industrial engineer position is needed, and why the existing senior engineer cannot undertake those duties. SoCalGas has provided the necessary support in its testimony as to why the additional industrial engineer is needed. For that reason, DRA's recommendation to disallow the additional industrial engineer position is not adopted, and SoCalGas' funding request for the additional engineer and two interns is reasonable and should be adopted.

TURN recommends that SoCalGas' forecast of the other customer service operations costs be reduced by $388,000. The basis for TURN's recommendation is that SoCalGas' adjustment to the five-year average results in an overinflated forecast of costs. In support of its argument, TURN points to the recorded 2010 costs as compared to SoCalGas' forecast for 2010. With the restructuring of SoCalGas' management to include the new VP position, as well as the addition of the additional industrial engineer position, we believe that SoCalGas' forecast of the other customer service operations costs is reasonable and should be adopted.

Based on the discussion above, and the adjustment to office credit and collections, it is reasonable to adopt O&M non-shared costs of $44.683 million for SoCalGas' customer service office operations.

10.3.3.3. O&M Shared Office Operations

10.3.3.3.1. Introduction

SoCalGas forecasts for test year 2012 that it will have $6.793 million in O&M shared office operations costs. This forecast of shared costs is made up of SoCalGas' costs that are retained by SoCalGas ($5.966 million) and the costs that SDG&E bills to SoCalGas ($827,000). These O&M shared costs come from the following six categories of services: customer remittance and bill delivery; customer service technology support; business planning and budgets manager; major markets credit and collections; VP engineering and operations staff; and market services. A description of the six categories of services and the costs associated with them are described in Exhibit 413.

10.3.3.3.2. Position of the Parties

10.3.3.3.2.1. TURN

TURN recommends that two adjustments be made to two cost centers that are included in the service category of customer remittance and bill delivery. TURN recommends that the costs retained by SoCalGas be reduced by $576,000, and that the shared costs billed from SoCalGas to SDG&E be reduced by $103,000. TURN's adjustments would reduce SoCalGas' costs by $567,000 and the costs billed to SDG&E would be reduced by $103,000.

The first adjustment that TURN recommends is to Account 2200-0355 for remittance processing and bill delivery. For test year 2012, SoCalGas estimated costs for this account at $4.067 million. The 2009 recorded costs were

$3.926 million. TURN contends that SoCalGas' use of its five-year average methodology is inappropriate for this account.[100] TURN contends that a five-year average is appropriate when there is no discernible trend in the costs. According to TURN, this account has been trending down due to more electronic bill payments and less payments by mail. TURN also points out that the recorded 2010 costs were $3.493 million, which was 17% below SoCalGas' 2010 forecast of the costs in this account. To reflect this downward trend, TURN uses the recorded 2010 data and recommends $3.493 million for this account, which is $574,000 below SoCalGas' request of $4.067 million. Since this is a shared service account, TURN's recommended adjustment reduces SoCalGas' costs by $510,000 and reduces costs billed out to SDG&E by $69,000.

The second adjustment that TURN recommends is to Account 2200-2026 for bill presentment and payment channel manager. SoCalGas forecasts $96,000 in labor and $4000 in non-labor costs for this account. TURN points out that this account no longer exists on the chart of accounts for 2010. TURN recommends that the $100,000 be removed, and as a result SoCalGas' costs are reduced by $66,000 and the costs billed to SDG&E are reduced by $34,000.

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[100] SoCalGas then adjusted the five-year by reducing it by $240,000 to reflect efficiency.

10.3.3.3.2.2. SoCalGas

SoCalGas contends that TURN's recommendation to adjust Account 2200-0355 is based on a selective use of 2010 data to update the costs in this account, and that the Rate Case Plan precludes the type of information that can be updated. SoCalGas contends that selective updating ignores the facts that certain costs may be lower than expected, and other costs may be higher than expected.

Regarding TURN's recommendation to adjust Account 2200-2026, SoCalGas agrees that in 2010 there were no charges booked to this account. The reason for that was because the employee who had been in that position took another position in November 2009. According to SoCalGas, this position was planned and remains planned through 2012, and that the position was subsequently filled.

10.3.3.3.3. Discussion

We first address TURN's recommendation to adjust Account 2200-0355. A review of the workpapers for how the five-year average was derived for this account shows a downward trend in 2008 and 2009. The recorded 2010 data also supports this downward trend for the costs in this account, and SoCalGas acknowledges that electronic payments are trending up and mail payments are trending down for this account. SoCalGas' use of its five-year average methodology, as reduced by its $240,000 adjustment, is still higher than what was recorded in 2009 and 2010. (*See* Exhibit 414 at 119-2120.) Given this trend, we agree with TURN that under the circumstances, it is reasonable to use TURN's estimate of $3.493 million instead of SoCalGas' estimate of $4.067 million for the costs in this account.

Turning to TURN's second recommendation to adjust Account 2200-2026, we do not agree with TURN's recommendation to remove the estimate of $100,000 for this account. No costs for this position were recorded in 2010 because the position was vacant for all of that year, and the position was not filled until July 2011. SoCalGas' testimony justifies why the position is still needed. Accordingly, TURN's recommendation to remove $100,000 from this account should not be adopted.

Based on the testimony of the parties, SoCalGas' forecast of the O&M shared services for customer service office operations should be adjusted by our discussion above. With that adjustment, the O&M shared office operations amount of $6.237 million is reasonable and should be adopted.

10.3.3.4. Capital Expenditures

For capital expenditures related to SoCalGas' customer service office operations, SoCalGas is requesting a total of $1.061 million for estimated expenditures in 2010. SoCalGas' request consists of $833,000 for its project to support new cost allocation and related rate designs that require significant changes and enhancements to its billing systems for large customer accounts, and $228,000 for its bill redesign project.

None of the other parties have objected to this request.

Based on the testimony of SoCalGas, its forecast of the capital expenditures in the amount of $1.061 million for 2010 for customer service office operations is reasonable and should be adopted.

10.4. Customer Information

10.4.1. Introduction

According to the Applicants, the customer services and information function is composed of "departments whose activities support and promote residential, commercial, industrial and government customer service programs and products, and the communication systems utilized to promote them." (Applicants' Opening Brief at 260.)

In the subsections below, we first address the customer services and information activities for SDG&E, followed by SoCalGas.

10.4.2. SDG&E Customer Information

10.4.2.1. Introduction

The customer services and information function at SDG&E provides information and outreach to its customers on a variety of programs and products. Among the activities are the following: providing customer assistance such as outreach and safety communications to residential special needs and medical baseline customers, and about natural gas appliance testing; providing account management activities to commercial, industrial, and government customers; managing research development and demonstration efforts, emerging technologies, electric vehicle, and biofuels programs; promoting programs and engaging in research that supports reliability and renewable sources of energy; and assisting commercial customers who are considering self-generation or cogeneration.

SDG&E is requesting total O&M expenses for customer services and information of $26.061 million for the 2012 test year. The $26.061 million is composed of a non-shared services forecast of $24.706 million, and a booked shared services forecast of $1.355 million. For capital expenditures related to customer services and information, SDG&E is requesting $8.128 million.

10.4.2.2. Non-Shared Services

SDG&E forecasts a 2012 test year expense of $24.706 million for nonshared O&M customer services information.

There are seven categories of activities that are included in SDG&E's O&M non-shared services. These seven categories are the following: customer assistance; customer programs; clean energy; clean transportation; commercial, industrial and government services; customer communications and research; and research development and demonstration.

In the subsections below, we address and discuss each of these seven categories separately.

10.4.2.2.1. Customer Assistance

10.4.2.2.1.1. Introduction

The customer assistance activities include delivering programs and services to special needs customers who benefit from assistance beyond traditional customer services. These special needs customers are residential customers with low or fixed incomes, and persons with medical conditions which require energy for life support equipment or special environmental conditions. The customer assistance group manages the medical baseline program, the neighbor-to-neighbor bill assistance program, the Low Income Home Energy Assistance Program, the 2-1-1 telephone service, and public safety outreach. In addition, the customer assistance group manages the CARE and Low Income Energy Efficiency (LIEE) programs. However, most of the program costs associated with those two programs is funded through the public purpose surcharge and not through base rates.

As part of the LIEE program, SDG&E conducts carbon monoxide testing (referred to as natural gas appliance testing or NGAT) in homes that have been weatherized through the LIEE program.[101] Pursuant to Commission decisions, SDG&E charges the NGAT program costs to base rates rather than to the public purpose program funds.

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[101] The NGAT is a safety measure that tests for gas leaks and carbon monoxide once a residence has been weatherized as part of the LIEE program.

For the 2012 test year, SDG&E requests a total of $1.185 million for customer assistance. This request is based on the five-year average ($767,000), and an incremental funding request of $418,000.[102] This incremental funding request is to support expansion of the existing programs and services for NGAT testing, and medical baseline customer outreach.

[102] SDG&E's original forecast ($1.392 million) of its O&M customer assistance costs included $75,000 to provide bill education and outreach to customers with limited English proficiency. This education and outreach effort is done through a contract with the Community Help and Awareness with Natural Gas and Electricity Services (CHANGES) program, which was formerly referred to as the Telecommunications Education and Assistance in Multiple-languages Collaborative. DRA and UCAN objected to this cost. DRA argued that it should be included in the costs of the CARE program, and UCAN argued that the costs were inflated and redundant. Since Resolution CSID-004 determined that the CHANGES program should be funded through the CARE budget, SDG&E agreed to remove its funding request of $75,000 to support the CHANGES education and outreach effort.

10.4.2.2.1.2. Position of the Parties

DRA recommends using the five-year average of $767,000 for O&M customer assistance costs, and to disallow the incremental funding amount of $418,000. DRA disagrees with SDG&E's justification for the incremental costs, and points out that SDG&E's 2010 recorded O&M customer assistance costs were $752,000, which is in line with the five-year average.

$275,000 is for NGAT testing. DRA contends that this should be disallowed because D.10-12-002 allowed SDG&E to track unanticipated NGAT costs in a memorandum account. If NGAT costs from 2012-2014 exceed the five-year average, the memorandum account will allow SDG&E to track those costs. DRA contends there is no reason why SDG&E's higher projected NGAT costs should be included in rates when there is a memorandum account to track those costs.

SDG&E's funding request consists of $275,000 for the medical baseline program. This incremental funding request consists of $75,000 for an employee to raise awareness of the medical baseline program, and $200,000 for an outreach campaign. DRA contends that community-based organizations (CBOs) have the best networks to reach out to potential medical baseline customers, and if the current CBOs are not sufficient to meet SDG&E's target enrollment goals, SDG&E should use additional CBOs instead of taking on this work internally.

10.4.2.2.1.2

UCAN also recommends that the Commission adopt the five-year average of $767,000 as the 2012 test year forecast for O&M customer assistance costs. UCAN contends that SDG&E is unlikely to perform as many NGATs as SDG&E has forecasted, and recommends that the average number of NGATs be reduced to 10,192 per year.

10.4.2.2.1.2

With regard to DRA's recommendation to track the NGAT costs in the memorandum account, SDG&E contends that the incremental NGAT costs should be included in base rates because the memorandum account expired in 2011. SDG&E contends that the memorandum account was only designed to track the costs associated with the 2009-2011 LIEE program cycle and the authorized level of funding from the prior GRC decision in D.08-07-046. SDG&E also contends that DRA has recommended that SoCalGas' incremental NGAT costs be adopted in base rates, which is different from what DRA recommends for SDG&E. SDG&E believes that these same kind of costs should be treated the same and included in base rates.

On UCAN's recommendation that the NGAT costs should be lower due to fewer tests, SDG&E contends that UCAN's forecast of an average of 10,192 tests will fall short of what SDG&E has forecasted. SDG&E also contends that the recommendations of DRA and UCAN to use the five-year average as the basis for the NGAT costs will ensure that actual NGAT costs will exceed what is in base rates that were developed when lower goals for NGAT were established.

SDG&E agreed in its rebuttal testimony that its forecast of NGATs should be reduced from a forecast of 15,288 to 11,500.

Although DRA contends that its use of the five-year average of $767,000 is close to the 2010 recorded O&M customer assistance costs of $752,000, SDG&E contends that the 2010 recorded expenses are not reflective of the 2012 test year forecasted expenses. If the recommendations of DRA and TURN are adopted to use the five-year average, SDG&E contends that this will deny SDG&E the ability to meet the goals that were mandated in D.08-11-031 to increase the number of homes that are to receive NGAT testing, and to enroll more customers in the medical baseline program.

SDG&E opposes DRA's recommendation to disallow the incremental funding of the medical baseline program. SDG&E contends that DRA's recommendation overlooks the fact that in order to qualify for medical baseline, a doctor's signature is required. Due to this requirement and to eliminate this hurdle, SDG&E plans to provide direct outreach to health care professionals in order to increase enrollment by having the doctor sign the form during the office visit by the eligible customer. Even if more CBOs were recruited to perform the outreach, as DRA suggests, more funding for training and related costs will still be needed.

10.4.2.2.1.3. Discussion

We first address the recommended disallowances of DRA and UCAN concerning the NGAT costs.

DRA argues that the NGAT costs should be tracked in the memorandum account that was established in D.10-12-002 instead of being included in base rates. We disagree with DRA for two reasons. First, the memorandum account that was authorized in D.10-12-002 is to track the difference between the recorded NGAT costs as a result of D.08-11-031, which increased the number of homes to be tested, and the authorized costs that were embedded in base rates in the 2008 GRC in D.08-07-046. (*See* D.10-12-002 at 3-4.) Since the 2008 GRC base rates expire at the end of 2011, the memorandum account will terminate as a result. Second, as the Commission has previously held in D.10-12-002 and D.08-11-031, NGAT is a basic utility service because promoting customer safety is a general utility function. As a basic utility service, the cost associated with NGAT should be included in base rates. (*See* D.10-12-002 at 3-4; D.08-11-031 at 135-137, Finding of Fact 73, Ordering Paragraph 65.) Accordingly, DRA's recommendation to disallow the NGAT costs from this GRC and to track it in the memorandum account established by D.10-12-002 is not adopted.

Next, we turn to UCAN's argument that SDG&E's forecast of the number of NGATs to be performed is too high, and the arguments of DRA and UCAN that the five-year average of the NGAT costs should be used. Since the five-year average includes the years of 2005-2009, the average of those costs will not capture the increase in the number of NGATs that was set as a goal in D.08-11-031 since only one month of 2008 and one year of the 2009 costs are included in the five-year average.

In order to determine what the appropriate number of NGATs should be, we need to compare the forecasts of SDG&E, with its revised NGAT number of 11,500 homes, with UCAN's recommendation of 10,192 homes. In 2010, the number of NGATs performed was 10,113. Although UCAN's recommendation is slightly higher than the 2010 recorded number, we believe a higher number of NGATs is warranted given how many NGATs were performed in 2010, and the Commission's goal of more NGAT testing. For that reason, we adopt 10,500 NGATs as a reasonable estimate of the NGATs that will be performed. Based on SDG&E's workpapers for calculating the incremental increase, we calculate that the incremental increase related to NGAT testing is $107,500. [103]

The next issue pertains to the O&M costs relating to the incremental funding to expand awareness and to encourage more customer participation in the medical baseline program. DRA contends that this additional outreach work be shifted to the CBOs instead. We agree with SDG&E's approach for expanding

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[103] (10,500 tests multiplied by $35 projected cost per test=$367,500) minus $260,000 (five-year average forecast.) (*See* Ex.156 at 6-7.)

the outreach of the medical baseline program in order to encourage more enrollment. SDG&E plans to increase enrollment in the program by doing outreach to health professionals, and providing them with information about the program. By enlisting the use of health professionals, this is likely to make enrollment easier since an eligible customer must obtain the doctor's signature in order to participate in this program. Even if CBOs are recruited to participate in this effort, there is still a need to provide SDG&E with sufficient staffing to assist the CBOs, and to provide the necessary program information. Accordingly, DRA's recommendation to disallow the incremental funding request for expanding the outreach for SDG&E's medical baseline program is not adopted.

Based on our review of all the testimony concerning SDG&E's forecast of its 2012 test year O&M customer assistance costs, and as adjusted above, we find customer assistance O&M costs of $1.150 million to be reasonable and should be adopted.

10.4.2.2.2. Customer Programs

10.4.2.2.2.1. Introduction

The customer programs group at SDG&E is primarily responsible for the administration of social programs, such as energy efficiency and demand response programs. The group also works with governmental agencies in the development of energy efficiency policies, and also provides market analysis support for various regulatory filings.

The costs of the program activities for energy efficiency and the majority of demand response programs are funded elsewhere, and are not part of base rates. The O&M expenses for the customer programs group are for the administration costs. The 2012 forecast for O&M customer programs activities is $799,000 and is the same as the 2009 adjusted recorded expenses. SDG&E did not use the five-year averaging methodology because the activity in the customer programs group is expected to remain steady.

10.4.2.2.2.2. Position of the Parties

UCAN recommends that the 2012 test year forecast for O&M customer programs costs be set at $1.004 million instead of the $799,000 recommended by SDG&E. UCAN's forecast is based on the five-year average.

SDG&E used the 2009 adjusted recorded expenses for its forecast. SDG&E did not use the five-year average because it expects the activity in customer programs to remain steady.

10.4.2.2.2.3. Discussion

Based on SDG&E's expectation that the activities for customer programs will remain steady, and because SDG&E is not forecasting any incremental costs, SDG&E's forecast of $799,000 is reasonable and should be adopted.

10.4.2.2.3. Clean Energy Programs

10.4.2.2.3.1. Introduction

The clean energy programs group provides customer support and program administration for clean energy programs. Among the programs this group administers is the Commission's Self-Generation Incentive Program, the California Solar Initiative, and the California Solar Initiative Thermal Program. The clean energy programs group at SDG&E works closely with the California

Center for Sustainable Energy (CCSE), who is the program administrator of these three programs in SDG&E's service territory. SDG&E's clean energy programs group is also responsible for the administration of its Sustainable Communities Program, which involves the placement of utility-owned clean energy generation systems on buildings in SDG&E's service territory.

For the 2012 test year forecast, SDG&E is requesting $1.542 million for O&M clean energy costs. This is a $548,000 incremental increase over the 2009 base year recorded costs of $994,000. Since the activities that the clean energy programs group is responsible for are recently implemented programs, SDG&E used the 2009 base year instead of a five-year average.

10.4.2.2.3.2. Position of the Parties

DRA recommends a disallowance of $243,000 for the O&M costs associated with the clean energy programs. DRA's recommended disallowance is composed of eliminating SDG&E's $70,000 funding request for public education about the Sustainable Communities Program, and the $173,000 funding request for two positions to support the incremental increase for the clean energy programs. DRA contends that outreach is not needed because potential participants are discovering the Sustainable Communities Program without outreach programs. DRA also contends that the capital budget for the

Sustainable Communities Project should be partially funded by commercial property owners.

10.4.2.2.3.2

UCAN recommends that the funding request of $1.542 million for the clean energy programs group be terminated. UCAN's recommended disallowance is based primarily on its contention that the Sustainable Communities Program should be terminated except for existing systems. Since UCAN recommends that this program be terminated, there is no need to continue customer support and program administration. UCAN also contends that the CCSE can administer the clean energy programs without assistance from SDG&E, and does not see a need for SDG&E to continue customer support and program administration in this area.

10.4.2.2.3.2

SDG&E contends that even though the CCSE is designated as the program administrator for three of the clean energy programs, SDG&E must still be involved at a certain level to support those programs. SDG&E's involvement includes collecting the funding for these clean energy programs through its rates, and the funds must be remitted to the CCSE. Through its metering and billing systems, SDG&E collects the generation data that is needed to calculate the incentive payments based on actual system performance. According to SDG&E, due to the growth of the Self-Generation Incentive Program, the California Solar Initiative, and the California Solar Initiative Thermal Program, SDG&E must dedicate more resources to meet the requirements of the programs and to maintain expeditious processing. Also, as more large solar systems are installed, SDG&E needs more tracking and processing to calculate and pay the incentives associated with the California Solar Initiative program.

In addition, SDG&E needs to stay informed at the Commission and at the CEC about any additions or changes to these programs to ensure that its rates and remittance to the CCSE is consistent with state directives. To eliminate all funding, as UCAN suggests, would ignore the work that SDG&E has to do with respect to these clean energy programs.

With regard to the Sustainable Communities Program, SDG&E contends that its full funding request should remain intact. SDG&E contends that this program is a valuable tool for studying distributed generation of the SDG&E distribution system. As for DRA's recommended disallowance of $70,000, SDG&E contends that DRA has justified its assertion that customers are learning about the program without SDG&E outreach. SDG&E contends that the success of the Sustainable Communities Program is due to SDG&E's outreach efforts.

As for DRA's suggestion that a portion of the Sustainable Communities Program be funded from investments from commercial property owners, SDG&E contends that this is a significant departure from the program that was approved in D.04-12-015, and that it would be more costly to market.

10.4.2.2.3.3. Discussion

SDG&E is requesting 2012 test year funding of $1.542 million for O&M clean energy costs. Part of this funding covers the costs associated with the Self-Generation Incentive Program, the California Solar Initiative, and the California Solar Initiative Thermal Program. All three of these programs were initiated by the Commission, and the CCSE is the program administrator for these three programs in SDG&E's service territory.

The remaining funding covers the costs associated with SDG&E's Sustainable Communities Program. This program was initiated by SDG&E and was first approved in D.04-12-015, and then approved again in SDG&E's 2008 GRC in D.08-07-046. SDG&E's clean energy group administers the Sustainable Communities Program. Of the $548,000 incremental funding request, $484,000 is requested to fund activities associated with the Sustainable Communities Program.

We first address the funding associated with the Self-Generation Incentive Program, the California Solar Initiative, and the California Solar Initiative Thermal Program. UCAN recommends that all of the funding to support SDG&E's clean energy group that work on various aspects of these programs be terminated. The reason for UCAN's recommendation to end funding is because it believes the CCSE has the ability to administer these three programs without SDG&E's assistance. We do not agree with UCAN. Although these three programs are administered by the CCSE, SDG&E must continue to provide support to CCSE to carry out these programs, as well as to track information about these programs for calculating the incentives and for reporting purposes, and to provide information and reports to the Commission and to the CEC. Accordingly, the funding associated with these three programs is necessary and reasonable to carry out these activities.

Since the rest of the funding request, as well as the majority of the incremental funding, covers the activities associated with the Sustainable Communities Program that brings us to the next issue as to whether the Sustainable Communities Program should continue. If funding for the Sustainable Communities Program is terminated, as recommended by UCAN, that would eliminate the need for most of the funding associated with the O&M costs in the clean energy group since support would only be needed for projects that are already in existence.

Earlier in this decision, we discussed UCAN's recommendation to terminate funding for the Sustainable Communities Program. For this GRC cycle, we allowed the Sustainable Communities Program to continue, but that program will terminate at the end of this GRC except for existing systems. As a result of this ramping down of this program over this GRC cycle, the O&M costs for education and outreach efforts on the Sustainable Communities Program should be reduced. DRA has recommended that incremental funding of $243,000 be disallowed, while UCAN recommends that all funding for the Sustainable Communities Program be terminated. Since we allow this program to ramp down through this rate cycle, it is reasonable to reduce the O&M costs for clean energy programs by $400,000.

Accordingly, it is reasonable to adopt $1.142 million as the O&M costs for the clean energy programs for test year 2012.

10.4.2.2.4. Electric Clean Transportation

10.4.2.2.4.1. Introduction

The electric clean transportation group provides customer outreach and education, engineering and marketing assessments related to the safe and reliable use of PEVs and charging facilities.

For the 2012 test year, SDG&E is requesting $2.946 million for O&M electric clean transportation costs. This is an incremental increase of $2.229 million over the recorded 2009 base year costs of $717,000. Since the electric clean transportation group has only a two year history, SDG&E used the 2009 base year as a starting point instead of a five-year average.

10.4.2.2.4.2. Position of the Parties

10.4.2.2.4.2

DRA recommends that the funding level for the electric clean transportation group be kept at the 2009 recorded costs of $717,000.

DRA recommends that SDG&E's request for communication, education and outreach in the amount of $1.508 million be eliminated. SDG&E contends that since the cost of a PEV is over $30,000, that PEV manufacturers and consumers have a strong interest in ensuring that consumers have the information they need about PEVs. DRA contends that as an electric utility, SDG&E should not be marketing products made by other companies.

DRA also recommends that SDG&E's request of $446,000 for field outreach, and on-road and charger infrastructure support installation, maintenance, and engineering support be eliminated. DRA contends that this effort should be undertaken by other entities that provide the charging infrastructure.

As part of the funding request for electric clean transportation, SDG&E proposes an additional $275,000 for market assessment and planning. DRA contends that the other market players who have an interest in the PEV market should bear these costs. SDG&E should not have to hire the staff to monitor PEV market trends, or the staff to validate the communications between charging stations and smart meters. DRA contends that this is the responsibility of the manufacturers.

10.4.2.2.4.2

UCAN recommends that funding for the electric clean transportation group be terminated. In addition to DRA's arguments as to why funding should be disallowed, UCAN contends that SDG&E's projection of the adoption of PEVs in the coming years is extremely optimistic, and that the high price of the PEVs does not justify SDG&E's education and outreach effort. UCAN also points to the outreach and advertising that is being done already by the PEV manufacturers. UCAN contends that in the event the adoption of PEVs is really high, the Commission could initiate a proceeding in which the electric utilities can seek funding and guidance about the role they should play in supporting PEVs.

10.4.2.2.4.2

SDG&E contends that its request for funding of the electric clean transportation group is consistent with the Commission's role in developing the state's electric vehicle strategic plan as set forth in R.09-11-009. According to SDG&E, the increased funding is needed to support the rapid growth in the use of electricity as a transportation fuel in the San Diego area. SDG&E contends that the adoption rate of PEVs is expected to outgrow other regions because San Diego was selected as one of the areas selected for the deployment of over 1000 Nissan Leaf vehicles, and for about 2500 public charging facilities, which is funded by grants awarded to ECOtality under the American Recovery and Reinvestment Act of 2009 and by the CEC.

SDG&E contends that to adopt DRA's recommended funding of $717,000 would ignore the major launch of electric vehicles in late 2010, and the Commission's support of the electric vehicle market. SDG&E contends that limiting all or part of the funding for electric clean transportation will hamper the development of utility infrastructure and curtail the adoption of electric vehicles.

D.11-07-089 directed SDG&E to collaborate with other stakeholders to develop an approach to customer outreach and education, so as to make customers aware of the availability, cost, and environmental impacts of electric vehicles, meter options, rate plans, and charging options. SDG&E contends that if funding for customer outreach and education is reduced or eliminated, that this will terminate SDG&E's role in collaborating with others.

As for UCAN's argument that the PEV adoption rate will be lower than anticipated, SDG&E contends that this argument ignores the state's goal of reducing GHG and reducing vehicle emissions, and the push to encourage PEVs in the San Diego area. SDG&E contends that it must be prepared for the rapid expansion of PEVs in the San Diego area, and that customers need to be provided with the assistance that the Commission has ordered SDG&E to provide.

With regard to DRA's argument that engineering support should not be provided by SDG&E, SDG&E contends that SDG&E's engineering assessment is of benefit to customers and electric vehicle service providers because it can assist them in determining the cost implications of alternate locations, minimize wasted effort and installation costs, and support the safe and reliable integration of charging equipment into SDG&E's system.

10.4.2.2.4.3. Discussion

UCAN recommends that all of the funding for the electric clean transportation group be terminated, while DRA recommends that the entire incremental funding request of $2.229 million be disallowed. The reasoning behind the recommendations of UCAN and DRA is that due to the high cost of PEVs, the growth in the PEV market will not be as strong as SDG&E believes it will be, and that the information and educational outreach about PEVs and charging facilities should be undertaken by the manufacturers instead of SDG&E.

The starting point for our analysis is Pub. Util. Code § 740.2 and D.11-07-029. That code section states in pertinent part as follows: "The commission, in consultation with the Energy Commission, State Air Resources Board, electrical corporations, and the motor vehicle industry, shall evaluate policies to develop infrastructure sufficient to overcome any barriers to the widespread deployment and use of plug-in hybrid and electric vehicles." The Commission was directed in that code section to adopt rules by July 1, 2011 to address the following:

(a) The impacts upon electrical infrastructure, including infrastructure upgrades necessary for widespread use of plug-in hybrid and electric vehicles and the role and development of public charging infrastructure.

(b) The impact of plug-in hybrid and electric vehicle on grid stability and the integration of renewable energy resources.

(c) The technological advances that are needed to ensure the widespread use of plug-in hybrid and electric vehicles and what role the state should take to support the development of this technology.

(d) The existing code and permit requirements that will impact the widespread use plug-in hybrid and electric vehicles and any recommended changes to existing legal impediments to the widespread use of plug-in hybrid and electric vehicles.

(e) The role the state should take to ensure that technologies employed in plug-in hybrid and electric vehicles work in a harmonious manner and across service territories.

(f) The impact of widespread use of plug-in hybrid and electric vehicles on achieving the state's goals pursuant to the California Global Warming Solutions Act of 2006 and renewables portfolio standard program and what steps should be taken to address possibly shifting emissions reductions responsibilities from the transportation sector to the electrical industry.

In compliance with the directive in Pub. Util. Code § 740.2 to adopt rules, the Commission opened R.09-08-009. In D.11-07-029, which was the Phase 2 decision in this rulemaking, the Commission addressed the role that the electric utilities should undertake with respect to education and outreach. D.11-07-029 authorized the electric utilities "to use funds to provide its customers with information [about plug-in hybrid and electric vehicles] regarding the choices available for metering arrangements, rates, demand response programs, charging equipment, installation, safety, reliability, and off-peak charging," and that such funds should be targeted at potential PEV customers. (D.11-07-029 at 87-88, Ordering Paragraph 8.) The Commission also stated that "the utilities should request approval for funding for ongoing or future education and outreach costs within their general rate cases or at another appropriate time." (D.11-07-029 at 69.)

It is clear from Pub. Util. Code § 740.2 and D.11-07-029 that the electric utilities are to collaborate with other interested stakeholders to prepare for the widespread deployment and use of PEVs, and to educate the public about the impact PEVs will have on customers and the electric utility. Accordingly, UCAN's recommendation to terminate all of the funding for the O&M costs associated with the electric clean transportation group is not justified or reasonable.

The issue then becomes what is a reasonable level of funding given that the San Diego area is the focus of deployment of PEVs and electric charging infrastructure. Since the 2009 funding level originated from the 2008 GRC settlement when PEVs were still in the infancy stage, the focus of the electric clean transportation group at the time was to monitor developments concerning PEVs and to do some education and outreach. With the increase in PEV and charging infrastructure activity in the San Diego area, additional funding is warranted, but not to the level of funding that SDG&E seeks. Based on the description in Exhibit 155 about the incremental communication, education and outreach expenses, it appears that some of this activity will not be targeted at potential PEV users, as D.11-07-029 has directed. For example, outreach activity at "community events," outreach to "multi-family dwellings," the use of "multiple communication channels" such as" radio and television communications," and providing "general information and education to all ratepayers," does not appear to control costs and to target customers with an interest in PEVs. (*See* Ex. 155 at 29-30; D.11-07-029 at 65.) In addition, PEV manufacturers and electric charging infrastructure providers can be expected to provide potential consumers with similar information.

For all of those reasons, it is reasonable to reduce SDG&E's incremental funding request from $2.229 million to $400,000, resulting in a total 2102 test year funding request of $1.117 million for the O&M costs for the electric clean transportation group.

10.4.2.2.5. Commercial, Industrial & Governmental Cust

omer Services

10.4.2.2.5.1. Introduction

The commercial, industrial and governmental customer services group provides support services to commercial customers, including agricultural, industrial, and governmental entities, and some customer services to residential customers. These support services provide customers with the information and the tools to assist them in understanding their rate and service options, to manage their energy costs, to acquire or modify their energy service needs, and to safely address unplanned service disruptions. These commercial customers make up about 54% of all SDG&E electric sales, and about 29% of gas sales. The commercial, industrial and governmental customer services groups are divided into these three functional areas: small and medium business customer services; large customer account management; and customer services staff support.

SDG&E is requesting $4.957 million for the test year 2012 forecast for O&M commercial, industrial and governmental customer services costs. Since this an established department, SDG&E uses its five-year averaging methodology as a starting point. SDG&E's 2012 test year forecast is a $174,000 incremental increase over the five-year average of $4.783 million, and an incremental increase of $120,000 over the 2009 adjusted recorded expenses of $4.837 million.

10.4.2.2.5.2. Position of the Parties

10.4.2.2.5.2

UCAN recommends using the five-year average of $4.783 million as the funding level for the O&M costs for the commercial industrial and governmental services group. For the major customer advisory panel that is part of the funding request, UCAN recommends that $34,200 of the cost of the major customer advisory panel be disallowed because it believes that at least six of the meetings could have been held at SDG&E facilities rather than at hotels, and the cost of the meals served could have been lower.

10.4.2.2.5.2

SDG&E is forecasting increased activity due to direct access re-enrollment. In addition, SDG&E plans to add a special investigator to respond to complex service orders that are expected to be generated as customers have more and better access to their detailed consumption data.

With regard to UCAN's recommendation to disallow the major customer advisory panel costs, SDG&E contends that the average annual costs for these costs are about $12,000 per year. Contrary to UCAN's belief that these advisory panel meetings are "private parties," SDG&E asserts that these meeting are more like interactive focus groups that are composed of executives of commercial customers who have an interest in energy industry issues. SDG&E contends it has made every effort to keep these events economical, while providing value to the panel attendees in terms of shared information and feedback.

10.4.2.2.5.2

Based on the evidence presented by SDG&E and UCAN, we believe that a reduction to SDG&E's 2012 test year forecast is warranted. A reduction will more closely reflect the 2009 recorded costs and the five-year average that have been experienced. Accordingly, $4.850 million should be adopted for the O&M costs associated with the commercial industrial and governmental services group.

10.4.2.2.6. Customer Communications & Research

10.4.2.2.6.1. Introdu

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The customer communications and research group is responsible for the following: producing a variety of communications using mass media and online media, and coordinating paid communications for SDG&E that are targeted at residential and commercial customers; producing collateral materials such as brochures, flyers, and exhibits, and coordinates; managing and oversight of SDG&E public presence on its website, and coordinating and conducting customer research.

For the 2012 test year, SDG&E is forecasting $8.500 million of O&M expense for customer communications and research. This is an incremental increase of $3.578 million over the five-year average of $4.922 million, and an incremental increase of $3.289 million over the 2009 recorded costs of $5.211 million. Since this is an established department, SDG&E used the five-year average as the starting point for its forecast.

10.4.2.2.6.2. Position of the Parties

DRA recommends disallowing $3.094 million of SDG&E's request of $8.500 million. The first area in which DRA recommends a disallowance is for SDG&E's proposed mass communications in the area of safety communications, smart meter outreach, and customer education. DRA's recommended disallowance would reduce SDG&E's spending on safety communications to $100,000 because SDG&E has not indicated that its existing safety messages are deficient. For smart meter outreach, DRA proposes to disallow that funding because it believes that other businesses will provide customers with information on how to optimize smart meter use.

The second area in which DRA recommends a disallowance is SDG&E's request for incremental funding of $1.098 million for website management. Included within the proposed activities are to provide information through social media, customer notifications, and customer research and design features such as graphics and navigation. DRA recommends that the Commission allow an incremental $288,000 to cover website changes and customer notifications, but to disallow the remaining incremental amount for social media, graphics and navigation, and additional functionality. DRA contends that this type of activity is not essential to SDG&E's primary mission of providing safe and reliable service, and not all customers use social media.

The third area of DRA's recommendation is to disallow the incremental amount of $495,000 related to the creation of separate communications teams for SDG&E and SoCalGas as a result of the 2010 reorganization. DRA contends that splitting communications into two separate groups was not justified. If the split was justified, DRA contends that the impetus for the split was due to SDG&E's desire to create specialized communications related to smart meters. Since DRA believes that outreach and education about smart meters should be performed by others, the incremental funding for the corporate center transfer should be disallowed.

10.4.2.2.6.2

UCAN recommends using the five-year average of $4.922 million for these O&M costs, and disallowing the incremental funding of $3.578 million.

10.4.2.2.6.2

SDG&E contends that its incremental funding request is for website management, enhancing website functions and social media channels, safety messaging, smart meter outreach, and including employees who transferred into the department.

With the full deployment of smart meters, SDG&E contends that it needs to provide education and outreach efforts to build awareness of the benefits of smart meters, and to lead customers to act and to take advantage of the various SDG&E programs and services that will lead to reductions in demand. Contrary to DRA's contention, SDG&E does not believe that the manufacturers of smart meter-related products will take on the role of providing the needed customer education and outreach.

Although DRA supports customer access to web services, and the ability to easily share concerns and provide feedback, DRA contends that social media and mobile applications are unnecessary. DRA also believes that smart meter education and outreach will not be needed since savvy customers will find what they need on the internet. UCAN also favors the use of the internet and self-service, but does not support social media as a viable outreach channel, and believes that the cost of providing the website should come from the savings of using such technology. SDG&E contends that the use of social media is large and growing, and that the use of social media as a means of communication during emergency situations is growing.

With regard to UCAN's recommended disallowances for SDG&E's mass media campaign, SDG&E contends that it is not a self-promotion campaign as UCAN suggests. Instead, it is a mass media campaign to build awareness of existing and new utility services, programs, resources, customer service offerings and safety.

SDG&E also contends that UCAN incorrectly calculated the amount of funding for customer communications and research. The 2008 test year funding request for SDG&E's customer communications was $5.644 million, which SDG&E contends was in line with the 2009 adjusted recorded expenses.

On the transfer of employees and DRA's recommended disallowance, SDG&E contends that the smart meter outreach is completely unrelated to split the communications and research group into two separate groups. Instead, the split was done due to the different customer base for SDG&E and SoCalGas, and was part of the 2010 reorganization. According to SDG&E, the overall corporate transfers did not result in a net growth to the utilities.

10.4.2.2.6.3. Discussion

UCAN recommends that the entire incremental funding of $3.578 million, as requested by SDG&E be disallowed, while DRA recommends that $3.094 million of the incremental funding request be disallowed. The recommendations of UCAN and DRA would essentially eliminate the incremental work associated with smart meter outreach and education, safety messages, website and social media activities, and the costs related to reorganization of the customer communications group at SDG&E.

We have reviewed and considered the testimony and arguments of the parties, and compared their forecasts to the historical costs. We believe that many of the incremental activities that SDG&E plans to undertake during the test year can be done for less than what SDG&E has forecasted. In addition, the incremental costs that SDG&E is requesting appears to be excessive as compared to the five-year average of $4.922 million, and the 2009 recorded cost of $5.211 million. Also some of the costs related to the website and social media appears to overlap with funding that SDG&E has requested elsewhere in this GRC. Based on all of those considerations, we agree with the reasoning of DRA and UCAN that SDG&E's O&M forecast should be reduced. It is reasonable under the circumstances to adopt $5.900 million as the O&M costs for SDG&E's customer communications and research costs.

10.4.2.2.7. Increasing Community Awareness

10.4.2.2.7.1. Introduction

The Joint Parties recommend that SDG&E conduct a community awareness program about nuclear power.[104] Such a program, if approved, would likely be overseen by SDG&E's customer communications and research group.

The Joint Parties favor nuclear power as an alternative to fossil fuels.[105] However, as a result of the problems at the Fukushima Daiichi nuclear plant in Japan, and a possible "Black Swan" event affecting SONGS,[106] they recommend

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[104] In Exhibit 391 at 22, the Joint Parties refer to Sempra, instead of to SDG&E, as the entity who should be ordered to undertake a nuclear community education and preparation campaign. Since it is SDG&E, and not SoCalGas or Sempra, who has an ownership interest in SONGS, we address this issue in the context of SDG&E only.

[105] In the opening brief of the Joint Parties at 17, they appear to backtrack over their support for nuclear power and state "that inexpensive natural gas may mitigate the need for a nuclear power revival and certainly may mitigate against the need for renewal of either the San Onofre or Diablo Canyon nuclear plants," and note that "it costs almost six times more for nuclear fuel per kilowatt than for gas per kilowatt."

[106] The understanding of the SDG&E witnesses is that a "Black Swan" event refers to a "very low-probability, high-impact event that occurs very infrequently." (12 RT 1105; 16 RT 1826.) In the opening brief of the Joint Parties, they refer to the recent shutdown of SONGs and the failure of the four steam tubes at SONGS to withstand pressure tests as a Black Swan event. (Joint Parties' Opening Brief at 18.)

that SDG&E "should engage as quickly as possible in major nuclear community education and, if necessary, a community preparation campaign," in order to reassure the communities around SONGS of its safety and the need for clean and reliable energy.[107]

The Joint Parties also recommend in its opening brief that due to the price of natural gas, and "the unexpected nuclear plant failures at San Onofre (and the potential for similar problems at Diablo Canyon)," the Commission should "seek to consolidate, in an expedited fashion, all nuclear plant issues affecting California relating to Sempra, Edison and PG&E." (Joint Parties' Opening Brief at 17 and 24.)

10.4.2.2.7.2. Position of SDG&E

SDG&E opposes the Joint Parties' request that SDG&E submit and undertake a comprehensive community outreach plan on nuclear safety. SDG&E notes that SCE, as the plant operator and majority owner of SONGS, already

[107] *Ibid.*

conducts this type of outreach in the communities near where SONGS is located, and that SDG&E ratepayers pay their share of these outreach programs. SDG&E contends that to impose a similar program on it would be duplicative, result in unnecessary costs, and would be an inefficient use of ratepayer funds. According to SDG&E, such a request should have been raised in SCE's GRC proceeding.

10.4.2.2.7.3. Discussion

The first issue that we address is the Joint Parties' request that the safety, seismic, nuclear economics, and plant relicensing issues associated with SONGS and PG&E's Diablo Canyon plant should be consolidated and handled in an expedited proceeding. As SDG&E correctly notes, those kinds of issues pertaining to SONGs, and to Diablo Canyon, are outside the scope of SDG&E's GRC proceeding. A.10-12-005 is only looking at the reasonableness of SDG&E's revenue requirement for the rate cycle associated with test year 2012. Accordingly, today's decision takes no action on the Joint Parties' request in its Opening Brief "to consolidate, in an expedited fashion, all nuclear plant issues affecting California relating to Sempra, Edison and PG&E," or to have "Sempra and/or Edison…conduct a comprehensive survey of ratepayer views on the renewal of" SONGS. (*See* Joint Parties Opening Brief at 24, Reply Brief at 11-12.)[108]

Next, we turn to the Joint Parties' request that "SDG&E and SoCalGas" be required "to submit within three months an educational and community outreach program [regarding nuclear education], including a budget and intended beneficiaries…," and "in the interim, SDG&E and SoCalGas should consult with consumer groups, especially those who have conducted outreach to minority, low-income, and non-English speaking communities." (*See* Joint Parties Opening Brief at 24, Reply Brief at 11-12.)

SDG&E has a 20% minority owner interest in SONGS, and is not the plant operator of SONGS. SCE is the majority owner of SONGS, and operates the plant. As the testimony shows, SCE conducts outreach programs in the communities near the SONGS plant, and SDG&E pays its share of these outreach programs to SCE. We agree with SDG&E that to impose a SONGS-related community outreach program on SDG&E would be duplicative of what SCE already does, and would result in an unnecessary program and costs that would be borne by SDG&E's ratepayers. To the extent the Joint Parties believe that the community outreach programs regarding SONGS should be expanded, that is an issue the Joint Parties should have raised in SCE's GRC proceeding. Accordingly, we do not adopt the Joint Parties' recommendation that SDG&E be required to submit and undertake a SONGS-related community outreach and preparation program.

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[108] After the close of hearings in this proceeding, the Commission opened Investigation 12-10-013 into SONGS Units 2 and 3.

10.4.2.2.8. Research Development & Demonstration

10.4.2.2.8.1. Introduction

SDG&E's research development and demonstration (RD&D) group was originally authorized in the 2008 GRC decision in D.08-07-046. As described in Exhibit 155, SDG&E considers the following types of activities to be RD&D: requirements definition and feasibility studies; technology assessments; laboratory research; field test beds; field prototype testing and pilot demonstrations; cross-cutting memberships in RD&D consortia; and co-funded projects with universities, national laboratories, and other RD&D partners.

SDG&E's 2008-2011 RD&D program consisted of the following five major program areas: operations; electric end-use; clean generation; clean transportation; and project management and administration. Each of these program areas are further divided into sub-programs. The operations area consists of reliability improvements for electric infrastructure, advancements in system planning, new technology such as advanced controls, distributed energy storage, and power flow optimization. The electric end-use area includes defining and developing new technologies to improve energy efficiency, reduce demand, and expand options for customers to manage their energy use. The clean generation area examines options for renewable energy in SDG&E's service territory and improves the integration of renewables and distributed energy resources with SDG&E's smart grid. Finally, the clean transportation area focuses on the technologies that support electric transportation.

In the 2012 test year, SDG&E plans to continue to focus on the following: improving transmission and distribution system reliability and performance; integration of end-use applications into the smart grid; expanding renewable and distributed energy resources options; mitigating intermittence through the use of energy storage; and development of new energy efficiency options for customer use.

For the 2012 test year, SDG&E is requesting $4.777 million for O&M research development and demonstration costs. This is an incremental increase of $3.251 million over the 2009 recorded costs of $1.526 million. Since SDG&E's RD&D group has only been around for a short time, SDG&E uses a zero-base year.[109] SDG&E is requesting continuation of balancing account treatment for RD&D expenses through the one way balancing account treatment in the Research Development & Demonstration Expense Account (RDDEA). Under the RDDEA, SDG&E is allowed to spend up to the authorized amount, and any spending below that level is refunded to ratepayers. Any spending above the authorized level is at the expense of shareholders.

SDG&E also proposes a sharing mechanism for any RD&D investments or activities that result in royalties or revenues. SDG&E proposes a 60% (ratepayer)

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[109] According to SDG&E, zero based budgeting is where all expenses must be justified for each new period, and starts from a zero base. The budget is then built around what is needed for the upcoming period, regardless of whether the budget is higher or lower than the previous one. (Ex. 175 at 30.)

and 40% (shareholders) sharing mechanism, which is similar to the same type of sharing mechanism that was authorized for SoCalGas.

10.4.2.2.8.2. Position of the Parties

10.4.2.2.8.3. DRA

DRA recommends that SDG&E's RD&D program be eliminated, and that only the funding of $153,000 for memberships in collaborative consortiums should be allowed. DRA contends that SDG&E does not need to conduct RD&D because there are multiple governmental and non-governmental entities involved in RD&D in the energy sector, and because SDG&E's role and focus should be on providing safe and reliable service. Since ratepayers are already paying for advanced technologies such as smart meters, the smart grid, renewables, and energy efficiency programs, DRA does not believe ratepayers should have to pay for RD&D investments.

10.4.2.2.8.4. UCAN

UCAN recommends RD&D funding of $1.717 million. UCAN contends that SDG&E's role in RD&D should be limited to monitoring developments in RD&D, and to evaluate whether those developments will produce technologies or processes that can be incorporated into SDG&E's operations, and to lower operating costs. The $1.717 million will provide funding for such activities.

Since research is not a core function of SDG&E, UCAN contends that the remainder of SDG&E's funding request for RD&D should be eliminated. UCAN contends that SDG&E should not be engaged in RD&D to develop or invent technology. UCAN also contends that SDG&E has not demonstrated that the RD&D benefits ratepayers. Of the 19 RD&D projects referred to by SDG&E in its testimony, SDG&E did not quantify or discuss how those RD&D projects will lower utility operating costs. UCAN further contends that SDG&E received funding in D.09-09-047 for energy efficiency activities and programs which duplicate some of the RD&D activities that SDG&E is requesting in this GRC. UCAN also points out that different private organizations, government institutions, and trade associations are already engaged in RD&D activities.

UCAN is opposed to SDG&E's 60/40 revenue sharing mechanism, and recommends that the Commission deny SDG&E's request to use ratepayer funds to pay for equity investments in RD&D projects. In the event the Commission believes an incentive is warranted, UCAN recommends that shareholders bear 20% of any loss on an investment. UCAN also recommends that SDG&E be able to demonstrate in the subsequent rate case that the investment did or was likely to have increased utility operational efficiencies.

10.4.2.2.8.5. SDG&E

SDG&E contends that DRA has provided no foundation for its proposed elimination of SDG&E's RD&D program. Eliminating the RD&D program will abandon the investment in RD&D that has been made to date. Since the RD&D is to develop technology that supports safety and reliability, research efforts into those areas would no longer be conducted if DRA's recommendation is adopted. DRA's recommendation would also stop the RD&D efforts into integrating new technologies with SDG&E's operating systems in order to implement a successful smart grid system. SDG&E contends that its "RD&D activities focus and collaborate on projects that utilize SDG&E specific system requirements in the development and demonstration of new technology to ensure it will integrate into the utility's system safely, enhance reliability and provide customer value." (Ex. 157 at 72.)

SDG&E contends that UCAN has not demonstrated that SDG&E's efforts in RD&D have been unsuccessful. SDG&E states that its funding request for O&M will leverage its participation in "ventures that support transmission and operational-related projects that improve the safety and reliability of energy service, reduce regional electric energy consumption and accelerate the development and commercialization of energy efficiency and demand response technologies, programs and service into the marketplace." (Ex. 157 at 65.)

Contrary to UCAN's assertions, SDG&E contends it is not inventing new technologies, but rather it is conducting experiments and demonstrations on system integration. According to SDG&E, this type of RD&D is needed to integrate and maximize the advanced technologies that ratepayers are currently funding in the form of smart meters, the smart grid, and renewable sources of energy. Without SDG&E's involvement in developing integration solutions, some new vendor products could have adverse effects on SDG&E's system due to interoperability issues.

On the sharing mechanism, SDG&E contends that UCAN's proposal is not well developed and appears to add complexities that will require staff time to manage and administer. In contrast, the current revenue sharing mechanism for SoCalGas is already in use, uncomplicated, and can serve as a model for SDG&E's proposed sharing mechanism.

10.4.2.2.8.6. Discussion

The starting point for our analysis of whether SDG&E's funding request for RD&D activities is appropriate is to look to Pub. Util. Code §§ 740 and 740.1. Section 740 provides that for the purpose of setting rates, "the commission may allow the inclusion of expenses for research and development."

Section 740.1 sets forth the guidelines the Commission shall consider "in evaluating the research, development, and demonstration programs proposed" by the utility. These guidelines are the following:

(a) Projects should offer a reasonable probability of providing benefits to ratepayers.

(b) Expenditures of project which have a low probability for success should be minimized.

(c) Projects should be consistent with the corporation's resource plan.

(d) Projects should not unnecessarily duplicate research currently, previously, or imminently undertaken by other electrical or gas corporations or research organizations.

(e) Each project should also support one or more of the following objectives:

(1) Environmental improvement.

(2) Public and employee safety.

(3) Conservation by efficient resource use or by reducing or shifting system load.

(4) Development of new resources and processes, particularly renewable resources and processes which further supply technologies.

(5) Improve operating efficiency and reliability or otherwise reduce operating costs.

Based on the above code sections, the contentions of DRA and UCAN that SDG&E should not be involved in RD&D are not entirely on point. Both the California Legislature and the Commission have recognized the value of RD&D efforts. The California Legislature expressly allows the Commission to include RD&D costs into rates so long as the utility's RD&D activities adhere to the guidelines set forth in Pub. Util. Code § 740.1. In D.08-07-046, the Commission adopted the settlement between SDG&E and DRA that authorized SDG&E to engage in RD&D at a funding level of $2.810 million with one- way balancing account treatment that is recorded in the RDDEA.[110]

We have reviewed SDG&E's RD&D activities, its proposed RD&D activities, and the process that SDG&E goes through to evaluate whether an RD&D activity should be pursued. SDG&E's evaluation of what RD&D activities it plans to pursue is consistent with the guidelines the Commission is to consider, as set forth in Pub. Util. Code § 740.1. Although DRA and UCAN are generally not in favor of SDG&E conducting its own RD&D, SDG&E is in a unique position to use its knowledge in the electric industry to carry out RD&D activities that affect various aspects of its utility operations. These include RD&D into the following:

- operational issues such as improving the reliability of the system using smart grid equipment, system planning to accommodate the growing presence of renewables and PEVs, and to examine how new technology can improve its electric operations;
- customer applications such as defining and testing of smart grid and HAN devices and technologies that interact with SDG&E's electrical system, technology development in the area of lighting, heating, ventilation, and air conditioning, and energy efficiency, and participation with others in collaborative RD&D efforts;
- clean generation such as ensuring the interoperability of distributed energy resources with SDG&E's system, and the dispatch ability of these resources;

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110 The RDDEA is described in section II of SDG&E's Preliminary Statement of its electric tariffs.

- clean transportation such as the development of advanced energy storage systems, and the compatibility of charging infrastructure with existing standards and codes;
- renewable energy involving wind, ocean and water energy, and the interoperability of renewables with storage and SDG&E's system.

In deciding whether all of SDG&E's proposed RD&D activities should be pursued or not, we must also consider the financial impact on ratepayers, and the economic conditions that ratepayers face. RD&D for SDG&E began in 2008 with an authorized funding level of $2.810 million, and RD&D spending in 2010 was $2.900 million. For the 2012 test year, SDG&E requests that RD&D funding be increased to $4.777 million. We realize that some growth in RD&D can be expected due to the ramp up in activity, however, we are concerned that RD&D costs may continue to grow in the future. In addition, some of the proposed RD&D activities appear to be duplicative of other research that is or has been performed. These include such RD&D activities into wind and water power, PEVs, HAN and appliances, and energy efficiency.

Based on the above, we adopt the recommendations of DRA and UCAN to reduce RD&D funding, but not to the amounts they have recommended. Instead, we authorize a 2012 test year funding amount of $2.750 million for O&M RD&D costs, which shall be accounted for in the RDDEA balancing account for this rate cycle. This funding amount is an incremental increase of $1.224 million above the 2009 recorded amount, and should provide sufficient funds for SDG&E to carry out its RD&D activities.

Next, we address the proposed 60 (ratepayer)/40 (shareholder) sharing mechanism that SDG&E proposes. The sharing mechanism would apply if SDG&E decides to make an equity investment or royalty position with a vendor involved in one of SDG&E's RD&D activities. SDG&E's testimony makes clear that under the proposed sharing mechanism, ratepayers would be made whole for their investments before any profits are distributed. Without the sharing mechanism, ratepayers would be at risk for any loss associated with such an investment, and would reap 100% of any of the profits. SDG&E proposes the sharing mechanism to provide itself with an incentive to search out possible vendors who may have a profitable product or service to offer. A similar sharing mechanism was approved as part of the settlement agreement adopted for SoCalGas in D.08-07-046.

UCAN is opposed to SDG&E's proposed 60/40 sharing mechanism. UCAN proposes that SDG&E shareholder bear 20% of any loss on an investment, which would give SDG&E a net 20% incentive from a successful investment. Under UCAN's proposal, SDG&E would also have to demonstrate "that the investment did or was likely to have increased utility operational efficiencies in a subsequent rate case proceeding." (Ex. 561 at 21.)

We have reviewed the testimony and considered the arguments of UCAN and SDG&E about their respective sharing mechanism proposals. Due to the adoption of the same type of sharing mechanism for SoCalGas in D.08-07-046, and to provide an incentive to SDG&E to seek out investments which may benefit both ratepayers and shareholders, we adopt SDG&E's 60 (ratepayer)/40 (shareholder) sharing mechanism proposal for this GRC rate cycle.

10.4.2.3. Shared Services

10.4.2.3.1. Introduction

There are O&M shared services costs for SDG&E's customer services and information. These shared services consist of the following three areas: biofuels market development; emerging technology; and environmental affairs. SDG&E also receives services billed in from SoCalGas.

For the 2012 test year, SDG&E forecasts that it will retain $548,000 in shared services costs, and will be billed $807,000 for shared services costs from SoCalGas. This will result in an O&M shared services book expense of $1.355 million for SDG&E in 2012.

10.4.2.3.2. Position of the Parties

10.4.2.3.2.1. DRA

DRA recommends eliminating the biofuels market development budget, which results in a reduction of $105,000 to SDG&E's book expense. DRA contends that SDG&E and SoCalGas already have staff who evaluate emerging technologies, and that it would be inefficient to have additional resources devoted just to the market development of biogas. DRA contends that once a cap and trade program is in place for California, large methane producers will have a regulatory directive and a financial incentive to reduce methane emissions, and that they may be inclined to fund biogas programs. At that point, SDG&E's

emerging technologies staff can work with those groups to jointly fund cost-effective biogas projects.

10.4.2.3.2.2. SDG&E

SDG&E contends that biogas is an untapped renewable resource, and that California is lagging behind the Commission and state's goals of tapping into this renewable resource. SDG&E contends that it can leverage SoCalGas' experience in natural gas processing technology and its distribution infrastructure to help promote the development of biogas in California. SDG&E contends that its proposed funding request for biofuels market development supports these state policies.

10.4.2.3.3. Discussion

DRA recommends that $105,000 in book expense for the shared service of biofuels market development be disallowed. SDG&E states that the biofuels market development shared service cost center was formed for the purpose of promoting and developing bio-gas markets, and that the primary focus of this shared service cost center is in promoting and supporting the installation of bio-gas conditioning systems at certain customer sites.

For the reasons stated elsewhere in this decision, we agree with DRA that SDG&E should not be in the business of owning biogas conditioning systems and installing them at customer sites to process the biogas that SDG&E owns. Accordingly, DRA's recommendation to disallow the $105,000 from SDG&E's book expense for O&M shared service costs should be adopted.

The other shared service expenses, as described in SDG&E's testimony, is reasonable and should be adopted. Adjusting for the $105,000 disallowance, the 2012 test year forecast for SDG&E's 2012 test year forecast of O&M shared service costs is $1.250 million.

10.4.2.4. Capital Expenditures

10.4.2.4.1. Introduction

SDG&E's capital expenditures for customer service and information fall into the following five key areas: (1) My Account online account management services, which consists of five separate projects; (2) customer contact and notification system; (3) customer relationship management system upgrade; (4) phase 3 of SDG&E's customer energy network; and (5) SDG&E's energy and environment center.

SDG&E forecasts a total of $8.128 million for the 2012 test year for capital expenditures related to customer service and information. For 2010, SDG&E requests $4.008 million, and for 2011, SDG&E requests $13.348 million.

10.4.2.4.2. Position of the Parties

10.4.2.4.2.1. DRA

DRA proposes to disallow all of SDG&E's capital expenditure projects for the customer service and information group, except for the My Account accessibility, and My Account enhancements 1 and 2 projects. DRA contends that these three My Account projects should be undertaken because they enhance accessibility for low income and marginalized customers. Thus, DRA's recommendation would allow 2010, 2011 and 2012 capital expenditures of $332,000, $135,000 and $1.884 million, respectively.

DRA's broad reasoning for disallowance of the other requested capital expenditures is that these capital projects are not directly related to SDG&E's core business of providing safe and reliable utility service, and are not reasonable because they do not provide ratepayers with value for the dollars spent.

For the My Account products and services, SDG&E claims that the current software can cause user confusion and navigation difficulties on the website, and that the "new structure will also help optimize customer access to utility services by supporting the recommendation and selection of utility product and service offerings based on an online shopping experience." (Ex. 510 at 15.) DRA contends that if the website navigation is a problem, that it is unlikely that 35% to 40% of SDG&E customers would be My Account users. DRA also contends that SDG&E is not an online retailer, and therefore it is unreasonable to upgrade portions of the website because they do not offer a state-of-the-art user interface.

For the My Account mobile services, DRA contends that since this project focuses only on mobile device users, that it is unreasonable to target this subset of customers in order to make viewing and interactive features more user friendly. DRA also contends that this same information can be accessed already over the internet using mobile devices.

On the My Account additional environment project, DRA contends that since the majority of the My Account upgrades are not needed, that this project to provide quality assurance testing environments and to build out additional My Account software is not needed.

For the customer contact and notification system project, DRA contends that there is no need to develop a preference center where customers can elect how to be contacted by SDG&E. DRA contends that this project is beyond what is necessary for communicating with customers, that it may be duplicative of the services provided by third party energy management companies, and it appears to be a marketing tool.

On the customer relationship management system upgrade project, DRA contends this is not needed for the same reasons why the customer contact and notification system should be disallowed, and because SDG&E did not describe any serious deficiencies with the current software.

For the customer energy network phase 3 project, which would expand third party access to residential and small commercial customer data, DRA recommends that this project be disallowed because the ratepayer benefits of third party access are unsubstantiated, and SDG&E should not have to pay for such platforms to provide third party access because of the potential for third party energy management.

On the Energy Innovation Center project, DRA recommends that SDG&E's entire funding request be disallowed.[111] DRA contends that SDG&E used the Commission's authorization to build a demonstration commercial kitchen to justify the construction of a green technology building costing $8.826 million. DRA recommends that this project be disallowed for three reasons. First, the technologies that are being shown off at the center are already being displayed in other buildings, in the competitive marketplace, and in the media. Second, DRA contends that there was no Commission directive to build the Energy Innovation Center, and that the Commission only authorized a demonstration kitchen

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[111] SDG&E also refers to the Energy Innovation Center as the San Diego Energy and Environmental Center.

project in D.09-09-047. DRA contends that there was no need to construct the Energy Innovation Center in order to house the demonstration kitchen. DRA's third reason for disallowing the center is that lack of classroom space does not justify building a new building to provide extra space for conducting energy efficiency seminars, demonstrating energy efficient products, to house a computer lab, and to have a demonstration kitchen.

10.4.2.4.2.2. UCAN

UCAN is opposed to any funding of SDG&E's information technology capital expenditures, and is also opposed to any funding for the Energy Innovation Center. Although UCAN favors the use of web based services and social media, UCAN contends that the "Commission should reject wide web upgrades until a [clear] vision for the efficiencies achievable through the upgrades is presented." (Ex. 555 at 13.)

On the Energy Innovation Center, UCAN recommends that the funding for SDG&E's Energy Innovation center be eliminated. UCAN contends that it attempted to trace how the Energy Innovation Center was paid for. According to an SDG&E data response, SDG&E did not request funding for an energy center in its 2008 test year GRC. Based on UCAN's analysis of various SDG&E's accounts, UCAN concludes "that SDG&E diverted at least $2.4 million from Energy Efficiency accounts" to fund the building of the Energy Innovation Center, and that SDG&E is seeking to secure additional funding for this completed project through this GRC". (Ex. 555 at 55.) UCAN contends that instead of building the center to increase classroom space, SDG&E could have shared space with the CCSE or elsewhere. In March 2010 when UCAN learned of SDG&E's plan to build the center, UCAN informed SDG&E that it did not see a need to spend ratepayer dollars on such a project. For the reasons cited by both DRA and UCAN, UCAN, recommends that the entire costs associated with SDG&E's Energy Innovation Center be disallowed.

10.4.2.4.2.3. SDG&E

SDG&E contends that all of the information technology capital expenditure projects help to expand self-service options, and are also the foundation to support the demand response program, and the proposed dynamic pricing program. SDG&E further contends that the demand for online information and communication will continue to increase at or above the current pace, which will require SDG&E to continue to invest and improve online services and electronic communication capabilities.

SDG&E contends that DRA is under the mistaken impression that parts of the project for expanding the My Account functions can be carried out, while other project parts should be eliminated. SDG&E contends that each of the expansion projects are inter-related, and eliminating one project will impact the other My Account projects.

On UCAN's recommendation to disallow the upgrade to the customer contact and notification system, SDG&E contends that this system will provide the capabilities for customers to choose their contact channel preferences, such as contact through email, home phone, cell phone, text, or social media. SDG&E also contends that this system is the foundation for the systems proposed in SDG&E's applications for a dynamic pricing program and demand response program.

SDG&E further contends that the proposed information technology capital expenditure projects are aligned with the recommendation of the Center for Accessible Technology to provide disabled customers and the elderly with emergency notifications through a variety of alternative formats, such as text message, email, and/or voice notifications.

For the customer relationship management upgrade, this will upgrade the software from version 5.0 to 7.0. Without investing in this upgrade, SDG&E contends that the initial ratepayer investment will be lost as the customer relationship management software will no longer be supported, and its value will diminish over time and become unusable. The systems that interface or will interface with the customer relationship management software are the customer contact and notification system, and the dynamic pricing program.

The customer energy network-Phase 3 is to develop the platform that will allow third party access to customer usage data. According to SDG&E, this upgrade is necessary in order to comply with the directive in ordering paragraph 8 of D.11-07-056 to build a common platform to allow third parties access to customers' usage data. This will allow third parties to access customer smart meter usage data, and provide it to customers.

The capital expenditure for the Energy Innovation Center is to create a place where training and workshops on energy efficiency and smart grid topics can be held, as well as a demonstration kitchen, and a computer lab. SDG&E contends that the Energy Innovation Center is a necessary and reasonable investment, and is consistent with the authority granted in D.09-09-047. In the two months that the Energy Innovation Center was open, there have been 53 events, 11 of which utilized the demonstration kitchen. The demonstration kitchen will also allow food service customers and manufacturers to come to a closer demonstration kitchen that showcases and tests energy efficient kitchen equipment. The Energy Innovation Center also serves as a model for commercial building energy saving strategies.

10.4.2.4.3. Discussion

We first address the information technology capital expenditures that SDG&E proposes to undertake. As shown in Exhibit 155 at page 85, these capital expenditures include the five My Account upgrade projects, the customer contact and notification system project, the Customer Relationship Management system upgrade, and the customer energy network phase 3 project.

In deciding whether SDG&E's request for these capital expenditures should be approved, there are a number of competing issues to consider. These issues include: to what extent should SDG&E and SoCalGas[112] use their websites and social media to communicate with customers; if websites and social media are used, what are the associated savings from using such channels of communication; should the roles of SDG&E and SoCalGas be limited to being providers of utility services instead of increasing and improving their internet presence; what are the consequences if software upgrades are not done; possible

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[112] Some of these information technology capital expenditures affect both SDG&E and SoCalGas.

overlap with demand response funding; and the cost of the information technology capital expenditures in light of current economic circumstances.

We have reviewed the testimony and arguments of SDG&E, DRA and UCAN regarding the capital expenditures for these information technology capital expenditures, and considered the competing issues. The information technology capital expenditures should be authorized in order to expand the channels of communication with customers, and to ensure that the existing software will continue to provide service into the future. However, due to the significant costs associated with these capital expenditures, to reduce some of the web navigation "look and feel" features that are "based on an online shopping experience,"[113] and to control costs by refining these projects to provide what is needed, reducing SDG&E's information technology capital expenditures by $2 million in 2011, and $1.500 million for the 2012 test year, is reasonable and should be adopted.

We turn now to address the capital expenditures request associated with SDG&E's Energy Innovation Center. SDG&E is requesting in this GRC, approval of the capital expenditures for this facility that occurred in the 2010-2012 timeframe. SDG&E began designing and constructing a retrofit of an existing building sometime in late 2009 to early 2010, and the facility was put into service around April 2011. According to SDG&E's Capital Project Workpaper:

> The project is a tenant improvement of a 27,000 square foot facility on Clairemont Mesa Blvd, in the community of Clairemont. The project consists of design, environmental abatement, and construction to develop a 200-person flexible seminar room, a lighting demonstration room, commercial

[113] *See* Exhibit 155 at 88.

> demonstration kitchen, smart 'Green' Home demonstration space, 10 staff offices, resource library, lobby, and other support functions such as restrooms and hallways. The project will result in a LEED-CI certification (goal: Platinum). Exterior improvements include a 100 kW solar (PV) array in the parking lot, a compressed natural gas fueling and four electric vehicle charging stations, and site landscaping. (Ex. 164 at 31; *See* Ex. 155 at 91, and Ex. 163 at 23.)

That Capital Project Workpaper also described the business purpose of the Energy Innovation Center as follows:

> SDG&E's Customer Programs and Customer Innovations departments offer SDG&E customers education and training related to energy efficiency, demand response, clean generation, and alternative fuel transportation. In support of these efforts, the SDG&E Energy & Environmental Center would provide a permanent, central venue for energy-related seminars and workshops. Additionally, the facility would showcase leading-edge technologies for industry professionals to incorporate into their own building projects. (Ex. 164 at 31.)

According to SDG&E, the "project justification" was described as follows:

> The project as described above has been approved at this level of funding by the Executive Finance Committee. The Commercial Demonstration Kitchen feature of the project is required for compliance with California Public Utilities Commission Decision 09-09-047, which approves SDG&E's Customer Programs' Statewide Workforce Education and Training Program. (Ex. 164 at 31.)

Both DRA and UCAN oppose SDG&E's capital expenditures request for the Energy Innovation Center. They argue that there was no Commission directive to build the Energy Innovation Center, and that instead of building the center they could have utilized classroom space at other facilities, and built the demonstration kitchen authorized in D.09-09-047 at another location.

SDG&E acknowledges that there was no "specific directive to build the [Energy Innovation Center] under D.09-09-047. However, SDG&E contends that the Energy Innovation Center "is a necessary and reasonable investment and consistent with the authority granted by the Commission in D.09-09-047" because it furthers the goals consistent with the authorization in D.09-09-047 to build a demonstration kitchen. (Ex. 157 at 106.) SDG&E argues that there was no space or the necessary ventilation at the CCSE to install a demonstration kitchen. The CCSE also had limited classroom space and no computer lab to accommodate computer-based learning. Due to the lack of classroom space, SDG&E had to limit the number of classes and events as it could not accommodate the demand for training seminars and workshops on a variety of energy efficiency topics. According to SDG&E, it "researched various locations and partnership arrangements, but concluded that renovation of an empty retail building in the Claremont Mesa area of San Diego was the optimal solution because of its centralized location and proximity to freeways." (Ex. 157 at 106.) Due to those circumstances, in late 2009 SDG&E's Executive Finance Committee approved the design and development of the Energy Innovation Center, which "would include a demonstration kitchen, multiple flexible seminar rooms, smart grid technology demonstrations, and the ability to host computer-based training." (Ex. 157 at 106.)

In deciding whether we should approve SDG&E's request for the capital expenditures for the Energy Innovation Center, which total to $8.826 million over three years, we must consider what the Commission authorized in D.09-09-047, and whether SDG&E's decision to retrofit a building and to seek funding for it is reasonable.

SDG&E cannot point to anywhere in D.09-09-047, or in the ALs that were filed in compliance with that decision, which authorized SDG&E to build the Energy Innovation Center or its equivalent.[114] In that decision, the Commission authorized the 2010-2012 budget for the utilities' energy efficiency programs. Included among the authorized SDG&E energy efficiency programs was a request for a food service center to offer education and training services on various aspects of food service. (*See* Amended Prepared Direct Testimony of SDG&E, Chapter II, at 70, sponsored by Athena M. Besa, March 2, 2009, A.08-07-023.)

SDG&E's request for funding of its capital expenditures for the Energy Innovation Center attempts to link the authorization for the food service center, to its justification to build the Energy Innovation Center. One of the justifications that SDG&E sets forth for building this facility is that it needed additional classroom space. However, SDG&E did not attempt to demonstrate that it could have leased or rented classroom space at other venues at a lower cost to hold its seminars and workshops, and to install a food service center, instead of deciding to go ahead with the design and retrofit of a separate building. Although the goal of retrofitting an existing building to demonstrate and showcase energy efficiency techniques and appliances, and PEV and compressed natural gas technology, is laudable, the Commission did not authorize SDG&E to proceed with the building of the Energy Innovation Center in D.09-09-047. Instead, D.09-09-047 only authorized SDG&E to establish a food service center, and such

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[114] *See* SDG&E Advice Letters 2127-E and 1903-G, dated November 23, 2009.

authorization cannot be used to justify the retrofit of a building which includes the food service center.

It is unreasonable to reward SDG&E for deciding to proceed with the Energy Innovation Center capital project when such a complex was not contemplated by SDG&E in the energy efficiency proceeding that led to D.09-09-047, or in SDG&E's prior GRC. Nor has SDG&E demonstrated in this GRC that lower cost alternatives were available to secure additional classroom space and to house the food service center. This is an important consideration as the 2009-2010 time period was during the midst of the economic downturn, and SDG&E seeks to recover $8.826 million in this proceeding. Since the Commission only authorized the building of a demonstration kitchen, we will allow capital expenditure funding of $2 million in 2011 for that facility, and deny the rest of the funding for the Energy Innovation Center.

Based on the above discussion, it is reasonable to adopt the following capital expenditures for customer service and information: for 2010, $1.217 million; for 2011, $8.586 million; and for 2012, $5.355 million.

10.4.3. SoCalGas Customer Information

10.4.3.1. Introduction

The customer services and information function at SoCalGas performs a variety of activities. Among the activities are the following: delivering and communicating information to its customers; conducting customer research; managing electronic information and services delivery channels; maintaining customer assistance and outreach programs; providing energy-related services to non-residential customers and residential developers; assisting large nonresidential customers with air quality-related compliance and regulatory issues; managing the Research Development & Demonstration program and the Natural Gas Vehicles program; commercial development of biofuel; and assessing emerging technologies for potential new utility services and related policy drivers.

SoCalGas is requesting total O&M expenses for customer services and information of $41.411 million for the 2012 test year.[115] The $41.411 million is composed of a non-shared services forecast of $34.681 million, and a shared services forecast of $6.730 million. For capital expenditures related to customer services and information, SoCalGas is requesting the following: $234,000 for 2010; $1.261 million for 2011; and $12.059 million for 2012.

10.4.3.2. Non-Shared Services

10.4.3.2.1. Introduction

SoCalGas forecasts a 2012 test year expense of $34.681 million for nonshared O&M customer services information.

115 SoCalGas originally requested funding of $41.536 million. As described later in this section of the decision, SoCalGas then agreed to reduce its request by $125,000 to a total of $41.411 million to reflect DRA's recommendation concerning the funding of bill education.

There are four categories of activities that are included in SoCalGas' O&M non-shared services. These four categories are the following: customer communications, research and e-services; customer assistance; nonresidential markets; and research development and demonstration. In the subsections below, we discuss each of these four categories separately.

10.4.3.2.2. Customer Communications

10.4.3.2.2.1. Introduction

As described in Exhibit 417, SoCalGas' customer communications oversees these four primary areas: customer communications; design and print production; customer research and analysis; and website and other electronic channels-based services and information delivery. According to SoCalGas, these customer communications activities include: (1) proactively communicating to customers through mass and targeted channels to build awareness of and improve access to existing and new utility services, programs and resources; (2) educating customers and stakeholders about utility-related topics such as managing gas usage, payment options, assistance and rebate programs, service offerings, and natural gas safety; (3) conduct research and customer satisfaction analyses to measure, evaluate, and anticipate customer information and service needs and preferences, supporting the development of new customer service options, targeted communications and delivery channels to satisfy those needs; and (4) leverage and expand e-channels, including social media, to support customer education and awareness-building objectives, and to meet increasing customer needs and expectations.

For test year 2012, SoCalGas requests a total of $7.919 million for customer communications. SoCalGas' request is based on a five-average of $5.655 million, and an incremental request of $2.264 million above the five-year average. According to SoCalGas, the incremental funding request will reflect growth in the following areas: enhance and expand website usability and accessibility; improve and expand electronic communications, social media, and online content; support expanded services for website and mobile devices; conduct related customer research; expand natural gas safety communications.

10.4.3.2.2.2. Position of the Parties

10.4.3.2.2.2

DRA recommends that SoCalGas' request for customer communications be reduced by $1.257 million. DRA's concern with SoCalGas' request for funding of customer communications is that it exceeds what DRA believes is necessary, and is geared toward meeting the desire of more affluent customers using high-end technologies. In particular, DRA objects to proposed investments in social media ($431,000) and mobile communications ($230,000). In addition, DRA recommends disallowance of $128,000 for additional customer research into customers using e-services because SoCalGas conducted a major customer survey in 2010, and substantial customer research about users adopting electronic technologies has been conducted already. DRA also recommends disallowance of $468,000 to double the length of its safety communications campaign from three to six weeks, to disseminate safety messages in multiple languages, and to use multimedia technologies to disseminate its messages.[116] DRA contends that since SoCalGas' primary responsibility is to provide safe and reliable gas service to its customers, that these additional e-services and related technologies are not needed.

10.4.3.2.2.2

Cfor AT recommends that SoCalGas and SDG&E continue to carry out and to build upon the accessibility improvements that were started in the last GRC as a result of an agreement between the two utilities and the Disability Rights Advocates, which was adopted in D.08-07-046. In particular, Cfor AT recommends that the utilities make their websites, telecommunications, emergency notifications, and written communications more accessible to customers who have disabilities that impact their ability to use standard forms of communication. The issues raised by Cfor AT are addressed in the settlement between SoCalGas, SDG&E, and Cfor AT, which was discussed earlier in this decision.

10.4.3.2.2.2

[116] TURN supports DRA's recommendation concerning the customer communications costs.

The Joint Parties recommend that "Sempra" undertake a "major nuclear community education and, if necessary, a community preparation campaign." (Ex. 391 at 22.) The issue raised by the Joint Parties is discussed above in SDG&E's customer service information section.

10.4.3.2.2.2

SoCalGas contends that DRA's recommendation to eliminate incremental funding ($230,000) for operating and improving SoCalGas' website and supporting new and expanded mobile-based e-services, and to eliminate incremental funding ($431,000) for social media communications, may widen the digital divide because there is some evidence to support the argument that minority communities tend to use smartphones, rather than home computers, to access the internet. Also, with the growth in smartphone sales, SoCalGas "needs to provide services and information for the mobile web user community that is easy to find, easy to use, and easy to understand." (Ex. 419 at 25.) In addition, the use of social media is growing among all populations.

Regarding DRA's recommendation to eliminate $128,000 in incremental funding for customer research, SoCalGas contends that its study performed in 2010 will not provide timely feedback on new information or services, and that updated research is necessary because it focuses on its customers, and SoCalGas' services and communications.

On DRA's recommendation to eliminate $468,000 in incremental funding for safety communications, SoCalGas contends that it is not lagging in sending out safety messages in multiple languages. According to SoCalGas, about half of its communications budget in 2010 was spent targeting diverse ethnic groups. As for extending its safety campaign from three to six weeks, SoCalGas believes that will lead to a greater recall by its customers about seeing or hearing SoCalGas' safety messages.

SoCalGas also contends that DRA's recommended disallowances are in conflict with the recommendation of Cfor AT, who recommends that there be improvements made to communications, websites, and other alternative formats, to reach people with disabilities. One form of improving communications to the disabled community is to use text message, e-mail, and voice notifications.

10.4.3.2.2.3. Discussion

DRA's recommended reduction of $1.257 million is composed of disallowances in four activities. If all of DRA's reductions were adopted, SoCalGas' incremental request over the five-year average would be reduced from $2.264 million to $1.007 million.

The first recommended disallowance of DRA is to disallow $230,000 for operating and improving SoCalGas' website and supporting new and expanded mobile-based e-services. DRA's second recommendation is to disallow $431,000 for social media communications. DRA raises a valid point about how technology-centric SoCalGas should be in communicating and providing interactive tools to its customers. However, this must be balanced against the benefits that this technology can provide to its customers. With the growing use of smartphones and social media channels by all customer populations, the ability to obtain information on demand using smartphones, and the ability to communicate with customers using mobile devices, there is a need for SoCalGas to expand services in this area. A growing number of customers prefer to use this type of technology to obtain information and to conduct transactions. For those reasons, we do not adopt DRA's recommendation to disallow a total of $661,000 for these types of activities. However, we believe that the costs of these kinds of activities can be reduced. Accordingly, it is reasonable to reduce SoCalGas' O&M costs in the area of mobile-based e-services and social media by $200,000.

The third recommendation of DRA is to disallow SoCalGas' incremental request of $128,000 for customer research of its customers using e-services. DRA points out that SoCalGas conducted research in 2010, and that substantial research already exists about usage trends for various electronic technologies. SoCalGas counters that targeting its own customers for research will provide timely feedback. We agree with DRA that SoCalGas' incremental request of $128,000 for this research should be disallowed. Plenty of recent research has been done on people's preferences for using new technologies, as well as SoCalGas' own research in 2010. To conduct this research again, when there is already movement by SoCalGas to add additional e-services, is not necessary. Accordingly, DRA's recommendation to reduce SoCalGas' incremental request by $128,000 should be adopted.

The fourth recommendation of DRA is to disallow SoCalGas' incremental request of $468,000 for safety communications. We are not persuaded by DRA's argument that the disallowance is warranted because SoCalGas has been deficient in providing safety communications to its non-English speaking customers. DRA has not pointed to any evidence in the record to support a lack of effort on SoCalGas' part to communicate gas safety to all of its customers. In addition, we are not persuaded by DRA's argument that lengthening SoCalGas' safety campaign from three to six weeks, as well as using electronic messaging channels and video production, should result in a disallowance. Providing information and promoting awareness about natural gas safety should not be reduced at this point in time when more communications of this type are needed. Accordingly, DRA's recommendation to reduce SoCalGas' incremental request by $468,000 is not adopted.

Based on the evidence presented, we find SoCalGas' test year 2012 forecast of the O&M expenses for customer communications to be reasonable, as adjusted in the manner described above. O&M funding for customer communications in the amount of $7.591 million should be adopted.

10.4.3.2.3. Customer Assistance

10.4.3.2.3.1. Introduction

The customer assistance activities include delivering programs and services to special needs customers who benefit from assistance beyond traditional customer services. These special needs customers are residential customers with low or fixed incomes, and persons with medical conditions which require natural gas for special environmental conditions. The cost associated with these customer service activities are separate from the programs and services specifically funded through the CARE and LIEE programs.

For the 2012 test year, SoCalGas originally requested a total of $5.199 million for customer assistance.[117] This request is based on the five-year average ($1.724 million), and an incremental request of $3.475 million. This incremental request is for natural gas appliance testing (NGAT), outreach for the medical baseline program, and bill education for customer with limited English proficiency.

[117] SoCalGas subsequently reduced the customer assistance cost forecast from $5.199 million to $5.074 million to reflect DRA's recommendation regarding the funding of bill education. (*See* Ex. 420, Ex. 599 at 98.)

10.4.3.2.3.2. Position of the Parties

10.4.3.2.3.2

DRA recommends disallowing $675,000 of SoCalGas' incremental funding request of $3.475 million for customer assistance. DRA's proposed disallowance is made up of two components. First, DRA recommends that the incremental request of $550,000 to increase participation in the medical baseline program be disallowed. SoCalGas' incremental request of $550,000 is for two positions ($150,000) to direct outreach, and $400,000 for providing program information through television, magazines, direct mail, doctors' offices, and pharmacies. DRA contends that instead of hiring additional positions, SoCalGas should seek out additional CBOs to assist in the dissemination of information about the medical baseline program.

The second component of DRA's recommendation is to disallow $125,000 for bill education to customers with limited English proficiency, to be conducted by the Commission's Telecommunications Education and Assistance in Multiple-languages (TEAM) Collaborative. DRA is not opposed to a contract with the TEAM Collaborative, but believes that this activity should be funded through the CARE program instead of as an O&M expense in the GRC.

DRA supports the funding request of SoCalGas for NGAT. DRA believes that SoCalGas will be able to complete 120,000 NGATs by 2012, and therefore recommends that the NGAT memorandum account, established in D.10-12-002 to record the additional NGAT expenses required by D.08-11-031, be eliminated.

10.4.3.2.3.2

TURN recommends using 2010 recorded costs ($3.227 million) for SoCalGas' O&M costs for customer assistance. TURN's forecast is based on the argument that SoCalGas' forecast of the volume and unit cost of the NGATs to be performed in the 2012 test year is not consistent with the recorded 2009 and 2010 data. TURN contends that the number of NGATs conducted by SoCalGas fell short of the targets specified in D.08-11-031. In addition, TURN contends that SoCalGas' $35 forecast of the per unit cost of an NGAT is higher than the unit cost per NGAT of $28.63 and $27.98 in 2009 and 2010, respectively.

10.4.3.2.3.2

Regarding DRA's recommendation to use CARE funding for the bill education program, SoCalGas agreed in Exhibit 420 to remove its incremental request for $125,000 to cover the expenses to support the TEAM Collaborative, which is now referred to as the Community Help and Awareness with Natural Gas and Electricity Services. As noted earlier, the removal of the $125,000 reduces SoCalGas' funding request for O&M customer assistance from $5.199 million to $5.074 million, and reduces SoCalGas' overall O&M customer services and information funding request from $$41.536 million to $41.411 million.

SoCalGas opposes DRA's recommendation to disallow the incremental funding of the medical baseline program. SoCalGas contends that DRA's recommendation overlooks the fact that if SoCalGas relies more on the CBOs to disseminate information about this program, that SoCalGas still needs to provide support to train the CBOs and to provide sufficient staffing for the new activities. SoCalGas also contends that the additional funding is needed to provide direct outreach to health care professionals because in order to enroll in the program a signature from a doctor is required.

SoCalGas is opposed to TURN's recommendation to use the 2010 recorded costs as the basis for the customer assistance forecast. In addition to its arguments concerning the use of 2010 data, SoCalGas asserts that TURN's recommendation would underfund its 2012 NGAT activity, which in turn will restrict SoCalGas' ability to provide required services to special needs customers and to fulfill the Commission's directives for low income programs. SoCalGas also contends that the 2010 data shows that the per unit cost of the NGAT is much higher than what TURN suggests.

On DRA's recommendation to eliminate the NGAT memorandum account, SoCalGas points out that with the establishment of the memorandum account in D.10-12-002, the recorded costs in that NGAT memorandum account will be disposed of in the next GRC or other appropriate proceeding.

10.4.3.2.3.3. Discussion

We first address TURN's recommendation to use the 2010 recorded costs ($3.227 million) as the forecast of the 2012 test year O&M customer assistance costs. Our review of the data concerning the five-year average that SoCalGas uses, and the 2010 recorded data that TURN uses, leads us to find that SoCalGas' use of the five-year average is more reflective of the trend in customer assistance costs, which have varied during 2005-2009 from $1.475 million to $2.159 million. Under TURN's method, the incremental work that SoCalGas plans to perform in the 2012 test year would be incorporated within the 2010 amount of $3.227 million, which we believe understates the funding that will be required.

TURN's underfunding is apparent after a reviewing the evidence about NGAT. About 80% of SoCalGas' incremental funding request is due to NGAT. SoCalGas' incremental funding related to NGAT is $2.800 million. The NGAT is designed to test for carbon monoxide, and is part of the LIEE program.
In D.07-12-051, the Commission adopted an initiative that all eligible customers

be allowed to participate in the LIEE programs, and to allow them to participate in all energy efficiency measures by 2020. To meet this initiative, D.08-11-031 directed SoCalGas to help 400,279 homes over three years, or 133,426 LIEE eligible homes per year. SoCalGas did not complete as many NGATs as D.08-11-031 had projected, and as a result SoCalGas' incremental funding for NGAT is included in this GRC to meet the Commission directives.

TURN contends that SoCalGas' forecast methodology is inappropriate because the number of NGATs that SoCalGas had forecasted fell way short of the actual NGATs performed. For that reason, TURN suggests that if certain adjustments were made to the number of NGATs that were contemplated by D.08-11-031, that the cost per NGAT would be much lower, and as a consequence the NGAT costs should be much lower than SoCalGas' forecast of $2.8 million which justifies using the 2010 recorded costs of $3.227 million as the 2012 test year forecast for customer assistance costs. However, under TURN's method, the total incremental funding for all customer assistance costs would be $1.503 million,[118] which underfunds the work associated with the incremental funding for NGAT, expanded outreach of medical baseline, and the customer assistance the program provides. For those reasons, we do not adopt TURN's recommendation to use the 2010 recorded customer assistance costs as the 2012 test year forecast of customer assistance costs.

DRA recommends that the NGAT memorandum account, authorized in D.10-12-002, be eliminated. DRA's reasoning for eliminating the balancing

[118] The $1.503 million is derived from TURN's use of the recorded 2010 customer assistance costs of $3.227 million minus the five-year average of $1.724 million.

account is because DRA recommends full funding of SoCalGas' NGAT funding request in this GRC.

We do not agree with DRA that the NGAT memorandum account should be eliminated at this time. D.10-12-002 authorized the memorandum account for the purpose of tracking "unanticipated and unforeseen" NGAT costs arising out of the directive in D.08-11-031 to expand NGAT. SoCalGas has not requested in this GRC to recover any of the costs from that memorandum account. However, SoCalGas has requested funding of NGAT for the 2012 test year in this GRC, which is appropriate since the Commission has classified NGAT "as a basic utility service." (D.10-12-002 at 3; *See* D.08-11-031 at 136.) Until SoCalGas seeks to recover any unanticipated and unforeseen NGAT costs recorded to the memorandum account, eliminating the memorandum account is premature. Accordingly, SoCalGas shall have until the next GRC application to seek recovery of the amounts, if any, that were recorded to the NGAT memorandum account. If SoCalGas does not make such a request in its next GRC application, then that memorandum account should be closed.

Next, we address DRA's recommendation to disallow the incremental medical baseline costs of $550,000. DRA's argument is that the additional outreach work that SoCalGas proposes to undertake, be shifted to CBOs instead. We agree with SoCalGas' approach for expanding the outreach of the medical baseline program in order to encourage more enrollment. SoCalGas plans to increase enrollment in the program by doing outreach to health professionals, and providing them with information about the program. By enlisting the use of health professionals, this is likely to make enrollment easier since an eligible customer must obtain the doctor's signature in order to participate in this program. Even if CBOs are recruited to participate in this effort, there is still a need to provide SoCalGas with sufficient staffing to assist the CBOs, and to provide the necessary program information. However, we believe that this effort can be achieved at a cost less than SoCalGas' incremental funding request of $550,000. For that reason, O&M funding for SoCalGas' customer assistance costs should be reduced by $200,000.

Based on our review of all the testimony concerning SoCalGas' forecast of its 2012 test year O&M customer assistance costs, and as discussed above, it is reasonable to adopt $4.874 million for SoCalGas' O&M customer assistance costs.

10.4.3.2.4. Nonresidential Markets

10.4.3.2.4.1. Introduction

The nonresidential markets group serves the larger nonresidential customers of SoCalGas, and is comprised of two subgroups. The first subgroup is commercial, industrial and government services, which provides account management and other customer services to medium and large commercial, industrial, and government customers. In addition to other duties, this subgroup provides assistance to customers in analyzing combined heat and power systems, customer bills, engine water pumping, and gas air conditioning. The second subgroup is capacity products and planning, which manages the accounts of very large customers, and the business relationship with interconnected gas producers and pipelines. This capacity products and planning subgroup also markets unbundled storage capacity and the California Energy Hub, and purchases natural gas to maintain system integrity.

For the 2012 test year, SoCalGas is requesting a total of $8.502 million for nonresidential markets. This request is based on the five-year average of $8.022 million, and an incremental funding request of $480,000. This incremental funding request provides support for increased air quality compliance regulations and activities, and for increased combined heat and power activities.

10.4.3.2.4.2. Position of the Parties

10.4.3.2.4.2

DRA recommends disallowance of SoCalGas' $480,000 incremental request for nonresidential markets, and that the five-year average of $8.022 million be adopted as the test year 2012 forecast. DRA contends that SoCalGas' incremental funding request is beyond the scope of services that should be funded by ratepayers. DRA takes the position that if large customers are violating air quality standards, releasing excessive amounts of GHG, or not investing in combined heat and power, that it is up to the state government to solve these problems, not SoCalGas. DRA also contends that SoCalGas' incremental funding request did not provide any data or analysis to show that it will produce demonstrable, cost effective results.

10.4.3.2.4.2

TURN recommends using 2010 recorded costs of $7.738 million, with no adjustments, for SoCalGas' O&M costs for nonresidential markets. TURN's use of the 2010 recorded costs is based on its argument that SoCalGas' forecast of 2010 costs was lower than 2010 actual costs, which calls into question SoCalGas' forecasting methodology.

10.4.3.2.4.2

SoCalGas contends that DRA's proposal is misguided because policies and goals concerning GHG, and the greater use of combined heat and power, have already been issued. As a result of these policies, SoCalGas already provides technical assistance to customers to determine the feasibility and economics of installing a combined heat and power system. Its funding request would expand this kind of assistance to meet the customers' increasing demand to explore combined heat and power implementation options.

Regarding DRA's recommended disallowance of incremental funding for air quality support, SoCalGas contends that these activities are not limited just to commercial and industrial customers, but also impact residential customers.

Without SoCalGas' Environmental Affairs staff, customers would have to do their own research to become informed of the changes in air quality regulations.

SoCalGas is opposed to TURN's recommendation to use 2010 recorded data for the reasons stated in the methodology section of this decision.

10.4.3.2.4.3. Discussion

We first address TURN's recommendation to use the 2010 recorded costs of $7.738 million as the 2012 test year forecast of the O&M expense for the nonresidential markets. We have compared SoCalGas' five-year averaging methodology to TURN's use of recorded 2010 data. The result of SoCalGas' five-year averaging methodology is $8.022 million. This is in contrast to TURN's use of one year of recorded data for 2010 in the amount of $7.738 million. Based on a review of the five-year data, and the incremental funding that SoCalGas is requesting, we believe that SoCalGas' five-year averaging methodology is a more reasonable reflection of what the costs are likely to be in the 2012 test year and during the rate cycle. Accordingly, TURN's recommendation to use the 2010 recorded costs for the 2012 test year forecast of O&M expense for the nonresidential markets is not adopted.

Although we do not adopt TURN's recommendation to use the 2010 recorded cost of $7.738 million as the test year 2012 amount, we are persuaded by TURN's reasoning that the use of SoCalGas' five-year average may overstate the actual O&M costs. This is reflected in the adjustment we make at the end of this discussion.

DRA recommends that the 2012 test year forecast of O&M expense for the nonresidential markets consist of only the five-year average of $8.022 million, and that SoCalGas' incremental funding request of $480,000 be disallowed. We are not persuaded by DRA's argument that SoCalGas' incremental funding request should be disallowed. $265,000 of the $480,000 is for work related to combined heat and power. This additional assistance in combined heat and power is to supplement the type of work that SoCalGas is already undertaking, and to target those customers who have the ability to install smaller combined heat and power systems. The installation of smaller combined heat and power systems is part of the CARB's plan to meet California's 2020 GHG reduction goals. $215,000 of the incremental funding request is to provide support to customers regarding new and existing air quality regulations. As SoCalGas points out in Exhibits 417 and 419, some of these new air quality regulations will impact smaller gas customers, including residential customers and restaurant operators. Without the assistance of SoCalGas, these smaller customers may not be aware of how these new air quality regulations will affect their use of gas-fired appliances. However, it is our belief that this type of assistance can be provided for less than SoCalGas' incremental funding request of $480,000.

Based on our review of the testimony concerning SoCalGas' forecast of its 2012 test year O&M nonresidential markets costs, and as discussed above, it is reasonable to reduce SoCalGas' forecast of $8.502 million by $400,000, which results in O&M costs of $8.102 million.

10.4.3.2.5. Research Development and Demonstration

10.4.3.2.5.1. Introduction

SoCalGas' research development and demonstration activities cover the following six major program areas: gas operations; customer applications; clean generation; clean transportation; solar-thermal and bioenergy; and project management, program planning and administration. The details of each of these programs are described in Exhibit 417 at 51-65, and in Appendix A of that exhibit.

For the 2012 test year, SoCalGas is requesting a total of $13.186 million for RD&D. This request is based on the use of a zero base forecast methodology, an incremental funding request of $3 million, and $186,000 in technology development support costs which is not a refundable RD&D cost. The incremental funding is being requested by SoCalGas to implement additional projects to accelerate the development, demonstration, and commercialization of solar-thermal, and bioenergy renewable resources.

SoCalGas proposes to maintain a one-way balancing account to track RD&D expenditures, which will be trued up at the end of the 2012 test year rate cycle.

SoCalGas also proposes to continue the sharing mechanism (60% to ratepayers and 40% to shareholders) for net revenues related to RD&D project assets, and from divestiture of equity investments initiated after implementation of the last GRC decision in D.08-07-046.

10.4.3.2.5.2. Position of the Parties

DRA recommends disallowance of SoCalGas' entire RD&D funding request of $13.186 million. DRA's disallowance is based on its argument that RD&D funding is not a necessary or reasonable use of ratepayer monies, and that sufficient research is being undertaken by governmental and non-governmental institutions. DRA also contends that the Commission's regulatory duty is to ensure the safety and reliability of the system, and that these safety and reliability concerns are not the driving force behind SoCalGas' RD&D activities.

Instead of RD&D projects which focus on the transportation of natural gas, the proposed RD&D projects target compliance with AB 32. Since AB 32 compliance is already being addressed through market mechanisms such as cap and trade, DRA contends there is no need to supplement research in that area.

DRA also contends that affordable utility service is undermined by the Commission's approval of increasing RD&D costs and other costs, which exerts significant and increasing upward pressure on rates.

In the event the Commission decides to fund RD&D, DRA recommends only allowing projects that are directly related to safety improvements, which are the projects included in SoCalGas' gas operations portion of the RD&D program. The funding for SoCalGas' gas operations amounts to $3 million. If this amount of funding is authorized, DRA recommends that the one-way balancing account be required as well.

10.4.3.2.5.2

TURN agrees in most respects with DRA's arguments about RD&D. TURN contends that SoCalGas should use ratepayer funds to deliver natural gas to their customers in a safe, reliable manner for a reasonable cost. TURN does not believe that SoCalGas should be using ratepayer funds to invent new products. TURN contends that SoCalGas' role should be to monitor the status of research on technologies, and to demonstrate whether those new technologies can be incorporated into utility operations in a manner that results in ratepayer benefits. TURN recommends that the Commission should limit SoCalGas' request for RD&D funding, and only continue the gas operations portion of SoCalGas' RD&D program, with funding of up to $5.588 million. TURN also recommends that the current one-way balancing account treatment be retained. TURN does not believe that SoCalGas should be using ratepayer funds to develop the other contemplated RD&D activities such as clean electric generation and clean transportation.

TURN also recommends ending the equity and royalty sharing mechanism in the RD&D program. TURN's recommendation is based on its contention that SoCalGas' ratepayers have put up close to $32 million, but have only received back $7.45 million of the ratepayers' investment. In contrast, TURN contends that SoCalGas' shareholders have provided zero dollars but received $7.45 million.

TURN also contends that that SoCalGas has not explained how it intends to invest ratepayer funds in RD&D equity investments in the future, and that SoCalGas has not met its burden of proving that its plans for using ratepayer funds is prudent, reasonable, and in the ratepayers' interest.

10.4.3.2.5.2

SoCalGas recommends that the recommendations of DRA and TURN concerning RD&D funding be rejected. SoCalGas contends that the recommendations of DRA and TURN are a radical departure from past Commission and state policy, and from DRA's past recommendations. SoCalGas points out the following: Pub. Util. Code § 740 allows ratepayer funding of RD&D; Pub. Util. Code § 740.1 sets forth the objectives that each RD&D project should support; and in the 1990 GRC (D.90-01-016), SoCalGas was directed to expand its RD&D activities to address air quality and environmental initiatives. SoCalGas points out that DRA has supported the continuation of SoCalGas' RD&D activities since at least 1990, and most recently in SoCalGas' 2008 GRC. SoCalGas also contends that TURN's argument fails to recognize that energy efficient equipment, and expansion of new uses for gas, help to reduce ratepayer costs through lower individual bills and through lower overall rates.

As for arguments of DRA and TURN that RD&D funding should be left to the government, universities, and private industry, SoCalGas contends that such programs require co-funding sources or are supported by industry participants.

SoCalGas also contends that its RD&D program is necessary because of the air quality requirements in its service territory, and the need to develop ultra-low emission gas-fired equipment.

As for DRA's argument that funding of SoCalGas' RD&D program has grown and lacks adequate spending controls, SoCalGas contends that from 1998 through 2010, RD&D expenditures were relatively flat, and were in the range of $7.2 million to $8.9 million. In 2008, RD&D spending then increased to $10 million. SoCalGas also contends that in the last 13 years, RD&D expenditures have made up between 0.43% and 0.63% of SoCalGas' annual authorized base margin revenues. The funding request for RD&D accounts for 0.62% of SoCalGas' test year GRC request. In addition to the one-way balancing account, SoCalGas contends that strong budget controls and screening criteria are in place to ensure that the RD&D projects meet the criteria in Pub. Util. Code § 740.1.

With respect to TURN's argument about equity investments and the sharing mechanism, SoCalGas contends that TURN has inaccurately portrayed the purpose and results of these two items.

10.4.3.2.5.3. Discussion

DRA and TURN contend that SoCalGas should not be involved in any RD&D projects unless it is related to the safety and reliability of providing natural gas, and provides benefits to ratepayers. The arguments of DRA and TURN concerning the forecast of O&M expense for RD&D raise the initial question of whether SoCalGas should be involved in RD&D at all.

As SoCalGas points out, Pub. Util. Code § 740 allows RD&D expenses to be included in rates. Thus, SoCalGas can request funding for RD&D projects so long as it meets the guidelines in Pub. Util. Code § 740.1. Pub. Util. Code § 740.1 sets forth five guidelines the Commission is to consider in deciding whether an RD&D project should be pursued.[119] These guidelines are:

(a) Projects should offer a reasonable probability of providing benefits to ratepayers.

(b) Expenditures on projects which have a low probability for success should be minimized.

(c) Projects should be consistent with the corporation's resource plan.

[119] The guidelines in Pub. Util. Code §740.1 were originally set forth in D.82-12-005 (9 CPUC2d 833).

(d) Projects should not unnecessarily duplicate research currently, previously, or imminently undertaken by other electrical or gas corporations or research organizations.

(e) Each project should also support one or more of the following objectives:

(1) Environmental improvement.

(2) Public and employee safety.

(3) Conservation by efficient resource use or by reducing or shifting system load.

(4) Development of new resources and processes, particularly renewable resources and processes which further supply technologies.

(5) Improve operating efficiency and reliability or otherwise reduce operating costs.

DRA contends that all of SoCalGas' RD&D projects should be disallowed because the projects are not related to safety and reliability, while TURN contends certain RD&D projects should be disallowed because SoCalGas should not be funding the development of new products or that have minimal benefit to ratepayers. We also note that Pub. Util. Code §§ 740 and 740.1 do not provide for automatic ratepayer funding of RD&D expenses.

With the above guidelines in mind, we have reviewed SoCalGas' request to fund its RD&D projects. These projects fall into six program areas as described in Exhibit 417. All of the described projects have a relationship to SoCalGas' gas operations or to the use of natural gas. SoCalGas also provides an overview of how these projects may provide benefits to ratepayers, the relationship of the projects to state policies and goals, and how the projects meet one or more of the stated objectives. However, some of these projects are unlikely to be successful or provide limited benefits, and some of the RD&D activities overlap or duplicate research that is being performed by other entities.

We have also considered DRA's argument that the RD&D budget is growing in size, and that SoCalGas' funding request for RD&D is 0.62% of its 2012 test year GRC request as compared to the range of 0.43% to 0.63% over the last 13 years. A review of the RD&D programs that SoCalGas proposes to fund suggests that some of these programs could be scaled back or eliminated, and that the funding request of $13 million is excessive.

Given the difficult economic circumstances that face ratepayers, and to help reduce RD&D costs, which ratepayers pay through rates, it is appropriate and reasonable to reduce SoCalGas' RD&D O&M costs as suggested by TURN. With TURN's reduction of $7.628 million, the amount of $5.558 million should be adopted as the O&M costs for RD&D.

We also approve SoCalGas' request to continue the use of a one-way balancing account for RD&D costs, with the limit for these costs as adopted above.

10.4.3.3. Shared Services

10.4.3.3.1. Introduction

The customer services and information area includes shared management and staff groups that provide support to the following: natural gas vehicles program, capacity products and planning, environmental affairs, biofuel market development; emerging technology; and the VP of customer solutions.

SoCalGas forecasts total booked O&M shared services of $6.730 million, which is composed of retained O&M shared services of $5.584 million, and $1.146 million in O&M shared services billed from SDG&E to SoCalGas.

10.4.3.3.2. Position of the Parties

10.4.3.3.2.1. DRA

DRA recommends that a forecast of $4.974 million for SoCalGas' booked shared services be adopted.[120] DRA recommends disallowing $1.124 million from SoCalGas' 2012 test year forecast of $6.730 million.[121] DRA's disallowance is based on reductions in four areas.

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[120] SoCalGas contends that DRA's recommended forecast of $4.974 million is inconsistent with DRA's discussion of its disallowances in Exhibit 539. SoCalGas calculates DRA's recommended booked expense at $5.606 million.

[121] The $1.124 million represents the difference between DRA's forecast of $5.606 million and SoCalGas' forecasts of $6.730 million as shown in Exhibit 419 at 43.

First, DRA proposes to disallow SoCalGas' incremental request for customer education and outreach for NGVs because NGV funding was static at $1.550 million from 1995-2008, and in 2009 the expenditure was only $1.396 million. DRA contends that the market for NGVs is not as strong as SoCalGas suggests, and that SoCalGas has not justified why the additional funding is needed.

The second reduction is to capacity products and planning. DRA recommends disallowance of the cost of the storage valuation software ($188,000) because DRA does not believe SoCalGas has justified the cost of new software.[122]

DRA's third reduction is to disallow SoCalGas' request for market assessments to advance the biofuel market because it does not believe that ratepayers should be subsidizing the market development of biofuels.

DRA's fourth reduction would disallow half of SoCalGas' incremental request for environmental affairs because DRA does not believe SoCalGas has justified why large customers need ratepayer assistance to comply with air quality regulations.

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[122] SoCalGas contends that the incremental funding associated with the storage valuation software upgrade is $168,000 and not the $188,000 that DRA recommends. SoCalGas contends that the $20,000 difference is associated with the non-labor employee expenses for three additional positions [FTEs].

10.4.3.3.2.2. SoCalGas

SoCalGas requests $2.256 million for its NGV customer education, education and training program. This is an incremental increase of $860,000 over the 2009 base year expenses of $1.396 million. SoCalGas contends that it presented significant evidence of long term historical and future market growth for NGVs. From 2000 to 2010, SoCalGas states that the use of natural gas as a vehicle fuel has grown at an average annual rate of 14.8% in the service territories of SoCalGas and SDG&E.

SoCalGas also points out that contrary to DRA's argument that the NGV funding is for market outreach activities, the majority of the incremental funding for the NGV program is for existing account management and support, and customer training courses that are focused on safety. The incremental funding would cover four account management and staff support positions. SoCalGas contends that without this incremental funding, it "will be unable to provide all of the NGV customer information, education and training services provided to customers in the past and will severely reduce NGV customer outreach and promotion activities." (Ex. 419 at 46.) SoCalGas further contends that without the necessary funding, that this would conflict with the requirement in Pub. Util. Code § 740.3 to "implement policies to promote the development of equipment and infrastructure needed to facilitate the use of electric power and natural gas to fuel low-emission vehicles." (*See* Ex. 419 at 47.)

For capacity products and planning, SoCalGas requests $2.767 million for the 2012 test year. This is an incremental increase of $488,000 over the five-year average of $2.279 million. SoCalGas points out that its storage products and hub services generated a $38.9 million benefit to ratepayers in 2009, and is profitable and of benefit to ratepayers. The software upgrade cost of $168,000 is a small cost relative to the benefits of such products and services. SoCalGas also contends that the current software does not have the capability to consider certain other relevant factors for pricing storage services.

For biofuel market development, SoCalGas is requesting $377,000, which is an incremental increase of $120,000 over the 2009 base year expense of $257,000. SoCalGas contends that it should be allowed to leverage its experience in natural gas processing technology and its distribution infrastructure to help promote the market development of biogas. SoCalGas also contends that such development is consistent with the state and the Commission's policies to develop biogas resources.

For environmental affairs, SoCalGas is requesting $476,999 for the 2012 test year. This is an incremental increase of $260,000 over the five-year average of $216,000. SoCalGas contends that DRA's recommended disallowance of $130,000 is arbitrary, and without support or analysis. SoCalGas contends that the environmental affairs staff acts as liaisons to governmental agencies that regulate air quality and to all customer classes of SoCalGas.

10.4.3.3.3. Discussion

We first address DRA's recommended disallowance for shared services NGV funding. SoCalGas requests $2.256 million for shared services NGV funding, while DRA recommends $1.550 million. SoCalGas' request represents an incremental increase of $860,000 over the 2009 base year expenses of $1.396 million. SoCalGas argues that the NGV market is continuing to grow, that federal and state legislation is continuing to emphasize the use of alternate transportation fuels, and there is an increase in the number of third party products and services for NGV vehicles and refueling equipment. DRA argues that the NGV market is not growing as strongly as SoCalGas claims, that half of the incremental funding is for market outreach activities, and SoCalGas has not presented a strong case for why additional program staff are needed.

We have reviewed the evidence presented by SoCalGas and DRA regarding shared services NGV funding. We agree with SoCalGas that the NGV market is likely to continue growing due to air quality and GHG concerns, and the cost of gasoline. However, we also agree with DRA that the additional staff positions may be more than necessary. Since the incremental funding of $860,000 would cover four account management and staff support positions, we believe that two fewer positions will provide sufficient staffing to manage and support existing customers, as well as providing support and outreach for the anticipated growth of the NGV market in southern California. Accordingly, it is reasonable to reduce these costs by $630,000, for a total 2012 test year forecast of $1.626 million for shared services NGV funding.

Next, we address DRA's recommended reduction of $188,000 to SoCalGas' $2.767 million forecast of capacity products and planning. DRA recommends that the cost of the software upgrade be disallowed because it believes SoCalGas has not justified the need for an upgrade, or explained why the staff cannot perform the necessary calculations without software. We have reviewed the evidence presented by SoCalGas and DRA. The additional software upgrade is a very minor expense considering the financial benefits that ratepayers receive from SoCalGas' storage and hub services. In order to continue providing those benefits, the licensing of one more user to use the software, and to enhance the analytic capability of the storage valuation software is reasonable. Accordingly, we do not adopt DRA's recommendation to disallow the software upgrade from the forecast of the capacity products and planning.

For biofuel market development, DRA recommends that the incremental increase of $120,000 be disallowed. DRA believes that ratepayers should not be subsidizing the market development of biofuels, and that the development of this market should be left to the private sector. However, DRA's objection to the development of the biofuels market overlooks the fact that this group has been around since 2008 and is focused on biogas market development. Even if DRA's recommendation were adopted, SoCalGas would still be requesting funding for similar biogas market development activities, which DRA does not object to. The activities of SoCalGas in biofuels presents the opportunity to utilize the biogas produced from organic waste, and the $120,000 cost to support market assessments and engineering studies in this area is a reasonable and worthwhile expense. Accordingly, DRA recommendation to disallow the $120,000 incremental increase from the shared services biofuel market development cost is not adopted.

The next issue is to address DRA's recommendation to disallow $130,000 from the shared services environmental affairs cost. DRA's recommended disallowance represents half of the incremental increase of $260,000 over the five-year average of $216,000. DRA's recommendation to disallow the $130,000 is based on the argument that the air quality compliance activities of large customers are being subsidized by ratepayers. We are not persuaded by DRA's argument that this should be a reason for disallowing this shared services cost. As SoCalGas noted in its testimony, air quality standards are becoming more stricter, and the regulations are becoming more complex. Since the use of natural gas by both large and small customers is affected by these air quality standards and regulations, we believe it is important for SoCalGas to have a role in explaining to its customers how the use of these standards and regulations will affect their businesses, and the way in which they consume natural gas. However, this activity appears to have some overlap with SoCalGas' similar requests in other areas. It also appears that the costs for this activity could be done for less than SoCalGas has forecasted. For those reasons, it is reasonable to reduce the shared services environmental affairs cost by $100,000.

We have reviewed all the evidence concerning the remainder of the O&M shared services cost for customer service and information. Except for the adjustments discussed above to the shared services NGV funding, and to the shared services environmental affairs costs, SoCalGas' forecast of the O&M shared services cost is reasonable, and the amount of $6.215 million should be adopted.

10.4.3.4. Capital Expenditures

10.4.3.4.1. Introduction

SoCalGas plans three capital projects to support the business needs and objectives in the customer service and information area. The three projects are for the Sustainable SoCal Program, California Producer Access, and Next Generation Envoy. The total amount requested for the 2012 test year is $12.059 million. SoCalGas also requests capital expenditures of $234,000 for 2010, and $1.261 million for 2011.

The Sustainable SoCal Program is for the installation of four biogas conditioning systems at small to mid-size wastewater treatment facilities.[123] These systems will capture the raw biogas (also called digester gas) and convert is to pipeline quality biogas (biomethane). This project will help develop the market potential of producing pipeline quality biogas from digester raw biogas that is generated from small to mid-size wastewater treatment plants. The

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[123] These wastewater facilities have raw biogas volumes in the range of 200 to 600 standard cubic foot per minute.

primary role of SoCalGas will be to design, install, own and to operate the biogas conditioning systems at these sites. To house these systems, SoCalGas proposes to lease a small space from the facility. All of this biogas will meet the gas quality specifications contained in SoCalGas' Rule 30, and will be compressed and injected into SoCalGas' pipeline system. This biogas will then be used by SoCalGas for its facilities and to fuel its compressed natural gas (CNG) fleet vehicles. SoCalGas forecasts the 2012 test year cost of the Sustainable SoCal Program at $11.272 million.

The second capital expenditure project is for California Producer Access. In D.07-08-029, the Commission adopted the terms and conditions by which natural gas produced by California gas producers will be granted access to the SoCalGas transmission system. As a result of D.07-08-029 and D.10-09-001, SoCalGas will need to make changes to various systems to accommodate the access by California gas producers. SoCalGas forecast costs of $234,000 for 2010 and $474,000 for 2011 for this project.

The third capital expenditure project is for the Next Generation Envoy (Envoy) project. Envoy is the electronic bulletin board operated by SoCalGas, which provides its customers with information about gas transportation, firm transmission rights and storage rights trading, hub services, and informational postings. This project will improve the usability of the Envoy system, allow Envoy to be accessed from other mobile devices, and allow customers to access their proprietary information. For this project, SoCalGas forecasts $787,000 in 2011, and $787,000 in 2012.

10.4.3.4.2. Position of the Parties

10.4.3.4.2.1. DRA

DRA recommends that the Sustainable SoCal Program be disallowed in its entirety. DRA contends that since natural gas is a deregulated commodity, SoCalGas should not be involved in the production of biogas. DRA also contends that SoCalGas has not explained why ratepayers should have to subsidize this unregulated production activity. In addition, DRA contends that the production of biogas is not cost-effective since the cost of gas at the SoCalGas border was $4.30 per million British thermal units (MMbtu) as of July 29, 2011. DRA also contends that SoCalGas did not compare the cost of producing biomethane to the cost of other renewable energy sources. Although the

Legislature and the Commission have made policy commitments to develop solar energy, DRA contends that no such policy commitments have been made for bioenergy. DRA further contends that if the ratepayers of SoCalGas have to fund this project that SoCalGas ratepayers will be cross subsidizing the ratepayers of the wastewater plants because those plants will no longer have to flare off the methane and incur costs associated with the reduction of GHG.

10.4.3.4.2.2. SoCalGas

SoCalGas contends that DRA misunderstands key elements of the Sustainable SoCal Program. Contrary to the contentions of DRA, SoCalGas contends that this program supports Commission and state policies, advances a valuable resource for the region and for SoCalGas' customers, and its costs are in the range of other renewable technologies.

SoCalGas contends that its ratepayers are not subsidizing the wastewater treatment facilities because they will only receive lease payments for allowing SoCalGas to site its biogas conditioning equipment. These facilities will not receive any compensation for the biogas. According to SoCalGas, "a small to mid-size wastewater treatment plant can flare their biogas to the atmosphere with minimal cost to the facility owner/operator." (Ex. 419 at 55.) Since the flaring of biogas is considered to be part of the active carbon cycle, this process of flaring does not create GHG emissions. Instead of flaring the biogas, that biogas will be captured and processed through the conditioning system. By eliminating the flaring of the biogas, this reduces criteria pollutant emissions. Under the

Sustainable SoCal Program, all of the benefits of the biomethane and the GHG credits will go to SoCalGas' ratepayers. Since the owners of the wastewater treatment facilities will only receive rent payments, and incur minimal fees to flare off biogas, SoCalGas contends that no subsidy will result due to this program.

SoCalGas rejects DRA's contention that SoCalGas did not provide a comparison of the cost of biomethane to other renewable energy sources. SoCalGas contends that such a comparison was provided to DRA in the data response request that DRA referenced. SoCalGas contends that its comparison of the cost of biomethane to the cost of electricity produced by photo voltaic thin film is the most relevant comparison because the thin film technology is relatively early in its market development.

SoCalGas contends that the Sustainable SoCal Program is supported by different groups, and is in accord with state initiatives and policies regarding renewable energy sources and GHG.

10.4.3.4.3. Discussion

Of the three capital expenditure projects that SoCalGas proposes to undertake, the only objection is to the Sustainable SoCal Program.

SoCalGas contends that this project fulfills the state's objective of promoting the use of biogas. In D.11-09-015, and Executive Order S-06-06, the Commission and Governor expressed support for the use of biogas. Most recently, the California Legislature enacted AB 1900 (Statutes of 2012, Chapter 602), which among other things, added Pub. Util. Code § 399.24. Subdivision (a) of that code section provides as follows:

> To meet the energy and transportation needs of the state, the commission shall adopt policies and programs that promote the in-state production and distribution of biomethane. The policies and programs shall facilitate the development of a variety of sources of in-state biomethane.

However, that legislation also provides that before the biomethane can be injected into a gas utility's pipeline, the biomethane must meet the standards that are being developed by the Office of Environmental Health Hazard Assessment, and the Commission, as provided for in Health and Safety Code § 25421.

Another factor to consider is that the Commission rejected SoCalGas' AL 4172 without prejudice. In that AL, SoCalGas sought to offer biogas conditioning service to potential biogas producers, and for SoCalGas to own bioenergy production facilities so as to produce raw biogas from organic matter for potential biogas producers.[124] SoCalGas proposed in that AL to offer both services as a NTP&S in accordance with the Commission's Affiliate Transaction Rules. The basis for the Commission's rejection of the AL was because the approach that SoCalGas proposed was "contrary to currently-established Commission Decisions and Rules on non-tariffed products and services…." (Ex. 319, Attachment L at 1.)

SoCalGas attempts to distinguish the rejection of AL 4172 from its Sustainable SoCal Program on the basis that SoCalGas will be using its own

[124] SDG&E filed AL 1991-G requesting the same authority as SoCalGas' AL 4172. SDG&E's AL 1991-G was also rejected by the Commission in the same Energy Division letter.

conditioning system to process the raw biogas, that it will own the biomethane, and that it will be used in SoCalGas' NGV fleet vehicles.

However, we are not persuaded by SoCalGas' argument that because SoCalGas will own the biomethane and use it to refuel its NGV fleet vehicles that this should trump the underlying rationale as to why AL 4172 was rejected. The rationale for rejecting the AL is because the proposed activity may be contrary to the Affiliate Transaction Rules concerning NTP&S.

The Affiliate Transaction Rules are designed to erect boundaries between transactions between the utility and its affiliates. (*See* D.06-12-029, Appendix A-3, II.B.) In the situation before us, SoCalGas proposes to own and operate the biogas conditioning systems which will produce biomethane for use in its fleet vehicles. Although the Commission supports the use of biogas, SoCalGas through the use of ratepayer funds should not be investing in these types of systems simply to produce biomethane in order to "Encourage and promote market development of the biogas market, particularly in the small size producer segments." (Ex. 417 at 89.) As SoCalGas itself acknowledges, the cost-benefit analysis for small to midsize wastewater treatment facilities "does not provide the necessary financial return for biogas producers to move forward with the installation of biogas conditioning facilities." (Ex. 417 at 89.) To require ratepayers of SoCalGas to fund the purchase, installation, and operation of the Sustainable SoCal Program, in order to refuel SoCalGas' NGV fleet vehicles is not a reasonable use of ratepayer funds. We note that requiring ratepayers to fund such a project, as SoCalGas has requested, is distinct from the Commission adopting "policies and programs that promote the in-state production and distribution of biomethane." (Pub. Util. Code §399.24(a).) Accordingly, we adopt DRA's recommendation that the entire request for the Sustainable SoCal Program capital expenditure be disallowed.

We have reviewed the testimony concerning the two other capital projects that SoCalGas proposes in the area of customer service information. We find the request of SoCalGas for capital expenditure funding of the California Producer Access and Next Generation Envoy projects to be reasonable and funding for these two projects should adopted as requested by SoCalGas.

Based on the above discussion, the following capital expenditures for customer information is reasonable and should be adopted: $234,000 for 2010; $1.261 million for 2011; and $787,000 for 2012.

11. Information Technology

11.1. Introduction

The Information Technology Services division of both SDG&E and SoCalGas are responsible for the administration and operations of the computing equipment and software technology which supports the utilities' daily operations. This equipment consists of computer, storage, communications, security, and system management hardware and software. In addition, this hardware and software require the necessary personnel "to support, maintain, enhance and manage this infrastructure in an effective and responsive manner." (Ex. 175 at 19; Ex. 179 at 18.) This division and all of the hardware and software support each utility's operations in the following areas: (1) continuing demand for information technology services from the respective utility's business and operations; (2) incorporating new operations tasks following completion of large capital projects; (3) technology upgrades due to obsolescence; (4) protecting its information technology from security threats; and (5) additional information technology requirements brought about by new or enhanced regulatory mandates. As a result of these needs and demands, both utilities have a large number of functioning business applications and technology platforms to provide utility services to their customers, as well as for the internal operations of the two utilities. Many of these information technology resources must be available 24 hours a day for day-to-day operations, as well as during outage conditions.

The Information Technology Services division incurs both O&M costs, as well as capital expenditures.

11.2. SDG&E Information Technology

11.2.1. Introduction

For test year 2012, SDG&E forecasts total O&M costs of $55.539 million. The O&M costs are made up of $14.837 million in non-shared costs, and $40.702 million in booked shared services costs. SDG&E's forecast of capital expenditures for 2010, 2011 and 2012 are $46.322 million, $100.966 million, and $70.528 million, respectively.

11.2.2. O&M Non-shared Services

11.2.2.1. Introduction

SDG&E's O&M non-shared services costs amount to $14.837 million. These non-shared services costs are composed of the following six work groups: IT Cisco Work Group 1; IT Cisco Work Group 2; IT Software Development Work Group 3; IT Smart Grid 6; IT SDG&E Metering Work Group 8; and IT Smart Meter Program Management Work Group 9.

The IT Cisco Work Group 1 is "responsible for the maintenance and enhancement programming support of CISCO Billing, Finance, SO/CI, CMT, Measurement and Administration applications for SDG&E customer systems."

(Ex. 175 at 26.) SDG&E forecasts an incremental increase of $759,000 over the 2009 adjusted recorded amount of $2.880 million due to an increase in the number of software developers to support enhancements to the Customer Information System that are being driven by new regulatory requirements and tariffs, and to support new smart meter functions for billing, measurement, and service order dispatch applications.

The IT Cisco Work Group 2 is "responsible for developing and planning business cases and project capital plans for IT Customer Care Systems SDG&E business process." (Ex. 175 at 27.) SDG&E does not forecast any change from the 2009 recorded level of $348,000.

The IT Software Development Work Group 3 provides support for the GIS, electric transmission and distribution operations, and activities supporting utility operations and support systems. SDG&E forecasts an incremental increase of $2.214 million due to the transition of personnel from capital projects to O&M roles.

The IT Smart Grid 6 has O&M activities that are associated with the smart grid capital projects.

The IT SDG&E Metering Work Group 8 "is responsible for the maintenance and enhancement programming support of SORT, DASR, MV90/MDMA and Meter applications for SDG&E customer systems." (Ex. 175 at 30.) SDG&E forecasts an incremental increase of $2.186 million over the 2009 adjusted recorded amount of $701,000 due to the addition of additional positions "to provide new or increased integration and application support services for Smart Meter, Meter Data Management, Head End, Outage Management (OMS), Distribution Management (DMS) and Sales Order

Automation systems, middleware upgrades and Direct Access market reopening systems changes," as well as for increases in software license costs.

The IT Smart Meter Program Management Work Group 9 "is responsible for the implementation and integration of Smart Meter Applications-supported SDG&E Customer Systems." (Ex. 175 at 31.) SDG&E forecasts an incremental increase of $1.841 million over the 2009 adjusted recorded amount of $900,000 due to the addition of positions to support HAN project work, and non-labor costs.

11.2.3. Shared Services

11.2.3.1. Introduction

The shared services costs retained by SDG&E amount to $39.986 million, and the shared services billed in from SoCalGas amount to $716,000. SDG&E's booked shared services costs total to $40.702 million.

SDG&E's shared services consist of the following 10 categories of management: senior VP –chief information technology officer; VP information technology; infrastructure engineering and operations; client services and enterprise support; network and communications services; utility operations and shared services; customer care systems; information security and information security compliance; business planning and budgets; and costs that are billed in from IT's SoCalGas cost centers.

11.2.4. Position of the Parties

11.2.4.1. DRA

DRA recommends $52.100 million as the total O&M information technology expenses for test year 2012. This is a difference of $3.4 million from SDG&E's forecast.

DRA's recommended disallowance of $3.4 million is composed of $1.9 million in HAN related expenses, and $1.5 million from personnel changes to projects from maintenance and enhancement programming support, customer system support, information security, and business planning.

DRA's recommended disallowance of the HAN related expenses are due to the reasons described earlier in the customer services field section of this decision. DRA essentially contends that all HAN expenses should be disallowed because they are premature, lack tangible benefits, and are inappropriate given the developing competitive market for HAN products and services. On DRA's recommended disallowance of $1.5 million for various personnel adjustments, DRA's testimony only described where its monetary adjustment came from but did not provide any reasons why the amounts should be disallowed.

11.2.4.2. SDG&E

On DRA's recommended disallowance of HAN-related costs, SDG&E disagrees with DRA's position on HAN as described in the customer services field section of this decision. SDG&E contends that its O&M costs for the HAN projects are reasonable and accurate.

Regarding DRA's $1.5 million recommended disallowance, SDG&E contends that DRA's methodology did not account for the actual drivers that impact future costs, and did not allow for changes in activity levels related to the project lifecycle.

SDG&E contends that its forecast was based on the identification and calculation of incremental changes from key drivers of growth, changing technology, and business and customer requirements. DRA did not identify any unreasonable assumptions in SDG&E's forecasts, and did not provide any analysis of SDG&E's forecast. SDG&E contends that the personnel changes "are reasonable, necessary, and will support useful services that will benefit customers." (Ex. 178 at 4.)

11.2.4.3. Discussion of O&M Costs

The testimony of SDG&E and DRA on the O&M expenses for information technology, and on the HAN costs have been reviewed and considered.

In the customer services field section of this decision, we discussed DRA's opposition to SDG&E's HAN investments, and determined that it is reasonable to reduce the funding of these HAN-related activities. We also determined that the funding request for a HAN testing laboratory was premature and disallowed the funding for the testing laboratory.

Consistent with how we funded the HAN activities in the other section, some reduction to the O&M costs for the IT smart meter program management work group 9 is warranted. Under that work group, SDG&E has requested incremental costs of $1.850 million for the addition of 4.2 FTEs to support HAN project work and for non-labor costs to support HAN software maintenance. Since we have reduced the 2012 HAN capital expenditures, it is appropriate and reasonable to reduce the 2012 HAN-related O&M costs in this work group. Accordingly, the 2012 test year forecast for the IT smart meter program management work group 9 should be reduced from $1.850 million to $600,000.

Regarding DRA's recommended disallowance of $1.5 million for various personnel adjustments, we have compared the forecasts of SDG&E and DRA to the historical costs, and to SDG&E's current staffing and its request for incremental positions. SDG&E's incremental increase amounts to over $9 million in non-shared costs. We are not convinced by SDG&E's testimony that all of these new positions are needed given the total O&M costs that SDG&E is requesting for information technology. Based on those considerations, we adopt DRA's recommendation to reduce the number of additional positions that SDG&E has requested for the test year. Accordingly, it is reasonable to reduce the non-shared costs by an additional $1.750 million.

Based on the reductions described above, the amount of $52.439 million should be adopted as the 2012 test year total O&M costs for SDG&E's information technology division.

11.2.5. Capital Expenditures

11.2.5.1. Introduction

For the period from 2010 to 2012, SDG&E proposes 50 information technology projects.[125] According to SDG&E, its capital expenditure projects are the result of the planning process it goes through in deciding which projects should move forward.[126] The majority of the capital projects are composed of a combination of costs that are related to regulatory mandates and to replace obsolete technology. Some of these capital projects are to improve the security and recoverability of its computer operations and data, and to provide new or enhanced capabilities.

SDG&E's forecast of capital expenditures for 2010, 2011 and 2012 are $46.322 million, $100.966 million, and $70.528 million, respectively. The following are summaries of some of these projects.

- Smart grid communication system projects: this project implements an advanced wireless communications system

[125] These information technology projects are listed in Exhibit 175 at 60-62.

[126] SDG&E's capital project planning process is described in Exhibit 175 starting at 9.

that will allow SDG&E to monitor, communicate with and control transmission and distribution equipment.

- Cyber security: to address the increased physical and cyber security requirements associated with the development, implementation, and operation of the smart grid system distribution and operation components.
- Wide area network (WAN) rebuild projects: to replace WAN routers, retire legacy networks, upgrade microwave transport paths and create network designs to support virtualized networks.
- Total personal computer replacement: refresh hardware to accommodate the roll out and use of the Windows 7 operating system.
- One Voice SDG&E: standardizes the phone system throughout SDG&E and the Sempra companies, but is specific to the costs of implementing this project for SDG&E, and retires end-of –life private branch exchange telephone systems.
- El Dorado migration: the preliminary costs to integrate the Commission-authorized purchase of the 480 megawatt combined cycle power plant in Nevada into SDG&E's business and security systems.
- Energy procurement projects: migrating away from an Excel-based application environment to support necessary and new functions to comply with stricter financial reporting, and to improve the performance of energy procurement decisionmaking.
- Mainframe web services upgrade: replacement of current web services application that have reached the end of service life cycle, and upgrade to a mainframe-based web services.
- Local area network (LAN) refresh projects: refresh obsolete LAN switches at branch office locations.
- Application testing and remediation: to test and remedy problems resulting from the migration of 12,000 personal

computers from a Windows XP operating system to a Windows 7 operating system.

- Conferencing refresh projects: upgrade the existing conferencing infrastructure to increase call capacity, provide external conferencing capability, and provide a foundation to integrate platforms.
- SAP PI upgrade: upgrade SAP PI from version 7.0 to 7.1, and associated equipment upgrades.
- IEO small capital projects: to address unanticipated growth and capacity issues, make improvements to storage, servers, operating system, and related infrastructure software.
- SDG&E streaming media: install infrastructure and management application for capturing and configuring streaming media content.
- GFMS server refresh: upgrades to GFMS hardware and operating systems in order for the GFMS applications to remain in a stable environment and until the new GIS solution is functional.
- MDMA and AMMS replacement: replacement of the MDMA and AMMS business applications.
- NCS small capital projects: address unanticipated breakage, growth, and capacity issues for network and telecommunications infrastructure components.

11.2.5.2. Position of the Parties

11.2.5.2.1. DRA

DRA recommends that the Commission approve $188.6 million for SDG&E's three years of capital expenditures for 2010-2012. This is a difference of $13.7 million from what SDG&E recommends be adopted. DRA's recommended disallowance of $13.7 million is composed of a disallowance of $12.6 million for

HAN-related projects, and a disallowance of about $1.1 million based on DRA's use of a three-year weighted average to forecast personnel positions.[127]

11.2.5.2.2. SDG&E

SDG&E opposes DRA's recommended disallowance of $12.6 million for HAN-related projects because of the reasons explained earlier in the customer services field section of this decision.

On DRA's remaining disallowance that is based on its methodology to forecast personnel positions, SDG&E contends that DRA's methodology is flawed, and that DRA failed to address why certain projects were selected for reductions. SDG&E contends that DRA's forecasting methodology is flawed because it does not allow for fluctuations in labor from year to year depending on the life of the project. In addition, DRA's forecasting methodology did not take into account the specific and known IT project salaries. SDG&E contends that its forecast methodology did take these items into account, and "more accurately reflects and produces a reasonable estimate of its forecasted capital expenses." (Ex. 178 at 6.)

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[127] Although DRA states that it used "a three-year weighted average method to forecast FTEs," it appears that DRA used recorded data from 2009 or 2010 and then made other adjustments. (See Ex. 514 at 5, 7-8; Ex. 182, Attachment A, at 2 of 4.) DRA stated it planned to correct this statement in its errata, but such a correction was not made. (*See* Ex. 514 at 4, footnote 8; Ex. 515.)

11.2.5.3. Discussion

We first address DRA's recommended disallowance of $12.6 million for HAN-related projects. DRA's recommendation seeks to disallow SDG&E's request for funding of $4.982 million in 2011, and $7.579 million in 2012, for HAN-related projects. As discussed earlier in the customer services field section of this decision, and in the above discussion of the O&M costs for information technology, we determined that it was appropriate to reduce the funding for HAN-related capital projects in 2011 by 25%, and in2012 by 50%. For those same reasons, it is appropriate and reasonable to reduce SDG&E's HAN-related information technology projects by 25% in 2011, and by 50% for 2012. Accordingly, SDG&E's capital expenditures for HAN-related projects in 2011 should be reduced by $1.246 million, and in 2012 by $3.789 million.

Next, we address DRA's recommendation to reduce capital expenditures by about $1.1 million due to DRA's lower forecast of personnel positions. The testimony and the arguments of SDG&E and DRA regarding these personnel positions and the methodologies they used have been reviewed and considered. Given the size of SDG&E's capital expenditure request over the three years, and the current economic circumstances, we agree with DRA that there should be a reduction of $1.1 million in capital expenditures related to the forecast of personnel positions.

In addition, we believe that further reductions in SDG&E's capital expenditures for information technology are warranted. Having reviewed SDG&E's information technology request, we are concerned about the size of the amounts that SDG&E is requesting. Over the three-year period, if SDG&E's request were fully adopted, SDG&E's investments in information technology would amount to about $270 million. Given the state of the economy, and the impact that SDG&E's information technology request will have on ratepayers, it is appropriate that further reductions be made to SDG&E's request. In addition, elsewhere in this decision, we have reduced the amount of funding for SDG&E's smart grid activities. Since part of SDG&E's information technology request is related to the smart grid communication system, and other related smart grid activities, it is appropriate to make reductions in this area as well. Since SDG&E's capital expenditure request for funding in 2011 and 2012 are $110.346 million, and $91.713 million, respectively, it is appropriate and reasonable to further reduce SDG&E's 2011 request by $15 million, and its 2012 request by $10 million. These reductions are necessary to reduce the financial impact on ratepayers, and to encourage SDG&E to take the initiative in controlling its information technology costs.

Based on the above discussion and reductions, funding of SDG&E's capital expenditures for 2010, 2011, and 2012 in the amount of $46.322 million, $83.620 million, and $56.739 million, respectively, should be approved.

11.3. SoCalGas Information Technology

11.3.1. Introduction

For the 2012 test year, SoCalGas forecasts total O&M costs of $52.406 million. The O&M costs are made up of $377,000 in non-shared costs, and $52.029 million in booked shared services costs. SoCalGas' forecast of capital expenditures for 2010, 2011 and 2012 are $68.594 million, $110.346 million, and $91.713 million, respectively.

11.3.2. O&M Costs

11.3.2.1. Introduction

The only O&M non-shared service for SoCalGas is provided by the education, training and communications work group. This work group "provides consulting to project teams to increase end-user engagement and productivity," and "ensures quality execution and adequate coverage on all change-related activities across multiple company programs." (Ex. 179 at 23.)

SoCalGas forecasts 2012 test year O&M costs of $377,000 which is based on the zero based method. This cost center was created in the fourth quarter of 2009, and the 2012 test year forecast reflects a full year of labor costs for four positions and associated employee expenses.

SoCalGas' O&M shared services come from the following four areas: VP of information technology; client services and enterprise support; network communication services; and IT costs that are billed in from SDG&E's cost centers.

The shared services costs retained by SoCalGas amount to $2.011 million, and the shared services billed in from SDG&E amount to $50.018 million.

11.3.2.2. Position of the Parties

11.3.2.2.1. DRA

DRA recommends shared and non-shared services expense of $51 million for SoCalGas. According to DRA, the difference of $1.4 million is from the Global Insight inflation rate adjustment on inter-company billing of $1.3 million, and $100,000 on customer care systems.

11.3.2.2.2. SoCalGas

SoCalGas contends that DRA did not explain how it chose projects to apply its proposed disallowances, and that the projects appear to have been selected at random. SoCalGas also contends that DRA's methodology does not account for the actual drivers that impact future costs, and does not allow for changes in activity levels based on the project lifecycle. According to SoCalGas, its methodology provides "a true picture of future cost requirements." (Ex. 182 at 3.)

11.3.2.3. Discussion

We have reviewed the testimony, the historical costs, and compared the methodologies used by DRA and SoCalGas. DRA's recommended disallowance of $1.4 million for SoCalGas' O&M IT costs is due to the adjustments it made using the Global Insight inflation rate for 2012.

As pointed out by DRA, the historical costs reveal that the information technology O&M costs for the Applicants have increased dramatically in recent years, which result in higher costs to ratepayers. In 2009, the Applicants' O&M costs rose to $87.929 million from the average O&M cost of $7.786 million that was experienced in 2007 and 2008. In 2010, the Applicants' O&M costs increased again to $131.945 million.

We recognize that information technology is constantly changing, and that computer platforms and systems can become outdated quickly. However, containment of these increasing costs by the Applicants is warranted given the difficult economic circumstances that ratepayers face. For those reasons, we agree with the approach that DRA has taken. DRA used the 2009 costs as a base for existing cost centers, and the 2010 costs as a base for the new cost centers. DRA then applied the Global Insight inflation rates to these base amounts. However, instead of applying DRA's recommended reduction of $1.4 million, it is reasonable under the circumstances to reduce SoCalGas' shared O&M information technology costs by $2 million to help contain these growing O&M costs, and to alleviate the cost burden on ratepayers. Accordingly, it is reasonable to adopt total information technology O&M costs for SoCalGas of $50.406 million.

11.3.3. Capital Expenditures

11.3.3.1. Introduction

For the period from 2010 to 2012, SoCalGas proposes 91 information technology projects.[128] According to SoCalGas, its capital expenditure projects are the result of the planning process it goes through in deciding which projects should move forward.[129] A significant number of the capital projects are driven by the need to replace obsolete technology.

SoCalGas' forecast of capital expenditures for 2010, 2011 and 2012 are $68.594 million, $110.346 million, and $91.713 million, respectively. The following are summaries describing about 80% of the capital expenditure projects.

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[128] These information technology projects are listed in Exhibit 179 at 36-37.

[129] SoCalGas' capital project planning process is described in Exhibit 179 starting at 8.

- Citrix 6: this is an integrated platform that is composed of hardware, operating system, and system software. It connects internal and external users to Sempra's IT environment. The vendor, Citrix Systems, will no longer support the current installed version 4, and as a result, the project will replace the various existing Citrix system component so that the upgraded Citrix system can be accommodated.
- Data center perimeter 2010: replacement of existing network perimeter hardware and security as it approaches end-of-life and end-of-support.
- Data center rebuild: project is to improve the reliability and stability of the core network by refreshing core and WAN routers, and migration of WAN routing from core routers and data link switching from core routers.
- Distributed backup growth: supplement the backup environment to meet the growing needs for data protection as the storage environment continues to grow.
- Distributed storage growth: provide additional storage capacity for storage growth.
- DS8100 storage arrays refresh 2012: replace the DS8100 storage area network arrays that were purchased in 2004 with newer technology.
- Enterprise encryption: improve protection of sensitive financial and human resources data by implementing a hardware-based encryption mechanism onto existing server operating systems, application servers, and database platforms.
- Enterprise service management: provide the tools, processes, and resources that will improve IT's ability to troubleshoot, monitor, and resolve incidents and outages, and to automate some routine ticketing tasks.
- Governance risk and compliance: improve information security-related governance, risk and compliance

management processes that are time- and resource intensive.

- SoCalGas grid communication system: replace the outmoded radio frequency systems with an advanced wireless communications system that will allow SoCalGas to communicate with the mobile workforce, which will enable rapid work order response and logistical efficiencies.
- Identity and access management: implement additional automated, self-service workflows to create and maintain identities within the corporate network.
- Java development kit/WebLogic Server/WebLogic Portal: upgrading obsolete Java programming language-based tools and application development framework to support new enhancements for critical business applications.
- LAN refresh: manage and replace LAN switches with performance capabilities required to support strategic business and information technology initiatives.
- LINUX/UNIX server refresh: continuation of the conversion of aging and difficult to maintain environments over to other platforms.
- Logistics mobile refresh & expansion: replacement or upgrade of current mobile barcode scanner and radio frequency identification tags to newer technology.
- Mainframe hardware upgrade: replace the current mainframe with an upgraded mainframe in order to support production workload.
- Messaging project: design and deploy infrastructure to support Exchange 14.
- Microwave refresh: upgrade circuits and provide incremental capacity to meet the requirements of major new programs.
- Records management: addresses the practice of maintaining company records, and is to include the organization, storage, and archiving of non-records.

- SAP Business Intelligence software enterprise agreement: instead of making spot purchases of software, switch to an enterprise agreement.
- SAP support pack: institute a plan and schedule to keep current with support packages, and to upgrade the SAP support pack level to the current release level.
- Security operations management: to respond to security incidents involving customer premise devices by evaluating and implementing security incident and event management solutions and related capabilities.
- MPK and RB server rooms: provide floor and rack space to house servers for known and upcoming capital projects, and to monitor and report on the physical components of the server rooms and other related spaces.
- SharePoint Refresh: leverage new hardware and existing infrastructure to provide connectivity between vendors and the company over a secure internet in order to securely share documents.
- System Management Server upgrade: replace hardware and software of 17 servers to move from the existing System Management Server to a System Center Configuration Manager due to product end-of-life support.
- Software code security: implement an executable code security program to automate the examination of custom software at the source code level to identify risk conditions, and provide guidance to coding teams to remediate and mitigate risk conditions.
- Source to pay: to automate, make more efficient, and to optimize discounts in the accounts payable process.
- Windows 7 platform replacement program: implement a program to replace personal computers and printers to accommodate the change to a Windows 7 operating system.

- Voice to service: implement a project to configure and integrate email, instant messaging, voice/video/web conferencing, and enterprise voice services.
- WAN rebuild: continue to replace remaining end-of-support WAN routers, upgrade microwave transport paths, and enable enterprise-wide traffic engineering, virtualized networks, and quality of service functionality deployment.
- Wintel refresh: continue to remove servers that have reached the end of their five-year life cycle and to eliminate Microsoft Windows Server 2000 from Sempra's environment which is no longer supported.

11.3.3.2. Position of the Parties

11.3.3.2.1. DRA

According to DRA, its recommended disallowance of $1.2 million for SoCalGas' capital expenditures "is from FTE changes of projects related to software code security, and SCG meter quality handheld system replacement," and is "based on DRA's use of a three-year weighted average method to forecast FTEs." (Ex. 514 at 2, 8. *See* Ex. 182, Attachment A, 2 of 4.)

11.3.3.2.2. SoCalGas

SoCalGas opposes DRA's recommended disallowance of $1.2 million for its capital expenditures. SoCalGas contends that DRA's methodology is flawed, and that DRA failed to address why certain projects were selected for reductions.

SoCalGas contends that DRA's forecasting methodology is flawed because it does not allow for fluctuations in labor from year to year depending on the life of the project. In addition, DRA's forecasting methodology does not take into account the specific and known IT project salaries, and only allows for growth that is based on escalation rates.

SoCalGas contends that it "is entering a cycle of upgrading aging software and hardware infrastructure," and that many "large replacements are cyclical in nature, thereby driving lower capital expenditures in some years while driving higher expenditures in others." (Ex. 182 at 4.) SoCalGas contends that its forecasting methodology is more reasonable and indicative of its funding needs because it takes into account the change in activities and employee salaries, and the change in skill sets that occur over the life of a project.

11.3.3.2.3. Discussion

DRA recommends that SoCalGas' IT capital expenditures be reduced by $1.2 million due to the methodology it used to calculate the personnel positions that would be needed for certain projects.

The testimony and the forecasting methodologies of DRA and SoCalGas have been reviewed, compared, and considered. We are concerned that the recommended forecasts of DRA and SoCalGas are too generous given the scope of these 91 information technology projects. If SoCalGas' capital expenditure request is adopted without any change, these projects would add up to

$270.653 million over the three-year period. DRA's recommendation would only reduce this amount by $1.207 million.

As noted earlier, we recognize that information technology is constantly changing, and that computer systems and platforms that are state of the art in one year may become obsolete in a few years time. However, that does not mean that the Commission should automatically approve these capital spending projects, especially given the economic circumstances that we find ourselves in.

As SoCalGas' testimony shows, the 2009 recorded capital expenditure was $34.401 million. Under SoCalGas' request, these capital costs would rise to $68.594 million in 2010, $110.346 million in 2011, and $91.713 million in 2012. Although SoCalGas contends that these level of capital expenditures are needed "to continue to provide the required level of IT services to support utility business customer needs," we believe that SoCalGas can accomplish the same level of service at less cost than it has forecasted. (Ex. 179 at 34.) Given the current economic circumstances, and the impact that these capital expenditures will have on ratepayers if fully authorized, it is reasonable to reduce the level of capital expenditures in 2011 and 2012 to encourage SoCalGas to reduce these costs while providing the same level of services. Instead of dictating to SoCalGas what projects should be reduced, that is best left to SoCalGas to decide. Under the circumstances, it is reasonable to adopt the following information technology capital expenditures for SoCalGas: $68.594 million in 2010; $98 million in 2011; and $85 million in 2012.

12. Business Solutions/Support Services[130]

12.1. Introduction

Under this category of Business Solutions/Support Services are the following four functions: Supply Management; Diverse Business Enterprises (DBE); Senior VP and Chief Information Technology Officer; and Business Planning. Each of these functions provide a range of services to SDG&E, SoCalGas, and on a limited basis to Sempra's Corporate Center and other affiliated companies.

The Supply Management function manages the overall purchase, distribution, and inventory management of materials, supplies, and services in support of both utilities.

For SDG&E, these "goods and services include gas and electric distribution equipment such as transformers, piping, cable, meters, construction services, electric generation maintenance materials and services, electric transmission and substation materials and services, fleet vehicles and equipment, IT and telecom products and services, engineering services, environmental, and other professional and technical services." (Ex. 288 at 2.)

For SoCalGas, these "goods and services include gas distribution equipment such as piping, meters, construction services, fleet vehicles and equipment, IT and telecom products and services, engineering services, environmental, and other professional and technical services." (Ex. 291 at 2.)

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130 The SDG&E and SoCalGas exhibits refers to these costs as O&M costs, but in their brief includes these costs as administrative and general (A&G) costs.

Supply Management also "involves administrative activities associated with general office support, such as phone service, office supplies, travel services and document management." (Ex. 288 at 2; Ex. 291 at 2.)

The DBE function supports the activities of both SDG&E and SoCalGas in complying with GO 156's goal of procuring 21.5% of a utility's goods and services from women, minority, and disabled veteran business enterprises.

The Senior VP and Chief Information Technology Officer provide leadership and direction for eight divisions or departments.

The Business Planning function provides the support for the annual planning and budgeting activity for O&M expenses and capital expenditures, as well as support for GRCs, shared service cost allocation, and financial analysis.

12.2. SDG&E Business Solutions/Support Services

12.2.1. Introduction

For the 2012 test year, SDG&E forecasts total O&M costs of $13.013 million. The O&M costs are made up of $8.133 million in non-shared costs, and $4.880 million in booked shared services costs.

SDG&E's non-shared services costs are composed of activities associated with the logistics shops south, and office services. The O&M costs of these two activities are attributable to the four functions described earlier. SDG&E's forecast of the 2012 O&M non-shared services costs for business solutions/business support is $8.133 million.

The responsibility of the logistics shops south is to ensure that the inventory levels of supplies and materials are maintained. The logistics shop is composed of purchasing activities, shop services such as welding and machining support, and warehousing activities.

The activities of office services provide the following kinds of services: mailing services, copy centers, travel agency, forms and stationery, archives and record management, and food services.

SDG&E used the five-year averaging methodology for its forecast of these O&M costs.

As described in Exhibit 288, SDG&E's shared services costs are composed of the following activities: foundation; office services; portfolio management; supply management director; diverse business enterprises; senior VP and chief information technology officer; business planning; and billed in costs from SoCalGas. SDG&E's forecast of the 2012 O&M shared services costs for business solutions/business support is $4.880 million.

12.2.2. Position of the Parties

DRA reviewed SDG&E's shared and nonshared O&M costs for the business solutions/business support category of activities. DRA does not oppose SDG&E's 2012 test year forecast for total O&M expense.

The Joint Parties raised several issues regarding the DBE program. Those DBE concerns are addressed later in this section of the decision.

12.2.3. Discussion

We have reviewed the testimony concerning SDG&E's shared and nonshared O&M costs for the business solutions/business support category of activities, and determine that SDG&E's 2012 test year forecast of total O&M costs of $13.013 million is reasonable and should be adopted.

12.3. SoCalGas

12.3.1. Introduction

For the 2012 test year, SoCalGas forecasts total O&M costs of $19.520 million for the business solutions/business support category of activities.

The O&M costs are made up of $12.559 million in non-shared costs, and $6.961 million in booked shared services costs.

SoCalGas' non-shared services costs are composed of activities associated with the logistics shops north, and office services. The O&M costs of these two activities are attributable to the four functions described earlier. SoCalGas' forecast of the 2012 O&M non-shared services costs for business solutions/business support is $12.559 million.

The responsibility of the logistics shops north is to ensure that the inventory levels of supplies and materials are maintained. This work is carried out through ordering, receiving, issuing of material and supplies, and physical inventories. The logistics shop is also composed of a fabrication and tool repair shop, and warehousing activities.

The activities of office services provide the following kinds of services: mailing services, copy centers, travel agency, forms and stationery, archives and record management, and food services.

SoCalGas used the five-year averaging methodology for its forecast of these O&M costs.

As described in Exhibit 291, SoCalGas' shared services costs are composed of the following activities: foundation; logistics shops north; portfolio management; and billed in costs from SDG&E. SoCalGas' forecast of the 2012 O&M shared services costs for business solutions/business support is $6.961 million.

12.3.2. Position of the Parties

12.3.2.1. DRA

DRA recommends a total 2012 test year forecast of $17.715 million for the O&M costs for the business solutions/business support category of activities.

DRA's recommendation is lower than SoCalGas' forecast by $1.805 million. The differences between DRA and SoCalGas are due to the different forecasting methodologies that were used.

DRA contends that SoCalGas' use of the 2009 recorded adjusted expenses and the five-year average for nonshared costs "do not reflect appropriate expectations for these cost centers based on historical data." (Ex. 512 at 5.) An example of this is that SoCalGas forecasted an increase for 2010, but the actual 2010 recorded adjusted costs showed a decrease.

DRA recommends that a three-year average be used instead to forecast the 2012 test year costs for nonshared services for the logistics shop north and office services cost centers. DRA contends that its three-year average reflects "the most current level of activity within these cost centers and historical expenses." (Ex. 512 at 6.)

For shared services costs, DRA used 2010 recorded expenses as the basis to forecast 2012 test year expenses for two cost centers, logistics shops north and portfolio management. DRA contends that the forecasting methodology that SoCalGas do not reflect the downward trend in these cost centers that occurred from 2005 to 2010. For that reason, DRA used the 2010 recorded expenses as the basis for its forecast.

12.3.2.2. Joint Parties

The Joint Parties raised concerns about the DBE program. Those DBE concerns are addressed later in this section of the decision.

12.3.2.3. SoCalGas

SoCalGas contends that DRA's forecasting methodologies are flawed and should be rejected because of the following: "(1) DRA treated the entire submittal as an exercise in arithmetic; (2) DRA used only three-year averages and

2010 actuals, which do not accurately reflect the resource requirements of the department; and (3) downward trends, as stated by DRA, will not continue." (Ex. 293 at 2.) In addition, SoCalGas contends that DRA's focus was to "produce lower rates, regardless of the accuracy of the forecast used," and that "DRA's methodology ignores any incremental growth." (Ex. 293 at 3.)

SoCalGas contends that its forecasting method is reasonable because it accounts for the workload that comes from distribution, transmission, and customer services field work. SoCalGas anticipates that this workload will come from TIMP and DIMP.

12.3.3. Discussion

We have reviewed and considered the testimonies and methodologies of SoCalGas and DRA concerning the O&M costs for the business solutions/business support category of activities. We agree with DRA that its methodology for forecasting the 2012 test year costs will result in a more accurate forecast than SoCalGas' methodology, and will better reflect recent historical costs. Based on DRA's recommendation, it is reasonable to adopt $17.715 million for the 2012 test year of total O&M costs for the business solutions/business support category of activities.

12.4. Diverse Business Enterprise Concerns

12.4.1. Introduction

GO 156 sets forth the Commission's rules governing the development of programs to increase the participation of women, minority, and disabled veteran business enterprises (WMDVBEs) in the procurement of contracts from the utilities. GO 156 sets a goal of 21.5% participation by WMDVBEs.

The DBE department is responsible for the GO 156 activities that SDG&E and SoCalGas participate in. This department consists of one shared service cost center that is located at SDG&E, and is composed of a director and eight personnel positions.

Both SDG&E and SoCalGas purchase a wide range of products and services as part of the WMDVBE program.

In 2008 and 2009, SDG&E achieved 29.23% and 29.08% WMDVBE spending, respectively. SoCalGas achieved 31.06% and 34.53% WMDVBE spending in 2008 and 2009, respectively. In 2010, SDG&E achieved 36% WMDVBE spending, while SoCalGas achieved 37% WMDVBE spending.

12.4.2. Position of the Parties

12.4.2.1. Joint Parties

The Joint Parties provided an analysis of two areas which relate to the operations of the DBE department of the Applicants.[131] These two areas concern the Applicants' record on diversity, and the Applicants' record with diverse small businesses.

On diversity, the Joint parties contend that the Applicants are using just one metric to measure their GO 156 progress, i.e., the Applicants are relying on contracts that are "primarily awarded to large and extremely large corporations that are only partly minority-owned and are often out-of-state." (Ex. 391 at 8.) The Joint Parties contend that very little data has been gathered on small businesses and on community-based small business technical assistance.

[131] The testimony of the Joint Parties refers to Sempra instead of to SDG&E and/or SoCalGas. Since these GRC proceedings involve SDG&E and SoCalGas, and not their parent company, we refer to the two utilities instead of to Sempra.

The Joint Parties also contend that it is difficult to determine the dollar amount and percentage of small business contracts awarded to minority and disabled owned businesses based on the prime contractor's records.

The Joint Parties further contend that the Applicants will make only modest improvement unless the Commission orders them to comply with the intent of the Commission's diversity goal in GO 156.

Based on the above, the Joint Parties contend that the Applicants are gaming the system because the Applicants can inflate their achievements "without awarding many contracts to small minority-owned businesses or small businesses generally." (Ex. 391 at 9.) The Joint Parties also allege that this may be the reason for the Applicants reluctance to gather data on small businesses, which the Applicants should be required to do.

On the Joint Parties' analysis of the Applicants' record with diverse small businesses, the Joint Parties contend that because the Applicants appear "to be quite self-satisfied and…confident that it has effectively 'gamed' the system," the Applicants are not amenable to making improvements to the data gathering and reporting process for small businesses, providing more funding for technical assistance, and justifying why large contracts cannot be unbundled.
(Ex. 391 at 11.)

The Joint Parties recommend that the Applicants make the following improvements.

First, the Applicants should adopt a metric that gathers data using the definition that a small business is defined as one that has $1 million or less in revenues. Such a metric should be used by the Applicants in reporting their GO 156 compliance, and for gathering information about small businesses in the Applicants' service areas. Another recommendation of the Joint Parties is to have the Applicants collect data on subgroups of Asian, Native Hawaiian, and other Pacific Islander groups using Government Code §§ 8310.5 and 8310.7 as a model. (*See* 12 RT 1098-1099; 24 RT 3161-3162.)

Second, the Joint Parties contend that since the "underlying thesis in GO 156" is to "develop a massive technical assistance program <u>in cooperation with</u> minority, women and disabled veteran business non-profits," that the Applicants should "collectively or individually set aside one fourth of one percent (0.25%) of the dollar amount of their procurement dollars for CBO oriented technical assistance…, all of which can be recovered from the ratepayers." (Ex. 391 at 12.) Although the Applicants have committed about $650,000 each year during the rate cycle for technical assistance, the Joint Parties contend "that this amount is insufficient for the wide array of capacity-building and technical assistance programs that are necessary during the Great Recession…." (Joint Parties' Opening Brief at 25.)[132] In particular, the Joint Parties believe that this technical assistance needs to be focused on the capacity building of small businesses whose annual revenue is $1 million or less.

Third, the Applicants "should be required to justify, in writing, any contract above one million dollars in size as to why it cannot be unbundled." (Ex. 391 at 16.)

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[132] The term "capacity building" has been referred to as "the potential of a small but experienced business to increase its sophistication and performance capacity in order to become a competitive bidder on larger projects." (D.11-05-019 at 47.)

12.4.2.2. SDG&E and SoCalGas

The Applicants contend that the Joint Parties' recommendations are unsupported by the record, and that the Joint Parties rely on materials that have not been admitted into the record of this proceeding.[133] In addition, the Applicants contend that these GRC proceedings are not the proper forum in which to add additional requirements to GO 156.

The Applicants believe that the DBE concerns raised by the Joint Parties can be categorized into the following four issues:

- Sempra is gaming the system by awarding DBE contracts to large DBEs and ignoring small firms, which the Joint Parties define as revenues of under $1 million.
- Sempra should have a metric that demonstrates the dollar amount and percentage of contracts awarded by race, ethnicity, gender, and disabled veterans status for all contracts with businesses with $1 million or less in revenue.
- Sempra should set aside 0.25% of the dollar amount of their procurement for CBO-oriented technical assistance.
- Sempra should be required to justify in writing any contract above $1 million in size as to why it cannot be unbundled and to submit such justification to the Commission.

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[133] The Joint Parties' opening and reply briefs contain numerous references to media articles, many of which were not introduced during the evidentiary hearing, or were published after the evidentiary hearing was concluded. To the extent the Joint Parties' rely on those outside-the-record articles to form the basis of their arguments, those articles have not been given any weight in this decision.

Regarding the "gaming the system" issue, the Applicants contend that they track and report their WMDVBE accomplishments as defined by the Commission, and that the firms included in their results have been certified by the Commission as eligible women and minority owned businesses. The Applicants also contend that the GRC proceedings are not the proper forum for making any changes to the Commission's definition of a diverse firm or to GO 156.

Regarding the use of metrics to track WMDVBE contracts with businesses who have $1 million or less in revenue, such a requirement is not set forth in GO 156, and any new reporting requirement should be taken up in a GO 156 proceeding.

Regarding the amount of funding for technical assistance provided by CBOs, the Applicants point out that it has agreed to invest $650,000 per year in technical assistance[134] and business development programs that target diverse business enterprises, and that the Applicants spend about $2 million a year in diversity efforts. As for the Joint Parties' contention that the funding for technical assistance is very small in comparison to the number of businesses in California, that logic is flawed because not all of the businesses in California sell the products and services that the Applicants need.

Regarding the proposal to justify why a contract with a value of more than $1 million cannot be unbundled, the Applicants contend that the decision not to require the utilities to unbundled contracts was made in the GO 156 proceedings, and that such a requirement would be onerous.

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[134] This amount was agreed to in an agreement with the Greenlining Institute.

12.4.3. Discussion

In analyzing the concerns that the Joint Parties have raised, we address the fact that the Joint Parties' recommendations seek to make changes to GO 156, or to the Commission decision that has addressed GO 156.

The allegation that the Applicants are gaming the system by entering into contracts with large WMDVBEs involves the kind of business that is eligible to participate in the GO 156 program. If the Applicants are awarding contracts to large-sized WMDVBEs, those WMDVBEs must still meet the definitions of what a WMDVBE is, and must be certified as eligible to participate in the GO 156 program. The Joint Parties, by seeking to introduce a subcategory of WMDVBEs that have revenues of $1 million or less, affects the definitions and eligibility criteria as set forth in GO 156. (*See* sections 1.3, 3, and 4 of GO 156.)

The Joint Parties recommendation that a metric be established which defines a small business as having revenues of $1 million or less, and to provide reports based on the use of such a metric, also involves the rules contained in GO 156. GO 156 does not define an eligible WMDVBE as being of a certain size, nor does it distinguish between large or small WMDVBEs. The Joint Parties seek to revise how WMDVBEs are classified, to add a definition defining what a small WMDVBE is, and to provide reports based on the distinction between large and small WMDVBEs. All of these changes would affect the definitions and reporting requirements in GO 156. (*See* sections 1.3 and 9 of GO 156.) In addition, if the objective of the Joint Parties' recommendation is to encourage the Applicants to enter into more contracts with smaller sized WMDVBEs, that is an issue that could be addressed in the "Goals" section of GO 156.

The recommendation of the Joint Parties that the Applicants be required to set aside one fourth of one percent (0.25%) of the dollar amount of their procurement dollars for CBO oriented technical assistance is also an issue addressed by section 6, utility implementation, of GO 156.[135] For example, section 6.1 of GO 156 provides that "Each utility shall maintain an appropriately sized staff to provide overall WMDVBE program direction and guidance and to implement WMDVBE program requirements." In addition, section 6.2 of GO 156 provides that "Each utility shall implement an outreach program to inform and recruit WMDVBEs to apply for procurement contracts," and that "Outreach activities may vary for each utility depending on its size, service territory, and specific lines of business." Section 6.2.1 of GO 156 provides that each utility shall at a minimum "Actively support the efforts of organizations experienced in the field who promote the interests of WMDVBE contractors." The Joint Parties' recommendation to require the Applicants to spend a certain amount for CBO technical assistance is an issue that is within the purview of GO 156 since it specifically refers to active support of the efforts of CBOs who promote WMDVBE contractors, to "an appropriately sized staff," and that "outreach activities may vary for each utility." All of these phrases suggest that the Joint Parties' recommendation to provide a certain level of funding for CBO technical assistance should be taken up in the context of a proceeding addressing GO 156. Indeed, in D.11-05-019, the Commission found that it would advance the goals of GO 156 for the "utilities to include in their annual GO 156 reports the approximate amount of funds, to the extent available, directly expended on

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[135] We are not convinced that the Joint Parties' recommendation to use one fourth of one percent of the procurement dollars for this assistance will result in a significant increase in GO 156 participation since many of the small businesses with revenues of $1 million or less do not offer the types of services and materials the Applicants need.

developing and distributing technical assistance to WMDVBEs and small businesses." (D.11-05-019 at 23, 64, and 74, Finding of Fact 4, Conclusion of Law 4.)

Similarly, the Joint Parties' recommendation that the Applicants justify in writing why a contract exceeding $1 million cannot be unbundled is also an issue within the purview of GO 156 and addressed in D.11-05-019. Section 6.3 of GO 156 provides for the establishment of a subcontracting program, and section 6.3.2 specifically identifies what kind of contracts are subject to the subcontracting program. In addition, section 6.2.1.(6) provides that the utility employees are encouraged to break apart purchases and contracts to accommodate the capabilities of WMDVBEs.

The Joint Parties also suggest that Government Code §§ 8310.5 and 8310.7 should apply to the type of data that the Applicants should collect. However, Government Code § 8310.5 only applies to "A state agency, board, or commission that directly or by contract collects demographic data as to the ancestry or ethnic origin of Californians…," and Government Code § 8310.7 only applies to the Department of Industrial Relations, and the Department of Fair Employment and Housing. In addition, the testimony of the Applicants at the evidentiary hearing, and sections 2.2 and 3 of GO 156 itself, make clear that it is the Clearinghouse for GO 156 that is responsible for collecting the type of data about WMDVBE that the Joint Parties recommend be collected.[136]

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[136] Section 2.2 of GO 156 states: "In assessing the suitability of a WMDVBE to bid for procurement contracts, a utility may require additional information or the completion of additional forms to comply with specific requirements created by the unique character of its business, such as insurance requirements, product and service codes, bonding limits, and so on. A utility may not, however, require such additional

Footnote continued on next page

We also note that the Joint Parties' recommendation on providing justification as to why such a contract cannot be unbundled is a collateral attack on D.11-05-019. That decision, issued in R.09-07-027, decided that the utilities did not have to take any specific actions to unbundle contracts. In R.09-07-027, the Joint Parties raised the same issue that the utilities be ordered to "unbundle contracts in excess of $1 million or explain why not." (D.11-05-019 at 48, 50.) Since Pub. Util. Code § 1709 provides that "In all collateral actions or proceedings, the orders and decisions of the commission which have become final shall be conclusive," the Joint Parties are barred from litigating that same issue in this proceeding.

Based on the above, the recommendations of the Joint Parties concerning the Applicants' relationships with diverse business enterprises are issues that should have been brought up in R.09-07-027, which addressed changes to GO 156, or should be raised in a future proceeding addressing changes to GO 156. Since the changes that the Joint Parties seek affect specific provisions addressed in GO 156, we refrain in this decision from making the changes the Joint Parties have recommended, and do not adopt the Joint Parties' recommendations concerning diverse business enterprises.

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information in order to verify that a business is in fact a WMDVBE." Section 3.2 states: "The primary purpose of the clearinghouse shall be to audit and verify the status of WMBEs, and to establish and maintain a database of WMDVBEs that is accessible to the Commission and to participating utilities." Section 3.3 states: "The clearinghouse auditing and verification program shall preclude the need for an individual utility to audit and verify the status of the WMBEs it does business with."

13. Administrative and General Expenses

13.1. Introduction

This section of the decision addresses the administrative and general expenses in the following departments: environmental services; fleet services; real estate, land and facilities; emergency preparedness & safety; human resources, disability, and workers' compensation; controller, regulatory affairs and finances; and legal and external affairs.

The administrative and general expenses for each department may consist of O&M costs, as well as capital expenditures. The O&M costs discussed in this section may include non-shared costs, and shared costs.

In the sub-sections below, we address each department separately, first for SDG&E, and then for SoCalGas.

13.2. Environmental Services

13.2.1. Introduction

This section addresses the O&M costs for the Environmental Services Department for SDG&E and SoCalGas. No capital expenditures have been included in the department costs.

The Environmental Services Department is responsible for overseeing "compliance with over 400 federal, state, regional and local environmental statutes, rules and regulations, including laws protecting air quality, water quality, hazardous materials, waste, cultural resources, land planning and natural resources." (Ex. 325 at 2; Ex. 328 at 2.) The activities that this department undertakes include the following: "tracking and analyzing the final versions of environmental regulations; developing compliance policies, procedures and tools; developing and delivering training material; developing and implementing internal quality assurance and quality control procedures; screening proposed projects (including proposed real and personal property transactions) for environmental compliance, soils contamination considerations and permitting needs; and developing and obtaining environmental permits and plans." (*Ibid.*)

In addition to the above responsibilities, the department "also manages a California certified environmental laboratory, two…treatment storage and disposal facilities…and the remediation of contaminated soils at current and former utility sites." (Ex. 325 at 2; Ex. 328 at 2.)

13.2.2. SDG&E Environmental Services

13.2.2.1. Introduction

SDG&E requests $11.047 million for O&M expense, and a book expense value of $8.906 million.[137] SDG&E forecasts the non-shared O&M costs amount at $3.433 million, and the book expense shared services O&M costs at $5.527 million.

The non-shared costs support the activities that the Environmental Services Department conducts and manages only for the benefit of SDG&E. The shared costs "include compliance support provided by SDG&E staff to SoCalGas, and compliance support provided by SoCalGas staff to SDG&E, in the areas of air and water quality, land planning, natural and cultural resources, site

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[137] SDG&E's request of $11.047 million consists of the non-shared O&M cost of $3.433 million, and 100% of SDG&E's shared services incurred costs of $7.614 million. The book expense value of $8.906 million represents a $54,000 reduction from SDG&E's original book expense of $8.960 million. This $54,000 difference is the subject of DRA's motion to assess penalties against SDG&E for a violation of Rule 1.1 of the Commission's Rules of Practice and Procedure. The discussion of DRA's motion follows.

assessment and mitigation, environmental laboratory sampling and analyses and hazardous waste management." (Ex. 325 at 23-24.)

For SDG&E, these O&M costs cover the work in the following eight functional areas: executive oversight; environmental services director; environmental strategy; environmental management; environmental operations; hazardous materials and waste; SDG&E environmental analysis laboratory; and site assessment and mitigation. These eight functional areas are described in more detail in Exhibit 325.

According to SDG&E, the major drivers of the O&M costs for the Environmental Services Department are the federal, state, and local governments' environmental laws, rules, and programs. As described in Exhibits 325 and 327, there are a number of activities SDG&E will have to undertake such as the following: monitoring and reporting for GHG regulations and programs; monitoring, reporting, and testing to meet emission-related standards and regulations; obtaining special permits; conducting biological assessments and studies, and water quality studies; obtaining stormwater permits; monitor and conduct PCB testing; obtaining and complying with hazardous waste permits; and conducting environmental and safety training courses.

13.2.2.2. Position of the Parties

13.2.2.2.1. DRA

DRA recommends O&M book expense of $7.795 million. DRA's $7.795 million consists of $2.268 million for non-shared O&M costs, and the book expense shared services of $5.527 million.

DRA's non-shared O&M cost of $2.268 million is the 2010 recorded amount for the cost center that records the costs of the two treatment storage and disposal facilities, cleanup, management and disposal of hazardous wastes and contamination, and environmental permits. SDG&E's non-shared O&M forecast of $3.433 million was based on the 2009 recorded amount of $2.867 million, plus an incremental increase of $566,000. DRA contend that the assumptions that SDG&E used to generate its "incremental increases are inaccurate and do not reflect actual expenses…." (Ex. 517 at 5.) DRA contends that the 2005-2009 recorded expenses did not show any dramatic increases or fluctuations, and for that reason DRA recommends using the 2010 recorded amount.

For the shared O&M costs, DRA agrees with SDG&E's book expense of $5.527 million. However, DRA recommends that a $1.203 million reduction be made to SDG&E's shared services incurred costs of $7.614 million, resulting in incurred costs of $6.411 million. DRA disagrees with SDG&E's methodology and with the incremental increases to three cost centers.

The two DRA reductions would reduce SDG&E's total O&M request of $11.047 million to $8.679 million.

13.2.2.2.2. SDG&E

Regarding DRA's reduction of $1.165 million to non-shared services, SDG&E contends that environmental expenses "are most directly tied to existing, new or modified compliance requirements," and that "DRA's use of 2010 data without compensating for the reasonably anticipated incremental future changes does not provide for environmental costs for compliance-related activities due to new or modified regulations." (Ex. 327 at 4.) SDG&E contends that DRA's use of the 2010 data would "not include 2012 incremental environmental-related compliance activities as the new program and/or regulatory requirements may not have existed in 2010." (*Ibid*.) SDG&E contends that its method of using the base year plus incremental adjustments is more appropriate because it reflects the cost of the future activities, and provides a reasonable and accurate estimate of the test year 2012 expenses.

With respect to DRA's reduction of $1.203 million to shared services, and DRA's acceptance of the booked expenses for the environmental expenses of both SDG&E and SoCalGas, SDG&E contends that this will leave a shortfall that affects both SDG&E and SoCalGas. SDG&E contends that the shortfall will result because DRA's reduction to incurred expense "will underfund the resultant booked expense." (Ex. 327 at 8.) SDG&E also describes in Exhibit 327 why DRA's recommended adjustments to three shared services cost centers are not appropriate or reasonable.

13.2.2.3. Discussion

We have reviewed the testimony and arguments of the parties concerning the costs for the Environmental Services Department. We have also considered the cost drivers and the programs which SDG&E contends are causing the O&M costs to increase, and we have also compared the forecasts of SDG&E and DRA to the historical data.

The first issue is to address DRA's recommendation to reduce the non-shared O&M costs by $1.165 million. The main differences between the forecasts of DRA and SDG&E are the amount of the base year forecast, and whether incremental costs are warranted. DRA contends that no incremental increase is warranted, and that the 2010 recorded amount should be used as the test year 2012 forecast for non-shared O&M costs. SDG&E contends that the 2009 recorded amount should be used as the base forecast, and incremental increases are needed "to address environmental permit fees increases and hazardous waste management and disposal requirement that did not occur in the base year." (Ex. 325 at 22.) We first note that the 2009 base forecast ($2.867 million) that SDG&E used is the second highest recorded cost over the 2005 to 2010 period. DRA's use of the 2010 recorded data ($2.268 million) is the lowest recorded cost during that same period. A five-year average of 2005-2009 will result in $2.760 million, while a six-year average of 2005-2010 will result in $2.679 million. Based on the historical averages for the non-shared costs, our review of the incremental increases that SDG&E requests, and DRA's position that no incremental increases are needed, it is reasonable to adopt a non-shared O&M amount of $3 million for test year 2012.

The second issue to address is the PCB-related O&M costs. According to the workpapers in Exhibit 326, SDG&E estimates there will be $747,206 in environmental PCB-related costs ($508,549 non-shared, and $238,657 shared) that it will undertake in test year 2012 as a result of the EPA's advance notice of a proposed rulemaking to phase out PCBs. As mentioned earlier in the section addressing SDG&E's electric distribution operations, we did not provide SDG&E with funding for activities related to the EPA's proposal to open such a rulemaking. The reason for not doing so is because the evidence demonstrates that the EPA is unlikely to institute a rule to phase out PCBs by the end of 2012. In addition, we have authorized SDG&E to establish the NERBA to record the costs of the EPA rule on the phase-out of PCBs. Since there is currently no EPA regulation phasing out the use of PCBs, it is not necessary to grant the request of SDG&E to include the costs of phasing out PCBs, and it is reasonable to reduce the non-shared ($508,549) and shared services ($238,657) O&M costs by $747,206 for activities related to the phase-out.

The third issue pertains to the other adjustments that DRA recommends to the shared services cost centers. We are not persuaded by DRA that those adjustments should be made.

Based on our above discussion, the non-shared O&M costs of $2.491 million should be adopted, and O&M shared costs of $5.288 million should be adopted, for test year 2012. This results in total O&M costs of $7.779 million.

13.2.2.4. DRA Motion Requesting Penalties for Rule 1 Violation

On April 10, 2012, following the close of the evidentiary hearings, DRA filed a motion requesting that the Commission levy penalties against SDG&E and/or SoCalGas for violating Rule 1.1 of the Commission's Rules of Practice and Procedure. DRA contends that SDG&E made a number of misleading and false statements pertaining to $54,000 in environmental fees that SDG&E had requested in its direct testimony and workpapers. In essence, DRA's motion alleges that SDG&E requested monies for environmental fees and in doing so referenced regulations and user fee schedules that do not apply to SDG&E's electric substations. DRA alleges that these misleading and false statements were contained in the direct and rebuttal written testimony and workpapers, and were made during the January 17, 2012 evidentiary hearing.

SDG&E filed a response to the motion on April 25, 2012. SDG&E's response contends that it made no misrepresentations or false statements, and that nothing it did was done intentionally, recklessly, or with gross negligence. SDG&E acknowledges that its workpapers mistakenly used the wrong cost matrix to calculate the fees, and that the confusion surrounding this unintentional mistake was compounded by the substitution of a new witness. After being examined on this fee issue at the evidentiary hearing, SDG&E's witness looked into the issue and discovered that the wrong cost matrix had been used. Afterwards, SDG&E removed the $54,000 from its request, and made that change in its February 17, 2012 update testimony (Exhibit 596), and in its March 2, 2012 comparison exhibit (Exhibit 598).

DRA filed a reply to SDG&E's response on May 2, 2012.

Rule 1.1 provides in pertinent part that anyone who "offers testimony at a hearing…" shall never "mislead the Commission or its staff by an artifice or false statement of fact or law."

We have reviewed DRA's motion and the related pleadings, and have also reviewed the applicable exhibits and the hearing transcript of January 17, 2012. We have also reviewed the applicable Commission decisions regarding alleged violations of this rule.[138]

Based on all those considerations, we conclude that SDG&E did not violate Rule 1.1.[139] It is apparent from a review of the transcript that there was some confusion about which environmental fees are paid, and what fee schedule, if

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[138] These decisions refer to Rule 1, which was the predecessor to current Rule 1.1.

[139] Since DRA's motion only refers to the actions of SDG&E's testimony and witness, we conclude that DRA's motion does not apply to SoCalGas.

any, applies to SDG&E's electric substations. (*See* 26 RT 3381-3385, 3411, 3414-3415, 3418-3419.) Part of the problem was that the original witness who sponsored the testimony, was replaced by another sponsoring witness. Although the wrong cost matrix was used in SDG&E's workpapers to justify its request for these fees, SDG&E researched this discrepancy after the January 17, 2012 testimony, and discovered that the wrong cost matrix was included in the workpapers. SDG&E then took steps to remove the amount requested in its February 17, 2012 update testimony, and in SDG&E's March 2, 2012 comparison exhibit. SDG&E also noted in footnote 1075 of its April 12, 2012 opening brief, two days after DRA's motion was filed, that these fees had been removed. Under the circumstances, and the actions that SDG&E took to correct this mistaken information regarding the fees for the electric substations, we conclude that no Rule 1.1 violation has occurred.[140]

13.2.3. SoCalGas Environmental Services

SoCalGas requests $2.856 million for O&M expense, and a book expense value of $4.856 million.[141] SoCalGas forecasts the non-shared O&M amount at $594,000, and the book expense shared services O&M amount at $4.262 million.

The non-shared costs support the activities that the Environmental Services Department conducts and manages only for the benefit of SoCalGas. The shared costs "include compliance support provided by SoCalGas staff to SDG&E, and compliance support provided by SDG&E staff to SoCalGas, in the

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140 We also note that this dispute could have been avoided earlier on by DRA through the use of data requests when this fee issue was first uncovered.

141 SoCalGas' $2.856 million consists of the non-shared O&M cost of $594,000, and 100% of SoCalGas' shared services incurred costs of $2.262 million.

areas of air and water quality, land planning, natural and cultural resources, site assessment and mitigation, environmental laboratory sampling and analyses and hazardous waste management." (Ex. 328 at 21.)

For SoCalGas, these O&M costs cover the work in the following seven functional areas: executive oversight; environmental services director; environmental strategy; environmental management; hazardous materials and waste; SDG&E environmental analysis laboratory; and site assessment and mitigation. These seven functional areas are described in more detail in Exhibit 328.

According to SoCalGas, the major drivers of the O&M costs for the Environmental Services Department are the federal, state, and local governments' environmental laws, rules, and programs. As described in Exhibits 328 and 330, there are a number of activities SoCalGas will have to undertake such as following: monitoring and reporting for GHG regulations and programs; monitoring, reporting, and testing to meet emission-related standards and regulations; screening for potential cultural resources impacts; obtaining special permits; obtaining stormwater permits; monitor and conduct PCB testing; tracking of new and proposed environmental regulations; auditing of hazardous waste vendors; and conducting environmental and safety training courses.

DRA reviewed SoCalGas' O&M costs for environmental services. DRA does not oppose SoCalGas' forecast of $594,000 for non-shared services, and does not oppose SoCalGas' forecast of $4.262 million for shared services. No other parties have taken issue with SoCalGas' O&M costs for environmental services.

Based on our review of the testimony of SoCalGas and DRA, it is reasonable to adopt SoCalGas' total O&M forecast of $2.856 million, and its book expense value of $4.856 million.

13.3. Fleet Services

13.3.1. Introduction

According to the Applicants, the "Fleet Services organization is a shared service organization, and provides vehicle acquisition and disposition, maintenance and repair, fuel management, and technical services to [SDG&E, SoCalGas], and, on a limited basis, to the parent company Sempra Energy Corporate Center…, and other affiliate companies of Sempra Energy." (Ex. 103 at 1; Ex. 106 at 1.)

Fleet Services provides daily support, and "manages a mix of vehicles consisting of autos, light duty, medium and heavy duty trucks, and power operated equipment including trailers and forklifts." (Ex. 103 at 2; Ex. 106 at 2.)

Both SDG&E and SoCalGas perform non-shared services for costs that are unique to each utility's fleet services. SDG&E and SoCalGas also perform shared services.

The Fleet Services organization consists of the following five groups: asset management; financial and systems management; maintenance operations – North; maintenance operations – South; director – Fleet Services. The activities of these five groups are described in Exhibits 103 and 106.

According to the Applicants, the key challenge facing Fleet Services is technological change, which is driven by the CARB's emissions reduction requirements. If retrofits of vehicles to meet these emission requirements is "not practical the alternative of early replacement of heavy duty vehicles, contribute significantly to upward pressures on Fleet costs." (Ex. 103 at 5; Ex. 106 at 5.)

13.3.2. SDG&E Fleet Services

13.3.2.1. Introduction

The SDG&E fleet consists of approximately 2300 vehicles, which can be categorized into the following vehicle types: automobiles; compact trucks and vans; medium duty trucks and vans; heavy duty trucks and vans; trailers; and construction equipment. According to SDG&E, in 2009 its "vehicles accumulated more than 20 million miles and were serviced at 11 fleet maintenance garages, including satellite facilities." (Ex. 103 at 4.)

SDG&E estimates total O&M costs for Fleet Services at $40.093 million. This total consists of $38.248 million in non-shared costs, and $1.845 million in shared costs.

SDG&E's non-shared services costs consist of the four following categories: ownership costs; maintenance operations; maintenance management; and vehicle and equipment rentals. Since SDG&E leases its vehicles, the ownership costs consist of lease amortization, interest, salvage value, and license fees. The maintenance operations consist of performing vehicle safety inspections, routine maintenance, repairing vehicle damage, managing fuel inventory, and ensuring compliance with applicable environmental, safety, and emission regulations. The maintenance management category consists of both a shared and non-shared function. The shared function involves training of technicians, while the non-shared function is garage supervision and support. The vehicle and equipment rentals cover the rental costs.

SDG&E's shared services costs include the following categories: asset management; financial and systems management; the training function within maintenance management; and the department director. The activities of these four groups are described in Exhibit 103.

13.3.2.2. Position of the Parties

13.3.2.2.1. DRA

DRA recommends total O&M costs of $31.752 million, which consists of $30.471 million in non-shared costs, and $1.281 million in shared costs.

DRA's recommendation is based on $7.777 million in reductions to the non-shared costs for ownership costs, maintenance operations, and maintenance management. DRA's recommendation is also based on $243,000 in reductions to some of the shared asset management cost centers.

DRA's recommended reductions are based on its opposition to SDG&E's forecast methodology and incremental increases. DRA contends that "SDG&E's assumptions used to generate incremental increases, which were added to 2009 recorded expense, including zero-based, five-year averages, and five-year linear trends[,] do not reflect future expected expenses within these cost centers." (Ex. 513 at 6.)

For ownership costs, DRA used the three-year average of 2008-2010 for one cost center, and the recorded 2010 amount for another cost center. DRA contends that its "forecast methods reflect the most current level of activity within these cost centers." (Ex. 513 at 6.) For these two cost centers, DRA's recommended forecast is $3.884 million less than SDG&E's forecast.

For maintenance operations, DRA used the three-year average of 2008-2010 because the recorded amounts for 2005-2010 showed fluctuations. DRA's recommended forecast is $3.744 million less than SDG&E's forecast.

For maintenance management, DRA used the 2010 recorded amount because the 2005-2009 recorded amounts "show only very small increases for the past three years," and the "2010 recorded expenses show only very small increases for the past three years." (Ex. 513 at 7.) DRA's recommended forecast is $149,000 less than SDG&E's forecast.

For the shared services asset management cost centers, DRA recommends using the 2010 recorded costs, instead of SDG&E's methodologies which "used 2009 recorded adjustment expenses, three and four-year averages, plus incremental expenses for activities within each cost center…." (Ex. 513 at 8.) DRA's recommended forecast of these shared services costs is $243,000 less than SDG&E's forecast.

13.3.2.2.2. SDG&E

SDG&E contends that DRA's recommended reductions would result in a forecast that is below the 2009 level. SDG&E contends that DRA's forecast will "impair SDG&E's ability to effectively run its fleet operations and meet its compliance requirements in 2012," and will affect its "ability to perform its day-to-day operations to serve its customers, respond to service calls, and provide timely response to emergency situations." (Ex. 105 at 2.) SDG&E further contends that DRA focused "exclusively on mathematically deriving lower forecasts for several cost categories," and did not acknowledge or discuss any of the cost drivers that SDG&E discussed. (*Ibid*.) Also, SDG&E contends that DRA "did not consider the regulatory and environmental mandates that SDG&E must comply with regarding its vehicles, thereby placing SDG&E at risk of fines and penalties for compliance failures." (Ex. 105 at 1.)

Regarding DRA's recommended reductions to the non-shared ownership costs, SDG&E contends that DRA's reductions to the amortization and interest cost centers, and DRA's agreement with SDG&E's salvage forecast, results in a severance of "the relationship that exists among those three integrated components," which will produce "strange and unintended consequences whereby no new vehicles could be purchased, while vehicles required for day-to-day service would have to be sold." (Ex. 105 at 3.) SDG&E contends that DRA's recommendation will result in a depleted fleet.

With regard to DRA's recommended reduction to the maintenance operations cost centers. SDG&E contends that DRA's recommendation fails to account for complying with the CARB's emissions reduction requirements. SDG&E contends that its technicians "must be trained and certified to perform maintenance on new particulate trap and selective catalytic reduction systems that have been mandated for installation on all diesel-powered vehicles by CARB." (Ex. 105 at 6.) According to SDG&E, these additional costs will be phased in from 2008-2013, which DRA's three-year average of 2008-2010 will not reflect.

SDG&E also contends that DRA's methodology will not reflect the increased costs that will be needed to comply with the CARB's requirement to retrofit diesel engines to comply with the Airborne Toxics Control Measure. SDG&E contends that these retrofit costs "are driven by particular vehicle type and expected dates for when those vehicles are up for mandatory retrofitting." (Ex. 105 at 7.) SDG&E contends that DRA's reduction to this cost center will significantly underfund the costs needed to comply with this regulation.

Regarding DRA's recommended reduction to maintenance management, SDG&E contends that DRA's own table shows that there is an observable cost trend in this cost center. This trend supports SDG&E's linear forecast, instead of DRA's use of 2010 recorded data. SDG&E also contends that the additional

technicians are "needed to keep pace with technological changes in vehicle maintenance and emissions monitoring associated with its vehicles, including hybrid and alternative fuel vehicles."
(Ex. 105 at 8.)

With respect to DRA's use of recorded 2010 data for its test year 2012 forecast of the shared services costs, SDG&E contends that DRA's use of the 2010 amounts will not accurately reflect the costs for test year 2012.

13.3.2.3. Discussion

We have reviewed the testimony and arguments of SDG&E and DRA concerning the fleet services O&M costs. We have also reviewed their differing forecasts, compared their forecasts to the historical data and averages, and considered the need for the incremental increases. In light of all those considerations, it is reasonable to do the following, as described in the paragraphs which follow.

For the non-shared O&M costs for ownership costs, we agree with SDG&E's methodology for calculating the amortization, interest and salvage costs. Since these three elements are interrelated to the leasing of vehicles, we do not adopt DRA's recommendation to reduce the ownership costs by $3.384 million.

For the non-shared maintenance operations and maintenance management costs, we believe that SDG&E's forecasts of these three cost centers are too high, while DRA's forecasts are too low. In order to provide sufficient funds to meet the CARB emission requirements, the necessary retrofits of diesel engines, and to meet changes to vehicle maintenance and emissions monitoring, it is reasonable to reduce funding for these cost centers by a total of $2.500 million, which will reduce SDG&E's forecasts of these cost centers from $15.812 million to $13.312 million.

For the shared services cost centers that DRA takes issue with, we agree with SDG&E that its forecasts of these costs will more accurately reflect the test year 2012 costs.

Accordingly, based on the discussion above, it is reasonable to adopt non-shared costs of $35.748 million, and shared costs of $1.845 million, for test year 2012.

13.3.3. SoCalGas Fleet Services

13.3.3.1. Introduction

The SoCalGas fleet consists of approximately 5100 vehicles, which can be categorized into the following vehicle types: automobiles; compact trucks and vans; light duty trucks and vans; medium duty trucks and vans; heavy duty trucks and vans; trailers; and construction equipment. In 2009, SoCalGas' "vehicles accumulated more than 34 million miles and were serviced at 49 fleet maintenance garages." (Ex. 106 at 4.)

SoCalGas estimates total O&M costs for Fleet Services at $50.691 million. This total consists of $49.187 million in non-shared costs, and $1.504 million in shared costs.

SoCalGas' non-shared services costs consist of the four following categories: ownership costs; maintenance operations; maintenance management; and vehicle and equipment rentals. Since SoCalGas leases its vehicles, the ownership costs consist of lease amortization, interest, salvage value, and license fees. The maintenance operations consist of performing vehicle safety inspections, routine maintenance, repairing vehicle damage, managing fuel inventory, and ensuring compliance with applicable environmental, safety, and emission regulations. The maintenance management category consists of both a shared and non-shared function. The shared function involves training of technicians, while the non-shared function is garage supervision and support. The vehicle and equipment rentals cover the rental costs.

SoCalGas' shared services costs include the following categories: asset management; financial and systems management; the training function within maintenance management; and the department director. The activities of these four groups are described in Exhibit 106.

13.3.3.2. Position of the Parties

13.3.3.2.1. DRA

DRA recommends total O&M costs of $43.240 million, which consists of $41.795 million in non-shared costs, and $1.445 million in shared costs.

DRA's recommendation is based on $7.392 million in reductions to the non-shared costs for ownership costs, maintenance operations, and maintenance management. DRA's recommendation is also based on $268,000 in reductions to some of the shared asset management cost centers.

DRA's recommended reductions are based on its opposition to SoCalGas' forecast methodology and incremental increases. DRA contends that SoCalGas' "assumptions used to generate incremental increases, that were added to 2009 recorded expense, includ[ing] zero-based, five-year averages, and five-year linear trends[,] do not reflect future expected expenses within these cost centers." (Ex. 513 at 11.)

For ownership costs, DRA used the three-year average of 2008-2010 for one cost center, and the recorded 2010 amount for another cost center. DRA contends that its "forecast methods reflect the most current level of activity within these cost centers." (Ex. 513 at 11.) For these two cost centers, DRA's recommended forecast is $2.862 million less than SoCalGas' forecast.

For maintenance operations, DRA used the three-year average of 2008-2010 because the recorded amounts for 2005-2010 showed fluctuations. DRA's recommended forecast is $4.322 million less than SoCalGas' forecast.

For maintenance management, DRA used the 2010 recorded amount because the 2005-2010 recorded amounts "show no drastic fluctuations for the past three years," and the "2010 recorded expenses reflect the most current level of activity within this cost center." (Ex. 513 at 12.) DRA's recommended forecast is $208,000 less than SoCalGas' forecast.

For the shared services asset management cost centers, DRA recommends using the three-year average of 2008-2010, instead of SoCalGas' methodology which "used 2009 recorded adjusted expenses, plus incremental expenses for activities within each cost center…." (Ex. 513 at 13.) DRA's recommended forecast of these shared services costs is $268,000 less than SDG&E's forecast.

13.3.3.2.2. SoCalGas

SoCalGas contends that DRA's recommended reductions would result in a forecast that is a $1.659 million increase above the 2009 level. SoCalGas contends that DRA's forecast will "impair [SoCalGas'] ability to effectively run its fleet operations and meet its compliance requirements in 2012," and will affect its "ability to perform its day-to-day operations to serve its vast service territory, respond to service calls, and provide timely response to emergency situations." (Ex. 108 at 2.) SoCalGas further contends that DRA focused "exclusively on mathematically deriving lower forecasts for several cost categories," and did not acknowledge or discuss any of the cost drivers that SoCalGas discussed. (*Ibid*.) Also, SoCalGas contends that DRA "did not consider the regulatory and environmental mandates that [SoCalGas] must comply with regarding its vehicles, thereby placing [SoCalGas] at risk of fines and penalties for compliance failures." (Ex. 108 at 1.)

Regarding DRA's recommended reductions to the non-shared ownership costs, SoCalGas contends that DRA's reductions to the amortization and interest cost centers, and DRA's agreement with SoCalGas' salvage forecast, results in a severance of "the relationship that exists among those three integrated components," which will produce "strange and unintended consequences whereby no new vehicles could be purchased, while vehicles required for day-to-day service would have to be sold." (Ex. 108 at 3.) SoCalGas contends that DRA's recommendation will result in a depleted fleet.

With regard to DRA's recommended reduction to the maintenance operations cost centers. SoCalGas contends that DRA's recommendation fails to account for complying with the CARB's emissions reduction requirements. SoCalGas contends that its technicians "must be trained and certified to perform maintenance on new particulate trap and selective catalytic reduction systems that have been mandated for installation on all diesel-powered vehicles by CARB." (Ex. 108 at 6.) According to SoCalGas, these additional costs will be phased in from 2008-2013, which DRA's three-year average of 2008-2010 will not reflect.

SoCalGas also contends that DRA's methodology will not reflect the increased costs that will be needed to comply with the CARB's requirement to retrofit diesel engines to comply with the Airborne Toxics Control Measure. SoCalGas contends that these retrofit costs "are driven by particular vehicle type and expected dates for when those vehicles are up for mandatory retrofitting." (Ex. 108 at 7.) SoCalGas contends that DRA's reduction to this cost center will significantly underfund the costs needed to comply with this regulation.

Regarding DRA's recommended reduction to maintenance management, SoCalGas contends that DRA's own table shows that there is an observable cost trend in this cost center. This trend supports SoCalGas' linear forecast, instead of DRA's use of 2010 recorded data. SoCalGas also contends that the additional technicians are "needed to keep pace with technological changes in vehicle maintenance and emissions monitoring associated with its vehicles, including hybrid and alternative fuel vehicles." (Ex. 108 at 8.)

With respect to DRA's use of the three-year averages for its test year 2012 forecasts of the shared services costs, SoCalGas contends that DRA's use of the three-year averages will not accurately reflect the costs for test year 2012.

13.3.3.3. Discussion

We have reviewed the testimony and arguments of SoCalGas and DRA concerning the fleet services O&M costs. We have also reviewed their differing forecasts, compared their forecasts to the historical data and averages, and considered the need for the incremental increases. In light of all those considerations, it is reasonable to do the following, as described in the paragraphs which follow.

For the non-shared O&M costs for ownership costs, we agree with SoCalGas' methodology for calculating the amortization, interest and salvage costs. Since these three elements are interrelated to the leasing of vehicles, we do not adopt DRA's recommendation to reduce the ownership costs by $2.862 million.

For the non-shared maintenance operations costs, and the non-shared maintenance management costs, we believe that SoCalGas' forecasts of these cost centers are too high, while DRA's forecasts are too low. In order to provide sufficient funds to meet the CARB emission requirements, the necessary retrofits of diesel engines, and to meet the technological changes to vehicle maintenance and emissions monitoring, it is reasonable to reduce funding for these cost centers by a total of $4.287 million, which will reduce SoCalGas' forecasts of these cost centers from $17.615 million to $13.328 million.

For the two shared services cost centers that DRA takes issue with, we agree with SoCalGas regarding the incremental costs, and that SoCalGas' forecasts of these costs will more accurately reflect the test year 2012 costs.

Accordingly, based on the discussion above, it is reasonable to adopt non-shared costs of $44.900 million, and shared costs of $1.504 million, for test year 2012.

13.4. Real Estate, Land and Facilities

13.4.1. Introduction

The Real Estate, Land and Facilities (RFE&F) organization is a shared services organization that is headed by a director, who oversees activities which are performed at both SDG&E and SoCalGas. REL&F "is responsible for the administration of real estate, facilities, and land services for a combined portfolio of 3.55 million square feet…." (Ex. 163 at 2; Ex. 167 at 2.) This organization provides services for both SDG&E and SoCalGas, as well as for Sempra's Corporate Center and non-utility affiliates. As part of its responsibilities, it "plans, acquires, builds, and maintains the operating and non-operating real estate and facility assets in support of the delivery of gas and electric energy…." (*Ibid*.)

This section describes the O&M costs and capital expenditures for the REL&F organization. We first discuss the REL&F activities by SDG&E, followed by SoCalGas.

13.4.2. SDG&E Real Estate, Land and Facilities

13.4.2.1. Introduction

SDG&E forecasts total O&M costs of $26.840 million for test year 2012. This total consists of $8.462 million in non-shared costs, and $18.378 million in shared costs. For capital expenditures, SDG&E forecasts $20.289 million in 2010, $32.596 million in 2011, and $25.598 million in 2012.

13.4.2.2. O&M Costs

13.4.2.2.1. Background

SDG&E's forecast of O&M costs for test year 2012 consists of $8.462 million in non-shared costs, and $18.378 million in shared costs.

The non-shared costs are made up of the following three components: non-shared rents; non-shared facility operations and capital programs; and non-shared land services and right of way.

The non-shared rents pays for the rent associated with "telecom sites, branch offices, an environmental laboratory, office, multi-use, and customer service facilities, trailers, and [right of way] easements." (Ex. 163 at 3.) SDG&E expects all the rents, with the exception of the right of way easement, "to increase by an average of 5% per year based on a combination of contractual increases and landlord estimates for operating expense increases." (*Ibid*.) SDG&E expects the right of way easements "to increase by an average of 10% per year based upon estimates received from landlords and recent escalations for such large properties as the Bureau of Land Management and the railroads." (*Ibid*.)

The facility operations of SDG&E's non-shared facility operations and capital programs provides the "operation and maintenance support for utility facilities including general offices, construction and operations centers, telecommunications sites, warehouse, and branch/bill payment offices."

(Ex. 163 at 4.) SDG&E's facility operations have four regions, and each region is managed by a facility manager and a team of mechanics. These mechanics provide building maintenance, repair and other services. In addition, facility operations negotiate and manage outside contractors for such services as janitorial, landscaping, trash, and pest control. Other outside contractors are hired for such services as electrical, mechanical, heating and ventilation, and fire safety.

The capital programs of SDG&E's non-shared facility operations and capital programs "is responsible for managing the overall design, build-out, and reconfiguration process for utility office and support facilities." (Ex. 163 at 6.)

The non-shared land services and right of way provides the services for acquiring land rights, and is composed of the land management group, and land survey support. Land management "is responsible for the protection and enforcement of land rights in the form of fee ownership, easements, licenses and leases for electric and gas distribution and transmission operating asset requirements including overhead and underground gas and electric facilities, electric substations, switching facilities, gas regulator stations, etc., and ensures and maintains the necessary access to those facilities." (Ex. 163 at 7.) Land management "also secures agreements with other utilities and municipalities for the installation of utility facilities," and provides survey and GIS support. (*Ibid*.) The land survey support group "is responsible for the management, service delivery and quality assurance oversight of survey contractors," and also provides training for planners involved in customer extensions. (*Ibid*.)

The shared services for REL&F provide the support for shared facilities and services. These shared services activities consist of shared rents, shared facility operations, shared facility capital programs, shared land services and right of way, and shared services billed in from SoCalGas.

The shared rents allocate the rental cost of shared building space to SDG&E, SoCalGas, the corporate center, and affiliates. In addition, shared rents has a corporate real estate manager who "provides strategic asset management, transaction management, lease negotiation and administration services for SDG&E, SoCalGas, corporate center, and other affiliates upon request." (Ex. 163 at 9.)

The shared facility operations consist of two workgroups. The first workgroup provides space planning services, and furniture and equipment moves, to SDG&E, SoCalGas and corporate center. The second workgroup provides facility operations for shared service activities using SDG&E employees or contractors. The key shared facilities are the Rancho Bernardo Data Center, and several leased office and operations facilities.

The shared facility capital programs "is responsible for managing the overall design, build-out, and reconfiguration process for utility office and support facilities." The Facilities Capital Programs department, which is centralized at SDG&E, "manages all facilities capital and select O&M projects for both SDG&E and [SoCalGas]…." (Ex. 163 at 13.)

The shared land services and right of way performs different functions, as described in Exhibit 163. The GIS department of land services provides a shared GIS database, which provides information on land easements, related utility infrastructure, and access to related property documents and maps. The land and right of way group is categorized as an SDG&E cost center, but it provides 100% support to SoCalGas for gas pipeline easements.

The shared services billed in from SoCalGas are for the shared costs that SoCalGas has allocated to SDG&E. The largest cost is for rents at facilities which are shared by both utilities.

13.4.2.2.2. Position of the Parties

13.4.2.2.2.1. DRA

DRA forecasts total O&M costs of $22.705 million. DRA's forecast consists of $6.427million in non-shared costs, and $16.278 million in shared costs.

DRA's forecast of the $6.427 million in non-shared O&M costs results in a reduction of $1.410 million from SDG&E's forecast of $7.837 million. As described in Exhibit 516, DRA uses the three-year average of 2008-2010 to forecast its test year non-shared O&M costs. DRA opposes SDG&E's forecast amounts because of SDG&E's methodology and reasoning for its incremental increases. DRA contends that SDG&E's assumptions used to generate the incremental increases, and which were added to the 2009 recorded amount, "do not reflect future expected expenses within these cost centers." (Ex. 516 at 9.) Since the last three years showed fluctuations for these cost centers, DRA contends its "three-year average provides an appropriate method to forecast [test year] 2012 expenses for non-shared services." (*Ibid*.)

For SDG&E's shared costs of $18.378 million, DRA recommends that the forecast be set at $16.278 million. DRA's shared cost forecast proposes to make reductions to 12 cost centers using the three-year average. DRA contends that "SDG&E's assumptions used to generate the incremental increases that were added to 2009 recorded expenses do not reflect future expected expenses within these cost centers." (Ex. 516 at 12-13.) As described in Exhibit 516, DRA proposes to reduce three of the cost centers in shared rents from SDG&E's forecast of $17.586 million to $15.530 million, a difference of $2.056 million on a total incurred basis. For the five cost centers in shared facility operations, DRA proposes to reduce SDG&E's forecast of $4.170 million to $3.242 million, a difference of $928,000 on a total incurred cost basis. For the three cost centers in shared facility capital programs, DRA proposes to reduce SDG&E's forecast of $3.311 million to $1.662 million, a difference of $1.649 million on a total incurred cost basis. For shared land services and right of way, DRA proposes to reduce SDG&E's forecast of $711,000 to $602,000, a difference of $109,000 on a total incurred basis.

13.4.2.2.2.2. SDG&E

SDG&E contends that DRA's forecast of the O&M costs lack support because DRA did not address the cost drivers and the incremental costs that SDG&E referenced as justification for its forecast of the O&M costs. If DRA's forecast is adopted, SDG&E contends this will significantly underfund its ability to meet O&M needs.

DRA's recommended reduction to the non-shared O&M costs is based on reductions to the non-shared cost categories of facility operations and capital programs, land services, and rents. SDG&E contends that its forecast of facility operations and capital programs is appropriate because these costs "can experience variations in its expenses as major maintenance projects come and go over the years." (Ex. 166 at 3.) The aging infrastructure, and increasing environmental and safety considerations also drive costs higher for this cost category. For the land services cost category, SDG&E contends that the increase in costs is attributable to an increase in corrective and preventative maintenance. For the cost category of rents, SDG&E contends that its forecast is "based upon all contractual rent and right-of-way agreements in place as of 2009 with fixed contractual escalations for base rents and an assumption of various increases for related operating expenses." (Ex. 166 at 5.)

With respect to the shared services O&M costs, SDG&E contends that DRA relied only on its three-year average methodology, and did not provide any justification to support DRA's contention that SDG&E's incremental increases will not reflect future expected expenses. SDG&E contends that its methodology for forecasting the shared costs "took into consideration the variability in the workflow, recent project deferrals, and expectations of increased costs due to aging infrastructure, environmental regulations, and new business expansion," and that there "is no evidence that DRA's lower forecasts are more reasonable or reliable than SDG&E's forecasts." (Ex. 166 at 6.)

13.4.2.2.3. Discussion

We have reviewed the testimony and arguments of SDG&E and DRA concerning the REL&F O&M costs. We have also reviewed their respective forecasts and compared them to the historical costs.

For SDG&E's non-shared O&M costs, we agree with SDG&E that rents are likely to continue increasing due to the rent escalation in facility contracts, as well as higher easement costs. We have also compared the forecasts of SDG&E and DRA for facility operations and capital, and agree with DRA that SDG&E's forecast is too high in comparison to the historical data. Based on these considerations, it is reasonable to reduce SDG&E's non-shared O&M costs by $300,000, for a total non-shared O&M cost of $8.162 million.

For the shared O&M costs, we are not persuaded that DRA's three-year averaging methodology is a more appropriate reflection of the test year 2012 shared O&M costs. However, after comparing the competing shared O&M cost forecasts of SDG&E and DRA to the historical data, and considering the incremental additions, it is reasonable to reduce SDG&E's shared O&M cost forecast of $18.378 million by $1 million.

With the above adjustments, SDG&E's total O&M costs for REL&F add up to $25.540 million.

13.4.2.3. Capital Expenditures

13.4.2.3.1. Background

SDG&E forecasts the following capital expenditures for REL&F: $20.289 million for 2010; $32.596 million for 2011; and $25.598 million for 2012. These capital projects are described by SDG&E as falling into 15 categories of projects, and are described in Exhibit 163, and summarized below.

The first category is the structures & improvements blanket. This category covers projects that need minor building modifications, upgrade, or facility improvements "to adequately support corporate business initiatives, to extend the life of the asset, or increase the functionality of a building or site." (Ex. 163 at 16.)

The second category is the safety/environmental blanket which cover projects that need "building and system modifications, site upgrades, and other facility improvements directed to safeguard SDG&E occupied facilities and sites, protect employees and company property, adhere to codes and regulations, and ensure compliance with safety and environmental requirements." (Ex. 163 at 16.)

The third category is the common plant blanket – infrastructure & reliability. This category "funds building facility infrastructure to support basic building operations, as well as requirements specific to the business unit operations and initiatives," and includes the "replacement of systems and major equipments affecting reliability, comfort and safety of employees at numerous sites throughout the portfolio." (Ex. 163 at 17.)

The fourth category is common plant blanket – remodels and reconfigurations. This category covers work station moves and changes.

The fifth category is common plant blanket – business unit expansions. This category covers the expansion and improvements of buildings and facilities to accommodate current and future space requirements.

The sixth category is the Beach Cities office expansion. This project is to improve and expand the office space, which currently consists of space in an existing building, and modular trailers.

The seventh category is the Ramona construction and operating center expansion. This project consists of "additional building, parking, warehouse and yard storage space for the support of expanding staff and crews necessary to maintain a growing service territory." (Ex. 163 at 20.)

The eighth category is the metro grid operations and distribution operations support. This project consists of expanding the current building which houses the back-up control center for the Mission Control Center. In its current configuration, the building cannot accommodate all of the staff that would be needed for full backup operations.

The ninth category is the facilities renewable energy projects. These projects install rooftop photovoltaic systems at various sites.

The tenth category is the Rancho Bernardo Data Center expansion – tape library expansion. This project is to expand the computer/server room into the space made available by demolition of the tape library.

The eleventh category is the Rancho Bernardo Data Center master plan. This project will expand the existing building and electrical and cooling systems to meet projected electric demand.

The twelfth category is the NERC CIP security monitoring facility. This project is to acquire a facility to house the NERC CIP security monitoring facility. The current location is housed in a 280 square feet area, "which is inadequate for current staff and projected future growth." (Ex. 163 at 22.)

The thirteenth category is the Rancho Bernardo UPS (uninterruptible power supply) replacement. The current system is undersized to handle all of SDG&E's computer operations. The project will replace the four existing UPS modules with six new energy efficient modules, which will accommodate projected growth over the next eight to ten years.

The fourteenth category is the San Diego Energy Innovation Center, which will "offer SDG&E customer education and training related to energy efficiency, demand response, clean generation, and alternative fuel transportation" at a central location. (Ex. 163 at 23.) Part of this project is the commercial demonstration kitchen, which complies with D.09-09-047.

The fifteenth category covers the other projects of less than $1 million.

13.4.2.3.2. Position of the Parties

13.4.2.3.2.1. DRA

DRA recommends the following for SDG&E's REL&F capital expenditures: $14.613 million for 2010; $19.419 million for 2011; and $10.419 million for 2012. DRA's recommended capital expenditures are based on its opposition to the amounts requested for eight budget codes which are described below. DRA does not object to the amounts requested for eight other budget codes.

DRA opposes some of the funding for the structures and improvements budget code. SDG&E requests $4.790 million in 2010, $4 million in 2011, and $4 million in 2012. DRA contends that SDG&E's responses to DRA's data request were inadequate. DRA recommends using a three-year average of $3.850 million for 2010, 2011, and 2012.

DRA opposes some of the funding for the safety/environmental blanket budget code. SDG&E requests $531,000 in 2010, $1.800 million in 2011, and $1.200 million in 2012. DRA contends that SDG&E's responses to DRA's data request were inadequate. DRA recommends using a three-year average of $601,000 for 2010, 2011, and 2012.

DRA opposes some of the funding for the common plant blanket – infrastructure and reliability budget code. SDG&E requests $3.090 million in 2011, and $2.990 million in 2012. DRA contends that SDG&E's responses to DRA's data request were inadequate. DRA recommends using a three-year average of $2.710 million for 2011 and 2012.

DRA opposes some of the funding for the common plant blanket – remodels and reconfigurations budget code. SDG&E requests $816,000 in 2010, $1.200 million in 2011, and $996,000 in 2012. DRA contends that SDG&E's responses to DRA's data request were inadequate. DRA recommends using a three-year average of $560,000 in 2010, 2011, and 2012.

DRA opposes all the funding for the common plant blanket – business unit expansions budget code. SDG&E requests $1.500 million in 2011, and $1.500 million in 2012. DRA contends that SDG&E's responses to DRA's data request were inadequate, and that SDG&E failed to provide supporting documentation and justification for this budget code. DRA recommends zero funding in 2010, 2011, and 2012.

DRA opposes all the funding for Rancho Bernardo Data Center master plan budget code. SDG&E requests $3 million in 2011, and $11 million in 2012. DRA contends that SDG&E's responses to DRA's data request were inadequate, and that SDG&E failed to provide supporting documentation and justification for this budget code. DRA recommends zero funding in 2011 and 2012.

For the reasons described in Exhibits 510and 516, DRA opposes all the funding for the San Diego Energy Innovation Center budget code. SDG&E requests $2.790 million in 2010, $4.760 million in 2011, and $1.270 million in 2012. DRA contends that SDG&E's responses to DRA's data request were inadequate to justify this capital project. DRA also contends there was no Commission directive to build this center, and that D.09-09-047 only authorized the building of a demonstration kitchen. DRA argues that there was no need for SDG&E to construct this center in order to house the demonstration kitchen. DRA recommends zero funding in 2010, 2011 and 2012.

DRA opposes all the funding for the budget code covering various other projects less than $1 million. SDG&E requests $1.760 million in 2010, $1.550 million in 2011, and $1.140 million in 2012. DRA contends that SDG&E's responses to DRA's data request were inadequate. DRA recommends zero funding in 2010, 2011, and 2012.

13.4.2.3.2.2. UCAN

UCAN recommends the adoption of the following for SDG&E's REL&F capital expenditures: $12.695 million in 2010; $19.525 million in 2011; and $10.820 million in 2012.[142]

[142] UCAN's testimony in Exhibit 561 contains two different amounts for SDG&E's capital expenditure forecast for 2012. Although Tables 1 and 3 of that exhibit refer to the 2012 amount as $9.120 million, the reductions described at page 4 of that exhibit suggests the 2012 amount should be $10.820 million.

UCAN emphasizes the need for the Commission to take notice of the 2010 recorded costs for capital expenditures. Although SDG&E forecast 2010 capital expenditures at $20.289 million, only $12.695 million in capital expenditures was recorded in 2010. UCAN contends that these 2010 recorded costs should be used to set the 2010 expenditures, rather than using SDG&E's forecast of 2010 capital expenditures.

UCAN opposes some of the funding for the structures and improvements budget code. SDG&E requests $4 million for 2012. UCAN contends that because SDG&E's 2010 recorded costs show that SDG&E only spent $2.864 million on structures and improvements in 2010, which was 60% of what SDG&E had forecasted for 2010, that SDG&E's 2012 forecast should be adjusted in the same manner. UCAN recommends funding of $2.400 million for 2012.

UCAN opposes some of the funding for the safety and environment budget code. SDG&E requests $591,000 in 2010, $2.400 million in 2011, and $1.196 million in 2012. UCAN believes that SDG&E has inflated its forecast for this budget code, relative to the historical spending. UCAN contends that because the 2010 recorded amount was $442,000, that SDG&E's 2010 forecasted amount of $591,000 should be adopted as the 2012 funding amount.

UCAN is opposed to all of the funding for the HAN testing lab budget code. SDG&E requests $700,000 in 2012, and an additional $1.250 million in 2013 and 2014. UCAN contends that funding for this budget code should be rejected because "SDG&E failed to properly inform the Commission that it intended to use funds authorized for [SDG&E's] facilities' infrastructure and reliability on building out a laboratory to test HAN functionality in its testimony," and that "HAN has little to do with ensuring SDG&E's facilities infrastructure is both functioning and reliable." (Ex. 561 at 6.) UCAN also contends funding for this project should be rejected because the HAN testing laboratory is an inefficient use of ratepayer funds, and that a single laboratory should be used by all three electric utilities.

UCAN is opposed to all of the funding for the business unit expansion budget code. SDG&E requests $1.500 million in 2011, and $1.500 million in 2012. UCAN contends that funding for this budget code should be rejected because this is a new common blanket account which did not appear in SDG&E's 2008 GRC, and UCAN is unaware that SDG&E ever recorded costs to this blanket account. UCAN recommends zero funding for this budget code in 2011 and 2012.

UCAN is opposed to all funding for the facilities renewable energy projects budget code. SDG&E requests $1 million in 2011 and in 2012, as well as $1 million per year in attrition years 2013 and 2014. UCAN contends that funding for this budget code should be rejected because the project is "hugely expensive and has an unreasonable payback for ratepayers." (Ex. 561 at 8.) UCAN contends that this project will result in SDG&E paying $0.72 to $0.76 per kilowatt hour, and that it is unreasonable for SDG&E's ratepayers to pay that much for photovoltaic generation. UCAN also compared the cost of SDG&E's photovoltaic generation with SCE's photovoltaic generation project in its 2012 GRC, and contends that SDG&E's costs over three times the costs that SCE reported. UCAN recommends zero funding for this budget code.

As described in Exhibits 555 and 561, and for the reasons cited by DRA, UCAN is opposed to all funding for the Energy Innovation Center budget code. UCAN contends that "space could have been made available" at the Center for Sustainable Energy. (Ex. 555 at 55.) UCAN recommends zero funding for the Energy Innovation Center.

13.4.2.3.2.3. SDG&E

SDG&E contends that each of its REL&F "capital expenditures budget codes were fully explained in direct testimony, and the forecasts were supported by the capital workpapers." (Ex. 166 at 11.) SDG&E also contends that it responded to the data requests which sought additional information on its capital projects.

With regard to DRA's recommendations, SDG&E contends that DRA did not provide any "analysis beyond general assertions that it received inadequate data request responses or that SDG&E failed to provide supportive documentation and justification for its capital expenditures request." (Ex. 166 at 10.) SDG&E further contends that DRA did "not raise a single specific issue with respect to any detail contained in SDG&E's Capital Project Workpapers." (Ex. 166 at 11.)

UCAN's recommendations apply 2010 recorded expenditures to all budget codes for 2010. SDG&E contends that UCAN's use of the 2010 recorded data is inappropriate for the reasons SDG&E referenced. SDG&E also contends that UCAN's reductions to the 2011 and 2012 forecasts for some of the blanket budget codes, due to the recorded 2010 data, lead "to imprudent and significant cuts to blanket budgets which will severely underfund the types of activities which UCAN does not dispute are necessary, and SDG&E would assert are essential." (Ex. 166 at 13.)

Regarding UCAN's recommendation to disallow the HAN testing lab, SDG&E contends that having a separate HAN lab "is a necessary and worthwhile investment that will contribute to smart metering assets as well as smart grid…." (Ex. 166 at 14.)

Both DRA and UCAN oppose all funding for the Rancho Bernardo Data Center master plan, but provide no reasons as to why funds should not be provided. SDG&E contends that this project is supported by a capital project workpaper, and "this project is clearly defined and scheduled for 2011 and 2012." (Ex. 166 at 14.)

Regarding UCAN's opposition to all funding for the facilities renewable energy projects budget code, SDG&E contends that these expenditures are justified, and further the State's goals, policies, and programs for energy efficiency and renewable energy.

Regarding the opposition to the funding of the Energy Innovation Center budget code, SDG&E contends that this project was described and supported in SDG&E's Exhibit 155, and that "SDG&E strongly supports the energy efficient initiatives that form the basis of why an [Energy Innovation Center] is a necessary and worthwhile facility." (Ex. 166 at 15-16.)

13.4.2.3.3. Discussion

We have reviewed the testimony and arguments of the parties concerning SDG&E's REL&F capital expenditures. In addition, we have reviewed the forecasts of SDG&E, DRA, and UCAN for all fifteen categories, and compared them to the historical costs and to each other.

We first address the 2010 funding level for SDG&E's REL&F capital expenditures. It is reasonable to adopt the actual recorded 2010 amounts as UCAN has suggested. This is appropriate because it represents the actual amount that was spent in 2010. Accordingly, the funding level of $12.695 million should be adopted for 2010.

Next, we address the funding level for the 2011 and 2012 capital expenditures.

In the customer information section of this decision, we addressed the funding request for SDG&E's Energy Innovation Center. For the reasons stated earlier in this decision, and except for the $2 million we authorized as referenced earlier, we disallow SDG&E's request for capital expenditure funding for the Energy Innovation Center budget code for 2011 and 2012.

We have also reviewed and considered the reductions or disallowances that DRA and UCAN have recommended for the other budget codes. We have also considered the need for these capital projects versus the additional financial impact on ratepayers. Based on our review, it is reasonable to adopt the following funding level for SDG&E's REL&F capital expenditures: $12.695 million for 2010; $19.700 million for 2011; and $20 million for 2012.

13.4.3. SoCalGas Real Estate, Land and Facilities

13.4.3.1. Introduction

SoCalGas forecasts total O&M costs of $42.064 million for test year 2012. This total consists of $17.682 million in non-shared costs, and $24.382 million in shared costs. SoCalGas' forecast is a reduction of $5.615 million from the 2009 recorded amount, due principally to a reduction in the gas company tower lease in downtown Los Angeles.

For capital expenditures, SoCalGas forecasts $27.162 million in 2010, $43.991 million in 2011, and $22.876 million in 2012.

13.4.3.2. O&M Costs

13.4.3.2.1. Background

SoCalGas' forecast of O&M costs for test year 2012 consists of $17.682 million in non-shared costs, and $24.382 million in shared costs.

The non-shared costs for SoCalGas have been combined into a single category which covers facility operations and rents. SoCalGas' non-shared rents relate to its 47 branch office leases, and numerous right of way licenses. According to SoCalGas, rents have been going up about 5% per year.

The non-shared facility operations provide the "operation and maintenance support for utility facilities such as general offices, bases, multi-use sites, telecommunications sites and branch offices." (Ex. 167 at 3.) SoCalGas' facility operations have eight regions, and each region is managed by a facility manager and a team of mechanics. These mechanics provide building maintenance, repair and other services. In addition, facility operations negotiate and manage outside contractors for such services as janitorial, landscaping, trash, and pest control. Other outside contractors are hired for such services as electrical, mechanical, heating and ventilation, and fire safety. SoCalGas' REL&F

organization manages 120 locations consisting of about 2 million square feet. These facilities include office buildings, warehouses, and operating bases.

The shared services for REL&F provide the support for shared facilities and services. These shared services activities consist of shared rents, shared facility operations, shared facility capital programs, and shared services billed in from SDG&E.

The shared rents category allocates the rental cost of shared building space to SoCalGas, SDG&E, corporate center, and other affiliates. The shared rents category consists of the following three workgroups: gas company tower rents; corporate real estate; and telecom rents. The gas company tower rent is the largest lease within SoCalGas' portfolio. The lease for this space was recently renewed, and covers 13 floors. The corporate real estate workgroup "provides strategic asset management, transaction management, lease negotiation and administration services for SDG&E, [SoCalGas], Corporate Center, and other affiliates upon request." (Ex. 167 at 9.) The telecom rents workgroup covers the rents for telecom facilities, which are increasing at an average of 5% per year.

The shared facility operations cover "O&M support for utility facilities including general offices, bases, telecommunications sites, warehouse, and branch offices." (Ex. 167 at 10.) The shared facilities include the gas company tower, and the Monterey Park facility that house activities for information technology, billing, payment processing, and fleet maintenance.

The shared services billed in from SDG&E cover the shared costs that SDG&E has billed to SoCalGas. These billed in services include REL&F management functions located at SDG&E and billed to SoCalGas, the facilities capital programs section which bills SoCalGas for the work it performs on

SoCalGas' behalf, and the work that the land and right of way department does for SoCalGas.

13.4.3.2.2. Position of the Parties

13.4.3.2.2.1. DRA

DRA forecasts total O&M costs of $37.843 million. DRA's forecast consists of $16.832 million in non-shared costs, and $21.011 million in shared costs.

DRA's forecast of the $16.832 million in non-shared O&M costs results in a reduction of $850,000 from SoCalGas' forecast of $17.682 million. As described in Exhibit 516, DRA uses the three-year average of 2008-2010 to forecast its test year non-shared O&M costs for facility operations and rents, and the transportation program. DRA opposes SoCalGas' forecast amounts because of SoCalGas' methodology and reasoning for its incremental increases. DRA contends that SoCalGas' assumptions used to generate the incremental increases, and which were added to the 2009 recorded amount, "do not reflect actual expenses within these cost centers." (Ex. 516 at 15.) Since the last three years showed fluctuations for these cost centers, DRA contends its "three-year average provides an appropriate method to forecast [test year] 2012 expenses for non-shared services." (*Ibid*.)

For SoCalGas' shared costs of $24.382 million, DRA recommends that the forecast be set at $21.011 million. This reduction is due to DRA's use of the three-year average from 2008-2010 to forecast its test year shared O&M costs. DRA opposes SoCalGas' shared O&M forecast amount because of SoCalGas' methodology and reasoning for its incremental increase. DRA contends that SoCalGas' assumptions that were used to generate the incremental increase, and which was added to the 2009 recorded amount, "are inaccurate and do not reflect actual expenses within these cost centers." (Ex. 516 at 17.)

DRA's shared cost forecast proposes to make reductions to five cost centers, using its three-year average. DRA proposes to reduce the shared rents from SoCalGas' forecast of $750,000 to $379,000, a difference of $371,000 on a total incurred cost basis. For the four cost centers in shared facility operations, DRA proposes to reduce SoCalGas' forecast of $4.467 million to $3.226 million, a difference of $1.241 million on a total incurred cost basis.

13.4.3.2.2.2. SoCalGas

SoCalGas contends that DRA's forecast of the O&M costs lack support because DRA did not address the cost drivers and the incremental costs that SoCalGas referenced as justification for its forecast of the O&M costs. If DRA's forecast is adopted, SoCalGas contends this will significantly underfund its ability to meet O&M needs.

DRA's recommended reduction to the non-shared O&M costs is based on reductions to the non-shared cost categories of facility operations and rents, and the transportation program. SoCalGas contends that DRA's three-year average is not a better approach for forecasting the rent costs because rents are based on contractual escalations, and right of way easement costs have been increasing about 5% per year. In addition, SoCalGas contends there are incremental costs for "maintenance on five emission vapor recovery systems and water and energy conservation projects." (Ex. 170 at 4.) With respect to the transportation costs, SoCalGas contends that there are three cost drivers which result in an increased forecast. The first driver is that the transportation subsidy to each employee is increasing from $60 per month to $75 per month. The second driver is that the rideshare program is being expanded. The third driver is increasing the downtown Los Angeles parking subsidy, which is no longer part of the lease agreement at the gas company tower. SoCalGas contends that DRA's use of the three-year average will significantly underfund the transportation costs.

With respect to the shared services O&M costs, SoCalGas contends that DRA relied only on its three-year average methodology, and did not address any of the cost drivers. SoCalGas contends that the key cost drivers for the shared rents and facility operations are due to the following: (1) the reduction in the gas company tower lease costs; (2) transfer of janitorial costs from rents to facilities operations; (3) O&M increases for the Monterey Park Data Center expansion; and (4) transfer of REL&F management position from SDG&E to SoCalGas. SoCalGas contends that these cost drivers are captured in SoCalGas' forecasts, and that these forecasts "support the necessary O&M labor and non-labor associated with providing workspace for employees and related equipment as well as to maintain those facilities, and to oversee these operations."
(Ex. 170 at 5.)

13.4.3.2.3. Discussion

We have reviewed the testimony and arguments of SoCalGas and DRA concerning the non-shared and shared O&M costs. We have also compared their forecasts to the historical data, and considered the cost drivers and the need for the incremental increases.

For the test year 2012 non-shared O&M costs, SoCalGas recommends $17.682 million, while DRA recommends $16.832 million. DRA's recommendation is lower by $850,000. Due to the contractual escalations in rent, the increase in easement costs, and the increase in transportation subsidies, SoCalGas' forecasts of the non-shared O&M costs is more reasonable than using the three-year average. Accordingly, SoCalGas' non-shared O&M forecast of $17.682 million should be adopted.

For the shared O&M costs, SoCalGas recommends $24.382 million, while DRA recommends $21.011 million. DRA's recommendation is lower by $3.371 million. In comparison to the 2009 recorded shared costs, SoCalGas' recommendation is lower by $6.438 million, while DRA's recommendation is lower by $9.809 million. Based on our review of the five shared O&M cost centers that DRA takes issue with, SoCalGas has not adequately explained why its 2012 forecasted amounts for these five cost centers have increased over the 2009 recorded amounts. Based on all of the above considerations, it is reasonable to reduce the total shared O&M costs by $3 million. Accordingly, $21.382 million should be adopted as SoCalGas' shared O&M costs for REL&F on a book expense basis.

13.4.3.3. Capital Expenditures

13.4.3.3.1. Introduction

SoCalGas forecasts the following capital expenditures: $27.162 million for 2010; $43.991 million for 2011; and $22.876 million for 2012. SoCalGas' capital expenditures have been categorized into 17 categories of projects, as described in Exhibit 167 and summarized below.

The first category is the infrastructure & improvements blanket. This category covers projects that need "building modifications, upgrades, and facility improvements to adequately support business initiatives, to extend the life of the asset, or increase the functionality of a building or site." (Ex. 167 at 14.)

The second category is the Anaheim building A chiller replacement. This project is to replace the existing chiller and cooling tower at the Anaheim campus. The chiller provides heating and cooling to all six buildings at the campus.

The third category is the Compton parking lot, which will remove and replace the existing asphalt.

The fourth category is the Downey Energy Resource Center chiller replacement. This project is to design and replace the existing heating and ventilation system at the Downey Energy Resource Center.

The fifth category is the facilities renewable energy efficiency projects. This consists of installing rooftop photovoltaic systems, and demand response systems, at various sites.

The sixth category is for the Monterey Park building A server room air handler replacement. This project will replace "14 old air handlers with new customer designed units featuring humidity controls and greater energy efficiency." (Ex. 167 at 16.)

The seventh category is the Monterey Park Data Center master plan. This project will expand the data center to meet the increased need for space and services.

The eighth category is the tenant improvement of building C at the Monterey Park Data Center. This project will demolish the interior of the existing space, and replace it with the "infrastructure and support systems necessary for a new stand-alone Data Center that will supplement the existing site services." (Ex. 167 at 17.)

The ninth category is the Monterey Park Data Center generators. This project will make improvements to the electrical distribution system to ensure around the clock capabilities.

The tenth category is the Monterey Park exterior site improvements. This project is to resolve the deterioration of the parking lot, reduce storm water runoff, and provide adequate lighting for walking and security.

The eleventh category is the Redlands headquarters parking lot expansion. This project will create additional parking at an adjacent lot to meet building occupancy needs.

The twelfth category is the Spence Street remodel. This project is to upgrade the control room to meet current pipeline standards, and to upgrade other parts of the facility.

The thirteenth category is the environmental and safety blanket. These projects are for "building and system modifications, site upgrades, and other facility improvements directed to safeguard [SoCalGas] occupied facilities and sites, protect employees and company property, adhere to codes and regulations, and ensure safety and environmental compliance." (Ex. 167 at 18.)

The fourteenth category is branch offices – ADA and ergonomics. This project involves bringing each branch office location into compliance with current Americans with Disabilities Act (ADA) accessibility guidelines, the California Building Code, and California Title 24 guidelines.

The fifteenth category is the gas company tower lease renegotiation. This project consists of considering alternatives, the renegotiation of the lease at the gas company tower in downtown Los Angeles, and tenant improvements. A new lease was executed in July 2010, and provides for a 15 year lease term following the expiration of the current lease.

The sixteenth category is the NGV refueling stations. Under this project, "NGV refueling stations will be upgraded to enhance the refueling reliability, capacity and response time for public and [SoCalGas] Fleet NGV users at [SoCalGas] NGV fueling stations." (Ex. 167 at 19.)

The seventeenth category is for various other projects that are less than $1 million.

13.4.3.3.2. Position of the Parties

13.4.3.3.2.1. DRA

DRA recommends the following for SoCalGas' REL&F capital expenditures: $21.644 million for 2010; $25.587 million for 2011; and $11.163 million for 2012. DRA's recommended capital expenditures are based on its opposition to the amounts requested for nine of the categories listed above, and which are described below. DRA does not object to the amounts requested for the other eight categories.

DRA opposes all funding for the Compton parking lot. SoCalGas requests $1.300 million in 2012. DRA contends that SoCalGas' responses to DRA's data request was inadequate, and that SoCalGas failed to provide supporting documentation and justification for this budget code. DRA recommends zero in capital expenditure funding for 2012.

DRA opposes all funding for the Monterey Park Data Center master plan. SoCalGas requests $359,000 in 2011, and $6.141 million in 2012. DRA contends that SoCalGas' responses to DRA's data request was inadequate, and that SoCalGas failed to provide supporting documentation and justification for this budget code. DRA recommends zero in capital expenditure funding for 2011 and 2012.

DRA opposes all funding for the Monterey Park exterior site improvements. SoCalGas requests $764,000 in 2010, and $2.735 million in 2011. DRA contends that SoCalGas' responses to DRA's data request was inadequate, and that SoCalGas failed to provide supporting documentation and justification for this budget code. DRA recommends zero in capital expenditure funding for 2010 and 2011.

DRA opposes all funding for the Redlands headquarters parking lot expansion. SoCalGas requests $2.290 million in 2012. DRA contends that SoCalGas' responses to DRA's data request was inadequate, and that SoCalGas failed to provide supporting documentation and justification for this budget code. DRA recommends zero in capital expenditure funding for 2010 and 2011.

DRA opposes all funding for the Spence Street remodel. SoCalGas requests $1 million in 2010. DRA contends that SoCalGas' responses to DRA's data request was inadequate, and that SoCalGas failed to provide supporting documentation and justification for this budget code. DRA recommends zero in capital expenditure funding for 2010.

DRA opposes some of the funding for the branch offices – ADA and ergonomics. SoCalGas requests $3.678 million in 2010, and $4.500 million in

2011. DRA contends that SoCalGas' data responses did not provide "concrete justification of its capital expenditure request," but SoCalGas' workpapers has a "project budget which helped DRA with its recommendation and analysis." (Ex. 516 at 25.) DRA recommends 50% of SoCalGas' request be approved, which results in DRA's recommendation of $1.840 million in 2010, and $2.250 million in 2011.

DRA opposes some of the funding for the gas company tower lease renegotiation and restack. SoCalGas requests $7.391 million in 2010, and $18.596 million in 2011. DRA notes that a $7.400 million lease allowance is to be funded by the landlord in November 2011. After reviewing SoCalGas' data responses, capital workpapers, and testimony, DRA recommends funding for 50% of the building and site construction, and 50% of system furniture. This results in DRA's recommendation of $7.391 million in 2010, and $7.250 million in 2011.

DRA opposes some of the funding for the NGV refueling stations. SoCalGas requests $1.510 million in 2010, $1.935 million in 2011, and $2.220 million in 2012. DRA contends that SoCalGas' data responses did not provide concrete justification for this budget code. DRA used the 2010 recorded amounts as the basis of its forecast, and recommends annual capital expenditures of $712,000 in 2010, 2011, and 2012.

DRA opposes all of the funding for various other projects that are less than $1 million. SoCalGas requests $1.120 million in 2010, $490,000 in 2011, and $472,000 in 2012. DRA contends that SoCalGas' data responses were inadequate, and did not justify SoCalGas' request. DRA recommends zero funding for 2010, 2011, and 2012.

13.4.3.3.2.2. TURN

TURN recommends the adoption of the following for SoCalGas' REL&F capital expenditures: $1.922 million in 2010; $21.062 million in 2011; and $6.826 million in 2012.[143]

TURN emphasizes the need for the Commission to take notice of the 2010 recorded costs for capital expenditures. Although SoCalGas forecast 2010 capital expenditures at $27.162 million, only $1.922 million in capital expenditures was recorded in 2010. TURN contends that these 2010 recorded costs should be used to set the 2010 expenditures, rather than using SoCalGas' forecast of 2010 capital expenditures. TURN recognizes that if this same logic about forecasted versus recorded expenditures were applied to the 2012 forecast, that TURN's recommendation would only be "7.1% of SoCalGas' capital expenditure forecast in 2012," which "might be too severe a recommendation…." (Ex. 550 at 3.) Instead, TURN recommends that SoCalGas' 2011 and 2012 capital expenditures be reduced by 50% after making other adjustments as described in Exhibit 550, resulting in a 2011 forecast amount of $21.063 million, and a 2012 forecast amount of $6.826 million.

TURN is opposed to SoCalGas' entire request of $2.290 million in 2012 for the Redlands headquarters parking lot expansion. TURN contends that the economics of such a project are imprudent because SoCalGas is paying $7,000

[143] TURN's Exhibit 550 refers to the 2012 amount as $6.826 or $6.824 million in some places, while in other places it refers to the 2012 amount as 6.326 or $6.327 million. Based on TURN's math references in Exhibit 550, it appears TURN intended to use the amount of $6.826 million as its 2012 forecasted amount.

per month for additional parking, or $84,000 per year, for a project that costs $2.290 million. TURN recommends zero funding for this project in 2012.

TURN is opposed to capital expenditure funding for the Monterey Park Data Center master plan. SoCalGas requests funding of $359,999 in 2011, and $6.141 million in 2012. TURN contends that the Commission should exclude these costs from rate base because the "construction of this project will begin in the 2nd quarter of 2012 and construction will be completed by the 4th quarter of 2013." (Ex. 550 at 4.) TURN recommends that the costs of this project be booked to construction work in progress instead, and that SoCalGas be allowed to earn accumulated funds used during construction. This project should then be evaluated in SoCalGas' next GRC for prudence and reasonableness. TURN recommends zero capital expenditure funding for 2011 and 2012.

TURN is opposed to all of the funding for the facilities renewable energy efficiency projects. SoCalGas requests funding of $1 million in 2011, and $1 million in 2012. TURN contends that SoCalGas did not provide any workpapers for this project, and that the project should be rejected because SoCalGas has failed to meet its "burden of proof that this is a reasonable use of ratepayer funds…." (Ex. 550 at 5.) TURN also contends that based on UCAN's analysis of SDG&E's request for the same type of project, that the economics of the cost of the proposed photovoltaic installations is poor. For those reasons, TURN recommends zero capital expenditure funding in 2011 and 2012.

TURN is opposed to some of the funding for the natural gas vehicle fueling stations. SoCalGas requests $1.510 million in 2010, $1.935 million in 2011, and $2.270 million in 2012. TURN contends that SoCalGas' request is expensive as compared to the recorded cost. The 2010 recorded cost was $714,000 as opposed to SoCalGas' 2010 forecast of $1.510 million. TURN recommends that the 2010 recorded costs be used as the capital expenditures forecast for 2010, 2011, and 2012.

13.4.3.3.2.3. SoCalGas

SoCalGas contends that each of its REL&F "capital expenditures budget codes were fully explained in direct testimony, and the forecasts were supported by the capital workpapers." (Ex. 170 at 8.) SoCalGas also contends that it responded to the data requests which sought additional information on its capital projects.

With regard to DRA's recommendations, SoCalGas contends that DRA did not provide any "analysis beyond general assertions that it received inadequate data request responses or that [SoCalGas] failed to provide supportive documentation and justification for its capital expenditures request." (Ex. 170 at 7.) SoCalGas further contends that DRA did "not raise a single specific issue with respect to any detail contained in [SoCalGas'] Capital Project Workpapers." (Ex. 170 at 8.)

SoCalGas contends that although TURN recommends reductions to all of SoCalGas' REL&F capital expenditures, TURN only provided a specific analysis on four projects. For the other capital projects, TURN's recommendations "were derived by making an across-the-board 50% reduction to [SoCalGas'] forecasts," which SoCalGas contends there "is no rational basis for this type of arbitrary methodology." (Ex. 170 at 9.)

With respect to the recommendations of TURN and DRA to disallow all capital expenditure funding for the Redlands headquarters parking lot, SoCalGas contends that this project "addresses the safety and security needs of its employees who work at the Redlands facilities." (Ex. 170 at 9.) This facility operates from 5:30 am to midnight," while the leased parking structure, which does not reside on SoCalGas' property, "operates from 9 am to 6 pm," and has no controlled entry and limited lot lighting. (Ex. 170 at 10.)

TURN and DRA also recommend no capital expenditure funding for the Monterey Park Data Center master plan. SoCalGas contends that due to the reduction in the office space at the gas company tower, several of its information technology employees and computer servers need to be relocated to Monterey Park. SoCalGas also contends that this capital project is not part of the 2011 and 2012 rate base.

Regarding TURN's opposition to any capital expenditure funding for the facilities energy efficiency projects, SoCalGas contends "that these expenditures are justified, and in furtherance of the State's goals, policies and programs for energy efficiency and development of renewable energy." (Ex. 170 at 11.) SoCalGas also states that it "expects improvements to the operational characteristics at project sites, cost reduction, and a reduction in demand for electricity from the grid, especially during peak demand periods." (*Ibid*.)

Regarding TURN's opposition to some of the funding for NGV refueling stations, SoCalGas contends that although it "only spent half of its estimated project costs for 2010, it is on track to complete the upgrades and enhancements to the NGV fueling stations by 2012." SoCalGas contends that many of its NGV stations are over 20 years old, and need replacement or equipment upgrades to ensure reliable operation of these stations. SoCalGas also contends that its customer load has increased at these stations.

With respect to TURN's reductions to other blanket capital budget projects, SoCalGas contends that its "table of historical costs for its capital blankets" show that the recorded amounts "are significantly higher than what TURN reflects in its testimony…." (Ex. 170 at 12.)

13.4.3.3.3. Discussion

As summarized in the above positions of the parties, we have reviewed the testimony and arguments of SoCalGas, DRA, and TURN regarding the capital expenditure funding for REL&F. We have also compared their forecasts to the historical costs, and to SoCalGas' reasoning for its capital projects.

For the 2010 capital expenditures, we agree with TURN's argument that since the 2010 recorded capital expenditures were only $1.922 million, that the Commission should adopt that amount as the funding level for 2010.

However, we are not persuaded by TURN's argument that because the 2010 recorded amount was so low, that there should be an across-the-board reduction of 50% to most of the other capital projects for 2011 and 2012. Instead, for 2011 and 2012, we have reviewed each of the capital projects, and considered the parties' arguments for each project. We have also reviewed the historical REL&F capital expenditures. SoCalGas' forecasts of these capital expenditures are substantially higher than what was experienced in 2005 through 2010. Based on the testimony and arguments of the parties, and our comparison to the historical costs, it is reasonable to reduce SoCalGas' capital expenditures funding request to the following: the actual recorded costs of $1.922 million for 2010; $38 million for 2011; and $19.500 million for 2012.

13.5. Emergency Preparedness & Safety

13.5.1. Introduction

The emergency preparedness and safety functions are performed by the Safety organization. This section addresses the O&M costs and capital expenditures for SDG&E and SoCalGas.

The emergency preparedness and safety functions are "primarily responsible for establishing and managing the programs, policies and guidelines to ensure the safety of" SDG&E and SoCalGas employees. (Ex. 190 at 1; Ex. 194 at 1.) These types of safety-related activities "help reduce injuries and provide a safe work environment for all employees." (*Ibid*.)

13.5.2. SDG&E Emergency Preparedness & Safety

13.5.2.1. Background

SDG&E requests total O&M costs of $4.643 million for test year 2012. This total consists of $1.005 million in non-shared services, and $3.638 million in shared services. SDG&E also requests capital expenditures of $113,000 in 2010, $250,000 in 2011, and $250,000 in 2012.

SDG&E's non-shared services cover its non-shared safety programs and Electric Magnetic Fields (EMF) Services.

Most of the activities in SDG&E's safety programs focus on field safety. These safety programs are "primarily responsible for ensuring operational compliance with safety regulations, managing programs, policies and guidelines to ensure the safety of SDG&E employees." (Ex. 190 at 3.) These safety programs include training programs, and field operations support.

EMF Services provides overall management of SDG&E's EMF activities. These activities include the following: tracking the EMF science; making EMF health literature available to customers and employees; responding to inquiries about EMF health issues, and coordinating responses with other SDG&E operational units; conducting EMF measurements in accordance with D.93-11-013 [52 CPUC2d 1]; and responding to school district representatives for data to comply with the EMF provisions of Title 5 of the California Code of Regulations regarding school site selection.

Except for the non-shared field safety and EMF activities, all other safety programs and services in the Emergency Preparedness and Safety department are shared between SDG&E and SoCalGas. These shared services departments consist of safety compliance, safety and emergency services technology, operations, and director. The activities of these shared services departments fall into the following four categories of management: safety programs; emergency services; utility security services; and billed in shared services.

The activities of the shared services safety program include the following: developing training programs; developing, implementing and maintaining safety and emergency services systems and technology; reducing and eliminating incidents by conducting job observations, investigating incidents, promoting defensive driving, using protective equipment, and using correct body mechanics. Shared services also includes the Safety and Emergency Services Director, who provides leadership and direction.

The shared services emergency services "is responsible for maintaining comprehensive and coordinated emergency response and recovery programs."

(Ex. 190 at 6.) Emergency services are responsible for all aspects of the Emergency Operation Centers, and the Gas Emergency Centers. In addition, emergency services are responsible for managing the Business Continuity and Resumption Planning Program, and the Emergency Action Plans.

The utility security services consist of contract security guards at four SDG&E sites, and three SoCalGas locations.

The capital expenditures for SDG&E's emergency preparedness and safety is "driven primarily by aging communications equipment and technology," and "[m]ore flexible and up-to-date equipment and systems will replace older and less efficient technology." (Ex. 190 at 7.) SDG&E forecasts capital expenditures of $113,000 in 2010, $250,000 in 2011, and $250,000 in 2012.

13.5.2.2. Position of the Parties

13.5.2.2.1. DRA

DRA recommends that the test year 2012 forecast for total O&M costs for emergency preparedness and safety be set at $4.493 million. DRA does not take issue with SDG&E's non-shared forecast amount of $1.005 million.

For shared services, DRA recommends $3.488 million instead of SDG&E's forecast of $3.638 million. DRA's recommended reduction is due to the use of a three-year average, and its opposition to most of the incremental increases that SDG&E added.

For SDG&E's capital expenditures, DRA recommends annual funding of $113,000 in 2010, 2011, and 2012. DRA contends that the 2011 and 2012 funding levels should be set lower than what SDG&E has requested because SDG&E failed to provide all supporting documentation, and "failed to provide a cost-benefit analysis for this blanket or different bids from different vendors." (Ex. 519 at 11.)

13.5.2.2.2. SDG&E

SDG&E contends that "its forecasts are reasonable, supportable, and reflective of the incremental needs and known cost drivers impacting this area." (Ex. 193 at 1.) SDG&E opposes DRA's forecasts because DRA did not dispute the substance of any program or activity, and did not discuss the "impacts of its proposals, or why its forecasts will be sufficient to meet the needs described in SDG&E's showing." (*Ibid*.) SDG&E further contends that DRA's forecasts "will underfund SDG&E's efforts to maintain and improve safety emergency response and recovery programs as well as to comply with Federal and State safety standards and requirements." (*Ibid*.)

As described in Exhibit 193, SDG&E contends that its forecasts are reasonable and justified because: the funds will be used to "fund improvements in emergency planning, training, and reporting;" the funds will be used to "ensure compliance with safety regulations and establish and manage programs, policies, and guidelines to ensure the safety of its employees;" that funding cuts to security services should not be compromised; and because DRA did not justify why the billed in costs should be reduced. (Ex. 193 at 3-4.)

Regarding DRA's reductions to SDG&E's capital expenditures, SDG&E argues that it provided the data which DRA claims was not supplied.

13.5.2.3. Discussion

We have reviewed the testimony and arguments of SDG&E and DRA concerning the O&M costs and capital expenditures for safety preparedness and safety. We have also compared their forecasts to the historical data, and considered SDG&E's request for incremental funding.

Based on those considerations, it is reasonable to adopt the forecast of SDG&E for the non-shared O&M costs. However, a comparison of the shared services O&M costs shows that SDG&E's forecast is too high compared to the historical costs. It is reasonable under the circumstances to reduce the shared services O&M costs by $200,000. Accordingly, the following O&M costs for SDG&E's emergency preparedness and safety should be adopted: $1.005 million in non-shared services, and $3.438 million in shared services.

For the capital expenditures, we are not persuaded by DRA's argument that the level of capital expenditures should remain at $113,000 for all three years. Based on the prior year recorded amounts, and the need to replace aging communications and technology in order to upgrade the equipment at the emergency operation centers, it is reasonable to adopt the following capital expenditures: $113,000 in 2010; $250,000 in 2011; and $250,000 in 2012.

13.5.3. SoCalGas Emergency Preparedness & Safety

13.5.3.1. Background

SoCalGas requests total O&M costs of $4.183 million for test year 2012. This total consists of $1.375 million in non-shared services, and $2.808 million in shared services.

SoCalGas' non-shared services cover its non-shared safety programs. Most of the activities in SoCalGas' safety programs focus on field safety. These safety programs are "primarily responsible for ensuring operational compliance with safety regulations, managing the programs, policies and guidelines to ensure the safety of [SoCalGas] employees." (Ex. 194 at 3.) These safety programs include training programs, and field operations support.

Except for the non-shared field safety, all other safety programs and services are shared between SoCalGas and SDG&E. These shared services departments consist of safety compliance, safety and emergency services technology, operations, and director. The activities of these shared services departments fall into the following three categories of management: safety programs; emergency services; and billed in shared services.

The activities of the shared services safety program include the following: developing training programs; developing, implementing and maintaining safety and emergency services systems and technology; reducing and eliminating incidents by conducting job observations, investigating incidents, promoting defensive driving, using protective equipment, and using correct body mechanics. In addition, the Safety and Emergency Services Director provides leadership and direction.

The shared services emergency services "is responsible for maintaining comprehensive and coordinated emergency response and recovery programs." (Ex. 194 at 6.) Emergency services are responsible for all aspects of the Emergency Operation Centers, and the Gas Emergency Centers. In addition, emergency services are responsible for managing the Business Continuity and Resumption Planning Program, and the Emergency Action Plans.

The capital expenditures for SoCalGas' emergency preparedness and safety is "driven primarily by aging communications equipment and technology," and "More flexible and up-to-date equipment and systems will replace older and less efficient technology." (Ex. 194 at 6.) SoCalGas forecasts capital expenditures of $650,000 in 2010, $850,000 in 2011, and $850,000 in 2012.

13.5.3.2. Position of the Parties

13.5.3.2.1. DRA

DRA recommends that the test year 2012 forecast for total O&M costs for emergency preparedness and safety be set at $3.643 million.

DRA takes issue with SoCalGas' non-shared forecast amount of $1.375 million. DRA recommends an amount of $1.045 million. DRA's recommendation uses the 2010 recorded amount for its test year 2012 forecast amount. DRA's recommendation does not include SoCalGas' incremental adjustment because of DRA's belief that SoCalGas' assumptions "are unjustified and do not reflect actual expenses." (Ex. 519 at 8.)

For shared services, DRA recommends $2.598 million instead of SoCalGas' forecast of $2.808 million. DRA's recommended reduction is due to the use of a three-year average for the safety emergency preparedness cost center, and its opposition to SoCalGas' request for an incremental increase.

For SoCalGas' capital expenditures, DRA recommends annual funding of $650,000 in 2010, 2011, and 2012. DRA contends that the 2011 and 2012 funding levels should be set lower than what SoCalGas has requested because SoCalGas failed to provide all supporting documentation, and "failed to provide a cost-benefit analysis for this blanket or different bids from different vendors." (Ex. 519 at 13.)

13.5.3.2.2. SoCalGas

SoCalGas contends that its "forecasts are reasonable, supportable, and reflective of the incremental needs and known cost drivers impacting this area." (Ex. 197 at 2.) SoCalGas opposes DRA's forecasts because DRA did not dispute the substance of any program or activity, and did not discuss the "impacts of its proposals, or why its forecasts will be sufficient to meet the needs described in [SoCalGas'] showing." (*Ibid*.) SoCalGas further contends that DRA's forecasts "will underfund [SoCalGas'] efforts to maintain and improve safety emergency response and recovery programs as well as to comply with Federal and State safety standards and requirements." (Ex. 197 at 3.)

As described in Exhibit 197, SoCalGas contends that its forecasts are reasonable and justified. On DRA's reduction to the safety programs, SoCalGas contends that funding is needed to ensure compliance with safety regulations, and to minimize the risk of job injuries. On DRA's reduction to field safety, SoCalGas contends that there is a need for additional staff because "[s]prains and strains are the company's highest frequency injuries," and the additional staff will provide help in those areas. (Ex. 197 at 5.)

Regarding DRA's reductions to SoCalGas' capital expenditures, SoCalGas argues that it provided the data which DRA claims was not supplied.

13.5.3.3. Discussion

We have reviewed the testimony and arguments of SoCalGas and DRA concerning the O&M costs and capital expenditures for safety preparedness and safety. We have also compared their forecasts to the historical data, and considered SoCalGas' request for incremental funding.

Based on those considerations, it is reasonable to adopt the forecast of SoCalGas for the non-shared O&M costs. However, for the shared O&M costs, we agree with DRA that SoCalGas' forecast of the shared O&M costs is too high given the historical costs. Based on the historical costs, and SoCalGas' incremental request, it is reasonable to reduce SoCalGas' shared O&M costs by $250,000. Accordingly, the following O&M costs for SoCalGas' emergency preparedness and safety should be adopted: $1.375 million in non-shared services, and $2.558 million in shared services.

For the capital expenditures, we are not persuaded by DRA's argument that the level of capital expenditures should remain at $650,000 for all three years. Based on the need to replace older and less efficient technology at the emergency centers, to acquire specialized tools, and to make infrastructure upgrades to meet the increased capacity and usage of the back-up data center, it is reasonable to adopt the following capital expenditures: $650,000 in 2010; $850,000 in 2011; and $850,000 in 2012.

13.6. Human Resources, Disability and Workers' Compensation

13.6.1. Introduction

This section addresses the O&M costs for the Human Resources Department, Workers' Compensation and Long term Disability Programs, and the offices of the Chief Executive Officer (CEO), President, and Chief Operating Officer (COO) for SDG&E and SoCalGas.

The challenges that face the operations of both SDG&E and SoCalGas are the same. Each utilities' workforce need "to have the skills and competencies necessary to provide safe, reliable, and sustainable" utility services. (Ex. 198 at 1; Ex. 201 at 1.) With the new technology that has been adopted, that requires retraining of "existing employees and then matching the employees and their new skill sets with the work that needs to be performed." (Ex. 198 at 2; Ex. 201 at 2.) Other challenges are increasing medical costs, mandatory requirements for drug testing, and increasing government reporting requirements.

13.6.2. SDG&E Human Resources, Disability and Workers' Compensation

13.6.2.1. Background

SDG&E forecasts total O&M costs of $15.556 million for test year 2012. This total amount consists of $11.493 million in non-shared O&M costs, and $4.063 million in shared O&M costs.

SDG&E's non-shared service costs consist of the following costs: diversity; staffing; relocation; Workers' Compensation and Long Term Disability; and CEO and President and COO.

The diversity department "is responsible for developing and directing the company-wide strategic business objective for managing workplace diversity." (Ex. 198 at 9.)

The staffing department "manages the recruitment and selection of a qualified and diverse workforce, while ensuring legal requirements are followed throughout the staffing process." (Ex. 198 at 14.) The staffing department also manages the costs for relocation, which is for out-of-area new employees and internal transferees.

For workers' compensation, this provides benefits to those who are injured on the job. SDG&E self-insures its workers' compensation program.

Long term disability "provides income replacement benefits equal to 60% of the employee's predisability earnings." (Ex. 198 at 20.)

The CEO is the highest ranking officer at SDG&E. The President and COO "directs the activities of the organization in accordance with policies, goals, and objectives established by the CEO." (Ex. 198 at 22.)

SDG&E's shared services costs consist of the following costs: VP of Human Resources; business partner and labor relations; organizational effectiveness; workforce readiness; business partner north; human resources services and analysis; and billed in costs from SoCalGas.

The VP of Human Resources provides the "leadership and strategic direction to the organization and manages the human resources function."

The business partner and labor relations department consists of human resources advisors, and labor relations advisors. The human resources advisors "serve as the primary point of contact on human resources issues for SDG&E's leadership and employees." (Ex. 198 at 11.) The labor relations advisors are responsible for union relations.

The organizational effectiveness group "provides employee and leadership development programs, instructional design activities, and organizational development programs for SDG&E." (Ex. 198 at 12.)

The workforce readiness department provides "guidance and support to organizations training young people in the underserved communities of Southern California in jobs that can lead to future careers." (Ex. 198 at 16.)

Business partner north provides supervision and leadership to human resources advisors and the human resources staffing group.

Human resources services and analysis is divided into the following four workgroups: human resources projects and compensation; employee care services; employee assistance program and wellness; and research and analysis. The human resources projects and compensation "is responsible for developing and delivering competitive compensation programs and ensuring legal compliance and adherence to compensation policies." (Ex. 198 at 17.) The employee care services "is responsible for managing and administering workers' compensation programs, short and long term disability, leave, and return to work programs for all Sempra employees." (Ex. 198 at 18.) The employee assistance program and wellness manages and administers the drug testing programs, the employee assistance program services, and the wellness programs and activities. Research and analysis "is responsible for ensuring that employment related tests meet legal requirements and the needs of SDG&E." (*Ibid*.)

13.6.2.2. Position of the Parties

13.6.2.2.1. DRA

DRA recommends that the test year 2012 forecast for total O&M costs for human resources, disability and workers' compensation be set at $11.536 million.[144]

DRA takes issue with SDG&E's forecast amount of $11.493 million for non-shared services. DRA recommends an amount of $8.339 million. DRA's recommendation is lower than SDG&E's forecasts because DRA takes issue with the following accounts as described in more detail in Exhibit 523: for diversity, DRA recommends $570,000 (the 2010 recorded amount) instead of SDG&E's forecast of $949,000; for staffing, DRA recommends $1.292 million (the 2010 recorded amount) instead of SDG&E's forecast of $1.577 million; for relocation, DRA recommends reducing the non-labor cost to $72,000 (the 2009 recorded amount), instead of SDG&E's forecast of $500,000, because relocation costs have remained low after 2007, and because certain portions of the relocation expenses should not be paid for by ratepayers; for long term disability, DRA recommends $1.073 million (the 2010 recorded amount) instead of SDG&E's forecast of $1.634 million; and for workers' compensation, DRA recommends $3.902 million (the 2010 recorded amount) for the non-labor costs due to the decline in costs over the past four years, instead of SDG&E's forecast of $5.403 million.

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[144] The $11.536 million amount is the corrected amount, as noted in footnote 1 of SDG&E's Exhibit 200, and in DRA's errata in Exhibit 524.

For shared services, DRA recommends $3.197 million instead of SDG&E's forecast of $4.063 million. DRA's lower shared services amount is due to its reductions to the following: for the VP of Human Resources, DRA recommends $209,000 instead of SDG&E's forecast of $299,000 due to the historical costs between 2006 and 2009; for Employee Care Services, DRA recommends $413,000 (five-year average for non-labor) instead of SDG&E's forecast of $453,000 due to the decline in non-labor costs from 2007 to 2010; for organizational effectiveness, DRA recommends $407,000 (2009 recorded) instead of SDG&E's forecast of $1.105 million due to DRA's belief "that this program should not be entirely funded by ratepayers since it appears to also provide shareholders value and benefits" (Ex. 523 at 19.); and for billed in costs, DRA recommends $271,000 instead of SDG&E's forecast of $309,000 due to an automatic adjustment in SDG&E's RO model as a result of the different labor and non-labor forecasts of DRA and SDG&E.

13.6.2.2.2. UCAN

For workers' compensation costs, UCAN recommends an amount of $4.235 million. UCAN's recommendation is based in part that medical costs be placed in the non-labor escalation category instead of as a non-standard expense which SDG&E escalated at 13% for 2010-2011, and 12% for 2011-2012.

UCAN supports DRA's recommendation of $1.073 million for long term disability costs. UCAN contends that SDG&E's derivation of its forecast is inconsistent with its use of labor escalators and headcount assumptions.

13.6.2.2.3. SDG&E

SDG&E's Exhibit 200 explains why it opposes the reductions of DRA and UCAN to the O&M costs.

Regarding DRA's reduction to the shared service of VP of Human Resources, SDG&E contends that the increase is due primarily to the reduced allocation to SoCalGas for this shared service as result of the 2010 reorganization, which results in a higher retained cost for SDG&E. SDG&E contends that DRA's recommended amount would not provide the necessary funding.

On DRA's recommended reduction to the shared service of organizational effectiveness, SDG&E contends that this is another cost impacted by the 2010 reorganization. By taking into account all the reorganization costs, SDG&E contends that the incremental increase is only $26,000.

On DRA's recommended reduction for the shared service of Employee Care Services, SDG&E contends that if DRA uses a five-year average for non-labor costs, that same average should also apply to labor costs. If the five-year average is used, that would increase SDG&E's request by $93,000. SDG&E contends that its forecast is more reasonable because it consistently uses the three-year average (2006-2009) for both labor and non-labor expenses.

Regarding DRA's reductions to non-shared services, SDG&E contends that DRA does not appear to have given any consideration to "SDG&E's explanation of planned incremental programs or cost drivers impacting the 2012 forecasts." (Ex. 200 at 6.) SDG&E also contends that DRA selectively used the 2010 data to produce certain of its forecasts.

On DRA's reduction to the non-shared organizational effectiveness, SDG&E contends that: DRA appears to have used unadjusted 2010 data; DRA did not annualize the costs which understates costs by 25%; and the 2010 data did not reflect the "existing labor vacancy throughout all of 2010." (Ex. 200 at 7.)

On DRA's reduction to non-shared staffing, SDG&E contends that the 2010 recorded data "does not consider SDG&E's incremental expense and places all its emphasis on data associated with a single year that is not representative of future or past years." (Ex. 200 at 7.) In addition, SDG&E contends that the 2010 data understates the costs because of a low level of hiring, and due to the low level of hiring, non-labor costs were also low. SDG&E also contends that its forecast of $1.580 million "is more in line with amounts derived under historical averaging than DRA's forecast of $1.292 million…."

On DRA's reduction to the non-shared relocation costs, SDG&E contends that its relocation program "is a standard relocation program provided by…a relocation program vendor," and that the relocation program provides benefits to ratepayers because these benefits "are used by SDG&E to recruit employees with the requisite skills and experience and to attract the most qualified employees to ensure the safe and reliable delivery of electricity and natural gas." (Ex. 200 at 9.) SDG&E also contends that these relocation costs are "returning to an upward trend," "due to rising relocation costs related to fuel, lodging, and other services experiencing cost increases." (Ex. 200 at 10.)

Regarding the reduction to workers' compensation by DRA and UCAN, SDG&E contends that it is not projecting workers' compensation "costs in 2012 that are anywhere near the costs experienced in 2006," and that its 2012 forecast "is $2 million less than the 2006 spend." (Ex. 200 at 11.) SDG&E also contends that there are known cost drivers that are driving up workers' compensation costs, and that DRA's use of 2010 recorded costs will not "adequately account for the known cost increases," and that "UCAN's forecast does not provide any indication that known cost drivers were ever considered." (Ex. 200 at 12-13.) SDG&E also contends that "UCAN's proposed use of non-labor escalation for a labor-driven cost such as [workers' compensation] does not represent use of the best available escalation factor." (Ex. 200 at 13.)

On the reductions of DRA and UCAN to long term disability costs, SDG&E contends that DRA's "forecast significantly underestimates [long term disability] costs in 2012 because it does not take into account anticipated increases in headcount or labor escalation." (Ex. 200 at 13.) On UCAN's reduction, SDG&E contends that long term disability costs do not go down because of lower employee counts. Instead, long term disability "costs increase with labor inflation since [long term disability] benefits are based on a percentage of an employee's pay." (Ex. 200 at 14.)

13.6.2.3. Discussion

We have reviewed the testimony and the arguments of the parties concerning the O&M costs for SDG&E's human resources, disability and workers' compensation. We have also compared the parties' forecasts to the historical costs, and considered the need for the incremental increases.

With regard to the non-shared costs, most of SDG&E's forecasts are in line with the costs that have been experienced in the past. However, based on our review of the non-shared costs for workers' compensation and long term disability, we believe that reductions to these costs are appropriate given the historical costs, and the cost increases that SDG&E expects. For workers' compensation, it is reasonable to reduce SDG&E's forecast of $5.403 million by

$850,000. For the long term disability costs, it is reasonable to reduce SDG&E's forecast of $1.634 million by $400,000. These two adjustments result in a non-shared O&M amount of $10.243 million, which should be adopted.

For the shared costs, we have reviewed the forecasts in light of the 2010 reorganization, and to the historical costs. We agree with SDG&E that DRA's forecasts do not consider the full impacts of the 2010 reorganization, which has offsetting reductions in other cost areas. Also, we are not persuaded by DRA's arguments that its recommended reductions to Employee Care Services and to billed in costs should be adopted. Accordingly, it is reasonable for the Commission to adopt shared O&M costs of $4.063 million.

13.6.3. SoCalGas Human Resources, Disability and Workers' Compensation

13.6.3.1. Background

SoCalGas forecasts total O&M costs of $33.578 million for test year 2012. This total amount consists of $27.179 million in non-shared O&M costs, and $6.399 million in shared O&M costs.

SoCalGas' non-shared service costs consist of the following costs: VP of Human Resources; diversity; labor relations; staffing; relocation; Employee Care Services; Workers' Compensation and Long Term Disability; and President and CEO and COO.

The VP of Human Resources "provides leadership and strategic direction to the organization and manages, directly and indirectly, the performance and productivity of utility employees." (Ex. 201 at 8.)

The diversity department "is responsible for developing and directing the company-wide strategic business objective for managing workplace diversity." (Ex. 201 at 9.)

Labor relations is responsible for union relations through the use of labor relations advisors.

The staffing department "manages the recruitment and selection of a qualified and diverse workforce, while ensuring legal requirements are followed throughout the staffing process." (Ex. 201at 14.) The staffing department also prepares and responds to requests for information regarding hiring practices and diversity goals.

The staffing department also manages the costs for relocation, which is for out-of-area new employees and internal transferees.

The Employee Care Services is part of the Human Resources Services and Analysis department. Employee Care Services "is responsible for managing and administering workers' compensation programs, short and long term disability, leave, and return to work programs for all Sempra employees." (Ex. 201 at 17.)

For workers' compensation, this provides benefits to those who are injured on the job. SoCalGas self-insures its workers' compensation program.

Long term disability "provides income replacement benefits equal to 60% of the employee's predisability earnings." (Ex. 201 at 20.)

The President and CEO is the highest ranking officer at SoCalGas. The COO reports to the President and CEO. The COO "directs the activities of the organization in accordance with policies, goals, and objectives established by the President & CEO." (Ex. 201 at 22.)

SoCalGas' shared services costs consist of the following costs: HR business partner; organizational effectiveness; human resources services and analysis; and billed in costs from SDG&E.

The HR business partner utilizes human resources advisors who "serve as the primary point of contact on human resources issues for utility leadership and employees." (Ex. 201 at 11.)

The organizational effectiveness group "provides employee and leadership development programs, instructional design activities, and organizational development programs for [SoCalGas]." (Ex. 201 at 12.)

The human resources services and analysis is divided into the following four workgroups: human resources projects and compensation; Employee Care Services; Employee Assistance Program and Wellness; and research and analysis. The human resources projects and compensation "is responsible for developing and delivering competitive compensation programs and ensuring legal compliance and adherence to compensation policies." (Ex. 201 at 17.) The Employee Care Services "is responsible for managing and administering workers' compensation programs, short and long term disability, leave, and return to work programs for all Sempra employees." (Ex. 201 at 17.) The Employee Assistance Program and Wellness manages and administers the drug testing programs, the employee assistance program services, and the wellness programs and activities. Research and analysis "is responsible for ensuring that employment related tests meet legal requirements and the needs of [SoCalGas]." (Ex. 201 at 18.)

13.6.3.2. Position of the Parties

13.6.3.2.1. DRA

DRA recommends that the test year 2012 forecast for total O&M costs for human resources, disability and workers' compensation be set at $28.752 million.[145]

DRA takes issue with SoCalGas' forecast amount of $27.179 million for non-shared services. DRA recommends an amount of $23.224 million. DRA's recommendation is lower than SoCalGas' forecasts because DRA takes issue with the following accounts as described in more detail in Exhibit 523: for relocation, DRA recommends reducing the non-labor cost to $50,000 (the 2009 recorded amount), instead of SoCalGas' forecast of $385,000, because relocation costs have remained at a low level in recent years, and because certain portions of the relocation expenses should not be paid for by ratepayers; for long term disability, DRA recommends $4.165 million (four-year average of 2007-2010) instead of SDG&E's forecast of $4.739 million; for workers' compensation, DRA recommends $14.400 million (four-year average of 2007-2010) instead of SoCalGas' forecast of $16.462 million; for diversity affairs, DRA recommends $423,000 instead of SoCalGas' forecast of $545,000; and for the President and

[145] As noted in footnotes 1 and 2 of SoCalGas' Exhibit 203, DRA's "Non-Shared Services" amount of $23.879 million, which appears in Table 31-2 and Table 31-13 of DRA's Exhibit 203, is incorrect. Instead of $23.879 million, the correct Non-Shared Services amount is $23.224 million, as shown in DRA's errata in Exhibit 524. DRA's correction has the effect of changing DRA's recommended total O&M costs from $29.407 million to $28.752 million in Table 31-2 of Exhibit 203.

CEO and COO, DRA recommends $1.188 million instead of SoCalGas' forecast of $1.744 million.

For shared services, DRA recommends $5.528 million instead of SoCalGas' forecast of $6.399 million. DRA's lower shared services amount is due to its reduction to employee development. DRA recommends $277,000 instead of SDG&E's forecast of $1.148 million.

13.6.3.2.2. TURN

TURN supports DRA's recommendation of $50,000 for relocation costs. In addition to the reasons cited by DRA, TURN contends that the 2007 and 2008 recorded amounts for relocation were $6,000 and $17,000, respectively. TURN points out that the recorded amounts for 2007 and 2008 were "far less than the five-year average of $0.134 million, let alone the Test Year forecast of $0.385 million." (Ex. 548 at 12.) TURN also contends that the three-year average of 2007-2010 results in an amount of $52,000, which is essentially the amount that DRA recommends, and which TURN supports.

For workers' compensation costs, TURN recommends an amount of $15.108 million in the event the Commission does not adopt DRA's recommended amount. TURN's recommendation is based in part that medical costs be placed in the non-labor escalation category instead of as a non-standard expense which SoCalGas escalated at 13% for 2010-2011, and 12% for 2011-2012.

13.6.3.2.3. SoCalGas

SoCalGas' Exhibit 203 explains why it opposes the reductions of DRA and TURN to the O&M costs.

Regarding the reduction of DRA and TURN to non-shared relocation costs, SoCalGas contends that its relocation program "is a standard relocation program provided by…a relocation program vendor," and that the relocation program provides benefits to ratepayers because these benefits "are used by [SoCalGas] to recruit employees with the requisite skills and experience and to attract the most qualified employees to help ensure the safe and reliable delivery of natural gas." (Ex. 203 at 7.) SoCalGas also contends that these relocation costs are "returning to an upward trend," "due to rising relocation costs related to fuel, lodging, and other services experiencing cost increases." (*Ibid*.) SoCalGas also contends that DRA's recommendation of $50,000 would not have covered SoCalGas' 2010 relocation costs, and will not cover SoCalGas' "expected relocation program costs in 2012." (Ex. 203 at 8.) In addition, SoCalGas contends that TURN's consultant also evaluated SDG&E's relocation costs and did not dispute SDG&E's forecast of $500,000. Since SoCalGas serves a larger service territory than SDG&E, SoCalGas contends "its forecasted needs in this area are at least on par with SDG&E if not greater." (Ex. 203 at 8.)

For the non-shared long term disability costs, SoCalGas contends that DRA's use of the four-year average "does not take into account the anticipated increases in headcount or labor escalation…." (Ex. 203 at 5.) SoCalGas also contends that DRA's recommended reductions to the long term disability costs for SoCalGas and SDG&E used two inconsistent forecasting methodologies. DRA used a four-year average for SoCalGas, but used the 2010 recorded amount for SDG&E, "presumably in an effort to capture the lowest possible test year forecast." (Ex. 203 at 5.)

For non-shared workers' compensation costs, SoCalGas contends that DRA's forecast does not consider the known cost drivers that will impact workers' compensation costs, and that DRA's forecast will result "in a significant underestimation of projected costs…." (Ex. 203 at 9.) Since SoCalGas' workers' compensation program is self-insured, the state and federal cost drivers, and increasing medical costs, will put upward pressures on SoCalGas immediately. SoCalGas also contends that "TURN's proposal to apply a non-labor escalation to the Medical subcategory is not appropriate when escalation factors for medical costs are known." (Ex. 203 at 10.)

For the non-shared diversity affairs costs in which DRA opposes the $122,000 for organizational effectiveness, SoCalGas contends that DRA did not provide any "justification for why [organizational effectiveness] programs and related costs merit cuts in forecasted funding," and to eliminate this amount "represents a significant under-funding of this important utility function. (Ex. 203 at 5.)

Regarding the non-shared President and CEO and COO costs, SoCalGas contends that "DRA's forecast is not representative of the costs for these positions…." (Ex. 203 at 6.) SoCalGas contends that after the 2010 reorganization, "the costs of the President & CEO, the COO, and an Executive Assistant were charged to this cost center, which is why [SoCalGas] used a zero-based methodology, and factored in expected cost drivers." (*Ibid.*) SoCalGas further contends that the compensation for these officers is reasonable, and that the dues to the American Gas Association are a "prudent investment for a gas utility…." (*Ibid.*)

With respect to DRA's recommended reduction to the shared employee development costs, SoCalGas contends that these costs were impacted by the 2010 reorganization, and that DRA did not consider the "offsetting reductions in allocations and direct costs in other cost centers…." (Ex. 203 at 3.) As a result of these offsets, SoCalGas contends that the incremental increase is $295,000, and that these incremental costs will fund new and additional training offerings as described in Exhibit 203 at 13.

13.6.3.3. Discussion

We have reviewed the testimony and the arguments of the parties concerning the O&M costs for SoCalGas' human resources, disability and workers' compensation. We have also compared the parties' forecasts to the historical costs, and considered the need for the incremental increases.

Based on our review of the non-shared costs, including workers' compensation and long term disability costs, it is reasonable to make adjustments to the following: reduce relocation costs from $385,000 to $285,000 based on the historical costs that have been incurred, and SoCalGas' expected hiring; reduce long term disability costs from $4.739 million to $4.539 million based on the historical costs that have been incurred, and expected increases; and reduce workers' compensation costs from $16.462 million to $16.011 million based on the historical costs that have been incurred, and the cost drivers which affect these costs. Based on our review of the diversity-related costs, and the costs of the President and CEO and COO, we are not persuaded by DRA's contention that reductions to these costs are warranted. Accordingly, it is reasonable to adopt non-shared costs of $26.428 million.

For the shared costs, we have reviewed the forecasts in light of the 2010 reorganization, and to the historical costs. We agree with SoCalGas that DRA's forecast does not consider the full impact of the 2010 reorganization, which has offsetting reductions in other cost areas. In addition, we agree with SoCalGas that the incremental costs will fund the programs that SoCalGas described in its testimony. Since we agree with SoCalGas' shared O&M forecast, we are not persuaded by DRA's arguments that an adjustment should be made to billed in costs. Accordingly, it is reasonable for the Commission to adopt shared O&M costs of $6.399 million.

13.7. Controller, Regulatory Affairs and Finances

13.7.1. Introduction

The Controller, Regulatory Affairs, and Finance divisions are shared services functions. The costs of these functions are allocated primarily to SDG&E and SoCalGas, and some of the Controller division costs are allocated to Sempra's Corporate Center and its affiliates.

The Controller division "provides Utility Account, Accounting Operations, Financial System and Business Controls, and Planning & Analysis services…." (Ex. 339 at 1; Ex. 341 at 1.)[146]

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[146] The direct testimony regarding Controller, Regulatory Affairs, and Finances for SDG&E and SoCalGas are the same. The direct testimony of SDG&E and SoCalGas are in Exhibits 339 and 341, respectively. The references to Exhibit 339 also refer to Exhibit 341. The rebuttal testimony for both utilities is contained in Exhibit 343.

Regulatory Affairs "provides policy, case management, regulatory analysis, and advocacy before various legislative and regulatory bodies," including the Commission. (Ex. 339 at 1.)

The Finance division "provides financial analysis, risk management, and strategic analysis services" to the utilities. (Ex. 339 at 2.)

For test year 2012, the book expense for SDG&E is forecast at $26.811 million. The incurred expense for SDG&E is forecast at $31.098 million. SDG&E's non-shared book expense is $12.229 million, and the shared book expense is $14.582 million.

For test year 2012, the book expense for SoCalGas is forecast at $22.220 million. The incurred expense for SoCalGas is forecast at $18.168 million. SoCalGas' non-shared book expense is $9.530 million, and the shared book expense is $12.690 million.

In the sub-sections below, we describe the activities of the Controller, Regulatory Affairs, and Finance departments, followed by the position of the parties and discussion of the costs for all three departments.

13.7.2. Controller

13.7.2.1. Background

The Controller division consists of the following six departments: VP – Chief Financial Officer (CFO) and Controller; utility accounting; accounting operations; financial systems and business controls; planning & analysis; and claims payments and recovery costs.

The VP –CFO and Controller function "provides oversight and guidance related to the financial and accounting services at both [SoCalGas] and SDG&E." (Ex. 339 at 9.) Prior to 2009, there were separate positions for the CFO and the Controller for both utilities. In late 2008, the CFO and Controller positions were combined, which resulted in one VP – CFO and Controller position. In addition to the VP – CFO and Controller position, there is a Director of Finance, and a VP of Accounting and Finance.

The utility accounting function "provides accounting services to ensure that [SoCalGas] and SDG&E policies, procedures, and transactional activities are accounted for and presented in conformity with SEC [Securities and Exchange Commission] statutes, GAAP [Generally Accepted Accounting Practices] and the FERC and CPUC regulatory reporting mandates." (Ex. 339 at 10.)

The accounting operations function consists of three primary areas: cost accounting; sundry services; and affiliate billing and costing. Cost accounting "is responsible for rate base accounting, operating cost accounting, new business accounting, fixed asset management, billable project accounting, and generation accounting." (Ex. 339 at 11-12.) Sundry services "is responsible for the provision of products and services…other than commodity, transportation and delivery costs." (Ex. 339 at 12.) Sundry services provide support in such areas as NTP&S, miscellaneous revenues, training on GAAP, and coordinating and supervising some of the Sarbanes-Oxley regulations. Affiliate billing and costing "is responsible for managing the cost allocation process, setting overhead rates and administering the cost allocation and overhead distribution processes to ensure that overhead costs are properly allocated to operations and maintenance…, capital and utility third party billings and accurately reflected in the financial statements." (Ex. 339 at 13.)

Financial systems and business controls consists of the following three sections: business controls; financial systems; and accounts payable. The business controls section "is responsible for organizing, coordinating, and managing several of the Utilities' compliance processes as they develop and expand under evolving state and federal guidelines." (Ex. 339 at 14.) These compliance processes include among other things, Sarbanes-Oxley compliance, accounting research for GAAP and International Financial Reporting Standards, records management, and forensic accounting and business controls. The financial systems section "provides technical support to accounting, budget systems and other operational users to obtain information, as well as assists in maintaining these systems…." (*Ibid*.) The accounts payable section is responsible for the "payment of all service and material invoices and contract obligations for" SoCalGas, SDG&E, and Sempra's Corporate Center.

The Planning and Analysis department "is responsible for developing and measuring the financial performance targets of SDG&E and [SoCalGas]." (Ex. 339 at 15.) This department's responsibility includes "administering the budgeting system and processing third party claims, and conducting "loss control/prevention activities designed to prevent and reduce accidents…." (Ex. 339 at 16.)

The Claims Payments and Recovery is responsible for "claims expenses to be paid to third parties and recovery expenses above the purchased insurance coverage." (Ex. 339 at 17.)

The book expense to SDG&E for the Controller's costs is $15.709 million, and the book expense to SoCalGas for the Controller's costs is $16.822 million.

13.7.3. Regulatory Affairs

13.7.3.1. Background

The Regulatory Affairs division is responsible for managing cases and issues before this Commission, FERC, CAISO, the CEC, and other regulatory agencies. Among its activities, Regulatory Affairs "calculates customer rates, administers tariffs, develops policy, analyzes and forecasts gas and electric demand, manages relationships between regulators and the Utilities, and ensures compliance with affiliate compliance rules." (Ex. 339 at 20.)

The Regulatory Affairs division consists of the following five departments: Senior VP – Finance, Regulatory, and Legislative Affairs; Regulatory Relations and Legislative Affairs; California case management; GRC, Rates, and Analysis; and FERC, CAISO, and Compliance.

The Senior VP "of Finance, Regulatory & Legislative Affairs provides leadership and oversight to the Controller, Regulatory Affairs, and Finance Divisions at both [SoCalGas] and SDG&E."

Regulatory Relations "is the primary point of contact between [SDG&E/SoCalGas] and the CPUC's Commissioners, advisors and key staff," and "is responsible for participating in case development; developing regulatory and advocacy strategies to achieve utility objectives and implementing those strategies; gathering information relating to CPUC policies, proceedings and procedures; analyzing and developing policy positions; and reporting and making recommendations to management of SDG&E and [SoCalGas]." (Ex. 339 at 23-24.)

The activities and responsibilities of Legislative Affairs include "reviewing proposed legislation, identifying operational and policy issues, consulting with subject matter experts, recommending positions and responses, and developing recommended future legislative actions and policies." (Ex. 339 at 24.)

The California case management group has the overall responsibility for the following: coordinating participation "in all regulatory proceedings and related activities before the CPUC…; managing all regulatory filings with the CPUC…; ensuring compliance with all CPUC directives and requirements…; ensuring the appropriate retention of all regulatory records and related information as part of the Utilities' Regulatory Central Files; and…maintaining effective working relationships with the CPUC and its staff and being responsive to their requests for information or assistance." (Ex. 339 at 25.)

The GRC, Rates and Analysis units consists of the GRC group, Rates and Analysis, and the Tariff group. The GRC group "is responsible for the management and coordination of" the utilities' proceedings before the CPUC. The Rates and Analysis group "provides economic analysis, demographics, gas and electric customer forecasts; alternate fuel price and gas price forecasts; gas and electric demand forecasts and analyses; gas and electric rate designs and cost allocation; and policy, analyses, and coordination for use in business development and regulatory proceedings." (Ex. 339 at 26.) The Tariffs group is responsible for the activities concerning ALs, responding to protests, and draft resolutions.

The FERC, CAISO, and Compliance groups perform various functions. The FERC and CAISO groups perform activities related to regulatory filings before the FERC, and stakeholder initiatives before the CAISO. The Affiliate Compliance group "is responsible for facilitating compliance with state and federal affiliate transaction-type rules, such as the CPUC's Affiliate Rules and FERC Standards of Conduct." (Ex. 339 at 28.) In addition, there are compliance costs related to non-transmission NERC reliability standards.

The book expense to SDG&E for the Regulatory Affairs' costs is $9.169 million, and the book expense to SoCalGas for the Regulatory Affairs' costs is $3.943 million.

13.7.4. Finance

13.7.4.1. Background

The Finance division "is primarily responsible for analyzing new projects, technologies, initiatives, and managing regulatory accounts" for the two utilities. (Ex. 339 at 31.) The Finance division consists of the following groups: Financial Analysis; Risk Management; and Strategic Analysis.

The Financial Analysis group "performs a wide variety of financial and regulatory accounting functions, including project evaluation, the development, analysis and implementation of revenue requirements, regulatory accounts and ratemaking mechanisms in support of regulatory filings and large-scale financial projects." (Ex. 339 at 33.) Financial Analysis also "maintains a utility treasury function that analyzes cash flows and financing requirements in support of the Utilities' short and long term debt issuances." (*Ibid*.)

The Risk Management group monitors "market, credit and operational risks for energy procurement operations…." (Ex. 339 at 36.)

The Strategic Analysis group "supports and facilitates the implementation of strategies intended to deliver the best value for customers and financial stability for the Utilities on a sustainable basis," including analyzing "the availability and economics associated with new technologies, as well as the demand for new products and services for both [the] electric and natural gas businesses." (Ex. 339 at 37.)

The book expense to SDG&E for the Finance division costs is $1.933 million, and the book expense to SoCalGas for the Finance division costs is $1.455 million.

13.7.5. Position of the Parties

13.7.5.1. DRA

13.7.5.1.1. DRA Position on SDG&E

For SDG&E, DRA recommends a total A&G cost of $23.872 million, instead of SDG&E's forecast of $26.811 million. DRA's recommendation consists of $9.538 million in non-shared costs, and $14.334 million in shared costs.

DRA reviewed all of the sub-accounts that make up the non-shared costs for the Controller, Regulatory Affairs, and Finance. DRA does not take issue with the sub-accounts for sundry billing, claims, and electric forecasting and tariffs. As set forth in Exhibit 525, DRA takes issue with the sub-accounts for cost accounting, claims payments and recovery, and FERC, CAISO and compliance.

For the cost accounting sub-account, DRA recommends $2.009 million instead of SDG&E's forecast of $2.051 million. DRA's recommendation is lower than SDG&E's forecast by $42,000 because DRA adjusted the non-labor expense.

DRA contends that the non-labor "expense for cost accounting remained significantly lower in the past 4 years, and do not support the increase in SDG&E's forecast…." (Ex. 525 at 7-8.) DRA used the 2009 recorded non-labor expense of $65,000 instead of SDG&E's non-labor amount of $107,000. DRA points out that the $65,000 is also equal to the five-year average of 2006-2010.

For the claims payments and recovery sub-account, DRA recommends $4.858 million instead of SDG&E's forecast of $6.914 million.[147] DRA's recommendation is lower than SDG&E's forecast by $2.056 million because DRA adjusted the non-labor expense. DRA contends that the non-labor expense "fluctuated significantly within the past 5 years, and does not support the increase in SDG&E's forecast…." (Ex. 525 at 9.) DRA used the 2010 recorded non-labor expense of $4.699 million instead of SDG&E's non-labor amount of $6.914 million.

For the FERC, CAISO and Compliance sub-account, DRA recommends $704,000 instead of SDG&E's forecast of $1.138 million. DRA's recommendation is lower than SDG&E's forecast by $434,000 because DRA used the two-year average of 2009-2010 "because of the low fluctuation over the past years." (Ex. 525 at 11.)

DRA reviewed all of the sub-accounts that make up the shared costs for the Controller, Regulatory Affairs, and Finance. DRA does not take issue with 30 of the sub-accounts. As described in Exhibit 525, DRA takes issue with the

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[147] DRA originally recommended $4.699 million for the claims payments and recovery sub-account. SDG&E then adjusted DRA's recommendation of $4.699 million to $4.858 million due to errors contained in SDG&E's 2010 actual claims data. (See Ex. 343 at 3, footnote 2.)

sub-accounts for business controls, Senior VP – Finance, Regulatory and Legislative Affairs, and California case management.

For the business controls sub-account, DRA recommends $186,000 instead of SDG&E's forecast of $200,000. DRA's recommendation is lower than SDG&E's forecast by $14,000 because DRA used the five-year average of 2006-2010 to estimate this sub-account cost. DRA believes its average reflects the most recent data for this sub-account cost.

For the Senior VP – Finance, Regulatory & Legislative Affairs sub-account, DRA recommends $483,000 instead of SDG&E's forecast of $525,000. DRA's recommendation is lower than SDG&E's forecast by $42,000. DRA's recommendation used the five-year average of 2006-2010, and contends that using the most recent data to average expenses for this sub-account is a reasonable approach.

For the California case management sub-account, DRA recommends $870,000 instead of SDG&E's forecast of $952,000. DRA's recommendation is lower than SDG&E's forecast by $82,000. DRA's recommendation used the five-year average of 2006-2010, and contends that using the most recent data to average expenses for this sub-account is a reasonable approach.

DRA also recommends an adjustment be made to the billed in costs from SoCalGas. Instead of using SDG&E's billed in cost of $3.064 million, DRA recommends billed in cost of $2.954 million. DRA contends that the adjustment is needed because of the different labor and non-labor forecasts that DRA and SDG&E used.

13.7.5.1.2. DRA Position on SoCalGas

For SoCalGas, DRA recommends a total A&G cost of $19.831 million, instead of SoCalGas' forecast of $22.220 million. DRA's recommendation consists of $7.430 million in non-shared costs, and $12.401 million in shared costs.

DRA reviewed all of the sub-accounts that make up the non-shared costs for the Controller, Regulatory Affairs, and Finance. DRA does not take issue with the sub-accounts for cost accounting, and regulatory tariffs. As set forth in Exhibit 525, DRA takes issue with the sub-account for claims payments and recovery.

For the claims payments and recovery sub-account, DRA recommends $5.209 million instead of SoCalGas' forecast of $7.062 million. DRA's recommendation is lower than SoCalGas' forecast because DRA adjusted the non-labor expense. DRA contends that the five-year average of 2006-2010 is a reasonable approach to estimating the test year 2012 non-labor expenses for this sub-account.

DRA reviewed all of the sub-accounts that make up the shared costs for the Controller, Regulatory Affairs, and Finance. DRA does not take issue with 17 of the sub-accounts. As described in Exhibit 525, DRA takes issue with the sub-accounts for financial planning, California case management, and regulatory accounts.

For the financial planning sub-account, DRA recommends $315,000 instead of SoCalGas' forecast of $407,000. DRA's recommendation is lower than SoCalGas' forecast by $92,000. DRA used the five-year average of 2006-2010 for its recommendation, and contends that the use of that average is reasonable since it reflects the most recent data for estimating both labor and non-labor costs in this sub-account.

For the California case management sub-account, DRA recommends $441,000 instead of SoCalGas' forecast of $520,000. DRA's recommendation is lower than SoCalGas' forecast by $79,000. DRA used the five-year average of 2006-2010 for its recommendation, and contends that the use of that average is reasonable since it reflects the most recent data for this sub-account.

For the regulatory accounts sub-account, DRA recommends $61,000 instead of SoCalGas' forecast of $75,000. DRA's recommendation is lower than SoCalGas' forecast by $14,000. DRA used the five-year average of 2006-2010 for its recommendation, and contends that the use of that average is reasonable since it reflects the most recent data for this sub-account.

DRA also recommends an adjustment be made to the billed in costs from SDG&E. Instead of using SoCalGas' billed in cost of $7.169 million, DRA recommends billed in cost of $6.721million.[148] DRA contends that the adjustment is needed because of the different labor and non-labor forecasts that DRA and SoCalGas used.

13.7.5.2. TURN and UCAN

For the A&G costs for Regulatory Affairs, TURN and UCAN recommend a total of $9.636 million instead of the $11.975 million recommended by the Applicants.[149] Of the $9.636 million, TURN and UCAN recommend that $6.242 million come from SDG&E, and that $3.394 million come from SoCalGas.

The recommendation of TURN and UCAN is based on the use of the four-year average of 2007-2010, instead of the five-year average of 2005-2009. In addition, the recommendation of TURN and UCAN reduces regulatory affairs labor costs by 5.4%, and assigns $800,000 for legislative affairs and affiliate transactions compliance to shareholders.

For the A&G costs for Financial Analysis, TURN and UCAN recommend that an adjustment of $213,000 be made to two cost centers, reducing the total costs from $1.567 million to $1.354 million. TURN and UCAN contend that this adjustment is needed because actual 2010 spending was less than SDG&E's forecast, even though a new staff person was added.

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148 In Exhibit 525 at 29, DRA referenced the billed in costs pertaining to SDG&E ($3.064 million) instead for the billed in costs pertaining to SoCalGas of $7.169 million. This discrepancy can be seen by comparing Table 32-15 and Table 32-7 in Exhibit 525.

149 The $9.636 million is referenced by TURN and UCAN in Exhibit 543 at 22, but SoCalGas refers to $9.469 million as the amount TURN and UCAN have recommended for the regulatory affairs A&G costs.

13.7.5.3. SDG&E and SoCalGas

13.7.5.3.1. SDG&E

For cost accounting, DRA recommends A&G costs of $2.009 million as opposed to SDG&E's amount of $2.051 million. SDG&E contends that DRA's methodology for arriving at its recommendation is inconsistent because DRA accepts SDG&E's forecast for labor, which consists of the five-year average of 2005-2009, but uses the 2009 recorded number for non-labor. SDG&E points out that DRA supported the use of the five-year average for SCE's Controller's organization in A.10-11-015. SDG&E contends that using the five-year average for both labor and non-labor costs for cost accounting "serves as a good basis for the costs SDG&E would expect to see over the rate case cycle by smoothing out the effects from year-to-year swings due to work flow, temporary vacancies, rate case cycles, etc." (Ex. 343 at 5.)

Regarding DRA's recommended amount of $4.858 million for SDG&E's non-shared A&G costs for claims payments, SDG&E contends that its three-year average of 2007-2009 is more appropriate because it reflects "the recent trends SDG&E is experiencing in claims activity, and also (versus one-year recorded) to account for the significant fluctuations that can be seen in claims expense from one year to the next." (Ex. 343 at 3.) SDG&E contends that DRA's use of a single year of data from 2010 "violates the fundamental premise that claims expense cannot be reasonably predicted by one year's activity," and that SDG&E "has seen volatility year to year, as evidenced by a fluctuation in claims expense from 2007-2009, where the expense went from $2.0 million in 2007, up to $9.5 million in 2008, and back down to $6.2 million in 2009." (Ex. 343 at 4.) SDG&E also contends that DRA's recommended amount fails to account for SDG&E's higher deductible, "which has increased from the historical level of $1 million to the current amount of $4 million." (*Ibid*.)

For the FERC, CAISO and compliance A&G costs, DRA recommends $704,000 as opposed to SDG&E's forecast of $1.138 million. To develop its forecast, SDG&E used the five-year average (2005-2009), and added $200,000 in costs to reflect NERC reliability standard compliance costs. According to SDG&E, those NERC reliability standard compliance costs were previously recovered as electric transmission costs. SDG&E contends that DRA's forecast, which is based on the two-year average of 2009-2010, did not even consider the incremental NERC costs.

Regarding DRA's recommended reductions to SDG&E's three shared A&G costs (business controls; Senior VP; and California case management), SDG&E is opposed to DRA's use of the five-year average of 2006-2010 since DRA only used this average on a selected basis to the Controller division. SDG&E also contends that DRA misapplied DRA's "five-year forecast to SDG&E book expenses (after inter-utility) allocations), rather than applying directly to incurred expenses (before inter-utility allocations) as SDG&E has done in developing its test year forecasts." (Ex. 343 at 7.) As a result, "DRA overstates the proposed reductions…." (*Ibid*.) SDG&E's Attachment C to Exhibit 343 shows how DRA should have applied the five-year forecast to incurred expenses.

Regarding DRA's recommended reduction to billed in costs from SoCalGas, SDG&E contends that DRA's reduction is "inaccurate and illogical" based on the size of DRA's reductions as compared to the percentage of SoCalGas' total shared service incurred charges.

13.7.5.3.2. SoCalGas

DRA's recommended amount for SoCalGas's non-shared A&G claims payments is $5.234 million as opposed to SoCalGas' forecast of $7.062 million. SoCalGas contends that DRA's methodology is significantly different and inconsistent from what DRA used for the forecast of SDG&E's claims payment amount. Instead of using the 2010 recorded claims, as DRA did for deriving the forecast for SDG&E, DRA used the five-year average of (2006-2010) to derive the SoCalGas claims payments amount of $5.234 million. In contrast, both SDG&E and SoCalGas used the "three-year average approach as the most reasonable means to balance the year-to-year volatility in claims expense, while still capturing the more recent changes in the liability claims environment." (Ex. 343 at 11.) SoCalGas also contends that DRA ignored the higher deductible that SoCalGas will pay.

Regarding DRA's recommended reductions to SoCalGas' shared A&G sub-accounts for financial planning, and California case management, SoCalGas is opposed to DRA's use of the five-year average of 2006-2010 because DRA only used this average on a selected basis to the Controller division. SoCalGas also contends that DRA misapplied DRA's "five-year average to book expense, rather than first averaging incurred expense and then applying 2012 Allocation percentages to arrive at book expense." (Ex. 343 at 12.) As a result, this "flawed methodology leads to inconsistent reporting of the recorded numbers and the subsequent test year forecasts." (*Ibid*.) Attachment C to Exhibit 343 shows how

DRA should have applied the five-year forecast to incurred expenses. SoCalGas also contends that DRA's forecast for California case management failed "to include one incremental FTE to support the increasing regulatory case load," although DRA raised "no objection to the additional FTE." (Ex. 343 at 13.)

With respect to DRA's reduction to the shared regulatory accounts, SoCalGas contends that it used the 2009 recorded amount as its base forecast since this "cost center had not evolved in the earlier years of the five-year average period (2005-2009)," and therefore "the costs from the prior years, more specifically 2005-2006, are understated." (Ex. 343 at 13.) SoCalGas contends that DRA's use of the five-year average (2006-2010) did not acknowledge this, and that DRA also misapplied the five-year average to book expense.

Regarding DRA's recommended reduction to billed in costs from SDG&E, SoCalGas contends that DRA's reduction is "inaccurate and illogical" based on the size of DRA's reductions as compared to the percentage of SDG&E's total shared service incurred charges.

SoCalGas also notes in Exhibit 343 that DRA acknowledged that DRA's forecast of SoCalGas' shared services was incorrect due to calculation errors. Instead of DRA's total shared services amount of $10.122 million, the corrected DRA total shared services amount should be $12.057 million.

TURN and UCAN have recommended reductions to shared services for regulatory affairs, and to financial analysis, for both SDG&E and SoCalGas.

The Applicants contend that the use of the four-year average of 2005-2009 for regulatory affairs is designed to yield a lower result, and ignores the incremental addition of three load research staff members. As for the reduction by TURN and UCAN to the 2010-2011 labor escalation, the Applicants contend that "compensation is different for a variety of legitimate and market driven reasons, regardless of the general similarities among these jobs." (Ex. 343 at 19.) The Applicants also contend that escalation is not presented or requested in the Controller division section, and that it would be incorrect and inappropriate to "remove dollars for labor escalation from [the Applicants'] forecasts which have not been escalated to begin with." (*Ibid*.)

As part of their recommended reductions to regulatory affairs, TURN and UCAN also recommend that the affiliate compliance department costs should be reduced by $277,000 on the theory that ratepayers should not have to pay to ensure that affiliate transactions abuse does not occur. The Applicants contend that the affiliate compliance department is an appropriate ratepayer expense because it is an "important component of the compliance process, with various responsibilities, including utility-specific oversight and services to ensure compliance, and the development and submittal of various mandated reports to the Commission on a periodic basis." (Ex. 343 at 20.) The Applicants also contend that TURN and UCAN did not take issue with the Applicants' affiliate compliance department costs in the prior GRC.

TURN and UCAN have also recommended as part of their recommended reductions to regulatory affairs that 100% of the costs incurred by Legislative Affairs be assigned to shareholders because lobbying activities are involved. The Applicants contend that TURN and UCAN appear to confuse the Legislative Affairs group with the State Governmental Affairs department. According to the Applicants, its State Governmental Affairs department participates in lobbying type activities, while Legislative Affairs performs an internal utility function, and does not engage in external lobbying.

TURN and UCAN also recommended that the $176,000 for the costs of the regulatory strategy group be denied because there were no recorded costs for this group in 2010. The Applicants contend that this group did record costs of $159,000 in 2010, which is close to the Applicants' 2010 forecasted costs of $164,000.

As for TURN and UCAN's recommended reduction to the financial analysis cost centers, the Applicants contend that TURN and UCAN have arbitrarily selected cost centers "that have 2010 recorded costs below 2009 levels," and that TURN and UCAN have considered "the cost declines to be indicative of future department demands…." The Applicants contend that the 2010 costs were lower due to additional vacancies, and that the labor count for the Finance division has increased "from 21 FTEs at the end of 2010 to 25 FTEs at August 31, 2011." (Ex. 343 at 23.)

13.7.6. Discussion

We have reviewed all of the testimony and arguments of the parties concerning the Controller, Regulatory Affairs, and Finance A&G costs. We have also reviewed their respective forecasts and compared them to the historical costs.

With respect to SDG&E's non-shared A&G costs, we are persuaded by DRA's testimony that reductions to SDG&E's cost accounting, claims payments and recovery, and to FERC, CAISO, and compliance, are warranted. A comparison of SDG&E's forecasted costs in these areas to the historical costs demonstrates that SDG&E's forecast is too high. Based on our review of the historical costs, it is reasonable to reduce SDG&E's non-shared A&G costs by $1 million.

With respect to SDG&E's shared costs, we have reviewed the recommended reductions by DRA and UCAN to SDG&E's shared costs. Based on a comparison of the historical costs, we are not persuaded by DRA's argument that reductions to SDG&E's shared costs are needed. However, we find merit with the testimony of UCAN and TURN that there should be a reduction to SDG&E's forecast of the regulatory affairs. It is reasonable to reduce SDG&E's shared A&G costs by $150,000.

As a result of the adjustments discussed above, the following should be adopted: SDG&E's non-shared book expense of $11.229 million; and SDG&E's shared book expense of $14.432 million.

Regarding SoCalGas' non-shared A&G costs, we are persuaded by DRA's arguments that the methodologies used by SoCalGas to forecast these A&G costs do not accurately reflect the changes to the labor and non-labor costs in certain accounts. This is apparent from a comparison to the historical costs for the various accounts. However, instead of making individual changes to each account, it is appropriate to reduce the total non-shared A&G amount that SoCalGas has forecasted. Under the circumstances, it is reasonable to reduce SoCalGas' non-shared A&G costs by $800,000.

With respect to the shared costs allocated to SoCalGas, we are persuaded by TURN and UCAN that there should be a $150,000 reduction to the shared regulatory affairs costs, based on the comparison to the historical costs.

Both of the adjustments to SoCalGas will result in the following, which should be adopted: SoCalGas' non-shared book expense of $8.730 million; and SoCalGas' shared book expense of $12.540 million.

13.8. Legal and External Affairs

13.8.1. Introduction

This section addresses the O&M costs related to the Legal and External Affairs departments of SDG&E and SoCalGas.

As part of the 2010 corporate reorganization, "many of the External Affairs and Legal functions were transferred to the Utilities, from Sempra Energy's Corporate Center, and independent External Affairs and Legal Departments were established at each Utility." (Ex. 228 at 2; Ex. 231 at 2.) As a result of this reorganization, and transfer of responsibilities, the costs of the newly created Legal and External Affairs departments for each utility are being requested as part of the Applicants' test year 2012 GRC requests. As described in Exhibits 228 and 231, the "incremental costs above those Corporate Center transferred costs were derived using a zero-based forecast methodology, since these newly-created departments did not have a cost history" at SDG&E or at SoCalGas. (*Ibid*.)

For SDG&E, the total O&M costs are forecasted at $9.453 million for test year 2012. For SoCalGas, the total O&M costs are forecasted at $6.782 million for test year 2012.

13.8.2. SDG&E

13.8.2.1. Introduction

For SDG&E, the total O&M costs are forecasted at $9.453 million for test year 2012. That total amount consists of $807,000 in non-shared costs, and $8.646 million in book expense shared services costs. SDG&E's total O&M costs are attributable to the activities performed by SDG&E's External Affairs Department, and its Legal Department.

The External Affairs Department is led by a VP, who is supported by an executive assistant. This department consists of these three groups: Regional Public Affairs; Media and Employee Communications; and Community Relations. The O&M costs associated with Regional Public Affairs is included as part of the electric distribution costs because that group primarily focuses on the electric distribution function. The Media and Employee Communications group "manages and coordinates external communications with the media and internal communications with employees on the vast array of topics that involve the utility and are of interest and importance to both ratepayers and employees." (Ex. 228 at 8.) The Community Relations group is "the liaison between SDG&E, community-based organizations, faith-based organizations, and the local communities…." (Ex. 228 at 10.)

SDG&E's Legal Department is led by a Senior VP/General Counsel. The Legal Department "provides legal services to SDG&E primarily through in-house attorneys and staff and, where needed, through outside counsel and attorneys and resources that reside at Corporate Center and [SoCalGas]." (Ex. 228 at 15.) Before the 2010 reorganization, "the legal function was performed by a consolidated law department which resided at Sempra Energy, and which provided legal service to all the subsidiaries of the parent, including the Utilities." (*Ibid*.) SDG&E's Law Department is organized into the following four practice areas: regulatory; litigation; commercial; and environmental. The Law Department is also supported with a support staff consisting of legal research attorneys, paralegals, and administrative assistants.

SDG&E proposed in Exhibits 228 and 230 to eliminate the tracking of time by the attorneys in SDG&E's Legal Department.

SDG&E's forecast of non-shared costs amounts to $807,000. These costs are "attributable to the activities performed by the Media and Employee Communications group within the External Affairs Department." (Ex. 228 at 4.) According to SDG&E, this forecast amount of $807,000 "was developed using a zero-based methodology, which included transferred costs from Corporate

Center of approximately $597,000." (*Ibid*.) The non-shared costs do not include any of SDG&E's Legal Department costs.

SDG&E's forecast of book expense shared services costs amounts to $8.646 million. This consists of $1.775 million in book expense costs for External Affairs, $6.696 million in book expense costs for Legal, and $175,000 in book expense for billed in costs from SoCalGas.

13.8.2.2. Position of the Parties

13.8.2.2.1. DRA

DRA analyzed and reviewed SDG&E's O&M costs for the Legal and External Affairs departments. DRA does not oppose SDG&E's forecast of the non-shared costs of $807,000 and the shared costs of $8.646 million.

In Exhibit 527, DRA opposed the request of SDG&E to stop the timekeeping tracking of its attorneys' time. DRA recommends that SDG&E's Legal Department continue to track the shared services attorneys' time to ensure that if the SDG&E attorney is working on a non-SDG&E matter, that SDG&E not be charged for that time. DRA also recommends "that if in the next GRC cycle either utility can show that there is a significant decrease of attorneys' sharing of services in the Utilities' Law Departments, and if the Utilities show that functions are solely dedicated, the Utilities' timekeeping proposal could be reviewed again and reconsidered." (Ex. 527 at 12.)

Subsequently, DRA and SDG&E agreed to a joint stipulation,[150] as set forth in Exhibit 234, which provides for the following:

[150] *See* 22 R.T. 2834-2835.

A. Attorneys employed by SDG&E should continue to track the time they spend working on matters on behalf of any Sempra Energy company other than SDG&E, including, among others, Sempra Energy and Southern California Gas Company.

B. Attorneys employed by SDG&E should not have to track the time they spend working on matters on behalf of SDG&E; and

C. This foregoing approach to attorney timekeeping should be implemented and remain in effect unless and until a party proposes a change to this attorney-timekeeping approach in a future SDG&E general rate case and the Commission adopts that change, or SDG&E and DRA mutually agree to a different approach in the future.

13.8.2.2.2. UCAN

UCAN recommends that several reductions be made to SDG&E's O&M costs for External Affairs (totaling $1.498 million), and the Legal Department (totaling $331,000).

UCAN "recommends zero ($0) funding for the Vice President of External Affairs, zero ($0) funding for Community Relations, $597,000 for Media & Employee Communications (Communications), $184,000 for Media & Employee Communications (Internal Communications), and zero ($0) funding for Regional Public Affairs." (Ex. 557 at 78.)

UCAN's recommended disallowance of all funding for Community Relations is based on the same argument that UCAN made to disallow funding of the O&M costs for Regional Public Affairs that were included by SDG&E in the electric distribution costs. UCAN contends that in D.08-07-046, "the Commission put SDG&E on notice about costs for public affairs and outreach after DRA proposed a disallowance of certain public affairs costs." (Ex. 557 at 78.) UCAN specifically points to the language in D.08-07-046 that "the companies are on notice that the bar has been raised and a more detailed justification is required for all public affairs and outreach expense to demonstrate genuine customer benefit that outweighs any incidental corporate image [] enhancement." (*See* D.08-07-046 at 74; Ex. 557 at 79.) UCAN further contends that "SDG&E continues to request funding for the Regional Public Affairs department and for parts of the External Affairs department to engage in activities in support of lobbying and corporate image enhancement." (Ex. 557 at 79.)

In the event the Commission does not adopt zero funding for Community Relations, UCAN contends that the Commission should deny funding of $125,000 for the additional position, which UCAN contends is not justified. UCAN further contends that the remaining amount of $402,000 should then be reduced by 30% to reduce the amount of ratepayer funding of what UCAN contends is shareholder activities. With those adjustments, the Community Relations amount would be $281,400.

UCAN recommends zero funding for the VP of External Affairs because UCAN believes that this position is not needed. Prior to the 2010 reorganization, UCAN notes that there was a similar position that only required $77,000. UCAN contends that "SDG&E has not explained what additional responsibilities are being asked of the VP of External Affairs that would provide ratepayer benefit to justify an increase from $77,000 to SDG&E and SoCalGas combined to $682,000 to SDG&E alone." (Ex. 557 at 82.)

UCAN recommends reducing funding for Media and Employee Communications (Communications) by $210,000. UCAN contends that the additional positions that SDG&E requests are not needed to manage the increasing number of issues with multiple channels of communication because social media channels have existed for years, and because SDG&E has requested funding for communications and outreach in other proceedings to address complex electricity issues.

UCAN also recommends reducing funding for Media and Employee Communications (Internal Communications) by $79,000. UCAN is concerned with the allocation of these costs between SDG&E and the corporate center. Instead of allocating 15% of these costs to corporate, UCAN believes that SDG&E's request of $263,000 "should be reduced by 30% to reduce the potential for ratepayer funding of shareholder activities." (Ex. 557 at 83.)

Regarding SDG&E's Legal Department costs, UCAN takes issue with SDG&E's request for six incremental employees. Although SDG&E requests the additional positions due to increasing duties in the regulatory, commercial, and environmental practices, UCAN contends that a look at SDG&E's "historical and forecasted expenses…does not confirm the trend toward overall increases for the Legal department," and that SDG&E's forecast is unreasonable. (Ex. 559 at 4.) UCAN recommends that SDG&E's Legal Department retained shared services should be $5.979 million, instead of SDG&E's forecast of $6.310 million.[151]

[151] In the event the Commission adopts DRA's recommendation to reduce the Corporate Center Legal department costs by $178,000, UCAN contends that this will increase UCAN's recommendation from $5.979 million to $6.157 million.

13.8.2.2.3. SDG&E

In Exhibit 230, SDG&E rebutted DRA's position on SDG&E's original proposal to do away with timekeeping for SDG&E's Legal Department. However, as a result of the joint stipulation between SDG&E and DRA, SDG&E agrees to retain timekeeping for its Legal Department as provided for in Exhibit 234. (*See* 22 R.T. 2834-2835.)

SDG&E opposes UCAN's reductions or disallowances to SDG&E's O&M costs for External Affairs.

Regarding UCAN's recommended disallowance of $527,000 for Community Relations, SDG&E contends that of the 78 pages of supplemental workpapers pertaining to Community Relations activities, UCAN only selected a few events which supposedly show that the events were to enhance SDG&E's corporate image. To the contrary, SDG&E contends that the topics involved utility-related issues, and that such "activities serve a useful utility function which do provide customers and the community at large with a better understanding of SDG&E's operations and initiatives and more opportunities for interaction and collaboration." (Ex. 230 at 9.)

Regarding UCAN's recommendation for zero funding of the VP of External Affairs, SDG&E contends that UCAN's inefficiency argument overlooks that the net impact of the 2010 reorganization was a decrease in costs. As for UCAN's argument that only $77,000 was spent for a similar position before the reorganization, SDG&E contends that UCAN does not understand "that this process of allocating costs ensures that ratepayers do not fund costs that are in support of another entity, but that these costs will appropriately be billed out." (Ex. 230 at 8.)

On UCAN's reduced funding for both Communications and Internal Communications, SDG&E contends that UCAN's argument "does not negate the need for SDG&E's request for a small increase in staff." (Ex. 230 at 10.) In addition, SDG&E contends that UCAN's recommendation to reduce funding for Internal Communications by 30% is arbitrary, and UCAN does not consider "the types of shared service activities that this department will be performing on behalf of Corporate Center in comparison to the overall responsibilities of the department…." (*Ibid*.) SDG&E also contends that the additional positions are warranted because staff is needed to quickly review social media responses, which operates on the premise that information needs to be disseminated in a reduced time frame.

Regarding UCAN's reductions to SDG&E's Legal Department O&M costs, SDG&E contends that UCAN's methodology that it used to develop its forecast of $5.979 million is not a sound approach. SDG&E contends that its Law Department should be viewed "as a separate organization for purposes of developing the 2012 forecast." (Ex. 230 at 5.) As for the disallowance of the six FTEs, SDG&E contends that UCAN provided no arguments or supporting facts as to why these positions should be eliminated. SDG&E contends that the "new regulations and initiatives regarding GHG emissions and system safety and reliability will contribute to the volume and complexity of matters before regulatory agencies which require legal counsel and representation." (Ex. 230 at 6.) SDG&E is requesting three attorneys, two paralegals, and one assistant.

13.8.2.3. Discussion

Since SDG&E and DRA have agreed in the joint stipulation (Exhibit 234) that SDG&E's Legal Department will keep track of the time that its attorneys spend on non-SDG&E matters, that issue needs no further discussion.

DRA has reviewed all of the O&M costs for SDG&E's Legal and External Affairs departments, and takes no issue with SDG&E's requested forecast amounts. UCAN has also reviewed some or all of these costs, and only takes issue with the costs described above in the position of the parties.

UCAN recommends that funding in the amount of $527,000 be disallowed for SDG&E's Community Relations activities. UCAN raised this same issue regarding the O&M costs for the Regional Public Affairs group that were included in SDG&E's electric distribution costs. We have reviewed the testimony of SDG&E and UCAN regarding the Community Relations costs, and the supplemental workpapers for the Community Relations cost center that are in Exhibit 229. We are not persuaded by UCAN's argument that the activities of the Community Relations group are in the nature of enhancing SDG&E's corporate image, or involve lobbying activities.

UCAN recommends that other reductions be made as well. UCAN contends that funding in the amount of $682,000 should be disallowed for SDG&E's VP of External Affairs, and that the additional position for Community Relations be disallowed. UCAN objects to these amounts because it believes these positions are unnecessary, and that similar activities were performed before the reorganization at a lower cost. UCAN also recommends a reduction of $289,000 to the Communications and Internal Communications. UCAN's reduction is based on its argument that additional positions are not needed to oversee work related to social media, and that less costs for Internal Communications should be allocated to SDG&E. For the Legal Department, UCAN recommends a reduction of $331,000 from SDG&E's retained costs of $6.310 million. This reduction is based on UCAN's argument that the six additional FTEs are not needed.

We have reviewed the testimony of SDG&E and UCAN concerning these reductions, and have also considered the need for the additional positions that SDG&E has requested in light of SDG&E's current staffing. We agree with UCAN that not all of these positions are needed, and that some of these activities can be performed with existing staff, or with less funds than SDG&E has requested. Based on all of those considerations, it is reasonable to reduce the legal and external affairs shared services that are allocated to SDG&E by $1.500 million.

Based on the above discussion, it is reasonable to adopt total O&M costs of $7.953 million for SDG&E's Legal and External Affairs departments. This total is composed of $807,000 in non-shared costs, and $7.146 million in book expense shared services cost.

13.8.2.4. SoCalGas

13.8.2.5. Introduction

For SoCalGas, the total O&M costs are forecasted at $6.782 million for test year 2012. That total amount consists of $1.371 million in non-shared costs, and $5.411 million in book expense shared services costs. SoCalGas' total O&M costs are attributable to the activities performed by SoCalGas' External Affairs Department, and its Legal Department.

The External Affairs Department is led by a Senior VP/General Counsel. This department consists of these three groups: Regional Public Affairs;

Communications (Media and Employee); and Community Relations. The O&M costs associated with Regional Public Affairs is included as part of the gas distribution costs because that group primarily focuses on the gas distribution function. The Communications group "manages and coordinates external communications with the media and internal communications with employees on the vast array of topics that involve the utility and are of interest and importance to both ratepayers and employees." (Ex. 231 at 7.) The Community Relations group is "the liaison between [SoCalGas], community-based organizations, faith-based organizations, and the local communities…." (Ex. 231 at 9.)

SoCalGas' Legal Department is led by a Senior VP/General Counsel. The Legal Department provides legal services to SoCalGas "primarily through in-house attorneys and staff and, where needed, through outside counsel and attorneys and resources that reside at Corporate Center and SDG&E." (Ex. 231 at 13.) Before the 2010 reorganization, "the legal function was performed by a consolidated law department which resided at Sempra Energy, and which provided legal service to all the subsidiaries of the parent, including the Utilities." (*Ibid*.) SoCalGas' Law Department is organized into the following four practice areas: regulatory; litigation; commercial; and environmental. The Law Department is also supported with a support staff consisting of legal research attorneys, paralegals, and administrative assistants.

SoCalGas proposed in Exhibits 231 and 233 to eliminate the tracking of time by the attorneys in SoCalGas' Legal Department.

SoCalGas' forecast of non-shared costs amounts to $1.371 million. These costs are composed of $703,000 in costs attributable to the activities performed by the Communications group within the External Affairs Department. According to SoCalGas, this forecast amount of $703,000 "was developed using a zero-based methodology, which included transferred costs from Corporate Center of approximately $366,000." (Ex. 231 at 4.) SoCalGas also forecasts $668,000 in non-shared costs "attributable to the dual activities of the Senior Vice President of External Affairs and General Counsel of the Legal Department…, and an executive assistant." (*Ibid*.)

SoCalGas' forecast of book expense shared services costs amounts to $5.411 million. This consists of $550,000 in book expense costs for External Affairs, $4.706 million in book expense costs for Legal, and $155,000 in book expense for billed in costs from SDG&E.

13.8.2.6. Position of the Parties

13.8.2.6.1. DRA

DRA analyzed and reviewed SoCalGas' O&M costs for the Legal and External Affairs departments. DRA does not oppose SoCalGas' forecast of the non-shared costs of $1.371 million, and the shared costs of $5.411million.

As mentioned in the SDG&E section above, DRA originally opposed the request of SoCalGas to stop the timekeeping tracking of its attorneys' time. (*See* Ex. 527 at 10.) Subsequently, DRA and SoCalGas agreed to a joint stipulation,[152] as set forth in Exhibit 235, which provides for the following:

A. Attorneys employed by SoCalGas should continue to track the time they spend working on matters on behalf of any Sempra Energy company other than SoCalGas,

[152] *See* 22 R.T. 2834-2835.

including, among others, Sempra Energy and San Diego Gas & Electric Company.

B. Attorneys employed by SoCalGas should not have to track the time they spend working on matters on behalf of SoCalGas; and

C. This foregoing approach to attorney timekeeping should be implemented and remain in effect unless and until a party proposes a change to this attorney-timekeeping approach in a future SoCalGas general rate case and the Commission adopts that change, or SoCalGas and DRA mutually agree to a different approach in the future.

13.8.2.6.2. TURN

Regarding SoCalGas' Legal Department costs, TURN takes issue with SoCalGas' request for three incremental employees. Although SoCalGas requests the additional positions due to increasing duties in the regulatory, commercial, and environmental practices, TURN contends that a look at SoCalGas' "historical and forecasted expenses…does not confirm the trend toward overall increases for the Legal Department," and that SoCalGas' forecast is unreasonable. (Ex. 548 at 9.) TURN recommends that SoCalGas' Legal Department retained shared services should be $3.212 million, instead of SoCalGas' forecast of $4.706 million.[153]

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[153] In the event the Commission adopts DRA's recommendation to reduce the Corporate Center Legal department costs by $129,000, TURN contends that this will increase TURN's recommendation from $3.212 million to $3.271million.

13.8.2.6.3. SoCalGas

In Exhibit 233, SoCalGas rebutted DRA's position on SoCalGas' original proposal to do away with timekeeping for SoCalGas' Legal Department. However, as a result of the joint stipulation between SoCalGas and DRA, SoCalGas agrees to retain timekeeping for its Legal Department as provided for in Exhibit 235. (*See* 22 R.T. 2834-2835.)

Regarding TURN's reduction to SoCalGas' Legal Department O&M costs, SoCalGas contends that TURN's methodology that it used to develop its forecast of $3.212 million is not a sound approach. SoCalGas contends that its Law Department should be viewed "as a separate organization for purposes of developing the 2012 forecast." (Ex. 233 at 5.) As for the disallowance of the three FTEs, SoCalGas contends that TURN provided no arguments or supporting facts as to why these positions should be eliminated. SoCalGas contends that the "new regulations and initiatives regarding GHG emissions and system safety and reliability will contribute to the volume and complexity of matters before regulatory agencies which require legal counsel and representation." (Ex. 233 at 6.) SoCalGas is requesting two attorneys, and one administrative assistant.

13.8.2.7. Discussion

Since SoCalGas and DRA have agreed in the joint stipulation (Exhibit 235) that SoCalGas' Legal Department will keep track of the time that its attorneys spend on non-SoCalGas matters, that issue needs no further discussion.

DRA has reviewed all of the O&M costs for SoCalGas' Legal and External Affairs departments, and takes no issue with SoCalGas' requested forecast amounts. TURN has also reviewed some or all of these costs, and only takes issue with the costs of the Legal Department.

For the Legal Department, TURN recommends a reduction of $1.494 million from SoCalGas' retained costs of $4.706 million. TURN's recommendation is based on its argument that the three additional FTEs are not needed. We have reviewed the testimony of SoCalGas and TURN concerning the Legal Department costs, and have also considered the need for the two additional attorneys and one administrative assistant that SoCalGas has requested. We have also taken into consideration the existing staffing of SoCalGas' Legal Department, and the historical costs. Based on all these considerations, we are persuaded by TURN's argument that SoCalGas' Legal Department O&M costs should be reduced, but not in the amount that TURN requests. It is appropriate, given the historical costs that SoCalGas has incurred, to reduce the shared legal costs by $600,000. This will have the effect of reducing SoCalGas' forecasted A&G costs of $6.782 million, to $6.182 million.

14. Corporate Center Costs Allocated to Utilities

14.1. Introduction

Sempra, as the parent company of SDG&E and SoCalGas, has a centralized Corporate Center which provides both utilities and Sempra's global operations with "corporate governance, policy direction and critical control functions, as well as services that are still performed most effectively as a centralized operation." (Ex. 272 at 1.)[154] The Corporate Center costs "are fully charged out using direct assignment and allocation to SDG&E, SoCalGas, or Global, or are retained at the Corporate Center." (*Ibid*.) The costs that are allocated to SDG&E and SoCalGas are then booked into the appropriate FERC accounts.

The Corporate Center is composed of the following seven divisions: Finance; Governance; Legal; Human Resources; External Affairs; Facilities/Assets (including depreciation); and Pension and Benefits.[155]

According to the Applicants, the costs of these seven divisions are allocated to the different business units, in a manner that associates "the costs as closely as possible to the level of service being provided to each business unit." (Ex. 272 at 3.) The Corporate Center uses the following approaches to allocate costs: direct assignment; causal/beneficial; and multi-factor. For direct assignment, all "costs that relate to a specific business unit are direct-assigned to that business unit." (Ex. 272 at 4.) The causal/beneficial method is used when costs cannot be directly assigned, and they are allocated "based on drivers that would be comparable to all business units and that would indicate the level of benefit received by each." (Ex. 272 at 5.) The multi-factor method "is used for functions that serve all business units but for which there is no causal relationship," and weighs the following four factors from all business units:

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[154] The direct testimony regarding the Corporate Center costs are in Exhibit 272 for SDG&E, and in Exhibit 274 for SoCalGas. Since the testimonies in both of those exhibits are the same, our citation is only to Exhibit 272. The rebuttal testimony of SDG&E and SoCalGas is contained in Exhibit 276.

[155] Insurance costs is also a shared service of the Corporate Center. The insurance costs are discussed in a separate section.

revenue; gross plant assets and investments; operating expenses; and FTEs. (*Ibid*.)

For 2012, Corporate Center forecasts a total budget of $244.100 million. Of that total, the amount allocated to SDG&E is $59.265 million, and the amount allocated to SoCalGas is $56.129 million.[156] The Applicants contend that these amounts are needed "to ensure that both SDG&E and SoCalGas continue to be in compliance and good standing with existing and new governmental, legal and regulatory requirements," which include the requirements of the Internal Revenue Service (IRS), the SEC, the Financial Accounting Standards Board, FERC, and the CPUC. (Ex. 272 at 10.)

In contrast to the Applicants' forecasts of the Corporate Center costs, DRA recommends $32.854 million be allocated to SDG&E, and $34.265 million be allocated to SoCalGas. UCAN's recommendation to change the multi-factor allocation, would reduce the allocation to SDG&E from $59.265 million to $49.211 million.

In the sub-sections below, we discuss each of the seven divisions of the Corporate Center.

14.2. Finance

14.2.1. Background

The Finance division "is responsible for raising and managing capital and maintaining the financial integrity of the Sempra Energy companies." (Ex. 272 at 13.) Among the responsibilities of the Finance division are the

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[156] The allocation amounts of $59.265 million (SDG&E) and $56.129 million (SoCalGas) appear in the updates, Exhibit 598 and 599. The original amounts, as cited in Exhibits 272 and 274, are $59.618 million for SDG&E, and $56.481 million for SoCalGas.

following: setting the financial and accounting policies, and ensuring compliance with GAAP and SEC rules; raising capital at the lowest possible cost, and maintaining a capital structure that supports strong credit ratings; tax planning and compliance; directing the corporate insurance and risk management program; and business planning and performance management.

As described in Exhibit 272, there are eight departments within the Finance division. These departments are the following: the Chief Financial Officer; Accounting Shared Services; Tax Services; Treasury; Investor Relations/Shareholder Services; Corporate Planning; Risk Management; and the Financial Leadership Program.

The forecast of the total escalated amount for the Corporate Center Finance division is $60.100 million, of which $13.232 million is allocated to SDG&E, and $14.419 million is allocated to SoCalGas. These forecasted costs are described in more detail in Exhibits 272-276.

14.2.2. Position of the Parties

14.2.2.1. DRA

For the Finance division A&G costs, DRA recommends $9.647 million for SDG&E, instead of the Corporate Center forecast of $13.232 million. For SoCalGas, DRA recommends Finance division A&G costs of $10.244 million, instead of the Corporate Center forecast of $14.419 million. (*See* Ex. 497 at 5.)

As described in Exhibit 496, DRA recommends that a series of reductions be made to the Corporate Center Finance division A&G costs, which affects the allocation of these A&G costs to SDG&E and SoCalGas. The adjustments that DRA recommends are based on four generic reasons. First, DRA recommends a reduction or disallowance because the utility already has an equivalent position, and allocating the same type of cost to the utility will result in a duplication of costs. The second generic reason is DRA's belief that the Applicants have not justified why the cost center or additional FTEs are needed. The third generic reason relies on D.89-12-057 for providing guidance on what type of methodology should be used to develop a forecast when there is a trend for three or more years, or if the costs have fluctuated, or when costs have remained steady or fluctuated slightly. The fourth reason for DRA's adjustments is due to DRA's differences with the multi-factor allocation, and the escalation rate.[157]

As discussed in Exhibits 489 and 496, DRA takes issue with the Applicants' multi-factor allocation. This multi-factor allocation affects all of DRA's adjustments to the Corporate Center A&G costs. DRA contends that the multi-factor allocation should exclude the revenues associated with the sales of the California Department of Water Resources' (CDWR) power contracts, and should exclude the gross value of SONGs. DRA contends that the CDWR contracts and the gross value of SONGS should be removed from the multi-factor allocation because they were not included in the SEC filings. DRA also contends that the multi-factor allocation should use net plant assets, instead of gross plant assets. DRA contends that because more utility plant is depreciated, as compared to unregulated affiliates, that using gross plant unfairly shifts more costs onto the utilities. DRA also contends that the multi-factor allocation should exclude the costs of international taxes since the operations of SDG&E and SoCalGas are in the United States.

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[157] The Applicants estimate that DRA's escalation adjustment will reduce the allocations to SDG&E and SoCalGas by $1 million. In the update testimony in Exhibit 596, more current escalation rates were used by the Applicants, which reduce the allocations to SDG&E by $197,000, and to SoCalGas by $196,000. The cost escalation factors are addressed in more detail later in this decision.

Instead of using the Applicants' multi-factor allocation of 41.54% to SDG&E, 41.52% to SoCalGas, and 16.94% to global/retained, DRA recommends an allocation of 39.79% to SDG&E, 40.33% to SoCalGas, and 19.88% to global/retained.

14.2.2.2. UCAN

UCAN contends that there are numerous flaws in Sempra's multi-factor allocation methodology "that result in an over-allocation of Corporate Center costs to SDG&E and SoCalGas." (Ex. 557 at 69.) UCAN agrees with DRA that the revenues associated with the CDWR power contracts should be excluded from the multi-factor allocation calculation because these contracts will become a credit to SDG&E in 2012. Since the CDWR will be returning monies to SDG&E's customers, UCAN contends it does not make sense to use the historical costs paid to CDWR in the regression forecast used for the multi-factor allocation, and that this will "erroneously increase the allocation of Corporate Center costs to SDG&E in 2012…." (Ex. 557 at 72.)

UCAN also agrees with DRA that the multi-factor allocation should not include the SONGS gross plant. UCAN contends that excluding the SONGS gross plant would be consistent with how Sempra "treats investments made by the utilities and investments made by its unregulated subsidiaries" using the "equity method" when there is "an ownership interest ranging from 20%-50%." (Ex. 557 at 73.) As a result, since SDG&E has a 20% ownership interest in SONGS, and because most of the SONGS plant has been depreciated, "only the net plant investment in SONGS should be included in the [multi-factor] calculation." (*Ibid*.)

UCAN also contends that Sempra's regression forecast should not be used because it failed to exclude Sempra's partial divestment of its global commodities division. By including this cost, UCAN contends that this overstates the allocation of Corporate Center costs to SDG&E and SoCalGas. UCAN recommends that the 2011 allocation percentages should be used for the multi-factor allocation because it is a conservative estimate of the allocations to SDG&E and SoCalGas. Using the 2011 allocation, UCAN recommends the following allocation in 2012: 35.24% to SDG&E; 40.85% to SoCalGas; and 23.91% to global/retained. UCAN's multi-factor allocation would have the effect of reducing the total allocation for SDG&E from $59.265 million to $49.211 million.

UCAN also contends that the 2010 reorganization makes it "virtually impossible to adequately assess the proposed costs in the GRC filing," because of "the transfer of certain Corporate Center functions to the individual utilities and the resulting loss of historical data." (Ex. 562 at 3.) According to UCAN's witness, it was apparent to him that by the time he left in 2006, that the earlier "2002 reorganization was not working as well as intended," and that a subsequent reorganization "could have been done long before 2010 and would have allowed the Commission and intervenors in the current proceeding to have a history of utility departments' expenses to use in their analysis of departments' costs." (Ex. 562 at 6.)

14.2.2.3. SDG&E and SoCalGas

14.2.2.3.1. Multi-Factor Allocation

Regarding the multi-factor allocation, the Applicants contend that the development of the multi-factor allocation can be traced back to the affiliate transaction conditions that were agreed to in D.98-03-073. Since that time, the Applicants contend that the multi-factor rates have been forecasted in a consistent manner in other proceedings, including the Applicants' 2008 GRC proceeding. The Applicants contend that neither DRA nor UCAN objected in those other proceedings to the same multi-factor allocation method that is being used in these consolidated proceedings.

The Applicants contend that it is appropriate to include the CDWR power contracts as part of the multi-factor calculation because "it still represents actual revenue-related collections effort at SDG&E…." (Ex. 276 at 5.) The Applicants also note that the CDWR sales collected by SDG&E from its customers originated more than 10 years ago, and that "SDG&E merely passes the billings on as a receivable and remits them concurrently to [CDWR] as a payable, with no reflection in the Income Statement." (*Ibid*.)

As for the recommendations of DRA and UCAN to exclude the SONGS gross plant from the multi-factor allocation, the Applicants contend that for FERC reporting purposes, "SONGS is required to be included on SDG&E's books, although it is no longer included in SDG&E's U.S. GAAP reporting." Since SONGS remains a component of SDG&E's generation portfolio, the Applicants contend "it is reasonable and appropriate to reflect its value like other assets in the Multi-Factor calculation." (Ex. 276 at 6.) As for UCAN's contention that the net asset value should be used, the Applicants contend that the equity method of accounting is only used when equity, such as a common stock, is owned. The Applicants contend that the ownership "of an equity instrument is distinguished from undivided ownership of the plant and assets," and that SDG&E's actual ownership in SONGS is different from an equity method investment. (Ex. 276 at 7.)

The Applicants also take issue with DRA's recommendation to only use net asset values in the multi-factor allocation calculation. The Applicants contend that gross assets provide "a relative measurement of the size of each Sempra Energy business unit, so the volume of sales and expense, assets in service, and employees are considered to reflect an overall level of activity." (Ex. 276 at 8.)

With regard to UCAN's recommendation to use the 2011 multi-factor percentages for 2012, the Applicants contend that this ignores the fact of including "regular business events occurring over the required forecasting period," and that the consistent "use of this objective approach over multiple GRCs will capture the overall impact of various business events over time, ensuring that any particular GRC forecast is reasonable." (Ex. 276 at 9.)

14.2.2.3.2. 2010 Reorganization

The Applicants contend that in 2006, UCAN's witness was not a member of the senior management team, and not involved in senior management decision making. As for UCAN's suggestion that the 2010 reorganization was done to obscure historical cost data and to prevent UCAN from determining the validity of the forecast, the Applicants contend that they provided reconciliations in response to numerous data requests to show the effect of the reorganization. The Applicants also contend that their zero-based forecasts are "an appropriate representation for all costs…." (Ex. 276 at 13.)

14.2.2.3.3. Finance

With respect to DRA's adjustment to the cost center for the Chief Financial Officer, the Applicants contend that DRA lacks an "understanding of the Corporate Center finance division responsibilities." (Ex. 276 at 15.) The Applicants contend there "is a distinct difference between the accounting and finance functions at the Utilities and the accounting and finance functions at Corporate Center." (*Ibid*.) The Corporate Center is "responsible for raising and managing capital and maintaining the financial integrity of the company as a whole," and that they "set financial and accounting policy, develop and publish [SEC] reports, ensure consolidated financials comply with GAAP and SEC rules, and prepared consolidated long and short term plans for Sempra Energy's Board of Directors, rating agencies, and market analysts." (*Ibid*.) None of this kind of work is performed by SDG&E or SoCalGas. In addition, the responsibilities and work activities of the Corporate Center's Chief Financial Officer pertain to activities that are performed by the Treasury, Audit Services, and Tax Services units that are located at the Corporate Center.

Regarding DRA's recommended reductions to Accounting Services, the Applicants contend there is no duplication of responsibilities for the Controllers. The utility Controllers, and the Corporate Center Controller, "oversee completely independent functions at their respective organizations, separate accounting, reporting and planning groups, all of which contribute to different business requirements." (Ex. 276 at 15.)

DRA takes issue with the cost center for corporate account special projects. Although DRA asserts that it was not provided with sufficient justification to support this cost center, the Applicants contend a thorough response was provided to DRA. The Applicants explained that this cost center absorbed the responsibilities of the former director of Corporate Financial Accounting, and this cost center performs special projects, as well as oversees the "accounting functions for the Corporate Center, including all its shared services functions and billings." (Ex. 276 at 17.)

For DRA's reduction to the accounting research cost center, DRA used 2010 recorded data because the costs have trended lower. The Applicants do not agree with the use of the 2010 data because "the costs for this group were unusually low in 2010 due to an extended absence by a senior employee." (Ex. 276 at 17.)

For DRA's reduction to the financial reporting director cost center, the Applicants oppose the use of 2010 data by DRA because DRA ignored that non-labor costs were higher in 2009 because of "a software implementation in 2009 which covered licenses and maintenance through 2010." (Ex. 276 at 18.)

Regarding DRA's reduction to the financial reporting cost center, the Applicants contend that total costs for this cost center have trended higher, and therefore DRA's use of 2010 recorded costs is wrong.

Regarding DRA's recommendation to reduce the fees in cost center 1100-0219, the Applicants contend that there is no apparent trend as DRA has suggested. The Applicants note that the 2010 recorded costs were higher than 2009, and that DRA has overlooked that external audit fees will increase as a function of capital growth.

DRA also made adjustments to the cost centers for the Tax Services group. The Applicants contend that instead of making individual adjustments to the cost centers, as DRA has done, the costs of the Tax Services group should be examined as a whole.

DRA has proposed to reduce the allocations for the cost center covering the VP of Corporate Tax. The Applicants contend that DRA ignored the evidence that shows costs have transferred from other tax cost centers as a result of the 2010 reorganization, and that the "department as a whole did not increase FTEs, and any fluctuations caused in individual cost centers were offset within the department…," and that "labor expense was flat." (Ex. 276 at 20.)

Regarding DRA's reduction to the domestic tax compliance cost center, the Applicants contend that "DRA appears to have selected averaging formulas and cost centers that suit its predisposition in favor of reductions…." (Ex. 276 at 21.)

DRA disallowed the entire allocation of the International Tax cost center. The Applicants contend that for allocation purposes, "the department's overall effort is averaged, and each cost center uses the same average allocation rates." (Ex. 276 at 22.) Even though this cost is primarily for international matters, other tax cost centers work primarily on utility matters. Despite this, each allocation from these cost centers is the same.

For DRA's reduction to the Tax Law group cost center, the Applicants contend that DRA used a two-year average when DRA had used a four-year average for domestic tax compliance.

DRA also made reductions to the cost center for corporate cash management. Although DRA used an average of historical costs, the Applicants contend that the "prior year costs are no longer comparable and should not be used for averaging," because short term lines of credit are renewed every two to three years, and the most recent rates reflect "today's more restrictive financial environment compared to the last line of credit renewal in 2008." (Ex. 276 at 23.)

For DRA's reduction to the cost center for the VP Investor Relations, the Applicants contend that DRA incorrectly assumed the incremental increase was due to a new FTE equivalent to a VP. The Applicants contend that the additional FTE is for an administrative assistant, which is less than DRA's reduction of $157,000.

With respect to DRA's reduction to the cost center for investor relations/shareholder services, the Applicants contend that since some of these costs were directly charged, that DRA's multi-factor allocation adjustment would not apply to some of the costs. As a result, DRA's adjustment to this cost center is skewed.

For DRA's reduction to the cost center for corporate planning/financial systems, and DRA's use of 2010 recorded data, the Applicants contend that DRA is "ignoring the fact that this department incurs cyclical costs for software maintenance and period upgrades for Sempra energy's financial systems." (Ex. 276 at 25.) The Applicants contend that their use of the five-year average reflects this.

DRA proposes a reduction to the cost center for the VP Risk Analysis and Management. DRA's reduction is based on the contention that the Applicants did not justify this expense. The Applicants contend that DRA was provided with "multiple explanations as to the function of this department…." (Ex. 276 at 26.) According to the Applicants, this "new department arose from increased lawsuits and litigation that resulted from the wildfires in 2007." (*Ibid*.)

DRA recommends disallowance of the financial leadership program cost center because of the funding for the utilities' rotation and internship programs.

The Applicants contend that the Corporate Center program is a separate program from that of the two utilities.

14.2.3. Discussion

14.2.3.1. Introduction

For the Finance division A&G costs, the Applicants request an allocation to SoCalGas of $14.419 million, and an allocation of $13.232 million to SDG&E. In contrast, DRA's recommended reductions result in an allocation to SoCalGas of $10.244 million, and an allocation of $9.647 million to SDG&E.

14.2.3.2. Multi-Factor Allocation

The first issue to address is the multi-factor allocation. The multi-factor allocation affects various Corporate Center A&G costs, and is not limited just to the Finance division. The multi-factor allocation is "used for functions that serve all business units but for which there is no causal relationship…." (Ex. 272 at 5; Ex. 274 at 5.) Both DRA and UCAN recommend that the multi-factor allocation be lowered from the allocations that Sempra used. Their reasoning for lowering the allocations is based on their belief that certain items should be excluded from the multi-factor allocation.

The starting point for determining whether the multi-factor allocation should be changed starts with D.98-03-073 (79 CPUC2d 343), from which this allocation method originated. In that decision, the Commission approved the merger agreement between SoCalGas' former parent company (Pacific Enterprises), and SDG&E's former parent company (Enova Corporation). As a condition of the approval of that merger, their former parent companies, and the predecessor parent company to Sempra, agreed to the mitigation measures that were contained in Attachment B to D.98-03-073. (*See* 79 CPUC2d at 431, 441-464.) As part of the mitigation measures, policy and guidelines for affiliate company transactions were established, including the allocation of parent company costs. For the allocation of the parent company costs, Attachment B to D.98-03-073 states:

> It is the intention that all Parent Company costs shall be allocated among the Affiliates, including utility Affiliates. Accordingly, all Parent Company costs, regardless of whether incurred directly by the Parent Company or incurred by an Affiliate and charged to the Parent Company, shall be allocated among all the Affiliates in the manner described below.
>
> 1. All costs that can be directly or indirectly assigned to Affiliates shall be so directly charged or allocated.
> 2. Common costs not assignable directly or indirectly shall be allocated based on a formula representing the activity of the Affiliate as it related to the total activity of the Affiliated group (four factor formula). The formula will be based on the Affiliate's proportionate share of (1) total assets, (2) operating revenues, (3) operating and maintenance expenses (excluding the direct Cost of Sales, purchased gas, cost of electric generation for utility operations and income taxes), and (4) number of employees. Each factor shall be equally weighted. The factors included in the formula will be periodically reviewed and modified to the extent required.
>   (79 CPUC2d at 452-453.)

It is important to note that the passage quoted above refers to <u>all</u> Parent Company costs, except for "costs which are not recoverable in rates of the utility Affiliate, such as charitable contributions and governmental relations activities…." (79 CPUC2d at 453.)

Both DRA and UCAN recommend that the sales revenue of the CDWR power contracts be excluded from the multi-factor allocation on the theory that the revenues from the CDWR power contracts were not included in the SEC filings, and because there will be a net credit to SDG&E in 2012. We are not persuaded by DRA and UCAN's arguments. First, as the Applicants point out, the CDWR power contracts represent revenue-related billings at SDG&E. After the CDWR contracts expire, SDG&E will be responsible for procuring the power that is provided by the expiring CDWR contracts. The revenues from those new sources of power will continue to be included as part of SDG&E's operating revenue. Second, the CDWR power contracts have been in existence since late 2001. Due to legislation enacted into law as a result of the energy crisis, the Commission ordered SDG&E and the other electric utilities to collect the revenue requirement associated with the CDWR power contracts from their electric customers. (*See* D.02-02-052.) DRA and UCAN could have raised objections to the inclusion of the CDWR power contracts as part of the multi-factor allocation in SDG&E's earlier rate proceedings, but failed to do so. Just because a CDWR credit is expected for SDG&E's customers in 2012 does not change our view that these revenues should be taken into consideration as part of the multi-factor allocation.

DRA and UCAN also contend that the multi-factor allocation should exclude the gross value of SONGS from this calculation. DRA recommends that SONGS be excluded because the gross value of SONGS is not included as part of the SEC filings. UCAN's argument is similar, and contends that only 20% of SONGS should be included in the calculation. The Applicants contend that SONGS is a component of SDG&E's generation portfolio and that its value should be reflected in the multi-factor allocation calculation.

We have reviewed the testimony and arguments of the parties concerning whether all or part of the value of SONGS should be included in the calculation of the multi-factor allocation. We have also considered the four factors that make up the multi-factor allocation, and the different accounting methods that could be used to justify a lower value for SONGS as part of the calculation of the multi-factor allocation. Based on all of those considerations, we are not persuaded that the multi-factor allocation formula should use a lower value for SONGS.

DRA also proposes to change the multi-factor allocation formula to consider net plant instead of gross plant. DRA contends that using gross plant assets results in a more costly allocation to SDG&E and SoCalGas, as compared to Sempra's non-utility affiliates who have much fewer assets. The Applicants contend that using gross plant provides "a relative measurement of the size of each Sempra Energy business unit, so the volume of sales and expenses, assets in service, and employees are considered to reflect an overall level of activity." (Ex. 276 at 8.) We agree with the Applicants that including gross plant in the multi-factor allocation, instead of net plant, results in a better measure of "the total activity of the Affiliated group." (79 CPUC2d at 452.)

UCAN contends that the multi-factor allocation should not use Sempra's regression methodology "because it fails to exclude Sempra's partial divestment of its Global Commodities division, which occurred in 2008." (Ex. 557 at 73.) By including the costs of the Global Commodities division in the regression, UCAN contends this overstates the allocation of the Corporate Center costs to the Applicants. UCAN recommends that the 2011 allocation be used instead. The Applicants contend that the regression analysis is warranted because "the calculation is objectively based on inclusion of regular business events occurring over the required forecasting period…," and that "[c]onsistent use of this objective approach over multiple GRCs will capture the overall impact of various business events over time, ensuring that any particular GRC forecast is reasonable." (Ex. 276 at 9.)

We have considered the testimony and the arguments of the Applicants and UCAN concerning the regression analysis, and whether the 2011 allocation percentages should be used. We find fault with UCAN's approach because it would exclude a single event, while ignoring other changes that affect the allocations. Over time, the regression analysis will account for these variations. For those reasons, we do not adopt UCAN's recommendation that the Corporate Center costs be allocated to SDG&E and SoCalGas using the 2011 allocations.

In summary regarding the multi-factor allocations, we do not adopt the recommendations of DRA and UCAN to change the allocation percentages.

14.2.3.3. Finance A&G Costs

We have reviewed all of the testimony and arguments concerning the allocations of the Corporate Center Finance division A&G costs to SDG&E and SoCalGas. DRA's recommendations result in reductions or disallowances of certain Finance division costs, which reduce or eliminate the allocations to SDG&E and SoCalGas. UCAN's recommendations result in reductions to the amounts allocated to SDG&E.

After reviewing the numerous adjustments that DRA and UCAN recommend be made, and having compared the forecast of the allocated amounts to the 2009 costs, we are persuaded by DRA's arguments that the allocations to SDG&E and SoCalGas may be overstated. In reviewing DRA's Exhibit 496, it is apparent that some cost cutting may need to be undertaken in the Finance Division. In 2009, the total recorded costs for this division was $47.946 million. However, the escalated forecasted total amount is $60.109 million. Although ratepayers of SDG&E and SoCalGas should bear a reasonable share of the increase in these costs, the Applicants must also bear part of this increase by taking cost cutting measures to control and reduce costs. Based on the reductions that DRA and UCAN have recommended to the Finance Division, and the difference between the 2009 recorded cost and the forecasted 2012 test year cost, it is reasonable under the circumstances to reduce the allocation to SDG&E, and to SoCalGas, by $800,000 each.

Although the Applicants and the other parties may quarrel with how the Commission arrives at the amount of the reductions that we have made throughout this decision, we point out that:

> Ratemaking is not, nor has it ever been, an exact science that guarantees perfect results from all perspectives. Ratemaking, whether in a general rate proceeding or by an attrition mechanism, is essentially the art of estimating future events based on judgment that is as fully informed as possible. (D.89-12-057 [34 CPUC2d at 227].)

Based on the discussion above, it is reasonable to adopt the following allocations of these costs: allocate $13.619 million to SoCalGas; and allocate $12.432 million to SDG&E.

14.3. Governance

14.3.1. Background

The Governance division covers certain functions that "represent the highest level of leadership of Sempra Energy." The cost centers that are included in the Governance division are: the Internal Audit Services department; the office of the Corporate Secretary; the Sempra Board of Directors; and the Executive division.

The forecast of the total escalated amount for the Corporate Center Governance division is $10.800 million, of which $ 3.118 million is allocated to SDG&E, and $2.931 million is allocated to SoCalGas.

14.3.2. Position of the Parties

14.3.2.1. DRA

For the Governance division A&G costs, DRA recommends an allocation of $2.672 million for SDG&E, instead of the Corporate Center allocation of $3.118 million. For SoCalGas, DRA recommends an allocation of $2.672 million, instead of the Corporate Center allocation of $2.931 million. (*See* Ex. 497 at 5.)

As described in Exhibit 496, DRA recommends that adjustments be made to three cost centers. The first adjustment is to cost center 1100-0041 for financial and operational audit services. Corporate Center is forecasting five new FTEs and two replacements to fill vacant positions. DRA contends that the Applicants' have not provided the justification for these positions. DRA also made an adjustment to this cost center for non-labor costs because of its contention that non-labor costs have shown a downward trend.

The second adjustment is to cost center 1100-0050 for audit quality assurance. DRA removed the costs because it believes the Applicants have not justified this cost center.

The third adjustment is to the Corporate Secretary cost center. DRA contends that since the costs in this cost center have been stable for three years, D.89-12-057 states that the last recorded year is an appropriate base estimate. For that reason, DRA used the 2010 recorded amount for its forecast of the Corporate Secretary cost. DRA's audit adjustment for the multi-factor allocation, and the different escalation rates also impact the Internal Audit and Corporate Secretary costs.

14.3.2.2. SDG&E and SoCalGas

DRA recommends reduction to the cost center covering financial and operational audit services. DRA's reduction is based on its contention that the Applicants did not provide justification for the increased staffing, and that the non-labor costs were trending down. The Applicants contend they provided specific data responses which described growth areas, and "the impact of capital growth on Internal Audit resources." (Ex. 276 at 27.) As for the trending that DRA observed, the Applicants contend that they provided "year-over-year explanations of historical spending levels in numerous data responses," and that the totals for this cost center were not trending down. (Ex. 276 at 28.) The Applicants further contend that when Internal Audit uses temporary consultants, that those services are recorded as non-labor costs when there are employee vacancies. As vacancies are filled, less temporary staffing is recorded as non-labor costs.

DRA also recommends removing all of the amounts for the audit quality assurance cost center. DRA contends that the Applicants provided insufficient justification, and that the 2010 recorded data showed very little expense. The Applicants contend that they explained in a response to a DRA data request that "this cost center was carved out from the existing Audit Services organization to provide administrative support to all audit groups and the VP," and that no new employees were added overall. (Ex. 276 at 28.)

DRA recommends reducing the corporate secretary cost center. DRA contends that because costs have been stable for three years, that the 2010 recorded costs should be used. After reviewing these costs, the Applicants "recognized some budget assumption errors that" result in them adjusting the forecast similar to the 2010 amount that DRA used. (Ex. 276 at 29.) The Applicants now accept DRA's adjustment to this cost center.

14.3.3. Discussion

For the Governance division A&G costs, the Applicants request an allocation to SoCalGas of $2.931 million, and an allocation of $3.118 million to SDG&E. In contrast, DRA's recommended reductions result in an allocation to SoCalGas of $2.672 million, and an allocation of $2.672 million to SDG&E.

We have reviewed the testimony and arguments of the Applicants and DRA concerning the A&G costs for the Governance division.

First, DRA has recommended adjustments to the cost center for financial and operational audit services. DRA contends that the Applicants did not provide sufficient justification for the additional positions. However, a review of the data response to DRA on this subject reveals that the additional FTEs are needed "to handle additional audit volume" as a result of new investments. (Ex. 276, Att. A at 40-41.) These new investments will generate additional audit work as described in that data response. As for DRA's recommended adjustment for non-labor costs, we do not agree with DRA that such an adjustment is warranted. The forecast of the labor and non-labor cost for this cost center are reasonable in light of the historical data and the additional FTEs.

DRA's second recommended adjustment is to remove all the costs for the audit quality assurance cost center because it contends the Applicants have not justified the costs. The testimony and the Applicants' data response establish that this cost center was created in 2009 for handling the responsibilities for annual risk assessment, department metrics and reporting purposes. Costs were incurred in 2009, and in 2010 the costs were less due to these costs being recovered in other cost centers. Based on this cost center's responsibilities and the historical costs in 2009 and 2010, we do not adopt DRA's recommendation to disallow these costs.

DRA's third recommended adjustment is to the cost center for the Corporate Secretary, wherein DRA uses the 2010 recorded amount. In Exhibit 276, the Applicants recognized that there were some budget assumption errors for this cost center, which caused them to adjust their forecast and to accept DRA's recommendation. As a result of the Applicants' acceptance of DRA's adjustment for this cost center, the RO model and the Applicants' total allocations should already incorporate DRA's adjustment.

Based on the above discussion of the A&G costs for the Governance division, the only adjustment that is adopted is DRA's adjustment to the Corporate Secretary cost center, which removes $182,000 from this cost center, and reduces the allocation to SDG&E and SoCalGas.

For the reasons explained in the escalation section of this decision, no adjustments to the Corporate Center costs have been made due to DRA's cost escalation factors adjustment.

14.4. Legal

14.4.1. Background

The Corporate Center's Legal division "provides legal services to all Sempra Energy companies." (Ex. 272 at 32.) The cost centers that make up the Legal division are: the General Counsel; the Law Department; and Outside Legal. The attorneys in the Law Department "offer services in the areas of litigation and labor, regulatory and environmental, and commercial and corporate, including real estate, mergers and acquisitions, and [SEC] matters." (*Ibid*.) These attorneys are also "available to provide peak legal capacity when

the business unit attorneys are unable to take on new matters."
(Ex. 272 at 32-33.)

The forecast of the total escalated amount for the Corporate Center Legal division is $38 million, of which $15.693 million is allocated to SDG&E, and $10.119 million is allocated to SoCalGas.

14.4.2. Position of the Parties

14.4.2.1. DRA

For the Legal division A&G costs, DRA recommends an allocation of $4.218 million for SDG&E, instead of the Corporate Center allocation of $15.693 million. For SoCalGas, DRA recommends an allocation of $4.218 million, instead of the Corporate Center allocation of $10.119 million. (*See* Ex. 497 at 5.)

As described in Exhibit 496, DRA recommends that adjustments be made to three cost centers. The first adjustment is to the Executive VP and General Counsel cost center. DRA contends that SDG&E and SoCalGas each have a Senior VP General Counsel. DRA contends that allocating costs from the Corporate Center's General Counsel to SDG&E and SoCalGas would be a duplication of costs, and for that reason recommends that nothing be allocated to SDG&E and SoCalGas.

DRA's second adjustment is to cost center 1100-0144 in the Law Department. DRA removed $565,100 ($400,000 in labor, and $165,100 in non-labor) from the Applicants' forecast because DRA believes that the Applicants have not justified the need for two additional FTEs.

The third adjustment is to the cost center for Outside Legal. DRA contends it removed $17.686 million from this cost center because the Applicants were unable to provide DRA with the types of services that were provided to them, and what will be provided to them in the future. DRA recommends that no costs from the Outside Legal cost center be allocated to SDG&E and SoCalGas.

14.4.2.2. SDG&E and SoCalGas

DRA recommends removing all of the costs allocated to SDG&E and SoCalGas for the cost center covering the Executive VP and General Counsel. DRA contends that since both SDG&E and SoCalGas have General Counsels, that no allocation should be made to the utilities for the cost of the Corporate Center General Counsel. The Applicants contend that the Corporate Center General Counsel is involved in practice areas that are "usually not handled at the business units," and that the Applicants have explained "the differences in the corporate and utility legal teams…." (Ex. 276 at 30.)

DRA recommends removing the costs and allocations associated with two attorney FTEs in the Law Department cost center because of a lack of justification. DRA also proposes to reduce the non-labor costs for this cost center. The Applicants contend that the two attorney FTEs are needed because "Sempra's capital plans call for significant new utility investments in electric generation, transmission, gas infrastructure, and new metering technology," which "creates demand on legal services at Corporate Center." (Ex. 276 at 30.) As for DRA's removal of non-labor costs, the Applicants contend that they provided a response explaining that the amount for the two attorney FTEs includes the non-labor costs for these FTEs. The Applicants also contend that DRA's multi-factor allocation adjustment was incorrectly applied to this cost center because of some direct charges.

DRA also recommends disallowing allocations of $17.686 million pertaining to the cost center for outside legal. The Applicants contend that

Corporate Center responded to about 70 questions from DRA asking about this cost center, including requests for historical detail through 2010. As for DRA's request regarding future outside legal costs, the Applicants contend that legal matters vary from year to year, and are generally non-recurring. As for DRA's contention that the 2010 reorganization makes contracting of outside legal help unnecessary, the Applicants contend "that the transfers of in-house staff had no impact on ongoing litigation or the need to use specialized outside counsel on behalf of business units." (Ex. 276 at 32.)

14.4.3. Discussion

For the Legal division A&G costs, the Applicants request an allocation to SoCalGas of $10.119 million, and an allocation of $15.693 million to SDG&E. In contrast, DRA's recommended reductions result in an allocation to SoCalGas of $4.218 million, and an allocation of $4.218 million to SDG&E.

Regarding DRA's recommended reduction to the cost center for Executive VP and General Counsel, we are not persuaded by DRA's argument that the services are duplicative. As described in Attachment A at 46 of Exhibit 276, the duties of the Corporate Center Executive VP and General Counsel are different from the duties of the General Counsels at SDG&E and SoCalGas, and the issues handled by the Corporate Center Executive VP and General Counsel focus primarily on Sempra-related matters. Accordingly, no adjustment to this cost center is warranted.

For the Legal Department cost center, DRA recommends removing the labor and non-labor costs associated with the two additional attorney FTEs due to a lack of justification. According to the Applicants' testimony, the additional attorney FTEs are needed because of Sempra's "new utility investments in electric generation, transmission, gas infrastructure, and new metering technology…" which results in a demand for additional legal services at the Corporate Center. (Ex. 276 at 30, Att. A at 47.) Also, the non-labor costs for these two FTEs are included in the $400,000 cost. Based on the Applicants' description of the increased investments and the need for two additional attorneys to handle the work associated with these investments, we do not adopt DRA's recommendation to reduce the costs in this cost center.

DRA recommends that $17.686 million be removed from the forecast of $27.778 million for outside legal costs. DRA's reasoning for removing these costs is because of its belief that the Applicants were unable to provide DRA with the type of legal services that have been provided, and that will be provided in the future. DRA also contends that due to the 2010 reorganization, these outside legal costs can be assumed by the legal staff at SDG&E and SoCalGas.

We are not persuaded by DRA's argument that the outside legal costs should be reduced entirely, as DRA has suggested. As the name of this cost center implies, these costs are to hire outside legal help to handle matters that are outside the expertise of Sempra's Legal Department. Reassigning attorneys from the Corporate Center into the legal departments of SDG&E and SoCalGas does not eliminate the need to hire outside legal help. However, we are concerned about the cost of outside legal, given the numbers of legal professionals at each utility, as well as at the corporate center. The outside legal costs make up about 70% of the Legal division's forecast of 2012 test year costs. To help control these costs, the test year forecast amount for the Legal division should be reduced. Under those circumstances, it is reasonable to reduce the allocation of the costs of the Legal division to SDG&E by $4 million, and to SoCalGas by $2.5 million. Accordingly, Legal division costs of $11.693 million allocated to SDG&E, and $7.619 million allocated to SoCalGas, should be adopted.

14.5. Human Resources

14.5.1. Background

The Corporate Center's Human Resources division provides services that support and maintain the Applicants' employees. As described in Exhibits 272 and 274, among the services that this division supplies are the following: developing corporate-wide policies, procedures and programs; providing policy oversight to the Applicants that are specific to their employees; design, implement and administer compensation and benefit programs for active and retired employees; supports payroll, benefits and human resources information system services; promote and manage corporate-wide employee volunteer opportunities and initiatives; and handle Human Resources administration, employee relations, training and development for certain Corporate Center employees.

The forecast of the total escalated amount for the Corporate Center Human Resources division is $18.300 million, of which $6.057 million is allocated to SDG&E, and $7.848 million is allocated to SoCalGas.

14.5.2. Position of the Parties

14.5.2.1. DRA

For the Human Resources division A&G costs, DRA recommends an allocation of $5.366 million to SDG&E, instead of the Corporate Center allocation of $6.057 million. For SoCalGas, DRA recommends an allocation of $5.366 million, instead of the Corporate Center allocation of $7.848 million. (*See* Ex. 497 at 5.)

As described in Exhibit 496, DRA recommends that adjustments be made to six cost centers. The first adjustment is to the costs for the Human Resources Senior VP. DRA recommends that the Applicants' forecast of $981,000 be reduced to $856,000, and that the allocations to SDG&E and SoCalGas be reduced. DRA's reduction for these costs is due to DRA's audit adjustment for the multi-factor allocation and the use of different escalation rates.

DRA's second adjustment is to the Executive Compensation cost center that is under the Compensation and Benefits division. DRA contends that since the expenses in this cost center have remained relatively stable for three or more years, that it is appropriate to use the 2010 recorded costs of $770,000 as the test year 2012 forecast instead of the Applicants' forecast of $960,000. As a result of this reduced forecast, DRA's allocation of the costs from the Executive Compensation cost center is lower. The compensation benefits costs are also affected by DRA's audit adjustment for the multi-factor allocation and the use of different escalation rates.

DRA's third adjustment is to the cost center for the Payroll and Human Resources Information Systems division. DRA's different multi-factor allocation and escalation rates results in a reduction for the forecast of $8.814 million to $8.811 million, and slightly different allocations to SDG&E and SoCalGas.

DRA's fourth adjustment is to the cost center 1100-0130 that is included under the Employee Development division. DRA contends that the costs from this cost center are duplicative of costs that are incurred at SDG&E and SoCalGas, and for that reason allocates nothing to SDG&E and SoCalGas from this cost center.

DRA's fifth and sixth adjustments are to two cost centers under the Employee Programs division. For cost centers 1100-0155 and 1100-0170, DRA contends that because the "2010 reorganization resulted in staff and programs being transferred to the Utilities, discontinued programs, and reduced staff," that allocating the costs from these two cost centers "is a duplication of costs that are now incurred at SDG&E and [SoCalGas]," and for that reason recommends that none of these costs be allocated to SDG&E and SoCalGas. (Ex. 496 at 41.)

14.5.2.2. SDG&E and SoCalGas

DRA proposes a disallowance of the allocations to SDG&E and SoCalGas for the cost center covering executive compensation services. DRA used 2010 recorded costs, while the Applicants' amounts use "a zero based approach, taking into consideration staffing and management needs." (Ex. 276 at 32-33.) The Applicants also contend "that 2010 is not a representative year because it contains a large prior-year credit and also does not include the cyclical consulting expense that is otherwise averaged in the 2012 forecast." (Ex. 276 at 33.)

DRA also proposes a disallowance of the allocations to SDG&E and SoCalGas for the cost center covering Corporate Human Resources Business Partner. DRA contends that since SDG&E and SoCalGas already have similar functions, that the Corporate Center functions are duplicative. The Applicants contend that this cost center "provides a broad range of human resources advisory services and support for employee relations, development and recruiting," including human resources "policy interpretation, performance management, employee discipline, career counseling, salary administration, employee/team development, and processing terminating employees from the Corporate Center." (Ex. 276 at 33.) Essentially, the utilities, and the Corporate Center, do not serve the same employees, and the utilities do "not provide this support for shared service employees at Corporate Center and is therefore not a duplicate function." (*Ibid*.)

DRA recommends disallowing all of the allocations to the utilities from the cost center covering the corporate community partnerships. DRA's recommendation is based on its belief that these activities are duplicative of those at SDG&E and SoCalGas. The Applicants contend that the two employees who work on corporate community partnerships at the Corporate Center "support employee-based giving and volunteer programs, which are not duplicate activities of the corporate-based community support activities that are now based at SDG&E." (Ex. 276 at 34.)

DRA also recommends disallowing the allocations for the cost center covering internal communications. DRA contends that these costs are duplicative of those at SDG&E and SoCalGas. The Applicants contend that this cost center is not duplicative, and that the activities of this cost center "primarily focuses on the administration of the Corporate intranet system and its use as a communication tool to all employees company-wide, including policy publication, company news, etc." (Ex. 276 at 34.)

14.5.3. Discussion

For the Human Resources division A&G costs, the Applicants request an allocation to SoCalGas of $7.848 million, and an allocation of $6.057 million to SDG&E. In contrast, DRA's recommended reductions result in an allocation to SoCalGas of $5.366 million, and an allocation of $5.366 million to SDG&E.

Regarding DRA's recommendation to reduce the cost center for the Human Resources VP, and to the cost center for Payroll and Human Resources information systems, we do not make those adjustments because they are based on DRA's multi-factor allocation adjustment, which we rejected earlier.

DRA recommends reducing the forecast for the Executive Compensation cost center by $126,000 due to DRA' view that costs have remained stable.

Instead of using the Applicants' zero-based methodology, DRA uses the 2010 recorded amount. We have reviewed the testimony of the Applicants and DRA for this cost center. Due to the inclusion of a prior year credit in the 2010 amount, we agree with the Applicants that the use of their zero-based methodology is a better method of forecasting costs for this cost center. We do not adopt DRA's recommendation to adjust this cost center.

DRA also recommends that three other adjustments be made to the following cost centers: 1100-0130; 1100-0155; and 1100-0170. DRA recommends that reductions for these cost centers be made because it believes these costs are duplicative of the costs incurred by similar units that are located at SDG&E and SoCalGas. We reviewed the testimony regarding the type of work that is being performed at these three cost centers. The work at these three cost centers is different from the work performed at the SDG&E and SoCalGas levels. These three Corporate Center cost centers perform work that targets a different group of employees than the work units at SDG&E and SoCalGas target. Accordingly, we do not adopt DRA's recommendations to reduce the costs and allocations in these three cost centers.

14.6. External Affairs

14.6.1. Background

The External Affairs division, which is referred to internally as Corporate Relations, "provides overall policy guidance for the Sempra Energy companies' interactions with external constituents." (Ex. 272 at 51.) The two major departments included in External Affairs are communications, and government affairs.

The communications department "oversees most shareholder communications, including media related activities (broadcast and print) and earnings announcements, which communicate critical information to investors and customers about the financial health and strategy of Sempra Energy, SDG&E and SoCalGas." (Ex. 272 at 52.)

The government affairs department has several components. The federal government affairs group is responsible for federal legislation and advocacy. The government programs group is responsible "for the management of the corporate political contributions budget and the operation of the Sempra Energy Employees Political Action Committee…." (Ex. 272 at 54.) The Corporate Compliance, Reporting and Analysis group oversees political contributions, lobbying, and gift reporting. The FERC Relations group is responsible for federal regulations and governmental advocacy.

The forecast of the total escalated amount for the Corporate Center External Affairs is $6.600 million, of which $1.061 million is allocated to SDG&E, and $1.120 million is allocated to SoCalGas.

14.6.2. Position of the Parties

14.6.2.1. DRA

For the External Affairs division A&G costs, DRA recommends an allocation of $885,000 to SDG&E, instead of the Corporate Center allocation of $1.061 million. For SoCalGas, DRA recommends an allocation of $936,000, instead of the Corporate Center allocation of $1.120 million. (*See* Ex. 497 at 5.)

As described in Exhibit 496, DRA makes three adjustments to the costs of the External Affairs division. The first adjustment is to the Communications costs. Instead of the Applicants' forecast of $2.661 million and its associated allocations, DRA recommends a forecast of $2.126 million and reduced allocations to SDG&E and SoCalGas. DRA's reduced forecast is due to the impact of DRA's multi-factor allocation and different escalation rates.

DRA's second and third adjustments are to two cost centers under Government Affairs. The second adjustment is to cost center 1100-0150. DRA removed $176,000 from the labor forecast because DRA contends the Applicants did not provide sufficient justification for this position. DRA further adjusted this cost center for non-labor costs because of the downward trend in non-labor costs. This cost center is also affected by DRA's multi-factor allocation and different escalation rates.

DRA's third adjustment is to cost center 1100-0157. DRA contends that the expenses in this cost center have fluctuated from year to year, and for that reason DRA used the four-year average (2007-2010) for its test year 2012 forecast. DRA's adjustment reduced the Applicants' forecast, and lowered the allocations to SDG&E and SoCalGas. DRA also adjusted this cost center by DRA's multi-factor allocation and different escalation rates.

14.6.2.2. SDG&E and SoCalGas

DRA proposes reducing the allocations to the utilities for the cost center covering VP Corporate Relations due to insufficient justification. The Applicants contend that data responses were provided explaining that the incremental costs were for a new FTE, and that the "increase represents a consolidation of certain compliance costs now under the responsibility of the new VP Corporate Relations that had previously been incurred by other cost centers eliminated in the reorganization." (Ex. 276 at 35.) The Applicants further contend that overall, "there is no actual increase," and that "DRA is proposing to single out a cost center for reduction without considering the overall changes in the organization." (*Ibid*.) DRA also recommends reducing the non-labor costs for this cost center. However, the Applicants contend that "year-over-year explanations of historical spending levels" were provided, and that in 2009 several consulting and membership contracts were terminated by the VP, "which reduced non-labor significantly but should not be construed as a trend." (*Ibid*.)

DRA recommends a reduction to the utility allocations for the cost center covering government programs and corporate responsibility. Due to fluctuating costs, DRA used a four-year average. The Applicants contend that its "zero-based approach takes into consideration individual job positions and cost elements and expected spending levels which is a more effective method of forecasting given the organizational changes that have occurred within this department." (Ex. 276 at 36.) The Applicants also contend that DRA selectively used the four-year average because the 2010 recorded costs "were the highest of any of the historical years," and that DRA "ignored the reasons for this increase, as explained in the workpapers." As a result, the Applicants contend that "the historical year costs are out of date and inappropriate to use for averaging." (*Ibid*.)

14.6.3. Discussion

For the External Affairs A&G costs, the Applicants propose to allocate $1.120 million to SoCalGas, and to allocate $1.061 million to SDG&E. In contrast, DRA's recommended reductions result in an allocation to SoCalGas of $936,000, and an allocation of $885,000 to SDG&E.

For the reasons mentioned earlier, we do not adopt DRA's multi-factor adjustments or its escalation adjustments, to the External Affairs A&G costs.

DRA recommends that the cost center for the VP Corporate Relations be reduced by $176,000. DRA contends that the Applicants have failed to justify the additional FTE. In addition, DRA reduced this cost center for non-labor costs because of its belief there was a downward trend from 2007-2010. We have reviewed the testimony of the Applicants and DRA concerning the costs in this cost center. As the Applicants have described, this FTE "represents a consolidation of certain compliance costs now under the responsibility of the new VP Corporate Relations that had previously been incurred by other cost centers eliminated in the reorganization," and that overall, "there is no actual increase." (Ex. 276 at 35.) To reduce this cost center as DRA has suggested, without looking at the decrease elsewhere, would not result in a reasonable estimate of the costs for this activity. As for DRA's non-labor reductions, we are not persuaded by DRA's argument that a reduction to non-labor costs should be made. As pointed out by the Applicants, several consulting and membership contracts were terminated in 2009, but this does not suggest there is a downward trend. Accordingly, we do not adopt DRA's recommendation to reduce the costs for this cost center.

DRA recommends that the amount forecasted for the cost center for government programs and corporate responsibility be reduced by $128,000. DRA's reduction is based on its belief that a four-year average is appropriate, instead of the Applicants' zero-based methodology, because of the significant fluctuations in recorded expenses. After comparing the forecasts of DRA and the Applicants to each other, and to the historical costs, including the 2010 costs, we agree with the Applicants that its methodology better represents the forecast of costs for this cost center. As described by the Applicants, some costs for this cost center were transferred from another cost center as a result of the 2010 reorganization. Accordingly, we do not adopt DRA's recommendation to reduce the amount for the cost center for government programs and corporate responsibility.

14.7. Facilities/Assets

14.7.1. Background

For purposes of these consolidated proceedings, certain cost centers were grouped under Facilities/Assets because "they relate to the physical environment and tools used in the conduct of corporate shared services." (Ex. 272 at 58.) As described in Exhibits 272 and 274, these cost centers include the following functions: depreciation and rate of return; property taxes; other facilities; and security services.

The forecast of the total escalated amount for Facilities/Assets is $15.700 million, of which $4.929 million is allocated to SDG&E, and $5.338 million is allocated to SoCalGas.

14.7.2. Position of the Parties

14.7.2.1. DRA

For the Facilities/Assets A&G costs, DRA recommends $4.767 million for SDG&E, instead of the Corporate Center forecast of $4.929 million. For SoCalGas, DRA recommends Facilities/Assets A&G costs of $5.192 million, instead of the Corporate Center forecast of $5.338 million. (*See* Ex. 497 at 5.)

As described in Exhibit 496, DRA recommends that adjustments be made to three cost centers (depreciation/rate of return; property taxes; and corporate security services) included in the Facilities/Assets category. The adjustments that DRA makes are due to either the multi-factor allocation or the different escalation rates, or both. DRA's adjustments have the effect of lowering the allocations to SDG&E and SoCalGas for the A&G costs associated with Facilities/Assets.

14.7.2.2. SDG&E and SoCalGas

DRA's adjustments to Facilities/Assets are due to the multi-factor allocation and the escalation differences. For the reasons stated earlier, the Applicants oppose DRA's adjustments to the Facilities/Assets A&G costs.

14.7.3. Discussion

For the Facilities/Assets A&G costs, the Applicants request an allocation to SoCalGas of $5.338 million, and an allocation of $4.929 million to SDG&E. In contrast, DRA's recommended adjustments result in an allocation to SoCalGas of $5.192 million, and an allocation of $4.767 million to SDG&E.

For the reasons mentioned earlier, we do not adopt DRA's multi-factor adjustments, or its escalation adjustments, to the External Affairs A&G costs.

14.8. Pension and Benefits

14.8.1. Background

The Pension and Benefits division covers the costs of labor overheads. As described in Exhibits 272 and 274, these costs include the following: employee benefits; payroll taxes; incentive compensation; long term incentives; and supplemental retirement.

The Applicants' forecast of the total escalated amount for Pension and Benefits is $94.600 million, of which $15.529 million is allocated to SDG&E, and $14.704 million is allocated to SoCalGas.

14.8.2. Position of the Parties

14.8.2.1. DRA

For the Pensions and Benefits A&G costs, DRA recommends an allocation of $5.303 million to SDG&E, instead of the Corporate Center allocation of $15.529 million. For SoCalGas, DRA recommends an allocation of $5.288 million, instead of the Corporate Center allocation of $14.704 million. (*See* Ex. 497 at 5.)

DRA recommends that seven adjustments be made to the A&G costs for Pensions and Benefits. The first adjustment is to cost center 1100-0802 for overhead that is under the employee benefits category. DRA reduced the labor costs for this cost center, as well as its adjustment for the multi-factor allocation.

DRA's second adjustment is to cost center 1100-0814, which is also under the employee benefits category. This cost center covers the pension costs for the Board of Directors. DRA contends that "SDG&E and [SoCalGas] already fund Board of Directors…fees, retainers and expenses and should not be expected to fund [Board of Director] pensions." (Ex. 496 at 49.) For that reason, DRA allocated nothing from this cost center to SDG&E and SoCalGas.

DRA's third adjustment is to the payroll taxes cost center. DRA reduced the labor costs in this cost center, which after applying DRA's escalation rate and the multi-factor allocation, reduces the costs to $3.379 million, and lowers the allocation to SDG&E and SoCalGas.

The fourth adjustment that DRA makes is to the cost center for the executive incentive compensation plan. Consistent with DRA's recommendation regarding compensation and incentives, DRA removed 50% of the incentive costs. DRA's adjustment to this cost center also includes DRA's adjustment for the multi-factor allocation, and escalation rates.

DRA's fifth adjustment is to the cost center for the incentive compensation plan overheads. Consistent with DRA's recommendation regarding compensation and incentives, DRA removed 50% of the incentive costs. DRA also reduced labor costs, which reduced the incentive compensation plan overheads. The effect of these adjustments, as well as DRA's adjustment for the multi-factor allocation, reduced the forecast for this cost center, and reduced the allocations to SDG&E and SoCalGas.

DRA's sixth adjustment is to the costs of the long term incentive plans. Consistent with DRA's recommendation regarding compensation and incentives, DRA removed all of the long term incentives.

The seventh adjustment that DRA makes is to the Supplemental Executive Retirement Plan. DRA recommends that none of these costs be allocated to SDG&E and SoCalGas. DRA contends that "Ratepayers already contribute the appropriate pension plan contributions required under pension law, and there is no reason that ratepayers need to provide even more funding to further supplement executive retirement expenses." (Ex. 496 at 50-51.) DRA points out that other regulatory commissions have disallowed such costs, and that DRA has taken the same position in other rate cases.

14.8.2.2. SDG&E and SoCalGas

DRA proposes a reduction to the allocations to SDG&E and SoCalGas for the A&G costs covering pension and benefits. The Applicants oppose DRA's labor reduction to the overhead adjustment. The Applicants also oppose DRA's multi-factor and escalation differences, except for the $75,000 adjustment to the Corporate Secretary cost center that was noted earlier.

DRA recommends disallowance of 50% of the requested incentive bonuses. The Applicants contend that the Total Compensation Study, which was sponsored by the Applicants and DRA, "found that total compensation was 'at market,' "and is within the guideline established by the Commission in D.95-12-055. (Ex. 374 at 4; Ex. 377 at 4.) The Applicants also contend that the incentive compensation plan is a reasonable cost that is part of the employees' total compensation package.

With respect to DRA's disallowance of long term incentives or supplemental retirement, the Applicants contend that long term incentives "are a critical component of a competitive compensation and benefits package needed to attract, motivate and retain key management employees."
(Ex. 374 at 11; Ex. 377 at 9.) Since the total compensation is "at market," the Applicants contend that "DRA should not be able to selectively exclude specific components of compensation from the revenue requirement."
(Ex. 374 at 11; Ex. 377 at 10.) Regarding DRA's disallowance of supplemental pension benefits, the Applicants contend that "Supplemental pension plans are an important component of a competitive compensation and benefits package for executive and other key employees," and that these "benefits are common in the external market, particularly among utilities." (Ex. 374 at 40; Ex. 377 at 37.)

14.8.3. Discussion

The cost forecasts for the Corporate Center employee pension and benefits are included in the costs of the Corporate Center, and the adopted costs are set forth in this discussion. In the Employee Issues section that follows in this decision, we address the concerns as to the reasonableness of the pension and benefits for SDG&E and SoCalGas.

For the Pension and Benefits A&G costs, the Applicants request an allocation to SoCalGas of $14.704 million, and an allocation of $15.529 million to SDG&E. In contrast, DRA's recommended reductions result in an allocation to SoCalGas of $5.288 million, and an allocation of $5.303 million to SDG&E.

Regarding the adjustments that DRA proposes to make for the multi-factor allocation, escalation, and labor, we do not adopt those adjustments for the reasons stated earlier. As a result, Corporate Center's allocation of the costs to SDG&E and SoCalGas for pension and benefits overhead, and payroll taxes, remains unchanged. With respect to DRA's recommendation to disallow the allocation of the Sempra Board of Directors' pension costs, we do not adopt that recommendation since Sempra's Board of Directors is distinct from the pensions of SDG&E and SoCalGas.

DRA recommends that ratepayers only bear 50% of the costs for Corporate Center's short term incentive compensation plan, and the incentive compensation plan overhead. For the long term incentive plan, and the supplemental retirement plan, DRA recommends that ratepayers not pay any of these costs. DRA's reasoning for its lower forecasts is because of DRA's position concerning compensation and employee benefits for SDG&E and SoCalGas, which is discussed later in this decision.

As discussed later in the Employee Issues section of this decision, we reduced the funding amounts requested by SDG&E and SoCalGas for short term incentive compensation by 50%. The reasoning for doing so is because of our belief that shareholders and ratepayers both share in the benefits of having a short term incentive compensation plan. It is reasonable and appropriate under the circumstances to reduce Corporate Center's allocation of the short term incentive compensation and overheads to SDG&E and SoCalGas by 50%. This 50% adjustment reduces the allocation to SoCalGas from $3.174 million to $1.587 million, and reduces the allocation to SDG&E from $3.213 million to $1.606 million.

DRA recommends that there be no ratepayer funding of the long term incentive plan, and supplemental retirement plan. In the Employee Issues section of this decision we found that long term compensation is stock-based compensation, which is tied to the financial performance of Sempra, and which benefits shareholders rather than ratepayers. For that reason, it is reasonable to disallow all ratepayer funding of Corporate Center's allocation of the costs of the long term incentive plan to SDG&E and SoCalGas.

With respect to the supplemental retirement plan, for the reasons discussed in the Employee Issues section of this decision, it is reasonable that the ratepayers allocation of Corporate Center's cost of the supplemental retirement plan be reduced by 50%. This will reduce the allocation to SoCalGas from $2.764 million to $1.382 million, and the allocation to SDG&E from $3.331 million to $1.666 million.

15. Insurance

15.1. Introduction

According to the Applicants, the responsibility for designing and implementing Sempra's insurance program is centralized at the Corporate Center in the Sempra Energy Risk Management Department (Risk Management). This is a Corporate Center shared service. With a few exceptions, Risk Management procures insurance coverage on a corporate wide basis for all Sempra business units. According to the Applicants, such a "structure provides maximum efficiencies in obtaining insurance, ensures regulatory and legal compliance, and eliminates potential insurance program deficiencies (i.e., gaps and duplication)." (Ex. 213 at 1.)[158]

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[158] The direct testimonies of the Applicants concerning the insurance costs are in Exhibit 213 for SDG&E, and Exhibit 215 for SoCalGas. Since both exhibits are the same, we cite to Exhibit 213.

As described in Exhibits 213 and 215, the two major categories of insurance that Risk Management obtains are property insurance and liability insurance. Also included in the costs of insurance are surety bonds.[159]

The property insurance provides coverage for damage or loss to assets. The property insurance policies and costs include the following: primary property all-risk; excess property all-risk; SONGS nuclear property, and non-nuclear property owned by SONGS; crime; policies covering other properties such as the Yuma transmission system, gas storage wells, coverage for loss of LNG cargos, and foreign country policies; and insurance broker fees.

The liability insurance provides coverage for claims from others. The liability insurance policies and costs include the following: general excess liability; wildfire liability; directors and officers liability; fiduciary liability; workers' compensation; SONGS liability; other liability policies covering the Yuma transmission system, group executive umbrella liability, auto liability, and liability policies for Sempra's global business units; and broker insurance fees.

Risk Management forecasts a total test year 2012 budget of $126.427 million, of which Risk Management has allocated $97.509 million to SDG&E, and $15.865 million to SoCalGas.[160] According to the Applicants, the primary factors affecting the $42.143 million increase in insurance costs over the 2009 total amount of $84.284 million are due to the following: wildfire property

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159 The surety bonds are procured on behalf of the Sempra business units. The surety bonds guarantee the contractual performance obligations of the Sempra business units to other parties.

160 The total forecasted insurance cost of $126.427 million is composed of $15.886 in property insurance, $109.378 million in liability insurance, and $1.162 million for surety bonds.

damage reinsurance to enhance coverage limits; standard escalation for most other policies, primarily commercial wildfire liability; the SONGs mutual property insurer is no longer issuing policyholder distributions; and the shift in allocation rates, primarily the multi-factor allocation.

DRA recommends that the allocation to SDG&E be reduced to $84.771 million, while UCAN recommends that the SDG&E allocation be reduced to $43.493 million. FEA recommends that the allocation to SDG&E be reduced to $67.810 million. (Ex. 217 at 1-2)

DRA recommends that the allocation to SoCalGas be reduced from $15.866 million to $14.185 million.

Since the insurance costs are a shared service, Risk Management also uses the following hierarchy to allocate costs to SDG&E, SoCalGas, and to the Sempra affiliates: direct assignment; causal/beneficial; and multi-factor. According to the Applicants, these allocation methods are used as follows:

> First, where a policy is procured for a specific business unit, or if the insurance carrier's invoice itemizes the premium by business unit coverage, the costs are directly assigned to the business units. Second, insurance policies covering multiple business units under a single premium are charged to the business units using a Causal/Beneficial factor if available. Third, policies for coverage such as general excess liability that support the Sempra Energy companies as a whole are allocated using the corporate Multi-Factor method. (Ex. 213 at 3.)

As with the other Corporate Center shared costs, the multi-factor allocation method weighs the following four factors from among all the business units: revenue; gross plant and investments; operating expenses; and FTEs. To derive the forecasted rates for 2012 using the multi-factor method, "historical factors from 2005-2009 were projected using a statistical forecasting method known as a least-squares formula." (Ex. 213 at 3-4.)

According to the Applicants, due to the nature of the events covered by commercial insurance policies, they "are unable to predict future year premiums with certainty beyond 12 months of the current policy year…." (Ex. 213 at 4.) As a result, the insurance "premiums are escalated using a standard escalation factor to account for insurance market conditions, as well as individually for internal growth (increases in underwriting criteria like values, payroll, number of employees, vehicles)…." (*Ibid*.)

The Applicants also describe in Exhibits 213 and 215 the market conditions and industry trends that affect the insurance costs. According to the Applicants, there are hard and soft insurance markets. The "hard markets are characterized by contraction of available capacity, restrictions on coverage and increasing premiums," whereas "[s]oft markets are characterized by adequate types and amounts of insurance…." (Ex. 213 at 4.) These hard and soft markets are affected by the insurance losses that occur, including property losses and wildfire liability losses. For example, during the 2009-2010 insurance renewal period, "Risk Management found there was far less wildfire liability and general liability insurance available and the cost of the insurance had dramatically increased." (Ex. 213 at 5.) During this insurance renewal period, "the general liability market experienced some premium increase pressure," but "the greatest pressure was felt in wildfire liability insurance premiums." (*Ibid*.)

15.2. Position of the Parties

15.2.1. DRA

DRA recommends that Risk Management's utility allocation of the insurance costs be reduced from $113.372 million to a total of $98.959 million. As a result of DRA's reduction in the utility allocation of the insurance costs, DRA recommends that SDG&E be allocated $84.771 million instead of Risk Management's allocation of $97.509 million. For SoCalGas, DRA recommends that SoCalGas be allocated $14.185 million instead of Risk Management's allocation of $15.866 million.

DRA's recommended amounts are based on a several adjustments to property insurance, and liability insurance.

DRA's first adjustment is to cost center 1100-0404 for property insurance – all risk excess. Risk Management assumed a 5% growth in property values, and used a 3.5% escalation factor, to arrive at its total forecast of $7.012 million. DRA contends that this cost center has shown a downward trend from 2006-2010, and therefore DRA used the 2010 recorded amount ($5.530 million) as the basis for its 2012 forecast. DRA then applied an escalation factor of 1.015% to the 2010 amount for 2011 and 2012, resulting in a 2012 forecast of $5.742 million before allocations. DRA's escalation factor relies on the information contained in the Global Insight Power Planner for the first quarter of 2010. Of the $5.742 million, DRA allocates $2.257 million to SDG&E, and $1.407 million to SoCalGas. DRA's amount includes DRA's adjustment for the multi-factor allocation.

DRA's second adjustment is to cost center 1100-0401 for SONGS nuclear property insurance. Risk Management forecasts total insurance costs of $964,000, which is allocated 100% to SDG&E. DRA contends that this cost center has shown an upward trend from 2005-2009, and that the 2010 recorded amount of $868,000 should be used as the basis for its 2012 forecast. DRA then applied an escalation factor of 1.015% to the 2010 amount for 2011 and 2012, resulting in a

2012 forecast of $90.282 million. DRA's amount includes DRA's adjustment for the multi-factor allocation.

DRA's third adjustment is due to its multi-factor adjustment which affects the property insurance costs by a total of $14,000.

DRA's fourth adjustment is to cost center 1100-0445 for wildfire excess liability. Risk Management forecasts $42.888 million in total costs for this cost center. DRA removed $8.376 million from Risk Management's forecast because of DRA's belief that $8.376 million was used in 2010 to pay for the first installment of the wildfire reinsurance policy, which is allocated 100% to SDG&E. A separate cost center, 1100-0446 was opened to record the wildfire reinsurance costs. As a result of the removal of the $8.376 million, DRA contends that this results in a 2010 adjusted recorded cost of $32.353 million in cost center 1100-0445. To arrive at its 2012 forecast for this cost center, DRA then escalated the $32.353 million by its escalation factor of 1.023% for 2011 and 2012, resulting in a total 2012 forecast of $33.891 million. With DRA's multi-factor adjustment, DRA proposes to allocate $33.715 million to SDG&E, and $119,000 to SoCalGas.

DRA's fifth adjustment is to cost center 1100-0446 for the wildfire damage reinsurance. Risk Management forecasts total costs of $35.779 million for this cost center in 2012. DRA contends that the 2010 recorded amount for this cost center was $24.230 million, not including the first installment of $8.376 million that was paid from cost center 1100-0445. Adding the first installment to the 2010 amount results in a total of $32.606 million. DRA then escalated the $32.606 million by its escalation factor of 1.023% for 2011 and 2012, resulting in a total 2012 forecast of $34.156 million, which is allocated 100% to SDG&E.

DRA's sixth adjustment is to cost center 1100-0427 for directors and officers liability insurance. Risk Management forecasts total costs of

$4.231 million for this cost center in 2012. DRA recommends that two adjustments be made to this cost center. First, DRA recommends that the forecast be reduced to a total of $3.897 million. This reduction is due to DRA's use of the 2010 recorded amount of $3.719 million as the base forecast because of DRA's belief that the costs have trended lower over the past four years. DRA's second adjustment is to reduce by 50% the amount that ratepayers pay for this cost center. DRA contends that in other decisions, the Commission allowed 50% of the cost of this insurance to be paid for by ratepayers, on the theory that directors and officers liability insurance benefits both shareholders and ratepayers. DRA contends that Risk Management has not provided any justification to deviate from this Commission policy. Based on these two adjustments, DRA recommends that $775,000 be allocated to SDG&E, and $786,000 be allocated to SoCalGas.

DRA's seventh adjustment is to cost center 1100-0429 for excess workers compensation liability insurance. Risk Management forecasts total costs of $2.142 million for this cost center in 2012. DRA used the 2010 recorded cost of $1.961 million as the basis of its forecast because "it reflects the most recent available insurance costs." (Ex. 498 at 14.) DRA then escalated this amount by its 1.023% escalation factor for 2011 and 2012 to arrive at its 2012 total forecast amount of $2.055 million. Of this amount, which includes DRA's multi-factor adjustment, DRA would allocate $882,000 to SDG&E, and $1.096 million to SoCalGas.

DRA's eighth adjustment is to cost center 1100-0439 for global workers liability insurance. Risk Management forecasts total costs of $321,000 for this cost center in 2012, of which 99.46% is allocated to Sempra's global business units. Instead of allocating $1,000 of these costs to SDG&E, DRA recommends that zero costs be allocated to SDG&E.

DRA's ninth adjustment is to cost center 1100-0425 for SONGs nuclear liability insurance. Risk Management forecasts total costs of $462,000 for this cost center in 2012, of which 100% is allocated to SDG&E. Since costs have trended slightly higher over the past four years, DRA uses the 2010 recorded amount of $334,000 as its base forecast. DRA then applied its escalation factor of 1.023% in 2011 and 2011, to arrive at its 2012 forecast amount of $350,000, which includes DRA's multi-factor allocation adjustment.

DRA's tenth adjustment is to cost center 1100-0433 for group executive liability insurance. Risk Management forecasts total costs of $94,000 for this cost center in 2012, of which $78,000 is allocated to SDG&E and SoCalGas. DRA contends that "ratepayers should not be required to fund this type of liability insurance" because it "serves to protect the interests of a limited, highly compensated group of executives and the testimony provides no evidence that this expenditure serves ratepayer interests." (Ex. 498 at 15.)

DRA's multi-factor allocation adjustment also results in a $730,000 reduction of the liability insurance costs that are allocated to SDG&E and SoCalGas.

DRA's eleventh adjustment is to the cost center for surety bonds. Risk Management forecasts total costs of $1.162 million for this cost center in 2012. Since these costs have trended higher over three or more years, DRA uses the 2010 amount of $1.067 million as its base forecast. DRA then escalated the 2010 amount by the 1.023% escalation factor for 2011 and 2012 to arrive at its 2012 forecast of $1.117 million. Of this amount, DRA recommends that $821,000 be allocated to SDG&E, and $247,000 be allocated to SoCalGas.

15.2.2. UCAN

UCAN recommends a lower insurance forecast for three types of insurance. The largest reduction that UCAN advocates for is the premium for wildfire liability insurance. UCAN also recommends a reduction to the premiums for nuclear property insurance, and the nuclear liability insurance.

SDG&E has requested a total of $78.444 million in test year 2012 for its allocated share of the wildfire liability insurance. This allocation is composed of an allocation of $42.665 million for wildfire liability insurance, and an allocation of $35.779 million for wildfire reinsurance. UCAN takes issue with the wildfire reinsurance premium, and recommends that the $35.779 million be disallowed.

UCAN contends that SDG&E's reliance on the commercial insurance market to increase its wildfire liability coverage by $600 million is not the most cost effective method to build coverage. UCAN contends that SDG&E "failed to examine the possibility of building wildfire liability capacity more cost effectively by restructuring the first $400 million of the placement using a variety of alternatives to the commercial insurance market." (Ex. 566 at 3.) UCAN contends that the purchase of the wildfire reinsurance could be costly because of the high premium, and the narrow scope of the wildfire reinsurance policy which covers only "named perils."

UCAN also contends that the Applicants' witness, who serves on an insurance company advisory committee, "creates a potential conflict between supporting the interests of SDG&E's shareholders and ratepayers and assuring the profitability of the insurance company." (Ex. 566 at 9.) In addition, UCAN contends that as "long as insurance premiums can be passed along to the ratepayers as an 'ordinary cost of doing business' with little or no scrutiny… there is no incentive on the part of the insurer to conduct serious negotiations and compete with the marketplace." (Ex. 566 at 10.) UCAN also contends that it does not appear that SDG&E attempted to use the $444 million settlement with Cox Communications, which arose as a result of the 2007 wildfires, as leverage in trying to lower the wildfire insurance premiums during the insurance renewal negotiations.

UCAN also contends that SDG&E has other options to protect itself against wildfire risks, and that SDG&E should have considered alternative program structures, such as catastrophe bonds, self-insurance, or a contingent capital project. UCAN's witness suggests that a "loss stabilization plan" could have been structured for a five-year term at a substantially lower cost than the wildfire reinsurance policy.

Risk Management allocated $964,000 to SDG&E for nuclear property insurance premiums. Although DRA accepted this amount, UCAN recommends that this amount be disallowed. UCAN's disallowance is based on the past distributions that the Nuclear Electric Insurance Limited (NEIL) has paid to its member-clients in the past. SDG&E assumes that no distributions will be paid in 2011 and 2012. As described, and attached to Exhibit 558, UCAN contends that in SCE's GRC, there was evidence that the NEIL will pay distributions in 2011 and 2012. As a result, UCAN calculates that the distributions SDG&E will receive will equal the $964,000 premium.

UCAN also contends that the same attachment to Exhibit 558 shows that there will be a zero increase in nuclear liability insurance. For that reason, UCAN recommends that the nuclear liability insurance allocated to SDG&E be reduced from $827,000 to $772,000.

15.2.3. FEA

FEA notes that SDG&E is requesting $97.509 million in allocated insurance costs, which is an increase of $42.302 million over the 2009 level. FEA recommends a lower insurance forecast for SDG&E's wildfire liability, and for two other liability policies.

FEA's first recommended adjustment is to Risk Management's allocation of $78.444 million in costs to SDG&E for wildfire liability ($42.665 million), and wildfire reinsurance ($35.779 million). FEA recommends that the costs of these two wildfire policies be reduced and limited to $65 million, instead of Risk Management's recommendation of $78.444 million. FEA's recommendation of $65 million uses the 2010 recorded amount for these two policies, as reported by the Applicants in response to a UCAN data request.

Since SDG&E was found to be at fault for two of the wildfires, FEA believes shareholders should pay for the increases in the cost of the wildfire insurance.

FEA's second adjustment is to the directors and officers insurance. Risk Management has forecasted a total of $4.231 million for this insurance. FEA contends that the cost of this insurance has been "steadily declining since 2007," and that the Applicants have not justified why this cost will increase in test year 2012. (Ex. 577 at 71-72.) FEA recommends that the amount for this insurance be set at the 2010 amount of $3.719 million. Since FEA believes that both shareholders and ratepayers benefit from having this kind of insurance, FEA contends it is reasonable for shareholders and ratepayers to share the cost of this insurance equally. FEA contends that prior Commission decisions, and other state commissions have applied this 50/50 split.

FEA's third adjustment is to the cost of the executive umbrella insurance in cost center 1100-0433. Risk Management has allocated $39,000 of the total cost of $94,000 to SDG&E. FEA recommends that SDG&E's allocation of $39,000 be removed entirely because this executive umbrella insurance is in addition to the liability coverage that is recovered from ratepayers and which already covers executives and other employees.

For the escalation of property and liability insurance, FEA is opposed to the Applicants' use of an escalation factor of 3.5%. FEA contends that the Applicants use of the 3.5% escalation factor is based solely on management discretion. FEA recommends that the property and liability insurance costs be escalated using the same Consumer Price Index (CPI) escalation factors that were used for other expenses.

15.2.4. SDG&E and SoCalGas

The Applicants contend that Risk Management's objective is to purchase appropriate limits of insurance with broad coverage to protect against catastrophic loss at the most economic cost feasible.

For the reasons stated elsewhere in this decision, the Applicants are opposed to DRA's multi-factor allocation adjustment. DRA's adjustment affects various insurance costs. The Applicants also point out several instances where DRA should not have applied the multi-factor adjustment.

The Applicants are also opposed to the lower escalation rates that DRA (1.015% and 1.023%) and FEA (CPI) have applied to their forecasts of insurance costs. The Applicants contend that insurance costs "do not escalate the same way as other expenses," and "are not subject to the standard escalation factors used by other utility areas." (Ex. 217 at 3-4.) Instead, the escalation in insurance costs is affected by "market pressures, such as loss history (individual as well as market), insurers' perception of future risk of loss, economic factors, and insurers' investment results." (Ex. 217 at 4.) The Applicants contend that the 3.5% escalation factor used by Risk Management is a reasonable and conservative assumption, and is lower than the overall recent experience for insurance costs. The Applicants contend that from 2005-2010, property insurance has increased by about 6% per year, and that liability insurance has increased by about 8% per year.

With respect to DRA's recommended adjustment to cost center 1100-0404 for property insurance – all risk excess, the Applicants contend that DRA's use of the 2010 recorded amount is inappropriate because the costs have not trended lower as DRA suggests. The Applicants contend that from 2005-2009 the premiums for this cost center have been higher than $6 million with no clear trend, and that the 2010 recorded amount "was the only year in recent history to fall below $6 million. (Ex. 217 at 5.)

The Applicants oppose the recommended reduction of DRA, and the recommended disallowance of UCAN, to cost center 1100-0401 covering SONGS nuclear property insurance. The Applicants disagree with DRA's use of the 2010 recorded amount, and contends that NEIL has announced that premium rates will increase starting in 2012. On UCAN's contention that NEIL will make distributions to SDG&E, the Applicants contend that more recent 2011 information indicates that NEIL will not declare a distribution in 2011, and that clients should budget for no distribution in 2012.

On DRA's recommended removal of $8.376 million from cost center 1100-0445 for wildfire liability, the Applicants contend that the 2010 recorded costs for this cost center "represent the total actual renewal amounts for this policy only," and does not include a double counting of the cost paid for the first installment of the wildfire reinsurance policy. (Ex. 217 at 9.)

The Applicants are also opposed to the recommendations of DRA, FEA, and UCAN to reduce or disallow the costs of the wildfire reinsurance in cost center 1100-0446. The Applicants contend that the use of the 2010 recorded amount by DRA and FEA would not be accurate because the 2010 amount did not represent a full year of payments for the premiums. The Applicants also contend that FEA's use of the 2010 recorded amount has no connection to FEA's argument that SDG&E was found at fault for two of the wildfires.

With regard to UCAN's contention that SDG&E should have pursued lower cost alternatives to the wildfire reinsurance policy, the Applicants assert, as described in Exhibit 217, that they fully explored alternative risk transfer mechanisms, and that they selected the most appropriate mechanism to address the risk exposure of a lack of insurance capacity. The Applicants also contend that Risk Management's reliance on the commercial and reinsurance market was "a sound and stable approach to risk transfer, and protects SDG&E and its ratepayers from the catastrophic wildfire risk exposure it faces," and that the "reinsurance transaction was completed by licensed reinsurance brokerage and reinsurance company professionals, with oversight from captive managers, the South Carolina Department of Insurance, and ratings agencies." (Ex. 217 at 18.)

DRA and FEA also recommend reductions to cost center 1100-0427 for directors and officers liability. The Applicants contend that the Commission's past treatment of certain costs are not precedent-setting. The Applicants further contend that directors and officers insurance "is no different from any other type of insurance, where it is a risk mitigation tool that protects against catastrophic losses," which would be incurred by Sempra's Board members and officers.

(Ex. 217 at 11.) The Applicants also contend there is no direct benefit to shareholders, and that this kind of insurance "is one of the factors that aid in attracting and retaining qualified officers and directors, which is in the best interests of both ratepayers and shareholders." (*Ibid*.) Since these costs are allocated on the multi-factor method, the Applicants further contend that "shareholders are already paying for a portion of this insurance…." (*Ibid*.) As for the use of the 2010 recorded amount by DRA and FEA, the Applicants contend that this amount was the lowest in six years, and was an aberration and did not reflect a downward trend as DRA and FEA suggest. Since rates for this insurance have hit near bottom, the Applicants expect that rates for directors and officers insurance will rise.

On DRA's recommended adjustment to cost center 1100-0429 covering excess workers' compensation insurance, the Applicants are opposed to DRA's use of the 2010 recorded amount as the basis for DRA's forecast.

On DRA recommended disallowance of the global workers' compensation liability insurance in cost center 1100-0439, the Applicants contend that such a policy covers utility employees, and that the policy is allocated based on actual premiums per business unit.

The Applicants are opposed to the reductions of DRA and UCAN to cost center 1100-0425 covering SONGS nuclear liability. The Applicants oppose DRA's use of the 2010 recorded amount because that amount included a credit, which results in an unusually low amount. The Applicants oppose UCAN's reduction for the escalation rate because the information that UCAN relied on is outdated. Instead of rates remaining flat, the Applicants contend that the premiums for SONGS nuclear liability are trending higher.

The Applicants oppose the disallowance of allocated costs for cost center 1100-0433 covering group executive liability insurance. The Applicants contend that this "policy is designed to protect key employee executives and their families against claims resulting from personal injury, bodily injury or property damage lawsuits," and that this "is one component of a competitive compensation and benefits package designed to help attract and retain leadership talent required to operate the company." (Ex. 217 at 16.) By attracting and retaining these key employees, the Applicants contend that this benefits ratepayers. The Applicants also contend that this executive umbrella liability insurance policy "is not in addition to, nor is it a duplication of, the insurance afforded by the commercial liability insurance." (*Ibid*.)

Regarding DRA's recommended reductions to the forecast of the surety bonds, the Applicants contend that DRA's use of the 2010 recorded amount should be rejected because the last three years have not trended higher as DRA suggests.

15.3. Discussion

The total insurance costs allocated to SDG&E and SoCalGas by Risk Management amounts to $113.375 million, of which $97.509 million is allocated to SDG&E, and $15.866 million is allocated to SoCalGas.

For the reasons discussed earlier in this decision, we do not adopt DRA's multi-factor allocation adjustment. As a result, no changes to the insurance costs are needed with respect to DRA's multi-factor allocation adjustment.

With respect to the escalation factor that Risk Management used to develop its forecasts of the insurance costs, we are not persuaded by the arguments of DRA and FEA that such adjustments should be made. As the Applicants have described in Exhibits 213, 215, and 217, the rise in insurance costs is not tied to the CPI. Instead, other factors unique to the insurance market have caused rates to rise, and the annual increase in insurance costs has averaged more than 6% for both property insurance and liability insurance. Accordingly, it is reasonable to use the Applicants' 3.5% escalation factor for the forecasts of the insurance costs.

We now turn to the adjustments to the various cost centers that the parties have recommended.

First, DRA recommends that cost center 1100-0404 for property insurance – all risk excess be adjusted from a total utility allocation of $7.709 million to $6.885 million. Based on a review of the Applicants' forecast and DRA's forecast to the historical costs, we agree that the Applicants' forecast of $7.709 million is more reasonable since that forecast is more reflective of the historical costs that have been incurred. Accordingly, it is reasonable to allocate from the total of $7.709 million, the following: $4.410 million to SDG&E; and $3.299 to SoCalGas.

Second, DRA and UCAN recommend reductions to the SONGS property insurance in cost center 1100-0401 and 1100-0402. DRA recommends that Risk Management's allocation to SDG&E of $1.020 million be reduced to $957,000. UCAN recommends that only $56,000 be allocated to SDG&E. We have reviewed the testimony of the Applicants, DRA, and UCAN concerning the costs of the SONGS property insurance. Based on information provided by the Applicants, it is unlikely that NEIL will make any distribution to offset this policy premium, and that the rates for this policy are likely to rise. Accordingly, the allocation of $1.020 million to SDG&E is reasonable, and the adjustments recommended by DRA and UCAN to this cost center are not adopted.

Third, DRA recommends removing $8.376 million from cost center 1100-0445 for wildfire liability because it believes this amount was for the wildfire reinsurance premium. This would reduce Risk Management's total forecast of $42.888 million to $34.512 million. However, the evidence presented by the Applicants establishes that the 2010 recorded costs in this cost center are only for the wildfire policy covered by this cost center. Since there is no double counting of the cost paid for the first installment of the wildfire reinsurance policy in this cost center, we do not adopt DRA's recommendation to remove $8.376 million from this cost center. Accordingly, it is reasonable to allocate $42.665 million to SDG&E, and $150,000 to SoCalGas.

Fourth, DRA, UCAN and FEA seek to reduce or disallow the costs of the wildfire reinsurance in cost center 1100-0446. Risk Management forecasts a total of $35.779 million, which is allocated 100% to SDG&E. DRA recommends an amount of $34.156 million, while FEA recommends $32.606 million. UCAN recommends that the entire cost of $35.779 million be disallowed. We have reviewed the testimony and the arguments of the parties concerning the costs of the wildfire reinsurance. Based on the evidence presented, we are not persuaded by UCAN's argument that SDG&E failed to pursue whether lower cost alternatives to the wildfire reinsurance could have been procured. FEA makes the argument that because SDG&E was found to be at fault for two the wildfires that occurred in 2007, that SDG&E should bear more of the costs of such insurance. We have also compared the various forecasts of the parties to the 2010 recorded cost, and have taken into consideration that the 2010 recorded cost did not include all of the premium payments. We have also taken into consideration that SDG&E's fire hardening activities should help to reduce the cost of wildfire insurance. Based on all those considerations, it is reasonable to reduce the amount of the wildfire reinsurance allocated to SDG&E from $35.779 million to $31.779 million.

The fifth adjustment is the recommendation of DRA and FEA to reduce the amount allocated to the utilities for directors and officers liability. Risk Management proposes to allocate $1.758 million to SDG&E, and $1.757 million to SoCalGas. DRA recommends that the total amount for this cost center should be $3.897 million instead of Risk Management's forecast of $4.231 million. With its 50% sharing, DRA proposes to allocate $1.551 million to SDG&E, and $1.572 million to SoCalGas. FEA proposes to use the 2010 recorded amount of $3.719 million as the total for this cost center, and that only 50% of the costs be allocated to the utilities. First, we address what the total amount should be for directors and officers liability. Based on a comparison of the forecasts of the Applicants, DRA, and FEA to the historical costs, it is reasonable to adopt the Applicants' total amount of $4.231 million. On the issue of whether the directors and officers liability should be borne mostly by SDG&E and SoCalGas, or if 50% of the costs should be borne by Sempra's shareholders, we agree with DRA and FEA. Although this type of insurance is used to attract and retain executives, the Applicants acknowledge that such insurance protects Sempra's Board members and officers from catastrophic losses, which is a benefit that accrues to shareholders, rather than ratepayers. For that reason, of the $3.515 million allocated to the two utilities, SDG&E and SoCalGas should each be allocated 50% of this amount, i.e., $879,000 each.

The sixth adjustment is to cost center 1100-0429 covering excess workers' compensation insurance. DRA recommends that Risk Management's total forecast of $2.142 million be reduced to $2.055 million, and that the utilities allocations be reduced accordingly. DRA's recommendation is based on the 2010 amount of $1.961 million, and escalated in 2011 and 2012 to $2.055 million. We have compared the forecasts of the Applicants and DRA to the historical costs, and agree with DRA that the Applicant's forecast appears too high in light of recent historical costs. For those reasons, it is reasonable to adopt DRA's forecast of $2.055 million for this cost center. This will result in an allocation to SDG&E of approximately $769,000, and to SoCalGas of approximately $954,000.

The seventh adjustment is DRA's recommendation to disallow all of the costs allocated to the utilities in cost center 1100-0439, which covers the global workers' compensation liability insurance. Based on the evidence presented, there are some employees who are located out of state. For that reason, we do not adopt DRA's adjustment to this cost center.

The eighth adjustment is the recommended reductions of DRA and UCAN to cost centers 1100-0425 and 1100-0426 covering the SONGS nuclear liability. DRA recommends using the escalated 2010 amount to reduce Risk Management's forecast of $827,000 to $715,000. UCAN's recommendation to eliminate the escalation for these costs would reduce the forecast to $772,000. We have compared the various forecasts of the parties to the historical costs, and considered the escalation arguments and the inclusion of a credit in the 2010 amount. Based on those reasons, it is reasonable to adopt Risk Management's forecast of $827,000 for this cost center, all of which is assigned or allocated to SDG&E.

The ninth adjustment is the recommendation of DRA and FEA to disallow the allocated costs for cost center 1100-0433 covering the group executive liability insurance. DRA contends that this umbrella policy should be disallowed as it does not benefit ratepayers, and only protects executives who are already highly compensated. FEA contends that similar insurance is already being funded by ratepayers. This is another form of compensation which helps to attract and retain executives. However, the Applicants also acknowledge that such a policy protects "key employee executives and their families against claims resulting from personal injury, bodily injury or property damage lawsuits." Based on those considerations, it is reasonable to split 50% of this cost with shareholders. Accordingly, SDG&E and SoCalGas should each be allocated $20,000 for the cost of this policy.

The tenth adjustment is DRA's recommendation to reduce Risk Management's $1.162 million forecast of the surety bonds to $1.117 million. DRA's recommendation is based on the 2010 amount of $1.067 million, escalated to $1.117 million. Based on recent historical costs, and our view regarding the escalation of insurance costs, it is reasonable to adopt Risk Management's forecast of this cost.

In summary, based on our review of all of the contested and uncontested insurance costs allocated to SDG&E and SoCalGas, and as discussed above, it is reasonable to adopt Risk Management's allocation of the insurance costs to SDG&E and SoCalGas as adjusted by our discussion concerning the costs of the wildfire reinsurance, directors and officers liability, excess workers' compensation, and the umbrella liability policy for executives and officers.

16. Employee Issues

16.1. Introduction

This Employee Issues section addresses the reasonableness of the compensation and employee benefits offered by SDG&E and SoCalGas. The components which make up the compensation and benefits program include the following: base pay; short-term incentives; long term incentives; special recognition awards; health benefits such as medical and dental; welfare benefits such as disability insurance, business travel insurance, and life insurance; retirement benefits such as pension savings plans and retirement savings plans; and other benefit programs such as educational assistance, emergency childcare, and mass transit incentive.

The compensation and benefit plans offered to an employee depend on the employee group the employee belongs to. The employee groups are described as executive, director, management, associate, and union employees. The Applicants contend that the total compensation offered to their employees are "structured to attract, motivate and retain a high-performing workforce." (Ex. 372 at 2-3; Ex. 375 at 2-3.)

In the subsections below, we first address compensation and employee benefits, followed by the defined benefit pensions and post-retirement benefits other than pensions (PBOP). Before doing so, we provide a brief description of the Total Compensation Study that Towers Watson prepared, which plays an important role in determining whether the compensation and benefits of SDG&E and SoCalGas are reasonable.

16.1.1. Total Compensation Study

In compliance with past Commission decisions, a Total Compensation Study was conducted by Towers Watson for the GRC applications of SDG&E and SoCalGas.[161] The purpose of the two studies was to evaluate the total compensation offered by SDG&E and SoCalGas in comparison to the external labor market. Such studies have been required by the Commission in order to

161 A copy of the study for SDG&E was attached to Exhibit 372, and a copy of the study for SoCalGas was attached to Exhibit 375.

provide an independent analysis of the reasonableness of a utility's employee compensation. (*See* D.08-07-046 at 21-22; D.95-12-055 [63 CPUC2d at 590]; D.96-01-011 [64 CPUC2d at 362-365].) The "total compensation" that was evaluated in the studies consists of base salaries, target short-term incentives, long term incentives and benefits.

DRA, together with SDG&E and SoCalGas, selected Towers Watson to do the study. The project team for the study included representatives from DRA, Sempra (for both SDG&E and SoCalGas), and Towers Watson. According to the results of the studies, SDG&E's total compensation is within 3.4% of the market, and SoCalGas' total compensation is within 3.2% of the market.

16.2. Compensation and Employee Benefits

16.2.1. Compensation

The compensation package of SDG&E and SoCalGas "includes base pay, short-term incentive compensation, long term incentive compensation (for key management employees only) and special recognition awards." (Ex. 372 at 5; Ex. 375 at 5.)

The base pay forms the foundation of the utilities' compensation program. For non-represented positions, the base pay is structured to "provide for individual differentiation based on an employee's performance, skills and experience." (Ex. 372 at 5; Ex. 375 at 5.) For represented positions, the base pay and pay grades "are subject to collective bargaining agreements and are adjusted consistent with contract negotiations." (Ex. 372 at 6; Ex. 375 at 6.)

The Total Compensation Study for SDG&E indicates that SDG&E's base pay is 1.2% below market, while the study for SoCalGas indicates that SoCalGas' base pay is 2.8% above market.

Short-term incentive compensation consists of an annual incentive plan that the Applicants refer to as the Incentive Compensation Plan (ICP). The ICP is a form of variable pay, which recognizes and rewards employee contributions for "meeting important customer service, safety, supplier diversity, financial, and project completion goals." (Ex. 372 at 6; Ex. 375 at 5.) Performance measures, are used for the ICP, and consist of financial measures, operating measures, and individual performance measures. All non-represented employees participate in the ICP.

The long term incentive compensation is part of the compensation program for key management and executive employees. The long term incentive compensation is performance-based, and is dependent on Sempra's four-year financial performance. These long term incentives are in the form of performance-based restricted stock units, and nonqualified stock options.

Special recognition awards are to "reward individual employees and teams for outstanding achievement, exceptional customer service, and process improvements and innovations." (Ex. 372 at 9; Ex. 375 at 9.) The awards may be financial or non-financial.

As summarized in the tables that appear at page 2 of Exhibits 372 and 375, the test year 2012 expense for compensation and benefit programs (excluding base pay, long term disability, and workers compensation) amounts to $139.093 million for SDG&E, and $134.279 million for SoCalGas.

To control compensation, the Applicants evaluate "the external labor market to ensure that its compensation and benefits package is competitive and cost-effective. (Ex. 372 at 34; Ex. 375 at 34.) This includes conducting and reviewing salary surveys, as well as conducting job studies. Sempra's compensation and benefits departments' purchase compensation survey databases to assess compensation for non-executive jobs, and for executive jobs. In addition Sempra reviews executive compensation and benefits data for other utility companies as reported in each utility company's annual statement. To assess their benefits, the Applicants participate in a Towers Watson database which "determines values for the benefits provided by participating companies by applying a standard set of actuarial methods." (Ex. 372 at 34-35; Ex. 375 at 35.) Internal processes are also followed to ensure that compensation and benefits are equitable and competitive.

16.2.2. Employee Benefits

Employee benefits are also part of total compensation. As described in Exhibits 372 and 375, these benefits consist of health benefits, welfare benefits, retirement benefits, and other benefit programs.

The health benefits include medical, dental, vision, employee assistance, wellness, and mental health and substance abuse. The cost of these health benefits are shared between the utilities and their employees, and the level of cost sharing depends on the type of benefit and level of coverage that is selected.

Regarding the utilities' medical cost trends, SDG&E and SoCalGas have experienced average medical escalation of 11.8% over the ten year period of 2001-2010. This is slightly above the 10.2% medical escalation experienced in California over that same period. As described in Exhibits 372 and 375, there are a number of factors which affect medical costs.

The welfare benefits consist of providing financial aid to employees in the event of injury, disability, or employee death. The welfare benefits that are included in the costs for this section are survivor benefits such as accidental death and dismemberment (AD&D) insurance, business travel insurance, and life insurance. The costs associated with disability and workers compensation benefits are addressed in a different part of this decision.

Retirement benefits include a defined benefit pension plan, a defined contribution (401k) retirement savings plan, and post-retirement health and welfare benefits. The retirement benefits that are included in the costs of this sub-section pertain to the 401k retirement savings plan, the nonqualified deferred compensation plan, and the supplemental pension plans. The costs of the defined benefit pension plan and PBOP benefits are discussed later in this section.

The other benefit program expenses cover the following: benefit administration fees and services; educational assistance; emergency day care; mass transit incentive; retirement activities; service recognition; and special events.

16.2.3. Position of the Parties

16.2.3.1. DRA

16.2.3.1.1. Compensation

With regard to compensation, DRA takes issue with the Applicants' short term incentive plans, the long term incentive programs, and the special recognition awards.[162]

The short term incentive plans are also referred to by the Applicants as the Incentive Compensation Plan (ICP). The ICP rewards employees for meeting goals regarding customer service, safety, supplier diversity, financial, and project completion. The ICP is based on financial and operating measures, and individual performance.

SDG&E forecasts a test year 2012 amount of $45.646 million for the ICP. DRA recommends that ratepayers only fund $12.600 million of the ICP.

DRA contends that SDG&E's Total Compensation Study shows that SDG&E's target ICP is 3.4% above the market,[163] and that the actual payout "is

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[162] DRA's position on the special recognition awards is described in DRA's position on employee benefits.

[163] DRA's testimony mistakenly refers to the target amount as being "1.4 percent above market." (Ex. 520 at 19.)

significantly above market and is out of range for various employee categories…." (Ex. 520 at 19.) DRA points out the following: for executive, actual ICP is 10% above market; for manager/supervisor, actual ICP is 6.8% above market; professional/technical, actual ICP is 5.8% above market; and physical/technical is 6.8% above market. Only the actual ICP paid to the clerical group is below market by 3.4%.

DRA contends that SDG&E's actual ICP payments have exceeded its target performance payouts from 2006-2010. As for Towers Watson's conclusion that SDG&E's total compensation is 3.4% above the average of the competitive market, DRA contends that is for the total of all the target compensation amounts and for all employee groups.

DRA recommends that SDG&E's 2010 target ICP amount of $43.962 million be used as the initial starting point to develop DRA's forecast of the test year 2012 ICP expense. Instead of having ratepayers fund 100% of the ICP, DRA contends that SDG&E shareholders should pay 100% of the $1.900 million in ICP costs for the executive category, and 70% of the remaining ICP expenses. DRA's recommended sharing formula results in ratepayers funding $12.6 million for SDG&E's 2012 ICP.

SoCalGas forecasts a test year 2012 amount of $29.408 million for the ICP. DRA recommends that ratepayers only fund $7.500 million of the ICP costs.

DRA contends that SoCalGas' Total Compensation Study shows that SoCalGas' target ICP is 1.4% above the market. However, DRA contends that SoCalGas' actual payout "is significantly above market and is out of range for various employee categories…." (Ex. 520 at 7.) DRA points out the following:

for manager/supervisor, actual ICP is 7.1% above market;

for professional/technical, actual ICP is 9% above market; and physical/technical is 4.4% above market.

The actual ICP paid to the executive group is below market by 2.1%.

DRA contends that SoCalGas' actual ICP payments have exceeded its target performance payouts from 2006-2010. As for Towers Watson's conclusion that SoCalGas' total compensation is 3.2% above the average of the competitive market, DRA contends that is for the total of all the target compensation amounts and for all employee groups.

DRA recommends that SoCalGas' 2010 target ICP amount of $26.350 million be used as the initial starting point to develop DRA's forecast of the test year 2012 ICP expense. Instead of having ratepayers fund 100% of the ICP, DRA contends that SoCalGas' shareholders should pay 100% of the $1.300 million in ICP costs for the executive category, and 70% of the remaining ICP expenses. DRA's recommended sharing formula results in ratepayers funding $7.500 million for SoCalGas' 2012 ICP.

DRA contends that its sharing proposal for the short term incentives is reasonable because it is unfair "to ask ratepayers to be solely responsible for ICP expenses each year when shareholders are reaping significant benefits." (Ex. 520 at 9.) DRA contends that actual ICP payouts have exceeded the targeted amounts, which indicates that financial performance has been above expectation. DRA further contends that if shareholders fund the ICP, there will be pressure for SDG&E and SoCalGas to meet performance measures, and to ensure that payouts are reasonable. DRA also points out that D.08-07-046, D.09-06-052, D.00-02-046, D.93-03-025, and D.11-05-018 all suggest that shareholders should be responsible for some portion of the ICP costs.

As for its recommendation that shareholders pay for 100% of the executive's ICP costs, DRA contends that the base salaries for the executives are already high, and that the executives also receive a number of additional benefits. DRA also contend that shareholders should be responsible for the costs of the short term incentives because the primary focus of the executives is on the interests of shareholders.

SDG&E and SoCalGas request funding for its long term incentive programs in the amounts of $10.148 million, and $5.361 million, respectively. DRA is opposed to any funding of the long term incentive programs for SDG&E and SoCalGas. DRA contends that the costs of the long term incentive programs have been excluded from rates in the past. DRA also contends that ratepayers should not have to pay for these costs because granting stock is clearly a shareholder-related expense, which does not provide any direct or identifiable benefit to ratepayers. DRA also cites to D.09-03-025 in which the Commission rejected SCE's request to include long term incentives in its forecast.

16.2.3.1.2. Employee Benefits

DRA also takes issues with the forecasts of the employee benefits.[164] SDG&E is requesting $81.947 million for these employee benefits, while DRA recommends $48.952 million. SoCalGas is requesting $98.189 million, while DRA recommends $60.660 million. DRA's recommendations are lower than the forecasts of SDG&E and SoCalGas for several reasons.

First, DRA uses a lower employee population count to calculate the cost of the employee benefits. DRA uses an employee count of 4241, as opposed to SDG&E's employee count of 5280. SoCalGas uses an employee count of 6236, while DRA uses an employee count of 5757. Since the RO model does not use the employee count or labor expense to forecast the employee benefits costs, "DRA divided each company's [test year] estimate by the [test year] population

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[164] For DRA's calculation of the employee benefits, DRA adds together the costs of health benefits, welfare benefits, retirement benefits, other benefit programs and fees, and the employee recognition program. (See Ex. 521 at 1; Ex. 372 at 2; Ex. 375 at 2; 28 R.T. 3686-3687.)

to arrive at a program cost per person, and then multiplied that program cost by DRA's estimated employee population to arrive at DRA's [test year] estimate." (Ex. 521 at 6.)

DRA's employee count adjustment affects various employee benefits, as shown in the table below, and as described below. DRA examined these other employee benefits and only made reductions to the forecasted amounts of SDG&E and SoCalGas based on the employee count adjustment.

($ in 000)

Name of Benefit	SDG&E Amount	DRA Adjusted SDG&E	SoCalGas Amount	DRA Adjusted SoCalGas
Dental	$3.420 million	$2.571 million	$3.675 million	$2.736 million
Vision	$375	$282	$487	$363
Employee Assistance Plan	$346	$260	$760	$566
Life Insurance	$738	$555	$906	$674
AD&D Insurance	$89	$67	$37	$28
Business Travel Insurance	$26	$20	$35	$26
Certain Other Benefit Programs[165]	$1.607	$1.205	$2.607	$1.863

For test year 2012 medical benefits, SDG&E forecasts $55.684 million, and SoCalGas forecasts $70.735 million. In addition to DRA's employee count

165 Except for its employee count adjustment, DRA does not take issue with the program costs for benefits administration fees, educational assistance, emergency childcare, and mass transit incentive.

adjustment, DRA takes issue with the medical escalation rates that SDG&E and SoCalGas used. DRA's second adjustment is to use Global Insight's forecast of medical escalation rates. DRA points out that SDG&E, SoCalGas, and DRA have used the Global Insight data to support other escalation rates in these proceedings. Global Insight forecasts the escalation of health care costs at 4.8% in 2010, 4.0% in 2011, and 4.10% in 2012. This is in contrast to the cost escalation rate of 12% that SDG&E and SoCalGas use for 2012, and 13% for 2011. As described in Exhibit 521, DRA contends that one source reports that the health care premium increases in California have averaged 8.5% from 2006-2010, and that other sources have reported average health care increases in 2009 of 4.5% to 6%, and in 2010 from 3% to 7%. As a result of applying DRA's employee count and cost escalation adjustments, DRA recommends a medical benefits forecast of $35.419 for SDG&E (instead of SDG&E's forecast of $55.684 million), and a forecast of $46.851 million for SoCalGas (instead of SoCalGas' forecast of $70.735 million).

For wellness benefits, DRA recommends that the amounts forecasted by SDG&E ($750,000) and SoCalGas ($795,000), be disallowed. DRA contends that ratepayers already fund the cost of the medical benefits and employee assistance benefits, which "essentially cover the same services that each company claims its Wellness program will cover." (Ex. 521 at 10.)

For mental health benefits, SDG&E forecasted $943,000, and SoCalGas forecasted $1.310 million. SDG&E and SoCalGas applied the same medical escalation rates to the mental health benefits, as it did for the medical benefits. Due to DRA's concern about the medical escalation rates, DRA recommends that the base year expense for each company be used to calculate the test year 2012 program cost, and that DRA's employee count adjustment be made. With these changes, DRA recommends $554,000 for SDG&E, and $770,000 for SoCalGas.

For the nonqualified retirement savings plans, SDG&E forecasted $217,000, and SoCalGas forecasted $146,000. DRA recommends that these amounts be disallowed because ratepayers should not have to "bear the costs of benefit programs in excess of federal limits and which serve to further enhance benefits to higher compensated employees." (Ex. 521 at 12.) DRA also contends that SDG&E and SoCalGas have not demonstrated that these benefits are needed to attract and retain skilled employees.

For the supplemental pension benefits, SDG&E forecasted $3.860 million, and SoCalGas forecasted $2.070 million. DRA recommends that these amounts be disallowed. DRA contends that ratepayers already fund the pension plan, which provides sufficient retirement benefits. DRA does not believe that ratepayers should have to pay for the costs of supplemental executive benefits that "exceed either what is authorized by the tax code and other pertinent laws and regulations, or what is offered as part of the company's normal employee coverage." (Ex. 521 at 13.) DRA contends that other states have disallowed supplemental pensions to executives.

For the 401(k) retirement savings plan benefits, SDG&E forecasts $12.974 million, and SoCalGas forecasts $13.791 million. SDG&E and SoCalGas both match 50% of employee contributions, up to 6% of eligible pay. The test year 2012 forecasts of SDG&E and SoCalGas were calculated by escalating the base year cost by their estimated match percentage of 3% for SDG&E, and 2.6% for SoCalGas. DRA recommends using each utility's actual historic match rate (2.3% for SDG&E, and 2.4% for SoCalGas) to calculate the test year 2012 costs.

With DRA's employee count adjustment, DRA recommends $8.020 million for SDG&E, and $9.784 million for SoCalGas.

DRA takes issue with certain other benefit programs that are not listed in DRA's employee count adjustment table. DRA recommends disallowance of all funding for the following: employee recognition ($422,000 for SDG&E, $579,000 for SoCalGas) retirement activities ($22,000 for SDG&E, $147,000 for SoCalGas); service recognition ($164,000 for SDG&E, $200,000 for SoCalGas); and special events ($310,000 for SDG&E, $452,000 for SoCalGas). DRA contends that these "employee benefit programs do not provide a clear and identifiable benefit to ratepayers," and "are not necessary or required for utility operations." (Ex. 521 at 17.) DRA contends that in D.93-12-043, D.05-04-037, and D.04-07-022, the Commission found that these kinds of expenses "fit the category of social, cultural, or charitable activities that should not be funded by ratepayers," or that such costs "do not present a clear ratepayer benefit." (Ex. 521 at 17.)

16.2.3.2. Joint Parties

The Joint Parties contend that the Commission should not rely on the two compensation studies prepared by Towers Watson. The Joint parties contend that the analysis by Towers Watson may not be independent because they may have received additional compensation that was paid for by ratepayers.

The Joint Parties also contend that the two studies did not compare the executive compensation of the Applicants to what the executives at the Los Angeles Department of Water and Power (LADWP) receive. The Joint Parties argue that LADWP is a relevant comparison because they are in the same geographic area as SoCalGas, and its total revenue is almost the same as the total revenue of SoCalGas. The Joint Parties contend that LADWP only has one employee who earns over $250,000, while SDG&E and SoCalGas combined have 93 people who earn over that amount, and 20 people who earn more than $400,000.

The Joint Parties contend that the impact of high or excessive executive compensation is that it affects and inflates compensation for the executives, managers, and professionals. The Joint Parties also contend that due to the high compensation, cost cutting at the executive and management levels becomes more difficult as these employees come to expect the other amenities and benefits associated with these higher paying positions.

The Joint Parties further contend that the economic condition of the ratepayers who have to pay for the executive compensation was not factored in by the Applicants or in the Towers Watson studies, and that 98% or more of the Applicants' employees "receive more than the median pay of ratepayers in their area," and receive health and other benefits that "are generally unavailable to 90% or more of the ratepayers." (Ex. 391 at 18.) The Joint Parties also argue that since local and state governments have been forced to cut back, that the Applicants should also lower their executive compensation packages. In addition, the Joint Parties contend that in a survey taken of over 200 SDG&E ratepayers, 171 of them were in favor of "a freeze on management and executive compensation salaries." (Ex. 391 at 20.)

16.2.3.3. TURN and UCAN

In analyzing executive compensation, TURN and UCAN contend that the Commission's consideration should include the following: (1) whether the compensation is similar to what is being requested by other utilities, and is the compensation appropriate to attract and retain talented managers; (2) whether offering compensation similar to that of other utilities is just and reasonable in light of the methods by which the compensation is set; (3) whether the employees being attracted and retained are necessary for the efficient operation of a regulated utility which benefits ratepayer; and (4) whether the compensation, in particular, stock-based incentive compensation, aligns the interests of utility management with shareholders and with ratepayers.

TURN and UCAN make several observations in Exhibit 543. One is to look at municipal utilities when considering the relationship of pay to performance. TURN and UCAN note in a table to Exhibit 543 that the compensation paid to the CEO of the Tennessee Valley Authority is half of what the CEO of Sempra earns. That table also notes that the CEO of LADWP makes $388,000.

TURN and UCAN also note that using a peer group or salary surveys to set compensation does not work very well because it can increase executive compensation if more utilities adopt the average reflected in the peer group study or salary survey. Also, choosing what other companies to include in the study or survey can affect the results if the companies chosen are larger.

TURN and UCAN performed an analysis of the compensation paid to five Sempra executives. TURN and UCAN contend that this analysis shows that "pay is not linked to performance, and that Sempra compensation appears high," and therefore the Commission should not "rubber-stamp incentive compensation for executives." (Ex.543 at 18.)

For long term incentive compensation, TURN and UCAN recommend that the Commission follow the decision in SCE's 2009 GRC and disallow all funding. TURN and UCAN contend that stock-based compensation only provides incentives to increase the stock price, and that the stock price does not provide any material benefits to ratepayers. TURN and UCAN also note that this type of compensation focuses primarily on a few executives.

With respect to SoCalGas' short term incentives such as the ICP, TURN and UCAN recommend that UCAN's recommendation on SDG&E's ICP, as described below, be followed for SoCalGas.

UCAN contends that SDG&E's incentive compensation program does not "adequately measure the quality and cost of SDG&E's electric service," and "provides weak or non-existent incentives for managers to control electricity rates or to provide safe and reliable electric service." (Ex. 557 at 15.) Instead, UCAN contends that SDG&E's ICP amounts to a "guaranteed annual bonus." (*Ibid*.)

In support of UCAN's contentions, it points out that SDG&E's actual ICP payouts have exceeded the target payouts in every year from 2003-2010, and have "benefited the vast majority of SDG&E's ICP-eligible employees." (Ex. 557 at 17.) Of these employees, UCAN contends that SDG&E's executives have disproportionately benefited from the ICP.

UCAN also contends that the data regarding SDG&E's reliability performance shows little or no correlation with SDG&E's ICP payouts. UCAN further contends that SDG&E's financial performance, which is a performance measure in the ICP, has not resulted in benefits for SDG&E's electric ratepayers.

As described in Exhibit 557, UCAN recommends that SDG&E's ICP performance measures be revised to "focus on safety, reliability, and performance, with a smaller share of the ICP to be based on the secondary priorities of customer service and operational excellence." (Ex. 557 at 28.) UCAN also favors revising the weight given to different performance measures. If UCAN's revisions are adopted to SDG&E's ICP, UCAN favors funding of the

ICP at $45.600 million. However, if no revisions are made to SDG&E's ICP, UCAN recommends no funding for the ICP.

TURN and UCAN also take issue with the employee benefits for both SDG&E and SoCalGas. Regarding the medical benefits, TURN and UCAN do not object to DRA's forecasts for both utilities, but propose alternative recommendations if the Commission does not adopt DRA's recommendations. The alternative recommendations of TURN and UCAN are based on a lower per employee cost using the lowest cost medical plan. TURN and UCAN acknowledge that medical coverage is an important part of an employee's non-monetary compensation, but that does not mean "that ratepayers should be paying for the choices of some employees to choose the most expensive coverage when other more affordable options are available." (Ex. 559 at 16; *See* Ex. 548 at 17.) Using the lowest cost medical plan will result in a program cost of $48.462 million for SDG&E, using SDG&E's employee headcount. If DRA's employee count is used, the program cost would be $36.428 million. Using SoCalGas' employee headcount, the medical plan program cost will result in $64.345 million. If DRA's employee count is used, the forecast for SoCalGas would be $47.897 million.

On the wellness benefit, TURN and UCAN support this type of program, but believes that SDG&E and SoCalGas have overstated the funding amount needed to support such programs. For SDG&E, UCAN recommends that the wellness expense be based on the three-year average of 2007-2009, which results in $338,000. For SoCalGas, TURN recommends that the wellness expense be based on the six-year average of 2005-2010, which results in $409,000.

TURN and UCAN recommend disallowance of all funding for retirement activities for SDG&E and SoCalGas. Their reasoning for doing so is that the gifts and parties are for past service, and contributions to the company's success.

TURN and UCAN also agree with DRA's recommendation to disallow all funding for special events night because there is no clear ratepayer benefit. If the Commission decides to fund this activity, UCAN recommends $201,000. For SoCalGas, TURN recommends funding of $200,000.

TURN and UCAN are also opposed to the funding requests of SDG&E and SoCalGas for Employee Recognition awards. TURN and UCAN agree with DRA's recommendation to disallow ratepayer funding of this activity. In the event the Commission allows funding, UCAN recommends that the test year 2012 amount be no higher than $247,000 for SDG&E. For SoCalGas, TURN recommends that the test year 2012 amount be no higher than $242,000. The recommendations of TURN and UCAN reflect the cost per employee for 2008 and 2009, multiplied by the recorded 2010 employee count.

On SDG&E's spot cash award program, for which SDG&E has requested $1.325 million in funding, UCAN contends that the program fails to provide adequate incentives to promote employee behaviors that benefit ratepayers, and that the spot cash award program is vague and may overlap with ICP payments. UCAN contends that SDG&E does not keep detailed records on this program, and that it appears employees are being rewarded for what should be included as part of the employee's regular work activities. UCAN recommends that SDG&E's spot cash award program be funded entirely by shareholders.

16.2.3.4. SDG&E and SoCalGas

16.2.3.4.1. Compensation

Regarding their respective requests for compensation funding, SDG&E and SoCalGas contend that their incentive compensation is one piece of the total compensation package, and that "[m]aintaining a competitive, market-based compensation and benefits program is critical to attracting, retaining and motivating a skilled, high-performing workforce." (Ex. 374 at 2; Ex. 377 at 2.) SDG&E and SoCalGas also contend that their respective target total compensation is within 3.4% and 3.2% of the market, which "falls within the Commission's previous determination that compensation levels that fall between plus or minus five percent of the relevant market are considered to be 'at market' and reasonable." (*Ibid*.) The Applicants also contend that compensation professionals "consider a range of plus or minus 10 percent of the average of the external market data to be competitive and broader ranges are common and expected for long term incentive plans and benefits." (Ex. 372 at 4; Ex. 375 at 4; *See* Towers Watson Studies at 6.) For those reasons, SDG&E and SoCalGas disagree with the contentions of the other parties that the compensation paid to their respective executives is excessive.

As for the Joint Parties contention that the Total Compensation Study for both utilities was not independent, the Applicants contend that Towers Watson was jointly selected by DRA, SDG&E, and SoCalGas, following a competitive selection process. In addition, "DRA was actively involved in all aspects of the study, including selection of the consultant and review and approval of the Study methodology, the results and the Total Compensation Study report." (Ex. 374 at 17; Ex. 377 at 15.)

Regarding the Joint Parties' contention that Towers Watson did not consider the LADWP salary data, the Applicants contend that the studies did not focus on one individual company, but instead used two peer groups "composed of 31 utility industry companies and 31 general industry companies comparable in annual revenues to Sempra," which is "the most relevant assessment of the competitiveness of total compensation." (Ex. 390 at 3.) The Applicants also contend that LADWP is a municipal organization, whose employees are employed by the City of Los Angeles, and that "LADWP was included in the peer group used for non-executive positions in the Study and all peer company data was weighed equally for these non-executive positions." (Ex. 390 at 7.) The executive positions at LADWP were not used in the two studies for the pay of the executives because LADWP is "a very different organization than an investor-owned utility overall," and has a very different operating structure, governance structure, and frankly, compensation and benefits structure." (28 R.T. 3800, 3803.)

The short term incentive compensation consists of the ICP for SDG&E and SoCalGas. The Applicants contend that the ICP "rewards employee contributions to meeting key safety, diversity, customer service, financial and strategic project goals." (Ex. 374 at 4; Ex. 377 at 4.) The Applicants also state that the ICP measures individual and company performance, and that virtually all of the non-represented employees participate in the ICP. According to the Applicants, "a portion of their total compensation is at risk based on meeting performance goals." (*Ibid*.)

SDG&E and SoCalGas contend that DRA is presenting a distorted view of the Applicants' ICP because DRA's arguments focus on the actual ICP compensation that was paid by the Applicants, and not on the target ICP expenses. The Applicants also point out that they are requesting cost recovery based on the target total compensation, and not on actual total compensation paid. As such, ICP compensation above the target is paid for by their shareholders.

The Applicants contend that their ICP is an important part of their competitive compensation package, and should not be treated any differently than base pay for cost recovery. The Applicants cite to D.92-12-057 and D.04-07-022 to support their argument that "incentive pay is part and parcel of the overall compensation scheme," and that the incentive pay could take the form of base pay, which would be recoverable from ratepayers so long as the total compensation does not exceed market levels. Consistent with these decisions, the Applicants contend that they should receive full cost recovery for their ICP expenses.

DRA argues that the financial performance measure of the ICP benefits only shareholders, and that the operational measure benefits ratepayers and shareholders equally. The Applicants dispute DRA's argument, and contends that a financially strong company will usually have lower financing costs, which will reduce the cost of utility projects, which in turn benefits ratepayers. As for the operational measures, the Applicants contend that the operational metric is related to customer satisfaction, safety, supplier diversity, and completion of major projects, all of which benefit ratepayers.

DRA also recommends that there be no ratepayer funding of the executive benefit programs because the executives are already highly compensated. The Applicants contend that these executive benefits, such as the ICP, long term incentives, nonqualified deferred compensation, and the nonqualified pension plans, are all part of the reasonable, and at market, total compensation package as described in the Total Compensation Study for SDG&E and SoCalGas.

The Applicants are opposed to the recommendations of TURN and UCAN to redesign the ICPs of both SDG&E and SoCalGas to conform to the revisions suggested by UCAN. The Applicants contend that "[c]ost recovery for incentive compensation should be treated no differently than base pay," and that the "allocation of total compensation between base pay and incentive compensation and the design of the incentive plans should be based on the company's discretion and not micromanaged by UCAN or any other party." (Ex. 374 at 8-9; Ex. 377 at 8-9.)

SDG&E is opposed to UCAN's recommendation that SDG&E's ICP be revised to adopt UCAN's safety performance measure, and a reliability performance measure based on five years of reliability measurements. SDG&E contends that it would be inappropriate to adopt a safety metric that combines injury statistics from the Division of Occupational Safety and Health, and compliance with GO 165 regarding inspection of electric distribution facilities. As for the reliability measures (SAIDI and SAIFI) that UCAN seeks to include for the ICP, SDG&E contend the Commission has never ordered any utility to include specific targets as part of their compensation programs. SDG&E also contends that the Commission should refrain from micromanaging the targets or weightings in the ICP, and that compensation incentives should be left to the utilities.

DRA, TURN, and UCAN recommend that 100% of the long term incentive plan expenses be disallowed. The Applicants contend that long term incentives "are a critical component of a competitive compensation and benefits package needed to attract, motivate and retain key management employees," and according to one compensation source, "89% of [United States] companies provide at least one long term incentive program." (Ex. 374 at 11; Ex. 377 at 9.) The long term incentives are in the form of performance-based restricted stock units, and are tied to a four year performance period which encourages employee retention and long term company performance. The Applicants point out that long term incentives also extend to some employees below the executive level.

The Applicants contend that since the Total Compensation Study for SDG&E and SoCalGas both found their respective total compensation to be competitive, that "DRA should not be able to selectively exclude specific components of compensation from the revenue requirement." (Ex. 374 at 11; Ex. 377 at 10.)

DRA, TURN, and UCAN recommend that the expense associated with the Employee Recognition program for SDG&E ($422,000) and SoCalGas ($579,000) be disallowed. The Applicants note that the Employee Recognition Program is one of two special recognition programs that SDG&E and SoCalGas have requested funding for. The other special recognition program is the Spot Cash Program. However, DRA did not address the Spot Cash Program in its testimony.

According to the Applicants, the special recognition programs are used by SDG&E and SoCalGas "to recognize outstanding achievements, exceptional customer service and process improvements and innovations," and are commonly used by many companies to recognize employees or team. (Ex. 374 at 14; Ex. 377 at 12.) The Employee Recognition awards are non-cash awards usually with a value of $100 or less. The Spot Cash awards are cash awards that range from $250 to $10,000. The Applicants contend that both of these award programs confer ratepayer benefit because of "improved customer services, increased reliability and a safer work environment." (Ex. 374 at 14; Ex. 377 at 13.)

16.2.3.4.2. Employee Benefits

The Applicants contend that in developing the forecasts for employee benefits, the forecasts are based primarily "on the number of employees, or headcount, as benefit costs are driven specifically by the number of employees receiving these benefits." (Ex. 374 at 19; Ex. 377 at 17.) In deriving the employee benefits, DRA used a lower employee count than what SDG&E and SoCalGas used. The Applicants contend that DRA's employee count is based on FTEs. The Applicants contend that "FTEs are an accumulation of part-time and full-time labor hours converted to 40-hour units," and that "headcount and FTEs are fundamentally different and are not interchangeable." (Ex. 374 at 18-19; Ex. 377 at 16-17.) An "FTE position is a calculation of activity level and does not represent the actual number of employees performing the work," which the Applicants contend produces inaccurate and unreliable forecasts for employee benefits. (Ex. 374 at 19; Ex. 377 at 17.) As described in Exhibits 374 and 377, the Applicants contend that DRA's use of FTEs to calculate the employee benefits for both companies understates the revenue requirement that is needed. The Applicants also contend that the recommendations of TURN and UCAN to reduce DRA's forecasts of employee benefits would further understate the amount of funding that is needed to provide the employee benefits.

DRA, TURN, and UCAN take issue with the forecasts of SDG&E and SoCalGas regarding medical benefits. The test year 2012 forecast of $55.684 million for SDG&E, and $70.735 million for SoCalGas, were "based on actual medical premium rate increases for 2009, 2010 and a forecast of 2011 and of 2012 rates." (Ex. 374 at 25; Ex. 377 at 23.) The "2011 increase in medical rates was within rounding of the 13% projected increase for 2011," and as a result of negotiations, the overall rate increase for 2012 is 6.8% instead of the forecast of the 12% increase that was forecasted. (*Ibid*.)

The Applicants contend that DRA's recommendation of using the Global Insight escalation rates to escalate the costs of medical benefits ignores the actual medical cost escalation that both companies faced in 2010 of 3.5% and in 2011 of 13%. The Applicants contends that DRA's use of Global Insight's escalation forecasts is inappropriate because it includes non-medical benefits such as dental and vision benefits, and is also affected when other companies in the index eliminate health benefit coverage. Also, the index used by Global Insight reports nationwide medical escalation, while California's medical escalation has generally exceeded the nationwide trends. The Applicants also contend that its medical cost escalation is consistent with what other California employers have experienced, including the California Public Employees' Retirement System which is the third largest purchaser of health care in the United States.

As for the alternate recommendations of TURN and UCAN to use the lowest cost medical plan to determine the medical benefit program costs, the Applicants contend that the cost sharing arrangements for an employee's choice of medical plan already encourages employees to select the lowest cost plan.

Since DRA's reduction of the program costs for the dental, vision, employee assistance, life insurance, accidental death and dismemberment, business travel insurance, and certain other benefit programs, offered by the Applicants is based on DRA's employee count adjustment, the Applicants oppose DRA's forecasts.

On DRA's disallowance of the wellness program costs, the Applicants contend that helping employees to manage their health provides benefits to the employees, the company, and to ratepayers. By providing onsite wellness programs, this provides convenient and easy access to employees, encourages employee participation, and reduces medical and sick leave costs.

For mental health benefits, the Applicants oppose DRA's forecasted amounts because DRA did not use any medical escalation, and because DRA made its employee count adjustment. The Applicants contend that medical escalation was appropriately included in their forecasts because the costs of mental health have continued to increase.

For the retirement savings plan benefits, DRA applied the five-year historical average contribution rate "to the average estimated eligible compensation per employee to determine the average company matching contribution per employee." (Ex. 374 at38; Ex. 377 at 35.) TURN and UCAN also made adjustments. The Applicants contend that their forecasts should be used, and that the adjustments that DRA, TURN and UCAN made should not be adopted.

The Applicants oppose DRA's recommendations that the funding requests for the nonqualified savings plans be disallowed. The Applicants contend that deferred compensation plans are part of a competitive compensation and benefits package, and that according to one executive compensation survey, that 77% of companies surveyed offer such plans. The Applicants also contend that such plans promote "successful recruiting of the best possible candidates for positions at the executive, director, attorney and management levels." (Ex. 374 at 39; Ex. 377 at 37.)

The Applicants also oppose DRA's recommendation to disallow funding for supplemental pension plans, which take the form of the Supplemental Executive Retirement Plan, and the Cash Balance Restoration Plan. The Applicants contend that supplemental pension plans are an important piece of a competitive compensation and benefits package for executive and other key employees, and that such benefits are common with other companies, including other utilities.

The Applicants also oppose DRA's recommendations to disallow all funding for retirement activities, service recognition, and special events. The Applicants contend that such programs "help to maintain employee engagement, productivity and morale." (Ex. 377 at 39; *See* Ex. 374 at 41.) The modest level of funding allows managers and supervisors to recognize key events in an employee's career. As for the alternate recommendations of TURN and UCAN to reduce the amount to the 2007 recorded amount, the Applicants contend that only some of the special event night costs were recorded in 2007, and that the balance of the expense was recorded in 2008.

16.2.4. Discussion

16.2.4.1. Preliminary Issues

In determining whether the funding requested for the compensation and employee benefits costs are reasonable or not, the starting point is to inquire whether the compensation and employees benefits are comparable to what is being offered by other employers. To aid in that evaluation, the Total Compensation Study for both SDG&E and SoCalGas provide that guidance.

Although the Joint Parties have questioned the impartiality and validity of those two studies, we are not persuaded by those arguments. First DRA had a role in choosing Towers Watson to prepare the studies, and also participated in the formation of the two studies. Second, the wages of the executives at LADWP do not provide an apples to apples comparison of the wages and benefits that the executives at SDG&E and SoCalGas make. LADWP is a municipal utility, whose employees are city employees. As such, their wages and benefits are restricted, and are not comparable to what executives make at investor-owned utilities. To only compare the wages and benefits that executives make at LADWP to what executives make at SDG&E and SoCalGas would be an unfair comparison. Third, the Total Compensation Study for both utilities used data from a number of other utilities, as well as data from non-utility companies comparable in revenue size to SDG&E and SoCalGas. These sixty or so companies provide a relevant comparison to what SDG&E and SoCalGas executives should make.

The Joint Parties and UCAN also contend that the compensation of the executives and other employees at SDG&E and SoCalGas is excessive in light of the economic circumstances that face us, and as compared to what other wage earners make. However, such arguments overlook the type of skills and experience that are needed to successfully and safely operate gas and electric utilities. As the Total Compensation Study for both companies show, the target total compensation of both utilities is within the market compensation level. If compensation and benefits are reduced, other utilities or companies may be able to attract these executives and skilled workers. As for the Joint Parties' comparison to workers who do not enjoy the same kinds of compensation and benefits, part of that is based on life circumstances and choices, and the other part is based on SDG&E and SoCalGas being able to attract and retain skilled workers. For those reasons, we do not agree with the arguments that wages and benefits should be frozen or reduced as a result.[166]

Based on the Total Compensation Study, we agree that both studies have determined that the target total compensation of SDG&E and SoCalGas is within the market compensation level of what is being offered by comparable companies.[167] However, that does not mean that the Commission should ignore the individual components that make up the compensation and employee benefits packages, and simply approve the entire amounts that SDG&E and SoCalGas have requested. Each of the components of such packages still need to

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166 We note however, that economic conditions do play a role in determining whether a particular cost that is paid for by a ratepayer, is reasonable or not.

167 In D.95-12-055, the Commission stated the "Total compensation that is, on average, 105% of market levels is likely to be well within the range of compensation in relevant markets." (63 CPUC2d at 591.)

be examined to ensure that the costs are related to the provisioning of utility service, and that the costs are reasonable to ratepayers.

16.2.4.2. Compensation

DRA, TURN, and UCAN take issue with various compensation components. The first component is short term incentives, or what SDG&E and SoCalGas refer to as the ICP.

DRA contends that ratepayers should not have to pay for any of the ICP costs for the executives of SDG&E and SoCalGas. This is based on DRA's argument that the actual ICP that has been awarded exceeds 5% of the market compensation level, and that the executives are already highly compensated. The Applicants point out that they are only requesting funding of the target compensation which is within the 5% range, and that any ICP paid above that funding level will be borne by shareholders. TURN and UCAN are also opposed to funding of the short term incentives unless the ICP for both SDG&E and SoCalGas are revised as UCAN has suggested.

We have reviewed and considered the positions of the parties and their arguments about whether executive ICP costs should be disallowed. We are not persuaded by DRA's argument that ratepayers should not have to pay for any of these costs. The ICP is part of the compensation to attract and retain executives and other employees. The ICP uses operating, individual performance, and financial metrics in deciding whether the executives will receive any ICP compensation. We disagree with DRA's contention that the primary focus of the executives, and others who qualify for the ICP, is on the interests of shareholders. The operating and individual performance metrics benefit ratepayers in ensuring that the executives are carrying out directives and activities to ensure the operational safety and reliability of the utility systems of SDG&E and SoCalGas. At the same time, the financial metric is of benefit to shareholders who in theory will see the price of the stock move upwards. However, at the same time, the financial metric may benefit ratepayers as a result of the companies' lower borrowing costs.

With respect to the argument of TURN and UCAN that the metrics for the ICPs of SDG&E and SoCalGas should be revised, we do not adopt that suggestion. SDG&E and SoCalGas are in the best position to decide what metrics to use to measure the performance of its employees, and to revise the metrics as UCAN has suggested would result in the Commission's micromanaging of the Applicants' variable compensation.

Based on all of those considerations, and our analysis of past Commission decisions in which the treatment of short term incentive compensation has varied, it is reasonable to reduce the cost of the short term incentives for both SDG&E and SoCalGas by 50% to reflect the benefits that shareholders receive from having a financially strong company, while recognizing that short term incentive compensation is a valuable tool for attracting and retaining skilled professionals to run and manage the companies. Accordingly, the short term incentive cost for SDG&E shall be reduced from $45.646 million to $22.823 million, and the short term incentive cost for SoCalGas shall be reduced from $29.408 million to $14.704 million.

The second component of compensation is long term incentive compensation, which takes the form of stock-based compensation. DRA, TURN and UCAN contend that since the executives and other upper level managers are compensated with stock, that this type of compensation is tied to the companies' financial performance which benefits only shareholders. Since only shareholders benefit, DRA, TURN and UCAN contend that the costs of long term compensation should be borne by shareholders. SDG&E and SoCalGas contend that long term compensation is necessary to attract, retain, and motivate their employees, and that many comparable companies offer the same type of long term incentive compensation.

In deciding who should pay for the cost of long term compensation, we need to examine whether ratepayers or shareholders benefit from such compensation programs, and how the Commission has treated such costs in the past. This type of compensation is stock-based, which means that when employees are awarded these stock units, that the value of the stock units will grow if the company's stock price increases. Since the long term compensation of both SDG&E and SoCalGas are based on four years of financial performance, these factors all point to benefits which accrue to shareholders. However, this type of compensation also benefits shareholders and ratepayers by attracting and retaining employees who are familiar with the corporate culture and goals of the two companies. As the Applicants point out, a financially strong company usually has lower borrowing costs, which benefits ratepayers by lowering costs. With regard to the Commission's past treatment of long term compensation, our review of the decisions show that the Commission has generally disallowed long term incentive compensation.

Although many companies offer long term compensation plans, that does not necessarily mean that ratepayers should have to pay for the costs of funding such a program. In considering whether such costs are reasonable, the benefit of this type of compensation plan clearly benefits the executives and shareholders if the value of the stock goes up. Since this stock-based compensation is tied to financial performance over a period of time, that clearly demonstrates that a premium is being placed on the companies' financial performance. In addition, the employees who received the stock-based compensation are already highly compensated through their base pay, and the short term incentive compensation. Another consideration is the cost to ratepayers, who see little benefit from such a program, but face increased costs if the cost of the long term incentive compensation program is included in the revenue requirement. Based on all these considerations, and given the state of the economy and the benefits that shareholders receive, it is reasonable to disallow ratepayer funding of the costs of the long term incentive compensation program for SDG&E in the amount of $10.148 million, and for SoCalGas in the amount of $5.361 million.

The third component of compensation is the special recognition awards. For SDG&E and SoCalGas, this takes the form of two programs, Employee Recognition, and the Spot Cash Program. DRA's testimony only took issue with the costs of the Employee Recognition program. UCAN recommends that SDG&E's Spot Cash Program be funded entirely by shareholders. We have reviewed the testimony and arguments of the parties concerning these two compensation-related programs. The Employee Recognition and Spot Cash programs provide SDG&E and SoCalGas with the ability to reward employees who help improve the operations of the company, or provide exceptional service, or otherwise distinguish themselves among their peers. We are not persuaded by UCAN's argument that the criteria for an award under these two programs are vague. Given the modest cost of these two programs, and the relationship of the employees' recognition to their job activities, it is reasonable that the program costs of the Employee Recognition and Spot Cash programs be paid for by ratepayers.

16.2.4.3. Employee Benefits

DRA, TURN and UCAN take issue with various aspects of the employee benefits that are offered by SDG&E and SoCalGas.

One of the issues that affect the costs of most of the employee benefits is the number of employees. DRA's forecasts of the employee benefits are based on an employee count which uses FTEs. DRA's employee count is about 1000 employees less than what SDG&E uses, and about 500 less than what SoCalGas uses. SDG&E and SoCalGas use the actual number of employees to calculate its employee benefits costs. SDG&E and SoCalGas contend that DRA's use of FTEs for its employee count is erroneous and results in an understatement of the costs of the employee benefits.

We have reviewed the testimony and arguments of the parties concerning how the costs of the employee benefits should be based upon. We agree with SDG&E and SoCalGas that the actual number of employees should be used to calculate the costs of the employee benefits, and accordingly have used their forecasts for these costs. Since we do not adopt DRA's employee count adjustment, and because no other party takes issue with the forecasted amounts, the costs that SDG&E and SoCalGas have forecasted for the following are reasonable: (1) for dental, $3.420 million for SDG&E, and $3.675 million for SoCalGas; (2) for vision, $375,000 for SDG&E, and $487,000 for SoCalGas; (3) for employee assistance plan, $346,000 for SDG&E, and $760,000 for SoCalGas; (4) for life insurance, $738,000 for SDG&E, and $906,000 for SoCalGas; (5) for AD&D insurance, $89,000 for SDG&E, and $37,000 for SoCalGas; (6) for business travel insurance, $26,000 for SDG&E, and $35,000 for SoCalGas; and (7) for benefits administration fees, educational assistance, emergency childcare, and mass transit incentive, $1.607 million for SDG&E, and $2.607 million for SoCalGas.

For the medical benefits, DRA's forecast is lower due to its employee count adjustment, and because of its use of the Global Insight health escalation rates, which are lower than the medical escalation rates used by SDG&E and SoCalGas. The forecasts of TURN and UCAN for SoCalGas and SDG&E are lower due to their recommendations to limit the costs of the medical benefits to the lowest cost medical plan.

We have reviewed the testimony and arguments of the parties, and reviewed the historical costs of the medical benefits and compared them to the parties' forecasts. Regarding the medical escalation rates, we believe that the escalation rates that SDG&E and SoCalGas propose will overestimate the cost of medical benefits, while DRA's use of the Global Insight's health escalation rates will tend to underestimate the cost of medical benefits. To arrive at a reasonable amount for medical benefits, the different escalation rates, and the difference between the costs of the historical and forecasted medical benefits must be considered. Under the circumstances, it is reasonable to adopt $50.115 million for SDG&E's medical benefits costs, and $63.660 million for SoCalGas' medical benefits costs.

As for the recommendation of TURN and UCAN to reduce the costs of the medical benefits based solely on the lowest cost medical plan, we do not adopt that recommendation. Offering a variety of medical plans to employees allows employees to choose the plan that best fits their individual needs. Although this may result in higher costs, it is reasonable to allow SDG&E and SoCalGas the flexibility to offer different medical plans to its employees.

For the wellness benefits, DRA opposes all ratepayer funding. TURN and UCAN support such programs, but recommends that the costs of the programs be reduced from SDG&E's forecast of $750,000 to $338,000, and from SoCalGas' forecast of $795,000 to $409,000. We do not agree with DRA's argument that the wellness benefits overlaps with the medical benefits. The wellness benefits help promote activities that lead to better health choices, and to lower overall costs. As for the recommendations of TURN and UCAN to reduce the costs of the wellness benefits, we have compared the different forecasts to the historical costs. The forecasts of SDG&E and SoCalGas for the wellness benefits are in line with historical costs. Accordingly, the forecast amounts of SDG&E and SoCalGas are reasonable and should be adopted.

Regarding the mental health benefits, DRA's forecasts are lower because of its employee count adjustment, and because it does not believe that the Applicants should have applied the medical escalation rates. We do not agree with DRA's reductions. As SDG&E and SoCalGas point out, mental health benefit costs have also increased, and that medical escalation rates should be applied. It is reasonable to adopt the forecasts of SDG&E and SoCalGas for these costs.

DRA recommends that ratepayers be excluded from paying the costs of the nonqualified retirement savings plans, and the supplemental pension plans, for both SDG&E and SoCalGas. We have reviewed and considered the testimony and arguments of the Applicants and DRA concerning the costs of these two plans. These types of plans primarily benefit the executives at both companies, and their shareholders, because such plans are offered to entice them to work at the two companies for a prolonged period of time. These plans also provide ratepayers with the benefit of having a continuity of executives and managers who are familiar with the corporate culture and the policies and objectives of the companies. For those reasons, it is reasonable and appropriate for ratepayers and shareholders to equally share in these costs. Accordingly, the ratepayers' share of the nonqualified retirement savings plans for SDG&E is $108,500, and $73,000 for SoCalGas. The ratepayer's share of the supplemental pension benefits is $1.930 million for SDG&E, and $1.035 million for SoCalGas.

Regarding the 401(k) retirement savings plan, DRA, TURN, and UCAN recommend lower forecasts due to their use of different matching percentages. We reviewed the testimony and arguments of the parties, but are not persuaded that the amounts forecasted by SDG&E and SoCalGas need to be changed.

DRA recommends no ratepayer funding for retirement activities, special events, and service recognition. TURN and UCAN agree with DRA's recommendation that there be no ratepayer funding for retirement activities and special events. We have considered the testimony and arguments of the parties concerning these three employee benefits. We agree with DRA, TURN, and UCAN that the funding requests for retirement activities and special events should not be borne by ratepayers. These two benefits are in the nature of programs that build loyalty and camaraderie between current and former employees with their respective companies, and are not related to any of their companies' job-related activities. For those reasons, we remove the costs of the retirement activities, and special events, from the revenue requirement of both companies.

With respect to service recognition, this is related somewhat to the employees' job activities and continuity of employment, but is also related to building loyalty between the employees and the companies. It is reasonable to have ratepayers bear 50% of these costs. Accordingly, SDG&E's service recognition costs shall be reduced from $164,000 to $82,000, and SoCalGas' service recognition costs shall be reduced from $200,000 to $100,000.

16.3. Pensions and Other Related Benefits

16.3.1. Background

This sub-section addresses the reasonableness of the qualified retirement benefits at SDG&E and SoCalGas. These retirement benefits include pension plans, and post-retirement benefits other than pension (PBOP).

According to the Applicants, the pension plans and the PBOP are key components of the total compensation package that is provided to the non-represented and represented employees at SDG&E and SoCalGas.

16.3.1.1. Pension Plans

SDG&E's pension plan consists of its "Company Cash Balance Plan," while SoCalGas plan consists of its "Pension Plan."[168] The SDG&E pension plan "provides benefits to approximately 4,650 active employees and 3,150 retirees, survivors, and terminated participants entitled to future benefits." (Ex. 404 at 1.) The SoCalGas pension plan "provides benefits to approximately 7,100 active employees and 6,700 retirees, survivors and terminated participants entitled to future benefits." (Ex. 406 at 1.)

The SDG&E pension plan consists of two types of pension benefits. The first is SDG&E's defined benefit pension plan, which provides "a retirement benefit based on final average earnings and years of service." (Ex. 404 at 1.) SDG&E's defined benefit pension plan applies to a non-represented employee

[168] We generally refer to the pension plan of each utility as the "SDG&E pension plan," or the "SoCalGas pension plan."

hired before July 1, 1998, and a represented employee hired before November 1, 1998. Benefit accruals under the defined benefit pension plan were frozen as of June 30, 2003.

SDG&E's second pension plan is the Cash Balance Plan, which applies to everyone after June 30, 2003. Under the Cash Balance Plan, participants "receive retirement credits equal to 7.5% of eligible earnings and interest on their account balances up to the date of distribution."(Ex. 404 at 2.)

The SoCalGas pension plan also consists of two types of pension benefits. The first is SoCalGas' defined benefit pension plan, which provides its represented employees with "a retirement benefit based on final average earnings and years of service." (Ex. 406 at 1.)

For SoCalGas' non-represented employees, prior to July 1, 1998, they participated in the same type of plan as the union employees. Beginning July 1, 1998, non-represented employees began participating in the Cash Balance Plan. Benefit accruals for non-represented employees under the defined benefit pension plan were frozen as of June 30, 2003.

For test year 2012, the pension benefit cost estimate for SDG&E is $84.250 million (including the $2 million surety bond), and the pension benefit cost estimate for SoCalGas is $110.060 million.[169] However, due to the "difficult economic circumstances facing many" of their customers, and to "lower the requested [test year] 2012 revenue requirement in an effort to help mitigate the rate pressures that customers would otherwise experience," SDG&E and

[169] The Applicants note that because "pension contributions are difficult to project with certainty due to the impacts of numerous external variables," the current estimates for 2012 are "very likely to change." (Ex. 404 at 3; Ex. 406 at 3.)

SoCalGas propose to hold the PBOP funding at their 2009 recorded levels.[170] (*See* Ex. 1 at 18; Ex. 2 at 15; Ex. 404 at 3; Ex. 406 at 3.) This proposal is contingent on the Commission also approving the Applicants' request to continue the two-way balancing account treatment for pension benefits and PBOP expenses.

For SDG&E, the 2009 recorded funding level for the pension benefit was $58.483 million, including the $1.650 million surety bond. The 2009 recorded funding level for SoCalGas was $75.105 million. Under their proposal, SDG&E and SoCalGas will continue in 2012 making the annual actual pension funding as required by law, and the annual actual PBOP funding as required by prescribed actuarial calculations. (*See* Ex. 1 at 18; Ex. 2 at 16.) Any shortfall or surplus "from the 2009 recorded level of expense will be recorded in the pension and/or PBOP balancing accounts for recovery in the subsequent year." (*Ibid*.) According to the Applicants, this will benefit their customers by delaying for at least one year the projected $25.767 million increase in pension benefit cost for SDG&E, and the projected $34.955 million increase for SoCalGas.

The Applicants request that the two-way balancing account for pension benefits and PBOP continue. The Applicants contend that the "Commission has consistently approved the use of a two-way balancing account as the mechanism for addressing the risk of variability in pension expense." (Ex. 404 at 12; Ex. 406 at 12.) The Applicants also request that they be allowed to continue the annual amortization of these two balancing accounts as part of their annual regulatory account update AL filing. They also request that their respective

[170] By delaying the 2012 increase for one year, the Applicants contend that this may mitigate future pension funding requirements by allowing for a return to historical market returns.

balancing accounts provide that the minimum required pension contribution and revenue requirement be increased in order to maintain the pension plans at a funded status of at least 85%.

16.3.1.2. Post-Retirement Benefits Other Than Pension

Post-retirement benefits other than pension or PBOP, refers to post-retirement health and life insurance benefits. Represented and non-represented employees of both utilities are eligible for PBOP upon their retirement if they meet certain eligibility criteria. Depending on the whether the employee is represented or non-represented, the PBOP consists of medical, dental, vision, health reimbursement account, and term life insurance.

For test year 2012, the PBOP cost estimate for SDG&E is $16.480 million, and the PBOP cost estimate for SoCalGas is $41.930 million. These cost estimates are based on an annual certified actuarial valuation. The PBOP expense is also included in the Applicants' proposal to keep the test year 2012 at the 2009 recorded level, subject to adjustment in the two-way balancing account in 2013. For SDG&E, the 2009 recorded funding level for PBOP was $15.554 million, and the 2009 recorded funding level for SoCalGas was $25.942 million. Under their proposal, SDG&E and SoCalGas will continue in 2012 making the annual actual PBOP funding as required by prescribed actuarial calculations. Any variance in 2012 between the "authorized and actual contributions would be subject to the current PBOP two-way balancing account mechanism." (Ex. 404 at 16; Ex. 406 at 16.)

16.3.2. Position of the Parties

16.3.2.1. DRA

DRA reviewed the pension plan testimonies of the Applicants. DRA agrees with the Applicants' proposal to use the 2009 recorded pension plan costs as the test year revenue requirement amounts, and to recover the difference between the funding pension expenses and the actual minimum contributions in the two-way balancing account. As a result, DRA recommends a test year 2012 expense of $56.833 million for SDG&E's pension costs. DRA's recommendation did not include the 2009 surety bond cost of $1.650 million because it contends that the surety bond is prohibited by D.09-09-011 from being recorded in the pension balancing account. For SoCalGas, DRA recommends a test year 2012 expense of $75.105 million for SoCalGas' pension costs. DRA agrees that the two-way balancing account for pension costs be continued.

For PBOP, DRA agrees with the Applicants' proposal to use the 2009 recorded PBOP costs as the test year revenue requirement amounts. As a result, DRA recommends a test year 2012 PBOP expense of $15.554 million for SDG&E, and $25.942 million for SoCalGas.

DRA, however, opposes the Applicants' request that the balancing account for PBOP continue as a two-way balancing account. DRA recommends that the Commission change the PBOP balancing accounts to one-way balancing accounts on the theory that the "cost of the risk to shareholders is already included in the opportunity to earn a rate of return." (Ex. 522 at 7.)

16.3.2.2. Joint Parties

The Joint Parties contend that the employees of both SDG&E and SoCalGas "receive ratepayer guaranteed full pensions unrelated to their contributions and are likely, by the time they retire, to have retirement benefits three or more times greater than the median ratepayer on Social Security." (Ex. 391 at 18.) The Joint Parties further contend that the Applicants' pension practice "relate to a prior era in terms of both government and corporate pension practices and plans," and that the pensions of the executives are "many times greater than that of the average ratepayer," and those on Social Security. (Ex. 392 at 9.)

The Joint Parties recommend that the Applicants be required "to revise all of its pension practices to follow the best practices instituted throughout the state of California by local governments and the state government," and that the Applicants' executives "share a far greater portion of the costs." (Ex. 392 at 9.)

16.3.2.3. UCAN

Regarding SDG&E's proposal to delay the increase in the funding of the pension benefits and PBOP costs by one year, UCAN contends that this is simply tied to the Applicants' justification for continuing the two-way balancing account treatment. UCAN also contends that the Applicants' proposal "end up benefiting shareholders more than ratepayers." (Ex. 557 at 14.)

16.3.2.4. SDG&E and SoCalGas

The Applicants point out that DRA did not address the Applicants' request to modify the current funding mechanism for its pension plans to avoid potential disruption in benefits to retirees. The Applicants contend that the Employee Retirement and Income Security Act of 1974 (ERISA) imposes certain consequences if a pension plan's funding falls below the 80 percent level. These consequences are "limitations on benefit distributions, higher required minimum contributions, and higher Pension Benefit Guarantee Corporation premiums." (Ex. 408 at 3.) To avoid these consequences, the Applicants request that future funding amounts for the pension plans be "based on the greater of the minimum required contribution or the amount necessary to maintain an 85 percent funding level." (*Ibid*.)

Due to the 2008 financial crisis, the value of SDG&E's pension assets declined, which caused the funded ratio to fall below 80%. To avoid the ERISA benefit restrictions, and to increase the funded ratio to the 80% level, SDG&E obtained a surety bond, backed by a letter of credit. Under the ERISA rules, SDG&E contends that "the security bond must remain in place until the plan's funded ratio reaches 90 percent." (Ex. 408 at 4.) In order to reach a 90% funded level, SDG&E would have to increase its minimum required contribution for test year 2012 by approximately $90.500 million. SDG&E is requesting in test year 2012 the $1.650 million to cover the surety bond expense.

Regarding DRA's position to change the PBOP two-way balancing account to a one-way balancing account, the Applicants contend that DRA's position is inconsistent and contrary to DRA's endorsement of the two-way balancing account for pension benefits. The Applicants contend that the rationale for maintaining a two-way balancing account for the PBOP costs is the same as having a two-way balancing account for pension benefits, i.e., "the inability to accurately predict the impact of external economic factors such as interest rates, return on benefit trust assets, legislative changes and, in the case of PBOP, health care trend rate." (Ex. 408 at 5.) Attachment B to Exhibit 408 illustrates the variability of these kind of factors. The Applicants also contend that DRA's rate of return argument is incorrect, and that "the return on investment from PBOP trust assets is dependent on economic conditions and market performance." (Ex. 408 at 6.)

UCAN contends that the Applicants' proposal regarding the use of 2009 recorded amounts for the test year 2012 pension benefits and PBOP costs is to justify continuation of the two-way balancing accounts. The Applicants contend that the goal of its proposal is "to relieve ratepayers of the projected pension funding increase for one year while the economy continues to improve and, hopefully, yields higher returns on the pension asset portfolio and lower required minimum contributions for 2013 and beyond." (Ex. 408 at 9.)

16.3.2.5. Discussion

We have reviewed the testimony and arguments of the parties concerning the pension benefits and the PBOP costs.

The Joint Parties expressed concern about the Applicants' executive pension benefits, and the pension benefits of their employees. However, we are not persuaded by the Joint Parties arguments that these pension benefits should be changed in the manner suggested by the Joint Parties. As the Applicants point out, pension benefits and PBOP are part of the overall compensation package offered to its employees in order to attract and retain experienced individuals. Also, the Applicants compare and revise the benefits that they offer, to what other utilities and other companies are doing in terms of compensation. As for the Joint Parties' suggestion that the pension benefits of the Applicants should be changed to reflect the type of pension benefits that the California state government provides, the Applicants pointed out several instances of how their pension benefits differ from what the state offers.

No one opposes continuing the two-way balancing account treatment for the pension benefits costs of both utilities. Also, since the circumstances warranting the two-way balancing accounts for the pensions benefits costs of both SDG&E and SoCalGas have not changed, we adopt the Applicants' request to continue the two-way balancing account treatment for their respective pension benefits costs.

With respect to the Applicants' request to continue the two-way balancing account treatment for the PBOP of both SDG&E and SoCalGas, we are not persuaded by DRA's argument that these balancing accounts should be changed to one-way balancing accounts. As the Applicants have demonstrated, the costs for PBOP vary considerably, especially for health care costs. Accordingly, we adopt the Applicants' request to continue the two-way balancing account treatment for their respective PBOP costs.

We also approve the Applicants' request to continue their annual amortization of the pension balancing account and the PBOP balancing account.

Regarding the Applicants' proposals to use their 2009 recorded amounts for pension benefits, and their 2009 recorded amounts for PBOP, as the costs for test year 2012, and to recover any difference between the 2009 amounts and the actual costs paid in 2012 through their two-way balancing accounts, we adopt that proposal as well. Deferring the pension benefits and PBOP increase by one year will provide some relief to ratepayers in 2012. Accordingly, we adopt test year 2012 costs for pension benefits as follows: for SDG&E, the amount of $56.833 million; and for SoCalGas, the amount of $75.105 million. For the test year 2012 costs for PBOP, we adopt the following: for SDG&E, the amount of $15.554 million; and for SoCalGas, the amount of $25.942 million.

With respect to SDG&E's request to include $1.650 million for the cost of the surety bond as part of its test year 2012 pension benefits cost, and to recover any difference between this amount and the actual surety bond amount in the balancing account, we approve that request. Although D.09-09-011 excluded the cost of a surety bond in that proceeding, the facts are different in this proceeding. Here, there is no issue of retroactive ratemaking, as there was in the proceeding which led to D.09-09-011. Since the surety bond is needed in test year 2012 in order to meet ERISA requirements, that pension-benefit related cost should be permitted. Accordingly, the pension benefits costs for SDG&E in test year 2012 shall be increased by the surety bond amount of $1.650 million, subject to adjustment through SDG&E's balancing account.

The Applicants have requested that they be allowed to adjust their respective future funding amounts for pension benefits based on the greater of the minimum required contribution, or the amount necessary to maintain an 85% funding level. No other parties have voiced opposition to this request, and the Applicants have explained that its request is reasonable in order to avoid possible ERISA consequences. Accordingly, SDG&E and SoCalGas shall be permitted to make this change in their future funding requests for pension benefits.

17. Rate Base

17.1. Introduction

Rate base is the depreciated asset value of the Applicants' net investments used to provide service to their customers. The major components of rate base are fixed capital, working capital, other deductions, and deductions for reserves. The Applicants are allowed to earn a rate of return on the sum of these rate base components. As presented in Exhibits 222 and 223, SDG&E's total weighted average rate base request for test year 2012 is $4,251,701,000.[171] Of this amount,

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[171] The Applicants describe the weighted average rate as a 13-month average that is calculated as "the sum of the monthly balances from December of the prior year

Footnote continued on next page

$3,732,955,000 is for the electric rate base, and $518,746,000 is for the gas rate base.

As presented in Exhibits 224 and 225, SoCalGas' total weighted average rate base request for test year 2012 is $3,578,963,000. [172]

SDG&E and SoCalGas have requested "to modify the ratemaking treatment of ad valorem taxes associated with capital construction projects." (Ex. 222 at 4; Ex. 224 at 5.) This change is requested because the applicable CFR "specifies that ad valorem taxes on physical property during the period of construction shall be included in the capital construction costs." (*Ibid*.) In accordance with their proposal, SDG&E and SoCalGas reduced the ad valorem tax expense for test year 2012, with corresponding increases to CWIP. Since no one objected to this change in treatment, we adopt the request of SDG&E and SoCalGas.

DRA and other parties have recommended a number of adjustments that affect the rate base amounts for SDG&E and SoCalGas. Except as discussed below, those other adjustments have been discussed in other sections of this decision. Based on our resolution of the adjustments that we have adopted in this decision, it is reasonable to adopt for test year 2012 a total weighted average rate base for SDG&E of $4,077,765,000, and a total weighted average rate base for SoCalGas for test year 2012 of $3,462,405,000.

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through December of the current year, less one-half of each December balance, divided by 12." (Ex. 222 at 2; Ex. 224 at 2.)

[172] As updated by Exhibit 596, SDG&E's proposed total rate base is $4,267,834,000, and SoCalGas' proposed total rate base is $3,622,427,000.

17.2. Working Cash Proposals

Working cash is one of the subsets of working capital that is included in rate base. Working cash is to compensate the Applicants' shareholders for providing funds to pay for the day-to-day operating expenses in advance of receipt of offsetting revenues from the Applicants' customers. SDG&E has calculated a working cash requirement of $126.8 million ($108.8 million for electric distribution, and $18 million for gas service). SoCalGas has calculated a working cash requirement of $42.5 million.

The working cash requirements would normally be included in the Applicants' test year 2012 GRC request, and the inclusion of working cash in rate base would allow the Applicants to earn a return on that. However, due to the state of the economy and to reduce the impact on the Applicants' customers, the Applicants have elected to request zero funding for their respective 2012 working cash requirements.[173]

No one objected to the Applicants' calculation of their respective working cash requirements, or to the Applicants' proposal to forego the working cash funding in this GRC. The working cash calculations for the Applicants are adopted, and their proposal to request zero funding for working cash is adopted.

17.3. Rate Base Issues Specific to SDG&E

17.3.1. Fuel in Storage

Another subset of working capital is fuel in storage. SDG&E has included in its gas rate base $358,000 for this item.

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[173] In the event economic conditions improve, the Applicants reserve the right to petition the Commission to return to normal treatment of working cash requirements. (Ex. 1 and 2)

DRA recommends that $358,000 of fuel in storage be removed from working capital for SDG&E's gas rate base for test year 2012. SDG&E's fuel in storage consists of gas line pack. The value of the fuel in storage is calculated based on line pack volumes in therms and the weighted average cost of gas. DRA recommends that gas line pack be removed from rate base and considered in SDG&E's next cost allocation proceeding where fuel-related items are considered. DRA points out that SoCalGas, in this proceeding, and PG&E in its GRC, did not include fuel in storage (gas line pack) in their rate base calculations. DRA recommends a total of $3.081 million for SDG&E's gas rate base working capital, as opposed to SDG&E's test year 2012 forecast of $3.439 million.

On SDG&E's fuel in storage, SDG&E points out that the Commission has included SDG&E's fuel in storage into gas rate base since 1982. The fuel in storage represents permanent fuel inventory maintained over the long term to assure continued and reliable operations. SDG&E also contends that DRA's proposal to defer this fuel in storage issue to its next cost allocation proceeding would prejudice SDG&E by denying timely cost recovery.

We agree with SDG&E that since fuel in storage has been included in SDG&E's gas rate base in the past, that the same treatment should apply in this GRC. Accordingly, DRA's proposal to remove SDG&E's fuel in storage from working capital, and to consider it in SDG&E's next cost allocation proceeding, is not adopted.

17.3.2. SDG&E Legacy Meters

17.3.2.1. Introduction

As a result of the replacement of the electromechanical meters with smart meters for SDG&E's electricity customers, the issue of rate recovery of SDG&E's legacy meters has arisen. The original installation costs of the legacy meters will not be fully depreciated at the time the legacy meters are replaced by the smart meters.

17.3.2.2. Position of the Parties

17.3.2.2.1. DRA

DRA recommends that SDG&E's legacy meters be removed from rate base, and that the legacy meters be excluded from earning the authorized rate of return. DRA further recommends that the net book value balance of $85.1 million for the legacy meters be amortized over six years with no rate of return. Under DRA's proposal, this will result in a rate recovery of the undepreciated portion of the legacy electric meters at six equal amounts of $14.18 million for each year from 2012 to 2017, excluding the gross up for franchise fees and uncollectibles. DRA also recommends that the rate recovery of the undepreciated portion of the legacy meters over the six year amortization be excluded from any escalation or attrition increases. DRA's proposal is based on its contention that the legacy meters are no longer used and useful because they have been replaced with the smart meters.

In the event the Commission believes that SDG&E should receive some rate of return on the undepreciated legacy meters, DRA's alternative proposal is to use a reduced rate of return of 4.5% over an amortization period of six years beginning in 2012 and ending in 2017. The 4.5% that DRA uses is the five-year average forecast of the five-year treasury note yield for 2012 through 2016, which closely corresponds to DRA's proposed six year amortization period. Under this alternative proposal, the net plant balance of $85.1 million would be amortized over 72 months at an annual interest rate of 4.5% which results in equal amounts of $18.01 million per year for six years, excluding the gross up for franchise fees and uncollectibles.

17.3.2.2.2. TURN

TURN contends that the remaining plant investment in the legacy electric meters should be removed from rate base and no longer be allowed to earn the authorized rate of return. TURN's position is based on the principle that a plant asset that is no longer used and useful should not be in rate base. TURN proposes that SDG&E be allowed to recover the unrecovered investment in the legacy meters over a six year amortization period, and that the rate of return be zero.

17.3.2.2.3. SDG&E

SDG&E contends that the proposals of DRA and TURN are unreasonable and contrary to Commission policy and D.07-04-043. SDG&E points out that although DRA was one of the parties to the all party settlement agreement approved in D.07-04-043, DRA is now objecting to the ratemaking treatment for the legacy meters that was included as part of SDG&E's advanced metering infrastructure (AMI) application.

SDG&E contends that the issue of how the legacy meters should be treated was addressed in the SDG&E's AMI proceeding in A.05-03-015. In the testimony supporting that application, SDG&E stated:

> SDG&E proposes to recover the remaining book value of the installed costs for existing meters consistent with current

> ratemaking treatment adopted by the Commission, using normal straight-line remaining life depreciation method. SDG&E will recover the installed cost of the existing meters over the remaining life prior [to] implementation of AMI technology. (Applicants' Opening Brief at 408)

SDG&E's AMI settlement was attached to D.07-04-043 as Appendix A. As part of the language of that settlement agreement, it stated: "In summary, the Settling Parties agree that SDG&E's AMI deployment and cost recovery proposal as set forth in SDG&E's Application 05-03-015, including the supporting testimony, is reasonable and should be adopted by the Commission with the following modifications…." (Applicants' Opening Brief at 409.) In addition, Finding of Fact 33 in D.07-04-043 stated: "The Settlement Agreement encompasses SDG&E's application and testimony, with specified modifications." (Applicants' Opening Brief at 409.) SDG&E contends that the cost recovery issues, including SDG&E's proposal regarding the legacy meters, were recognized in the Settlement Agreement and in D.07-04-043. Thus, SDG&E contends that it should be entitled to earn its authorized rate of return on its unrecovered investment in the legacy meters, which as of December 31, 2009 had an estimated remaining life of about 27.5 years. SDG&E also contends that such treatment is consistent with Financial Account Standard 71.

SDG&E also contends that the Commission should not treat SDG&E any differently than how it treated PG&E's legacy meters in D.11-05-018. Like PG&E, SDG&E was directed by the Commission to implement an AMI deployment plan, and unlike PG&E, SDG&E has not experienced delays in its deployment of meters. SDG&E further contends that a zero or reduced rate of return would also be contrary to the regulatory policy of encouraging technological innovation as stated in D.11-05-018 at 62, and would also send a negative signal to investors who are considering investing in utilities. SDG&E also contends that DRA's proposal for a 4.5% return is better than a zero return, but is still inequitable. It is inequitable because as of a certain date, an $85 million investment in a regulated utility that once provided investors with an after tax yield of 8.4% will yield just 2.7% after combined federal and state taxes of 40%. If the Commission is inclined to adopt DRA's alternative proposal, SDG&E contends that a rate of 4.61% should be used, which is the six-year average (beginning in 2012 and ending in 2017) resulting in an annual recovery of $18.11 million instead of DRA's calculation of $18.01 million.

SDG&E also points out that DRA's primary and alternative proposals for rate recovery of the legacy meters are too simplified. According to SDG&E, DRA's method fails to account for income tax expenses, property tax expense, deferred taxes, and basis of return.

SDG&E further contends that if the Commission decides that amortization of SDG&E's retired electric legacy meters should be accelerated, the Commission should allow SDG&E to earn its full rate of return. If the Commission does not accommodate that request, then the rate of return should be set with the same formula as applied in PG&E's decision in D.11-05-018. If the Commission decides that SDG&E legacy meters should be treated similarly to those of PG&E, then SDG&E proposes that the 6 year amortization period be applied with a rate of return of 6.2%.

SDG&E contends that when its AMI program was approved, benefits were expected from the implementation of AMI, and if dynamic pricing is approved, demand response benefits will also accrue. If the proposals of DRA and TURN are adopted, SDG&E argues that even more benefits would accrue to ratepayers by denying or lowering the rate of return on the legacy meters. However, these additional benefits were not contemplated as part of the settlement adopted in D.07-04-043.

17.3.2.2.4. SCE

SCE is opposed to the proposals of DRA and TURN. SCE contends that the proposals of DRA and TURN would strip SDG&E of any return on its legacy meters. SCE also points out that DRA and TURN made similar arguments in PG&E's GRC proceeding as to why PG&E should not earn a rate of return on the legacy meters. Although a reduced rate of return was adopted for PG&E, SCE contends the Commission should not do so for SDG&E. SCE recommends that SDG&E receive a full rate of return on its electromechanical meters. SCE believes that the "Commission should acknowledge that SDG&E invested in technological innovation in furtherance of Commission policy and grant it the full rate of return on its legacy meters." (SCE Opening Brief at 6.) If the Commission were reduce the rate of return on the legacy meters, SCE says there may be adverse long term consequences for utility operation and implementation of Commission policy.

17.3.2.3. Discussion

The starting point for our analysis of SDG&E's legacy meters, which have been taken out of service due to their replacement with smart meters, is to examine two decisions relevant to this issue. These decisions are: D.11-05-018 in which the Commission examined whether a rate of return was justified for PG&E's legacy meters; and D.07-04-043 in which the Commission adopted a settlement concerning SDG&E's replacement of the legacy meters by authorizing SDG&E to implement its AMI project.

In D.11-05-018, the Commission revised the ratemaking treatment of PG&E's legacy meters that had been set forth in PG&E's AMI proceedings in A.05-06-028 (D.06-07-027) and in A.07-12-009 (D.09-03-026). A review of both D.06-07-027 and D.09-03-026 reveals that the Commission only discussed the ratemaking treatment for the incremental costs associated with PG&E's smart meters. D.06-07-027 and D.09-03-026 did not specifically address the ratemaking treatment of PG&E's legacy meters, although D.06-07-027 referenced that "The record is composed of all documents that were filed and served on parties...," and D.09-03-026 recognized that PG&E had provided testimony on the revenue requirement associated with PG&E's smart meters. (D.06-07-027 at 6; D.09-03-026 at 162.) However, the Commission recognized in D.11-05-018 that in A.05-06-028 and A.07-12-009, PG&E had:

> [p]roposed ratemaking for the retired electromechanical meters, by which the original cost of the meters would be deducted from both the electric plant in service balance as well as the depreciation reserve balance. **The result of that ratemaking is that, for rate recovery, the undepreciated balance of the electromechanical meters is amortized over the estimated remaining life of electric meters (approximately 18 years for 2011) with the unamortized balance being included as an element of rate base and earning the authorized rate of return. That is, there would be no effect on rate base compared to what would occur if the electromechanical electric meters had continued to be used and useful and were not replaced by SmartMeters.** No party expressed opposition to this proposed ratemaking in either A.05-06-028 or A.07-12-009." (D.11-05-018 at 34, emphasis added.)

The relevance of D.11-05-018 is that the factual situation involving PG&E's legacy meters is very similar to what developed in SDG&E's AMI proceeding, and D.11-05-018 utilizes an approach that essentially modified the ratemaking treatment of the legacy meters that had been decided in the prior Commission decisions of D.06-07-027 and D.09-03-026.

An abbreviated history of the factual situation that led up to SDG&E's replacement of its legacy meters begins with SDG&E's AMI proceeding in A.05-03-015. SDG&E filed A.05-03-015 in response to R.02-06-001. In A.05-03-015, SDG&E presented testimony about the replacement of its legacy meters with smart meters. The evidence and D.07-04-043 demonstrate that SDG&E presented a brief description in A.05-03-015 about how SDG&E's legacy meters would be accorded ratemaking treatment. SDG&E witness Edward Fong testified that he presented testimony in A.05-03-015 that addressed "Cost Recovery and Other Issues," wherein he stated: "SDG&E proposes to recover the remaining book value of the installed costs for existing meters consistent with current ratemaking treatment adopted by the Commission, using normal straight-line remaining life depreciation method." (Ex. 346 at 4, Attachment A at 26.) A settlement was reached in A.05-03-015 between SDG&E, DRA, and UCAN in which the settlement parties agreed "that SDG&E's AMI deployment and cost recovery proposal as set forth in SDG&E's Application 05-03-015, including the supporting testimony, is reasonable and should be adopted by the Commission with the following modifications."[174] (Ex. 346 at 5, Attachment B at 2.) The settlement of SDG&E's AMI deployment was then adopted by the Commission in D.07-04-043. In Finding of Fact 33 of that decision, the Commission stated that the adopted settlement "encompasses SDG&E's application and testimony, with specified modifications."

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[174] The modifications to the settlement adopted in D.07-04-043 are not relevant to this discussion.

Based on the evidence presented in this proceeding, it is apparent that there was testimony in D.07-04-043 about the future ratemaking treatment of SDG&E's legacy meters. Although SDG&E's testimony in A.05-03-015 did not explicitly state that the legacy meters would continue to earn a rate of return, that testimony did state that "SDG&E proposes to recover the remaining book value of the installed costs for existing meters **consistent with current ratemaking treatment adopted by the Commission**…." (Ex. 346 at 4, emphasis added.) As noted by TURN's witness, this means that SDG&E's "unrecovered net investment [in SDG&E's legacy meters will] continue to earn the utility's authorized rate of return." (Ex. 554 at 2.) No party in A.05-03-015 challenged SDG&E's proposal for cost recovery of its legacy meters.

D.07-04-043 is relevant to this discussion because it establishes the ratemaking treatment of the legacy meters at the time the Commission authorized SDG&E to move forward with its replacement of the legacy meters with the smart meters. In addition, D.07-04-043 is relevant to the approach adopted in D.11-05-018 for analyzing the legacy meter issue because it raises the same kinds of facts which allowed the Commission to revisit whether the ratemaking treatment for the legacy meters that was implicitly approved in a prior decision should be changed. For the reasons stated in the succeeding paragraphs, we are not persuaded by SDG&E's argument that D.07-04-043 is determinative as to what kind of ratemaking treatment should be given to SDG&E's legacy meters.

In D.11-05-018, the Commission first addressed the threshold issue of "whether the ratemaking for meter devices replaced by SmartMeters has already been addressed and decided by the Commission in D.06-07-027 and D.09-03-026, and, therefore, whether it is appropriate for TURN to raise the issue in this proceeding." (D.11-05-018 at 35.)[175] In deciding that issue, the Commission reviewed what had taken place in PG&E's AMI proceeding, and took into account several equitable considerations. The Commission concluded that no party had addressed PG&E's ratemaking treatment of its legacy meters in PG&E's AMI proceedings, that neither of the Commission decisions contained "specific discussion of PG&E's ratemaking proposal for retired meters or includes findings, conclusions or ordering paragraphs in which this issue is specifically identified," and PG&E's ratemaking proposal for the meter retirement of the legacy meters "was not specifically adopted or litigated in either A.05-06-028 or A.07-12-009." (D.11-05-018 at 39.) The Commission then went on to conclude that the issue about ratemaking treatment of the legacy meters was "important and relevant, and the Commission likely did not fully understand and consider the ramifications of PG&E's proposed ratemaking in those prior proceedings." In addition, the Commission stated "There are significant financial consequences associated with TURN's recommendation that results in the exclusion of rate of return costs…," and that "Neither the magnitude of the net plant balance for prematurely retired meters, nor the associated rate of return costs were identified in PG&E's prior AMI testimony." (D.11-05-018 at 40.) As a consequence, the Commission stated "there is good reason to believe that PG&E's ratemaking proposal for retired meters was not fully understood and considered by the Commission in the two prior AMI proceedings," and the "Commission should now fully examine this issue and

[175] We note that normally an effort to change a prior Commission decision should be through the filing of a petition for modification, as provided for in Rule 16.4 of the Rules of Practice and Procedure.

determine whether the outcome in D.09-03-026 is just or needs to be changed." (D.11-05-018 at 40-41.)

The factual situation with SDG&E's legacy meters raises the same threshold issue that the Commission confronted in D.11-05-018 regarding the revisiting of PG&E's legacy meters. SDG&E presented scant testimony in A.05-03-015 about how the ratemaking treatment of the legacy meters would unfold in the future once those meters were replaced by the smart meters. This scarcity of information, supplied by SDG&E, about the ratemaking treatment of the legacy meter retirements may be one of the reasons why DRA and no other party raised the legacy meter in A.05-03-015, and which may have contributed to a lack of understanding of the ramifications of SDG&E's proposed ratemaking in A.05-03-015. Both DRA and TURN have pointed out in this proceeding the extent to which ratepayers will be impacted if SDG&E is allowed to earn its rate of return on the legacy meters that are no longer used and useful, as well as a return on the associated smart meter infrastructure that replaced the legacy meters. Accordingly, it is equitable to use the approach taken in D.11-05-018 to reexamine whether the ratemaking treatment that was mentioned in A.05-03-015 for SDG&E's legacy meters is just or needs to be changed.

In deciding whether SDG&E should be entitled to earn a rate of return on the legacy meters, we examine TURN's argument that SDG&E's legacy meters are no longer used and useful.[176] SDG&E acknowledged in its testimony that its

[176] SDG&E, DRA, and TURN are in agreement that SDG&E should be allowed to receive rate recovery of the unrecovered net plant balance of $85.1 million for SDG&E's legacy meters. However, they disagree on whether SDG&E should be allowed a rate of return on that net plant balance, and the time period in which to recover that balance.

retired legacy meters are no longer used and useful. The concept of an asset that is used and useful is integral in deciding whether a utility plant asset can be included in rate base.

As pointed out by SDG&E, DRA, TURN, and SCE, there are a number of decisions which address whether a utility should be allowed to earn a rate of return on a utility plant asset that is no longer used and useful. Many of the decisions cited or referenced by the parties in this proceeding, were also cited by the parties in PG&E's GRC proceeding and summarized in D.11-05-018. (*See* D.11-05-018, Section 5.3 at 42-48.)[177] Those cited decisions were reviewed for applicability to SDG&E's situation, and our view of those citations remains unchanged from what we adopted in D.11-05-018. As noted in D.11-05-018, plant that is not used and useful is normally excluded from rate base, and "therefore excluded from earning a rate of return." (D.11-05-018 at 53-54.) However, exceptions to this general policy are made when circumstances such as governmental action "specifically encourage or require a utility to prematurely retire an asset, or group of assets, that was functioning properly at the time." (D.11-05-018 at 54-55.) Under those kinds of exceptions, a rate of return may be warranted.

In deciding whether a rate of return is warranted, the Commission considers the following, as summarized in D.11-05-018:

> In doing so, the causes, as well as the burdens and benefits of the plant items in question, have been taken into consideration in determining the appropriate ratemaking balances and solutions. The particular circumstance of each

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[177] *See*, for example, the following: Exhibit 506 at 10-12; Exhibit 554, footnote 12 at 5, footnote 15 at 6; SCE Reply Brief, footnote 47 at 8.

> situation has been, and must be, evaluated in making these determinations. There are a number of previous Commission decisions that relate to the issue at hand, and to the extent they are relevant to circumstances of this case, they will be used as a guide in resolving the issue.
>
> We will grant rate of return treatment for the retired meters, despite the fact that they are no longer used and useful, due to our consideration of two facts. The first fact is that AMI implementation was encouraged by the Commission, as a means for implementing Commission demand side management policies. The second fact is that AMI implementation for PG&E…was found by the Commission to be cost-effective." (D.11-05-018 at 53-54.)

The situation with SDG&E's legacy meters is essentially the same as what occurred with PG&E's legacy meters, though with additional lag time for PG&E's implementation of its smart meters. Accordingly, we agree with SDG&E that the approach taken in D.11-05-018 for PG&E's legacy meters, should also be used by the Commission in its review of how SDG&E's legacy meters should be treated. Thus, the approach that we take in analyzing whether SDG&E's legacy meters should earn a rate of return is guided by two considerations, the cause of how the utility plant asset became stranded, and the burdens and benefits of the plant asset in question.

TURN contends that the Commission's finding in D.11-05-018 "that AMI implementation was encouraged by the Commission," should not apply to SDG&E's legacy meters. We do not agree with TURN. TURN argues that SDG&E was the one who was anxious to roll out the smart meters to replace its legacy meters, and therefore no rate of return is warranted. However, as in PG&E's situation, it was the Commission that "encouraged deployment of AMI…." (D.11-05-018 at 55.) This is apparent from the caption heading in R.02-06-001 which states: "Order Instituting Rulemaking on policies and practices for advanced metering, demand response, and dynamic pricing." It was also the assigned Commissioner and ALJ in R.02-06-001 that ordered SDG&E and the other electric utilities to file their AMI applications by March 15, 2005. (*See* R.02-06-001 Rulings of July 21, 2004, December 24, 2004.) Thus, the same finding that applied to PG&E's legacy meters is equally applicable to SDG&E's legacy meters, i.e., "AMI implementation was encouraged by the Commission…." (D.11-05-018 at 54.)

As a result of the Commission's AMI and demand response strategies, as well as D.07-04-043, it was the Commission that encouraged or required SDG&E to prematurely retire the legacy meters that were replaced by SDG&E's AMI deployment of its smart meters. Under those kinds of circumstances, as noted in D.11-05-018, a rate of return on plant that is no longer used and useful may be warranted. Following the approach taken in D.11-05-018, that brings us one step closer to allowing SDG&E to earn a return on the legacy meters.

Next, we consider the burdens and benefits, or what D.11-05-018 refers to as "cost-effectiveness." In D.07-04-043, the Commission adopted a settlement between SDG&E, DRA and UCAN concerning the modified AMI project as agreed to in that settlement, and found that there were net benefits of between $40 million and $51 million. (D.07-04-043, Finding of Fact 35, Conclusion of Law 7.) D.07-04-043 also examined SDG&E's original AMI project, and amended AMI project, and concluded that without the settlement agreement, SDG&E's original proposal and amended proposal were not cost effective. (D.07-04-043, Conclusion of Laws 3 and 5.) TURN makes the argument that because the demand response benefits have not yet been realized because of a delay in implementing dynamic pricing, SDG&E's AMI project may no longer be cost effective. Indeed, SDG&E's witness Fong testified that the 18 to 24 month delay in demand response benefits affects the original forecast of demand response benefits. (27 RT 3549-3552.) In analyzing the applicable decisions in D.11-05-018, the Commission determined that if there is a net benefit to ratepayers, the utility should be allowed to earn a rate of return. (D.11-05-018 at 55-56.) These cost effectiveness items are of concern, and should be a consideration in determining whether a rate of return for SDG&E's legacy meters is justified.

In weighing the cost effectiveness, the Commission determined in April 2007 that there were net benefits from the settlement that was adopted in D.07-04-043. However, those benefits may be less than originally forecasted due to the delay in implementing dynamic pricing. Since it is too early to tell whether the delay in dynamic pricing will lower the net benefits to SDG&E's customers, or become a net burden on its customers, a rate of return is justified because D.07-04-043 determined that the adopted AMI project has net benefits. However, TURN's point about the delay in dynamic pricing is something we can consider in determining what the rate of return should be.

The evidence in this proceeding provides us with a range of options as to the rate of return SDG&E should receive. From SDG&E's perspective, it believes it should be entitled to a rate of return on the undepreciated legacy meters over the full amortization period. SDG&E also takes backup positions and argues that if the amortization period is reduced to six years, it should still be allowed to earn its authorized rate of return for the six years. Next, if this is not allowed, SDG&E believes it should receive the same treatment as PG&E and receive a rate of return of 6.2%. SDG&E's last fallback position is that if DRA's alternative proposal is adopted, that an interest rate of 4.61% should be used instead of DRA's rate of 4.47%. The primary position of TURN and DRA is to amortize the unrecovered investment in legacy meters over six years with no rate of return.

DRA's alternative proposal is six years amortization with a return of 4.47%. If DRA's alternative is adopted, TURN recommends a return of no higher than 2.36%.

In deciding what the appropriate return for SDG&E's legacy meters should be, we have considered and weighed the following: the Commission's encouragement of AMI deployment; the net benefits of SDG&E's adopted AMI project; the possibility of a lower net benefit (or a net burden) in the future due to the delay in dynamic pricing; that SDG&E (and PG&E in D.11-05-018) have been allowed to earn a rate of return on their AMI investments; allowing SDG&E to earn a rate of return over the remaining life of the undepreciated legacy meters will result in ratepayers having to pay for two meter sets; the rate of return allowed in D.11-05-018 for PG&E's legacy meters; the expectations of those who invested in SDG&E and of the investment community; and balancing the need of encouraging utilities to invest in future innovative technologies.

Based on a weighing and balancing of all those considerations, SDG&E should be allowed to earn a rate of return of 6.2%. This return shall be applied to a six year amortization of the undepreciated balance of SDG&E's legacy meters, which is approximately $85.1 million. Such treatment is fair and reasonable in light of our discussion above.

The method that we adopt results in an annual recovery for legacy meters of $18.9 million for each year from 2012 through 2017, as shown in Attachment B (Table B-7) of this decision. In determining SDG&E's test year 2012 revenue requirement using the results of operations model, recovery of legacy meter costs is reflected in SDG&E's electric distribution O&M expenses. The $18.9 million included in SDG&E's adopted 2012 test year electric distribution O&M expenses attributable to legacy meter cost recovery is not subject to post-year test year escalation for 2013, 2014, and 2015 under the method that we adopt in the post-test year ratemaking section of this decision. Accordingly, SDG&E shall reduce its test year 2012 authorized electric distribution expenses shown in the summary of earnings tables in Attachment B of this decision by $18.9 million before it escalates electric distribution O&M expenses to determine its authorized 2013 attrition year increase in electric distribution revenue requirements.

17.4. Rate Base Issues Specific to SoCalGas

17.4.1. Introduction

TURN has raised two issues concerning the rate base of SoCalGas. These issues are the forecast of new business forfeitures, and the accounting treatment of regulator purchases that will close to plant in 2012.

17.4.2. New Business Forfeitures

The new business forfeitures are accounted for in Account 161. A developer must pay a refundable advance when the costs of new gas service are higher than the line extension allowances, and new customers are not immediately available to take service. This refundable advance is referred to as the "customer advance for construction." When new customers connect their gas service, the customer advance for construction is refunded to the developer. The forfeiture results if there are any costs in excess of the allowance remaining after ten years, the costs are converted to CIAC and subtracted from gross plant.

SoCalGas is forecasting for test year 2012 new business forfeitures of $4.856 million. TURN is forecasting $5.657 million. The main difference between the forecasts is because of the five-year average (2005-2009) that SoCalGas used, and the three-year average (2008-2010) that TURN used. The effect of TURN's proposed forecast would reduce the rate base by $801,000.

SoCalGas objects to the general use of 2010 data in the GRC. With reference to TURN's forecast of new business forfeitures, SoCalGas took the position in Exhibit 226 and in its opening brief that TURN's use of the 2010 data resulted in forecast of $7.691 million instead of the $5.657 million, and that TURN's forecast did not account for overhead and state and federal taxes.

TURN points out in its reply brief that SoCalGas appears to rely on TURN's witness William Marcus' earlier testimony, and not on his revised testimony which was admitted into evidence as Exhibit 545. Marcus revised his testimony in Exhibit 545 as a result of SoCalGas' testimony in Exhibit 226. (*See* TURN Reply Brief, footnote 27 at 12.) Hence, SoCalGas' forecast of new business forfeitures is $4.856 million, and TURN's revised forecast, which incorporates the adjustments that SoCalGas pointed out, is $5.657 million. Thus, the only issue to address is whether SoCalGas's five-year average of 2005-2009 should be used, or if TURN's more recent three-year average of 2008-2010 should be used.

TURN contends that SoCalGas' five-year average should not be used because refunds of the customer advance for construction have likely increased in 2009-2010 from earlier years due to the reduction in the line extension allowances in 1998, which increases the amount that developers had to advance in 1999 and later years. Due to the state of the economy in 2010 and in the test year, TURN contends the 2010 data of actual forfeitures reflects the downward trend of the economy and the increase in new business forfeitures due to the economy.

SoCalGas contends that the timing of new business forfeitures occur over a three to ten year period based on SoCalGas' Rules 20 and 21 on gas main extensions and gas service extensions, respectively. Due to this timing, SoCalGas believes its five-year average of 2005-2009 is more appropriate.

We have analyzed the six years of data from 2005 through 2010. The three years of 2008-2010 are the three highest amounts since 2005. The five-year average that SoCalGas used in its forecast incorporates two of the three highest amounts for the 2008-2010 timeframe. It is reasonable to use SoCalGas' five-year average for the forecast of new business forfeitures since it better reflects the timing of new business forfeitures.

17.4.3. Regulators

Gas regulators are used to reduce the pressure of the gas that enters the distribution system from the high pressure pipelines, and to reduce the pressure at the customer's meter set. The regulators also provide billing support in that delivery pressure is used to compute the gas volumes delivered to customers. Gas regulators are included in the capital category for meters and regulators, and are accounted for in Account 163.

Starting in 2011, SoCalGas anticipates purchasing an additional 17,000 regulators above the levels purchased in 2009 to replace obsolete equipment. In addition, SoCalGas is instituting a systematic approach to replace regulators from 2012 through 2017 in order to avoid an unplanned surge in replacements as older regulators begin to decline in effectiveness. In 2012, SoCalGas plans to purchase 100,000 regulators over the 2011 level, and in 2013, it plans to address more than 300,000 meter locations. These regulators are accounted for in Account 163.

TURN has made two adjustments to this forecast. The first adjustment is related to relationship between the forecast of regulators that are needed for new business growth, which is tied to the meter forecast. The second adjustment is to place the 100,000 regulators, which SoCalGas plans to purchase in late 2012, into 2013 instead of closing them to plant in service in 2012. TURN also points out that SoCalGas' regulator replacement program appears to be at odds with the testimony of another SoCalGas witness. TURN's adjustments result in a test year 2012 reduction of $3.651 million.

SoCalGas contends that the other SoCalGas witness did not mention the regulator program because the regulator work is normally performed with planned meter change work. As for the forecasted expenditures for the regulators, SoCalGas contends that this is needed in order to secure a sufficient inventory of regulators before the change-outs occur. SoCalGas does not agree with TURN's belief that every regulator purchased in 2012 must be installed in that year with no inventory carryover.

We do not adopt TURN's position that the purchase of regulators in 2012 should be deferred to closing to plant in 2013. Although all the regulators purchased in 2012 will not be installed in 2012, we agree with SoCalGas that an inventory of regulators are needed in anticipation of future needs.[178] In addition, SoCalGas is closing to plant in 2012 78.87% of the regulators purchased in 2012. This percentage is based on a five-year average, as opposed to a 100% factor, which is typical for regulator purchases. Accordingly, deferring the regulators purchased in 2012 to 2013 is not adopted.

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[178] TURN acknowledges in its opening brief that "rate basing carryover inventory is not per se unreasonable, and as SoCalGas points out, this type of accounting and ratemaking treatment is permitted by the FERC USOA". (TURN Opening Brief at 20; 22 RT 2822-2823.)

As for TURN's adjustment to the number of regulators that are needed for new growth, that is dependent on whose forecast we adopt for new meters. In the section addressing the forecast of customers, we adopt a slightly lower forecast of new meter sets (64,223). As a result, the number of new business regulators should be reduced as a result. To account for the lower number of new regulators, it is reasonable to reduce the regulator forecast amount by $700,000.

18. Depreciation

18.1. Introduction

This section addresses the depreciation expense and amortization expense and accumulated reserve for SDG&E, and the depreciation expense and accumulated reserve for SoCalGas.

For SDG&E, the depreciation and amortization expense for recorded year 2009 is $223 million for electric plant, and $43 million for gas plant, and the expense being requested for test year 2012 is $284 million for electric plant, and $54 million for gas plant. The amortization expense for SDG&E is for land rights and software. For test year 2012, the requested amortization expense is $32 million of the $284 million in electric plant, and $9.482 million of the $54 million in gas plant. [179]

For SoCalGas, the Gas Plant depreciation expense for recorded year 2009 is $291 million, and the depreciation expense being requested for test year 2012 is $370 million.

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[179] For SDG&E, the reference to "electric plant" covers its electric production, electric distribution, and related general and common plant, while "gas plant" refers to its gas plant and its related general and common plant.

To derive the Applicants' depreciation expense, depreciation studies for SDG&E and SoCalGas were prepared. According to the Applicants, the methods used to calculate the mortality characteristics,[180] and to calculate the straight line remaining life depreciation rates, in the depreciation studies are consistent with the Commission's Standard Practice U-4, Determination of Straight-Line Remaining Life Depreciation Accruals, which was issued in 1961. To derive the mortality characteristics the Applicants used a simulated plant records (SPR) method to develop life-curve combinations for SoCalGas, and a retirement rate actuarial method and forecast method to develop observed life tables for SDG&E. The test year 2012 depreciation expense for both SDG&E and SoCalGas were calculated using the depreciation rates in the depreciation studies.

DRA, TURN, and UCAN have proposed various adjustments to SDG&E's depreciation expense, which are discussed below. According to the Applicants, the combined impact of the adjustments recommended by DRA, TURN, and UCAN, as adjusted for overlap, would reduce SDG&E's total depreciation expense by about $47.867 million. For SoCalGas, the recommended adjustments by DRA and TURN, adjusted for overlap, would result in a combined reduction of about $88.930 million.

18.2. Average Service Lives

18.2.1. Introduction

DRA did not oppose the Applicants' average service lives as presented in those studies. TURN and UCAN propose adjustments to the average service lives of certain accounts of the Applicants.

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180 The mortality characteristics are the average service lives, retirement dispersions, and net salvage rates.

18.2.2. SoCalGas Average Service Lives

18.2.2.1. Position of the Parties

18.2.2.1.1. TURN

TURN objects to SoCalGas' proposed average service lives, and to the retirement dispersion pattern that SoCalGas selected. The dispersion pattern relies on the industry standard Iowa survivor curves, which is what TURN used as well.[181] TURN also contends that SoCalGas' proposed life-curve combinations lack support and justification, and that SoCalGas failed to provide a detailed explanation of its life-curve combinations. In contrast, TURN stated that it presented a more defined basis for their recommendations by reviewing the SPR analyses, seeking additional information from SoCalGas, and relying on its witness "40 years of experience in dealing with depreciation matters." (Ex. 551 at 12.) TURN asserts that SoCalGas' proposal understates the appropriate average service lives.

For SoCalGas, TURN recommends adjustments to four gas plant accounts. The total impact of the adjustments that TURN recommends is a depreciation expense reduction of $49.645 million annually based on plant as of December 31, 2009.

[181] The Iowa survivor curves are used to determine mortality characteristics of assets. The curves plot the percent surviving versus the age of the group.

18.2.2.1.2. SoCalGas

SoCalGas made some general observations as to why its average service lives should be adopted. SoCalGas contends that its depreciation study was performed by using Standard Practice U-4, which the Commission and DRA have recognized as the appropriate guide to determining average service lives and future net salvage rates. In addition, SoCalGas used first hand knowledge of its plant to come up with its depreciation studies, and included the analysis and adjustment of historical data. SoCalGas also contends it has a lot of older transmission and distribution pipe in operation that will need replacing, and that its average service lives reflect this current mix of plant assets.

For three of the four gas plant accounts that TURN proposes adjustments for, SoCalGas contends that the same Iowa curve was authorized in the 2008 GRC, and that PG&E's recently authorized average service lives support the reasonableness of SoCalGas' results rather than TURN's. On account 390 regarding structures and improvements, SoCalGas contends its currently authorized average service life of 20 years is more reasonable than TURN's proposal of 30 years.

18.2.3. SDG&E's Average Service Lives

18.2.3.1. Position of the Parties

18.2.3.1.1. TURN and UCAN

TURN and UCAN object to SDG&E's proposed average service lives, and contend that SDG&E has understated the reasonable expected average service life for three electric accounts, and three gas accounts. TURN and UCAN contend that SDG&E relied on a mathematical curve-fitting process to analyze historical data, which "inappropriately assigns an equal weight to all points tested, even though each point may reflect widely differing levels of investment." (Ex. 552 at 9.) TURN and UCAN contend that justifiable and professional judgment must be used rather than on relying on mathematical curve-fitting. TURN and UCAN also expressed concern with SDG&E's time period for its data base that it analyzed, which fails to account for significant changes in the type of investment placed into service over time, and fails to capture important information such as the impacts of changing programs and policies that have an impact on life characteristics.

For SDG&E, TURN and UCAN recommend adjustments to three electric accounts, and three gas plant accounts. The three electric accounts make up 59%

of the electric distribution plant investment, and the three gas accounts make up 87% of gas transmission plant and 56% of gas distribution plant investment. The total impact of the adjustments that TURN and UCAN recommend is a depreciation expense reduction of $17.754 million annually based on plant as of December 31, 2009.

18.2.3.1.2. SDG&E

SDG&E also made the same general observations that SoCalGas made, as to why its average service lives should be adopted. SDG&E contends that its depreciation study was performed by using Standard Practice U-4, which the Commission and DRA have recognized as the appropriate guide to determining average service lives and future net salvage rates. In addition, SDG&E used first hand knowledge of its plant to come up with its depreciation studies, and included an analysis and adjustment of historical data. SDG&E also contends it has a lot of older transmission and distribution pipe in operation that will need replacing, and that its average service lives reflect this current mix of plant assets.

For the three electric accounts that TURN and UCAN propose adjustments for, SDG&E contends that its average service lives are reasonable and present a better fit as shown in its Iowa curve analysis.

For the three gas plant accounts that TURN and UCAN propose adjustments for, SDG&E contends that PG&E's recently authorized average service lives for these three accounts support the reasonableness of SDG&E's average service lives rather than those of TURN and UCAN.

18.2.4. Discussion

The adjustments that TURN and UCAN propose result in longer average service lives, as compared to what the Applicants have recommended. This is accomplished through the use of more conservative life-curve combinations, which according to TURN and UCAN are based on their witness' knowledge and experience as set forth in Exhibits 551 and 552. The adjustments of TURN and UCAN have the effect of reducing depreciation expense, which lowers the overall revenue requirement.

We have reviewed the competing testimonies of the Applicants, and of TURN and UCAN.

For SoCalGas, we adopt the average service lives that SoCalGas proposed. Our reasoning for adopting SoCalGas' average service lives instead of TURN's is based on the similar average service lives that were adopted previously for SoCalGas in its 2008 GRC, as well as the average service lives that were adopted for PG&E for the same accounts based on the depreciation parameters that the Commission adopted in PG&E's recent GRC proceeding. In addition, there is the likelihood that the transmission and distribution integrity management programs will lead to earlier retirements of transmission and distribution mains. Furthermore, SoCalGas' average service lives better reflect the mix of plant assets that are providing service to current ratepayers. For account 390, structures and improvements, SoCalGas' average service lives are correlated to the structure's lease period, and reflect the allocation of costs to ratepayers receiving service.

For SDG&E, we adopt the average service lives that SDG&E has proposed. For the three electric accounts, SDG&E's life-curves are more representative of the data, as compared to the life-curves of the TURN and UCAN witness. For the three gas accounts, the average service lives are comparable to the average service lives adopted for PG&E for the same accounts, and reflect the current mix of assets and the transmission and distribution integrity programs that are underway.

Based on the evidence presented, the average service lives of the Applicants are adopted.

18.3. Future Net Salvage and DRA's Third Party Reimbursement

18.3.1. Introduction

Future net salvage rates were included in the Applicants' depreciation studies. The future net salvage rates are based on a determination of the salvage value and the cost of removal, and are expressed as a percentage of the cost of the retired asset. The future net salvage rate is used to reduce the Applicants' depreciation expense in recognition that there is some residual value remaining after the asset has been retired and removed.

DRA believes that the Commission should adjust several net salvage rates of SDG&E and SoCalGas to zero. This is based on DRA's belief that monies for CIAC were not spent or assigned to accumulated depreciation reserve from 2000 to 2010.

TURN and UCAN propose adjustments to the future net salvage rates of the Applicants.

18.3.2. Position of the Parties

18.3.2.1. DRA

DRA disagrees with two of the future net salvage rates for SDG&E, and one for SoCalGas, that were contained in the Applicants' depreciation studies. DRA's disagreement regarding these three future net salvage rates centers on its contention that the funds that the Applicants receive for CIAC, less expenses, should be booked to gross salvage. DRA refers to the CIAC funds as third party reimbursements.

DRA believes that CIAC should be booked to gross salvage because in its review of the Applicants' depreciation studies, DRA compared the amount the applicants collected for future net salvage through authorized rates to the actual net salvage dollars that were spent by the Applicants for the six year period of 2005-2010. During that period, DRA contends that SDG&E collected about $406 million in rates from customers for net salvage, but only spent about $190 million for the cost of removal. SoCalGas collected about $432 million in rates from customers for net salvage, and only spent about $85 million for the cost of removal. DRA acknowledges that the unspent amounts collected will be used to prefund the cost of removal in the future.

Due to this difference between what has been collected and spent on net salvage, DRA believes that an adjustment of two future net salvage rates are warranted for SDG&E, and one future net salvage rate is warranted for SoCalGas. DRA's other reason as to why it believes these adjustments are needed is because it will help mitigate the Applicants' lack of record keeping concerning the CIAC.

DRA's adjustment would reduce the future net salvage rate for SDG&E's electric distribution underground conduit (Account 366) from 40% to zero percent, and its gas distribution mains (Account 376) from 45% to zero percent. For SoCalGas, DRA's adjustment would reduce the future net salvage percentage for its gas mains (Account 376) from 55% to zero percent. As a result, DRA's adjustments would reduce SDG&E's rate base by $123 million, and SoCalGas' rate base by $10 million, by zeroing out the future net salvage rates. DRA contends that this total deduction of $133 million corresponds to the amounts of third party reimbursements that were received from 2000-2010 which have not been spent or assigned to accumulated depreciation reserve. DRA contends that these adjustments will still allow the Applicants to continue to collect sufficient funds in rates to pre-fund the future cost of removal.

18.3.2.2. TURN and UCAN

TURN and UCAN contend that the Applicants failed to properly support its future net salvage proposals through a "mechanical application of a 15-year average of its historical database." (Ex. 551 at 23; Ex. 552 at 30.) For SoCalGas, TURN proposes adjustments to five accounts, which results in a $19.016 million reduction to annual depreciation expense based on plant as of December 31, 2009. For SDG&E, TURN and UCAN propose adjustments to six accounts, which results in a $22.860 million reduction to annual depreciation expense based on plant as of December 31, 2009.

TURN and UCAN also contend that the Applicants are requesting excessive negative levels of net salvage due to the accounting treatment by the Applicants of reimbursed retirements, which causes the Applicants' historical database to yield excessive levels of negative net salvage. TURN and UCAN assert that the "amounts received as 'reimbursed retirements' should be recorded as salvage rather than a reduction to the cost of new plant in service." (Ex. 551 at 25; Ex. 552 at 31.) To remedy this, TURN and UCAN suggest that the Applicants be ordered to revise its historical database to determine the proper amount of depreciation expense in this proceeding. If this is not feasible, TURN and UCAN recommend that the Applicants be ordered to do the following: "(1) changes its practices so that it properly accounts for reimbursed retirements in accordance with NARUC's [National Association of Regulatory Utility

Commissioners] Interpretation 67 regarding this matter; and
(2) perform account-specific analysis necessary to revise the Company's historical database on an annual basis, appropriately reflecting reimbursed retirements such that by the time of the next depreciation study there is a minimum of 10 years of corrected and appropriately accounted-for net salvage." (Ex. 551 at 27; Ex. 552 at 34.)

18.3.2.3. SDG&E and SoCalGas

The Applicants contend that DRA's proposal is improper, poorly supported, and lacks any precedent or authority. The Applicants contend that it is impossible to have a future net salvage rate of zero. According to the Applicants, an appropriate future net salvage rate allows the utility to accrue an amount for future cost of removal in an equitable manner. The cost of removing that asset should be collected from the generation of customers for whom this asset was used to provide service, which is known as the principle of intergenerational equity. This principle is incorporated into the Applicants' future net salvage rates. The Applicants contend that DRA's proposal is contrary to this principle, and is arbitrary in that DRA's proposal targets two of the largest gas accounts for SDG&E, and one of the largest gas accounts for SoCalGas.

The Applicants contend that the adjustments recommended by TURN and UCAN "are inferior to the sound and reasoned outcomes" of the Applicants' depreciation studies, and which were conducted in accordance with the Commission's Standard Practice U-4 methodology. (Ex. 240 at 2; Ex. 244 at 2.) In addition, the challenges by TURN and UCAN to the Applicants' depreciation method and studies are contrary to DRA's acceptance of the same depreciation studies (except for DRA's CIAC argument).

18.3.2.4. SCE

SCE supports the Applicants' accounting for CIAC, and contends that DRA's proposal would fundamentally change how the utilities account for CIAC. SCE further states that DRA's proposal conflicts with the FERC USOA, and with the guidance provided by NARUC. SCE also contends that DRA's assertion that SCE applies all CIAC payments, less expense, to gross salvage is false.

18.3.3. Discussion

We are not persuaded to change or adjust the future net salvage rates based on the arguments of DRA, TURN and UCAN.

We first address DRA's proposal, and the similar argument of TURN and UCAN, that the Applicants be ordered to prospectively change their ratemaking accounting for CIAC so that all CIAC, less expenses, are assigned to gross salvage.

CIAC are the payments received from certain customers "to install, improve, replace, or expand facilities other than those normally provided by the utility." (Ex. 361 at 2.) The most common CIAC projects are for relocation and installation of new facilities. The Applicants and SCE contend that DRA's proposed accounting for CIAC is based on faulty reasoning, and is contrary to the FERC USOA, and the guidance provided by NARUC. We agree. As the Applicants and SCE point out, DRA fails to distinguish between different scenarios as to how CIAC is treated.

In reviewing what accounting treatment is correct, it is important to keep in mind the possible construction scenarios that may result in CIAC being paid to the Applicants. These scenarios are: (1) the construction and installation of a new asset; (2) retirement of an existing asset; and (3) replacement, which includes the construction and installation of a new asset and the retirement of an existing asset.

Under the first scenario of the installation of a new asset and CIAC reimbursement from a third party to the Applicants, the "CIAC payments are credited (or offset) against the related projects' actual costs." (Ex. 361; *See* Ex. 589 at 15.) Such treatment is consistent with the FERC's Uniform System of Accounts for electric utilities and gas utilities found in Part 101 and Part 201 of Title 18 of the CFR, respectively. The relevant passage in paragraph 2.D. of the electric plant instructions in Part 101, and the gas plant instructions in Part 201, states: "Contributions in the form of money or its equivalent toward the construction of gas plant shall be credited to the account charged with the cost of such construction." There is nothing in the USOA which requires all CIAC to be assigned to net salvage.

Under the second scenario of when an existing asset is retired without any replacement, and the Applicants receive CIAC reimbursement from a third party, the payment is credited to accumulated depreciation. Such treatment is provided for in "Balance Sheet Accounts" 108.B in Part 101 and Part 201 of the CFR, which state in pertinent part: "<u>At the time of retirement</u> of depreciable [electric/gas] utility plant, this account shall be charged with the book cost of the property retired and the cost of removal and <u>shall be credited with the salvage value and any other amounts recovered</u>, such as insurance." (Emphasis added.) It is important to note that the "any other amounts," such as CIAC, are credited to accumulated depreciation only when the plant is <u>retired</u>. Thus, DRA's argument that this passage "provides that the <u>entire</u> [CIAC] should be credited to the depreciation reserve" is wrong. (Ex. 471 at 16, emphasis added.)

Under the third scenario of retiring an existing asset and replacing it with a new asset, if the CIAC helps reimburse for retirement and replacement costs, a portion of that is applied to the cost of the new asset and a portion applied against accumulated depreciation. This is consistent with paragraph 11, "Work Order and Property Record System Required," under the Electric Plant Instructions of Part 101 of the CFR, and the similar provision found in the Gas Plant Instructions of Part 201 of the CFR, which state "that all items relating to the retirements shall be kept separate from those relating to construction…."

As for DRA's argument that NARUC Interpretation 67 and SCE's actions in A.10-11-015 support DRA's proposed method of assigning all CIAC to gross salvage, this is contradicted by the testimony of the Applicants and SCE.[182]

Simply put, DRA's proposal to have the Applicants "prospectively change its accounting system regarding [CIAC] so that retirement data associated with [CIAC] is available and all [CIAC] less expense are assigned to gross salvage," is not supported by the evidence. Similarly, the argument of TURN and UCAN that the CIAC funds should be booked as salvage is also not supported by the evidence.

We now turn to DRA's proposed $133 million adjustment. DRA proposes to make that adjustment by zeroing out the future net salvage rates for SDG&E's underground conduit and gas distribution mains, and SoCalGas' mains. DRA's proposed adjustment is based on the premise that from the period from 2000-

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182 TURN and UCAN also rely on NARUC Interpretation 67 to support its argument that "the funds obtained from a third party be assigned to plant, all funds received less expenses 'shall' be booked as salvage in the accumulated provision for depreciation." (Ex. 551 at 25; Ex. 552 at 32.)

2010, CIAC money was not "spent or assigned to accumulated depreciation reserve," and that the Applicants were unresponsive to DRA or were deficient in their recordkeeping. (Ex.471 at 12-15, 19.)

We are not persuaded, based on the Applicants' data responses to DRA and the timing differences as explained by the Applicants, that the Applicants were unresponsive to DRA or had poor records. Since we have found that the Applicants accounting of CIAC funds is in accord with the FERC USOA, as discussed above, and because DRA's proposal to adjust the future net salvage rates of the Applicants is tied to its CIAC argument, DRA's zeroing out of the future net salvage rates is not adopted.

We now turn to the proposed adjustments of TURN and UCAN to the Applicants' proposed future net salvage rates. In our analysis of the proposed adjustments, we have reviewed the competing testimonies and the briefs of the Applicants, and of TURN and UCAN.

For SoCalGas, we adopt the future net salvage rates that SoCalGas proposed. Our reasoning for adopting SoCalGas' future net salvage rates instead of TURN's is based on the observed trends for future net salvage, the data relied on by SoCalGas for its future net salvage, and the familiarity of the SoCalGas witness with the assets that are the subject of TURN's adjustments.

For SDG&E, we adopt the future net salvage rates that SDG&E proposed based on the following reasons. For the six electric accounts that are subject to the proposed adjustment of TURN and UCAN, SDG&E's future net salvage rates are more representative of the data that SDG&E uses than the data that TURN and UCAN rely on. In addition, the SDG&E witness is more familiar with the SDG&E assets than the witness who is sponsoring the adjustments for TURN and UCAN.

Based on the evidence presented, the future net salvage rates of the Applicants are adopted.

19. Taxes

19.1. Introduction

This section on taxes covers the tax expense of SDG&E and SoCalGas. The tax expense covers the following three categories of taxes: (1) payroll taxes; (2) ad valorem (property-related taxes); and (3) income taxes. Included within this section are the franchise fees that SDG&E and SoCalGas incur.

For payroll tax expense for test year 2012, SDG&E forecasts a total of $16.661 million, and SoCalGas forecasts a total of $37.243 million.[183] For ad valorem taxes, SDG&E forecasts a total of $62.947 million, and SoCalGas forecasts a total of $44.082 million.[184] For income taxes, SDG&E forecasts a total of $171.392 million, and SoCalGas forecasts a total of $133.576 million. For franchise fees, SDG&E forecasts a total of $58.349 million, and SoCalGas forecasts a total of $29.651 million.[185]

In the sub-sections below, we address each of the four categories of expense, and the issues that parties have raised.

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[183] These two amounts are the payroll taxes for non-capitalized wages. If capitalized payroll taxes are included, SDG&E's forecast would be $32.323 million, and SoCalGas' forecast would be $45.775 million.

[184] These amounts do not include the capitalized ad valorem tax on CWIP. For SDG&E, this amounts to $1.515 million, and $1.747 million for SoCalGas. (*See* Ex. 596 at 12.)

[185] The forecasts of SDG&E and SoCalGas for these expenses will be affected by the O&M expense and capital that are adopted in this decision, and will be recalculated to reflect the adopted amounts.

19.2. Payroll Taxes

19.2.1. Introduction

As described in Exhibits 298 and 300, the payroll taxes cover the cost of the following: (1) Federal Insurance Contributions Act (social security taxes); (2) Federal Unemployment Tax Act; and (3) California State Unemployment Insurance. The payroll taxes were estimated by applying the tax rate on the test year 2012 O&M and capital labor up to the maximum wage base. Since the payroll taxes are paid for by the employer and the employee, the costs included in this section pertain only to the payroll tax liability of SDG&E and SoCalGas.

19.2.2. Position of the Parties

19.2.2.1. DRA

DRA takes issue with the forecasts of SDG&E and SoCalGas for payroll taxes. Instead of using the Applicants' composite tax rates, DRA's composite tax rate was derived for the five-year average of 2006-2010. DRA also contends that the Applicants' double counted the effect of the increase in the Old Age, Survivors, and Disability Insurance (OASDI)

19.2.2.2. TURN and UCAN

TURN takes issue with SoCalGas' forecast of its payroll taxes, while UCAN takes issue with SDG&E's forecast of its payroll taxes. Instead of SoCalGas' forecast of $45.775 million (includes capitalized payroll taxes), TURN forecasts $36.067 million. Instead of SDG&E's forecast of $32.323 million, UCAN forecasts $17.100 million.

The differences between the forecasts of the Applicants, and the forecasts of TURN and UCAN, are because of the different taxable wage base estimates, the change in payroll tax rates, and the forecast of TURN and UCAN for inflation. TURN and UCAN used a wage base estimate of $110,700, which came from the 2011 edition of the Annual Report of the Social Security Trust fund. The Applicants used a wage base estimate of $114,900 which is based on the 2009 edition of that report. For the Social Security payroll tax percentage, the TURN and UCAN calculation reflects the constant maximum income and inflation.

19.2.2.3. SDG&E and SoCalGas

On DRA's reductions to the forecasts of SDG&E and SoCalGas for payroll taxes, the Applicants contend that they did not use the five-year average (2005-2009) to calculate the total composite tax rate as DRA claims. Instead, the Applicants "calculated a companywide composite tax rate for the 2009 base year by dividing total payroll taxes paid in 2009 by 2009 Medicare taxable wages…." (Ex. 302 at 16.) Since the Applicants did not make unauthorized updates to earlier forecasts based on later data, they contend the 2009 represents the correct base year to forecast the test year. Since DRA's total composite tax rate uses a five-year average that includes 2010 data, the Applicants contend that it is inappropriate to make an isolated update using 2010 data. The Applicants also contend that they did not double count the effect of an increase in the OASDI taxable wage base. The Applicants further contend that their forecasted composite payroll tax rates of 7.15%for SDG&E, and 7.81% for SoCalGas, are reasonable and should be adopted.

Regarding the forecasts of TURN and UCAN, the Applicants acknowledge that the payroll tax data may differ from what was originally forecast when the Applicants submitted their applications. However, the Applicants contend it would be inappropriate to make isolated updates by using 2011 information because "selective updating ignores the fact that while certain costs may be lower than expected, other costs are higher than expected and there is no provision to reflect those instances." (Ex. 302 at 18.) The Applicants also contend that their forecasted composite payroll tax rates are reasonable and should be adopted.

19.2.3. Discussion

We have reviewed the testimony and the arguments concerning the forecasts of the payroll taxes for SDG&E and SoCalGas. We agree with SDG&E and SoCalGas that, under the circumstances and with the update, their forecasts of the payroll taxes are reasonable and should be used instead of adopting the adjustments that DRA, TURN and UCAN have proposed.

19.3. Ad Valorem Taxes

19.3.1. Introduction

The ad valorem taxes cover the taxes paid to the California State Board of Equalization (SBE) on property owned and used by SDG&E and SoCalGas.

The ad valorem taxes "are a function of the assessed value of property and a tax rate applied to that value." (Ex. 298 at 4; Ex. 300 at 3.) The primary indicator of value for utility property that is being assessed is the historical cost less depreciation (HCLD), and the secondary indicator is the capitalized earnings ability (CEA). According to the Applicants, HCLD is used as the primary indicator of value because it approximates rate base, and the "HCLD is equal to the estimated cost of property which is subject to assessment by the SBE less the accumulated depreciation taken on the property." (Ex. 298 at 4; Ex. 300 at 4.) The CEA is an income approach to assessing value, which "is used when the property being appraised is purchased in anticipation of receiving income…, and the actual future income stream can be reliably forecast, or a hypothetical income stream can be estimated by comparison to other similar properties." (*Ibid*.)

None of the other parties oppose the ad valorem forecasts of SDG&E and SoCalGas. Based on our review of the testimony, it is reasonable to adopt to adopt the ad valorem forecasts of SDG&E and SoCalGas.

19.4. Income Taxes

19.4.1. Introduction

The income taxes covered in this section are for the taxes incurred by SDG&E and SoCalGas for federal income tax, and the California Corporation Franchise Tax. In their forecasts of these taxes, SDG&E and SoCalGas used the federal and state tax rates of 35% and 8.84%, respectively. The methodology and adjustments they made are described in greater detail in Exhibits 298 and 300.

DRA has raised two issues with respect to the Applicants' forecasts of income taxes. The first issue pertains to meals and entertainment while on business travel. The second issue deals with recent tax law changes for bonus depreciation, and the effect on net operating losses.

19.4.2. Meals and Entertainment

19.4.2.1. Position of the Parties

19.4.2.1.1. DRA

DRA recommends that the Applicants' 100% allowance for business travel meals should be reduced to 50%, and that any business travel that includes entertainment and paying for family members be eliminated from the revenue requirement.

DRA contends that the Commission's "ratemaking reflects an Internal Revenue Code limit of 50 percent on the deduction for expenditures on meals incurred as part of business travel," and cites to D.09-03-025 in which the

Commission disallowed meals and business expense in SCE's test year 2009 GRC. (Ex. 480 at 7.) DRA also contends that the spending on entertainment and family be eliminated from the revenue requirement because of the Commission's policy that "entertainment, political, and social expenses of utilities…are an unfair economic burden on ratepayers." (Ex. 480 at 8; *See* D.09-03-025 at 315.)

Since DRA's accounting adjustment for these kinds of expenses should have been done earlier, DRA removed "them at a more aggregated level" by making the adjustment in the income tax section. (*See* Ex. 480 at 8-9.) As a result, DRA estimates reductions of $773,000 for SDG&E, and $889,000 for SoCalGas.

19.4.2.1.2. SDG&E and SoCalGas

The Applicants contend that "DRA's proposed adjustments to recoverable costs pertain to the accounting of Applicants'' meals and entertainment expenses, which is outside the scope of Applicants' tax showing." (Ex. 302 at 2.) The Applicants further state that "Federal and state tax laws provide a deduction for only 50% of business meals and entertainment expenses," and that the

"Applicants' respective tax expense calculations will reflect this deduction in accordance with the outcome of this accounting issue." (Ex. 302 at 2-3.)

In their opening brief, the Applicants state that the "company maintains strict policies over [meals and entertainment' that require documentation of business purpose, which are subject to IRS and internal auditing." (Applicants' Opening Brief at 428.) The Applicants also assert that meals and entertainment "serves a business interest by enhancing business relationships with vendors, suppliers and other key constituents who play a role in [SoCalGas'] business in serving ratepayers." (Applicants' Opening Brief at 429.)

19.4.2.2. Discussion

We have reviewed the testimony and arguments of the parties, and also reviewed the decisions cited by DRA. DRA's recommendation to adjust the income taxes is essentially based on its contention that SDG&E and SoCalGas have not justified their meals and entertainment expenses, which are normally addressed as part of the A&G expenses. Instead of recommending an adjustment to the Applicants' A&G expenses, DRA seeks to make that adjustment in the income tax expenses.

We note that neither DRA nor the Applicants have fully investigated the meals and entertainment issue. DRA's audit of the Applicants apparently did not look into this issue, and DRA's A&G witness did not raise this as an issue. On the other hand, the Applicants did not provide any documentation in its rebuttal testimony on taxes that support its argument that the meals and entertainment serve a business interest. In D.09-03-025, the Commission disallowed SCE's meals and entertainment because SCE did not have any accounting safeguards in place to show that these expenses are justified as a business expense.

Based on all these considerations, it is reasonable to adopt DRA's recommendation to make reductions to the income taxes of SDG&E and SoCalGas because the Applicants have not demonstrated that the meals and entertainment expenses serve a useful business-related purpose. However, instead of adopting DRA's amounts, we will reduce the total income tax expense for SDG&E by $500,000, and for SoCalGas by $500,000. Should DRA decide to address the meals and entertainment issue in future GRC applications, it should raise the meals and entertainment issue in connection with the A&G expenses.

19.4.3. Bonus Depreciation and Net Operating Losses

19.4.3.1. Introduction

The Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 (Tax Relief Act) provides for an extension and enhancement of bonus depreciation for 2010, 2011, and 2012. Bonus depreciation is an additional amount of deductible depreciation that can be taken in an accelerated manner. According to DRA, the "effect of the bonus depreciation provisions is to reduce current income tax obligations on an IRS basis so as to create net operating losses." (Ex. 480 at 12; *See* Ex. 590 at 6-7.)

It is the convergence of the bonus depreciation and the net operating loss which has caused DRA to take issue with the Applicants' net operating losses. Instead of incorporating bonus depreciation into DRA's version of its Results of Operation model, DRA "constructed a factor to gross-up its deferred taxes offset to ratebase and thereby reflect the impact of the surge in bonus depreciation created by the Tax Relief Act." (Ex. 480 at 12-13; Ex. 302 at 5.)

Both SDG&E and SoCalGas have made adjustments to their rate base due to reflect the net operating loss created by the accumulated deferred federal income tax (ADFIT), and the bonus depreciation. The ADFIT is a result of "the difference between normalized tax depreciation computed using a book life and book method and the comparable tax depreciation computed using ACRS [accelerated cost recovery system] or MACRS [modified accelerated cost recovery system]…." (Ex. 298 at 15; Ex. 300 at 12.)

A brief review of recent legislation and applicable laws is needed in order to understand how bonus depreciation, the ADFIT, and the net operating loss affect the Applicants. Since the effective data of the Applicants' last GRC decision, four pieces of federal legislation were enacted that have tax implications for the Applicants' test year 2012 forecasts. The Tax Relief Act extended and enhanced the bonus tax depreciation provisions that were in effect in 2010 pursuant to earlier legislation. Section 401 of the Tax Relief Act amended Internal Revenue Code section 168(k) "to extend the period in which taxpayers may elect to claim bonus tax depreciation on qualified capital additions for income tax reporting purposes." (Ex. 298 at 16; Ex. 300 at13.) As a result of that amendment, qualified property that is acquired and placed in service after September 8, 2010 and before January 1, 2012, is eligible for 100% bonus depreciation. Property that is acquired and placed in service after December 31, 2011 and before January 31, 2013 is eligible for 50% bonus depreciation.[186] According to the Applicants, the "effect of these bonus

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[186] On March 29, 2011, the IRS issued Revenue Procedure 2011-26 which sets forth the rules and interpretation concerning the 100% and 50% bonus depreciation allowances set forth in Internal Revenue Code section 168(k). In order to be eligible for the bonus

Footnote continued on next page

depreciation provisions is to reduce current income taxes paid and to increase deferred income tax liabilities that will be paid in the future."[187] (*Ibid*.)

The bonus depreciation that is allowed by the Tax Relief Act is subject to the tax normalization rules in Internal Revenue Code section 168 and the Treasury Regulations under former Internal Revenue Code section 167. The tax normalization rules address how to implement the deferral of the benefit from the bonus depreciation, and what can be done with the deferred tax benefit. The normalization rules require that when a utility claims accelerated tax depreciation, such as bonus depreciation, the utility makes an adjustment to a reserve to reflect the amount of deferral of the federal income tax liability resulting from that depreciation. This results in the ADFIT balance.

21.4.3.2. Position of the Parties

21.4.3.2.1. DRA

The Applicants recomputed their federal tax depreciation on forecasted capital additions to reflect the impact of the 100% and 50% bonus depreciation provisions. As a result of the bonus depreciation, the Applicants state that "current taxes have decreased and deferred federal income tax liabilities have

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depreciation, the property must meet the requirements set forth in Revenue Procedure 2011-26.

[187] The Applicants quantified the impact of the bonus depreciation in July 2011. At that time, SDG&E's "forecasted deferred taxes increased by $155 million compared to the original filing of December 2010 (deferred taxes increased from $506.9 million to $661.9 million)," and SoCalGas' "forecasted deferred taxes increased by $92.2 million compared to the original filing of December 2010 (deferred taxes increased from $563.7 million to $655.9 million)." As a result of the bonus depreciation's impact on current tax liabilities, SDG&E projects it will be in a tax net operating loss in 2010 of -$17.5 million and 2011 of -$34 million. SoCalGas projects it will be in a tax net operating loss position in 2010 of -$35.4 million, 2011 of -$165.9 million, and 2012 of -$29.1 million. (Ex. 302 at 4; Ex. 303.)

increased compared to the Application filing," and the "increase in the accumulated deferred tax reserve results in a reduction to rate base and the revenue requirement…." (Ex. 298 at 18; Ex. 300 at15.) Due to the bonus depreciation, SDG&E will be in a tax net operating loss position in 2010 and 2011, and SoCalGas will be in a tax net operating loss position in 2010, 2011, and 2012. The Applicants propose carrying back the net operating losses to the previous two years, and then carrying forward the remaining net operating losses.

DRA opposes the Applicants' carry back and carry forward of the net operating losses. DRA recommends that the Applicants' carry back and carry forward proposal be rejected because it believes that D.84-05-036 prohibits the practice of using carry forwards for ratemaking purposes. DRA points to the statement in D.84-05-036 (15 CPUC2d at 55) that states: "We agree that the practice of excluding carry backs and carry forwards from the test-year calculation of income taxes is well founded and should continue."

DRA recommends that its gross-up benefits factor method be adopted to account for the net tax benefits resulting from the Tax Relief Act. DRA had insufficient time to input its forecasts and adjustments into the Results of Operations model that was updated by the Tax Relief Act. To "capture the effect of the bonus depreciation, DRA constructed a factor to gross-up its deferred taxes offset to ratebase and thereby reflect the surge in bonus depreciation created by the 2010 Tax Relief Act." (Ex. 480 at 12-13) DRA's gross-up factor is composed of the ratio of DRA's Plant-in-Service over the Applicant's Plant-in-Service as originally filed in December 2010, multiplied by the quantity of the Applicant's deferred tax balance from the update less its deferred tax balance from the December 2010 application. DRA contends that this gross up factor captures the effect of the bonus depreciation on ratemaking. DRA's method would result in an approximate increase of $53.241 million to accumulated deferred taxes for SDG&E, and an approximate increase of $86.046 million to accumulated deferred taxes for SoCalGas.

7.2.4.1.1. PG&E

PG&E is opposed to DRA's recommendation that the Applicants be prevented from carrying forward the net operating loss. PG&E contends that DRA's proposal to eliminate the deferred tax asset would have the effect of reducing the rate base by more than the Applicants are forecasting. PG&E contends that DRA's reliance on D.84-05-036 is in error, and that DRA "confuses income tax expense with deferred income tax liabilities and/or assets."[188] (Ex. 579 at 2.) PG&E also contends that DRA's gross-up factor proposal could violate the normalization requirements of the Internal Revenue Code.

7.2.4.1.2. SCE

SCE takes the position that DRA's proposal to prohibit the Applicants' use of the carry forward of the net operating losses, and DRA's gross up factor method, are inappropriate. SCE contends that "Under the DRA's proposal, every dollar of accelerated depreciation claimed by the Company on its tax returns will reduce its rate base – even though, to the extent the deductions simply produced an NOL carry forward, they did not defer any tax…." SCE

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188 PG&E distinguishes between "tax expense" and "deferred taxes." PG&E contends that: "Tax expense is like any other cost in the Results of Operations (RO) that is being currently collected dollar for dollar. 'Deferred taxes' are taxes that are *included* in tax expense (and thus currently collected from customers), but that are not forecasted to be currently paid to the government because of accelerated tax depreciation. Deferred taxes…are treated as government-supplied, not investor-supplied, capital and the utility is not entitled to earn a return on the government-supplied capital. Mechanically,…this is accomplished by deducting deferred taxes from rate base." (Ex. 579 at 4.)

asserts that DRA's gross up factor method would violate the tax normalization rules, and the resulting penalty will harm both ratepayers and shareholders.

7.2.4.1.3. SDG&E and SoCalGas

The Applicants contend that they have properly reflected the bonus depreciation and net operating losses in their tax expense, and in their Results of Operation models. They contend that DRA's use of the gross-up factor should be rejected because it is inaccurate, lacks a regulatory foundation, and it significantly overstates the deferred taxes created by the bonus depreciation.

The Applicants contend that the tax normalization rules prevent the Applicants "from passing the current income tax savings resulting from bonus depreciation to ratepayers by lowering the revenue requirement for income tax expense in the cost of service." (Ex. 298 at 17; Ex. 300 at13.) Since the bonus depreciation acts as an investment incentive for the taxpayer, the tax normalization rules are intended to prevent the customers of regulated utilities from receiving lower rates as a result of reduced tax expense. However, the tax normalization rules allow the ADFIT balance generated by the bonus depreciation to reduce the rate base. According to the Applicants, this reduction in rate base is consistent with the concept that utilities are allowed to earn a return on investor-supplied capital, but are not entitled to earn a return on government-supplied capital, i.e., the bonus depreciation.

The bonus depreciation under the Tax Relief Act results in tax deductions that exceed taxable income in some years, which produces a net operating loss. The Applicants contend that this deferred tax asset is not utilized "until the company monetizes the extra bonus depreciation benefit by obtaining a refund of prior years' taxes or offsetting future years' taxes." (Ex. 298 at 19; Ex. 300 at15.) This monetization occurs through the carry back and carry forward of the net operating loss. The Applicants propose to carry forward these unused tax benefits, i.e., net operating losses, to future years.

7.2.4.2. Discussion

We reject DRA's proposal that the Applicants should be prevented from carrying forward the net operating losses that resulted from the impact of the bonus depreciation pursuant to the Tax Relief Act, and to use DRA's gross up factor method.

First we analyze whether D.84-05-036 prohibits a carry forward of a net operating loss. The Applicants, PG&E, and SCE contend that the exclusion of carry backs and carry forwards in D.84-05-036 was only in the context of income tax expense, which is an expense item in a utility's cost of service. The Applicants and the other utilities contend that D.84-05-036 did not address the recognition of deferred taxes [or the rate base impact of carryovers]. DRA takes a contrary view, and argues that D.84-05-036 prohibits the use of carry backs and carry forwards in all situations.

We agree with the Applicants and the other utilities that since the Applicants are reflecting the carry forward as an adjustment to rate base, and not as part of the income tax expense calculation, that this is proper and does not run afoul of the prohibition in D.84-05-036 that "Carry backs and carry forwards should be excluded from the test-year <u>income tax calculation</u>." (D.84-05-036, Conclusion of Law 8 [15 CPUC2d at 61], emphasis added.) In sections I (Introduction) and II (Issues Presented) of D.84-05-036, it is clear that the decision was focusing on the "determination of reasonable allowable ratemaking expenses, and on the "test-year income tax expense." (*Id*. at 43-45.)[189] Based on our review of D.84-05-036, and the references cited by DRA, the Applicants, and the other utilities, we agree with the interpretation of the Applicants and the other utilities that D.84-05-036 does not prohibit the carry back or carry forward of deferred taxes.

Second, the Applicants and the other utilities cite several reasons why DRA's gross-up factor should not be adopted.

One of the Applicants' criticisms of DRA's position, is that DRA did not run the Results of Operations model with the Tax Relief Act update with DRA's other adjustments to determine the effects of the bonus depreciation. Instead, "DRA constructed a factor to gross-up its deferred taxes offset to ratebase and thereby reflect the surge in bonus depreciation created by the 2010 Tax Relief Act." (Ex. 480 at 12-13.) We concur with the Applicants that the tax impacts of the bonus depreciation "must be properly modeled in order to produce accurate, reliable, and reasonable results." (Ex. 302 at 5.) That is because the bonus depreciation, when applied to the qualified capital additions, will have a cumulative effect going forward. DRA's gross-up factor does not account for whether the 50% or 100% bonus depreciation applies, and which assets qualify for this treatment. As a result, DRA's gross-up factor is likely to yield inaccurate

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[189] In the discussion section of D.84-05-036 pertaining to net operating loss carry backs and carry forwards, it is clear that the decision was referring to carry backs and carry forwards in the context of "calculating the appropriate test-year income tax expense." (15 CPUC2d at 55.)

results about the impact of bonus depreciation, as opposed to modeling the bonus depreciation in the Results of Operations model.

Another criticism of DRA's gross-up factor is that it will violate the tax normalization rules by including in the ADFIT balance an amount of deferred taxes attributable to claimed but not yet used depreciation deduction, i.e., the monetization issue. We agree that DRA's gross-up factor will conflict with the timing requirement of the tax normalization rules. As pointed out by SCE's witness, if DRA's gross-up factor is used and is determined to violate the tax normalization rules, this could result in adverse impacts on the Applicants as well as on their customers.

We are persuaded by the testimony of the Applicants and the other utilities on bonus depreciation, the tax normalization rules, and net operating loss, as to why DRA's proposal to prohibit the Applicants from carrying forward their net operating losses, and DRA's gross-up factor method to account for the effects of the Tax Relief Act, should both be rejected.

As for how the calculation of deferred taxes should be done, the Applicants in their reply brief responded to the proposal of TURN and UCAN that the calculation of deferred taxes should include the incentive compensation payments and the actual return. We are persuaded by the Applicants' argument that "a utility's actual tax position as reflected on tax returns or FERC forms will not match the income taxes computed as part of a utility's cost of service or GRC revenue requirement." (Applicants Reply Brief at 258.) As the Applicants point out, and as D.84-05-036 recognized, there are a variety of income and deduction items that are not included in the GRC. Thus, including some items in the calculation of deferred taxes, but excluding other items, would end up in a skewed calculation. Accordingly, the proposal of TURN and UCAN to include the incentive compensation payments and actual return in the calculation of deferred taxes is not adopted.

7.3. Franchise Fees

6.1.1. Introduction

The franchise fees cover the "payments made to counties and incorporated cities pursuant to local ordinances granting a franchise to the company to place utility property in the public rights of way." (Ex. 298 at 28; Ex. 300 at 19.) The franchise fees are based on the gross receipts, as described in Exhibits 298 and 300.

6.1.2. Position of the Parties

6.1.2.1. DRA

To compare the forecasts of the Applicants' franchise fees, DRA used a five-year average of 2006-2010. DRA's use of more recent data results in a $796,000 reduction to SDG&E's forecast of electric franchise fees, and no reduction to SoCalGas' forecast.

6.1.2.2. TURN and UCAN

TURN obtained 2010 data regarding SoCalGas' franchise fees. Since that 2010 data has a lower franchise fee percentage than each of the preceding five years, TURN used a five-year average of 2006-2010 to obtain a lower franchise fee percentage. TURN's recommendation to use the lower franchise fee percentage results in a reduction of $130,000.

UCAN obtained 2010 data regarding SDG&E's franchise fees. According to UCAN, the 2010 confirms that SDG&E's forecast of the electric franchise fees is reasonable. However, UCAN contends that the 2010 data shows that gas franchise fees should not be calculated using SDG&E's five-year average of 2005-2009. Instead, UCAN recommends that the gas franchise fees be calculated using the two-year average of 2009-2010 to calculate the gas franchise fees. UCAN's recommendation results in a reduction of $106,000.

6.1.2.3. SDG&E and SoCalGas

Regarding DRA's reduction to SDG&E's forecast of franchise fees, the Applicants contend that DRA's use of 2010 data is inappropriate because it makes an isolated update. The Applicants also contend that DRA's methodology for calculating the annual composite franchise fee rates is flawed because DRA did not account for the timing of when these franchise fees are paid. The Applicants contend that the methodology they used properly matches "the franchise fees expected to be paid in 2012 to the gross receipts that generated those franchise fees." (Ex. 302 at 20.)

The Applicants also oppose TURN's reduction to SoCalGas' forecast of franchise fees, and UCAN's reduction to SDG&E's forecast of franchise fees. The Applicants contend that the use of the 2010 data by TURN and UCAN is inappropriate because it makes an isolated update. The Applicants also contend that UCAN's use of a two-year average to calculate SDG&E's gas franchise fees does not result in more reliable results than a five-year average.

6.1.3. Discussion

We reviewed the testimony and arguments of the parties concerning the forecasts of the franchise fees. Under the circumstances, it is reasonable to use the five-year average that SDG&E and SoCalGas propose to calculate the forecasts of the franchise fees. The use of the five-year average for both SDG&E and SoCalGas provide a uniform approach for forecasting the franchise fees for both utilities.

7. Miscellaneous Revenues

a. Introduction

Miscellaneous revenues are fees and revenues that the Applicants collect from non-rate sources for providing specific products or services. These revenues include such things as service establishment charges, late payment charges from large customers, returned check charges, collection fees, and rents. The miscellaneous revenues are used to lower rates by reducing the base margin revenue requirements charged to customers for utility service.

As described below, TURN and UCAN recommend that certain adjustments be made to the miscellaneous revenues of the Applicants.

b. SDG&E Miscellaneous Revenue

SDG&E estimates test year 2012 total miscellaneous revenues of $18.902 million for electric distribution, and $5.428 million for gas base margin service.[190] Below is a summary of the proposed test year forecasts of miscellaneous revenues (in thousands of dollars) as compared to recorded 2009.

Description	2009 Recorded	2012 Test Year
Electric Customer Services	8,078	6,586
Rent from Electric Property	5,655	5,006[191]
Other Electric Revenues	7,234	6,547
Electric Subtotal	20,967	18,139
Gas Customer Services	3,508	2,596

[190] According to SDG&E, these miscellaneous revenues exclude the revenues from electric transmission properties and facilities, wheeling charges, and other non-distribution sources.

[191] In Exhibit 435, SDG&E reduced the rent from pole attachment fees from $20.89 to $13.30 as a result of the pole attachment fee agreed to in the approval of SDG&E AL 2225-E in a letter from the Commission’s Energy Division dated February 23, 2011. This reduction in the pole attachment fees reduced the rent from electric property from $5.77 million to $5.006 million.

Rents from Gas Property	195	377
Other Gas Revenue	1,944	2,455
Gas Subtotal	5,647	5,428
Total	26,614	23,567

Each of the above accounts has various components of miscellaneous revenues as described in Exhibit 433.

UCAN recommends that an adjustment be made to SDG&E's estimate of miscellaneous revenues in rents from electric property that comes from pole attachment fees. UCAN's adjustment uses a forecast of 138,370 poles multiplied by a $20.89 fee per pole for a test year 2012 forecast of $3.077 million for pole attachment fees. This is an increase of $852,000 over SDG&E's original forecast of $2.288 million.

SDG&E's original test year 2012 forecast of $2.288 million for pole attachment fees was based on a forecast of 100,589 poles multiplied by the $20.89 fee per pole. However, as noted in the footnote to the table above, SDG&E revised its pole attachment fee forecast as a result of a settlement in a Commission complaint case. SDG&E's revised forecast amounts to $1.524 million and is based on 100,589 poles at a settlement pole attachment fee of $13.30.

UCAN contends that SDG&E's use of the settlement fee of $13.30 is a below-cost fee that prevents SDG&E's ratepayers from being fully compensated for the use of SDG&E's poles, and that ratepayers end up subsidizing the telecommunications providers who attach to poles. UCAN further contends that SDG&E did not adequately represent the interests of its ratepayers when the settlement was reached and agreed to attachment fees which are below cost. UCAN further contends that the settlement provides for increasing the pole attachment fees over time, and that if the PTY ratemaking does not account for this, ratepayers will lose even more in subsequent years. If the Commission does not adopt UCAN's pole attachment fee of $20.89, UCAN recommends that the revenue from the pole attachment fees should be normalized over four years from 2012-2015 resulting in an average pole attachment fee of $14.39, which results in revenues of $2.2 million if 138,370 poles are used.

As SDG&E points out, UCAN did not protest the settlement of the pole attachment fees that was the subject of SDG&E's AL 2225-E.[192] Thus, we are not persuaded by UCAN's argument that we should use a pole attachment fee of $20.89 per pole for the forecast of revenues from pole attachment fees.

However, as UCAN points out, the pole attachment fees that were approved in the settlement provides for an increase in fees from $13.30 in 2012 to $14 in 2013, $14.75 in 2014, $15.50 in 2015, and $16.35 in 2016. We agree with UCAN that the four year average (2012-2015) of the settlement pole attachment fees, which results in $14.39 per pole should be used in the forecast of the revenues from the pole attachment fees as this will provide a more reasonable forecast of these revenues over the GRC cycle.

In order to arrive at the forecast of revenues from the pole attachment fees, SDG&E and UCAN disagree on how many poles should be used in the calculation. SDG&E contends that UCAN's use of 138,370 poles is inaccurate because it includes one-time attachment fees that do not generate annual revenue. Since UCAN did not provide a persuasive reason as to why the use of 100,589 poles should not be used in the calculation, we believe that SDG&E's use of the 100,589 poles is more reasonable than UCAN's estimated number of poles.

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[192] SDG&E's AL 2225-E shows that UCAN was served with a copy of the AL filing.

Accordingly, the test year 2012 forecast of revenues from the pole attachment fees will use the price per pole of $14.39 multiplied by 100,589 poles, which results in a revenue forecast of $1.668 million. Based on the testimony presented, we adopt the remainder of SDG&E's methodology and forecasts of its test year 2012 miscellaneous revenues as reasonable.

c. SoCalGas Miscellaneous Revenues

i. Introduction

SoCalGas estimates total miscellaneous revenues of $103.655 million for test year 2012. Below is a summary of the proposed test year forecasts of miscellaneous revenues (in thousands of dollars) as compared to recorded 2009.

Description	2009 Recorded	2012 Test Year
Customer Services	34,965	33,722
Rent from Gas Property	3,457	666
Other Gas Revenues	31,228	66,295
Other Adjustments	8,215	2,972
Total	77,865	103,655

Each of the above accounts have various components of miscellaneous revenues as described in Exhibit 436.

TURN recommends that adjustments be made to SoCalGas' estimate of miscellaneous revenues in customer services from residential parts, commercial parts, and pipeline services. TURN also recommends adjustments to the rents from gas property, and to other gas revenues from crude oil sales, training activity, and the Federal Energy Retrofit Program.[193] TURN's adjustments result

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[193] As described in Exhibits 437 and 439, SoCalGas subsequently adopted TURN's recommendations regarding rent from property, and training activity. SoCalGas also made adjustments to its revenues from crude oil sales as a result of TURN's adjustments, but continues to disagree on whether TURN's use of a later oil price forecast is appropriate.

in an increase of $2.744 million in miscellaneous revenues over SoCalGas' forecast.

We have reviewed the testimony concerning SoCalGas' forecast of its test year 2012 miscellaneous revenues. Except as noted and adjusted below, we adopt SoCalGas' methodology and forecasts of the test year 2012 miscellaneous revenues as reasonable.

ii. Residential and Commercial Parts

The miscellaneous revenues from residential and commercial parts come from replacing parts in residential gas appliances, and food industry gas appliances. SoCalGas forecasts test year 2012 revenues from the residential parts program of $1.521 million, and from the commercial parts program of $3.063 million, for a total of $4.584 million. TURN forecasts total revenues of $4.765 million from these two services, an increase of $181,000.

SoCalGas used its five-year average, and then adjusted the result for customer growth to arrive at its test year 2012 forecast.

For its adjustment to revenues from residential and commercial parts, TURN used the two year average of 2009-2010 multiplied by TURN's 2012 customer base. TURN contends that SoCalGas' forecast is lower than the recorded amounts for 2008 and 2009, even though the recorded revenues increased each year from 2005-2009. TURN also points out that SoCalGas raised its prices for both residential and commercial parts in 2008, and raised its prices for commercial parts again in 2010. TURN contends its forecast is more reasonable because it reflects the price increases.

We adopt TURN's forecast of the revenues from residential and commercial parts as reasonable. We believe that TURN's forecast is more reflective of the revenue generated from these parts programs as the 2009 and 2010 data incorporates the SoCalGas price increases for these services.

iii. Pipeline Services

Revenues from pipeline services are generated from the installation and maintenance of gas facilities for commercial customers, school districts, cities, and counties.

SoCalGas is proposing a test year 2012 forecast for revenues from pipeline services at zero. According to SoCalGas, it provides pipeline services at the request of different customers. SoCalGas forecasted zero revenues because it expects very little or no activity in 2012 for pipeline services, and because construction work on military installations and campus style projects have decreased due to economic factors.

TURN proposes that the forecast for revenues from pipeline services be set at $709,000. TURN contends that SoCalGas collected revenue for pipeline services in each of the years from 2005-2010, and that the average from 2005-2009 was $761,000 in nominal dollars. In 2010, SoCalGas recorded revenues of $449,000 for pipeline services.[194] If this data were used, the 6-year average from 2005-2010 would be $709,000. Since the amount of revenue received in any year is uncertain and fluctuates, TURN contends that a long average is an appropriate way of treating uncertain revenues.

We adopt TURN's methodology and forecast of $709,000 as revenues from pipeline services in test year 2012 as reasonable. TURN's use of the six year average is appropriate under the circumstances, as compared to SoCalGas'

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[194] TURN points out that SoCalGas' application in this GRC forecasted zero revenues from pipeline services for 2010.

forecast of zero. Although economic uncertainty has caused construction projects to be cut back, TURN's six-year methodology reflects the fluctuations and uncertainty caused by the economy in recent years.

iv. Crude Oil Sales

Revenues from crude oil sales come from the sale of crude oil produced at SoCalGas' underground storage fields. The oil sales revenue forecast are based on the forecasted price of oil times the forecasted volumes. SoCalGas is forecasting revenues of $6.689 million from crude oil sales for test year 2012. TURN recommends a forecast of $7.215 million.

The major difference between the two forecasts is due to TURN's use of August 31, 2011 oil prices instead of SoCalGas' oil prices of August 2009. SoCalGas contends that it is unreasonable to pick another point in time in the future to update the price forecast, and that this also circumvents the GRC updating process.

SoCalGas used closing oil prices from August 2009 to generate the revenues from crude oil sales that was submitted as part of its GRC filing in December 2010. Under the circumstances of how much time has elapsed from the August 2009 closing oil prices, we believe that the more recent oil prices that TURN relied on should be used to forecast the revenues generated from SoCalGas' crude oil sales. The use of TURN's more recent oil prices is reasonable because it reflects the more recent trends in crude oil prices. Accordingly, TURN's methodology and its forecast of $7.215 million are adopted as the test year 2012 forecast of revenues from crude oil sales.

v. Federal Energy Retrofit Program

The Federal Energy Retrofit Program is a federal program that authorizes and encourages the federal government to enter into contracts with utilities to install cost effective energy efficiency measures. Under this program, SoCalGas receives revenues from these infrastructure improvement contracts.

SoCalGas is forecasting revenues of $440,000 from the Federal Energy Retrofit Program for test year 2012. TURN's forecast recommendation of $526,000 is an increase of $80,000 over SoCalGas' forecast.

SoCalGas used its five-year average, and contends its forecast is appropriate and is similar to how it forecasts the revenues from customer service field activities. SoCalGas contends that TURN's methodology produces the highest result, as opposed to the most accurate result. SoCalGas contends that in light of the year to year variations reflected in the revenues from customer service field activities, that its forecast is more reasonable than TURN's method.

TURN contends that SoCalGas' use of the five-year average methodology is inappropriate because SoCalGas acknowledged that this program was in a start-up phase in 2005 and that the low 2005 level of revenue is unlikely in the future. TURN recommends that a five-year average of 2006-2010 be used, which would exclude the 2005 data.

We adopt TURN's methodology and forecast of $526,000 as reasonable for revenues from this program. Since this program did not begin until 2005, SoCalGas' five-year averaging methodology of 2005-2009 may underestimate the revenues from this program. Under the circumstances, TURN's methodology of using the five-year average of 2006-2010 is more reflective of the revenues received on an annual basis from this program.

b. Sales and Customers

21.4. Introduction

This section addresses the forecasts of electric and gas customers for SDG&E, and the forecast of gas customers for SoCalGas. The customer forecasts are an important component of the Applicants' overall GRC applications because it affects the O&M costs, and capital expenditures.

This section also addresses the forecast of sales for both SDG&E and SoCalGas.

21.5. SDG&E

21.5.3. Electric Customers and Sales

SDG&E developed its "electric customer forecasts using statistical models based on demographic data, economic data, seasonal patterns and other inputs that influence customer growth." (Ex. 266 at 1.) The economic and demographic data that SDG&E used were based on February 2010 information from Global Insight's Regional Economic Service. A brief description of how the different customer forecasts were developed is set forth in Exhibit 266, and the details behind each forecast are set forth in Exhibit 267.

SDG&E defines its total customers as total active meters. SDG&E forecasts the following number of total average annual electric customers for test year 2012.

Electric Customers	2010	2011	2012
Residential	1,227,609	1,234,330	1,244,624
Small Commercial	121,464	122,916	124,819
Medium/Large C/I	23,922	24,572	25,433
Agricultural	3,348	3,348	3,348
Lighting	6,126	6,019	5,920
Total	1,382,469	1,391,185	1,404,144

SDG&E's total electric sales are forecast at 20,809 gigawatt hours. This forecast is from the CEC's California Energy Demand 2010-2020 Commission-Adopted Forecast, with a publication date of December 2009.

21.5.4. Gas Customers and Sales

SDG&E forecasts 859,709 average annual total gas customers for test year 2012. Of this amount, the forecast of residential gas customers is 829,373, and the forecast of commercial and industrial gas customers is 30,231. For 2010 and 2011, SDG&E forecasts average annual total gas customers of 847,063 and 852,465, respectively.

SDG&E used econometric and statistical techniques to develop quarterly-data forecasts of residential meters, and commercial and industrial meters. A brief description of how the forecasts for the gas customers was developed is set forth in Exhibit 246, and the details behind each forecast is set forth in Exhibit 247.

For the gas sales of SDG&E, it used the gas throughput forecast that was adopted in D.09-11-006.

21.5.5. Position of the Parties

21.5.5.2. DRA

DRA forecasts total electric customers of 1,382,492 in 2010, 1,392,090 in 2011, and 1,405,459 in 2012.[195] According to DRA, its "forecast for total electric customers differs from SDG&E's forecast by less than one percent." (Ex. 491 at 2.)

For total gas customers, DRA forecasts 847,309 in 2010, 852,551 in 2011, and 859,721 in 2012.

For its forecast of electric and gas customers, DRA developed econometric models that are similar to the models used by SoCalGas, or used the same methodology that SoCalGas used. The differences between the models that DRA

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[195] *See* Exhibit 492.

and SoCalGas used are described in Exhibit 491. DRA's forecasts of total electric customers, and total gas customers, are slightly higher than SDG&E's forecasts of total electric and gas customers. The reason for the difference is because of the slightly different models and/or the use of more recent data. DRA relied on the June 2011 University of California Los Angeles' Anderson Forecast for the Nation and California (UCLA Anderson Forecast) for its building permit and employment data. The building permit data is used in the modeling of residential customers, while employment data is used in the modeling of commercial and industrial customers. DRA states that since its forecasts are very close to SDG&E's forecasts, "DRA concludes that SDG&E's forecasts of electric and gas customers for [test year] 2012 are reasonable." (Ex. 491 at 15.)

DRA also adopts as reasonable SDG&E's electric sales forecast, and gas sales forecast.

21.5.5.3. UCAN

UCAN contends that SDG&E "used unrealistic customer growth and energy consumption forecasts," and that SDG&E's forecasts should be replaced by "more realistic forecasts based on up-to-date economic information." (Ex. 557 at 46.)

UCAN forecasts total electric customers of 1,380,437 in 2010, 1,387,461 in 2011, and 1,397,296 in test year 2012. UCAN's forecast of total electric customers is lower than SDG&E' forecast due primarily to the use of more recent building permit data and employment data. At the time SDG&E prepared its forecast, it used Global Insight's employment forecast and housing starts growth forecast from February 2010. UCAN used more recent data from Global Insight's July 26, 2011 forecasts of employment growth, and housing starts growth. UCAN then ran SDG&E's model using this updated data. As described by

UCAN in Exhibit 557, the July 2011 employment growth forecast "is much less optimistic than its February 2010 employment growth forecast," and the July 2011 housing starts growth forecast is 41% less than the February 2010 forecast. (Ex. 557 at 48.) UCAN also contends that its comparison of the 2011 forecasts of SDG&E, DRA, and UCAN, to the actual January-June 2011 average customer count shows that UCAN's forecast deviated by the smallest amount, and "UCAN's forecast appears to most closely predict actual customer counts." (Ex. 557 at 50.)

UCAN also contends that SDG&E's forecast of electric sales and peak demand are too high and outdated. SDG&E's forecast is from the CEC's December 2009 report. UCAN contends that the Commission should use SDG&E's sales and demand forecasts that it submitted in the Long Term Procurement Plan (LTPP) proceeding in R.10-05-006 as a starting point. UCAN also contends that an adjustment should be made to the LTPP forecasts because it does not believe that SDG&E's LTPP forecasts incorporate all of the energy savings. With this adjustment, UCAN recommends an electric sales forecast of 20,352 gigawatt hours, and a 2012 peak demand of 4,422 megawatts.

UCAN contends that the electric sales and peak demand forecasts, and the forecast of electric customers, affect other parts of SDG&E's GRC testimony.

21.5.5.4. SDG&E

On the forecasts of electric customers, SDG&E contends that it reviewed DRA's modeling and worked with DRA to resolve discrepancies that SDG&E had identified. SDG&E contends that this resulted in a change to DRA's forecast of electric customers, which brought "DRA's results even closer to those of SDG&E." (Ex. 268 at 1 and 5; *See* Ex. 492.) SDG&E also points out that DRA concluded that SDG&E's forecasts of electric and gas customers are reasonable, and that SDG&E's forecasts of electric and gas sales are reasonable.

SDG&E contends that UCAN's forecast of electric customers is too low because UCAN's forecast did not "take into account actual electric customer counts through June 2011 for a forecast starting point." (Ex. 268 at 5.) SDG&E re-calculated UCAN's forecast using the updated customer counts, which resulted in adjusted customer forecasts of 1,382,924 in 2010, 1,390,866 in 2011, and 1,401,032 in 2012.

SDG&E also contends that UCAN's comparison of the forecasts to the January-June 2011 actual data contained two errors. If these two errors were corrected, SDG&E contends that its 2011 forecast, for the first six months, tracks almost identically to the actual customer counts.

SDG&E also contends that the use of more recent data should not be permitted because of the reasons it described before.

Regarding UCAN's recommendation to use SDG&E's LTPP forecast as the starting point for the electric sales forecast in this proceeding, SDG&E contends that at the time it prepared the rebuttal testimony, that the LTPP proceeding was still ongoing, and the appropriate electric sales forecast was undecided.

21.5.6. Discussion

We have reviewed the testimony and arguments of the parties, and compared the forecasts of customers to each other. We have also considered whether the more recent data that DRA and UCAN relied on to develop their respective forecasts should be allowed.

SDG&E acknowledged that the UCLA Anderson Forecast is very similar to the information contained in the February 2010 Global Insight forecasts that SDG&E relied upon. As for the use of the later Global Insight forecast, SoCalGas acknowledged that new home building permits have declined since SoCalGas first developed its customer forecast in 2010. Based on those acknowledgements, and the slow economic growth that has taken place during the processing of these applications, and because the timing of these proceedings allowed the other parties to prepare their testimony at a later point in time, we are not persuaded by SDG&E's argument that we should disregard the more recent data that DRA and UCAN relied on to develop their forecasts.

By permitting the use of the July 2011 Global Insight data, and the June 2011 UCLA Anderson Forecast, the next question to decide is which customer forecast we should adopt. Due to the economic slowdown, and the overly optimistic building permit forecast and employment data that SDG&E used to develop its customer forecast, the forecasts of SDG&E and DRA are too high. However, as SDG&E points out, UCAN's calculation did not use updated customer counts. SDG&E then re-adjusted UCAN's calculation.

Based on all of these considerations, it is reasonable under the circumstances to adopt UCAN's forecast of electric customers, as re-adjusted by SDG&E. This re-adjusted forecast of the number of electric customers better reflects the economic conditions that have occurred during the timeframe of this proceeding. Accordingly, we adopt UCAN's electric customer forecast, as re-adjusted by SDG&E, which results in total electric customers of 1,382,924 for 2010, 1,390,866 for 2011, and 1,401,032 for 2012.

As for UCAN's contention that a lower growth estimate will impact the costs in other areas of SDG&E's proceeding, we have examined the impact of slower growth in other sections of this decision.

The next issue is to decide what electric sales forecast should be used for the purposes of SDG&E's GRC application. Since the LTPP proceeding was still ongoing at the time these consolidated proceedings were litigated, we adopt SDG&E's electric sales forecast for purposes of these proceedings.

Regarding the forecast of SDG&E's customers and gas sales, DRA agreed that SDG&E's forecasts were reasonable. No other party took issue with SDG&E's gas customer forecast, or with its gas sales forecasts. Our review of the testimony concerning those forecasts leads us to conclude that both of those forecasts are reasonable and should be adopted.

21.6. SoCalGas

21.6.3. Introduction

SoCalGas forecasts 5,621,055 average annual total active gas meters for test year 2012.[196] Of this amount, the forecast of residential gas customers is 5,410,339, and the forecast of commercial and industrial gas customers is 210,717. For 2010 and 2011, SoCalGas forecasts average annual active meters of 5,520,424 and 5,565,817, respectively.[197]

SoCalGas used "econometric and statistical techniques to develop quarterly-data forecasts of residential, commercial and industrial customers." (Ex. 251 at 2.) A brief description of how the forecasts for the gas customers was developed is set forth in Exhibit 251, and the details behind each forecast is set forth in Exhibit 252.

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[196] SoCalGas' forecast of meters for each customer class was split into active and inactive meters. The inactive meters were forecasted by applying a factor "based on seasonal and multi-year historical patterns of inactive meters for that particular customer class." (Ex. 251 at 3.) The number of active gas meters "is equal to the number of connected meters less the number of inactive meters." (*Ibid.*)

[197] Based on these forecasts, SoCalGas forecasts new meter sets of 45,527, 55,495, and 64,799 for 2010, 2011, and 2012, respectively. (*See* Ex. 252 at 11.)

For the gas sales of SoCalGas, it used the gas throughput forecast that was adopted in D.09-11-006.

21.6.4. Position of the Parties

21.6.4.2. DRA

For test year 2012, DRA forecasts total active customers of 5,584,627 instead of SoCalGas' forecast of 5,621,055. DRA's 2010 forecast of 5,520,424 total active customers is the same as what SoCalGas has forecasted. For 2011, DRA's forecast is 5,536,450 compared to SoCalGas' forecast of 5,565,817. DRA acknowledges that its forecasts are "very close" to the forecasts of SoCalGas. (*See* Ex. 495 at 10.)

For its forecast of customers, DRA developed econometric models that are similar to the models used by SoCalGas. The differences between the models are described in Exhibit 495. DRA's forecast of total residential customers is slightly below SoCalGas total residential customers because of the different models, and because DRA relied on more recent data than what SoCalGas used. Although DRA used different models from what SoCalGas used to forecast the commercial and industrial customers, DRA adopted SoCalGas' forecast of the commercial and industrial customers after concluding that SoCalGas' forecasts were consistent with the historical growth and the expected growth for these customers in its service territory.

21.6.4.3. TURN

TURN forecasts total active customers of 5,554,681 for SoCalGas for test year 2012. For 2010 and 2011, TURN forecasts total active customers of 5,516,668 and 5,530,069, respectively. TURN also forecasted new meter sets of 26,585 for 2010, 23,413 for 2011, and 33,245 for 2012.

TURN's forecast of total active customers is lower than SoCalGas' forecast due primarily to the use of more recent building permit data. At the time SoCalGas prepared its forecast, it used Global Insight's building permit forecasts from February 2009. TURN used the building permit forecasts contained in Global Insight's July 26, 2011 forecast. As described by TURN in Exhibit 545, the July 2011 building permit forecast is about 50% less than the February 2009 forecast.

As described by TURN in Exhibit 545, to arrive at its forecast of total active meters, it updated the forecast of building permits, and re-estimated the models making several adjustments, including the use of a variable in single-family to reflect the slower conversion of building permits to new meter sets that occurred prior to 1990, and another variable to reflect the slower conversion of building permits to new meter sets that has occurred during the 2007-2010 period.

As a result of TURN's lower forecast of customers, TURN recommends reducing SoCalGas' capital spending in five accounts that relate to customer growth. The effect of TURN's recommendation would reduce growth-related capital spending by $89 million as shown in Table 7 of Exhibit 545.

21.6.4.4. SoCalGas

SoCalGas contends that its forecast of active customers and new meter sets is reasonable in light of the recorded data it had through the 2009 year, and "took into account reasonable forecast outlooks and inputs at the time the forecast was conducted." (Ex. 255 at 1.)

Although DRA and TURN used methodologies similar to what SoCalGas used, the differences are due primarily to the use of more recent recorded data, and more recent economic forecasts. As a result, SoCalGas' forecast of new meter sets is affected by the more recent data about home building permits.

SoCalGas acknowledges that economic conditions have not improved as quickly than it originally forecasted. However, SoCalGas contends that it would be inappropriate to make isolated updates because other cost drivers could have increased or decreased, and to revise all the factors would be an endless exercise. In addition, SoCalGas points out that the Rate Case Plan "is very prescriptive regarding the types of information that may be updated in a [GRC] and the proposals by DRA and TURN contravene this intent." (Ex. 255 at 2.) In addition, SoCalGas contends that "the revenue requirement associated with the customer and new meter forecasts must reflect the level of activity that [SoCalGas] expects to occur over the 2012-2015 period." (Ex. 255 at 2-3.)

21.6.5. Discussion

We have reviewed the testimony and arguments of the parties, and compared the forecasts of customers and new meter sets to each other. We have also considered whether the more recent data that DRA and TURN relied on to develop their respective forecasts should be allowed.

SoCalGas acknowledges that the new home building permits have declined since it developed its forecast in 2010. Based on the slow economic growth that has taken place during the processing of these applications, and because the timing of these proceedings allowed the other parties to prepare their testimony at a later point in time, we are not persuaded by SoCalGas' argument that we should disregard the more recent data that DRA and TURN relied on to develop their forecasts.

By permitting the use of the July 2011 Global Insight data, and the June 2011 UCLA Anderson Forecast, the next question to decide is which customer forecast we should adopt. Due to the economic slowdown, and the overly optimistic building permit forecast and employment data that SoCalGas used to develop its customer forecast and forecast of new meter sets, SoCalGas' customer forecast is too high. In reviewing TURN's methodology, TURN appears to make several adjustments that have the effect of reducing the customer forecast by too much. DRA's customer forecast uses the employment and building permit data from the UCLA Anderson Forecast, which is similar to the data that SoCalGas relied on. However, DRA's modeling produced a total customer forecast that is less than SoCalGas using the updated data. DRA also compared its modeling results to the historical data, which reflect that historical data. Based on those various considerations, it is reasonable under the circumstances to adopt DRA's customer forecasts as it better reflects the economic conditions that have occurred during the timeframe of this proceeding. Accordingly, we adopt DRA's total active customer forecast of 5,520,424 for 2010, 5,536,450 for 2011, and 5,584,627 for 2012.

As for TURN's contention that a lower growth estimate will affect growth-related capital spending, we have examined the impact of slower growth in other sections of this decision.

The next issue to address is the forecast of new meter sets. Based on SoCalGas' customer forecasts, SoCalGas forecasts the number of new meter sets as follows: 45,527 in 2010; 55,495 in 2011, and 64,799 in 2012. Since we do not adopt the customer forecasts of SoCalGas and TURN, it is apparent that the forecast of the new meter sets should reflect the adopted customer forecast of DRA. DRA did not forecast the number of new meter sets. Based on our analysis of the relationship of the number of active customers to the number of new meter sets, it is reasonable to adopt the following as the number of new meter sets: 45,527 in 2010; 55,365 in 2011; and 64,223 in 2012.

Since no one disputes SoCalGas' use of the gas throughput forecast that was adopted in D.09-11-006 for its sales forecast, we adopt that gas sales forecast for the purposes of this proceeding.

22. Regulatory Accounts

This section summarizes the various requests of SDG&E and SoCalGas concerning regulatory accounts.

As part of its requests, SDG&E and SoCalGas have requested that the undercollection or overcollection in certain regulatory accounts be addressed. Originally these amounts were addressed in Exhibits 262 and 264. These amounts were then revised in the update testimony in Exhibit 596. None of the other parties have contested the requests of SDG&E and SoCalGas regarding these regulatory balances.

SDG&E requests disposition of the forecasted balances in four regulatory accounts. The first regulatory account is the Advanced Metering Infrastructure Balancing Account. According to Exhibit 596, there is an overcollection of $11.041 million on the electric side, and an undercollection of $3.830 million on the gas side. SDG&E requests that these balances be incorporated into its customers' applicable electric distribution and gas transportation rates for the 2012 GRC rates. Since no one opposed this request, we grant SDG&E's request to dispose of the balances in this balancing account as requested.

The second regulatory account is the DIMPBA. According to Exhibit 596, there is an overcollection of $70,084. We have addressed the disposition of SDG&E's DIMPBA in the Customer Service section of this decision.

The third regulatory account is the RDDEA. According to Exhibit 596, there is an overcollection of $46,379 which represents the balancing account interest. SDG&E requests that the balance in the RDDEA be amortized in the rates of electric customers upon the implementation of the 2012 GRC revenue requirement in this proceeding. Since no one opposed this request, we grant SDG&E's request to dispose of the balance in this balancing account as requested.

SDG&E also requests that the Commission approve its requests concerning the pension balancing account, the PBOP balancing account, the tree trimming balancing account, and to establish the NERBA. All of those issues have been addressed elsewhere in this decision.

SoCalGas requests disposition of the forecasted balances in three regulatory accounts. The first regulatory account is the DIMPBA. According to Exhibit 596, there is an overcollection of $136,000. We have addressed the disposition of SoCalGas' DIMPBA in the Customer Service section of this decision.

The second regulatory account is the RDDEA. According to Exhibit 596, there is an overcollection of $927,000. SoCalGas requests that the balance in the RDDEA be allocated to customers on an equal percent of authorized margin basis upon the implementation of the 2012 GRC revenue requirement in this proceeding. Since no one opposed this request, we grant SoCalGas' request to dispose of the balance in this balancing account as requested.

The third regulatory account is the Polychlorinated Biphenyls Expense Account (PCBEA). According to Exhibit 596, there is an undercollection of $399,000. SoCalGas requests that it be allowed "to amortize the PCBEA balance in gas customers' rates on an equal cents per therm…basis with the implementation of the 2012 GRC, transfer any residual balance at the end of the amortization period to its [Integrated Transmission Balancing Account], and eliminate the PCBEA." (Ex. 264 at 4.) Since no one opposed this request, we grant SoCalGas' request to dispose of the balance in the PCBEA as requested.

Like SDG&E, SoCalGas also requests that the Commission approve its requests concerning the pension balancing account, the PBOP balancing account, and to establish the NERBA. All of those issues have been addressed elsewhere in this decision.

23. Escalation

23.4. Introduction

This section addresses the cost escalation factors that are used by SDG&E and SoCalGas in their labor O&M costs, non-labor O&M costs, and capital-related costs for test year 2012, and the PTY. The cost escalation factors "account for the effects of inflation on [the Applicants'] expenses between 2009 and 2012." (Ex. 248 at 1; Ex. 253 at 1.) The cost escalators are "used to inflation-adjust costs from 2009 nominal dollars into [test year] 2012 nominal dollars, using escalation series from Global Insight's Utility Cost Information Service" (Global Insight). (*Ibid*.)

As contemplated by the Rate Case Plan in D.89-01-040, the Applicants updated their cost escalation factors in Exhibit 596, the update testimony of the Applicants. The updated cost escalations were developed based on the indexes from Global Insight's 3rd Quarter 2011 Power Planner forecast that was published in November 2011. The updated cost escalations also incorporate the O&M labor escalators for wage increases that were agreed to in the new labor agreements for SDG&E and SoCalGas. These updated escalation factors for SDG&E and SoCalGas appear in Exhibit 596 at 3.

According to the Applicants, Global Insight's cost escalators "are based on recorded utility cost data gathered by the [FERC] according to its Uniform

System of Accounts…, then forecasted by Global Insight by functional categories…of grouped FERC accounts." (Ex. 248 at 1-2; Ex. 253 at 1-2.)

For the labor O&M escalation factors, the Applicants used the labor escalators that were agreed to in the new labor agreements for SDG&E and SoCalGas.

For the non-labor O&M escalation factors, SDG&E and SoCalGas developed separate factors based on their different businesses. SDG&E "combined various weighted Global Insight utility cost series to develop single escalation indexes for non-labor O&M gas and non-labor O&M electric expenses." (Ex. 248 at 2.) SoCalGas "combined various weighted Global Insight utility cost series to develop a single escalation index for non-labor O&M expenses." (Ex. 253 at 2.)

For the capital cost escalation factors, both SDG&E and SoCalGas used the construction cost indexes that were forecasted by Global Insight.

For the PTY escalation, SDG&E and SoCalGas propose that their respective "base margin revenue requirements be updated each year according to the PTY ratemaking mechanism…" of the Applicants. (Ex. 248 at 5; Ex. 253 at 4.) For PTY O&M costs, a utility input price index "is calculated and used to adjust O&M expenses to reflect the expected cost inflation of goods and services that [SDG&E and SoCalGas] will incur to serve its customers." (*Ibid*.) This index is based on Global Insight's forecasts.

23.5. Position of the Parties

23.5.3. DRA

For SDG&E, DRA agrees with SDG&E's proposed escalation methodology and results for gas and electric non-labor, electric shared services, and capital escalation. DRA disagrees with SDG&E's proposed labor escalation factors, and appears to disagree with SDG&E's escalation factors for gas shared services.[198]

For SoCalGas, DRA agrees with SoCalGas' proposed escalation methodology and results for non-labor escalation rates, and capital escalation. DRA disagrees with SoCalGas' proposed escalation factors for labor, and shared services.

DRA disagrees with the labor escalation factors for SDG&E and SoCalGas. The Applicants' labor escalation factors are based on a weighted average of three labor related indexes from Global Insight. These indexes were derived from the combined recorded wage and salary expenses from SDG&E and SoCalGas, which include the labor escalation factors agreed to with the unions. DRA is proposing a labor escalation methodology that is different from its approach taken in previous GRCs. Instead of relying on the escalation rates agreed to with the unions, "DRA proposes to base union wage escalation on forecasts taken from the Global Insight Power Planner. DRA's recommended labor escalation rates are: 1.77% for 2010; 2.09% for 2011; and 2.61% for test year 2012. In contrast, the Applicants recommended labor escalation rates are: 2.61% for 2010; 3.02% for 2011; and 2.37% for test year 2012.

Regarding the escalation factors for the PTY ratemaking mechanism, DRA recommends that the mechanism use the CPI – Urban index. DRA contends that

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[198] In Exhibit 493 at 1, DRA states that it agrees with SDG&E's escalation methodology and results for "electric shared services," which implies that DRA does not agree with SDG&E's escalation factor for gas shared services. Then in Exhibit 493 at 13, DRA states that it "adopts SDG&E shared services O&M escalation index." However, Table 6-1 of Exhibit 493 shows differences between the shared services escalation rates of DRA, and those of SDG&E and SoCalGas.

the Commission should adopt this index for the PTY since it will "encourage the Utilities to manage costs, and to operate efficiently and productively between rate cases." (Ex. 529 at 6.)

23.5.4. FEA

In Exhibit 577, FEA expressed some concerns with the methodologies that SDG&E used to derive its proposed escalation factors for labor O&M, non-labor O&M, shared services, and capital costs. FEA contends that since the methodologies SDG&E used are "cumbersome to follow," FEA recommends the escalation factors be based on the most recent CPI. (Ex. 577 at 11.) For the labor escalation factor, FEA agrees with DRA's position to use the Global Insight's labor factors for the different labor categories, instead of SDG&E's labor escalation factor of 3.5%.

23.5.5. SCGC

SCGC recommends that the Commission use the CPI – Urban index, instead of the utility-specific index, for the first three pieces of SoCalGas' PTY ratemaking mechanism. SCGC contends that a utility-specific index will produce rate increases that exceed what a PTY mechanism using the CPI would yield.

23.5.6. UCAN

UCAN contends that the Applicants' revenue requirements are based on "greatly overstated O&M escalation factors." (Ex. 557 at 56.) UCAN contends by using "UCAN's recommended escalation factors for labor O&M, non-labor O&M, and corporate O&M in place of Sempra's recommended escalation factors would reduce SDG&E's 2012 revenue requirement by approximately $8 million and SoCalGas' 2012 revenue requirement by approximately $16 million." (*Ibid*.)

Since it is reasonable to use actual data instead of forecast data whenever possible, UCAN contends that the Commission should use the latest escalation factors that come from the update testimony. However, UCAN disagrees with the Applicants' use of the data from Global Insight. UCAN contends that the Global Insight forecast "is based on assumptions and methods that are not publicly available," and that UCAN has not been provided with "historical forecasts that would enable UCAN to assess the accuracy of the forecasts…." (Ex. 557 at 56-57.) UCAN recommends that the 2012 escalation rates be based on the actual escalation observed through the end of 2011. For the labor O&M escalation factors, UCAN recommends that the factors be based on a linear regression of actual data from the Bureau of Labor Statistics from the start of 2009 until the end of 2011. UCAN contends that this linear regression method should be used instead of the Global Insight forecast "because it provides a simple and transparent way to forecast escalation rates consistent with the escalation observed in the recent past." (Ex. 557 at 57.) For the non-labor escalation factors, UCAN recommends that the forecast data come from the most recent Global Insight forecast.

For the PTY cost escalation factors, "UCAN recommends that SDG&E use actual data on price changes for the first half of the year and an escalation forecast for the remaining half-year," and "that the resulting escalation factor be trued up when actual data are available." (Ex. 557 at 67.) UCAN contends that the Applicants' O&M escalation for the PTY period is flawed because it appears the Applicants are not proposing to true up the 2012 forecast, which could result in the overcharging of ratepayers.

23.5.7. SDG&E and SoCalGas

The Applicants contend that using the CPI – Urban index is not appropriate for escalating utility costs, and that none of the other parties have argued that the "CPI is a better indicator of utility costs than an index tracking utility industry costs." (Ex. 250 at 2.) The Applicants contend that the CPI - Urban index measures changes in the prices of specific goods and services purchased by a typical household in the United States, as shown in Table SRW-1 in Exhibit 248. As such, that index does not measure the price changes for goods and services purchased by businesses, or by utilities in particular. Since utility-specific indexes, or other segment-specific indexes, are available, they should be used to provide "better estimates of anticipated utility cost increases." (Ex. 250 at 3.)

The Applicants contend that using the CPI – Urban index is likely to understate utility cost escalations. Instead of using the cost escalation factors to keep costs down, and to incent management to work harder, as the other parties argue, the Applicants contend that the purpose of the "cost escalation factors is to cover changes in industry costs that are generally beyond an individual utility's control – and thereby help ensure that the utility can cover the costs of providing safe, reliable and obligatory service to its customers." (Ex. 250 at 2.)

DRA, FEA, and UCAN take issue with the Applicants use of the actual union wage increases for the union component of the O&M labor escalator. DRA, FEA, and UCAN recommend that Global Insight's forecast of the wages of United States utility service workers be used instead. The Applicants contend that DRA's position is a reversal of DRA's position in other rate cases in which DRA supported the same kind of actual union wage escalation-based methodology. The Applicants further contend that the Rate Case Plan recognized that the updated labor escalation factors should be based on contract negotiations that have been completed.

UCAN argues that separate labor escalation factors should be used for SDG&E and SoCalGas, instead of a single labor cost escalator which the Applicants used. The Applicants contend that the single labor cost escalator is appropriate because "there remain many areas of employee/work overlap and interchangeability (where SDG&E employees do work for SoCalGas, and vice versa)." (Ex. 250 at 6-7.)

Regarding the cost escalation factors for the PTY ratemaking mechanism, the Applicants contend that since DRA accepts the use of the Global Insight forecasts for non-labor and capital costs for the test year 2012 forecasts, that the same logic applies as to why those indexes should be adopted for the PTY mechanism.

23.6. Discussion

We have reviewed the testimony and arguments of the parties concerning the cost escalation factors, and have compared their forecasts to each other. We have also considered whether Global Insight's utility-specific index is a better indicator of what future utility costs will be, as opposed to using the CPI – Urban index. Using utility-specific indexes, as well as the union approved wage increases for labor escalation, will provide a better reflection of what utility costs will be. To substitute the CPI – Urban index for the utility-specific index would not accurately reflect the costs that affect the utility industry since the CPI – Urban index only examines the price changes for a basket of goods and services consumed by a typical household. Based on all those considerations, we agree that the Applicants' cost escalation factors, as updated and set forth in

Exhibit 596 at 3, should be adopted as the cost escalation factors for the forecasts for test year 2012.

The PTY escalation is discussed later in this decision.

24. Audit and Accounting Issues

24.4. Introduction

As part of the review of the GRC applications of SDG&E and SoCalGas, DRA performed a limited audit. Based on its audit, DRA recommends several adjustments as described in Exhibit 489. DRA recommends changes to the multi-factor allocation percentages, and that the Corporate Center's allocation to SDG&E and SoCalGas of the costs of working on international taxes be disallowed. Those two issues have been discussed elsewhere in this decision. DRA also recommends that the short term lending rate be used to calculate the allowance for funds used during construction (AFUDC) of SDG&E and SoCalGas.

The Joint Parties raised the issue about the reliability and independence of the outside audit of SDG&E and SoCalGas. The Joint parties suggest that the outside audit may be misleading, which could affect certain amounts in the GRC applications of SDG&E and SoCalGas.

Except for the issues that have been addressed elsewhere, this section addresses the audit and accounting issues that the Applicants and other parties raised.

24.4.3. Mapping, Segmentation, and Reassignment

SDG&E and SoCalGas provided testimony on two accounting-related steps that they need to go through in order to generate the revenue requirement from the RO model. The first is the "mapping" process that SDG&E and SoCalGas use to translate their O&M cost forecasts from a cost center format to a

FERC USOA format.[199] As described by the Applicants, the purpose of this translation, or mapping, is to allow for the proper processing of the O&M costs in the RO model so that a revenue requirement result can be produced.

The second accounting-related step is related to the reassignment of certain costs to capital, which applies to both SDG&E and SoCalGas. The reassignment process recognizes that certain "costs are incurred in support of construction efforts." (Ex. 458 at 1; Ex. 460 at 1.) The costs that are reassigned to capital become part of the rate base. For SDG&E, there is also the preliminary step of SDG&E allocating the common costs to its electric, electric generation, and gas services department, which is referred to as "segmentation."

For the reassignment and segmentation processes, certain "reassignment rates" and "segmentation rates" are used, as described in Exhibits 458 and 460.

None of the other parties take issue with the mapping process, or the segmentation and reassignment rates and processes. We have reviewed the testimony concerning these processes and the rates that SDG&E and SoCalGas used. We adopt as reasonable the mapping processes, the segmentation and reassignment processes, and the segmentation and reassignment rates that SDG&E and SoCalGas use in their GRC applications.

24.5. Calculation of Allowance for Funds Used During Construction (AFUDC)

24.5.3. Introduction

The AFUDC represents the forecasted financing costs (both debt and equity) that are used to finance utility plant construction, i.e., construction work

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[199] In D.08-07-046, SDG&E and SoCalGas were ordered to file their GRCs using a cost center system of internal accounting and control.

in progress (CWIP). The AFUDC generally cannot be recovered until the facility becomes operative. During plant construction, the AFUDC is accumulated in the CWIP. When the facility becomes operative, i.e., used and useful, the AFUDC is then capitalized. The utilities are then allowed to recover the capitalized AFUDC in rates through depreciation charges over the useful life of the asset, and a return is earned on the undepreciated portion of the AFUDC.

24.5.4. Position of the Parties

24.5.4.2. DRA

DRA proposes that the Applicants be ordered to calculate their AFUDC rate with short term debt, more specifically, the three month commercial paper rate forecast by Global Insight. Global Insight's forecast of short term debt rates for 2010, 2011 and 2012 are 0.23%, 0.34%, and 1.76%, respectively. DRA bases its AFUDC proposal on the theory that "if the utilities were not regulated utilities, the utilities' management would do all that is in their power to drive down the AFUDC rate…." Since the utilities have the ability to issue short term debt, DRA proposes that the Applicants use short term debt to finance all of their CWIP.

DRA also contends that the Applicants did not follow the FERC formula for calculating the AFUDC rates.[200] DRA contends that the FERC formula calls for the average CWIP to be financed 100% by the forecasted average short term debt, and that the "remainder of CWIP that is not covered by average short term debt is to be covered by an average of the prior year long term debt, preferred stock, and common equity, weighted by their respective balances." (Ex. 489 at 16-17.) If DRA's AFUDC rates were adopted, DRA contends that the

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[200] The FERC formula that DRA relies on is found in 18 CFR, Subchapter C, Part 101, Section 3.A.17.

dollar savings over the period 2010 through 2012 would total about $44.3 million for SDG&E, and $50.6 million for SoCalGas. (*See* Ex. 489 at 17, 19-20)

24.5.4.3. SDG&E and SoCalGas

SDG&E and SoCalGas are opposed to DRA's proposal to use short term debt as the rate to calculate AFUDC. Instead of DRA's proposal to use short term debt, SDG&E and SoCalGas request that the Commission find as reasonable the use of their currently authorized rates of return of 8.40% and 8.68%, respectively, for the test year 2012 AFUDC.

The Applicants contend that DRA has a mistaken understanding of the FERC regulations, misinterprets the purpose and intent of the Applicants' short term financing authority, and has a general misunderstanding of financial theory and management.

The Applicants contend that DRA misunderstands the FERC formula when DRA states that the "FERC formula for calculating AFUDC rates show that average [CWIP] is to be first financed 100% by average short-term debt forecasted." (Ex. 489 at 16.) The Applicants contend that the FERC's AFUDC formula instructs that short-term debt is only one component of the formula, "and the aspect of the calculation attributed to short-term debt balances and related costs shall be estimated for the current year and should be adjusted as actual data becomes available." (Ex. 350 at 3.) The Applicants further contend that the FERC makes it clear that "the AFUDC rate should reflect the cost of long-term capital funding, with adjustments for current-year estimates of short-term working capital." (Ex. 350 at 4.)

The Applicants contend that D.06-05-029 does not support DRA's proposal to use short term debt to finance AFUDC. The Applicants contend that this decision "neither orders SDG&E to issue large amounts of short-term debt, nor requires SDG&E to finance capital expenditures with short-term funding." (Ex. 350 at 5.) The Applicants also point out that although D.06-05-029 stated that "During times when market conditions make long term financing unattractive, it may be necessary for a utility to issue short-term debt to finance its construction expenditures and cash requirements," that decision also stated "short-term borrowing should be reduced when practicable." (D.06-05-029 at 6.)

The Applicants also contend that DRA misunderstands financial theory and management, and that DRA's proposal is contrary to prudent financial practice. The Applicants take the position that financial theory and practice suggest that the funding of long-lived assets should be done with long term sources of capital such as equity and debt. If short term debt is used in the manner that DRA proposes, the Applicants contend that this will result in a continuing need to renegotiate or roll over short term debt, and under some market conditions this could lead to problems in obtaining short term financing and higher costs associated with short term financing. The Applicants also assert that using short term financing to determine the rate of return to long term investors denies those investors with a reasonable opportunity to earn a fair rate of return.

24.5.4.4. PG&E

PG&E contends that a competitive business would never finance something similar to CWIP using short term debt, as DRA has suggested. PG&E argues that banks will not provide unlimited amounts of short term credit, and are likely to avoid lending to a company that wants to finance substantial permanent assets with short term debt.

PG&E also argues that DRA's proposal would be difficult to implement because the Applicants would have to refinance its short term debt every several days or weeks, depending on market conditions. This constant refinancing poses a liquidity risk if disruptions in the credit markets affect short term borrowing. PG&E further argues that most financial managers seek to finance assets like plant and machinery with long term borrowing and equity, and DRA has offered no evidence that unregulated entities finance substantial portions of their permanent assets with short term debt that must be continually rolled over.

PG&E also contends that the capital markets are likely to treat continuous financing with short term debt as additional permanent debt. This may affect the credit ratings of the Applicants.

PG&E recommends that if the Commission does not reject DRA's proposal outright, that the Commission should defer consideration of DRA's proposal to the utilities' cost of capital proceeding. PG&E recognizes that although debt due within one year is normally excluded from the utilities' capital structure, DRA's proposal would essentially result in the Applicants carrying high levels of short term debt (estimated at $400 million) on a permanent basis. PG&E contends that the cost of capital proceeding would be an appropriate place to examine the use of short term debt to finance CWIP, and where finance issues that affect the utilities' financial risk are ordinarily considered.

24.5.4.5. SCE

SCE contends that the FERC USOA does not require the Applicants to use short term debt to finance CWIP. SCE argues that the FERC orders that established the AFUDC formulas and the USOA regulations explained that the purpose of the formulas is to allow for the recovery of short term debt, and that there was no intention to mandate the use of short term debt for construction purposes. SCE points out that even the DRA witness admitted that the FERC formula does not require the utility to finance CWIP with short term debt. (*See* 32 RT 4387-4389)

24.5.5. Discussion

We are not persuaded by DRA's argument that the rate for AFUDC should be calculated using the three month commercial paper rate. First, DRA's own witness sponsoring the short term financing proposal acknowledged that the FERC formula does not direct the financing activities of the Applicants, and there is nothing in that formula that requires CWIP to be financed 100% by short term debt.

Such an interpretation is supported by the Applicants' citation to the decision of the Federal Power Commission, the predecessor of the FERC, when it proposed the "uniform formulary method for determining the maximum rates to be used in computing" AFUDC. (57 Federal Power Commission at 608.)[201] In discussing this proposed formula, the Federal Power Commission noted that "[m]any respondents objected to the weight given short-term debt in the proposed rule…," and that "[t]hese respondents argued that short-term debt is not necessarily the first source of construction funds, as would be indicated by application of [t]he proposed formula, and should be ignored or given less weight." (*Ibid*.)

The Federal Power Commission stated that "[i]t is generally impossible to specifically trace the source of funds used for various corporate purposes, and **it was not the purpose of our proposed rule to do so**." (*Id*. at 608-609, emphasis

[201] The proposed formula, and the adopted version of that formula, which was addressed in 57 Federal Power Commission at 614-615, is substantially the same as what currently appears in 18 CFR, Subchapter C, Part 101, Section 3.A.17.

added.) Instead, the rule was proposed to "give a utility an opportunity to be compensated for the total cost of capital devoted to utility operations, including its construction program." (*Id*. at 609.)

We also agree with the position of the Applicants, PG&E and SCE that assets with long lives are generally financed with long term financing rather than short term financing. In addition, we agree with the utilities' perspective that if short term debt is used exclusively as the AFUDC rate, this will lead to a continuing need to refinance the short term debt. This, in turn, may result in problems in refinancing this debt, as well as higher borrowing costs.

For all of the above reasons, we do not adopt DRA's proposal that the AFUDC rates should be based on short term financing, such as DRA's proposal to use Global Insights forecast of the three month commercial paper rate. Instead, it is reasonable to use the currently authorized rates of return of 8.40% for SDG&E, and 8.68% for SoCalGas, for AFUDC for test year 2012.

24.6. Auditing of SDG&E and SoCalGas

The Joint Parties have raised the issue about the reliability and independence of the outside audit conducted by Deloitte & Touche of SDG&E. The Joint Parties contend that the Commission should carefully consider the accuracy of the Deloitte & Touche audit of the financial data of SDG&E because of remarks by the Public Company Accounting Oversight Board (PCAOB) concerning various audits that Deloitte & Touche had conducted of public companies, and because of the monies that Deloitte & Touche receives from the Sempra companies for auditing work.

The Joint Parties contend that the PCAOB issued a report around October 2011 that was critical of 27 of 61 audits of public companies that Deloitte & Touche had conducted in 2007. The names of those public companies that had been audited by Deloitte & Touche were not provided by the Joint Parties, and were not made public in the PCAOB report. The Joint Parties also point out that Deloitte & Touche has received from the Sempra companies an average of $14 million a year for auditing and other services. Due to the PCAOB's scrutiny of the audits conducted by Deloitte & Touche, and because of the monies that Deloitte & Touche received from the Sempra companies, the Joint Parties sought to compel a person from Deloitte & Touche to testify at the evidentiary hearing regarding the use by the Sempra companies of Deloitte & Touche.

Various witnesses testified for the Applicants about the process used for hiring outside auditors, and that the financial documents that the outside auditors review do not form the basis for the test year 2012 forecasts.

In our review of the Joint Parties' allegation that the Deloitte & Touche audit is somehow misleading or that misleading financial data has affected the GRC application, we first note that the Joint Parties' November 28, 2011 motion to call a Deloitte & Touche employee to testify about the audit it had conducted of SDG&E was denied on January 12, 2012. In denying the Joint Parties' motion, the ALJ determined that: there were no allegations of fact in that motion to establish that the PCAOB's report was relevant to the forecasts of the test year 2012 revenue requirements; that the motion failed "to establish a relevant nexus that of the audits the PCAOB reviewed, that these audits involved the Applicants;" and that there were no allegations of fact that any employee of Deloitte & Touche prepared or created any of the data used by the Applicants to create the test year 2012 forecasts. (*See* Jan. 20, 2012 ALJ Ruling at 4-5; Feb. 7, 2012 ALJ Ruling at 3.)

During the evidentiary hearings, the Joint Parties had an opportunity to cross examine several of the Applicants' witnesses concerning the use of outside auditors at SDG&E and SoCalGas and the scope of work that they perform for the Applicants, and the process for developing the 2012 test year forecasts. The Utility Accounting Group at SDG&E and SoCalGas is responsible for ensuring the accuracy and integrity of the accounting data that goes into the general ledger, which forms the basis of the financial statements that the outside auditors review. This accounting process that takes place for both utilities is also subject to internal auditing. DRA also conducted an audit of the books and records of SDG&E and SoCalGas, and confirmed the integrity of the accounting systems used by the utilities.

None of the testimony elicited from the Applicants' witnesses suggest that the audits of the Applicants were used in any way to develop the test year 2012 forecasts of either SDG&E or SoCalGas, or that the financial data of either utility was misleading or suspect.

The Joint Parties have failed to demonstrate that the outside audit of the Applicants somehow resulted in misleading or erroneous financial information that affected the underlying revenue requirement forecasts of the Applicants. Accordingly, we find no merit in the Joint Parties' unsubstantiated contention that the forecasts of the test year 2012 revenue requirements have somehow been tainted by the audits that Deloitte & Touche conducted of SDG&E and SoCalGas.

The Joint Parties also infer that SDG&E and SoCalGas should re-think whether Deloitte & Touche should be hired as the outside auditor to review the financial records of both companies, or to restrict how long an outside auditor can perform audits for a public utility. However, the testimony in this regard established that the Audit Committee of the Board of Directors of Sempra decides who to hire as the outside auditor. The selection of that outside auditor is then ratified by the Sempra shareholders. The Audit Committee of Sempra goes through this process every year to evaluate the qualifications of the auditors that they hire. Since we do not find any merit in the Joint Parties' contention that the financial audits of the Applicants were misleading or erroneous, or that the test year 2012 forecasts were tainted by the audits, we do not place any restrictions on SDG&E or SoCalGas as to which auditors they can use, or how many audits an outsider auditor can perform.[202]

25. Results of Operations Model and Summary of Earnings

The RO model is a computer model that compiles all of the cost estimates, and produces the revenue requirements and a Summary of Earnings for SDG&E and SoCalGas. The revenue requirement is shown in the Summary of Earnings report which is generated by the RO model. Based on the positions of SDG&E and SoCalGas, their updated forecasts of costs, and revisions agreed to in their rebuttal testimony or during the hearings, another run of the RO model resulted in updated revenue requirements for SDG&E and SoCalGas. As reflected in Exhibit 596, the revenue requirement requested by SDG&E is now $1,848,737,000 on a combined basis ($1,527,278,000 for electric, and $321,459,000 for gas). As

[202] We note that the Joint Parties filed a petition requesting that the Commission open a rulemaking into whether the outside audits of public utilities should be verified for accuracy, and raising the same kinds of auditing issues in that proceeding. The Commission denied that petition in D.12-08-003.

updated by Exhibit 596, the revenue requirement requested by SoCalGas is now $2,112,476,000.[203]

Based on the adjustments and recommendations that we have adopted throughout this decision, the RO model was re-run using our adopted amounts. The resulting Summary of Earnings for SDG&E and SoCalGas are found in Attachment B of this decision. As a result of the adjustments that we have adopted and run through the Results of Operation model, the test year 2012 revenue requirement for SDG&E is $1,749,376,000, and the test year 2012 revenue requirement for SoCalGas is $1,951,712,000. The adjustments that we have made to the RO model result in the aforementioned revenue requirements, which should be adopted by the Commission. The adopted revenue requirements will provide customers of SDG&E and SoCalGas with safe and reliable service at reasonable rates.

Due to the delays in this proceeding, and because of the upcoming 2013 summer, it is reasonable to delay SDG&E's recovery of its GRC memorandum account balances until September 1, 2013. This delay will help reduce the rate impact on SDG&E's customers if recovery of the GRC undercollections is started before the 2013 summer. Due to typically higher summer electric bills, a delay in collecting the unrecovered revenue requirement will reduce the rate impact on SDG&E's customers. In addition, collection of the unrecovered revenue

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[203] In comparison, if all of DRA's cost estimates and positions were adopted, and adjusted as described in Exhibit 596, DRA's estimated revenue requirement for SDG&E and SoCalGas would be $1,548,936,000 and $1,786,738,000, respectively. (*See* Exhibits 501, 531, 596.)

requirement for SDG&E should be spread over the remaining term of this GRC cycle, that is, from September 1, 2013 through December 31, 2015.

For SoCalGas, we will allow SoCalGas to begin recovery of its GRC memorandum account balance beginning July 1, 2013. Allowing SoCalGas to commence recovery of its undercollection earlier is reasonable because its gas customers are only impacted by the rate increase in providing the natural gas service. As with SDG&E, SoCalGas should spread the collection of its unrecovered revenue requirement over the period from July 1, 2013 through December 31, 2015.

SDG&E and SoCalGas should be authorized to file Tier 1 ALs within 15 days from the effective date of this decision to implement the revenue requirements authorized by this decision.

The revenue requirement for the PTY is described in the next section.

26. Post-Test Year Revenue Requirement Issues

26.4. Introduction

This section addresses the proposals of SDG&E and SoCalGas for their respective post-test year (PTY) ratemaking framework proposals. Their framework consists of three different mechanisms. The first mechanism is their PTY ratemaking mechanism, as described in Exhibits 398 and 400.[204] Their PTY ratemaking mechanism derives the level of authorized revenues during the PTY period. SDG&E and SoCalGas both request that the PTY period cover the three-year period of 2013, 2014, and 2015. For SDG&E, its proposed mechanism would adjust its gas and electric authorized revenue requirements in the PTY by

[204] SDG&E and SoCalGas use essentially the same type of PTY ratemaking mechanisms. The difference between the two mechanisms is noted in the text.

applying separate formulas to the medical, O&M, and capital-related revenues. For SoCalGas, its proposed mechanism would adjust its gas authorized revenue requirement in the PTY by applying the same separate formulas to the medical, O&M, and capital-related revenues.

The second and third mechanisms that SDG&E and SoCalGas propose are an earnings sharing mechanism and a productivity sharing mechanism. Both of these mechanisms are included within the PTY ratemaking mechanism.

All three of these mechanisms are described in more detail below.

The other PTY issue is the number of years that should be covered by this GRC rate cycle, which we address first.

26.5. Term of the GRC Rate Cycle

26.5.3. Background

Both SDG&E and SoCalGas request that this GRC cycle cover the four year term of 2012-2015, instead of the traditional GRC term of three years.

The Applicants contend that a four year term will do the following: (1) provide the utilities with greater incentives to undertake technology-driven investments that enhance efficient operations; (2) provide customers and the Commission a measure of rate certainty, since the cost elements to be escalated and associated escalation factors will be clearly identified and known; and (3) reduce the costs that would be incurred by the Applicants, the Commission, and other parties of litigating another GRC proceeding within three years.

If the three year GRC term is retained, the Applicants note that it would have to file its GRC Notice of Intent, for test year 2015, beginning in August 2013. According to the Applicants, the three year GRC term results in their employees "being in constant rate case mode, which takes them away from their main work responsibilities to provide safe and reliable utility service to its customers."

(Ex. 398 at 17; Ex. 400 at 13.) The Applicants note that the Commission has previously allowed longer GRC rate case terms for both companies.

The four year GRC term is also tied to the three mechanisms that the Applicants are proposing. According to the Applicants, the "longer the term between rate cases, the stronger the incentive to reduce costs since many productivity enhancing investments have a longer cost/benefit life than the usual three-year GRC cycle." (Ex. 398 at 16; Ex. 400 at 12.) Under a four year GRC term, the PTY ratemaking mechanism would cover three years instead of two years. Along with the earning sharing mechanism, and the productivity sharing mechanism, the Applicants contend that these three mechanisms will provide the Applicants "with the incentive to invest in longer-term productivity enhancing investments and operations changes." (Ex. 398 at 2; Ex. 400 at 2.)

26.5.4. Position of the Parties

26.5.4.2. DRA and UCAN

DRA and UCAN both support the four year GRC term.

26.5.4.3. FEA

The FEA opposes SDG&E's proposal for a four year GRC term. Since SDG&E plans to make significant changes to its infrastructure and operations during the PTY, the FEA does not believe that the cost savings from postponing the GRC for another year justify adopting a four year term.

The FEA contends that the prior Commission decisions which allowed a longer GRC term, should not result in the Commission adopting a longer GRC term in this proceeding. FEA contends that two of the decisions cited by the Applicants were related to settlements, while the others applied when SDG&E was subject to performance-based ratemaking.

26.5.4.4. SCGC

SCGC also opposes the Applicants' proposal for a four year GRC term. SCGC's reasoning to retain the traditional three year GRC term is because of the investments that SoCalGas proposes to make as part of its Pipeline Safety Enhancement Plan that it filed in response to D.11-06-017.

All of these costs that SoCalGas plans to make are incremental to the pipeline safety activities that SoCalGas proposed in this GRC. Due to the revenue requirement impact of SoCalGas' proposed PTY investments, SCGC contends there needs to be a more aggressive review of SoCalGas' proposed investments, and that this should take place in a test year 2015 GRC proceeding.

26.5.4.5. SDG&E and SoCalGas

The Applicants contend that the most compelling reason for adopting a four year GRC term is because it will motivate SDG&E and SoCalGas "to engage in productivity enhancement investments over the entire Test Year and PTY period." (Ex. 402 at 8.)

As for SCGC's opposition to a four year GRC term, the Applicants contend that instead of having some or all of their Pipeline Safety Enhancement Plan projects reviewed in a GRC, that it is proper to address the Pipeline Safety Proceeding (R.11-02-019) separately from a GRC proceeding.[205]

26.5.5. Discussion

We first address the term of this GRC cycle because it is a consideration in deciding whether the PTY ratemaking mechanism, and the two other mechanisms should be adopted. SDG&E and SoCalGas view the four-year GRC

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[205] In D.12-04-021, the Commission transferred the review of the Pipeline Safety Enhancement Plan of SDG&E and SoCalGas to A.11-11-002.

term as an integral part of their PTY ratemaking framework, whereas DRA separates the four year GRC term from the Applicants' PTY ratemaking proposals.

Due to the lag time in the processing of these consolidated GRC proceedings, as discussed earlier, it is appropriate to consider the passage of time, and where we would be if a traditional three year GRC term was adopted. If we adhere to the three year GRC term, SDG&E and SoCalGas would be required under the Rate Case Plan to file its Notice of Intent of their test year 2015 GRC in August 2013. Under the circumstances, that is not practical as SDG&E and SoCalGas would have to gear up to initiate and file a new GRC proceeding by the end of 2013.

It is appropriate and reasonable under the circumstances to allow this GRC cycle to cover the PTY period of 2013-2015, for a total of a four year GRC term. This will permit the Applicants, the Commission, and other parties sufficient time to prepare for the next GRC that will begin with test year 2016. Accordingly, SDG&E and SoCalGas shall be required to file their test year 2016 GRC proceedings beginning with the Notice of Intent in August 2014.

26.6. PTY Ratemaking Framework

26.6.3. Background

Instead of requesting a traditional annual attrition mechanism to adjust their test year revenue requirement in the PTY period, SDG&E and SoCalGas are proposing that their PTY ratemaking mechanism be adopted. SDG&E and SoCalGas propose that their PTY ratemaking mechanism remain in effect during the term of the GRC cycle.

The Applicants contend that their PTY ratemaking mechanism is very similar to the traditional PTY attrition mechanism. Under their proposed mechanisms, separate formulas would be applied to the O&M-related and capital-related revenue requirements.

The Applicants' PTY mechanisms share six common components, with one additional component for SDG&E's mechanism. The earnings sharing mechanism, and the productivity investment sharing mechanism are included as part of the PTY ratemaking mechanism. Each of their mechanisms consist of the following six components: (1) O&M expense adjustment; (2) capital-related cost adjustment; (3) medical cost adjustment; (4) Z-factor adjustment, if applicable; (5) earnings sharing mechanism; and (6) productivity investment sharing mechanism. The additional component for SDG&E is to account for incremental capital investment and O&M programs that were not included in the test year. Each of these components is described in more detail in Exhibits 398 and 400.

Of particular note is SDG&E's additional component. According to SDG&E, this adjustment component "is needed because some Smart Grid capital investments are not scheduled to be added to rate base until the end of 2012 and therefore the associated capital-related costs will not be fully reflected in 2012 authorized base margin." (Ex. 398 at 10.) According to SDG&E, in test year 2012, the revenue requirement for smart grid will be $25 million. However, due to the additional smart grid investments that SDG&E plans to make, the smart grid revenue requirement in 2013, 2014, and 2015 will be $76 million, $98 million, and $121 million, respectively. (*See* Ex. 398 at 11.) If this component is adopted, "SDG&E will be authorized to roll the needed capital revenue requirement into SDG&E's base margin in the year after the Smart Grid investments are put into rate base." (Ex. 398 at 11.)

Another item of note regarding the Applicants' PTY ratemaking mechanism is that they would be allowed to automatically suspend the PTY ratemaking mechanism if SDG&E or SoCalGas reports one year of net operating income, subject to treatment under this mechanism, "which results in a [rate of return] of 300 or more basis points above or 250 basis points below its authorized [rate of return]." (Ex. 398 at 21; Ex. 400 at 19-20.) Such a suspension would trigger a formal review of the PTY ratemaking mechanism.

The PTY ratemaking mechanism would also be subject to voluntary suspension if the utility reports one year of net operating income that results in a rate of return of 175 basis points below its authorized rate of return.

The earnings sharing mechanism would share the earnings above or below the authorized rate of return with ratepayers and shareholders during the PTY period. The proposed bands for the earnings sharing mechanism are described in Exhibits 398 and 400.

The productivity investment sharing mechanism is to encourage the Applicants to make more investments that enhance productivity. The productivity benefits that result would be reflected in test year 2016, and possibly in 2015.

26.6.4. Position of the Parties

26.6.4.2. DRA

According to DRA, it "does not oppose a PTY ratemaking mechanism which will provide the Utilities with some reasonable level of revenue increases in 2013-2015." (Ex. 529 at 1.) However, DRA opposes the increase and methodologies that SDG&E and SoCalGas have proposed for the PTY period. DRA further contends that the Applicants are not automatically entitled to PTY revenue adjustments, and cites to D.93-12-043 as support for this proposition. (*See* D.93-12-043 [52 CPUC2d at 492].)

DRA recommends a PTY ratemaking mechanism that is based on allowing SDG&E and SoCalGas to increase their authorized 2012 revenue requirement by the CPI – Urban. DRA contends that the use of this index will provide SDG&E and SoCalGas with an incentive to properly manage their expenditures and expenses. DRA also contends that the use of its recommended index is reasonable in light of past Commission decisions that used the CPI to produce fixed dollar PTY adjustments. Instead of using the "complicated proposals" of the PTY ratemaking mechanism of SDG&E and SoCalGas, DRA contends its formula is much simpler to use. (Ex. 529 at 9.)

In the event the Commission does not adopt DRA's primary CPI – Urban attrition adjustment, DRA recommends a mechanism similar to what SDG&E and SoCalGas have proposed, except with a different composition of adjustments. DRA's alternative is to base the PTY increases on the following: (1) offset of customer growth and productivity gains; (2) an O&M expense adjustment based on CPI –Urban; (3) an OpEx related adjustment; (4) a capital-related cost adjustment based on CPI – Urban; (5) delete SDG&E's separate smart grid incremental capital-related adjustment; (6) a medical cost adjustment based on Global Insight's forecast ; (7) continuation of the current Z-factor adjustment process; (8) continuation of existing base margin exclusions and opposition to the NERBA; (9) support for a four year GRC term; (10) modifications to the Applicants' proposed earnings sharing mechanism; (11) opposition to the Applicants' productivity sharing mechanism; (12) opposition to voluntary and mandatory suspensions of the PTY ratemaking mechanism; and (13) support of the Applicants' proposed regulatory filings.

26.6.4.3. FEA

The FEA opposes SDG&E's PTY ratemaking mechanism. FEA contends that an attrition increase should not be automatic or an entitlement. FEA contends that adopting SDG&E's PTY ratemaking mechanism would tend to insulate SDG&E from the "economic pressures of the ongoing depressed economy." (Ex. 577 at 16.)

FEA further contends that SDG&E has not demonstrated the need for a complicated PTY ratemaking mechanism, as opposed to the simple attrition increases that have been authorized in the past.

FEA opposes the earnings sharing mechanism because "65% of the first band of earnings (51 to 100 basis points above the authorized [rate of return]) would go to ratepayers, but ratepayers would absorb 40% of losses between 101 and 250 points below the authorized [rate of return]…." (Ex. 577 at 20.)

FEA is also opposed to SDG&E's proposal to include the PTY smart grid investments into the PTY ratemaking mechanism. FEA contends the smart grid expenditures are too speculative at this point.

The FEA recommends that SDG&E's PTY ratemaking mechanism be rejected, and that a simple approach be used, such as using the CPI, for the purpose of escalating PTY costs. FEA contends that this would provide an incentive for SDG&E to control its costs.

If the Commission decides to adopt SDG&E's PTY ratemaking mechanism, the FEA recommends that O&M and capital expenditures be escalated by the CPI – Urban, that the PTY smart grid expenditures be excluded from the PTY mechanism, and that the earnings sharing mechanism be asymmetrical so that ratepayers are not "responsible for reimbursing SDG&E for earnings below the authorized [rate of return]." (Ex. 577 at 22-23.)

26.6.4.4. SCGC

SCGC is opposed to SoCalGas' PTY ratemaking mechanism. SCGC contends that each "individual component of SoCalGas' proposed mechanism is complex," and that SoCalGas' industry specific PTY ratemaking mechanism will produce increases in excess of what DRA has recommended. (Ex. 319 at 18.)

Instead of using the formulas that come from the utility, SCGC recommends that a broader index such as the CPI - Urban be used. By adjusting PTY increases to the CPI, SCGC contends that this "places SoCalGas within the market context generally experienced by the businesses and residences that make up the body of ratepayers rather than placing the utility in a special category in which only industry specific practices drive rate increases." (Ex. 319 at 21-22.)

SCGC further contends that due to the economy, that it is "appropriate to place restraint on utility cost increases, thus incenting management to work harder." (Ex. 319 at 22.)

SCGC favors the retention of the Z-factor adjustment.

Regarding SoCalGas' proposed earning sharings mechanism, SCGC contends that this is another attempt by SoCalGas to obtain a guaranteed rate of return. SCGC also contends that the proposed mechanism is more generous to shareholders than to ratepayers when earnings are above the authorized rate of return. SCGC recommends that the Commission use the earnings sharing mechanism that was adopted in D.05-03-023, which was more generous to ratepayers.

SCGC opposes SoCalGas' proposal for a productivity investment incentive mechanism. SCGC contends that ratepayers have already paid for the net savings that are expected from the OpEx program in 2015.

26.6.4.5. UCAN

UCAN contends that SDG&E's PTY ratemaking framework "would allow earnings above normal levels" without any proof of above-normal performance. (Ex. 556 at 6.) Instead of these PTY mechanisms improving productivity and performance, UCAN contends that these mechanisms are simply rewarding cost cutting.

UCAN contends that SDG&E's proposed earnings sharing mechanism, and the productivity sharing mechanism, "could reward SDG&E for actions that harm ratepayers and could be easily gamed to increase shareholder earnings without providing increased ratepayer benefit." (Ex. 557 at 41.) Examples of how UCAN believes these two mechanisms can be manipulated are described in detail in Exhibit 557.

UCAN also recommends that the Commission reject $120.5 million of the $141.700 million that SDG&E has requested as part of its PTY smart grid request. UCAN opposes the PTY request for the reasons it expressed concerning the smart grid capital expenditures.

26.6.4.6. SDG&E and SoCalGas

As described in Exhibits 398 and 400, the Applicants contend that they have proposed a reasonable and balanced PTY ratemaking framework.

The Applicants raise the same arguments about the use of the CPI – Urban that they raised in the escalation section of this decision. The Applicants contend that the CPI – Urban is not the appropriate index to use because it measures changes in a basket of goods and services that a typical household purchases. The Applicants contend that an index that tracks utility-specific costs should be used instead. As for the decisions that the other parties cited where the CPI – Urban was used, the Applicants contend that those decisions occurred in settlements which are not precedential and do not bind the Commission. The Applicants also point to other decisions where the CPI – Urban was not used.

The Applicants also argue in favor of using the Towers Watson forecast of medical cost escalation, instead of Global Insight's forecast of health cost.

With regard to SDG&E's PTY smart grid investments, SDG&E contends that these investments are necessary for the reasons stated in the smart grid section. If these PTY smart grid investments are made, and SDG&E is not allowed to account for this in its PTY ratemaking mechanism, SDG&E contends it will face a revenue requirement deficiency in 2013, 2014, and 2015 of $50 million, $72 million, and $96 million, respectively.

The other parties argue that the Applicants' proposed earnings sharing mechanism should not be adopted, or should be adopted with revisions. The Applicants contend that their mechanism should be adopted without change because the proposed sharing bands that the Applicants propose "are appropriately calibrated to ensure that the benefits associated with any cost saving initiatives that succeed in achieving reductions beyond those required by the implied productivity factor…will be allocated in an equitable manner between customers and shareholders." (Ex. 402 at 15.)

On the productivity sharing mechanism, the Applicants contend that this will provide the Applicants with an incentive to engage in productivity enhancing incentives throughout the GRC cycle and beyond, and that ratepayers will receive the benefits of these cost reductions in 2015 and 2016.

26.6.5. Discussion

SDG&E and SoCalGas have proposed a PTY ratemaking framework that is based on a four year GRC term, and the adoption of the PTY ratemaking mechanism proposal, the earnings sharing proposal, and the productivity investment sharing mechanism. The other PTY proposal is DRA's recommended proposal to use the CPI – Urban to calculate the PTY revenue requirements for 2013, 2014, and 2015. The other parties propose variations of these two proposals.

In deciding what the PTY revenue requirement should be, we agree with DRA and FEA that a PTY revenue requirement is not an entitlement. As all the parties have pointed out, there have been many instances where the Commission has used different formulas to develop the PTY revenue requirement. In deciding what an appropriate adjustment should be, the Commission takes into account many different considerations, including allowing the utility the opportunity to earn its authorized rate of return.

Having reviewed all of the testimony and arguments of the parties concerning the PTY proposals, we hesitate to adopt the proposal of SDG&E and SoCalGas to adopt their PTY ratemaking mechanisms. Their proposed mechanisms seek to include the use of two formulas which lean in their favor. These are the use of Global Insight's utility-specific cost index, and a California-specific health care cost index.

In addition, SDG&E's mechanism would allow smart grid-related O&M costs and capital costs to be accounted for in its PTY ratemaking mechanism, which has the potential to increase the revenue requirement in 2013 by an additional $50 million, an additional $72 million in 2014, and an additional $96 million in 2015.

In the escalation section of this decision, we adopted the position of SDG&E and SoCalGas concerning the use of Global Insight's utility-specific cost index, and the use of the index for California-specific health care costs.

However, that does not mean we should automatically use those same indexes for the PTY period.

We also note that by using those two indexes for escalation, we arrived at a more reasonable forecast of costs for the test year. That is, we erred in favor of SDG&E and SoCalGas in predicting what the costs should be in 2012 by using cost indexes with higher increases than what DRA and some of the other parties had recommended. As a result, the test year 2012 revenue requirement is already higher than what some parties recommended. If our adopted test year revenue requirement is too high, this problem will be compounded if we use these same escalation factors as part of an adopted PTY ratemaking mechanism.

With respect to SDG&E's PTY ratemaking mechanism, including the PTY smart grid costs and capital expenses as part of that mechanism will allow SDG&E to recover these costs without the benefit of any further review by the parties or the Commission. This could result in a cumulative increase over the PTY period by $218 million based solely on the additional PTY smart grid investments. As we discussed in the smart grid section, there are some smart grid investments that we believe should be reduced or curtailed.

As several parties point out, these GRCs have occurred in the midst of a stagnant economy, which has reduced the ability of many ratepayers to take on the burden of additional rate increases.

Other parties have also cast suspicion on whether the earnings sharing mechanism and the productivity investment sharing mechanism favor shareholders over ratepayers, and whether these mechanisms can be gamed. As UCAN points out, the Applicants also have the discretion, within the parameters of safety and reliability considerations, to engage in cost cutting.

Based on all of those considerations, we do not adopt the PTY ratemaking framework that SDG&E and SoCalGas have proposed as it would essentially lead us down a path that allows SDG&E and SoCalGas to recover much of the PTY costs and expenses that they incur. SDG&E and SoCalGas should only be given a reasonable opportunity to earn their authorized rate of return, and not a mechanism that brings them closer to achieving that target. Instead, we adopt DRA's proposal to use the CPI – Urban to determine the PTY revenue requirements of SDG&E and SoCalGas. Although this index is different from the utility-specific index, and the California-specific health care cost index that the Applicants recommend be used, we believe that the CPI – Urban will provide SDG&E and SoCalGas with a reasonable opportunity to earn their respective authorized rate of return during the PTY given the test year 2012 revenue requirements that we have adopted in today's decision.

Although we do not adopt the PTY ratemaking framework proposed by SDG&E and SoCalGas, we approve the continued use of the current Z-factor process for both utilities. However, the proposal of SDG&E and SoCalGas to request approval of Z-factor costs though the Commission's AL process is denied. Any Z-factor costs that will result in an increase in costs shall be filed as an application.

27. Non-Tariffed Products and Services

27.4. Introduction

This section describes the proposals of SDG&E and SoCalGas to offer non-tariffed products and services (NTP&S). NTP&S are products and services offered by the Applicants that are not tariffed utility services, but require the increased use of utility assets or excess capacity. NTP&S offerings currently include such activities as replacing parts on natural gas appliances, pipeline services, rental of property, and meter testing and repair services. Other NTP&S offerings that the Applicants are considering include such activities as bio-gas conditioning services, combined heat and power services, or customer-specific offerings.

The Applicants have been offering NTP&S under Rule VII of the affiliate transaction rules that were first adopted in D.97-12-088 (77 CPUC2d 422), as modified by D.98-08-035 (81 CPUC2d 607).[206] These rules were created to govern the relationship between the utilities and their affiliates under their holding company structures. The rules were also designed to protect ratepayers from cross subsidizing non-utility products and services provided by the utilities, and to ensure that the utilities do not use their market position to unfairly compete in areas where the Commission is trying to foster competition. Also, the rules were designed to enhance competition, and level the playing field among the utilities, their holding companies, and competing businesses that may provide the same kinds of products and services.

As part of the affiliate transaction rules, before a NTP&S offering can be offered, the utility must demonstrate, and the Commission must adopt, a reasonable mechanism for the treatment of the benefits and revenues derived from the NTP&S offerings. The Applicants propose that the Commission adopt three NTP&S sharing mechanism proposals in this proceeding so as to provide guidance to the Applicants and to Commission staff as to how the benefits and revenues for NTP&S offerings will be handled. The Applicants propose the following sharing mechanisms for three categories of NTP&S offerings.

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[206] Subsequently, D.06-12-029 adopted revisions to the affiliate transaction rules for the large electric and gas utilities and their holding companies.

The first category is for existing NTP&S. The Applicants' sharing mechanism proposal for this first category provides that any increase in revenues above the forecasted miscellaneous revenue attributable to the Applicants' portfolio of NTP&S, as adopted by the Commission for test year 2012, be shared on a gross revenue basis with 90% to shareholders and 10% to ratepayers.[207] For example, if the test year 2012 forecast of miscellaneous revenue for SoCalGas' NTP&S is $6.8 million, and for SDG&E's NTP&S is $3.8 million, the Applicants propose that the incremental gross revenues above $6.8 million for SoCalGas, and $3.8 million for SDG&E, be shared with 90% of the increase going to shareholders and 10% allocated to ratepayers. The existing NTP&S offerings would be those included in the NTP&S reports that were filed with the Commission on June 24, 2010.

The second category applies to new NTP&S offerings that do not require significant incremental shareholder expenditures. Under this second sharing mechanism proposal, the Applicants propose that shareholders retain 90% of the gross revenues and ratepayers receive 10% of the gross revenues. The Applicants propose that this mechanism apply to new NTP&S offerings, where less than 50% of the total cost to offer the service is borne by shareholders.

The third category is for new NTP&S offerings that require significant incremental shareholder expenditures to develop and market. Under this third sharing mechanism proposal, the Applicants request that these significant incremental shareholder expenditures mean that more than 50% of the total

[207] The Applicants have excluded from this category the NTP&S offerings related to oil production because those services already have Commission approved sharing mechanisms in place.

utility costs to offer the services are incremental costs borne by the shareholders. Under this sharing mechanism, the Applicants propose a 50/50 sharing of after tax net earnings above a rate of return benchmark, where shareholders retain half of the net after tax earnings above the benchmark and ratepayers retain the other half. Under the proposal, the Applicants would be allowed to recover incremental costs, capital costs, and corporate income taxes on the NTP&S net revenues, before the sharing of net benefits. The Applicants also propose that the gross revenue and incremental costs for all the NTP&S offerings in this third category "be aggregated so that all of the revenues derived from such NTP&S would be netted out against all incremental costs." (Ex. 313 at 5; Ex. 315 at 5.) Under this sharing mechanism proposal, the rate of return benchmark would be set at the Applicants' authorized rate of return plus 50 basis points. The Applicants also propose that they be allowed to request "an additional 25 to 50 basis points (above the 50 basis points described above) to the benchmark return for specific categories of NTP&S that: 1) provide significant environmental benefit; 2) support the development of renewable energy; and/or 3) promote the development of new technologies." (Ex. 313 at 8; Ex. 315 at 8.)

Under the Applicants' proposals, all three sharing mechanisms would have accounting safeguards in place to "prevent cross subsidies and assure that any incremental costs associated with the offering of NTP&S are borne entirely by utility shareholders," as well as to "protect against anti-competitive cross subsidies." (Ex. 313 at 1; Ex. 315 at 1; *See* Ex. 318.)

27.5. Position of the Parties

27.5.3. SDG&E and SoCalGas

The Applicants believe that the three proposed sharing mechanisms are needed in order to provide certainty to the Applicants and to Commission staff as to how the revenues from NTP&S offerings will be treated, in advance of the filing of any AL or application to offer a NTP&S. By providing this guidance and certainty beforehand, the Applicants will be in a better position on a going forward basis to assess whether to grow an existing NTP&S offering, and to develop new NTP&S offerings that benefit customers. In addition to providing NTP&S offerings that meet customer needs, ratepayers will also receive a share of the monies under the three sharing mechanism proposals without exposing them to financial risk. The Applicants contend that their sharing mechanism proposals will not result in increased rates for ratepayers because the forecasted miscellaneous revenues will continue to be an offset to the revenue requirement of the Applicants, and to the extent revenues from NTP&S exceed the miscellaneous forecast, ratepayers will see benefits through the sharing mechanism proposals.

The Applicants contend that the three sharing mechanism proposals are reasonable, and "fairly allocate the benefits between ratepayers and shareholders based on the relative risk each assumes, while also providing significant incentives for the [Applicants] to maximize revenues from these services." (Ex. 313 at 2; Ex. 215 at 2.) The Applicants point out that the sharing mechanism proposals for the first and second categories are similar to the 90/10 sharing mechanism that was adopted in D.99-09-070 (2 CPUC3d 579) for SCE. The Applicants believe that the 90/10 sharing is appropriate based on the risks to shareholders and to ratepayers, and provides the Applicants with the opportunity to recover their incremental costs.

For this third category of NTP&S offerings, the Applicants contend that since significant incremental costs will be incurred, the shareholders need sufficient assurance that they will recover their costs. That is why the Applicants have proposed that the 50/50 sharing for this third category be done on net earnings rather than gross revenues. The Applicants also contend that due to the significant incremental shareholder investment that will be needed, this third sharing mechanism will provide them with the incentive to offer new NTP&S offerings.

The Applicants contend that their objective with the sharing mechanisms is to fairly allocate the benefits between ratepayers and shareholders based on the relative risk each assumes, while providing significant incentives for the utilities to maximize revenues from these services. The Applicants also contend that there are accounting safeguards for all three sharing mechanisms that will prevent cross subsidies, and any incremental costs for NTP&S will be borne entirely by shareholders. Any sharing mechanism established in this decision would apply on a prospective basis.

27.5.4. SCGC

SCGC opposes the sharing mechanism proposals of the Applicants and recommends that the proposals be rejected.[208] SCGC contends that Rule VII of the affiliate transaction rules adopted by the Commission is intended to limit "NTP&S activities to those that use a portion of an existing utility asset or capacity that is necessary in providing utility services without compromising the quality or reliability of those services or increasing utility costs." (Ex. 319 at 5.) SCGC believes that "NTP&S activities are intended to be insignificant in size and scope when compared to utility activities," and that such activities "should be

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[208] SCGC's testimony is directed at SoCalGas, but since the sharing mechanism proposals of SDG&E and SoCalGas are identical, we refer to the Applicants instead of just SoCalGas.

temporary and interruptible in nature." (Ex. 319 at 6.) SCGC contends that SoCalGas' sharing mechanism proposals overstep the bounds of the affiliate rules because the NTP&S offerings will result in substantial use of employees, as well as utility-related activities, to support its NTP&S activities.

SCGC contends that the first category sharing mechanism proposal is too favorable to shareholders because they would retain 90% of the gross revenues above the test year 2012 forecast of miscellaneous revenues. SCGC believes that 100% of any revenues realized from this first category of activities should be credited to ratepayers, and if the Commission believes some incentive should be given to the Applicants, the Commission should allow the shareholders to earn no more than 10% of incremental revenues, and the remaining 90% or more should go to ratepayers. SCGC also recommends that regardless of how the sharing is apportioned, the Commission should apply the incremental revenues that flow to ratepayers be an offset to the increase in revenue requirement from applying the PTY indexing mechanism.

For the second category of NTP&S, SCGC contends that the Applicants' proposal for shareholders to receive 90% of gross revenues is also too generous because the NTP&S offering would use an existing utility asset or capacity, which is valuable and not economically replicated. SCGC recommends that if a sharing mechanism were to be adopted, after the recovery of the incremental costs by the Applicants, ratepayers should receive 90% and shareholders should receive 10%.

For the third category of NTP&S, SCGC contends that the Applicants' proposal for a 50/50 sharing is too generous, and is inconsistent with the Commission's affiliate transaction rules. With the aggregating of the category three activities, SCGC contends that the category three activities would have to be very successful overall before ratepayers would receive any benefit from the sharing mechanism. SCGC believes that these category three activities should be performed by the Applicants' affiliates, rather than as a NTP&S activity, to avoid anti-competitive consequences.

27.5.5. TURN

TURN also opposes the Applicants' NTP&S sharing mechanism proposals. TURN contends that the Applicants have not presented any evidence that the current sharing mechanism prevents them from pursuing any NTP&S. TURN believes that the 90% shareholder reward under the first two sharing mechanism proposals is too high, and that the third sharing mechanism is an unreasonable way to allocate the benefits between shareholders and ratepayers. TURN also favors a gross revenue sharing mechanism, as opposed to a net revenue sharing mechanism. TURN contends that a net revenue sharing mechanism may lead to problems and gaming in determining what the incremental costs should be.

27.6. Discussion

At issue is whether the three proposed NTP&S sharing mechanisms should be approved by the Commission. The Applicants are not seeking approval of specific NTP&S offerings in these proceedings, and according to the Applicants, any such offerings will be requested in AL filings or in other applications as may be required by the Commission.

The starting point for analyzing the Applicants' NTP&S sharing mechanism proposals is the Commission's affiliate transaction rules set forth in Rule VII, which for the large utilities, is set forth in D.06-12-029. Rule VII governs utility products and services, including the offering of NTP&S by the utility. Before a utility can offer a new NTP&S, Rule VII.D requires that the utility establish and the Commission adopt a "reasonable mechanism for treatment of benefits and revenues derived from offering such products and services…." The Applicants contend that these three sharing mechanisms they are proposing will fulfill the requirement of Rule VII.D. The Applicants contend that the arguments of SCGC and TURN regarding specific NTP&S offerings that the Applicants may or may not offer are not relevant to the issue of having a relevant mechanism in place.

Before a utility is permitted to offer a NTP&S, Rule VII.C.4 of the affiliate transaction rules require that the offering must meet the following conditions:

> a. The nontariffed product or service utilizes a portion of a utility asset or capacity;
>
> b. such asset or capacity has been acquired for the purpose of and is necessary and useful in providing tariffed utility services;
>
> c. the involved portion of such asset or capacity may be used to offer the product or service on a nontariffed basis without adversely affecting the cost, quality or reliability of tariffed utility products and services;
>
> d. the products and services can be marketed with minimal or no incremental ratepayer capital, minimal or no new forms of liability or business risk being incurred by utility ratepayers, and no undue diversion of utility management attention; and
>
> e. The utility's offering of such nontariffed product or service does not violate any law, regulation, or Commission policy regarding anticompetitive practices.

We agree with the Applicants that the focus in this GRC is on whether the Applicants' proposals are reasonable mechanisms. At this stage, the determination of whether a specific NTP&S offering meets the requirements of Rule VII.C.4 should be left to when SDG&E or SoCalGas file an AL or application seeking authority to make a specific NTP&S offering.

However, both SCGC and TURN raise valid concerns about the reasonableness of the Applicants' sharing mechanism proposals. SCGC and TURN question whether the sharing percentages that ratepayers would receive from the Applicants' proposals for all three categories of NTP&S are fair or not.

Currently, existing NTP&S offerings are treated as miscellaneous revenues. These miscellaneous revenues are forecast for test year 2012, and are used to offset the Applicants' overall GRC revenue requirements. Under the Applicants' proposals, this existing treatment would be affected by the Applicants' category one sharing proposal if revenues exceed the test year 2012 forecast.

The category one sharing mechanism proposal covers the existing NTP&S offerings that the Applicants currently offer. If the Applicants' proposal is adopted, the test year 2012 forecast of miscellaneous revenues, which is forecasted at $3.845 million for SDG&E and $6.777 million for SoCalGas, will continue to offset the Applicants' revenue requirements. However, if the Applicants are able to grow these existing services, any revenue increase above the test year 2012 forecast of miscellaneous revenues, as adopted by the Commission for test year 2012, will be shared on a gross revenue basis with 90% going to shareholders and 10% to ratepayers. SCGC and TURN argue that the 90% share to shareholders is too high, while the Applicants point out that ratepayers receive 100% of the existing NTP&S revenues up to the adopted test year 2012 forecast of miscellaneous revenues. If we retain the existing miscellaneous revenue offset, shareholders will receive all of the revenues if the actual revenues exceed the test year 2012 forecast of miscellaneous revenues. If actual miscellaneous revenues are below the test year 2012 forecast, ratepayers receive all of the revenues as an offset to the revenue requirement.

In deciding whether the category one sharing mechanism proposal is reasonable, we must decide whether shareholders should be entitled to 90% of the gross revenues that exceed the adopted test year 2012 forecast. The 90% to shareholders means that the Applicants are rewarded for growing existing NTP&S beyond the forecasted 2012 miscellaneous revenue sales. One view is that the shareholders should be rewarded for the Applicants actively promoting and marketing these existing NTP&S offerings. The other view is that since the existing NTP&S offerings use existing assets of the Applicants, that ratepayers should receive a share of the increase in sales.

The Commission has considered what the appropriate sharing percentages should be in other proceedings. The Applicants, as well as SCGC and TURN, point to D.99-09-070 in which SCE was authorized to adopt a revenue sharing mechanism for its NTP&S offerings. The Applicants contend that their category one proposal is similar to what the Commission adopted for SCE in D.99-09-070 in that shareholders receive 90% of gross revenue. SCGC and TURN contend, however, that D.99-09-070 provides for two types of sharing. For NTP&S offerings that are deemed "active," because it requires significant shareholder investment, shareholders receive 90%. However, when there is lower shareholder involvement, which is deemed "passive," shareholders receive 70%.

In Resolution G-3456, issued October 6, 2011, SDG&E and SoCalGas were authorized to initiate a new NTP&S offering called the "mover services program." Under that program, the utility offers to put customers who have called to initiate or transfer their utility service (within their service territory) in contact with companies selling products or services that may be of interest to such customers. In Resolution G-3456, the Commission, using D.99-09-070 as a guide, decided that this offering was a passive type of activity and shareholders should receive 70% of the gross revenues.

The above decision and resolution endeavor to balance the asset, personnel cost, and risk incurred by ratepayers in the provision of the product or service with the benefits to ratepayers. If utility assets or personnel are being used to offer the NTP&S, ratepayers may be rewarded a greater share. If more risk is undertaken by the Applicants, the shareholders may be entitled to a higher percentage of the sharing.

In applying those considerations to category one, i.e., existing NTP&S offerings being offered by the Applicants, there is not significant shareholder involvement or additional investment required from the shareholders. The Applicants have not demonstrated that they will incur significant additional costs to grow these existing service offerings. Instead, the Applicants just need to engage in more marketing and promotion of the existing service offerings to increase revenues. Since the infrastructure or components are already in place to offer these existing service offerings, we agree with SCGC and TURN that the proposal to have shareholders receive 90% of gross revenues above the test year 2012 forecast of miscellaneous revenues is not reasonable. Accordingly, the Applicants' category one sharing mechanism proposal is not adopted, and the current structure of developing a forecast of miscellaneous revenues and offsetting those revenues against the revenue requirement will continue.

We now examine the Applicants' sharing mechanism proposal for their category two NTP&S offerings. The Applicants propose that this sharing mechanism apply to situations where less than 50% of the total cost of offering this new NTP&S offering is borne by shareholders. Under this category two sharing mechanism proposal, shareholders would receive 90% of the gross revenues and ratepayers would receive 10% of the gross revenues.

The Applicants contend that their category two sharing mechanism proposal is similar to the sharing mechanism adopted for SCE in D.99-09-070. SCGC and TURN contend that the sharing percentage to shareholders is too high under the Applicants' proposal. The sharing mechanism that was authorized for SCE in D.99-09-070 is different from what the Applicants are proposing for category two. In SCE's situation, an NTP&S offering is classified as active if it involves an incremental shareholder investment of at least $225,000. Unless SCE demonstrates that this threshold amount has been reached, a new NTP&S offering is deemed to be passive and shareholders receive 70%, instead of the 90% for an active investment. (*See* 2 CPUC3d at 596.)

Under the Applicants' proposal, there is no specified amount of investment. Instead, if less than 50% of the total cost of this new service is borne by shareholders, the Applicants' shareholders would be entitled to 90% of the gross revenues. If we apply the guideline of $225,000 set forth in D.99-09-070 to the Applicants' category two NTP&S offerings, one cannot easily determine, without more information, whether the Applicants' new service offerings involve more shareholder monies which would warrant the higher sharing percentage of 90% as used in D.99-09-070. Under the Applicants' sharing mechanism proposal, ratepayers will bear at least 50% of the costs associated with the new NTP&S offering, and applying the guidelines in D.99-09-070, this would be viewed as a passive activity in which shareholders would be entitled to 70% instead of 90%. Accordingly, the Applicants' category two sharing mechanism proposal is not adopted because it is unreasonable as to the ratepayers' share of the revenues.

The Applicants' third sharing mechanism proposal would apply to new NTP&S offerings that require significant incremental shareholder investment. Under the Applicants' proposal, significant incremental shareholder investment would mean that more than 50% of the total cost to offer the services would be borne by shareholders.

SCGC points out that with all of the conditions associated with the Applicants' category three sharing mechanism proposal, that ratepayers are likely to see little, if any, sharing. Under the Applicants' proposed sharing mechanism, the Applicants would be allowed to recover their incremental costs, capital costs, and corporate income taxes on the NTP&S net revenues above a rate of return benchmark, plus additional basis point adjustments, all in favor of the shareholders, before any sharing of net benefits take place. In addition, the Applicants' sharing mechanism proposal calls for all the gross revenue and incremental costs for NTP&S offerings in this third category to be aggregated. We agree with SCGC that the conditions that are part of the Applicants' sharing mechanism proposal are high hurdles to overcome before ratepayers receive any sharing. Although shareholders are expected to fund more than 50% of the total cost of each NTP&S offering, the aggregation of different category three NTP&S makes it very difficult for ratepayers to receive any benefits. This sharing mechanism proposal is not fair to ratepayers because ratepayers are still funding up to 50% of the total cost of the new NTP&S offering through the use of utility assets or personnel. Despite the ratepayers funding of up to 50% of the NTP&S total cost, there would be a series of deductions in favor of the shareholders to meet the conditions of this sharing mechanism before ratepayers receive any share. In our view, that is not a reasonable sharing mechanism, and the Applicants' category three sharing mechanism proposal is not adopted.

Today's rejection of the Applicants' three proposed sharing mechanisms does not prevent the Applicants from offering NTP&S offerings in the future. Under the affiliate transaction rules, the Applicants are free to continue offering existing NTP&S offerings, or to propose new NTP&S offerings with reasonable sharing mechanisms.

28. Other Issues

28.4. Introduction

The Utility Workers Union of America (UWUA) has proposed several safety-related initiatives in SoCalGas' GRC. Local 132 of the UWUA represents about 3800 members who work at SoCalGas.

UWUA's objective is to have SoCalGas promote a culture of safety. UWUA proposes that this safety culture be developed through a safety training program using the Systems of Safety program, and to adapt the existing organizational safety structure at SoCalGas and UWUA to foster the development of an effective safety culture. In addition, UWUA is focused on improving the interaction of SoCalGas employees with SoCalGas' customers in the area of customer service and safety, and ensuring safe and quality service.

In order to improve customer service and safety, UWUA also proposes that SoCalGas restore the levels and standards for safety related services that were previously in place. Those issues have been addressed elsewhere in this decision.

As described below, this section also seeks comment from UWUA and other interested parties on the possible conflict between D.05-02-054, and the November 14, 2011 ruling on UWUA's preliminary eligibility for intervenor compensation.

28.4.3. UWUA Safety Culture Proposal for SoCalGas

28.4.3.2. Position of UWUA

The UWUA is proposing that a safety culture be promoted at SoCalGas. The recommendations of UWUA are rooted in the perspective of UWUA members, who work at SoCalGas, and are also customers of SoCalGas. UWUA believes they offer a unique and independent perspective for proposing that certain programs and procedures be adopted to improve safety and service.

The two components of UWUA's proposal are safety training, and a safety organization.

For safety training, UWUA proposes that SoCalGas be ordered in its GRC to implement a safety training program that involves "training and empowering" the employees at SoCalGas, "in a systems approach to safety – identifying hazards and threats proactively and working to eliminate them before they cause injury and damage by addressing the safety system implicated in the threat." (Ex. 581 at 5.) This systems approach to safety is based on the Systems of Safety approach that was originally developed by the Institute for Sustainable Work and Environment, and is currently administered through the UWUA Power for America Training Trust.[209] The Systems of Safety training would be performed by UWUA members who work at SoCalGas, and who have received training in safety analysis and employee engagement. The training uses a small group activity method to encourage hands-on worker involvement in safety, and teaches "the values of respect, promoting participation and sharing

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[209] The Systems of Safety approach uses small groups led by worker-trainers to encourage worker involvement and decision making in safety. In addition, the approach involves identifying and eliminating risks and hazards by using six systems to analyze an incident or to identify and eliminate a potential risk or hazard.

decision-making power along with an analytical method based on a systems approach to safety." (Ex. 582 at 3.) According to UWUA, the Systems of Safety approach trains employees in techniques to identify and characterize hazards, and allows workers to become more engaged and involved, as opposed to a classroom training method. UWUA proposes that its Systems of Safety training be taught to all SoCalGas employees over a period of two years. According to UWUA, the Systems of Safety program has been implemented at SONGs in cooperation with SCE.

UWUA estimates that training the SoCalGas workforce using the Systems of Safety program will cost $3 million over two years. This cost includes training cost overheads.

The second component of UWUA's safety culture proposal is to adapt the existing organizational structure of safety committees,[210] meetings, and conferences at SoCalGas, to promote more communication between SoCalGas' management, its workers, and Commission staff. This communication would focus on identifying hazards and preventing incidents, rather than imposing punishment after the event has occurred. UWUA has made the same recommendation is the Gas Safety Rulemaking in R.11-02-019. Other changes that UWUA recommends for SoCalGas' existing organizational structure for safety are the following: (1) designation by UWUA of employee/union safety representatives for each of the 12 operating regions who can, respond to safety incidents, verify and report on safety systems improvements, conduct Systems of

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210 The existing safety committees at SoCalGas were formed as the result of the collective bargaining agreement with SoCalGas, and include SoCalGas employees who are members of UWUA as well as SoCalGas management.

Safety training, and work with SoCalGas management and Commission staff to monitor and enforce safety plan implementation; (2) regular meetings of all employees at the unit level to facilitate hazard mapping, system of safety analysis, and development of hazard elimination approaches; and (3) create robust communication channels for employee/union communication with Commission staff as recommended by UWUA in its July 15, 2011 comments in the Gas Safety Rulemaking.

UWUA estimates that the cost associated with its safety organization recommendations will result in an annual cost of $650,000 as a result of releasing 12 employees to take on the responsibilities of the employee/union representative.

28.4.3.3. Position of SoCalGas

SoCalGas values the input of its employees, including those who are members of the UWUA, on SoCalGas' safety programs and initiatives. However, SoCalGas is opposed to the Commission requiring that specific safety programs and materials be used by SoCalGas. SoCalGas contends that safety analysis methods similar to the Systems of Safety program are already in use by SoCalGas, and to train 5300 SoCalGas employees in similar safety system methods would not be an effective use of ratepayer funds.

In addition, SoCalGas recommends that the Commission refrain from requiring SoCalGas to incorporate UWUA members into SoCalGas' safety programs and initiatives. If the Commission believes that UWUA members should have a role in SoCalGas' safety programs, SoCalGas recommends that this issue be addressed in the Gas Safety Rulemaking proceeding.

SoCalGas contends that it is in the best position to determine what kinds of safety programs it should use in its training of employees, and that the UWUA has not demonstrated that SoCalGas should be ordered to use another safety program instead.

In regards to UWUA's proposal to adapt or improve the existing safety organization, SoCalGas contends that the designation of 12 employees to carry out safety culture communication and training will not improve the safety culture at SoCalGas, and is not an effective use of ratepayer funds. Under UWUA's proposal, the designated employees would be involved in root cause investigations. SoCalGas contends that special investigative experience, analytical skills and job knowledge are needed in order to perform a root cause analysis of a safety or hazard incident. Instead of using the designated employees selected by UWUA, SoCalGas contends it is in the best position to decide who has the necessary qualifications and the availability to effectively participate in the investigation of an incident. SoCalGas also points out that qualified instructors already train the SoCalGas safety committee members in incident investigation techniques. Although these techniques are not the same as those used in the Systems of Safety program, they still include ways of identifying underlying factors and hazards. Regarding the creation of communication channels between Commission staff and the employees of SoCalGas and UWUA, SoCalGas contends that this issue is outside the scope of this GRC, and should be addressed in the Gas Safety Rulemaking as appropriate.

28.5. Discussion

28.5.3. Systems of Safety Proposal

UWUA recommends that the Commission require SoCalGas to adopt the UWUA-sponsored Systems of Safety program as part of SoCalGas' training program. If adopted, the Systems of Safety program would involve safety training of SoCalGas employees by UWUA members who are employees of

SoCalGas. In order to provide this training, SoCalGas would have to allow up to 12 employees the time off from their regular job responsibilities so that these employees can take on the role of training the other SoCalGas employees. This Systems of Safety program would take about two years to complete, and would cost about $4.300 million over two years.[211]

As SoCalGas points out in its testimony, it already provides safety training to its employees. These programs include the Injury and Illness Prevention Program, which is required by the California Department of Industrial Relations. This program relates to occupational safety and health, and encourages employees to inform SoCalGas of workplace hazards without fear of reprisal. Workers at SoCalGas also receive formalized training at all phases of their careers, and work safety is integrated into this training. In addition, SoCalGas conducts frequent meetings with its employees to discuss health and safety issues. There are also systems in place "for employees to report hazards, close calls, and 'near miss' safety incidents." (Ex. 393 at 5.) Meetings are also held regularly to discuss near misses, and to work toward reducing hazards and preventing injuries. SoCalGas also conducts job observations, where safe behaviors of employees are reinforced, and instruction is given on how to eliminate or improve behaviors that could jeopardize safety. SoCalGas also has about 500 employees who serve on local safety committees, whose membership is decided by unions and by SoCalGas management. The safety committees

[211] The $4.300 million includes the $3 million estimated cost of the program over two years, and an estimated $1.300 million over two years of allowing up to 12 workers to take the time off to provide this training and to engage in the other safety organization tasks that UWUA recommends.

work to reduce hazards and to prevent injuries, and also play a role during incident investigations. Throughout the training and initiatives described above, SoCalGas incorporates the input of its UWUA members.

The UWUA has not alleged that SoCalGas' safety programs and initiatives, and training, are deficient. Nor has UWUA demonstrated that the Systems of Safety program is better than the training methods that SoCalGas currently uses. The witness for SoCalGas also attended the Systems of Safety training over a five day period in August 2011, and believes that the concepts taught in the August 2011 training are similar to those that are currently used in SoCalGas' safety training. The witness for SoCalGas also pointed out where the Systems of Safety program lacks objectivity, such as using illustrations depicting an adversarial atmosphere between management versus employee. In addition, SoCalGas contends the Systems of Safety approach reduces the employee's personal accountability for safety.

Since SoCalGas already provides a variety of safety training and initiatives to its employees, and because UWUA has not demonstrated that the Systems of Safety program is better than, or substantially different from the safety training programs and materials that SoCalGas already uses, we do not adopt UWUA's recommendation that SoCalGas be required to use the UWUA-sponsored Systems of Safety program during this GRC rate cycle. We agree with SoCalGas that it is in the best position to decide which safety training programs it should use.

28.5.4. Safety Organization Proposal

The second component of UWUA's safety culture proposal is to promote more communication between SoCalGas' management, its workers, and

Commission staff, by adapting the existing organizational structure of safety committees, meetings, and conferences at SoCalGas.

UWUA contends that the key to improving the safety of a utility is to have a free flow of communication between utility management, utility workers, and Commission staff. The communication efforts should be focused on identifying hazards and preventing incidents. To improve these communication channels, UWUA proposes that it be allowed to designate one employee/union safety representative for each of the 12 operating regions. These representatives would respond to safety incidents and perform root cause analysis in incident investigations. They would also verify and report on the implementation of safety system improvements, and work with SoCalGas management and Commission staff to monitor and enforce safety plan implementation. In addition, these representatives would conduct the Systems of Safety training.

UWUA also proposes that there be regular meetings (at least quarterly) of all employees at the unit level in order "to facilitate hazard mapping, system of safety analysis and development of hazard elimination approaches." (Ex. 581 at 13.)

UWUA also proposes that the Commission create channels of communication between the employees/union with Commission staff responsible for utility safety and enforcement, as recommended by UWUA in the Gas Safety Rulemaking.

UWUA estimates that the designation of 12 employees to support the safety culture communication and Systems of Safety training will cost about $650,000 per year.

UWUA has not demonstrated that the existing safety structure at SoCalGas, which involves both SoCalGas management and its employees, is defective or deficient in addressing the same kinds of issues that the UWUA has raised. In addition to the safety training that its employees receive, SoCalGas holds frequent meeting to discuss health and safety related issues. SoCalGas also has a system in place to report hazards, safety incidents, and close calls. SoCalGas also knows which employees, including those who are UWUA members, have the experience to best contribute to an investigation of a safety incident. SoCalGas also plans to continue working with UWUA and its members to address safety concerns. SoCalGas also contends that it remains committed to the safety of its employees and customers. For all of those reasons, we do not adopt UWUA's proposed changes to the existing safety organization structure at SoCalGas.

28.6. Comment on UWUA's Eligibility for Intervenor Compensation

In a November 14, 2011 ruling, the ALJ ruled that the UWUA had made a showing of significant financial hardship, and was preliminarily determined to be eligible for intervenor compensation in this proceeding. In contrast, the Commission held in D.05-02-054 that a labor union was not eligible for intervenor compensation because it did not meet the definition of a "customer" as set forth in Pub. Util. Code section 1802(b)(1). When UWUA files a request for an award of compensation following the issuance of this decision, UWUA should discuss in its request whether D.05-02-054 is applicable to UWUA, and parties interested in this issue may file a response to UWUA's request in accordance with Pub. Util. Code section 1804(c).

10. Findings of Fact

1. As described in this decision, a thorough review and evaluation process was undertaken to arrive at the adopted revenue requirements for SDG&E and SoCalGas.

2. Several parties, and many of the participants at the public participation hearings, raised concerns about the Applicants' proposed rate increases in light of the state of the economy.
3. The Applicants made two proposals to help mitigate the rate impact on their customers during the economic downturn.
4. D.08-07-046 rejected the argument that the use of the most recent recorded data was contrary to the updating procedure set forth in the Rate Case Plan.
5. Each proposed methodology must be reviewed and considered for each cost forecast, and the Commission needs to weigh the competing arguments as to which methodology yields a more reasonable forecast.
6. A Joint Motion for the adoption of the MOU Settlement between Cfor AT, SDG&E, and SoCalGas, which resolves certain physical access and communication access barriers, was filed on February 24, 2012.
7. The MOU Settlement is reasonable in light of the whole record, consistent with the law, and in the public interest.
8. Electric procurement covers SDG&E's costs of procuring, managing, planning, and administering of its electric and fuel supply for bundled customers.
9. As discussed in the electric procurement section, the O&M costs of $9.358 million are reasonable.
10. Gas procurement covers SoCalGas' costs of procuring natural gas for the core customers of SDG&E and SoCalGas.
11. As discussed in the gas procurement section, the O&M costs of $3.639 million are reasonable.

12. Non-nuclear electric generation covers SDG&E's O&M costs and capital expenditure costs associated with its non-nuclear electric generation activities.
13. As discussed in the non-nuclear electric generation O&M costs section, the O&M costs of $31.761 million are reasonable.
14. As discussed in the non-nuclear electric generation capital expenditures section, capital expenditures of $7.991 million in 2010, $12.009 million in 2011, and $10.037 million in 2012 are reasonable.
15. SDG&E owns a 20% share of SONGS.
16. The SONGS section addresses SDG&E's share of the SONGS O&M cost (except for refueling outage O&M) and capital costs.
17. D.12-11-051 authorized the O&M and capital costs for SONGS.
18. As a result of the shutdown of SONGS in January 2012, the Commission ordered the SONGS O&M and capital costs authorized in D.12-11-051 to be subject to review and refund.
19. D.12-11-051 made SDG&E subject to the same conditional refund of SDG&E's share of the SONGS-related O&M and capital costs.
20. As discussed in the SONGS section, the following costs are reasonable: the A&G loader to the SONGS capital costs; the Unit 1 spent fuel storage and the associated escalation; the SONGs site easement fees; and SDG&E's 20% share of the SONGS O&M and capital costs authorized in D.12-11-051.
21. The electric distribution operations section addresses the O&M and capital costs associated with SDG&E's electric distribution system.
22. As described in this decision, the O&M costs for SDG&E's electric distribution operations consists of 19 cost categories.

23. The ERO O&M costs for fire hazard prevention, as adjusted by the discussion, are reasonable.
24. Funding of $160,000 for the ERO O&M cost for safety culture change is reasonable.
25. The $927,000 request for the ERO O&M costs for the EPA and PCBs is not authorized because the EPA's rule regarding the phase-out of PCBs has not been issued.
26. The costs associated with implementing an EPA rule regarding the phase-out of PCBs is likely to be substantial.
27. The $151,200 request for the ERO O&M cost for climbing gear is reasonable.
28. The $170,000 request for the ERO O&M cost for pathing changes is reasonable.
29. The $300,000 request for the ERO O&M cost for RIRAT is not authorized because SDG&E has not proved that this request is justified.
30. The $273,000 request for the ERO O&M cost for OpEx on-going support is reasonable.
31. It is reasonable to reduce the $41.923 million request for the ERO O&M cost for ARSO by $3 million.
32. The $26,990 request for the ERO O&M cost for the impact of PEVs is reasonable.
33. The $4.892 million request for the ERO O&M cost for vacation and sick leave is reasonable.
34. Reducing the $3.643 million request for the ERO O&M cost for smart grid to $1.500 million is reasonable.

35. As discussed in the ERO troubleshooting/engineering section, the O&M funding amount of $7.251 million is reasonable.
36. As discussed in the skills and compliance training section, an O&M funding amount of $3.800 million is reasonable.
37. As discussed in the project management section, an O&M funding amount of $1.100 million is reasonable.
38. As discussed in the service order team section, SDG&E's O&M funding amount of $270,000 is reasonable.
39. No evidence has been presented to suggest that the funding request for regional public affairs involves activities that are of a lobbying nature, or to enhance the corporate image.
40. As discussed in the regional public affairs section, an O&M funding amount of $1.3287 million is reasonable.
41. As discussed in the grid operations section, an O&M funding amount of $327,000 is reasonable.
42. As discussed in the substation construction and maintenance section, an O&M funding amount of $8 million is reasonable.
43. As discussed in the system protection section, an O&M funding amount of $641,000 is reasonable.
44. As discussed in the electric distribution operations section, an O&M funding amount of $9 million is reasonable.
45. As discussed in the distribution operations/electric geographic information management, an O&M funding amount of $1.400 million is reasonable.
46. As discussed in the equipment maintenance and lab section, an O&M funding amount of $1.650 million is reasonable.

47. As discussed in the construction services section, an O&M funding amount of $5 million is reasonable.
48. As discussed in the tree trimming section, an O&M funding amount of $25.500 million is reasonable.
49. As discussed in the pole brushing section, an O&M funding amount of $4 million is reasonable.
50. As discussed in the asset management section, an O&M funding amount of $5.055 million is reasonable.
51. As discussed in the distribution engineering section, an O&M funding amount of $969,000 is reasonable.
52. As discussed in the officer section, the O&M funding amount of $417,000 is reasonable.
53. As discussed in the administrative and management section, the O&M funding amount of $150,000 is reasonable.
54. SDG&E's electric distribution capital projects consists of 114 different projects and are managed within the following six project categories: (a) new business; (b) capacity; (c) reliability; (d) mandated; (e) franchise; and
(f) fire hardening and AMI.
55. The use of a "top down" approach to analyze the new business category of electric distribution capital projects is similar to how parties to a settlement agree on an overall amount for a certain category of costs, and is an appropriate approach for determining what the reasonable level of capital funding should be.
56. As discussed in the electric distribution capital expenditures section, it is reasonable to adopt capital funding of $52.631 million in 2010, $61

million in 2011, and $71 million in 2012, for the new business category of projects.

57. We agree with DRA and UCAN that the sustainable community energy systems project should end at the end of this GRC cycle.
58. As discussed in the electric distribution capital expenditures section, it is reasonable to adopt capital funding of $19.128 million in 2010, $38 million in 2011, and $22 million in 2012, for the capacity category of projects.
59. As discussed in the electric distribution capital expenditures section, it is reasonable to adopt capital funding of $50.565 million in 2010, $49 million in 2011, and $58 million in 2012, for the reliability category of projects.
60. As discussed in the electric distribution capital expenditures section, it is reasonable to adopt capital funding of $31.153 million in 2010, $32 million in 2011, and $30 million in 2012, for the mandated category of projects.
61. As discussed in the electric distribution capital expenditures section, it is reasonable to adopt capital funding of $18.214 million in 2010, $17.750 million in 2011, and $16.750 million in 2012, for the franchise category of projects.
62. As discussed in the electric distribution capital expenditures section, it is reasonable to adopt capital funding of $1.871 million in 2010, $6 million in 2011, and $14 million in 2012, for the fire hardening specifics and AMI category of projects.

63. None of the parties have demonstrated that a reliability performance incentive approach or a RIIM will help solve the decline in reliability that was measured from 2008-2010.
64. There is insufficient evidence to determine what caused SDG&E's reliability measures to decline.
65. SDG&E has a continuing obligation under Pub. Util. Code § 451 to provide safe and reliable service.
66. Included within SDG&E's electric distribution operations request are the smart grid capital projects, which consist of the following: (a) renewable growth and projects involving energy storage, dynamic line ratings, phasor measurement units, capacitor SCADA, and SCADA expansion; (b) PEVs and projects involving smart transformers, and public access charging facilities;
(c) reliability and projects involving wireless faulted circuit indicators, and phase identification; and (d) smart grid development involving an integrated test facility project.
67. The state's policy to modernize the electric transmission and distribution system is expressed in Pub. Util. Code § 8360, while Pub. Util. Code § 8366 provides in part that "Smart grid technology may be deployed in a manner to maximize the benefit and minimize the cost to ratepayers and to achieve the benefits of smart grid technology."
68. Assuming SDG&E's PTY proposal was granted as requested, the additional revenue requirement impact from SDG&E's proposed PTY smart grid investments would amount to $50 million in 2013, $72 million in 2014, and
$96 million in 2015.

69. As discussed in the smart grid section, the O&M funding amount of $1.003 million is reasonable.
70. Phase two of the energy storage rulemaking is currently underway, and the major issue to be decided in that proceeding is whether procurement targets for energy storage are appropriate, and if so, how much should be procured.
71. Due to the ongoing energy storage rulemaking, it would be unreasonable and premature to invest heavily into energy storage projects that have not been evaluated for technological viability and cost effectiveness, and therefore no capital funding for energy storage should be authorized for 2011 and 2012.
72. It is reasonable to allow reduced funding of SDG&E's dynamic line ratings project of $1.463 million in 2011, and $1.463 million in 2012.
73. It is reasonable to reduce the funding for the phasor measurement units and to authorize capital expenditure funding of $900,000 in 2011, and $1.500 million in 2012.
74. As discussed in the smart grid section, it is reasonable to reduce funding for the capacitor SCADA project, the SCADA expansion project, and the smart transformers project.
75. D.11-07-029 prohibited electric utilities from owning electric vehicle service equipment, such as charging stations, except for their own use.
76. D.11-07-029 allows SDG&E to request funds in this proceeding for its public access charging facilities as long as it provides convincing evidence that prohibiting SDG&E from owning such equipment would result in underserved markets or market failures in areas where non-utility entities fail to properly serve all markets.

77. It is reasonable to disallow all ratepayer funding of SDG&E's proposal to deploy public access charging facilities.
78. As discussed in the smart grid section, it is reasonable to reduce funding of the wireless fault circuit indicators project, and to authorize capital expenditure funding of $1.202 million in 2011, and $1.199 million in 2012.
79. As discussed in the smart grid section, it is reasonable to disallow all ratepayer funding for the phase identification project.
80. As discussed in the smart grid section, it is reasonable to reduce ratepayer funding for the integrated test facility.
81. The gas distribution section addresses the O&M costs and the capital expenditures associated with the natural gas distribution operations of SDG&E and SoCalGas.
82. SDG&E's non-shared O&M costs for gas distribution are classified into the following three categories: field operations and maintenance; asset management; and operations management and training.
83. SDG&E's field operations and maintenance covers the O&M activities that address the physical condition of the gas distribution system.
84. As discussed in the field operations and maintenance section, it is reasonable to adopt a total O&M forecast of $11.578 million for SDG&E.
85. SDG&E's asset management covers the O&M activities that evaluate the condition of the gas distribution system.
86. As discussed in SDG&E's asset management section, it is reasonable to adopt O&M costs of $1.581 million for the pipeline O&M planning workgroup, and $848,000 for the cathodic protection workgroup.

87. SDG&E's operations management and training covers the O&M activities that provide the leadership and operations support to the organization responsible for gas distribution.
88. As discussed in the operations management and training section, it is reasonable to adopt O&M costs of $1.099 million for these SDG&E activities.
89. As discussed in SDG&E's gas distribution O&M shared services, it is reasonable to adopt $88,000 for the O&M shared services cost.
90. SDG&E's gas distribution capital expenditures are classified into the following 14 categories, plus its smart meter project: (a) new business; (b) system minor additions, relocations, and retirements; (c) meter and regulator materials; (d) pressure betterment; (e) distribution easements; (f) pipe relocation – franchise and freeway; (g) tools and equipment; (h) NERBA; (i) code compliance; (j) replacement of mains and services; (k) cathodic protection; (l) regulator station improvements; (m) local engineering;
(n) Camp Pendleton – San Onofre 1; and (o) smart meter project.
91. SDG&E's new business category covers the changes and additions to the existing gas distribution system to serve new customers.
92. As discussed in SDG&E's new business category, it is reasonable to adopt capital funding of $2.011 million in 2010, $2.250 million in 2011, and $2.900 million in 2012.
93. SDG&E's system minor additions, relocations, and retirements cover the costs that are not covered in other work categories.

94. As discussed in SDG&E's system minor additions, relocations, and retirements section, it is reasonable to adopt capital funding of $604,000 in 2010, $754,000 in 2011, and $754,000 in 2012.
95. SDG&E's meter and regulator materials covers the cost of purchasing new gas meters and pressure regulators for use by new customers or for replacements.
96. As discussed in SDG&E's meter and regulator materials section, it is reasonable to adopt capital funding of $6.083 million in 2010, $4.665 million for 2011, and $4.665 million for 2012.
97. SDG&E's pressure betterment covers the costs of projects to improve pressure in areas where there is insufficient capacity or pressure to meet load growth.
98. As discussed in SDG&E's pressure betterment section, it is reasonable to adopt capital funding of $1.972 million in 2010, $2 million in 2011, and
$2.500 million for 2012.
99. SDG&E's distribution easements cover the costs of obtaining gas distribution easements.
100. As discussed in SDG&E's distribution easements section, it is reasonable to adopt capital funding of $11,000 in 2010, $30,000 in 2011, and $30,000 in 2012.
101. SDG&E's pipe relocation – franchise and freeway covers the costs of relocating existing gas facilities when they conflict with public improvements by local or state agencies.
102. As discussed in SDG&E's pipe relocation – franchise and freeway section, it is reasonable to adopt capital funding of $3.672 million in

2010;

$2.400 million in 2011; and $2.900 million in 2012.

103. SDG&E's tools and equipment covers the costs of new tools and equipment that field personnel use to construct, operate, and maintain the gas distribution system.

104. As discussed in SDG&E's tools and equipment section, it is reasonable to adopt capital funding of $143,000 in 2010, $1.846 million in 2011, and $446,000 in 2012.

105. SDG&E's code compliance covers the cost of upgrades or addition to facilities to ensure compliance with minimum federal safety standards for gas pipelines.

106. As discussed in SDG&E's code compliance section, it is reasonable to adopt capital funding of $441,000 in 2010, $349,000 in 2011, and $441,000 in 2012.

107. SDG&E's replacement of mains and services covers the costs of replacing deteriorated gas distribution pipelines.

108. As discussed in SDG&E's replacement of mains and services, it is reasonable to adopt capital funding of $1.233 million in 2010, $1.528 million in 2011, and $1.487 million in 2012.

109. SDG&E's cathodic protection covers the cost of installing new and replacement cathodic protection systems and equipment.

110. As discussed in SDG&E's cathodic protection section, it is reasonable to adopt capital funding of $364,000 in 2010, $458,000 in 2011, and $458,000 in 2012.

111. SDG&E's regulator station improvements cover the costs of small capital projects that are not covered under other budget codes.

112. As discussed in SDG&E's regulator station improvements section, it is reasonable to adopt capital funding of $461,000 in 2010, $1.050 million in 2011, and $600,000 in 2012.
113. SDG&E's local engineering covers the costs of a range of services to support gas distribution capital construction.
114. As discussed in SDG&E's local engineering section, it is reasonable to adopt capital funding of $4.590 million in 2010, $4.900 million in 2011, and
$5.100 million in 2012.
115. SDG&E's Camp Pendleton – San Onofre 1 covers the cost of replacing the master metered gas distribution system with an individually metered gas distribution system at Camp Pendleton.
116. As discussed in SDG&E's Camp Pendleton – San Onofre 1 section, it is reasonable to adopt capital funding of $439,000 in 2010.
117. SDG&E's smart meter project covers the cost of the purchase and installation of the smart meter gas meter modules, the replacement of meters due to smart meter module incompatibility, and related equipment.
118. As discussed in SDG&E's smart meter project section, it is reasonable to adopt capital funding of $50.472 million in 2010, $4 million in 2011, and zero funding in 2012.
119. SoCalGas' non-shared O&M costs for gas distribution are classified into the following four categories: field operations and maintenance; asset management; operations management and training; and regional public affairs.

120. SoCalGas' field operations and maintenance covers the O&M activities that address the physical condition of the gas distribution system.
121. As discussed in SoCalGas' field operations and maintenance section, it is reasonable to adopt a total O&M forecast of $69.857 million.
122. SoCalGas' asset management covers the O&M activities that address the physical condition of the gas distribution system.
123. As discussed in SoCalGas' asset management section, it is reasonable to adopt O&M costs of $6.750 million for the pipeline O&M planning workgroup, and $7.067 million for the cathodic protection workgroup.
124. SoCalGas' operations management and training covers the O&M activities that provide the operations leadership, field management, operations support, and field technical skills training.
125. As discussed in SoCalGas' operations management and training section, it is reasonable to adopt O&M costs of $9.450 million for these activities.
126. SoCalGas' regional public affairs cover the O&M activities associated with working with governmental entities, and as a point of contact regarding SoCalGas' activities.
127. As discussed in SoCalGas' regional public affairs section, it is reasonable to adopt O&M costs of $3.907 million for these activities.
128. As discussed in SoCalGas' gas distribution O&M shared services, it is reasonable to adopt $1.155 million for the O&M shared services cost.
129. SoCalGas' gas distribution capital expenditures are classified into the following categories: (a) new business; (b) new business – Twenty-nine Palms;

(c) pressure betterment; (e) supply line replacements; (f) main replacements;

(g) service replacements; (h) main and service abandonments; (i) regulator station projects; (j) cathodic protection; (k) pipeline relocations – freeway;

(l) pipeline relocations – franchise; (m) mobile home parks; (n) other distribution capital projects; (o) meter guard installations; (p) meters and regulators;

(q) equipment/tools; (r) NERBA; and (s) field capital support.

130. SoCalGas' new business category covers the changes and additions to the existing gas distribution system to serve new customers.

131. As discussed in SoCalGas' new business section, it is reasonable to adopt capital funding of $12.350 million in 2010, $17.415 million in 2011, and
$21.650 million in 2012.

132. As discussed in SoCalGas' new business section, it is reasonable to adopt capital funding for the Twenty-nine Palms Marine base of $400,000 in 2010,
$4.600 million in 2011, and zero funding in 2012.

133. SoCalGas' pressure betterment projects cover the costs of projects to improve pressure in areas with insufficient capacity or pressure to meet local growth.

134. As discussed in SoCalGas' pressure betterment projects section, it is reasonable to adopt capital funding of $9.341 million in 2010, $11.720 million in 2011, and $11.930 million in 2012.

135. SoCalGas' supply line replacements cover the costs of replacing high pressure distribution pipelines.
136. As discussed in SoCalGas' supply line replacements section, it is reasonable to adopt capital funding of $1.237 million in 2010, $2.612 million in 2011, and $2.592 million in 2012.
137. SoCalGas' main replacements cover the costs associated with replacing the main lines that support the delivery of gas to customers, and the service lines if needed.
138. As discussed in SoCalGas' main replacements section, it is reasonable to adopt capital funding of $32.063 million in 2010, $29.873 million in 2011, and $29.598 million in 2012.
139. SoCalGas' service replacements cover the costs of replacing the service lines that support the delivery of gas to its customers.
140. As discussed in SoCalGas' service replacements section, it is reasonable to adopt capital funding of $11.458 million in 2010, $11.029 million in 2011, and $11.000 million in 2012.
141. SoCalGas' main and service abandonments cover the costs associated with the abandonment of distribution main lines and service lines without installing replacement pipeline.
142. As discussed in SoCalGas' main and service abandonments section, it is reasonable to adopt capital funding of $2.515 million in 2010, $3.013 million in 2011, and $3.013 million in 2012.
143. SoCalGas' regulator station projects covers the costs associated with the upgrade, relocation, and replacement of regulator stations.

144. As discussed in SoCalGas' regulator station projects section, it is reasonable to adopt capital funding of $3.831 million in 2010, $6.000 million in 2011, and $6.250 million in 2012.
145. SoCalGas' cathodic protection covers the costs of installing and replacing cathodic protection systems and equipment.
146. As discussed in SoCalGas' cathodic protection section, it is reasonable to adopt capital funding of $3.362 million in 2010, $3.782 million in 2011, and
$3.800 million in 2012.
147. SoCalGas' pipeline relocation – freeway covers the costs of relocating or altering existing gas facilities due to the planned construction or reconstruction of freeways.
148. As discussed in SoCalGas' pipeline relocation – freeway section, it is reasonable to adopt capital funding of $1.740 million in 2010, $2.196 million in 2011, and $2.179 million in 2012.
149. SoCalGas' pipeline relocation – franchise covers the costs of relocating or altering existing gas facilities due to construction of roads or railway systems.
150. As discussed in SoCalGas' pipeline relocation – franchise section, it is reasonable to adopt capital funding of $11.016 million in 2010, $8.800 million in 2011, and $8.900 million in 2012.
151. SoCalGas' mobile home parks cover the cost of purchasing existing natural gas distribution systems that are located at mobile home parks.
152. As discussed in SoCalGas' mobile home parks section, it is reasonable to adopt annual capital funding of $67,000 for 2010, 2011, and 2012.

153. SoCalGas' other distribution capital projects covers the costs of other activities that are not specifically included in other categories of work.
154. As discussed in SoCalGas' other distribution capital projects, it is reasonable to adopt capital funding of $2.653 million in 2010, $3.073 million in 2011, and $3.073 million in 2012 for these activities.
155. As discussed in SoCalGas' other distribution capital projects, it is reasonable to adopt capital funding for the meter guard installations of $1.227 million in 2010, $1.097 million in 2011, and $1.210 million in 2012.
156. SoCalGas' meters and regulators cover the costs for the purchase of gas meters, pressure regulators, and other related equipment.
157. As discussed in SoCalGas' meter and regulators section, it is reasonable to adopt capital funding of $20.501 million in 2010, $23.310 million in 2011, and $28.025 million in 2012.
158. SoCalGas' equipment/tools cover the costs of tools and equipment used by field personnel for the maintenance and repair of the gas distribution system.
159. As discussed in SoCalGas' equipment/tools section, it is reasonable to adopt capital funding of $2.401 million in 2010, $7.253 million in 2011, and $1.393 million in 2012.
160. SoCalGas' field capital support covers the costs for the range of services that support gas distribution field capital asset construction.
161. As discussed in SoCalGas' field capital support section, it is reasonable to adopt capital funding of $34.649 million in 2010, $32.500 million for 2011, and
$32 million for 2012.

162. The gas transmission section addresses the O&M costs for the gas transmission operations of SDG&E and SoCalGas.
163. SDG&E's gas transmission system consists of about 168 miles of high pressure pipelines and two compressor stations.
164. As discussed in SDG&E's gas transmission O&M costs section, it is reasonable to adopt the following: $969,000 for its pipeline O&M costs; $2.120 million for its compressor station O&M costs; $108,000 for its technical services O&M costs; and $613,000 for its shared O&M costs.
165. SoCalGas' gas transmission system consists of about 3,989 miles of high pressure pipelines and eleven compressor stations.
166. As discussed in SoCalGas' gas transmission O&M costs section, it is reasonable to adopt the following: $17.227 million for its pipeline O&M costs; $7.685 million for its compressor station O&M costs; $1.950 million for its technical services O&M costs; and $4.152 million for its shared O&M costs.
167. The gas storage and engineering section address the O&M costs, and the capital expenditures, associated with the gas storage operations of SoCalGas, and the gas engineering operations of SDG&E and SoCalGas.
168. SoCalGas owns and operates four underground storage fields, which require compressors, regulators, and monitoring equipment.
169. As discussed in SoCalGas' gas storage O&M costs section, it is reasonable to adopt O&M costs of $27.607 million.
170. SoCalGas' gas storage capital expenditures consist of the following categories of projects: compressor stations; wells; pipelines; purification; and auxiliary equipment.

171. As discussed in SoCalGas' gas storage capital expenditures section, it is reasonable to adopt capital funding of $4.430 million in 2010, $5.851 million in 2011, and $5.851 million in 2012, for the compressor stations.
172. As discussed in SoCalGas' gas storage capital expenditures section, it is reasonable to adopt capital funding of $11.055 million in 2010, $7.616 million in 2011, and $7.616 million in 2012, for capital projects related to the wells.
173. As discussed in SoCalGas' gas storage capital expenditures section, it is reasonable to adopt capital funding of $4.222 million in 2010, $3.093 million for 2011, and $3.093 million in 2012, for pipelines.
174. As discussed in SoCalGas' gas storage capital expenditures section, it is reasonable to adopt capital funding of $2.031 million in 2010, $4.191 million in 2011, and $4.191 million in 2012, for purification equipment.
175. As discussed in SoCalGas' gas storage capital expenditures section, it is reasonable to adopt capital funding of $5.923 million in 2010, $7.454 million in 2011, and $6.645 million in 2012, for auxiliary equipment.
176. The gas engineering section addresses the O&M expenditures for gas engineering, and the capital expenditures for gas transmission and gas engineering, for both SDG&E and SoCalGas.
177. SDG&E operates about 246 miles of DOT-defined transmission pipeline, and about 8345 miles of gas distribution main pipelines.
178. SDG&E's transmission and distribution pipelines are subject to the federal pipeline safety regulations known as TIMP and DIMP.
179. As discussed in the SDG&E gas engineering section, it is reasonable to adopt non-shared O&M costs of $700,000 for SDG&E's gas engineering costs.

180. TIMP requires an operator of a gas transmission pipeline to perform recurring assessments of its pipelines, as well as other activities to manage the integrity of the transmission pipelines.
181. A two-way balancing account to recover the costs of complying with TIMP is appropriate due to the cost of compliance, and possible changes in pipeline inspection requirements in the future.
182. A two-way balancing account to recover the costs of complying with TIMP will ensure that SDG&E has sufficient funds to carry out all the necessary TIMP-related work to ensure that its gas transmission system remains safe and reliable.
183. Parties will have the opportunity to review the reasonableness of these TIMP-related expenses in this balancing account when those expenses are reported in the Annual Regulatory Account Balance Update.
184. As discussed in the SDG&E gas engineering section, it is reasonable to adopt non-shared O&M costs of $5.339 million for SDG&E's transmission pipeline integrity costs.
185. DIMP requires an operator of a gas distribution pipeline to develop and implement an integrity management plan.
186. A two-way balancing account for SDG&E to recover the costs of complying with DIMP is appropriate due to the cost of compliance, and possible changes in requirements.
187. A two-way balancing account to recover the costs of complying with DIMP will ensure that SDG&E carries out the necessary work to ensure that its gas distribution system remains safe and reliable.

188. Parties will have the opportunity to review the reasonableness of these DIMP-related expenses in SDG&E's balancing account when those expenses are reported in the Annual Regulatory Account Balance Update.

189. As discussed in SDG&E's gas engineering section, it is reasonable to adopt non-shared O&M costs of $3.373 million for SDG&E's distribution pipeline integrity costs.

190. SDG&E's non-shared O&M costs for public awareness includes the cost of complying with 49 CFR § 192.616.

191. As discussed in SDG&E's gas engineering section, it is reasonable to adopt non-shared O&M costs of $200,000 for SDG&E's public awareness costs.

192. As discussed in SDG&E's gas engineering section, it is reasonable to adopt shared O&M costs of $1.881 million for SDG&E.

193. The capital expenditures for SDG&E's gas engineering covers the following capital projects: (a) gas transmission – new additions; (b) gas transmission – pipeline replacements; (c) gas transmission – pipeline relocations – freeway; (d) gas transmission – compressor stations; (e) gas transmission – cathodic protection; (f) gas transmission – LNG support; (g) gas transmission – meter and regulator stations; (h) gas transmission – pipeline integrity – projects for distribution; (i) gas transmission – capital tools; (j) gas transmission – direct supervision and engineering overheads; and (k) distribution integrity management program.

194. As discussed in SDG&E's gas engineering capital expenditures section, it is reasonable to adopt capital funding as follows: (a) for gas

transmission – new additions, $56,000 in 2010, $500,000 in 2011, and $500,000 in 2012; (b) for gas transmission – pipeline replacements, zero in 2010,
$1.500 million in 2011, and $617,000 in 2012; (c) for gas transmission – pipeline relocations – freeway, $88,000 in 2010, $212,000 in 2011, and $212,000 in 2012; (d) for gas transmission – compressor stations, $4.048 million in 2010,
$2.486 million in 2011, and $2.610 million in 2012; (e) for gas transmission – cathodic protection, $49,000 in 2010, $94,000 in 2011, and $94,000 in 2012; (f) for gas transmission – meter and regulator stations, $60,000 in 2010, $444,000 in 2011, and $444,000 in 2012; (g) for gas transmission – pipeline integrity – projects for distribution, $2.626 million in 2010, $2.698 million in 2011, and $920,000 in 2012; (h) for gas transmission – capital tools, $14,000 in 2010, $20,000 in 2011, and $20,000 in 2012; (i) for gas transmission – direct supervision and engineering overheads, $220,000 in 2010, $220,000 in 2011, and $220,000 in 2012; and (j) for distribution integrity management program, $2.829 million in 2011, and $4.500 million in 2012.

195. SoCalGas operates about 3989 miles of DOT-defined transmission pipeline, and about 47,600 miles of gas distribution main pipelines.

196. SoCalGas' transmission and distribution pipelines are subject to the federal pipeline safety regulations known as TIMP and DIMP.

197. The SoCalGas gas engineering section addresses the O&M costs and capital expenditures for its gas storage, gas transmission, and gas distribution.

198. SoCalGas' non-shared O&M costs for gas engineering are divided into the following cost categories: gas engineering; TIMP; DIMP; and public awareness.
199. As discussed in the SoCalGas gas engineering section, it is reasonable to adopt non-shared O&M costs of $12.567 million for SoCalGas' gas engineering costs.
200. A two-way balancing account for SoCalGas to recover the costs of complying with TIMP is appropriate due to the cost of compliance, and possible changes in pipeline inspection requirements in the future, and any costs in excess of the authorized TIMP O&M costs will be subject to recovery through a Tier 2 AL process.
201. A two-way balancing account to recover the costs of complying with TIMP will ensure that SoCalGas has sufficient funds to carry out all the necessary TIMP-related work to ensure that its gas transmission system remains safe and reliable.
202. Parties will have the opportunity to review the reasonableness of these TIMP-related expenses in SoCalGas' balancing account when those expenses are reported in the Annual Regulatory Account Balance Update.
203. As discussed in the SoCalGas gas engineering section, it is reasonable to adopt non-shared O&M costs of $20.760 million for SoCalGas' TIMP-related gas engineering costs.
204. A two-way balancing account for SoCalGas to recover the costs of complying with DIMP is appropriate due to the cost of compliance, and possible changes in requirements, and any costs in excess of the

authorized DIMP O&M costs will be subject to recovery through a Tier 2 AL process.

205. A two-way balancing account to recover the costs of complying with DIMP will ensure that SoCalGas carries out the necessary work to ensure that its gas distribution system remains safe and reliable.

206. Parties will have the opportunity to review the reasonableness of these DIMP-related expenses in SoCalGas' balancing account when those expenses are reported in the Annual Regulatory Account Balance Update.

207. As discussed in SoCalGas' gas engineering section, it is reasonable to adopt non-shared O&M costs of $24.947 million for SoCalGas' distribution pipeline integrity costs.

208. As discussed in SoCalGas' gas engineering section, it is reasonable to adopt non-shared O&M costs of $600,000 for SoCalGas' public awareness costs.

209. As discussed in SoCalGas' gas engineering section, it is reasonable to adopt shared O&M costs of $16.053 million for SoCalGas.

210. The capital expenditures for SoCalGas' gas engineering covers the following capital projects: (a) pipeline integrity - distribution; (b) DIMP;

(c) transmission pipelines – new additions; (d) transmission pipelines – replacements and pipeline integrity program; (e) transmission pipeline - relocations – freeway; (f) transmission pipeline relocations – franchise/private; (g) gas transmission – compressor stations; (h) gas transmission pipelines – cathodic protection; (i) gas transmission – meter and regulator; (j) gas transmission – auxiliary equipment; (k) gas transmission – pipeline land rights; (l) gas transmission – laboratory equipment; (m) gas transmission and storage – capital tools; (n) gas storage - supervision and engineering direct overheads; (o) gas transmission – supervision and engineering direct overheads; (p) Coastal Region Conservation Program; and (q) Sustainable SoCal Program.

211. As discussed in SoCalGas' gas engineering capital expenditures section, it is reasonable to adopt capital funding as follows: (a) for pipeline
integrity – distribution, $14.405 million in 2010, $22.902 million in 2011, and $20.762 million in 2012; (b) for DIMP, $14.262 million in 2011, and $30.224 million in 2012; (c) for transmission pipelines – new additions, $9.519 million in 2010, $2.801 million in 2011, and $9.269 million in 2012; (d) for transmission pipelines – replacements and pipeline integrity program, $42.766 million in 2010, $35.227 million in 2011, and $25.917 million in 2012; (e) for transmission pipeline - relocations – freeway, $1.019 million in 2010, $2.010 million in 2011, and $2.010 million in 2012; (f) for transmission pipeline
relocations – franchise/private, $10.104 million in 2010, $8.128 million in 2011, and $11.105 million in 2012; (g) for gas transmission – compressor stations,
$2.303 million in 2010, $4.450 million in 2011, and $11.300 million in 2012;
(h) for gas transmission pipelines – cathodic protection, $2.413 million in 2010, $1.793 million in 2011, and $1.793 million in 2012; (i) for gas transmission – meter and regulator, $8.777 million in 2010, $4.526

million in 2011, and $4.526 million in 2012; (j) for gas transmission – auxiliary equipment, $882,000 in 2010,
$1.651 million in 2011, and $1.651 million in 2012; (k) for gas transmission – pipeline land rights, $4 million in 2011, and $7.300 in 2012;
(l) for gas transmission – laboratory equipment, $265,000 in 2010, $455,000 in 2011, and $295,000 in 2012; (m) for gas transmission and storage – capital tools, $307,000 in 2010, $307,000 in 2011, and $307,000 in 2012; (n) for gas
storage - supervision and engineering direct overheads, $240,000 in 2010, $278,000 in 2011, and $335,000 in 2012; (o) for gas transmission – supervision and engineering direct overheads, $904,000 in 2010, $1.046 million in 2011, and
$1.260 million in 2012; (p) for Coastal Region Conservation Program, $886,000 in 2010, $664,000 in 2011, and zero in 2012; and (q) zero funding for the Sustainable SoCal Program.

212. The Commission ordered PG&E to provide a semi-annual "Gas Transmission and Storage Safety Report" in D.11-04-031, and a semi-annual "Gas Distribution Pipeline Safety Reports" in D.11-05-018.

213. Pub. Util. Code § 958.5, which was recently enacted into law with an effective date of January 1, 2012, requires all natural gas utilities to file a gas transmission and storage safety report with the Safety and Enforcement Division.

214. Based on various sections of the Pub. Util. Code, the Commission can impose a reporting requirement on SDG&E and SoCalGas about their gas distribution operations.

215. Pursuant to Pub. Util. Code § 958.5, the Safety and Enforcement Division is to review these safety reports to assess whether the projects and activities are being carried out, and to track whether SDG&E and SoCalGas are spending their allocated funds on projects and activities that ensure the safety and reliability of their respective gas transmission, gas distribution, and gas storage operations.
216. The customer service section addresses the O&M expenses and capital expenditures of SDG&E and SoCalGas for the following kinds of customer service-related activities: contact with customers out in the field, call center and branch offices; office operations that support customer-related activities such as billing services, credit and collections, remittance processing, and technology support; and customer information, that provides customers with information about programs and products.
217. Customer service field activities include providing service at customer locations by field technicians.
218. The call center handles telephone calls from customers.
219. The branch offices and authorized payment locations provide in-person bill payment services.
220. SDG&E's field, call center and branch offices section covers the O&M costs and capital expenditures associated with its customer service field and customer contact operations.
221. As discussed in SDG&E's field, call center and branch offices section, it is reasonable to adopt the shared services O&M amount of $788,000.

222. As discussed in SDG&E's customer services field section, it is reasonable to adopt $19.639 million for SDG&E's non-shared O&M costs for its customer services field activities.

223. As discussed in SDG&E's call center section, it is reasonable to adopt non-shared call center O&M costs of $11.784 million, and $627,000 in shared call center O&M costs.

224. As discussed in SDG&E's branch offices and authorized payment location section, it is reasonable to adopt $1.900 million for the O&M costs for these activities.

225. UCAN alleges that customer satisfaction with SDG&E's workers in the field or at the call centers have declined, and that SDG&E has not taken steps to remedy these problems.

226. As discussed in the SDG&E customer satisfaction section, we are not persuaded that customer satisfaction has declined or that SDG&E is not taking responsive action.

227. No additional data record keeping requirements need to be imposed on SDG&E.

228. There is no merit in UCAN's allegation that SDG&E failed to provide data to UCAN about SDG&E's Service Guarantee program, and therefore we do not require that the cost of that program be shared with SDG&E's shareholders.

229. SDG&E's capital expenditures for customer service field and customer contact activities address the following capital projects: helpdesk support; Service Order Routing Technology upgrade; HAN DRCA implementation;
HAN systems integration; HAN laboratory; and DERMS.

230. D.07-04-043 and D.11-07-056 provided the policy and direction for how the Commission should proceed with HAN-related projects.

231. As discussed in the SDG&E capital expenditures section for customer service field and customer contact activities, it is reasonable to adopt capital funding as follows: $5.041 million in 2011, and $12.376 million in 2012.

232. CCUE raised the issue that SDG&E should have a sufficient workforce on hand to respond to a major event.

233. SDG&E has mutual assistance agreements with other utilities, which can provide skilled workers to assist SDG&E if a major event occurs.

234. Pub. Util. Code § 961 requires a gas utility to develop a plan for the safe and reliable operation of its gas operations, and that such a plan and the updates are to include information about "an adequately sized, qualified, and properly trained gas corporation workforce to carry out the plan."

235. Since R.11-02-019 is addressing the workforce issues identified in Pub. Util. Code § 961, we refrain from deciding in this proceeding what the adequate size of SDG&E's gas workforce should be.

236. SoCalGas' field, call center and branch offices section covers the O&M costs and capital expenditures associated with its customer service field and customer contact operations, and meter reading.

237. As discussed in SoCalGas' customer services field section, it is reasonable to adopt $129.500 million for SoCalGas' O&M costs for its customer services field activities.

238. As discussed in SoCalGas' call center section, it is reasonable to adopt call center O&M costs of $46.413 million.

239. As discussed in SoCalGas' branch offices and authorized payment location section, it is reasonable to adopt $10.619 million for the O&M costs for these activities.
240. As discussed in SoCalGas' meter reading section, it is reasonable to adopt $32.917 million as the O&M costs for SoCalGas' meter reading activities.
241. SoCalGas' capital expenditures for customer service field and customer contact activities address the following capital projects: additional mobile data terminals; software application for customer service field operating efficiency; forecasting and scheduling enhancements to PACER applications; software upgrade to the call center recording system; purchase of a new meter reading handheld system; and replacing 1600 mobile data terminals.
242. As discussed in the SoCalGas capital expenditures section for customer service field and customer contact activities, it is reasonable to adopt capital funding as follows: $12.224 million in 2010, $10.968 million in 2011, and
$19.506 million in 2012.
243. As described in the UWUA recommendations section, UWUA makes several recommendations about how to improve SoCalGas' response times in the areas of customer service field and customer contact, and requests that additional revenues be authorized so that SoCalGas can meet the UWUA's recommended service standards.
244. UWUA's recommendations are based on its allegations that SoCalGas needs to restore the levels and standards for safety that were previously

in place at SoCalGas, and that there is a chronic shortage of employees in key positions that involve customer service and safety.

245. The plan required by Pub. Util. Code § 961 requires the gas utility to address how it responds to reports of leaks and other hazardous conditions.

246. To the extent SoCalGas has addressed gas safety and reliability issues in the plan that it submitted in the Gas Safety Rulemaking (R.11-02-019), those issues will be addressed in that proceeding.

247. To achieve a 100% response time within the timeframe for responding to A1 leaks is outweighed by the cost of such an undertaking.

248. For the reasons discussed in the UWUA recommendations section, UWUA's recommendation that there be a 100% response time within 30 minutes and 45 minutes for an A1 leak call is not adopted.

249. Reducing the time it takes to complete a non-leak order has a direct relationship to the number of employees who can respond to those situations, and the cost of those additional employees.

250. UWUA did not present any evidence to show that longer response times to complete a non-leak order has created actual problems, or that it will reduce customer safety.

251. After weighing and balancing the issues of safety, and the cost impact of adding additional employees to meet UWUA's recommendation about responding to non-leak orders, UWUA's recommendation for additional funds to hire additional staff is not adopted.

252. Since SoCalGas has a policy in place to inspect for acceptable gas connectors, and to expand the inspection when unacceptable

connectors are found, we do not adopt UWUA's recommendation to have the field person check the connectors on every appliance.

253. UWUA has not demonstrated that SoCalGas' customers are dissatisfied with the time it takes for a customer service representative to talk to them.

254. In view of the level of service that the call center is able to achieve with the current staffing, and the cost to achieve a 90% level of service, UWUA's recommendation that incoming call center calls be answered within 60 seconds 90% of the time is not adopted.

255. Calls regarding gas leaks are given top priority, and go to the top of the telephone queue to be answered.

256. UWUA's recommendation to increase the average handle time of each call to 270 seconds is not adopted because SoCalGas is in the best position to decide how to best staff its call center, and to decide what procedures need to be in place in order to minimize the time required to handle each call in a satisfactory manner.

257. UWUA's recommendation to add a customer contact representative at each of the 47 branch offices is not adopted because most of the transactions can be handled by the existing branch office staff.

258. SDG&E's office operations consist of non-shared O&M expenses for the following: (a) billing services; (b) office credit and collections; (c) bill delivery; (d) postage; (e) customer services technology support; and (f) customer service operations.

259. As discussed in the SDG&E office operations section, it is reasonable to adopt the following non-shared O&M costs: (a) $4.916 million for billing services; (b) $2.776 million for office credit and collections; (c)

$844,000 for bill delivery; (d) $4.673 million for postage; (e) $900,000 for customer service technology support; and (f) $1.735 million for customer service operations.

260. The prefunding of anticipated postage is money that is paid prior to the period to which it is applied, and therefore a prepayment.

261. As discussed in the SDG&E office operations section, it is reasonable to adopt shared services O&M costs of $4.220 million.

262. SDG&E's capital expenditures for customer service office operations consists of a billing regulatory project, and a bill redesign project.

263. As discussed in SDG&E's office operations capital expenditures section, it is reasonable to adopt capital funding of $1.013 million in 2010, and
$456,000 in 2011.

264. SoCalGas' office operations consist of non-shared O&M expenses for the following: (a) billing services; (b) measurement data operations; (c) office credit and collections; (d) bill delivery; (e) postage; (f) customer service technology support; and (g) other customer service operations.

265. As discussed in the SoCalGas office operations section, it is reasonable to adopt the following non-shared O&M costs: (a) $7.512 million for billing services; (b) $1.223 million for measurement data operations; (c) $5.560 million for office credit and collections; (d) $4.991 million for bill delivery;
(e) $20.629 million for postage; (f) $3.133 million for customer services technology support; and (g) $1.635 million for other customer service operations.

266. As discussed in the SoCalGas office operations section, it is reasonable to adopt shared services O&M costs of $6.237 million.
267. SoCalGas' capital expenditures for customer service office operations consists of a project supporting new cost allocation and rate designs for its billing system, and a bill redesign project.
268. As discussed in SoCalGas' office operations capital expenditures section, it is reasonable to adopt capital funding of $1.061 million in 2010.
269. SDG&E's non-shared O&M costs for its customer information function is classified into the following categories: (a) customer assistance; (b) customer programs; (c) clean energy; (d) clean transportation; (e) commercial, industrial and government services; (f) customer communications and research; and (g) research development and demonstration.
270. As discussed in the SDG&E customer information section, it is reasonable to adopt the following non-shared O&M costs: (a) $1.150 million for customer assistance; (b) $799,000 for customer programs; (c) $1.142 million for clean energy; (d) $1.117 million for clean transportation; (e) $4.850 million for commercial, industrial and government services; (f) $5.900 million for customer communications and research; and (g) $2.750 million for research development and demonstration.
271. D.11-07-029 addressed the role that the electric utilities should undertake with respect to education and outreach.
272. Pub. Util. Code § 740.2 and D.11-07-029 make clear that the electric utilities are to collaborate with other interested stakeholders to prepare

for the widespread deployment and use of PEVs, and to educate the public about the impact PEVs will have on customers and the electric utility.

273. Some of the education and outreach expenses do not appear to be targeted at potential PEV users.

274. The Joint Parties recommend that SDG&E be required to conduct a community awareness program about nuclear power as part of its customer communications efforts.

275. SCE, as the majority owner of SONGS, conducts outreach programs in the communities near the SONGS plant, and SDG&E pays its share of those outreach programs to SCE.

276. The Joint Parties' recommendation that SDG&E be required to undertake a SONGS-related community outreach and preparation program is not adopted because that would be duplicative of what SCE already does, and would result in an unnecessary program and costs that would be borne by SDG&E's ratepayers.

277. SDG&E proposes a 60% (ratepayer) and 40% (shareholders) sharing mechanism for any RD&D investments or activities that result in royalties or revenues.

278. Pub. Util. Code § 740 provides that for the purpose of setting rates, the Commission may allow the inclusion of expenses for research and development.

279. Pub. Util. Code § 740.1 sets forth the guidelines the Commission is to consider in evaluating the research, development, and demonstration programs being proposed by the utility.

280. Some of SDG&E's proposed RD&D activities appear to be duplicative of other research that is or has been performed.

281. SDG&E's proposed RD&D sharing mechanism is the same as what was adopted for SoCalGas in D.08-07-046.

282. As discussed in the SDG&E customer information section, it is reasonable to adopt shared O&M costs of $1.250 million.

283. SDG&E's capital expenditures for customer information are in the following areas: (a) My Account online account management services; (b) customer contact and notification system; (c) customer relationship management system upgrade; (d) phase 3 of SDG&E's customer energy network; and (e) SDG&E's energy and environment center.

284. Nothing in D.09-09-047, or in the ALs that were filed in compliance with that decision, authorized SDG&E to build the Energy Innovation Center or its equivalent.

285. It is unreasonable to reward SDG&E for deciding to proceed with the Energy Innovation Center capital project when such a complex was not contemplated by SDG&E in the energy efficiency proceeding that led to D.09-09-047, or in SDG&E's prior GRC.

286. SDG&E has not demonstrated that lower cost alternatives were available to secure additional classroom space to house the food service center.

287. As discussed in SDG&E's capital expenditures section for customer information, it is reasonable to adopt capital funding as follows: $1.217 million in 2010; $8.586 million in 2011; and $5.355 million in 2012.

288. SoCalGas' non-shared O&M costs for its customer information function is classified into the following categories: (a) customer

communications, research and e-services; (b) customer assistance; (c) nonresidential markets; and

(d) research development and demonstration.

289. As discussed in the SoCalGas customer information section, it is reasonable to adopt the following non-shared O&M costs: (a) $7.591 million for customer communications, research and e-services; (b) $4.874 million for customer assistance; (c) $8.102 million for nonresidential markets; (d) $5.558 million for research development and demonstration.

290. D.10-12-002 authorized the NGAT memorandum account for the purpose of tracking unanticipated and unforeseen NGAT costs arising out of the directive in D.08-11-0031 to expand NGAT.

291. SoCalGas has not requested in this proceeding to recover any of the costs from the NGAT memorandum account.

292. As discussed in the SoCalGas customer information section on shared services, it is reasonable to adopt shared O&M costs of $6.215 million.

293. SoCalGas' capital expenditures for customer information are in the following areas: (a) Sustainable SoCal Program; (b) California producer access; and (c) the Next Generation Envoy.

294. The Sustainable SoCal Program is for the installation of four biogas conditioning systems at small to mid-size wastewater treatment facilities, which capture the raw biogas, which is then converted to pipeline quality biogas.

295. Under the Sustainable SoCal Program, SoCalGas will design, install, own and operate the biogas conditioning systems at these sites, and the

biogas will be used by SoCalGas for its facilities and to fuel its CNG vehicles.

296. The California Producer Access project is to make changes to various systems to accommodate access by California gas producers.

297. The Next Generation Envoy project is to improve the usability of its electronic bulletin board known as Envoy.

298. Support for the use of biogas is found in D.11-09-015, Executive Order S-06-06, and in Assembly Bill 1900 which added Pub. Util. Code § 399.24, and Health and Safety Code § 25421.

299. Before biomethane can be injected into a gas utility's pipeline, the biomethane must meet the standards being developed by the Office of Environmental Health Hazard Assessment, and the Commission.

300. The Commission rejected SoCalGas' AL 4172, which sought to offer biogas conditioning service to potential biogas producers.

301. To require ratepayers to fund the purchase, installation, and operation of the Sustainable SoCal Program is not a reasonable use of ratepayer funds.

302. SoCalGas' request that ratepayers fund the Sustainable SoCal Program is distinct from the Commission adopting "policies and programs that promote the in-state production and distribution of biomethane."

303. As discussed in the SoCalGas customer service capital expenditures, it is reasonable to adopt capital funding of $234,000 in 2010, $1.261 million in 2011, and $787,000 in 2012.

304. The information technology section covers the O&M costs and capital expenditures for the administration and operations of the computing

equipment and software technology which supports the daily operations of SDG&E and SoCalGas.

305. As discussed in the SDG&E information technology section, it is reasonable to adopt $52.439 million as the total for SDG&E's information technology-related O&M costs.

306. As discussed in SDG&E's information technology section on capital expenditures, SDG&E proposes 50 information technology projects for the
2010 to 2012 period.

307. As discussed in SDG&E's information technology section on capital expenditures, it is reasonable to adopt capital funding of $46.322 million in 2010, $83.620 million in 2011, and $56.739 million in 2012.

308. As discussed in the SoCalGas information technology section, it is reasonable to adopt $50.406 million as the total for SoCalGas' information technology-related O&M costs.

309. As discussed in SoCalGas' information technology section on capital expenditures, SoCalGas proposes 91 information technology projects for the 2010-2012 period.

310. As discussed in the SoCalGas information technology section on capital expenditures, it is reasonable to adopt capital funding of $68.594 million in 2010, $98 million in 2011, and $85 million in 2012.

311. The business solutions/support services consist of the following four functions which provide a range of services primarily to SDG&E and SoCalGas: supply management; DBE; senior VP and chief information technology officer; and business planning.

312. As discussed in the SDG&E business solutions/support services, it is reasonable to adopt $13.013 million as the total for SDG&E's O&M costs for these activities.
313. As discussed in the business solutions/support services section for SoCalGas, it is reasonable to adopt $17.715 million as the total for SoCalGas' O&M costs for these activities.
314. GO 156 sets forth the rules regarding the development of programs to increase the participation of women, minority, and disabled veteran business enterprises in the procurement of contracts from the utilities, and sets a goals of 21.5% participation.
315. The DBE department is responsible for the GO 156 activities that SDG&E and SoCalGas participate in.
316. The Joint Parties allege that the Applicants are gaming their GO 156 participation by using large companies that are only partly minority owned, and recommend that the Applicants define a small business as one that has $1 million or less in revenues, that 0.25% of their procurement dollars be spent on providing technical assistance to small businesses, and that they be required to justify why a contract above $1 million cannot be unbundled.
317. The three recommendations of the Joint Parties seek to affect various provisions of GO 156.
318. Government Code §§ 8310.5 and 8310.7 are not applicable to the collection of data regarding DBE participation.
319. The administrative and general expenses section addresses the O&M costs and any applicable capital expenditures for the following: (a) environmental services; (b) fleet services; (c) real estate, land and

facilities;

(d) emergency preparedness and safety; (e) human resources, disability, and workers' compensation; (f) controller, regulator affairs and finances; and

(g) legal and external affairs.

320. Environmental services oversees compliance with various agencies' environmental statutes, rules, and regulations, and manages an environmental laboratory, two treatment storage and disposal facilities, and remediation of contaminated soils.

321. As discussed in the SDG&E environmental services section, it is reasonable to adopt total O&M costs of $7.779 million for these activities.

322. On April 10, 2012, following the close of evidentiary hearing, DRA filed a motion alleging that SDG&E violated Rule 1 by making a number of misleading and false statements pertaining to $54,000 in environmental fees that it requested by referencing regulations and using fee schedules that did not apply.

323. SDG&E took steps after its witness was questioned about using certain environmental fees, and that the $54,000 was removed from its request in Exhibits 596 and 598, and the removal of these fees was noted in the opening brief.

324. As discussed in the SoCalGas environmental services section, it is reasonable to adopt total O&M costs of $2.856 million, and its book expense value of $4.856 million.

325. Fleet services is primarily responsible for acquiring and disposing of vehicles, the maintenance and repair of vehicles, and fuel management.

326. As discussed in the SDG&E fleet services section, it is reasonable to adopt non-shared O&M costs of $35.748 million, and shared O&M costs of

$1.845 million, for these activities.

327. As discussed in the SoCalGas fleet services section, it is reasonable to adopt non-shared O&M costs of $44.900 million, and shared O&M costs of $1.504 million.

328. REL&F is responsible for the administration of real estate, facilities, and land services.

329. As discussed in the SDG&E real estate, land and facilities section, it is reasonable to adopt non-shared O&M costs of $8.162 million, and shared O&M costs of $17.378 million.

330. The capital expenditures for SDG&E's REL&F cover 15 categories of projects as described in that section.

331. As discussed in the capital expenditures section of SDG&E's REL&F, it is reasonable to adopt capital funding of $12.695 million in 2010, $219.700 million in 2011, and $20 million in 2012.

332. As discussed in the SoCalGas real estate, land and facilities section, it is reasonable to adopt non-shared O&M costs of $17.682 million, and shared O&M costs of $21.382 million.

333. The capital expenditures for SoCalGas' REL&F cover 17 categories of projects as described in that section.

334. As discussed in the capital expenditures section of SoCalGas' REL&F, it is reasonable to adopt capital funding of $1.922 million in 2010, $38 million in 2011, and $19.500 million in 2012.

335. The emergency preparedness and safety functions handle and manage the programs, policies and guidelines relating to the safety of SDG&E and SoCalGas employees.

336. As discussed in the SDG&E emergency preparedness & safety section, it is reasonable to adopt total O&M costs of $4.443 million, and capital funding of $113,000 in 2010, $250,000 in 2011, and $250,000 in 2012.

337. As discussed in the SoCalGas emergency preparedness & safety section, it is reasonable to adopt total O&M costs of $3.933 million, and capital funding of $650,000 in 2010, $850,000 in 2011, and $850,000 in 2012.

338. The section on human resources, disability and workers' compensation covers the O&M costs for those types of activities.

339. As discussed in the SDG&E human resources, disability and workers' compensation section, it is reasonable to adopt non-shared O&M costs of
$10.243 million, and shared O&M costs of $4.063 million.

340. As discussed in the SoCalGas human resources, disability and workers' compensation, it is reasonable to adopt non-shared O&M costs of
$26.428 million, and shared O&M costs of $6.399 million.

341. The controller, regulatory affairs and finances section addresses the costs of these three units.

342. As described in the controller section, the controller division is composed of six departments which provide services such as utility

accounting, accounting operations, financial system and business controls, and planning and analysis.

343. As described in the regulatory affairs section, regulatory affairs consists of five departments, which manages cases and issues before various regulatory agencies.

344. As described in the finance section, the finance division is primarily responsible for analyzing new projects, technologies, initiatives, and managing the regulatory accounts.

345. As discussed in the controller, regulatory affairs and finances section, it is reasonable to adopt A&G costs for SDG&E in the total amount of $25.611 million, and A&G costs for SoCalGas in the total amount of $21.270 million.

346. The section on legal and external affairs covers the costs related to those activities, and as a result of the 2010 corporate reorganization, many of those functions were transferred to SDG&E and SoCalGas from Sempra's Corporate Center.

347. SDG&E and DRA agreed in Exhibit 234 that SDG&E's Legal Department will keep track of the time that its attorneys spend on non-SDG&E matters.

348. As discussed in the legal and external affairs section for SDG&E, it is reasonable to adopt total O&M costs of $7.953 million.

349. SoCalGas and DRA agreed in Exhibit 235 that SoCalGas' Legal Department will keep track of the time that its attorneys spend on non-SoCalGas matters.

350. As discussed in the legal and external affairs section for SoCalGas, it is reasonable to adopt total O&M costs of $6.182 million.

351. The section addressing corporate center costs allocated to utilities covers the costs allocated by Sempra's Corporate Center to SDG&E and SoCalGas

352. Sempra's Corporate Center consists of the following divisions: (a) finance; (b) governance; (c) legal; (d) human resources; (e) external affairs; facilities/assets; and (f) pension and benefits.

353. Sempra's finance division, which consists of eight departments, is responsible for raising and managing capital, and maintaining the financial integrity of the Sempra companies.

354. The multi-factor allocation, which originated in D.98-03-073, affects various Corporate Center A&G costs.

355. For the reasons stated in the Corporate Center finance section, we do not adopt the recommendations of DRA and UCAN to change the allocation percentages used in the multi-factor allocation.

356. As discussed in the Corporate Center finance section, it is reasonable to adopt an allocation of $13.619 million to SoCalGas, and $12.432 million to SDG&E, for the finance division A&G costs.

357. Sempra's governance division includes the Internal Audit Services department, the office of the Corporate Secretary, the Sempra Board of Directors, and the Executive division.

358. As discussed in the Corporate Center governance section, the Applicants accepted DRA's adjustment to remove $182,000 from the cost center for the Corporate Secretary, and after that adjustment it is reasonable to adopt the allocations to SDG&E and SoCalGas.

359. Sempra's legal division provides legal services to all Sempra companies, and the cost centers consist of the General Counsel, the law department, and outside legal.
360. As discussed in the Corporate Center legal section, it is reasonable to adopt the allocations of $7.619 million to SoCalGas, and $11.693 million to SDG&E.
361. Corporate Center's human resources division provides services that support and maintain all employees.
362. As discussed in the Corporate Center human resources section, it is reasonable to adopt the allocations of $7.848 million to SoCalGas, and $6.057 million to SDG&E.
363. Corporate Center's external affairs division provides overall policy guidance for the Sempra companies interactions with external constituents.
364. As discussed in the Corporate Center's external affairs section, it is reasonable to adopt the allocations of $1.120 million to SoCalGas, and $885,000 to SDG&E.
365. Corporate Center's facilities/assets relate to the physical environment and tools used in corporate shared services.
366. As discussed in the Corporate Center's facilities/assets section, it is reasonable to adopt the allocations of $5.338 million to SoCalGas, and $4.929 million to SDG&E.
367. Corporate Center's pension and benefits division covers the costs of labor overheads.
368. As discussed in the Corporate Center's pension and benefits section, it is reasonable to reduce the allocations to SoCalGas and SDG&E by

the adjustments for the following: short term incentive compensation and overheads; long term incentive plan; and the supplemental retirement plan.

369. The insurance section addresses the activities associated with the procurement of insurance by Sempra's Risk Management Department.

370. For the reasons stated in the insurance section, and based on our review of all of the contested and uncontested insurance costs allocated to SDG&E and SoCalGas, it is reasonable to adopt Risk Management's allocation of the insurance costs to SDG&E and SoCalGas as adjusted by our discussion concerning the costs of the wildfire reinsurance, directors and officers liability, excess workers' compensation, and the umbrella liability policy for executives and officers.

371. The employee issues section addresses the compensation and employee benefits offered by SDG&E and SoCalGas, which include the following:
(a) base pay; (b) short-term incentives; (c) long term incentives;
(d) special recognition awards; (e) health benefits; (f) welfare benefits;
(g) retirement benefits; and (h) other benefit programs.

372. The Towers Watson study, which evaluated the total compensation offered by SDG&E and SoCalGas in comparison to the external labor market, concluded that SDG&E's total compensation is within 3.4% of the market, and SoCalGas' total compensation is within 3.2% of the market.

373. The Towers Watson Total Compensation Study provide guidance in determining whether the funding requested for compensation and employee benefits costs are reasonable or not.

374. We are not persuaded by the arguments that the Total Compensation Study for SDG&E and SoCalGas should be disregarded on the grounds the studies are biased and invalid.
375. The arguments that the compensation paid to executives and other employees at SDG&E and SoCalGas are excessive overlook the type of skills and experience that are needed to successfully and safely operate gas and electric utilities, and to retain those employees.
376. Each of the components of the compensation and employee benefit packages need to be examined to ensure that the costs are related to the provisioning of utility service, and that the costs are reasonable to ratepayers.
377. The ICP is part of the compensation to attract and retain executives and other employees.
378. SDG&E and SoCalGas are in the best position to decide what metrics to use to measure the performance of its employees, and to revise the metrics as UCAN has suggested would result in the micromanagement of the variable compensation such as ICP.
379. It is reasonable to reduce the cost of the short term incentives for both SDG&E and SoCalGas by 10%, which reduces SDG&E's funding from $45.646 million to $22.823 million, and reduces SoCalGas' funding from $29.408 million to $14.704 million.
380. Based on the different considerations regarding long term incentive compensation, it is reasonable to disallow ratepayer funding of this cost, which amounts to $10.148 million for SDG&E, and $5.361 million for SoCalGas.

381. Given the modest cost of special recognition awards, and the relationship of the employees' recognition to their job activities, it is reasonable that the costs of the Employee Recognition and Spot Cash programs be paid for by ratepayers.

382. We agree with the Applicants that the costs of the employee benefits should be based upon the actual number of employees, instead of FTEs.

383. For the reasons stated in the compensation and benefits section, it is reasonable to adopt the following employee benefits costs: (1) for dental, $3.420 million for SDG&E, and $3.675 million for SoCalGas; (2) for vision, $375,000 for SDG&E, and $487,000 for SoCalGas; (3) for employee assistance plan, $346,000 for SDG&E, and $760,000 for SoCalGas; (4) for life insurance, $738,000 for SDG&E, and $906,000 for SoCalGas; (5) for AD&D insurance, $89,000 for SDG&E, and $37,000 for SoCalGas; (6) for business travel insurance, $26,000 for SDG&E, and $35,000 for SoCalGas; (7) for benefits administration fees, educational assistance, emergency childcare, and mass transit incentive, $1.607 million for SDG&E, and $2.607 million for SoCalGas.; (8) for medical benefits, $55.684 million for SDG&E, and $70.735 million for SoCalGas; (9) for wellness benefits, $750,000 for SDG&E, and $795,000 for SoCalGas; (10) for mental health benefits, $943,000 for SDG&E, and $1.310 million for SoCalGas; (11) for nonqualified retirement savings plans, $108,500 for SDG&E, and $73,000 for SoCalGas; (12) for supplemental pension benefits, $1.930 million for SDG&E, and $1.035 million for SoCalGas; (13) for the 401(k) retirement savings plan, $12.974 million for SDG&E, and $13.791 million for SoCalGas; (14) zero

funding for retirement activities, and special events; (15) for service recognition, $82,000 for SDG&E, and $100,000 for SoCalGas.

384. The pensions and other related benefits section addresses the qualified retirement benefits at SDG&E and SoCalGas, which include pension plans and PBOP.

385. The pension plans of SDG&E and SoCalGas consist of a defined pension plan, and a Cash Balance Plan.

386. Due to the economic circumstances, and to help lower the test year 2012 revenue requirement, SDG&E and SoCalGas propose to hold the PBOP funding at the 2009 recorded level for the test year, as long as the two-way balancing account treatment for pension benefits and PBOP is continued.

387. PBOP refers to post-retirement health and life insurance benefits.

388. The Joint Parties' recommendation to revise the pension and PBOP benefits is not adopted because these benefits are part of the overall compensation package to attract and retain experienced individuals, and the benefits are comparable to what other utilities and other companies are doing in terms of compensation.

389. The proposal of SDG&E and SoCalGas to use their 2009 recorded amounts for pension benefits, and their 2009 recorded amounts for PBOP, as the costs for test year 2012, and to recover any difference between the 2009 amounts and the actuals costs paid in 2012 through their two-way balancing accounts, is adopted.

390. Deferring the pension benefits and PBOP increase by one year will provide some relief to ratepayers in 2012.

391. As discussed in the pension and other related benefits section, it is reasonable to adopt as the test year 2012 costs for pension benefits as follows:
for SDG&E, the amount of $56.833 million; and for SoCalGas, the amount of $75.105 million.
392. As discussed in the pension and other related benefits section, it is reasonable to adopt as the test year 2012 costs for PBOP as follows:
for SDG&E, the amount of $15.554 million; and for SoCalGas, the amount of $25.942 million.
393. As discussed in the pension and other related benefits section, it is reasonable to increase the pension benefits costs for SDG&E in the test year by the surety bond amount of $1.650 million, and to recover any difference between this amount and the actual surety bond amount in the balancing account.
394. SDG&E and SoCalGas request that they be allowed to make a change to the formula for funding pension benefits in order to avoid possible ERISA consequences.
395. The rate base section addresses the depreciated asset value of the Applicants' net investments used to provide service to their customers, upon which they are allowed to earn a rate of return.
396. Based on the adjustments adopted in today's decision, it is reasonable to adopt for test year 2012, a total weighted average rate base for SDG&E of $4,077,765,000, and a total weighted average rate base for SoCalGas of $3,462,405,000.
397. Working cash is a subset of working capital that is included in rate base, and is to compensate shareholders for providing funds to pay for

the day-to-day operating expenses in advance of the receipt of offsetting revenues from customers.

398. Due to the state of the economy, and to reduce the impact on customers, SDG&E and SoCalGas propose to request zero funding for their respective 2012 working cash requirements.

399. For the reasons stated in the section on rate base issues specific to SDG&E, DRA's proposal to remove SDG&E's fuel in storage from working capital and to consider it in SDG&E's next cost allocation proceeding, is not adopted.

400. Due to the replacement of the electromechanical meters with smart meters for SDG&E's electricity customers, the issue of rate recovery of SDG&E's legacy meters has arisen.

401. Two decisions relevant to the issue of SDG&E's legacy meters are D.11-05-018, in which the Commission examined whether a rate of return was justified for PG&E's legacy meters, and D.07-04-043, in which the Commission adopted a settlement concerning SDG&E's replacement of the legacy meters with smart meters.

402. There was little testimony in A.05-03-015 about how the ratemaking treatment of SDG&E's electromechanical meters would be treated once those meters were replaced by smart meters.

403. SDG&E acknowledges that its retired electromechanical meters are no longer used and useful.

404. It was the Commission that encouraged or required SDG&E to prematurely retire the legacy meters that were replaced by the smart meters.

405. As discussed in the section on rate base issues specific to SoCalGas, it is reasonable to use SoCalGas' five-year average for the forecast of new business forfeitures, and to reduce the number of new regulators by reducing the regulator forecast amount by $700,000.
406. The depreciation section addresses the depreciation expense, amortization expense, and accumulated reserve as applicable to SDG&E and SoCalGas.
407. To derive the depreciation expense for SDG&E and SoCalGas, depreciation studies were prepared.
408. The proposed adjustments to average service lives by TURN and UCAN would have the effect of reducing depreciation expense, which lowers the overall revenue requirement.
409. For the reasons stated in the depreciation section, the average service lives that SDG&E and SoCalGas used are adopted.
410. As discussed in the depreciation section, the arguments of DRA, TURN, and UCAN to change or adjust the future net salvage rates are not supported by the evidence, and are not adopted.
411. The section on taxes addresses payroll taxes, ad valorem taxes, income taxes, and franchise fees.
412. As discussed in the taxes section, it is reasonable to adopt the forecasts of SDG&E and SoCalGas for payroll taxes.
413. As discussed in the taxes section, it is reasonable to adopt the forecasts of SDG&E and SoCalGas for ad valorem taxes.
414. DRA seeks to adjust the income taxes for both SDG&E and SoCalGas because it does not believe they have justified their respective meals and entertainment expense.

415. As described in the taxes section, neither DRA nor the Applicants have fully investigated the meals and entertainment issue, and based on those considerations, it is reasonable to reduce the total income tax expense for SDG&E by $500,000, and for SoCalGas by $500,000.
416. If DRA decides to address the meals and entertainment issue in future GRC applications, that should be raised in connection with the utility's A&G expenses.
417. The Tax Relief Act provides for an extension and enhancement of bonus depreciation for 2010, 2011, and 2012.
418. Bonus depreciation is an additional amount of deductible depreciation that can be taken in an accelerated manner.
419. DRA's gross-up factor, to account for the impact of bonus depreciation, is likely to lead to inaccurate results, as opposed to modeling the bonus depreciation in the Results of Operations model.
420. DRA's proposals to prohibit SDG&E and SoCalGas from carrying forward their net operating losses, and to use its gross-up factor method to account for the effects of the Tax Relief Act, are not adopted.
421. As discussed in the taxes section, the proposal of TURN and UCAN to include the incentive compensation payments and actual return in the calculation of deferred taxes is not adopted.
422. As discussed in the franchise fees section, it is reasonable to adopt the SDG&E and SoCalGas forecasts of the franchise fees.
423. Miscellaneous revenues are fees and revenues that the Applicants collect from non-rate sources for providing specific products or services, and include service establishment charges, late payment charges, returned check charges, collection fees, and rents.

424. Miscellaneous revenues are used to lower rates by reducing the base margin revenue requirement charged to customers for utility service.
425. As discussed in the SDG&E miscellaneous revenue section, it is reasonable to adopt SDG&E's forecast of the test year 2012 miscellaneous revenues, as adjusted by the increased pole attachment fees of $1.668 million.
426. As discussed in the SoCalGas miscellaneous revenue section, it is reasonable to adopt SoCalGas' forecast of the test year 2012 miscellaneous revenues, as adjusted by the revisions to residential and commercial parts, pipeline services, crude oil sales, and the Federal Energy Retrofit Program.
427. The forecast of customers and sales affects the O&M costs, and capital expenditures.
428. As discussed in the forecast of customers and sales section, it is reasonable to adopt an electric customer forecast for SDG&E of 1,382,924 for 2010, 1,390,866 for 2011, and 1,401,032 for 2012, and the electric sales forecast of SDG&E.
429. As discussed in the forecast of customers and sales section, it is reasonable to adopt SDG&E's gas customer forecast, and sales forecast.
430. As discussed in the forecast of customers and sales section, it is reasonable to adopt the following number of active gas customers for SoCalGas: 5,520,424 in 2010; 5,536,450 in 2011; and 5,584,627 in 2012.
431. As discussed in the forecast of customers and sales section, it is reasonable to adopt for SoCalGas the following number of new meter sets: 45,527 in 2010; 55,365 in 2011; and 64,223 in 2012.

432. Since no one disputes SoCalGas' gas throughput forecast, it is reasonable to adopt SoCalGas' gas sales forecast.
433. The regulatory accounts section summarizes the various requests of SDG&E and SoCalGas concerning its regulatory accounts.
434. The requests concerning the DIMPBA, the pension balancing accounts, the PBOP balancing accounts, the tree trimming balancing account, and the NERBA, have been addressed elsewhere in this decision.
435. The escalation section addresses the cost escalation factors that are used by SDG&E and SoCalGas in their labor O&M costs, non-labor O&M costs, and capital-related costs.
436. As discussed in the escalation section, it is reasonable to use the cost escalation factors of SDG&E and SoCalGas, as updated in Exhibit 596, as the cost escalation factors for test year 2012.
437. The audit and accounting issues section addresses the audit and accounting issues that have not been addressed elsewhere in this decision.
438. As discussed in the audit and accounting issues section, it is reasonable to adopt the mapping process, reassignment of certain costs to capital, and the segmentation process, that SDG&E and SoCalGas used in these proceedings.
439. As discussed in the section on AFUDC, we do not adopt DRA's proposal that the AFUDC rates should be based on short term financing, and instead, it is reasonable to use the authorized rate of return of 8.40% for SDG&E, and
8.68% for SoCalGas.

440. The Joint Parties question the reliability and independence of the outside audit of SDG&E, and suggest that this may affect the documents that SDG&E used in this proceeding.

441. None of the testimony elicited from the witnesses suggest that the outside audits of SDG&E and SoCalGas were used in any way to develop the test year 2012 forecasts, or that the financial data of either utility was misleading or suspect.

442. The Audit Committee of the Board of Directors of Sempra decides who to hire as the outside auditor, and that selection is then ratified by shareholders.

443. We do not place any restrictions on SDG&E or SoCalGas as to which auditors they can use, or how many audits an outside auditor can perform.

444. The RO model is a computer model that compiles all of the cost estimates and produces the revenue requirements and a Summary of Earnings for SDG&E and SoCalGas.

445. Based on the adjustments and recommendations that we have adopted throughout today's decision, the RO model was re-run using our adopted amounts, and result in a test year 2012 revenue requirement of $1,749,376,000 for SDG&E, and $1,951,712,000 for SoCalGas, as shown in Attachment B.

446. Due to the delays in this proceeding, and because of the upcoming 2013 summer, it is reasonable to delay SDG&E's recovery of its GRC memorandum account balances until September 1, 2013.

447. The adopted revenues requirements will provide customers of SDG&E and SoCalGas with safe and reliable service at reasonable rates.

448. The section on post-test year revenue requirement issues addresses the proposals for PTY ratemaking, and how long the PTY period should be.
449. For the reasons discussed in the PTY revenue requirement issues section, it is reasonable to adopt a PTY period covering 2013, 2014, and 2015.
450. Instead of a traditional annual attrition mechanism to adjust their test year revenue requirement in the PTY period, SDG&E and SoCalGas are proposing that their PTY ratemaking mechanism be adopted.
451. The PTY ratemaking framework of SDG&E and SoCalGas is based on a four-year GRC term, and the adoption of the PTY ratemaking mechanism proposal, the earnings sharing proposal, and the productivity investment sharing mechanism.
452. SDG&E's PTY ratemaking mechanism contains an additional component to account for incremental capital investment and O&M programs that are not included in the test year.
453. DRA proposes to use the CPI – Urban to calculate the PTY revenue requirements for 2013, 2014, and 2015.
454. The Commission has used different formulas in the past to develop the PTY revenue requirement, and in doing so, takes into account many different considerations including allowing the utility the opportunity to earn its authorized rate of return.
455. The proposed PTY ratemaking mechanism uses two formulas (the utility-specific cost index, and the California-specific health care costs) which lean in their favor.

456. SDG&E's additional component of its ratemaking mechanism would allow smart grid-related O&M costs and capital costs to be accounted for in its PTY ratemaking mechanism, which has the potential to increase the revenue requirement in 2013 by an additional $50 million, an additional $72 million in 2014, and an additional $96 million in 2015.
457. The adopted test year 2012 revenue requirements are higher than what some of the other parties recommended, and if these amounts are too high, this problem will be compounded if the same escalation factors that SDG&E and SoCalGas propose to be used, are adopted.
458. The adopted PTY mechanism using the CPI –Urban will provide SDG&E and SoCalGas with a reasonable opportunity to earn their respective authorized rate of return during the PTY given the test year 2012 revenue requirements that we have adopted in today's decision.
459. The section on non-tariffed products and services addresses the proposals for the offering of such services by SDG&E and SoCalGas.
460. SDG&E and SoCalGas propose three sharing mechanisms for NTP&S so that there is certainty as to how such offerings will be treated so that the Applicants can assess whether or not to proceed with such offerings.
461. The category one sharing mechanism proposal covers the existing NTP&S offerings that the Applicants currently offer, and any revenue increase above the test year 2012 forecast of miscellaneous revenues will be shared on a gross revenue basis with 90% going to shareholders and 10% to ratepayers.
462. The category two sharing mechanism proposal applies to new NTP&S offerings that require significant incremental shareholder

expenditures, and shareholders would retain 90% of the gross revenues and ratepayers receive 10% of the gross revenues.

463. The category three sharing mechanism proposal applies to new NTP&S offerings that require significant incremental shareholder expenditures to develop and market, and there would be a 50/50 sharing of after tax net earnings above a rate of return benchmark.

464. For the reasons set forth in the non-tariffed products and services section, the NTP&S proposals of SDG&E and SoCalGas are not adopted.

465. Under the affiliate transaction rules, the Applicants are free to continue offering existing NTP&S offerings, or to propose new NTP&S offerings with reasonable sharing mechanisms.

466. UWUA proposes that SoCalGas be required to promote a culture of safety using a safety training program that uses the UWUA-sponsored Systems of Safety program.

467. As discussed in the other issues section, UWUA's recommendation that SoCalGas be required to use the Systems of Safety program is not adopted because SoCalGas already provides a variety of safety training and initiatives to its employees, and because UWUA has not demonstrated that its program is better than, or substantially different from the safety training programs and materials that SoCalGas already uses.

468. UWUA recommends that SoCalGas be required to change the existing organizational structure of safety committees, meetings, and conferences at SoCalGas by doing the following: allowing UWUA to designate one employee/union safety representative for each of the 12

operating regions to respond to safety incidents and to perform root cause analysis in incident investigations; that regular meetings of employees be held to eliminate hazards in the workplace; and that channels of communication between the employees and union take place with the Safety and Enforcement Division.

469. As discussed in the other issues section, UWUA's safety organization proposal is not adopted because UWUA has not demonstrated the existing safety structure at SoCalGas, which involves both management and its employees, is defective or deficient in addressing the safety organization issues that UWUA has raised.

470. If UWUA requests an award of compensation, UWUA should discuss in its request whether D.05-02-054 is applicable to UWUA.

Conclusions of Law

1. In response to the scoping ruling granting the joint motion to establish memorandum accounts, SDG&E and SoCalGas filed ALs to establish their respective GRC memorandum accounts for these proceedings to record the difference between the rates currently in effect, and the final rates adopted in these proceedings.

2. To the extent there are any other outstanding motions or requests that have not been addressed in this decision, those motions and/or requests should be denied.

3. The oral and written rulings of the assigned ALJ that were issued in this proceeding should be confirmed.

4. The Commission's duty and obligation under Pub. Util. Code § 451 is to establish just and reasonable rates to enable SDG&E and SoCalGas to provide safe and reliable service, while allowing SDG&E and SoCalGas an opportunity to

earn a fair return on the property that the companies use in providing their utility services.

5. The parties' use of more recent data is not prohibited by the Rate Case Plan.

6. The Joint Motion to adopt the MOU Settlement should be granted, and the terms set forth in the MOU Settlement should be adopted.

7. SDG&E should be authorized to continue its two-way SONGS balancing account through this rate cycle.

8. SDG&E should be authorized to establish a two-way balancing account called the New Environmental Regulatory Balancing Account (NERBA) to record the following: the costs associated with a final EPA rule on the phase-out of PCBs; and the costs associated with complying with the mandatory GHG reporting rule in Subpart W of Part 98 of Title 40 of the CFR.

9. SDG&E's request to treat the tree trimming costs in a two-way balancing account should be denied, and the one-way balancing account should continue.

10. SDG&E's request that pole brushing costs be booked to a two-way balancing account should be denied.

11. The sustainable community energy systems project should be wound down, and funding of new projects should end after this GRC cycle is completed.

12. CCUE's recommendation to adopt and impose performance incentives or a RIIM-type mechanism on SDG&E should not be adopted.

13. As discussed in this decision, SDG&E should continue to collect the reliability-related data over the course of this GRC cycle, and to keep a record of the cause of the outages.

14. SDG&E should include in its next GRC filing: a discussion and summary of its reliability measures, with a comparison to the reliability data from the two

prior GRC cycles; a summary of the cause of the outages and a discussion of the trends that were observed; and whether an incentive-type mechanism should be adopted to help improve reliability, along with the details of how such a mechanism should operate.

15. SDG&E has not provided convincing evidence that its proposal to deploy public access charging facilities will result in an underserved market or a market failure.

16. SoCalGas should be authorized to establish a two-way balancing account called the New Environmental Regulatory Balancing Account (NERBA) to record the following: the costs associated with complying with the mandatory greenhouse gas reporting rule in Subpart W of Part 98 of Title 40 of the CFR.

17. Pub. Util. Code § 969 provides that the costs relating to TIMP are to be recovered through a balancing account, and that the Commission retains the discretion to decide if a two-way balancing account should be established.

18. SDG&E should be authorized to establish a two-way balancing account to recover the TIMP-related O&M costs and capital expenditures of complying with TIMP.

19. SDG&E should be authorized to establish a two-way balancing account to recover the DIMP-related O&M costs and capital expenditures of complying with DIMP.

20. SDG&E should be authorized to close out its DIMPBA.

21. SoCalGas should be authorized to establish a two-way balancing account to recover the TIMP-related O&M costs and capital expenditures of complying with TIMP.

22. SoCalGas should be authorized to establish a two-way balancing account to recover the DIMP-related O&M costs and capital expenditures of complying with DIMP.

23. SoCalGas should be authorized to close out its DIMPBA.

24. Pursuant to Pub. Util. Code § 958.5, SDG&E is required to provide a gas transmission safety report, and SoCalGas is required to provide a gas transmission and storage safety report.

25. In conducting their gas operations, SDG&E and SoCalGas are obligated under Pub. Util. Code § 451 to "furnish and maintain such adequate, efficient, just and reasonable service, instrumentalities, equipment and facilities…as are necessary to promote the safety, health, comfort, and convenience of its patrons, employees, and the public."

26. To ensure compliance with Pub. Util. Code § 451, the Commission has authority under Pub. Util. Code §§ 581, 582 and 584 to order a public utility to provide reports to the Commission.

27. SDG&E should be ordered to provide a "Gas Transmission and Distribution Safety Report" in the format described in Attachment C of this decision.

28. SoCalGas should be ordered to provide a "Gas Transmission and Distribution and Gas Storage Safety Report" in the format described in Attachment C of this decision.

29. SDG&E and SoCalGas should be required to compile the same type of monthly and annual data as shown on pages 65 and 66 of Exhibit 145, and to supply that information in its next GRC filing, as well as upon demand by Commission staff.

30. SDG&E and SoCalGas should each explain in their next GRC filings what efforts they have taken to minimize delays in responding to A1 leak calls.

31. Prefunded postage must be accounted for by SDG&E in FERC Account #165, instead of being included as part of postage expense.

32. RD&D costs may be included in rates so long as the utility's RD&D activities adhere to the guidelines set forth in Pub. Util. Code § 740.1.

33. SDG&E's 60 (ratepayer)/ 40 (shareholder) sharing mechanism for RD&D should be adopted for this GRC rate cycle.

34. SoCalGas should have until the next GRC application to seek recovery of the amounts, if any, that were recorded to the NGAT memorandum account, and if such a request is not made, then the NGAT memorandum account should be closed.

35. SoCalGas' requests to continue using a one-way balancing account for RD&D costs, and to continue its RD&D sharing mechanism, should be granted.

36. AL 4172 was rejected because the activity may be contrary to the Affiliate Transaction Rules concerning NTP&S.

37. The Joint Parties' recommendation that the Applicants explain why procurement contracts with a value of more than $1 million cannot be unbundled is a collateral attack on D.11-05-019, as such, the Joint Parties are barred from litigating that same issue in this proceeding.

38. Since the recommendations that the Joint Parties have made concerning diverse business enterprises affect specific provisions in GO 156, those recommendations cannot be adopted in this proceeding.

39. Based on the record, SDG&E did not violate Rule 1, and therefore no penalties are warranted.

40. Although the Total Compensation Study determined that the target total compensation of SDG&E and SoCalGas is within the market compensation level, that does not mean the Commission should ignore the individual components that make up the compensation and employee benefits packages, and simply approve the entire amounts that the utilities have requested.

41. The requests of SDG&E and SoCalGas to continue their two-way balancing account treatment for their respective pension benefits and PBOP costs should be granted.

42. The requests of SDG&E and SoCalGas to continue their annual amortization of their respective pension balancing accounts and PBOP balancing accounts should be granted.

43. The proposal of SDG&E and SoCalGas to use the 2009 recorded costs for pension benefits and PBOP for test year 2012, subject to recovery through the two-way balancing account, should be granted.

44. The request of SDG&E and SoCalGas that they be allowed to adjust their respective future funding amounts for pension benefits based on the greater of the minimum required contribution, or the amount necessary to maintain an 85% funding level, should be granted.

45. The request of SDG&E and SoCalGas to change how they treat ad valorem taxes associated with capital construction projects should be granted.

46. The request of SDG&E and SoCalGas to receive zero funding for working cash in test year 2012 should be adopted.

47. The factual situation which led to D.11-05-018 is very similar to what was developed in SDG&E's AMI proceeding.

48. D.11-05-018 utilized an approach that essentially modified the ratemaking treatment of the legacy meters that had been decided in prior decisions.

49. D.07-04-043 is relevant because it established the ratemaking treatment of SDG&E's legacy meters at the time the Commission authorized SDG&E to replace those meters with smart meters, and the factual situation is similar to what occurred in D.11-05-018, in which the Commission revisited the issue of whether the ratemaking treatment for legacy meters that was implicitly approved in a prior decision should be changed.

50. It is equitable to use the approach taken in D.11-05-018 to reexamine whether the ratemaking treatment that was mentioned in A.05-03-015 is just or needs to be changed.

51. The general policy is that plant which is not used and useful is normally excluded from rate base, and is therefore excluded from earning a rate of return.

52. An exception to this general policy is made when circumstances, such as governmental action, specifically encourage or require a utility to prematurely retire an asset, or group of assets, that was functioning properly at the time, in which case a rate of return may be warranted.

53. The approach taken in D.11-05-018 should also be used to review how SDG&E's legacy meters should be treated.

54. A rate of return on SDG&E's legacy meters is justified because D.07-04-043 determined that the adopted AMI project has net benefits, but the delay in realizing those benefits is something we should consider in determining what the rate of return should be.

55. Based on a weighing and balancing of all the considerations discussed in this decision, SDG&E should be allowed to earn a rate of return of 6.2% on the legacy meters, and this return should be applied to a six year amortization of the undepreciated balance of SDG&E's legacy meters.

56. Since the Applicants are reflecting the carry forward as an adjustment to rate base, and not as part of the income tax expense calculation, that is proper and does not run afoul of the prohibition in D.84-05-036 that carry backs and carry forwards should be excluded from the test year income tax calculation.

57. SDG&E's request to dispose of the balance in its Advanced Metering Infrastructure Balancing Account should be granted as requested.

58. The requests of SDG&E and SoCalGas to dispose of their balances in their respective RDDEA should be granted as requested.

59. The request of SoCalGas to dispose of the balance in its PCBEA should be granted as requested.

60. The Joint Parties have not proven that the outside audits of SDG&E and SoCalGas resulted in misleading or erroneous financial information that affected the underlying revenue requirement forecasts of SDG&E and SoCalGas for test year 2012.

61. All of the O&M costs and capital expenditures found to be reasonable in this decision should be adopted, and incorporated into the RO model to produce the test year 2012 revenue requirements for SDG&E and SoCalGas.

62. SDG&E and SoCalGas should be authorized to file Tier 1 ALs within 15 days from the effective date of this decision to implement the revenue requirements authorized by this decision.

63. SDG&E and SoCalGas should be required to file their test year 2016 GRC proceedings beginning with their respective Notice of Intent in August 2014.

64. The PTY ratemaking framework that SDG&E and SoCalGas have proposed should not be adopted because that would essentially lead us down a path that allows SDG&E and SoCalGas to recover much of the PTY costs and expenses that they incur without any further review.

65. SDG&E and SoCalGas should only be given a reasonable opportunity to earn their authorized rate of return, and not a mechanism that brings them closer to achieving that target.

66. DRA's proposal to use the CPI – Urban to determine the PTY revenue requirements of SDG&E and SoCalGas should be adopted.

67. SDG&E and SoCalGas should be authorized to continue using the current Z-factor process in the event circumstances outside the control of the Applicants arise. However, the proposal of SDG&E and SoCalGas for approval of Z-factor costs though the Commission's AL process should be denied, and any Z-factor cost that will result in an increase in costs should be filed as an application.

68. Under the affiliate transaction rules, before a NTP&S offering can be offered, the utility must demonstrate, and the Commission must adopt, a reasonable mechanism for the treatment of the benefits and revenues derived from the NTP&S offerings.

O R D E R

1. The February 24, 2012 joint motion, filed by the Center for Accessible Technology, San Diego Gas & Electric Company, and Southern California Gas Company, requesting that the Memorandum of Understanding between these three entities attached to that joint motion be approved and adopted, is granted, and the terms set forth in that Memorandum of Understanding are approved and adopted.

2. The adjustments to the operations and maintenance cost forecasts and the capital expenditures forecasts of San Diego Gas & Electric Company, and Southern California Gas Company, as set forth in the Findings of Fact and Conclusions of Law in this decision, are adopted.

3. The adopted adjustments, after inputting them into the Results of Operations model, result in the revenue requirements shown in Attachment B of this decision, which are adopted.

   a. For San Diego Gas & Electric Company, the adopted combined gas and electric test year 2012 revenue requirement is $1,749,376,000.

   b. For Southern California Gas Company, the adopted test year 2012 revenue requirement is $1,951,712,000.

4. The Division of Ratepayer Advocates' post-test year mechanism for 2013, 2014, and 2015, is adopted, and San Diego Gas & Electric Company and Southern California Gas Company shall use that post-year mechanism to adjust their respective test year 2012 revenue requirements for 2013, 2014, and 2015.

5. Within 15 days from the effective date of this Order, San Diego Gas & Electric Company (SDG&E) shall file a Tier 1 Advice Letter, with revised tariff sheets, to implement the 2012 and 2013 revenue requirement authorized by Ordering Paragraph 3 and Ordering Paragraph 4 of this Order.

   a. The revised tariff sheets shall (a) become effective within 45 days of the date of this Order, subject to a finding of compliance by the Commission's Energy Division, and (b) comply with General Order 96-B.

   b. The balances recorded in SDG&E's General Rate Case Revenue Requirement Memorandum Account from January 1, 2012 until the effective date of new tariffs required by this Order, shall be amortized in rates beginning September 1, 2013 through December 31, 2015.

6. Within 15 days from the effective date of this Order, Southern California Gas Company (SoCalGas) shall file a Tier 1 Advice Letter with revised tariff sheets to implement the 2012 and 2013 revenue requirement authorized by Ordering Paragraph 3 and Ordering Paragraph 4 of this Order.

a. The revised tariff sheets shall (a) become effective within 45 days of the date of this Order, subject to a finding of compliance by the Commission's Energy Division, and (b) comply with General Order 96-B.

b. The balances recorded in the SoCalGas General Rate Case Revenue Requirement Memorandum Account from January 1, 2012 until the effective date of new tariffs required by this Order, shall be amortized in rates beginning July 1, 2013 through December 31, 2015.

7. The sustainable community energy systems project for San Diego Gas & Electric Company (SDG&E) shall end at the end of this General Rate Case (GRC) cycle.

a. SDG&E shall plan for the conclusion of this project, and taper off the funding of new projects as this GRC cycle ends.

b. SDG&E shall propose future operation and maintenance expenses for existing operational community energy systems in its next GRC filing, for review in that proceeding.

8. As set forth below, San Diego Gas & Electric Company (SDG&E) shall be required to serve a semi-annual Gas Transmission and Distribution Safety Report (Safety Report) on the Directors of the Safety and Enforcement Division and the Energy Division.

a. The format of SDG&E's Safety Report shall be in the format as described in Attachment C of today's decision.

b. SDG&E shall serve its first Safety Report beginning July 1, 2013, and the initial period covered by the Safety Report shall cover the one year period from January 1, 2012 through December 31, 2012.

c. Each subsequent Safety Report shall cover each subsequent six-month period, and the second semi-annual Safety Report shall be served on September 1, 2013, and on each March 1 and September 1 thereafter until further notice.

9. As set forth below, Southern California Gas Company (SoCalGas) shall be required to serve a semi-annual Gas Transmission and Distribution and Gas Storage Safety Report on the Directors of the Safety and Enforcement Division and the Energy Division.

   a. The format of SoCalGas' Safety Report shall be in the format as described in Attachment C of today's decision.
   b. SoCalGas shall serve its first Safety Report beginning July 1, 2013, and the initial period covered by the Safety Report shall cover the one year period from January 1, 2012 through December 31, 2012.
   c. Each subsequent Safety Report shall cover each subsequent six-month period, and the second semi-annual Safety Report shall be served on September 1, 2013, and on each March 1 and September 1 thereafter until further notice.

10. In accordance with Pub. Util. Code § 958.5, the Safety and Enforcement Division shall review San Diego Gas & Electric Company's (SDG&E) Gas Transmission and Distribution Safety Report, and Southern California Gas (SoCalGas) Company's Gas Transmission and Distribution and Gas Storage Safety Report.

    a. The review by the Safety and Enforcement Division shall monitor SDG&E's and SoCalGas' respective gas storage and pipeline-related activities to assess whether the projects that have been identified as high risk are being carried out, and to track whether each utility is spending its allocated funds on the storage and pipeline-related safety, reliability, and integrity activities for which they have received approval for.
    b. If the Safety and Enforcement Division detects any problems with the way in which SDG&E or SoCalGas prioritize or carry out their capital expenditure projects or operation and maintenance activities, these problems shall be brought to the Commission's attention immediately.

c. The Energy Division shall provide the Safety and Enforcement Division with the necessary assistance to review and monitor these reports.

11. San Diego Gas & Electric Company (SDG&E) is authorized to continue the two-way balancing account authorized in Decision 06-11-026, as modified by Decision 11-07-049, applicable to all operating and maintenance costs for the San Onofre Nuclear Generating Station billed to SDG&E by Southern California Edison Company until the later of December 31, 2015 or the issuance of a decision setting SDG&E's base rate revenue requirement for Test Year 2016.

12. San Diego Gas & Electric Company (SDG&E) is authorized to establish a two-way balancing account called the New Environmental Regulatory Balancing Account to record the following: the costs associated with a final United States Environmental Protection Agency rule on the phase-out of polychlorinated biphenyls in electric and non-electric equipment; and the costs associated with complying with the mandatory greenhouse gas reporting rule in Subpart W of Part 98 of Title 40 of the Code of Federal Regulations.

a. SDG&E shall file a Tier 2 advice letter within 45 days of the effective date of this decision to establish this balancing account.

13. San Diego Gas & Electric Company (SDG&E) is authorized to establish a two-way balancing account to recover the operations and maintenance costs, and capital expenditures costs, of complying with the transmission integrity management program.

a. SDG&E shall file a Tier 2 Advice Letter within 45 days of the effective date of this decision to establish this balancing account.

14. San Diego Gas & Electric Company (SDG&E) is authorized to establish a two-way balancing account to recover the operations and maintenance costs, and

capital expenditures costs, of complying with the distribution integrity management program.

a. SDG&E shall file a Tier 2 Advice Letter within 45 days of the effective date of this decision to establish this balancing account and to close out its current distribution integrity management program balancing account (DIMPBA). Any balance remaining in the DIMPBA shall be amortized in gas transportation customers' rates on an equal percent of authorized margin basis.

15. Southern California Gas Company (SoCalGas) is authorized to establish a two-way balancing account called the New Environmental Regulatory Balancing Account (NERBA) to record the costs associated with complying with the mandatory greenhouse gas reporting rule in Subpart W of Part 98 of Title 40 of the Code of Federal Regulations.

a. SoCalGas shall file a Tier 2 Advice Letter within 45 days of the effective date of this decision to establish this balancing account and to close out its current distribution integrity management program balancing account (DIMPBA). Any overcollection remaining in the DIMPBA shall be amortized in gas transportation customers' rates on an equal percent of authorized margin basis.

16. Southern California Gas Company (SoCalGas) is authorized to establish a two-way balancing account to recover the operations and maintenance costs, and capital expenditures costs, of complying with the transmission integrity management program.

a. SoCalGas shall file a Tier 2 Advice Letter within 45 days of the effective date of this decision to establish this balancing account.

17. Southern California Gas Company (SoCalGas) is authorized to establish a two-way balancing account to recover the operations and maintenance costs, and

capital expenditures costs, of complying with the distribution integrity management program.

a. SoCalGas shall file a Tier 2 Advice Letter within 45 days of the effective date of this decision to establish this balancing account.

18. San Diego Gas & Electric Company's 60 (ratepayer)/40 (shareholder) sharing mechanism for research development and demonstration is adopted for this general rate case cycle.

19. Southern California Gas Company's requests to continue using a one-way balancing account for research development and demonstration (RD&D) costs, and to continue its RD&D sharing mechanism are granted.

20. As set forth below, San Diego Gas & Electric Company (SDG&E) and Southern California Gas Company (SoCalGas) are authorized to continue their two-way balancing account treatment for their respective pension benefits and post-retirement benefits other than pensions costs.

a. SDG&E and SoCalGas may continue their annual amortization of their respective pension balancing accounts and post-retirement benefits other than pensions balancing accounts.

b. SDG&E and SoCalGas may use their respective 2009 recorded costs for pension benefits and post-retirement benefits other than pensions for test year 2012, subject to recovery through the two-way balancing account.

c. SDG&E and SoCalGas may adjust their respective future funding amounts for pension benefits based on the greater of the minimum required contribution, or the amount necessary to maintain an 85% funding level.

21. The requests of San Diego Gas & Electric Company and Southern California Gas Company to change how they treat ad valorem taxes associated with capital construction projects are granted.

22. San Diego Gas & Electric Company and Southern California Gas Company are each authorized to continue using the current Z-factor process in the event circumstances outside their control arise. If either company requests recovery of costs through the Z-factor process, it must file an application to make its request.

23. San Diego Gas & Electric Company and Southern California Gas Company shall each file their respective test year 2016 general rate case applications beginning with their respective Notices of Intent in August 2014.

24. To the extent there are any outstanding motions or requests that have not been addressed in this decision, those motions and/or requests are denied.

25. The oral and written rulings of the assigned Administrative Law Judge that were issued in this proceeding are confirmed.

26. Application (A.) 10-12-005 and A.10-12-006 are closed.

This decision is effective today.

ATTACHMENT A

Glossary

A: Application

AB: Assembly Bill

ADA: Americans with Disabilities Act

AD&D: accidental death and dismemberment

ADFIT: accumulated deferred federal income tax

AFUDC: allowance for funds used during construction

A&G: administrative and general

AMI: advanced metering infrastructure

ARSO: Area Resource Scheduling Organization

Bcf: billion cubic feet

CAISO: California Independent System Operator

CALTRANS: California Department of Transportation

CARB: California Air Resources Board

CARE: California Alternate Rates for Energy

CBOs: community based organizations

CCSE: California Center for Sustainable Energy

CCUE: Coalition of California Utility Employees

CDWR: California Department of Water Resources

CEA: capitalized earnings ability

CEC: California Energy Commission

CEO: Chief Executive Officer

Cfor AT: Center for Accessible Technology

CFO: Chief Financial Officer

CFR: Code of Federal Regulations

CHANGES: Community Help and Awareness with Natural Gas and Electricity Services

CIAC: contribution in aid of construction

CIS: customer information system

CIP: critical infrastructure protection

CNG: compressed natural gas

CPI: Consumer Price Index

CPSD: Consumer Protection and Safety Division

CPUC: California Public Utilities Commission

D.: Decision

DBE: Diverse Business Enterprises

DERMS: distributed energy resource management system

DIMP: Distribution Integrity Management Program

DIMPA: Distribution Integrity Management Program Account

DOT: United States Department of Transportation

DRA: Division of Ratepayer Advocates

DRCA: demand response control application

EMF: Electric Magnetic Fields

EPA: United States Environmental Protection Agency

ERISA: Employee Retirement and Income Security Act of 1974

ERO: electric regional operations

ERRA: Energy Resource Recovery Account

ERT: estimated restoration time

ETR: energy technician residential

FACTA: Fair and Accurate Credit Transactions Act

FEA: Federal Executive Agencies

FERC: Federal Energy Regulatory Commission

FHPMA: Fire Hazard Prevention Memorandum Account

FTEs: full time equivalents

GAAP: Generally Accepted Accounting Practices

GE: General Electric Corporation

GHG: greenhouse gas

GIS: geographic information system

GO: General Order

GRC: general rate case

HAN: home area network

HCLD: historical cost less depreciation

ICP: Incentive Compensation Plan

IOUs: investor-owned utilities

IRS: Internal Revenue Service

IT: information technology

LADWP: Los Angeles Department of Water and Power

LIEE: Low Income Energy Efficiency

LNG: liquefied natural gas

LTPP: Long Term Procurement Plan

MDAQMD: Mojave Desert Air Quality Management District

MOU: Memorandum of Understanding

MRTU: Market Redesign and Technology Upgrade

MRTUMA: Market Redesign and Technology Upgrade Memorandum Account

MW: megawatt

NARUC: National Association of Regulatory Utility Commissioners

NEIL: Nuclear Electric Insurance Limited

NERBA: New Environmental Regulatory Balancing Account

NERC: North American Electric Reliability Corporation

NESHAP: National Emissions Standards for Hazardous Air Pollutants

NGAT: natural gas appliance testing

NGBA: Non-fuel Generation Balancing Account

NGV: natural gas vehicle

NTP&S: non-tariffed products and services

OASDI: Old Age, Survivors, and Disability Insurance

O&M: operations and maintenance

OpEx: Operational Excellence 20/20 program

PACER: service order scheduling and routing system

PBOP: post-retirement benefits other than pensions

PCBEA: Polychlorinated Biphenyls Expense Account

PCBs: polychlorinated biphenyls

PEVs: plug-in electric vehicles

PG&E: Pacific Gas and Electric Company

PHMSA: Pipeline and Hazardous Materials Safety Administration

PTY: post-test year

R.: Order Instituting Rulemaking

RD&D: research, development and demonstration

RDDEA: Research Development and Demonstration Expense Account

REL&F: Real Estate, Land and Facilities

RICE: reciprocating internal combustion engines

RIIM: Reliability Investment Incentive Mechanism

RIRAT: Reliability Improvements in Rural Areas Team

RPS: Renewable Portfolio Standard

SAIDET: system average interruption duration exceeding threshold

SAIDI: system average interruption duration index

SAIFI: system average interruption frequency index

SBE: California State Board of Equalization

SCADA: supervisory, control and data acquisition

SCAQMD: South Coast Air Quality Management District

SCE: Southern California Edison Company

SCGC: Southern California Generation Coalition

SDG&E: San Diego Gas & Electric Company

SEC: Securities and Exchange Commission

Sempra: Sempra Energy

SoCalGas: Southern California Gas Company

SORT: Service Order Routing Technology

TEAM: Telecommunications Education and Assistance in Multiple-languages

TIMP: Transmission Integrity Management Program

TURN: The Utility Reform Network

UCAN: Utility Consumers Action Network

UPS: uninterruptible power supply

USOA: Uniform System of Accounts

UWUA: Utility Workers Union of America

VP: Vice President

WMDVBE: women, minority, and disabled veteran business enterprises

(END OF ATTACHMENT A)

ATTACHMENT B

Table B-1
San Diego Gas & Electric Company
2012 Combined Results of Operations
(in Thousand of Dollars)

Line No.	Item	SDG&E Request (Based on February 2012 Updated Testimony)	Adopted	Difference (SDG&E Request Less Adopted)
1	Base Margin	$ 1,825,067	$ 1,726,194	$ 98,873
2	Miscellaneous Revenues	$ 23,670	$ 23,183	$ 487
3	Revenue Requirement	$ 1,848,737	$ 1,749,376	$ 99,361
	OPERATING & MAINTENANCE EXPENSES			
4	Distribution (A) (B)	$ 148,240	$ 145,864	$ 2,376
5	Gas Transmission	$ 3,916	$ 3,810	$ 106
6	Generation	$ 33,687	$ 31,761	$ 1,926
7	Nuclear Generation (SONGS)	$ 120,108	$ 120,108	$ -
8	Engineering	$ 13,749	$ 13,592	$ 157
9	Procurement	$ 10,442	$ 9,358	$ 1,084
10	Customer Services	$ 92,887	$ 83,268	$ 9,619
11	Information Technology	$ 54,759	$ 53,076	$ 1,683
12	Support Services	$ 93,506	$ 89,059	$ 4,447
13	Administrative and General	$ 470,076	$ 409,364	$ 60,712
14	Subtotal (2009$)	$ 1,041,370	$ 959,260	$ 82,110
15	Shared Services Adjustments	$ (43,301)	$ (43,592)	$ 292
16	Reassignments	$ (141,163)	$ (121,782)	$ (19,381)
17	FERC Transmission Costs	$ (48,484)	$ (42,784)	$ (5,700)
18	Escalation	$ 29,139	$ 26,737	$ 2,402
19	Uncollectibles	$ 3,176	$ 3,004	$ 172
20	Franchise Fees	$ 58,498	$ 55,400	$ 3,098
21	Total O&M (2012$)	$	$	$

		899,235	836,243	62,993
22	Depreciation & Amortization	$ 340,469	$ 327,361	$ 13,108
23	Taxes on Income (C)	$ 170,927	$ 166,967	$ 3,960
24	Taxes Other Than on Income	$ 79,607	$ 76,274	$ 3,334
25	Total Operating Expenses	$ 1,490,239	$ 1,406,844	$ 83,395
26	Return	$ 358,498	$ 342,532	$ 15,966
27	Rate Base	$ 4,267,834	$ 4,077,765	$ 190,069
28	Rate of Return	8.40%	8.40%	
29	Revenues at Present Rates	$ 1,609,221	$ 1,609,221	$ -
30	Net increase over Present Rates	$ 239,516	$ 140,156	$ 99,361
31	Derivation of Base Margin			
32	O&M Expenses	$ 899,235	$ 836,243	$ 62,993
33	Depreciation	$ 340,469	$ 327,361	$ 13,108
34	Taxes	$ 250,535	$ 243,241	$ 7,294
35	Return	$ 358,498	$ 342,532	$ 15,966
36	Revenue Requirement	$ 1,848,737	$ 1,749,376	$ 99,361
37	Less: Misc. Revenues	$ 23,670	$ 23,183	$ 487
38	Base Margin	$ 1,825,067	$ 1,726,194	$ 98,873

(A) The adopted electric distribution O&M expense includes the $18.9 million Legacy Meter revenue requirement (see Table B-7). This amount is not subject to PTY escalation.

(B) The adopted O&M distribution expense includes the impact of a $500,000 reduction due to income tax. This reduction is discussed in Section 21.4.

(C) The adopted Taxes on Income does not reflect the $500,000 reduction in income taxes. See footnote B.

Table B-2
San Diego Gas & Electric Company
2012 Gas Summary of Earnings
(in Thousand of Dollars)

Line No.	Item	SDG&E Request (Based on February 2012 Updated Testimony)	Adopted	Difference (SDG&E Request Less Adopted)
1	Base Margin	$ 316,001	$ 293,512	$ 22,489
2	Miscellaneous Revenues	$ 5,458	$ 5,273	$ 185
3	Revenue Requirement	$ 321,459	$ 298,785	$ 22,674
	OPERATING & MAINTENANCE EXPENSES			
4	Distribution [(A)]	$ 22,137	$ 17,387	$ 4,750
5	Gas Transmission	$ 3,916	$ 3,810	$ 106
6	Generation	$ 164	$ 156	$ 9
7	Nuclear Generation (SONGS)		$ -	$ -
8	Engineering	$ 13,304	$ 13,288	$ 16
9	Procurement	$ 359	$ 335	$ 24
10	Customer Services	$ 31,970	$ 29,697	$ 2,273
11	Information Technology	$ 21,646	$ 21,300	$ 346
12	Support Services	$ 19,146	$ 18,283	$ 863
13	Administrative and General	$ 101,339	$ 86,537	$ 14,802
14	Subtotal (2009$)	$ 213,981	$ 190,793	$ 23,188
15	Shared Services Adjustments	$ (9,438)	$ (9,708)	$ 270
16	Reassignments	$ (33,446)	$ (28,622)	$ (4,824)
17	FERC Transmission Costs	$ -	$ -	$ -
18	Escalation	$ 7,860	$ 6,893	$ 967
19	Uncollectibles (0.174%)	$ 550	$ 511	$ 39
20	Franchise Fees (2.1104%)	$ 6,669	$ 6,194	$ 475
21	Total O&M (2012$)	$	$	$

		186,175	166,060	20,115
22	Depreciation & Amortization	$ 54,505	$ 53,261	$ 1,244
23	Taxes on Income (B)	$ 23,761	$ 24,134	$ (373)
24	Taxes Other Than on Income	$ 12,953	$ 12,319	$ 634
25	Total Operating Expenses	$ 277,393	$ 255,774	$ 21,620
26	Return	$ 44,065	$ 43,011	$ 1,054
27	Rate Base	$ 524,585	$ 512,038	$ 12,548
28	Rate of Return	8.40%	8.40%	
29	Revenues at Present Rates	$ 283,998	$ 283,998	$ -
30	Net increase over Present Rates	$ 37,460	$ 14,787	$ 22,674
31	Derivation of Base Margin			
32	O&M Expenses	$ 186,175	$ 166,060	$ 20,115
33	Depreciation	$ 54,505	$ 53,261	$ 1,244
34	Taxes	$ 36,713	$ 36,453	$ 261
35	Return	$ 44,065	$ 43,011	$ 1,054
36	Revenue Requirement	$ 321,459	$ 298,785	$ 22,674
37	Less: Misc. Revenues	$ 5,458	$ 5,273	$ 185
38	Base Margin	$ 316,001	$ 293,512	$ 22,489

(A) The adopted O&M distribution expense includes the impact of a $250,000 reduction due to income tax. This reduction is discussed in Section 21.4.

(B) The adopted Taxes on Income does not reflect the $250,000 reduction in income taxes. See footnote A.

Table B-3
San Diego Gas & Electric Company
2012 Electric Summary of Earnings
(in Thousand of Dollars)

Line No.	Item	SDG&E Request (Based on February 2012 Updated Testimony)	Adopted	Difference (SDG&E Request Less Adopted)
1	Base Margin	$ 1,509,067	$ 1,432,682	$ 76,384
2	Miscellaneous Revenues	$ 18,212	$ 17,909	$ 303
3	Revenue Requirement	$ 1,527,278	$ 1,450,591	$ 76,687
	OPERATING & MAINTENANCE EXPENSES			
4	Distribution [(A) (B)]	$ 126,103	$ 128,477	$ (2,374)
5	Gas Transmission	$ -	$ -	$ -
6	Generation	$ 33,523	$ 31,605	$ 1,917
7	Nuclear Generation (SONGS)	$ 120,108	$ 120,108	$ -
8	Engineering	$ 445	$ 305	$ 141
9	Procurement	$ 10,083	$ 9,023	$ 1,060
10	Customer Services	$ 60,917	$ 53,571	$ 7,346
11	Information Technology	$ 33,113	$ 31,776	$ 1,337
12	Support Services	$ 74,360	$ 70,776	$ 3,584
13	Administrative and General	$ 368,737	$ 322,827	$ 45,910
14	Subtotal (2009$)	$ 827,390	$ 768,468	$ 58,922
15	Shared Services Adjustments	$ (33,862)	$ (33,884)	$ 22
16	Reassignments	$ (107,717)	$ (93,160)	$ (14,557)
17	FERC Transmission Costs	$ (48,484)	$ (42,784)	$ (5,700)
18	Escalation	$ 21,279	$ 19,844	$ 1,435

19	Uncollectibles (0.174%)	$ 2,626	$ 2,493	$ 133
20	Franchise Fees (3.4345%)	$ 51,829	$ 49,205	$ 2,623
21	Total O&M (2012$)	$ 713,061	$ 670,183	$ 42,878
22	Depreciation & Amortization	$ 285,964	$ 274,100	$ 11,864
23	Taxes on Income [(C)]	$ 147,166	$ 142,833	$ 4,334
24	Taxes Other Than on Income	$ 66,655	$ 63,955	$ 2,700
25	Total Operating Expenses	$ 1,212,846	$ 1,151,070	$ 61,775
26	Return	$ 314,433	$ 299,521	$ 14,912
27	Rate Base	$ 3,743,249	$ 3,565,728	$ 177,521
28	Rate of Return	8.40%	8.40%	
29	Revenues at Present Rates	$ 1,325,222	$ 1,325,222	$ -
30	Net increase over Present Rates	$ 202,056	$ 125,369	$ 76,687
31	Derivation of Base Margin			
32	O&M Expenses	$ 713,061	$ 670,183	$ 42,878
33	Depreciation	$ 285,964	$ 274,100	$ 11,864
34	Taxes	$ 213,821	$ 206,788	$ 7,034
35	Return	$ 314,433	$ 299,521	$ 14,912
36	Revenue Requirement	$ 1,527,278	$ 1,450,591	$ 76,687
37	Less: Misc. Revenues	$ 18,212	$ 17,909	$ 303
38	Base Margin	$ 1,509,067	$ 1,432,682	$ 76,384

(A) The adopted electric distribution O&M expense includes the $18.9 million Legacy Meter revenue requirement (see Table B-7). This amount is not subject to PTY escalation.
(B) The adopted O&M distribution expense includes the impact of a $250,000 reduction due to income tax. This reduction is discussed in Section 21.4.
(C) The adopted Taxes on Income does not reflect the $250,000 reduction in income taxes. See footnote B.

Table B-4
San Diego Gas & Electric Company
2012 Electric Distribution Summary of Earnings
(in Thousand of Dollars)

Line No.	Item	SDG&E Request (Based on February 2012 Updated Testimony)	Adopted	Difference (SDG&E Request Less Adopted)
1	Base Margin	$ 1,212,355	$ 1,140,003	$ 72,352
2	Miscellaneous Revenues	$ 18,212	$ 17,909	$ 303
3	Revenue Requirement	$ 1,230,567	$ 1,157,912	$ 72,655
	OPERATING & MAINTENANCE EXPENSES			
4	Distribution (A) (B)	$ 125,859	$ 128,355	$ (2,496)
5	Gas Transmission	$ -	$ -	$ -
6	Generation	$ 454	$ 430	$ 24
7	Nuclear Generation (SONGS)	$ -	$ -	$ -
8	Engineering	$ 445	$ 305	$ 141
9	Procurement	$ 10,059	$ 9,000	$ 1,059
10	Customer Services	$ 60,795	$ 53,471	$ 7,324
11	Information Technology	$ 32,957	$ 31,622	$ 1,336
12	Support Services	$ 73,083	$ 69,549	$ 3,534
13	Administrative and General	$ 359,638	$ 314,748	$ 44,889
14	Subtotal (2009$)	$ 663,290	$ 607,479	$ 55,811
15	Shared Services Adjustments	$ (32,999)	$ (33,023)	$ 24
16	Reassignments	$ (105,528)	$ (90,971)	$ (14,557)
17	FERC Transmission Costs	$ (48,484)	$ (42,784)	$ (5,700)
18	Escalation	$ 19,158	$ 17,911	$ 1,246

19	Uncollectibles	$ 2,109	$ 1,984	$ 126
20	Franchise Fees	$ 48,770	$ 46,188	$ 2,582
21	Total O&M (2012$)	$ 546,316	$ 506,784	$ 39,532
22	Depreciation & Amortization	$ 247,768	$ 236,079	$ 11,688
23	Taxes on Income (C)	$ 120,169	$ 115,964	$ 4,205
24	Taxes Other Than on Income	$ 56,591	$ 54,016	$ 2,576
25	Total Operating Expenses	$ 970,843	$ 912,843	$ 58,000
26	Return	$ 259,724	$ 245,069	$ 14,654
27	Rate Base	$ 3,091,947	$ 2,917,491	$ 174,456
28	Rate of Return	8.40%	8.40%	
29	Revenues at Present Rates	$ 1,067,894	$ 1,067,894	$ -
30	Net increase over Present Rates	$ 162,673	$ 90,018	$ 72,655
31	Derivation of Base Margin			
32	O&M Expenses	$ 546,316	$ 506,784	$ 39,532
33	Depreciation	$ 247,768	$ 236,079	$ 11,688
34	Taxes	$ 176,760	$ 169,980	$ 6,780
35	Return	$ 259,724	$ 245,069	$ 14,654
36	Revenue Requirement	$ 1,230,567	$ 1,157,912	$ 72,655
37	Less: Misc. Revenues	$ 18,212	$ 17,909	$ 303
38	Base Margin	$ 1,212,355	$ 1,140,003	$ 72,352

(A) The adopted electric distribution O&M expense includes the $18.9 million Legacy Meter revenue requirement (see Table B-7). This amount is not subject to PTY escalation.

Table B-5
San Diego Gas & Electric Company
2012 Generation Summary of Earnings
(in Thousand of Dollars)

Line No.	Item	SDG&E Request (Based on February 2012 Updated Testimony)	Adopted	Difference (SDG&E Request Less Adopted)
1	Base Margin	$ 135,351	$ 131,135	$ 4,216
2	Miscellaneous Revenues	$ -	$ -	$ -
3	Revenue Requirement	$ 135,351	$ 131,135	$ 4,216
	OPERATING & MAINTENANCE EXPENSES			
4	Distribution	$ 244	$ 122	$ 122
5	Gas Transmission	$ -	$ -	$ -
6	Generation	$ 33,069	$ 31,176	$ 1,893
7	Nuclear Generation (SONGS)	$ -	$ -	$ -
8	Engineering	$ -	$ -	$ -
9	Procurement	$ 25	$ 23	$ 2
10	Customer Services	$ 122	$ 100	$ 23
11	Information Technology	$ 156	$ 154	$ 1
12	Support Services	$ 1,277	$ 1,227	$ 49
13	Administrative and General	$ 7,252	$ 6,231	$ 1,021
14	Subtotal (2009$)	$ 42,145	$ 39,033	$ 3,111
15	Shared Services Adjustments	$ (863)	$ (861)	$ (3)
			$ -	
16	Reassignments	$ (2,189)	$ (2,189)	$ -
17	FERC Transmission Costs	$	$	$

		-	-	-
18	Escalation	$ 2,122	$ 1,933	$ 189
19	Uncollectibles	$ 236	$ 228	$ 7
20	Franchise Fees	$ 1,395	$ 1,352	$ 43
21	Total O&M (2012$)	$ 42,846	$ 39,497	$ 3,348
22	Depreciation & Amortization	$ 23,933	$ 23,685	$ 247
23	Taxes on Income	$ 19,594	$ 19,434	$ 160
24	Taxes Other Than on Income	$ 7,592	$ 7,455	$ 137
25	Total Operating Expenses	$ 93,963	$ 90,071	$ 3,892
26	Return	$ 41,387	$ 41,064	$ 324
27	Rate Base	$ 492,704	$ 488,852	$ 3,852
28	Rate of Return	8.40%	8.40%	
29	Revenues at Present Rates	$ 131,167	$ 131,167	$ -
30	Net increase over Present Rates	$ 4,184	$ (32)	$ 4,216
31	Derivation of Base Margin			
32	O&M Expenses	$ 42,846	$ 39,497	$ 3,348
33	Depreciation	$ 23,933	$ 23,685	$ 247
34	Taxes	$ 27,185	$ 26,889	$ 297
35	Return	$ 41,387	$ 41,064	$ 324
36	Revenue Requirement	$ 135,351	$ 131,135	$ 4,216
37	Less: Misc. Revenues	$ -	$ -	$ -
38	Base Margin	$ 135,351	$ 131,135	$ 4,216

Table B-6
San Diego Gas & Electric Company
2012 SONGS Summary of Earnings
(in Thousand of Dollars)

Line No.	Item	SDG&E Request (Based on February 2012 Updated Testimony)	Adopted	Difference (SDG&E Request Less Adopted)
1	Base Margin	$ 161,361	$ 161,544	$ (183)
2	Miscellaneous Revenues	$ -	$ -	$ -
3	Revenue Requirement	$ 161,361	$ 161,544	$ (183)
	OPERATING & MAINTENANCE EXPENSES			
4	Distribution	$ -	$ -	$ -
5	Gas Transmission	$ -	$ -	$ -
6	Generation	$ -	$ -	$ -
7	Nuclear Generation (SONGS)	$ 120,108	$ 120,108	$ -
8	Engineering	$ -	$ -	$ -
9	Procurement	$ -	$ -	$ -
10	Customer Services	$ -	$ -	$ -
11	Information Technology	$ -	$ -	$ -
12	Support Services	$ -	$ -	$ -
13	Administrative and General	$ 1,847	$ 1,847	$ -
14	Subtotal (2009$)	$ 121,955	$ 121,955	$ -
15	Shared Services Adjustments	$ -	$ -	
16	Reassignments	$ -	$ -	$ -
17	FERC Transmission Costs	$ -	$ -	$ -
18	Escalation	$ -	$ -	$ -
19	Uncollectibles	$ 281	$ 281	$ (0)
20	Franchise Fees	$ 1,664	$ 1,666	$ (2)
21	Total O&M (2012$)	$ 123,899	$ 123,902	$ (2)
22	Depreciation & Amortization	$ 14,264	$ 14,335	$ (72)

23	Taxes on Income	$ 7,404	$ 7,434	$ (31)
24	Taxes Other Than on Income	$ 2,472	$ 2,485	$ (13)
25	Total Operating Expenses	$ 148,039	$ 148,156	$ (117)
26	Return	$ 13,322	$ 13,388	$ (66)
27	Rate Base	$ 158,598	$ 159,384	$ (787)
28	Rate of Return	8.40%	8.40%	
29	Revenues at Present Rates	$ 126,161	$ 126,161	
30	Net increase over Present Rates	$ 35,200	$ 35,383	
31	Derivation of Base Margin			
32	O&M Expenses	$ 123,899	$ 123,902	$ (2)
33	Depreciation	$ 14,264	$ 14,335	$ (72)
34	Taxes	$ 9,876	$ 9,919	$ (43)
35	Return	$ 13,322	$ 13,388	$ (66)
36	Revenue Requirement	$ 161,361	$ 161,544	$ (183)
37	Less: Misc. Revenues	$ -	$ -	$ -
38	Base Margin	$ 161,361	$ 161,544	$ (183)

Table B-7
SDG&E Legacy Meter Analysis
(in Millions of Dollars)

	A	B	C = B * 6.2%	D = C * 1.68765	E = A + D	F
Year	Amortization	Ratebase	6.2% Return	Return after tax gross up	Return + Amortization	Yearly Recovery
2012	13.9	83.1	5.2	8.7	22.6	18.9
2013	13.9	69.3	4.3	7.2	21.1	18.9
2014	13.9	55.4	3.4	5.8	19.7	18.9
2015	13.9	41.6	2.6	4.3	18.2	18.9
2016	13.9	27.7	1.7	2.9	16.8	18.9
2017	13.9	13.9	0.9	1.4	15.3	18.9
	83.1		18.0		113.6	113.6

NOTES:

1. The 2012 ratebase balance has less one year depreciation at 2.32%.
Therefore, the undepreciated balance for the Legacy meters is $83.13M. ($85.1M - $1.97M = $83.13M)

2. $18.9M per year is added to SDG&E's Non-shared services workgroup 1ED014-000 for recovery.

Table B-8
Southern California Gas Company
2012 Results of Operations
(in Thousand of Dollars)

Line No.	Item	SCG Request (Based on February 2012 Updated Testimony)	Adopted	Difference (SCG Request Less Adopted)
	Description			
1	Base Margin	$ 2,009,822	$ 1,849,152	$ 160,670
2	Miscellaneous Revenues	102,654	$ 102,560	$ 94
3	Revenue Requirement	$ 2,112,476	$ 1,951,712	$ 160,763
	Operating and Maintenance Expenses			
4	Gas Distribution (A)	$ 132,337	$ 98,192	$ 34,145
5	Transmission	$ 32,357	$ 31,015	$ 1,342
6	Underground Storage	$ 28,939	$ 28,607	$ 332
7	Engineering	$ 94,452	$ 72,613	$ 21,839
8	Procurement	$ 3,639	$ 3,639	$ -
9	Customer Services	$ 323,893	$ 307,903	$ 15,990
10	Information Technology	$ 47,472	$ 46,153	$ 1,319
11	Support Services	$ 121,314	$ 112,388	$ 8,926
12	Administrative and General	$ 373,881	$ 335,347	$ 38,534
13	Subtotal (2009$)	$ 1,158,284	$ 1,035,857	$ 122,427
14	Shared Services Adjustments	$ 34,754	$ 34,961	$ (207)
15	Reassignments	$ (80,997)	$ (73,607)	$ (7,389)
16	Escalation	$ 62,108	$ 54,355	$ 7,752
17	Uncollectibles (0.278%)	$ 5,468	$ 5,031	$ 437
18	Franchise Fees (1.4593%)	$ 29,730	$ 27,386	$ 2,345

19	Total O&M (2012$)	$ 1,209,348	$ 1,083,983	$ 125,364
20	Depreciation	$ 372,774	$ 361,271	$ 11,503
21	Taxes on Income [(B)]	$ 134,602	$ 128,621	$ 5,981
22	Taxes Other Than on Income	$ 81,325	$ 77,300	$ 4,025
23	Total Operating Expenses	$ 1,798,049	$ 1,651,176	$ 146,873
24	Return	$ 314,427	$ 300,537	$ 13,890
25	Rate Base	$ 3,622,427	$ 3,462,405	$ 160,022
26	Rate of Return	8.68%	8.68%	
27	Revenues at Present Rates	$ 1,873,343	$ 1,873,343	
28	Net increase over Present Rates	$ 239,132	$ 78,369	
29	Derivation of Base Margin			
30	O&M Expenses	$ 1,209,348	$ 1,083,983	$ 125,364
31	Depreciation	$ 372,774	$ 361,271	$ 11,503
32	Taxes	$ 215,928	$ 205,921	$ 10,006
33	Return	$ 314,427	$ 300,537	$ 13,890
34	Revenue Requirement	$ 2,112,476	$ 1,951,712	$ 160,763
35	Less: Miscellaneous Revenues	$ 102,654	$ 102,560	$ 94
36	Base Margin	$ 2,009,822	$ 1,849,152	$ 160,670

(A) The adopted O&M distribution expense includes the impact of a $500,000 reduction due to income tax. This reduction is discussed in Section 21.4.

(B) The adopted Taxes on Income does not reflect the $500,000 reduction in income taxes. See footnote A.

ATTACHMENT C

ATTACHMENT C

A. Gas Transmission and Distribution Safety Report

San Diego Gas & Electric Company shall serve the Gas Transmission & Distribution (GT&D) Safety Report (as described in this subsection A), and Southern California Gas Company (SoCalGas) shall serve the Gas Transmission and Distribution and Gas Storage Safety Report (GT&D&GS) Safety Report (as described in subsections A and B), [1] on the Directors of the Safety and Enforcement Division and the Energy Division. SDG&E and SoCalGas shall serve their initial respective reports on July 1, 2013, and this report shall cover the twelve month period from January 1, 2012 through December 31, 2012. Each subsequent report shall cover the preceding six months (e.g., January 1, 2013 through June 30, 2013), and shall be served beginning on September 1, 2013, and on each March 1 and September 1 thereafter until further notice.

The GT&D Safety Report for SDG&E, and the GT&D&GS Safety Report for SoCalGas shall include the following:

1. A thorough description and explanation of the: strategic planning and decision-making approach that the utility uses to determine and rank the following: the pipeline transmission safety, integrity, and reliability of its pipeline transmission projects; the pipeline distribution safety, integrity, and reliability of its pipeline distribution projects; the operation and maintenance (O&M) activities related to

[1] SDG&E and SoCalGas are also referred to in this subsection A as the "utility." The term "Safety Report" as used in this subsection A refers to both the GT&D Safety Report, and the GT&D&GS Safety Report.

both gas transmission and gas distribution activities; the inspections of the utility's gas transmission and distribution pipelines. If there has been no change since the last Safety Report on how the utility determines and ranks how projects and activities are prioritized, the Safety Report may reference the earlier report.

2. The Safety Report shall describe the amount of funds budgeted at the beginning of each calendar year and over the rate case period, as well as the amount spent during the reporting period and for that calendar year, for each cost center related to capital expenditures and O&M activities for gas transmission and gas distribution. To the extent these funds are specified in a settlement or other document, such as workpapers or testimony, references to where these amounts are mentioned shall be provided.

3. The Safety Report shall identify and describe each gas transmission capital expenditure project, each gas distribution capital expenditure project, and the O&M work activities related to gas transmission and gas distribution, which were planned to start during the reporting period, and the project costs associated with each project or work activity exceeding $250,000. For each project or work activity with a cost of $250,000 or less, those may be reported as an aggregate total by cost category. The utility shall also identify in the Safety Report whether such capital expenditure projects and O&M work activities were included in any prior application filed with the Commission, and provide a reference to those prior documents supporting such a request.

4. For each gas transmission and gas distribution capital expenditure project or gas transmission and gas distribution O&M work activity with a cost exceeding $250,000, the Safety Report must identify and describe each such project or work activity, that were started, underway, or completed during the reporting period, and the amount

spent on each project and activity during the reporting period, the amount spent during that calendar year, and the total amount spent on each project or activity.[2] For projects or work activity with a cost of $250,000 or less, those may be reported as an aggregate by cost center. The Safety Report shall include the start date, the completion date or anticipated completion date, and a description of the work that was performed during the reporting period. If the utility began a project or O&M activity during the reporting period that was not previously identified as a planned project or activity in a prior Safety Report, the utility shall provide an explanation of why that project or activity proceeded ahead of other projects or activities that were previously listed as a planned project or activity, and the source of the monies to be used on this project or activity.

5. If the utility does not spend the entire amount budgeted for gas transmission capital expenditure projects, gas distribution capital expenditure projects, or O&M activities related to gas transmission and gas distribution, the utility must provide an explanation in its Safety Report. Similarly, if the utility spends in excess of the amount budgeted for these projects or O&M activities, the utility must provide an explanation in its Safety Report.

6. After experience is gained with the Safety Report and should circumstances warrant, the Safety and Enforcement Division and the Energy Division may increase the Safety Report threshold amount set forth in numbered paragraphs 3 and 4 of this Attachment. Any increase in the Safety Report threshold amount shall be accomplished by notifying the Executive Director in writing of such a

[2] In order to compare and reconcile the amount that was actually spent to the budgeted amounts, the utility must include and itemize other costs and expenses of the project or work activity that was undertaken, such as administrative and general expense or indirect or overhead costs.

change, and serving the letter on the service list in this proceeding.

7. The utility shall provide the Safety and Enforcement Division and the Energy Division with an electronic spreadsheet with the data required in this decision and attachment, including but not limited to the following information for each project or activity:
    a. cost of project, forecasted and actual;
    b. start date;
    c. completion date or anticipated completion; and
    d. utility region where project is located.

B. Gas Transmission and Distribution and Gas Storage Safety Report

The GT&D&GS Safety Report shall include the following:

1. All of the information required in the GT&D Safety Report as set forth above in subsection A of this Attachment.
2. A thorough description and explanation of the: strategic planning and decision-making approach SoCalGas uses to determine and rank gas storage capital expenditure projects; and the O&M activities related to gas storage. If there has been no change since the last GT&D&GS Safety Report on how SoCalGas determines and ranks how gas storage capital expenditure projects and O&M activities related to gas storage are prioritized, the GT&D&GS Safety Report may reference the earlier report.
3. The GT&D&GS Safety Report shall describe the amount of funds budgeted at the beginning of each calendar year and over the rate case period, as well as the amount spent during the reporting period and for that calendar year, for each cost center related to capital expenditures and O&M activities for gas storage. To the extent these funds are specified in a settlement or other document, such as workpapers or testimony, references to where these amounts are mentioned shall be provided.

4. The GT&D&GS Safety Report shall identify and describe each gas storage capital expenditure project, and the O&M work activities related to gas storage, which were planned to start during the reporting period, and the project costs associated with each project or work activity exceeding $250,000. For each project or work activity with a cost of $250,000 or less, those may be reported as an aggregate total by cost category. SoCalGas shall also identify in the GT&D&GS Safety Report whether such gas storage capital expenditure projects and O&M work activities were included in any prior application filed with the Commission, and provide a reference to those prior documents supporting such a request.

5. For each gas storage capital expenditure project or gas storage O&M work activity with a cost exceeding $250,000, the GT&D&GS Safety Report must identify and describe each such project or work activity, that were started, underway, or completed during the reporting period, and the amount spent on each project and activity during the reporting period, the amount spent during that calendar year, and the total amount spent on each project or activity.[3] For projects or work activity with a cost of $250,000 or less, those may be reported as an aggregate by cost center. The GT&D&GS Safety Report shall include the start date, the completion date or anticipated completion date, and a description of the work that was performed during the reporting period. If SoCalGas began a project or O&M activity during the reporting period that was not previously identified as a planned project or activity in a prior GT&D&GS Safety Report, SoCalGas must provide an explanation of why that project or activity proceeded ahead of other projects or activities that were previously

[3] In order to compare and reconcile the amount that was actually spent to the budgeted amounts, SoCalGas must include and itemize other costs and expenses of the project or work activity that was undertaken, such as administrative and general expense or indirect or overhead costs.

listed as a planned project or activity, and the source of the monies to be used on this project or activity.

6. If SoCalGas does not spend the entire amount budgeted for gas storage capital expenditure projects or O&M activities related to gas storage, SoCalGas must provide an explanation in its GT&D&GS Safety Report. Similarly, if SoCalGas spends in excess of the amount budgeted for these projects or O&M activities, SoCalGas must provide an explanation in its GT&D&GS Safety Report.
7. After experience is gained with the GT&D&GS Safety Report and should circumstances warrant, the Safety and Enforcement Division and the Energy Division may increase the GT&D&GS Safety Report threshold amount set forth in numbered paragraphs 4 and 5of this Attachment. Any increase in the GT&D&GS Safety Report threshold amount shall be accomplished by notifying the Executive Director in writing of such a change, and serving the letter on the service list in this proceeding.
8. The utility shall provide the Safety and Enforcement Division and the Energy Division with an electronic spreadsheet with the data required in this decision and attachment, including but not limited to the following information for each project or activity:
    a. cost of project, forecasted and actual;
    b. start date;
    c. completion date or anticipated completion; and
    d. utility region where project is located.

(END OF ATTACHMENT C)