



# Utility General Rate Case – A Manual for Regulatory Analysts

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California Public Utilities Commission  
Policy & Planning Division

Maryam Ghadessi  
*Principal Author*  
**POLICY AND PLANNING  
DIVISION**

Marzia Zafar  
*Director*  
**POLICY AND PLANNING  
DIVISION**

November 13, 2017





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## OVERVIEW

Utilities are considered to be natural monopolies. What are monopolies? Monopolies are businesses or markets where one producer (or a group of producers acting in concert) controls supply of a good or service, and where the entry of new producers is prevented or highly restricted. So, in a nutshell your basic necessities (i.e. electricity, gas, & water services) are provided by government imposed monopolies. So what? Well, the natural instinct of any business is to maximize profits. But, when there is little to no competition, then monopolies can restrict access/service and/or increase the price with the customer having no choice. That is where the Commission comes in. The Commission is responsible for ensuring that utility service monopolies provide safe and reliable service at just and reasonable rates.

So, let us re-cap: Utilities are government imposed monopolies or at least they are very similar to monopolies in that they own and control the distribution and delivery of basic necessities. In other words there is no competition to keep the utility from indiscriminately raising the price of service. To remedy this situation, regulation was established long ago to ensure the safe and reliable delivery of service at just and reasonable rates.

For utilities, regulation represents tradeoffs by imposing restraints on utilities and in return, they receive certain protections. For example, prices charged are regulated and can never exceed the original cost of the asset dedicated to utility service. Utilities have a regulated capital structure (not over-leveraged that would make them unstable), and tax benefits are conveyed to ratepayers as reductions to their rates. On the other hand, utilities have the exclusive right to provide electric service in their service territories (e.g. provide a monopoly service). And utilities are entitled to recover the costs of reasonably-incurred investments, even when they retire prematurely, etc.

How do regulators do that? Well, regulators start by asking the utility to compile a report that provides answers to the following key questions;

1. What kind of infrastructure and investments does the utility need to serve its customers?
2. What is the prudent and reasonable cost of providing the service? and,
3. What rates would allow the utility company a reasonable opportunity to recover its costs, including a reasonable return on invested capital (i.e. profit)?

This report is called a General Rate Case. It is the single most important case for the utility and the regulator since it establishes the revenue from customers to provide safe and reliable service at just and reasonable rates (cost). An effective regulator has to find the balance between what's really needed to maintain safe and reliable service and what's gold-plating. In other words, an effective regulator has to choose the appropriate



quality of service, avoid wasted costs, and set reasonable rates to recover the prudent cost.

The rest of this write-up is a more detailed explanation of how a General Rate Case works.

## **GRC REVIEW PROCESS – Chapter 1**

### **I. INTRODUCTION**

The Commission establishes rates for utilities under its jurisdiction in a rate-setting proceeding called, the General Rate Case (GRC). The Commission's Rules of Practice and Procedure Article 2 and Appendix A of the Commission decision (D.) 07-07-004 set the rules and procedures for GRC review process.

In this section we discuss the authority granted to the Commission by the Public Utilities Codes for establishing just and reasonable rates and the principles that emerge from the Public Utilities Codes and guide the Commission in establishing rates. We will also discuss the original and the current modified rate case plan that set the rules and procedures for the GRC review process at the Commission.

### **II. AUTHORITY FOR RATE REGULATION**

The Commission is mandated by Sections 451, 454, and 728 of the Public Utilities Code to establish just and reasonable rates for utilities under its jurisdiction. According to Public Utilities Code 451 to be legal all public utility charges must be just and reasonable. Public Utilities Code 451 states:

“All charges demanded or received by any public utility, or by any two or more public utilities, for any product or commodity furnished or to be furnished or any service rendered or to be rendered shall be just and reasonable. Every unjust or unreasonable charge demanded or received for such product or commodity or service is unlawful.”

Public Utilities Code 454 and 728 hold the Commission responsible for ensuring that rates are just and reasonable. According to Public Utilities Code 454 a public utility can change its' rate only after the Commission establishes that the new rate is just. Public Utilities Code 454 states:

“[A] public utility shall not change any rate or so alter any classification, contract, practice, or rule as to result in any new rate, except upon a showing before the commission and a finding by the commission that the new rate is justified.”



And Public Utilities Code 728 directs the Commission to put in effect rates that are just and reasonable whenever the Commission finds that the existing rates are unjust and unreasonable. Public Utilities Code 728 states:

“Whenever the commission, after a hearing, finds that the rates or classifications, demanded, observed, charged, or collected by any public utility for or in connection with any service, product, or commodity, or the rules, practices, or contracts affecting such rates or classifications are insufficient, unlawful, unjust, unreasonable, discriminatory, or preferential, the commission shall determine and fix, by order, the just, reasonable, or sufficient rates, classifications, rules, practices, or contracts to be thereafter observed and in force.”

### **III. PRINCIPLES of RATE REGULATION**

The statutory authority to establish just and reasonable rates require the Commission to set rates sufficient to cover the prudent costs of providing utility service. Included in the cost of providing service is a return on capital used to finance purchase of plants and assets. Investors expect a reasonable return on their capital investment. The Commission is mandated by statute to ensure that utilities are able to attract capital by offering an adequate or fair rate of return to investors. This mandate stems from the Supreme Court in the Bluefield and Hope decisions.

Fairness in rate regulation entails that the Commission should try to strike a balance between the interests of the ratepayers, on one hand, and the regulated utility (its owners; stockholders), on the other hand. Ratepayers are interested in reliable and safe utility service at the lowest possible rates. Investors ultimately are interested in earning maximum return on their capital. The role of the Commission in this process is to assure the interests of the ratepayers and utility are balanced by providing the utility with adequate and reasonable funding levels for both operating and capital costs.

### **IV. RATE-SETTING PROCESS**

Major investor-owned utilities in California must seek approval from the Commission through a General Rate Case (GRC) application to change their rates. The GRC application is filed with the Commission and is available for the public to review on the Commission’s website. Utilities under the jurisdiction of the Commission can change the rates only after the Commission completes the GRC application review process and issues an order authorizing changes in rates.

The application filing begins a formal evidentiary process in which the Commission must establish the amount of money that needs to be collected from ratepayers through rates i.e. Revenue Requirement. The establishment of a utility’s revenue requirement is the



basis for setting the overall level of the utility's rates. Revenue requirement is the amount of gross revenues needed by the utility to cover its operating expenses, book depreciation, return, taxes, etc.

It should be pointed out that utilities in California recover a large portion of their revenue requirement through balancing and memorandum accounts. A balancing account is an account established to record certain authorized amounts for recovery through rates and to ensure that the revenue collected matches the authorized amounts. Balancing accounts usually accrue interest – to be additionally returned to ratepayers if the utility is over-collected, or to recover additional revenue if the utility is under-collected.

Memorandum accounts are similar to balancing accounts except that they do not usually establish an authorized revenue requirement and are subject to further scrutiny by the CPUC. Upon Commission review expenses accrued in Memorandum accounts may or may not be recoverable through rates.

In 2012 the portion of revenue requirement recovered through balancing and memorandum accounts for SCE, SDG&E, SoCalGas, and PG&E was 45.24%, 44.09%, 54.45%, and 40.00%, respectively. Disallowances of operating expenses from these balancing and memorandum accounts have not been material for utilities in California in the past.<sup>1</sup>

The development of a utility's revenue requirements is the first analytical step of the rate-setting process, which includes cost allocation and rate design. After revenue requirement is determined, then the next step is to allocate the revenue requirement to various classes of customers (cost allocation) and finally the rate structure for each customer rate class needs to be determined (rate design). Cost Allocation determines what portion of the revenue requirement to collect from various customer classes (residential, small business, commercial, industrial) and rate design determines how to collect those dollars from various customer classes.

### **A. GRC PROCEEDINGS**

In California the GRC process for major investor-owned utilities – Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), San Diego Gas & Electric Company (SDG&E), Southern California Gas Company (SoCalGas) - typically consists of two separate proceedings. GRC Phase 1 sets the revenue requirement while GRC Phase 2 marginal costs<sup>2</sup> is established, revenue requirement is allocated across different customer classes, and rates for each customer class are developed. For major utilities each Phase of GRC proceedings, from the date utilities file an

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<sup>1</sup> D.12-12-034.

<sup>2</sup> Marginal costs are the change in total costs resulting from the generation of one additional kilowatt of electricity.



application to the date the final decision is published, typically take two years to complete.

The GRC process for utilities that are small or operate across multiple jurisdictions - PacifiCorp, California Pacific Electric Company, and Bear Valley Electric Services - consist of one proceeding in which both revenue requirement is determined, and rates are established. For utilities that are small or multi-jurisdictional GRC proceedings typically takes one year.

Major investor-owned utilities operating in California are required to file a GRC application with the Commission every 36 months (3 years). In 2015 San Diego Gas & Electric Company (SDG&E), Southern California Gas Company (SoCalGas), and the Office of Ratepayer Advocates filed a petition for modification and requested the Commission to change the length of the GRC cycle for major investor-own utilities from three to four years. Decision (D.)16-06-005 denied the petition.

However D.16-06-005 ordered that the proceeding to remain open and directed the Energy Division to hold a workshop within six months to address the pertinent issues that are involved in moving to a longer GRC cycle, and to provide a workshop report on whether a longer GRC cycle is worth pursuing. The proceeding is still open.

In their GRC filings utilities provide various data for the base year, which is the last year of recorded costs. In GRC proceedings the Commission sets a new revenue requirement for test year and post-test year(s). Test year is the year used for evaluating a utility's cost of service. Base year is typically used as a basis to forecast revenue requirement for test-year. Post-test year are the two years succeeding the test year. Post-test year revenue requirement is usually estimated by adjusting test year revenue requirement based on forecasted increases (Inflationary cost increases, additional capital investments) during the post-test year period.

Below is an example of a large energy utility Rate Case Cycle:

- ✓ Base Year: 2014
- ✓ Rate Case Cycle: 2017 – 2019
- ✓ Test Year: 2017
- ✓ Post Test Years / Attrition Years: 2018 and 2019
- ✓ Application Submitted: 3rd – 4th quarter 2015

## **B. STEPS in GRC REVIEW PROCESS**

The Commission's Rules of Practice and Procedure Article (Rule) 2 and the Commission's Rate Case Plan (RCP) as embodied in Decision (D.) 07-07-004 set the rules and procedures for the GRC review process. Commission Decision 07-07-004 (Appendix A page A-30) also set the filing requirement list for RCP. In addition the





Commission is mandated by Public Utilities Code 314.5 to inspect and audit the books and records of utilities for regulatory and tax purposes at least once every three years. An audit is conducted in connection with GRC.

The RCP was initially developed by the Commission to provide guidance to the utilities on the type of information they need to present, and the schedule they need to follow in GRC proceedings. As a result of Senate Bill (SB) 705<sup>3</sup> (signed into law on October 7, 2011) and its emphasis on making natural gas safety a top priority, the Commission modified the RCP in D.14-12-025 to incorporate a risk-based decision-making framework into GRCs.

In this next section the original RCP as was developed in D.07-07-004 will be laid out. Subsequently the framework that was adopted in D.14-12-025, the Refined Straw Proposal, will be discussed.

## **V. ORIGINAL RATE CASE PLAN**

### ***1. Notice of Intent***

The review process begins when the applicant serves the Notice of Intent (NOI) on the Office of Ratepayer Advocates (ORA). The NOI includes prepared testimony, draft exhibits and a brief statement of the amount of increase sought and the reasons for the proposed increase. Appendix A (page A-30) of D.07-07-004 sets the standard requirement list of documents supporting an NOI (a copy of Appendix A is attached). The application can be filed only after the NOI has been accepted by ORA.

The acceptance of the NOI will be based upon whether the applicant has substantially complied with the requirements of the Commission's Rules and the RCP. If there are deficiencies in the utility application it is the responsibility of ORA to identify and notify the deficiencies in the NOI to the applicant. The service of the NOI is completed after deficiencies are corrected and the NOI has been accepted by the ORA.

### ***2. Filing of Application***

An application may be filed no sooner than 60 days after the NOI has been accepted by ORA. In conformity with the Commission's Rules the application should include final exhibits, prepared testimony, and other evidence, and should be served on all parties to the last general rate case. The application serves as the request of the utility for ratepayer funds to continue the operation of the utility for the next 3 years.

Also the utility is required to provide notification to ratepayers that it has made a request for a rate change, how they can participate in the proceeding, etc., within 45 or 75 days

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<sup>3</sup> SB 705 was codified into Public Utilities Code Sections 961 and 963 in Chapter 522 of the Statutes of 2011.



as required by Rule 3.2(b)-(d). This notification is usually made through notices added to monthly customer bills.

The date the application is filed will be noted as Day 0 under the rate case plan.

### ***3. Assigned Administrative Law Judge and Commissioner***

Once the utility files its application with the Commission then the President of the Commission working in concert with the Chief Administrative Law judge assigns a Commissioner and an Administrative Law Judge (ALJ) to oversee the proceeding. The assigned ALJ in cooperation with the assigned Commissioner develop proposed decisions for the full Commission's consideration.

### ***4. Protests/Responses filed***

Pursuant to the Rule 2.6 protests or responses to the application are due within 30 days after the notice of the filing of the application was mailed or published. The protest must state the grounds for the protest, the effect of the application on the protestant, and the reasons the application is not justified.

### ***5. Prehearing conference (PHC)***

In any proceeding in which it is preliminarily determined that a hearing is needed the assigned Commissioner may set a prehearing conference for 45 to 60 days after the initiation of the proceeding. The assigned ALJ will conduct a PHC to identify the issues to be addressed in the proceeding, determine whether evidentiary hearings are needed, and to discuss the schedule for the proceeding and other procedural matters.

Parties that file a protest to the application may submit PHC statements. PHC statements should address the procedural schedule, scope of issues to be included in (or excluded from) the proceeding, need for evidentiary hearings, appropriate category for the proceeding, discovery issues, and list and description of other matters the parties wish to address at the PHC.

### ***6. Scoping Memo***

After the PHC, the Assigned Commissioner issues a scoping memo determining the procedural schedule, assigns the presiding officer, and addresses the scope of the proceeding and other procedural matters for the proceeding. The scoping memo should also state the category and the need for hearing. For an example of a scoping memo see PG&E's 2017 GRC [Scoping Memo](#).

### ***7. Public Participation Hearings***

Pursuant to Commission Decision 14-12-025, a series of Public Participation Hearings (PPHs) may be held on GRC application within 45 days of the filing date, prior to evidentiary hearings. The purpose of the PPHs is to provide an opportunity for customers to communicate directly with the Commission about how the utility's



application, if granted, would impact them. PPHs are scheduled in locations throughout the utility's service territory in the communities affected by the project to allow for comments from members of the public who are not parties in the proceeding. Commissioners can attend these public participation hearings.

At PPHs utilities provide parties with a roadmap of their GRC filing, summarize the contents of the exhibits, and answer questions about their GRC proposals. For an example of PPH announcement see PG&E's 2017 GRC [Public Participation Hearings](#).

#### *8. Discovery from Parties*

Pursuant to Rule 10.1 any party may obtain discovery (documents or other things) from any other party regarding any matter that is relevant to the subject matter involved in the pending proceeding, unless the expense of that discovery outweighs the likelihood that the information will lead to the discovery of admissible evidence.

A person may become a party to a GRC proceeding by; (a) filing an application, petition, or complaint, (b) filing a protest or response to an application, (c) making an oral motion to become a party at a prehearing conference or hearing; or (d) filing a motion to become a party. Parties file written testimony, cross-examine witnesses at evidentiary hearings, file written briefs, and appeal any final decision.

#### *9. Proposal of Settlements*

Pursuant to Rule 12.1, within 30 days after the PHC parties may propose in writing settlements of any issue or an outcome to the proceeding. Settlements need not be joined by all parties but must be signed by the applicant and the complainant.

The settlement motion should contain a statement of the factual and legal considerations adequate to advise the Commission of the scope of the settlement and of the grounds on which adoption is urged. In GRC proceedings the settlement motion must be supported by a comparison exhibit indicating the impact of the settlement in relation to the utility's application and, if the participating staff supports the settlement, in relation to the issues staff contested, or would have contested, in a hearing.

Prior to signing any settlement, the settling parties should convene at least one conference with notice and opportunity to participate provided to all parties for the purpose of discussing settlements in the proceeding. Attendance at any settlement conference is limited to the parties and their representatives.

Pursuant to Rule 12.2 parties can file comments contesting all or part of the settlement within 30 days of the date settlement was served. Comments must specify the factual issues that the party opposes and if hearing is requested the contested facts that would



require a hearing. Parties can file reply comments within 15 days after the last day for filing comments.

The settlement will be approved if the Commission finds that the settlement is reasonable and in the public interest. Commission adoption of a settlement is binding on all parties to the proceeding in which the settlement is proposed.

Pursuant to Rule 12.3 the Commission can decline to set hearing if there are no contested issues of fact. If a hearing is set, it will be scheduled after the close of the comment period. Parties to the settlement must provide one or more witnesses to testify on the contested issues. Contesting parties may present evidence and testimony on the contested issues.

Pursuant to Rule 12.4 the Commission can reject a proposed settlement whenever it determines that the settlement is not in the public interest. The Commission can then hold hearings on the underlying issues, allow the parties time to renegotiate the settlement, or propose alternative terms to the parties to the settlement which are acceptable to the Commission.

#### ***10. Evidentiary Hearings Notice***

Evidentiary hearings are commonly held in Phase I of GRC. In contrast parties typically reach settlements in Phase II of GRC, in which case evidentiary hearings are not held.

If evidentiary hearings are set, pursuant to Rule 13.1, the Commission and the utility should give notice of the time, date, and place of evidentiary hearings. The Commission should give notice not less than ten days before the date of hearing. And the utility should give notice to entities that may be affected by the decision by posting in public places and publishing in a newspaper.

In GRC proceedings parties will generally file prepared testimony. When evidentiary hearings are held copies of prepared testimony including any exhibits should be served to all parties prior to hearing. Prepared testimony should constitute the entirety of the witness's direct testimony, and should include any exhibits to be offered in support of the testimony and, in the case of an expert witness, a statement of the witness's qualifications.

In order to become part of the proceeding's record, prepared testimony is offered into evidence in the evidentiary hearings. In addition to receipt of prepared testimony, in the evidentiary hearings cross-examination of witnesses sponsoring the written testimony takes place. In the absence of an evidentiary hearing, prepared testimony may be offered into evidence by written motion or by oral motion at a prehearing conference.



The assigned ALJ may require the production of further evidence upon any issue. Upon agreement of the parties, the presiding officer may authorize the receipt of specific documentary evidence as a part of the record within a fixed time after the hearing is adjourned.

Whether or not evidentiary hearings are set, the schedule will generally provide for the filing of briefs by the parties. The ALJ may fix the time for the filing of briefs. Concurrent briefs are preferable. The ALJ may outline specific issues to be briefed. Briefing of additional issues is optional. Factual statements in closing briefs must be supported by evidence in the record. Citations to the transcript must indicate the transcript page number(s) and identify the party and witness sponsoring the cited testimony. Reply Briefs may be filed 14 days after Opening Briefs.

In GRC proceedings in which hearings were held, a party has the right to make a final oral argument before the Commission, provided that the party makes such request in its closing brief or, if closing briefs are not permitted, in the manner specified in the scoping memo or later ruling in the proceeding. A quorum of the Commission shall be present.<sup>4</sup>

A proceeding is considered submitted for decision by the Commission after the taking of evidence, the filing of briefs, and the presentation of oral argument as may have been prescribed.

#### ***11. Issuance of Proposed Decision***

Pursuant to Rule 14.2 the ALJ should file a proposed decision. A proposed decision should be filed no later than 90 days after submission. In GRC proceedings that hearing is held, an alternate proposed decision by the assigned Commissioner or assigned ALJ should be filed concurrently with the proposed decision.

#### ***12. Comments on Proposed or Alternate Decision***

Pursuant to Rule 14.3 parties can file comments on a proposed or alternate decision within 20 days of the date of its service on the parties. Comments in general rate cases shall not exceed 25 pages and should include a subject index listing the recommended changes to the proposed or alternate decision, a table of authorities and an appendix setting forth proposed findings of fact and conclusions of law.

Comments should focus on factual, legal or technical errors in the proposed or alternate decision and in citing such errors should make specific references to the record or applicable law. Comments proposing specific changes to the proposed or alternate decision should include supporting findings of fact and conclusions of law.

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<sup>4</sup> A Commissioner may be present by teleconference to the extent permitted by the Bagley-Keene Open Meeting Act.



Replies to comments may be filed within five days after the last day for filing comments and should be limited to identifying misrepresentations of law, fact or condition of the record contained in the comments of other parties. Replies should not exceed five pages in length.

In addition to parties to the proceeding any person may comment on a draft or alternate draft resolution by serving comments on the Commission no later than ten days before the Commission meeting when the draft or alternate resolution is first scheduled for consideration.

### ***13. Appeal and Review of Presiding Officer's Decision***

Parties can file an appeal and Commissioners can file a request for review of the proposed decision within 30 days of the date the decision is served. Any Appeals and requests for review should set forth specifically the grounds on which the requestor believes the proposed decision to be unlawful or erroneous. References to the record or the law must be clear.

Any party may file its response no later than 15 days after the date the appeal or request for review was filed. The Commission is not obligated to withhold a decision on an appeal or request for review to allow time for responses to be filed.

### ***14. Decision in Rate-setting Proceeding***

Pursuant to Rule 15.1 and 15.4 the Commission must vote on proposed or alternate decisions in a rate-setting proceeding in Commission Business Meetings. Commission Business Meetings are held on a regularly scheduled basis to consider and vote on decisions. Commission Business Meetings are open to the public. But in a rate-setting proceeding, the Commission can hold a Rate-setting Deliberative Meeting to consider the proposed decision in closed session. Notice of the time and place of these meetings will appear in the Commission's Daily Calendar.

### ***15. Application for Rehearing***

Pursuant to Rule 16.1 application for rehearing of a Commission decision should be filed within 30 days after the date the Commission mails the decision. Filing of an application for rehearing does not excuse compliance with a decision.

Applications for rehearing shall set forth specifically the grounds on which the applicant considers the decision of the Commission to be unlawful or erroneous. The purpose of an application for rehearing is to notify the Commission of a legal error, so that the Commission can correct it promptly. The resolution of the application for rehearing is reached when the petition is either granted or denied



## VI. CURRENT RATE CASE PLAN

The Refined Straw Proposal, adopted in D.14-12-025, modified the original RCP for major investor owned utilities, PG&E, SDG&E, SoCalGas Company, and SCE, to incorporate a process that assesses the risks relevant to the utility operations, and ensures that utilities' requested revenue requirement is sufficient for managing and mitigating operating risks in a cost-effective manner.<sup>5</sup> More specifically the Refined Straw Proposal added the following three new processes to the original RCP:

1. The Commission should hold a periodic generic Safety Model Assessment Proceeding (S-MAP) either as part of GRC proceeding or as a separate proceeding. The purpose of SMAP should be to: (1) allow parties to understand the models the utilities propose to use to prioritize the programs/projects intended to mitigate risks and (2) allow the Commission to establish standards and requirements for those models.
2. At the initial phase of GRC the utility should presents the top risks for which the utility expects to seek recovery in the GRC, in the Risk Assessment and Mitigation Phase (RAMP). Initially the focus of RAMP will be on asset conditions but as the process matures the Commission can move beyond just asset conditions. RAMP should be based on the model that was vetted in the S-MAP and has to comply with CPUC requirements for the model as determined in the most recent S-MAP. There would be no Commission decision in this phase. However the utility's presentation and the staff and interested party responses would inform the utility's recommended projects and funding requests in the GRC.
3. Each utility has to submit two annual verification documents:
  - a. A Risk Mitigation Accountability Report, in which the utility compares its GRC projections of the benefits and costs of the risk mitigation programs adopted in the GRC with the actual benefits and costs, and explains any discrepancies; and
  - b. A Risk Spending Accountability Report, in which the utility compares its GRC projected spending for approved risk mitigation projects with the actual spending on those projects, and explains any discrepancies.

The Commission staff is expected to audit these reports and make the findings available to all interested parties.

Furthermore, D.14-12-025 eliminated the NOI process in the original RCP. The Refined Straw Proposal's timeline for the processing of a GRC replaced the timing of the NOI process with the timing for the RAMP process. In the two tables below, the schedule

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<sup>5</sup> For small energy utilities, Bear Valley Electric Service, Liberty Utilities, PacifiCorp doing business as Pacific Power, and Southwest Gas Corporation, D.14-12-025 envision transition to begin three years from the effective date of the decision.



that is to be followed in filing the RAMP (Table 1), and incorporating the RAMP into the GRC application filing (Table 2) are reflected. The adopted GRC schedule, as shown below in Table 2, modifies and replaces the RCP schedule that was adopted in Appendix A of D.07-07-004.

**Table 1(RAMP Application)**

| <b>Date</b>  | <b>Activity</b>   |
|--|---|
| September 1 of the year prior to the GRC filing date.    | Utility sends letter to Executive Director (with a copy to the Chief ALJ) requesting that an Order Instituting Investigation (OII) be initiated for the utility's upcoming GRC filing, and pursuant to this decision. |
| By November 15 of the year prior to the GRC filing date. | OII for the upcoming GRC initiated.   |
| By November 30 of the year prior to the GRC filing date. | Utility files RAMP submission in the OII.   |
| By December 15 of the year prior to the GRC filing date. | PHC held.   |
| By December 15 of the year prior to the GRC filing date. | Utility and SED hold public workshop on utility's RAMP submission.  |
| February 28, prior to the GRC filing date.               | SED files and serve staff report on utility's RAMP submission.  |
| By March 15, prior to the GRC filing date.               | Staff hosts public workshop on SED staff report.  |
| April 10, prior to the GRC filing date.                  | Other parties serve comments on utility's RAMP submission, and on SED's staff report.   |
| April/May  | If needed, additional workshops on RAMP-related items.  |
| May to August, prior to the GRC filing date.             | Utility incorporates RAMP results into its GRC filing.  |





**Table 2 (GRC Application Filing)**

|  |   |
|--|---|
| September 1  | Utility files GRC application, and serves prepared testimony including changes resulting from the RAMP process. |
| Per Rule 2.6(a).   | Protests and responses filed to GRC application.  |
| By October 15  | Utility holds public workshop on overall GRC application.   |
| By October 31  | PHC held.   |
| By February 20   | ORA serves opening testimony.   |
| By March 17  | Intervenors serve opening testimony.  |
| May 1  | Concurrent rebuttal testimony served.   |
| March/April  | Public Participation Hearings.  |
| May/June (Three or four weeks of evidentiary hearings.)            | Evidentiary hearings held, if needed.   |
| To be decided.   | Opening briefs filed.   |
| To be decided.   | Reply briefs filed.   |
| May/June   | Update testimony and hearings, if necessary.  |
| September/October  | Proposed decision.  |
| November   | Final decision.   |
| In accordance with Verification schedule discussed in D.14-12-025. | Utility files annual Risk Mitigation Accountability Report and Risk Spending Accountability Report.             |

In D.14-12-025 the Commission recognized that there are oftentimes other circumstances or events that interfere with the timely proceeding of GRCs. Therefore D.14-12-025 allowed the assigned Commissioner and ALJ the discretion to alter the schedule as may be needed. Furthermore, the actual requirements for RAMP and GRC filings related to risk assessment and mitigations continue to evolve and are subject to further refinement in the S-MAP proceeding and via determination made in each RAMP/GRC.

**VII. CONCLUSION**

In this chapter the authority granted to the Commission by the Public Utilities Codes for establishing just and reasonable rates and the principles that emerge from the Public Utilities Codes and guide the Commission in establishing rates were discussed. We also discussed the Commission's Rules of Practice and Procedure that set the rules and procedures for GRC review process.



## DEVELOPING REVENUE REQUIREMENT – Chapter 2

### I. INTRODUCTION

Utility regulation aims to provide safe and reliable electricity service at a fair price. Cost of service regulation tries to accomplish these goals by setting the standard that service should be provided at the original cost of assets placed in service or operating expenses.

Cost of service regulation sometimes is referred to as rate of return regulation because in cost of service ratemaking utilities have an opportunity to earn authorized rate of return on prudently incurred capital investments. However utilities are not guaranteed to earn their authorized return. Rates are set prospectively and an element of the authorized revenues is planned to repay investors for the use of their money. However, if the utility fails to manage its business efficiently and overspends, then it will likely fail to earn its authorized rate of return. This uncertainty is symmetrical, and if the utility spends less than authorized revenues it will earn greater than its authorized return.

An alternative to cost of service regulation, performance based regulation, has been implemented in many natural monopoly industries. Performance based regulation are designed to control costs by establishing a benchmarked price or revenue cap.<sup>6</sup>

Cost of service regulation is currently used in California. In cost of service regulation rates are set based on the total amount a utility requires to pay all operating expenses and capital costs or revenue requirement. Revenue requirement determination is the first step in cost of service study. Subsequent steps in cost of service study (functionalization of costs, classification of costs, and allocation of costs to customer classes) are intended to allocate the total revenue requirement to various customer classes in a fashion that reflects the cost of providing utility services to each class. After revenue requirement is allocated to customer classes, to develop rates for each customer class, rate design analysis is conducted.

In this chapter revenue requirement determination is discussed.

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<sup>6</sup> If utilities are able to accomplish cost savings, they would earn a higher return. Alternatively, if they exceed their revenue-cap, they will incur losses.



## II. REVENUE REQUIREMENT DETERMINATION

Revenue Requirement is defined as reasonable and prudent amount of revenue that enables the utility to provide safe and reliable service to its customers. The establishment of the revenue requirement is an important first step in the cost of service process. Revenue requirement is the basis for rate design.

Utility's cost of providing service includes operating expenses such as Operation and Maintenance (O&M) expenses, taxes, and depreciation. In addition to reasonable operating expenses, revenue requirement includes a reasonable return on investment.

Utilities borrow capital to finance investment in physical plant and assets (rate base) needed to fulfill public utility service obligation. The return on rate base provides for payment of interest on debt and a return on the equity provided by the investors. Determining revenue requirements usually necessitates establishing a rate base, defined to be the value of the assets on which the utility is entitled to earn a return, and the setting of a fair return rate on the rate base.

Furthermore utilities normally receive revenues from sources other than retail sales of electricity. To find the total amount that has to be collected from ratepayers other operating revenues must be deducted from revenue requirement. Revenue requirement can be written as:

$$\text{Revenue Requirements} = \text{O\&M} + \text{Taxes} + \text{Depreciation} + \text{Rate Base} * r - \text{OR}$$

Where:

O&M = normal business expenses for running a utility company,  
Taxes = Federal, state and local taxes,  
Depreciation = accumulated depreciation of plants used to produce and deliver the utility's product,  
Rate Base = net value of plant in service plus working capital,  
r = rate of return on invested capital, and  
OR = other operating revenue.

An important starting point for establishing revenue requirements is determining the test year or test period that are used as a means for evaluating a utility's cost of service. In what follows first the concept of test year is explained. Subsequently various components of revenue requirement are discussed.

There is generally three types of test-year periods; historical, forecasted, and pro forma.

A historical test-year period is based on the preceding 12-month period for which actual costs and data are available. A forecasted test period is future time period in which all of the costs and data are projected. Finally, a pro forma is a combination of the historical and forecasted test year. A pro forma test period begins with historical data and costs



and then adjusts for costs or changes that are “known and measurable”. The standards for known and measurable adjustments are set by the regulatory authority reviewing the study. In many cases, the utility must provide proof that the adjustment reflects a changed operating condition. Examples of known and measurable changes include a labor contract that specifies a certain percent adjustment to labor rates, or paid invoices for services rendered on new capital projects.

The disadvantage of the historical test year is that the utility’s costs and data may lag behind current costs but the advantage is the use of actual costs and data. The disadvantage of a forecasted test period is that it may be difficult to forecast costs, and it lacks the certainty of a historical test year but the advantage is that costs for the test year will likely agree with the utility’s budget or anticipated costs. The disadvantage of the pro forma test year is that it may not entirely capture changes in costs, but the advantage is that it has adjusted for only those costs that needed adjustment in the test year.

In California to develop rates that properly recover costs into the future a forecasted test period is used. Setting revenue requirement based on expected future inflation and anticipated higher utility costs allows utilities to recover those expected future costs. The use of a forecasted test period allows the revenue requirement to represent a forward-looking perspective.

Different components of revenue requirement are discussed in the following sections.

**1. Operation and Maintenance Expenses**

O&M expenses comprise a major part of revenue requirements. O&M expenses are incurred in the normal business of running a utility company. Since O&M expenses are incurred as part of providing utility services they are generally attributable to a specific function in the operation of producing or delivering electricity to customers

To record O&M expenses typically a system of accounts is used. A system of accounts enables the utility to record each transaction into the appropriate account within the system of accounts. In addition a system of accounts facilitates monitoring of each O&M expense item. To keep their records, utilities in California use the Uniform System of Accounts as recommended by the Federal Energy Regulatory Commission<sup>7</sup> and adopted by the California Public Utilities Commission.

Major categories of accounts and costs are as follows:

|            |                               |
|------------|-------------------------------|
| 100 Series | Assets and other debits       |
| 200 Series | Liabilities and other credits |
| 300 Series | Electric plant accounts       |

<sup>7</sup> Code of Federal Regulations Title 18, Subchapter C, Part 101.



|            |  |
|------------|--|
| 400 Series | Income, and revenue accounts   |
| 500 Series | Electric O&M expenses  |
| 900 Series | Customer accounts, customer service and informational sales, and general and administrative expenses |

Another consideration is that some expenditure that might normally be considered O&M expenses must be capitalized. For example salaries and wages of employees who devote time to a project that is a capital investment should be capitalized as a part of the cost of the project. When capitalized, such expenditures are accounted for in the same manner as other capitalized costs associated with the project and are not included as O&M expenses. Rather, these capitalized expenses are recovered over the operating life of the capital asset.

The list of operations and maintenance expenses include; purchased power and fuel expenses, other electric production O&M expense, electric transmission O&M expense, electric distribution O&M expense, customer accounts, services, and marketing expense, and administrative and general (A&G) expense.

In California purchased power and fuel costs are authorized annually through Energy Resource Recovery Account (ERRA) proceedings and not through GRCs. Although utilities have pre-approved authority to enter into long-term power purchase agreements, in ERRA proceedings they are required to justify contract administration, and compliance with upfront standards. In addition in California to forecast future O&M expenses, factors that will impact future expenses such as the number of customers served, demand, inflation, and operating conditions or maintenance are analyzed.

**2. Depreciation**

Depreciation is the loss in value of facilities, not restored by current maintenance, which occurs because of wear and tear, decay, inadequacy, and obsolescence. The annual depreciation expense allows the utility to recover its original capital investment over the useful life of the depreciable assets. Depreciation expense is borne by the customers who benefit from the use of an asset during the useful life of the asset.

Depreciation expense is typically recovered on an equal annual basis over the average service life of the asset (straight-line basis). The annual depreciation cost is thus calculated as the original cost of the asset, less the estimated net-salvage value, over the estimated average service life of that asset. The straight-line approach assesses depreciation cost equally each year to customers who benefit from the use of the asset during its entire life.

Currently in California many of the assets in service will cost more to retire than expected when they first were placed into service. For electric and gas utilities, the cost



of retirement of assets leads to the need to collect more depreciation expense from utility ratepayers than the cost to build and install the capital asset. This circumstance leads to a “negative net-salvage” condition, and an increase in depreciation expense. In recent California GRCs this issue has been heavily litigated.

The annual depreciation cost can be written as:

$$\text{Annual cost (\$)} = (\text{Total asset value} - \text{Net salvage value}) / \text{Estimated service life}$$

Under cost-of-service ratemaking, book depreciation is a cash item. Because depreciation expense is a noncash expense, the inclusion of book depreciation in calculating revenue requirements provides the utility with cash outlay necessary for the construction or installation of a long-lived asset. Depreciation expense is the lowest-cost source of funds because the utility does not have to re-enter the capital markets to finance new investments.

In addition utilities can take a tax deduction (tax depreciation) for book depreciation expense when the revenue is received. In other words, utilities can list tax depreciation as an expense on their tax return to reduce the amount of their taxable income. Book depreciation expense is taxable income without an offsetting deduction which stems from the tax depreciation.

### *3. Taxes*

Investor-owned utilities are responsible for paying taxes to local, state, and federal authorities. Therefore, federal, state, or local income taxes are properly included in total revenue requirements.

Examples of local taxes include property taxes, which are based on the assessed value of utility property (i.e. rate base). Different states use various methods of assessing taxes, such as gross receipts taxes, franchise taxes, capital stock taxes, and income taxes. In California utilities pay franchise taxes that are based on the corporation’s allowable California taxable income. Finally federal taxable income is estimated by subtracting O&M expenses, tax depreciation expense (typically calculated at a higher rate than regulatory depreciation expense, over a shorter depreciable life), interest expense, different administrative expenses, and state and local taxes from revenues.

### *4. Other Operating Revenue*

Other operating revenues include the amounts collected by a utility for services other than retail sales of electricity. An example of these revenue sources is when a utility allows space on its distribution poles for the use of cable television lines and receives payments for the service. These revenues must be deducted from the amount that has to be collected from ratepayers since the services are produced through the use of plant or utility personnel, the costs of which are borne by the utility’s retail service customers.



## 5. Rate Base

To determine the return on the capital provided by investors for the facilities, regulators generally multiply a utility's net plant investment (rate base) by an adopted rate of return. This multiplication results in a portion of the revenue requirement being designated as available to pay investors for the use of their funds. The earnings that the utility will be allowed to recover from customers are designed to provide a fair return on the capital for the rate base. The authorized return on capital is added to utilities' other expenses (O&M, depreciation, taxes, etc.) to determine overall revenue requirement. Rate base and its calculation are thus key components in the ratemaking process.

Rate base is defined as the remaining value of the assets on which investors are entitled to earn a return. Individual regulatory agencies have specific requirements concerning the items allowed in rate base. In general, rate base consists primarily of gross plant in service less accumulated depreciation (depreciated rate base), and working capital.

The Plant-In-Service accounts record the original cost of all utility investment still providing service. The accumulated book depreciation is subtracted from the plant in service balance, leaving rate base or remaining book value of the assets (i.e. the portion that still must be financed). To this balance is added working cash, which provides cash flow to finance lags between providing service and receiving payment. Rate Base is further reduced by the accumulated deferred taxes.

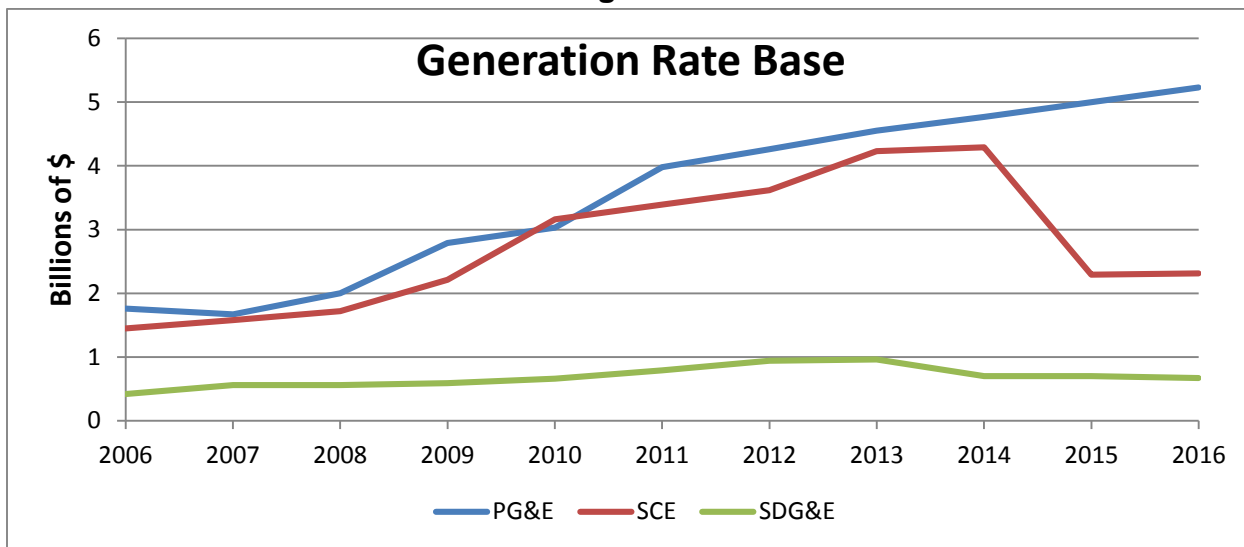
When the utility becomes entitled to a higher tax depreciation in a given year than the book depreciation collected, this creates a deferred tax. The phenomenon is often characterized as an "interest-free loan" from the federal government. Because the utility has the use of the book depreciation revenues without having to pay taxes in a given year, there is no need to finance that portion of rate base. Therefore deferred taxes are subtracted from the rate base. This phenomenon is strictly a timing issue, as the utility and its ratepayers will pay the same amount of taxes over the assets lives, the deferred tax will "unwind" over time, forcing the revenue requirement "gross-up" for taxes to increase in the latter years of an asset's operating life.

Examples of deferred tax deductions include accumulated deferred tax liabilities resulted from Accelerated Cost Recovery System and Modified Accelerated Cost Recovery System tax depreciation, deferred tax assets resulting from net operating losses, and deferred Investment Tax Credits. To estimate funds supplied by investors other items such as refundable contributions, and advances for constructions are also subtracted from the rate base.



Figure 1 show PG&E, SCE and SDG&E’s generation rate base over time. As the Figure illustrate PG&E’s generation rate base has been increasing overtime. But SCE and SDG&E’s generation rate base has declined overtime. The decline for SCE is especially significant. Utilities in California have transitioned from owning and operating most of their electric generation needs to purchasing generation from other parties under purchase power agreements. As reflected by Figure 1 for SCE and SDG&E the substantial increase in the number of procurement transactions has dampened the investment in generation.

Figure 1



The decline in the generation rate base for SCE and SDG&E has been more than offset by the growth in distribution rate base. Figure 2 shows PG&E, SCE and SDG&E’s generation and distribution rate base overtime. As Figure 2 illustrates when electric distribution rate base is added to generation rate base the trend is upward slopping for all three major IOUs in California.





Figure 2

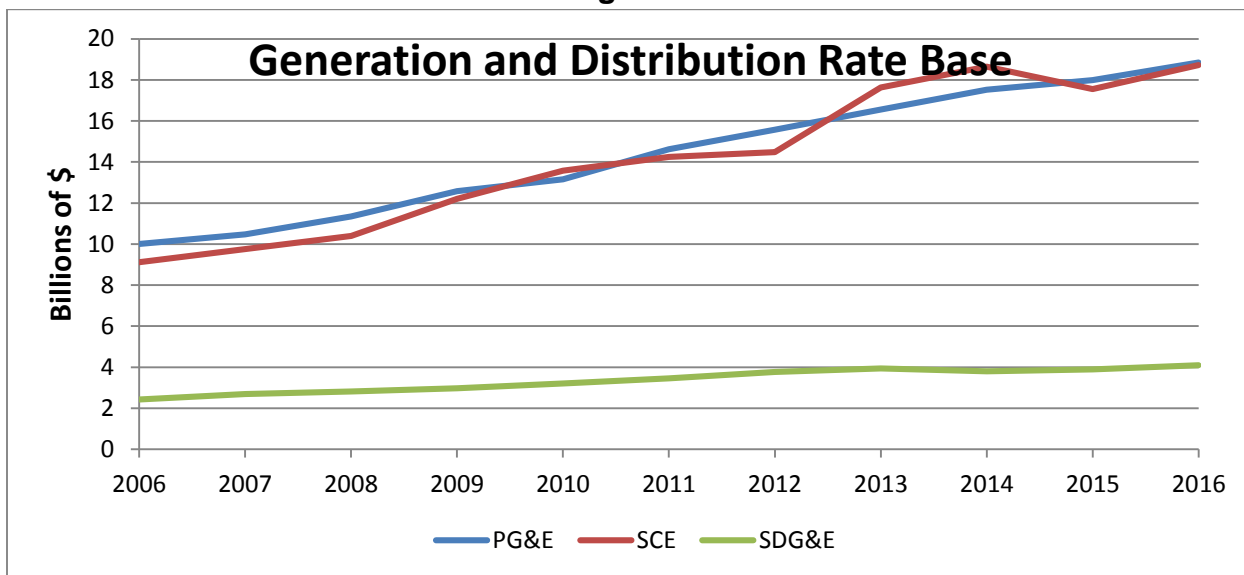
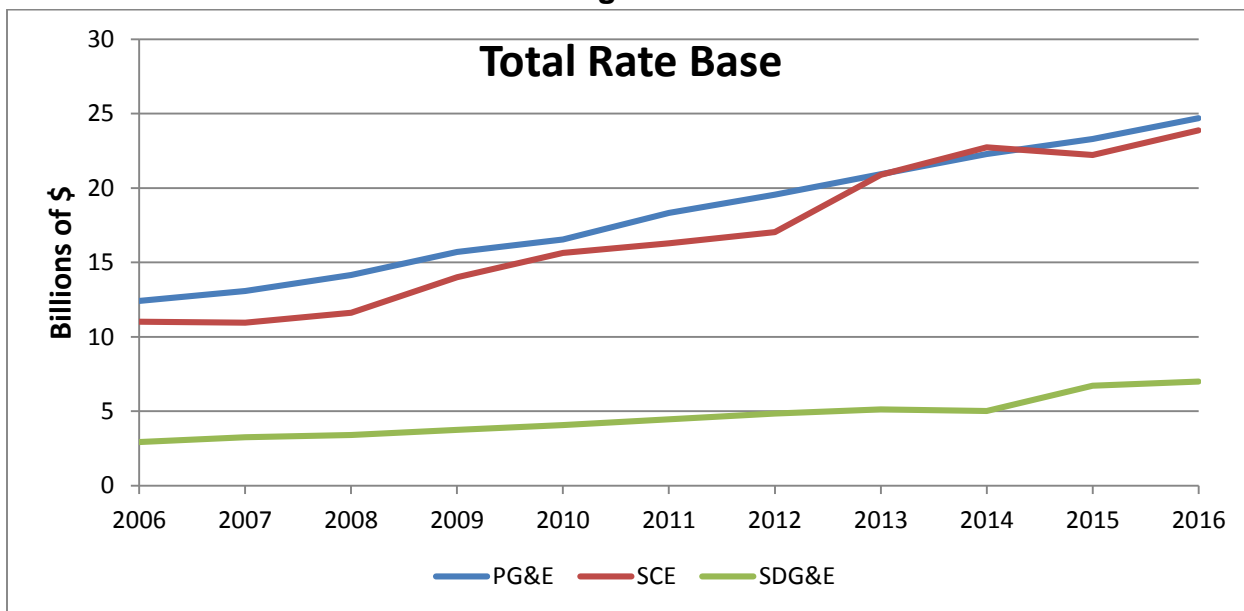


Figure 3 shows the total electric rate base, which includes transmission rate base. As the Figure illustrates the total electric rate base has a steeper upward slope for all the major IOUs in California.

Figure 3



Next we will discuss how rate base is estimated.



*a. Gross Plant in Service*

Gross plant in service is the starting point in estimating rate base. Rate base is estimated by deducting accumulated depreciation, and accumulated deferred taxes, and adding working cash to gross plant in service. Gross Plant is the total capital assets currently dedicated to utility service. Examples of gross plant in service include lands, buildings, equipment, structures, and other physical facilities used to serve customers. It also includes land and land rights acquired for future construction of utility facilities.

Gross plant in service is typically recorded using the original cost of the investment, which is the cost of a facility to the owner first putting it into public service. The original cost of the investment may be different from the current cost of replacing the asset. The Commission in California uses the original cost for valuation of the facilities and other items included in rate base. The primary issue related to plant in service is the used and useful standard.

The principle of used and useful is commonly applied to utility property. According to this principle a utility must demonstrate that the new plant is used and useful before being allowed to include the investment in its rate base. The used and useful standard has a twofold meaning. At the preliminary level it implies that the facility is built and provides service to customers. In addition the principal requires an examination of the utility's prudence in deciding to construct or purchase the utility plant.

In other words according to the used and useful standard to be included in the rate base the new asset must be required and operate in an effective and efficient manner. When the utility is found to be imprudent, assets are excluded from rate base, and the cost recovery for the remaining book value of the asset is denied. In those circumstances costs are borne by shareholders rather than ratepayers.

On the other hand, when assets are retired prematurely, for reasons other than imprudence, assets would be excluded from the rate base, which means the utility would not be permitted to earn a rate on return on assets, but the remaining book value of the asset will be amortized in customer rates. For example, in D.11-05-018 the Commission in California permitted rate recovery for PG&E's prematurely retired electro-mechanical meters and in D. 92-08-036 the Commission permitted cost recovery of the remaining investment in SONGS 1 after its early retirement.

*b. Accumulated Depreciation*

Accumulated depreciation represents the sum of all depreciation charges that a utility has expensed for a given asset included in gross plant in service. To find the net book value of a plant accumulated depreciation must be deducted from the original cost of the plant. The amount of accumulated depreciation depends on the methods used to calculate annual depreciation (e.g. straight line vs. accelerated basis).



### *c. Working Capital*

The primary components of working capital are materials and supplies inventories and working cash. The inventory of materials and supplies are needed to support the maintenance and construction activities of utilities. Firms require working cash because normally there is a time lag between payment of expenses and collection of revenues. Including working capital in the rate base allows investors to earn a return for supplying the funds needed for investment in inventory of parts and supplies and day-to-day cash needs.

The average amount of funds supplied by investors depends on materials and supplies inventories, and the average days between the payment of expenses and collection of revenue. To find the length of time funds are tied up in working capital lead/lag studies are conducted. In California utilities are recommended to follow the Commission Standard Practice U-16 for determining their working cash requirement.<sup>8</sup>

In some regulatory jurisdictions funds used to finance the construction of new facilities, construction work in progress, CWIP, can be included in rate base during construction. A regulated utility can then recover its costs plus a reasonable return on investment during construction of new plants, before the facilities are included in rate base. The justification for including CWIP in the rate base is that it cushion against huge one-time increase in rates or rate shock when unusually large new facilities such as a major new power plant are put in to service. Including CWIP in rate base increases rates during the construction period, but rates after the project is completed are lower than when CWIP is not included in rate base.

California and number of other jurisdictions do not allow CWIP to be included in rate base and thus are not included in the estimation of a utility's allowed return. However, even in justifications where allowances for CWIP is permitted, since the plant is not yet used and useful, to include CWIP in the rate base regulators often require that work be completed within a specified time period, evidence that funds were borrowed to finance the construction, and improved quality of service. Never-the-less some states prevent or severely restrict the inclusion of CWIP in rate base because of the equity question raised by the inclusion of CWIP in rate base which is whether current ratepayers should provide a return on plant that does not provide service to them.

An alternative to including CWIP in rate base is capitalization of project financing costs, until the project is completed and entered onto the books. The Allowance for Funds Used During Construction (AFUDC) allows utilities to accumulate or accrue on their books their financing costs for future recovery. These funds could not be included in rate base until the facilities are deemed used and useful. Consequently the utility could

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<sup>8</sup> The Commission's position regarding Standard Practice U-16 is articulated in D.95-12-055.



not earn a return on its investment until the facilities are included in rate base. Utilities in California are allowed to accumulate financing cost through AFUDC for future recovery. utilities recognize AFUDC when they report earnings to investors and the Security and Exchange Commission (SEC). However, since there are no concurrent revenues, for lengthy construction projects, AFUDC can become a substantial amount and may cause cash-flow problems for the utility.

*d. Return on Rate Base*

The return component of revenue requirement is intended to provide a return on capital employed to finance facilities used to provide service. Investors expect to earn a return on their capital. The Commission sets the authorized rate of return on capital (debt, preferred and common stocks) and the authorized capital structure (i.e. debt to equity ratio), which together determine rate of return on rate base. The return on rate base as well as utilities' other expenses (O&M, depreciation, taxes, etc.) makes-up the authorized revenue requirement.

For major investor-owned utilities, P&G, SCE, SDG&E, and SoCalGas, the Commission sets the authorized rate of return on capital in a separate proceeding called Cost of Capital proceeding. Major investor-owned utilities operating in California are required to file a Cost of Capital application with the Commission every 36 months (3 years).

In what follows first the legal standards for setting a rate of return as established by the United States Supreme Court in the Bluefield and Hope decisions<sup>9</sup>are explained. That is followed by a brief discussion of how authorized rate of return is set at the Commission.

*e. Legal Standard for setting Return*

The Bluefield decision states that a public utility should be provided an opportunity to earn a return necessary for it to provide utility service. The Court stated:

“The return should be reasonably sufficient to assure confidence in the financial soundness of the utility, and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise money necessary for the proper discharge of its public duties.”

The Hope decision reinforces the Bluefield decision and it emphasizes that such returns should be commensurate with returns available on alternate investments of comparable risks. The idea is based on the basic principal in finance that rational investors will only invest in a particular investment opportunity if the expected return on that opportunity is equal to the return investors expect to receive on alternative investments of comparable risk. The Hope decision states:

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<sup>9</sup> Bluefield Water Works & Improvement Co. vs Public Service Commission of West Virginia (1923) 262 U.S. 679. Federal Power Commission vs. Hope Natural Gas Co. (1944) 320 U.S. 591.



“The return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks.”

Two standards emerge from these decisions. First, return should be adequate to enable a utility to attract investors to finance the replacement and expansion of a utility’s facilities to fulfill its public utility service obligation. Second, to attract capital a utility should be able to offer returns to investors comparable to those achieved on alternative investments of comparable risk. Utilities use long-term capital such as bonds, preferred stocks, and common equity to finance investment in physical plant and assets (rate base) needed to provide utility service. The return component of revenue requirement is intended to pay the interest on debt, the dividend on preferred stock and provide a fair rate of return on equity stock.

*f. Weighted Average Cost of Capital*

To estimate the overall rate of return (ROR) or cost of capital the weighted average cost of debt, preferred equity, and common equity, where the weights are the market-value percentages of debt, preferred equity, and common equity in a firm's capital structure is calculated. ROR or cost of capital, which is called the firm's weighted average cost of capital (WACC), is specified by the following formula:

$$WACC = w_d k_d + w_p k_p + w_c k_c$$

Where,

$w_d$  = % of debt in capital structure,

$w_c$  = % of equity in capital structure,

$w_p$  = % of preferred stock in capital structure,

$k_d$  = cost of debt,

$k_s$  = cost of equity, and

$k_p$  = cost of preferred stock.

To apply the formula, one must estimate the cost of debt, preferred stock and common equity using methodologies accepted by both financial economists and regulators. In addition, one must determine the appropriate capital structure mix of debt, preferred stock, and common equity. With these inputs, the Commission sets ROR using the above equation. To determine the weighting of debt, preferred and equity capital sometimes the actual capital structure of the utility is used. However, the capital structure can change over time. For that reason sometimes regulatory agencies set a hypothetical capital structure based on an examination of similar companies or industries. In addition if the utility is a subsidiary of another company, the parent company’s capital structure may be used for the weighting of the costs of capital. In California a hypothetical capital structure, which is expected to approximate the actual capital structure of the utility over the long run is used.



Total rate of return is also affected by the return on different types of capital. Returns to debt and preferred Stock are more predictable than the return to common stocks. Return to bondholders, interest payment, is set by contract, therefore it is generally easy to predict. Preferred stock dividends are also set by contract, which make preferred stock similar to bonds. Measurement of return to common equity is involved since return to common equity is not contractual. Dividends to common stockholders depend on the firm's earnings- and thus are not known with certainty. Instead, the authorized return on equity must be estimated.

The estimation of return on equity is based on the principal that rational investors will only invest in a particular investment opportunity if the expected return on that opportunity is equal to the return investors expect to receive on alternative investments of comparable risk. In other words, for rational investors the expected return on alternative investments of commensurate risk sets the minimum return they would be willing to accept. Accordingly in cost of capital proceedings to estimate authorized return on equity (ROE) the expected return in capital markets on alternative investments of comparable risk are measured using accepted models.

To estimate cost of common equity, to reduce errors that may result from the application of any one model, several financial models accepted by both financial economists and regulators are employed. The three financial models the Commission uses to measure return on common equity are the Capital Asset Pricing Model (CAPM), Discounted Cash Flow (DCF) and Risk Premium (RP) Model. The Commission also considers additional risk factors not specifically included in the financial models such as financial, business and regulatory risk.

Business, financial, and regulatory risks are considered by rating agencies in setting utility bond ratings. Business risk refers to fluctuation in cash flows resulting from operations or regulatory decisions. Financial risk is determined by the amount of debt or financial leverage in a company's capital structure. The two main types of regulatory risks are regulatory lag risk (delay beyond the statutory period) and cost recovery risk (the ability of consistently recovering costs).

### **III. CONCLUSION**

In this chapter revenue requirement determination was discussed. Revenue requirement determination is the first step in cost of service study. Subsequent steps in cost of service study allocate total revenue requirement to various customer classes. After cost of service study is performed, to develop rates for each customer class, rate design analysis is conducted.