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A.92-05-010
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DECISION NO. 92-11-047 CASE NO. APP. NO. 92-05-016

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Decision 92-11-047 November 23, 1992

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

In the Matter of the Application of PACIFIC GAS AND ELECTRIC COMPANY for authority to: (i) increase its authorized rate of return on common equity, (ii) adjust its authorized capital structure, (iii) adjust its cost factors for embedded debt and preferred stock, and (iv) increase its overall rate of return for calendar year 1993. (Electric and Gas)(U 39 M)	Application 92-05-009 (Filed May 8, 1992)
And Related Matters.	Application 92-05-010 (Filed May 8, 1992) Application 92-05-012 (Filed May 11, 1992) Application 92-05-013 (Filed May 8, 1992) Application 92-05-014 (Filed May 8, 1992) Application 92-05-016 (Filed May 8, 1992)

(See Appendix A for appearances.)

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OPINION

I. Summary of Decision

Today's order establishes the 1993 ratemaking cost of capital for Southern California Gas Company (SoCalGas), Pacific Gas and Electric Company (PG&E), Southern California Edison Company (Edison), San Diego Gas & Electric Company (SDG&E), Southwest Gas Corporation (Southwest), and Sierra Pacific Power Company (SPPC). The rates of return on rate base authorized by this decision will be reflected in 1993 attrition filings of Edison, SDG&E, and Southwest, and will be incorporated in the 1993 test year rates for SDG&E, PG&E, and SPPC, whose general rate cases are pending.

We conclude that for 1993, the energy utilities should be authorized returns on common equity (ROE) and overall returns on rate base as follows:

Utility	Common Equity	Rate Base
SoCalGas	11.90%	9.99%
PG&E	11.90	10.13
Edison	11.80	9.94
SDG&E	11.85	9.94
Southwest	11.95	10.11
SPPC	11.95	9.82

We also deny the applicants' proposed equity ratio increases which were based upon the treatment by the credit rating agencies of Power Purchase Agreements (PPAs) as debt equivalents.

II. Procedural Matters

A. Procedural Background

By Decision (D.) 89-01-040 dated January 27, 1989, we modified the Rate Case Plan for energy and telecommunication utilities. As part of the modifications, we removed consideration of cost of capital issues from general rate cases involving seven designated gas and electric utilities (SoCalGas, PG&E, Edison, SDG&E, Southwest, SPPC, and Pacific Power & Light Company) and established a separate, generic, annual cost of capital (ACC) proceeding.

Each of these utilities is required to file an application for rate adjustments which reflect its projected cost of capital for the following year. The plan provides that the new rates will be implemented on January 1 in conjunction with the utility's pending general rate case or its attrition rate adjustment filing as applicable. This is the fourth ACC proceeding under the modified Rate Case Plan in which the cost of capital of each of the utilities is reviewed.

In accordance with the modified Rate Case Plan, PG&E, SPPC, Southwest, Edison, SoCalGas and SDG&E filed Applications (A.) 92-05-009, A.92-05-010, A.92-05-012, A.92-05-013, A.92-05-014, and A.92-05-016, respectively. By a letter request to the Executive Director, Pacific Power & Light Company (Pacific) requested an exemption from participation in the 1992 ACC proceeding. That request was granted by the Executive Director's letter dated May 8, 1992. The remaining applications were consolidated for hearings which were held before Administrative Law Judge (ALJ) Watson during August and September 1992.

The ALJ required a representative of Pacific to attend the prehearing conference (PHC) to explain how Pacific expects to deal with this year's operational attrition and whether it intends to seek an exemption again next year. At the PHC, counsel for Pacific stated that Pacific will not seek a price increase based on any attrition, whether it be financial or operational, for 1993. Pacific expects to make no filings for operational attrition, but will make a filing stating it will seek no increase. The Division of Ratepayer Advocates (DRA) stated at the PHC that DRA did not object to this procedure. Pacific's decision not to make an attrition filing this year was based on both the limitations on making a filing for 1993 in the Electric Revenue Adjustment

Mechanism (ERAM) settlement in D.90-12-022 and Pacific's commitment to rate stability due to the economics of the area which it serves and its concerns about trying to remain competitive. Pacific also stated on the record that it would be willing to accept an ROE below 9.25%, if such is set by the Commission for small utilities for 1993.

We confirm the ALJ's conclusion in her July 16, 1992 PHC ruling that:

> "Pacific's approach to the annual operational attrition filing is acceptable for this year only. Pacific is expected to participate in future cost of capital proceedings absent the Commission's grant of a petition of modify Appendix C of D.89-01-040 to remove Pacific from the list of utilities required to participate in this annual proceeding."

We also share the ALJ's concern over proper notice of this proceeding under Rules 24 and 52 of the Commission's Rules of Practice and Procedure. Various problems with Rules 24 and 52 compliance have arisen in the past and occurred again this year. Therefore, in all future cost of capital proceedings, the following procedures should be followed.[1]

In order to fulfill the requirement of prompt notification of the Commission of the mailing of the notices required by Paragraph 1 of Rule 24, all notices of compliance with Paragraph 1 shall be made pursuant to filings in the respective company's docket. Notice shall not be effected by letter either to the Executive Director or the assigned ALJ. Also, in order to fulfill the Rule's requirement that the Commission be notified

1 We do not detail the lengthy provisions of Rules 24 and 52, but expect applicants to fully comply with their requirements in future ACC proceedings, consistent with the directives in this decision.

promptly, such filings must be made no later than the date of the PHC in the ACC proceeding.

We also wish to clarify the Rule 24, Paragraph 1 requirement for stating in the notice, "in general terms", the proposed increases in rates. In the ACC proceeding, not only shall the Paragraph 1 of Rule 24 notice include a statement as to the dollar and percentage increase in rates, but it shall also state the percentage return on common equity and the percentage overall return on rate base being requested in the utility's cost of capital filing.

Instead of a general description of the rate increase, an applicant may properly comply with Paragraph 1 of Rule 24 in the ACC proceeding by serving, at the time the application is filed, a full copy of the application upon the entities required to be noticed by Paragraph 1 of Rule 24. In such case, the notice of compliance shall be included in the application.

The parties shall have until the first day of the hearing, each year, to file with the Commission proof of publication as is required by Paragraph 2 of Rule 24. By that date, they shall also file proof of mailing of bill inserts as required by Paragraph 3 of Rule 24 and Rule 52 notice of hearing by posting and publication within the time parameters of that Rule.

We also confirm the ALJ's grant of Edison's motion for waiver of Rules 23(b) and (c) in order to defer its statement of amount and percentage of rate increase sought to A.92-05-047.

On August 11, 1992, the ALJ issued a ruling (August ALJ Ruling) declaring:

> "Prime issues in this proceeding are whether the level and type of purchased power agreements (PPAs) impact the level of financial risk to the utilities, and if so, whether the ratemaking capital structure and return on common equity should be adjusted to reflect the risk. No party has presented in its testimony on these issues a percipient witness from a bond rating agency.

"The applicants bear the burden of proof on these issues."

We concur with her assessment of the burden of proof in this proceeding.

Testimony and evidence were presented on behalf of the six applicants as well as jointly by Toward Utility Rate Normalization (TURN) and Utility Consumers' Action Network (UCAN) (hereinafter referred to as UCAN), the City of Los Angeles (Los Angeles), the Department of the Navy representing all Federal Executive Agencies (FEA), and DRA. While he did not present testimony or evidence, Mr. Robert Doelle, representing Pacific Water and Power, Inc. (PWP) participated in the hearings by briefing. The matters were submitted with the filing of concurrent opening briefs on September 8, 1992. The Data Resources, Inc. (DRI) October 1992 control forecast update was submitted by DRA as a joint late-filed exhibit, as required by the PHC ruling, on October 6, 1992. We hereby adopt it as late-filed Exhibit DRA-9.

B. Pending Motions

On September 17, 1992, PG&E filed a motion to strike Appendix B of UCAN's opening brief. Edison also filed a motion to strike UCAN's Appendix B and the addendum brief attachments to PWP's September 10, 1992 addendum brief. Edison also requested both PWP and UCAN be sanctioned "to send a clear signal to parties that the Commission disapproves of these tactics and that in the future, they will not be countenanced." (Motion at 2-3.) No responses to either motion were received. The materials sought to be stricken are various newspaper articles, published after the close of hearings. We grant the motions to strike, but deny Edison's request for sanctions.

PWP attempted to file its opening brief late on September 9, 1992. On September 11, 1992, PWP filed a motion to accept late-filed opening brief and addendum. The motion is granted.

C. <u>Edison's Petition to Set Aside Submission</u>

On November 12, 1992 Edison filed a Rule 84 petition to set aside submission and accept late-filed exhibits. In its comments, filed the same day, Edison argued as evidence in this proceeding, the late-filed exhibits attached to the petition. Edison requests we accept as evidence a Duff & Phelps press release dated October 27, 1992 and an S&P Creditweek report dated November 2, 1992. Edison contends these publication qualify under Evidence Code § 452(h) as "Facts and propositions that are not reasonably subject to dispute and are capable of immediate and accurate determination by resort to sources of reasonably indisputable accuracy." Edison also requests we take official notice of Section 712 of the National Energy Strategy Act, signed into law on October 24, 1992, based on an October 5 Conference Report on H.R. 776, The Energy Policy Act of 1992.[2]

Rule 84 requires a party to explain why such evidence was not previously adduced. Due to the date these documents were available, we believe Edison has delayed unduly in bringing them to our attention. We observe that pursuant to Rule 42(b), other parties have 15 days from the date of service of the petition to respond. Due to the Thanksgiving holiday, responses are not due until November 30, 1992. Since this decision is set for the November 23, 1992 agenda, Edison's tardy petition unduly prejudices

2 Although we dismiss Edison's petition for procedural reasons, we observe that we do not interpret § 712 to mandate our consideration of the impacts of PPAs on our utilities' costs of capital in this proceeding or next year's. First, the legislation states proceedings pending at the time of its enactment cannot be used to meet its requirements. Second, the legislation merely requires "a general evaluation of...the potential for increases or decreases in costs of capital" due to the "purchase of long-term wholesale power supplies...." It does not mandate utility-specific examinations. After a thorough review of this new legislation, we will determine the procedure for compliance.

the rights of parties to respond meaningfully to the petition. Edison should have had sufficient time to file by November 5 in order to permit the Rule 42(b) response time to elapse prior to our consideration of the proposed decision on the November 23 agenda. Edison has failed to explain why such evidence was not adduced before November 12. We therefore deny the petition to set aside submission and strike the portion of Edison's comments which deal with this purported evidence.[3]

D. Ex Parte Notices

The ex parte notices filed in this proceeding do not constitute part of the record (Rule 1.2.) However, we are nonetheless disturbed by the content of one such notice. In Edison's Notice of Ex Parte Communication, filed October 30, 1992 in A.92-05-013, Edison disclosed written materials used in the ex parte communication with a Commissioner. As required by our Rules, a copy was attached. On page 2 of that attachment, in the first paragraph under numbered heading (4), Edison misrepresented the content of the ALJ's proposed decision, by a quote attributed to that proposed decision, which does not appear therein. We place all parties to whom the ex parte rules apply on notice that under its Rule 1.5 provision on sanctions, we hereby interpret Rule 1's admonition "never to mislead the Commission or its staff by an artifice or false statement of fact or law" to apply to the content of ex parte communications and the notices thereof. Similar

3 We also note that Rule 77.3 discloses that "[n]ew factual information, untested by cross-examination, shall not be included in comments and shall not be relied on as the basis for assertions made in post publication comments." PG&E, DRA, and UCAN also included in their comments references the facts set forth in ex parte notices. Rule 1.2 states ex parte notices are not part of the record of the proceeding. Therefore, such references violate both Rule 1.2 and Rule 77.3. We have therefore given them no weight. We caution participants in any of our proceedings not to utilize such references.

conduct in the future is subject to imposition of sanctions under Rule 1.

III. Generic Issues

In this generic annual proceeding, we establish rates of return on rate base and returns on equity with regard to differences among the energy utilities. For this reason, we analyze each utility separately. Three United States Supreme Court decisions establish the legal criteria for determining appropriate rates of return. Bluefield Water Works and Improvement Company v. West Virginia Public Service Commission (1923) 262 U.S. 679, 43 S. Ct. 675; Federal Power Commission v. Hope Natural Gas Company (1944) 320 U.S. 591, 64 S. Ct. 281; and Duquesne Light Co. v. Barasch (1989) 488 U.S. 299, 109 S.Ct. 609. Hope states that, as long as a rate enables a company to operate successfully, to maintain its financial integrity, to attract capital and to compensate its investors for the risk assumed, it will not be adjudged invalid even though it produces a meager return. (320 U.S. at 605.) The return should be equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties. (Bluefield, 262 U.S. at 692-693.) However, a rate may not be so low as to be confiscatory, and in making this analysis, the focus is whether the rate is unjust or unreasonable, to some extent, based on what is a fair rate of return given the risks under a particular ratesetting system and the amount of capital upon which investors are entitled to earn that return. (Duquesne 488 U.S. at 310.) However, Duquesne declares: "The constitution, within broad limits, leaves the states free to decide what ratesetting methodology best meets their needs in balancing the interests of the utility and the public." (488 U.S. at 316.)

Under our Constitutional guidelines, we are concerned with, among other things, reasonable compensation to utility investors for the risks they assume. "[W]e must identify the risks for which investors require compensation, evaluate the relative magnitude of these risks on the utility over the test period, and quantify these observations into an authorized rate of return on common equity and total capital." (33 CPUC2d 525, 538 (1989).) In so doing, we combine the qualitative assessments of risk with quantitative model results in arriving at a final judgment on required returns on equity. (Id.)

In subsequent sections, we consider factors unique to each applicant and determine the appropriate capital costs on a case-by-case basis. However, this section addresses common issues which warrant general discussion.

A. Power Purchase Agreements and the Capital Structures

PG&E, Edison, and SDG&E request increases in the equity ratios in their capital structures to offset their alleged increased financial risk due to treatment by credit rating agencies of PPAs as debt equivalents. PG&E requests that its equity ratio be increased from 46.75% to 49.50% (2.75 percentage points); Edison from 46% to 48% (2 percentage points); and SDG&E from 49.50% to 52.50% (3 percentage points). Although both PG&E and SDG&E request decreases in their preferred stock ratios (PG&E from 5.75% to 5.50% and SDG&E from 6% to 5.50%), Edison requests that its preferred stock ratio be increased from 6% to 7%.

These applicants' ROE requests are premised on these capital structure changes. PG&E requests that its authorized ROE be increased from 12.65% to 13%. Without an increased common equity ratio, PG&E would need an ROE of 13.40% to achieve its requested revenue requirement. (Tr. Mountcastle at 192.) Edison requests an increase in its ROE from 12.65% to 13.05%. Edison would need an ROE of 13.45% without capital structure changes to achieve its requested revenue requirement. (Tr. Simpson at 104.)

SDG&E requests an increase in its ROE from 12.65% to 13%. However, SDG&E would lower its ROE request to 12.75% if its equity is increased to 52.5% and AA utility bond rates at the time of the Commission's decision do not increase beyond 8.4% to 8.9% on both an actual and forecast basis. (SDG&E-1 Malquist at 1.) SDG&E would need an ROE of 13.45% without an increased common equity ratio to achieve its requested revenue requirement. (Tr. Malquist at 301.)

Since we have emphasized that the burden of proof as to the debt equivalence of PPAs and the necessity of increasing equity ratios and/or ROEs to account for this treatment is on the utilities, we are making a thorough review of the record in reaching our conclusion to deny the common equity increases. We believe that a discussion of how the rating agencies arrive at their ratings and how the market views them is germane to our assessment of the rating impacts of the PPAs claimed by the utilities. Therefore, we will first examine the methodology used by the credit rating agencies. Next, we will assess the general financial ramifications of credit ratings in the financial markets. Finally, we will analyze the effects of the PPA debt equivalents on Edison, PG&E, and SDG&E based on the company-specific evidence they presented, prior to elaborating upon our conclusion.

1. Credit Rating Agency Methodology

The record contains information about the treatment of PPAs as off-balance sheet debt by three rating agencies and their methods for calculation of various financial ratios and for otherwise assessing the risks of the PPAs when rating the utilities' bonds, preferred stock and commecial paper. Each rating agency employs a somewhat different method. In response to the August ALJ Ruling, PG&E, Edison, and SDG&E jointly sponsored testimony from Mr. William A. Abrams, a senior vice president of Duff & Phelps Inc. (Duff & Phelps) who is in charge of utility credit ratings and a member of the Duff & Phelps Fixed Income

Rating Committee.[4] Appended as Exhibit 1 to his testimony (SCE-9) is the October 1, 1991 "Duff & Phelps Perspective--The Purchase Power Commitment." His testimony also reflects that since its publication, Duff & Phelps has further refined its computational methods for PPAs. Exhibit 2 is the November 18, 1991 Standard & Poor's (S&P) "Creditweek Credit Comment" addressing PPAs. This is superceded by Exhibit PG&E-2, which is an August 18, 1992 letter to PG&E witness Mountcastle from a Director of S&P. The letter discusses briefly S&P's revised methodology as applied to California utilities and encloses the May 1992 S&P Creditweek Credit Comments updating Exhibit 2 to Abrams' testimony. Exhibit 3 to Abrams' testimony is the June 1992 "Moody's Special Comment--Purchase Power as an Asset." Although applicants attempted to obtain a percipient witness from S&P, S&P has a policy of not testifying in rate case proceedings.

Financial markets look at a number of quantitative measures of financial integrity in the process of assessing credit quality. The primary, but not only, financial ratios are: debt leverage, interest coverage, and internal funds ratios. Debt leverage is determined by the following equation:

$$\frac{\text{Total debt (adjusted for off-balance sheet obligations)}}{\text{Total capital outstanding (adjusted for off-balance sheet obligations)}} = \text{Debt leverage}$$

4 In assessing his testimony, we regard him as a witness for the utilities as opposed to the more neutral presentations set forth in literature in the record.

Interest coverage is computed as follows:

$$\frac{\text{Pre-tax earnings (adjusted for off-balance sheet obligations but excluding non-cash earnings)}}{\text{Total interest expense (adjusted for off-balance sheet obligations)}} = \text{Interest coverage}$$

The internal funds ratio is determined as follows:

$$\frac{\text{Net Cash Flow}}{\text{Capital requirements}} = \text{Internal funds ratio}$$

Rating agencies consider a lower value for the debt leverage ratio computation and higher values for the interest coverage and internal funds ratio computations as indicators of reduced financial risk to bond holders and therefore indicative of higher credit quality. (SCE-9 Abrams at 9.)

These ratios are financially measurable indicators of financial integrity. However, in addition to these quantitative measures, the rating agencies also include a judgmental assessment of qualitative circumstances which have a bearing on risk exposure. These include the outlook for sales, competition, quality of management, the regulatory environment, the quality of reported earnings, and the quality of the balance sheet. (SCE-9 Abrams at 10.)

The rating agencies differ in their methods to quantify the risk of PPAs and to assess their different qualitative benefits and risks. The rating agencies differ on the amount of PPA debt equivalents imputed when making financial ratio calculations. Also, the qualitative assessment of PPA-specific risk factors occurs in different places in the rating agencies' overall analyses. "You must apply a tremendous amount of judgment to the numbers you are looking at." (Tr. Abrams at 903.) For example, when Duff & Phelps analyzes a mortgage bond rating and has financial ratios within its range for an AA- company, but the qualitative factors are poor, Duff & Phelps will not rate that company an AA-. (Tr. Abrams at 902.) SDG&E acknowledges that it is still possible to maintain a credit rating if you are a little bit outside the rating agency ratios due to consideration of other factors, such as quality of management. (Tr. Malquist at 291.)

Similarly, when they evaluate utilities which are not purchasing capacity but are instead building plant, the rating agencies differ in the assessment of their financial integrity. The rating agencies also differ in their opinions of regulatory climate, company management and affected territory. As Abrams observed, "we differ on many, many things. And that is why you have more than one credit rating agency, because these differences are recognized in the investment community and we do come to a balance." (Tr. Abrams at 863-864.)

We review below the methodology of the three rating agencies. We leave our assessment of the validity of their methodology, as it relates to our regulatory perspective, to our conclusion on these issues.

a. <u>S&P</u>

S&P has just recently developed the mathematical scale to quantify and assign a debt equivalent to all PPAs, including take-and-pay. It will continue to fine tune the application of its methodology to individual contracts and utilities because it believes the process "is an art, not a science." (PG&E-2, Mountcastle at 1.)

S&P's method blends an assessment of the PPAs' qualitative factors with their quantitative financial impact before imputing debt in the financial ratios. S&P first takes the net present value of future capacity payments discounted at 10%. This 10% discount factor approximates a utility's average cost of capital. The result is a <u>potential</u> debt equivalent which is finalized when multiplied by a PPA-specific risk factor between 0 and 100%. The risk factor is based on a qualitative analysis of the risks of the underlying PPAs, e.g., whether they are take-and-pay or take-or-pay, or involve sale/leasebacks of plant, and the extent to which market, operating and regulatory risk are borne by the utility. The potential off-balance sheet debt equivalent is then multiplied by the percentage risk factor to obtain the dollar amount of debt equivalents which is added to the utility's reported debt in calculating the debt leverage ratio. To adjust the interest coverage ratio, S&P then takes 10% of the PPA dollars added to reported debt and adds this smaller figure into that ratio calculation. S&P can make similar PPA adjustments to two other traditionally important ratios, funds from operations to interest coverage and funds from operations to average total debt. (PG&E-2, Mountcastle, Creditweek at 14-15.) After the ratios are calculated, other generic qualitative factors are then assessed before the rating is assigned.

The S&P ratio calculations work as follows:

S&P Method

(Illustrative Figures)

	Before PPA Adjustment		After PPA Adjustment	
Total Debt	$3,435,000	= 64.5%	($3,435,000+338,300)	= 66.6%
Total Capital	5,325,000		(5,325,000+338,300)	
Pre-Tax Earnings	700,000	= 2.66x	(700,000+ 33,830)	= 2.47x
Total Interest Exp.	263,000		(263,000+ 33,830)	

Purchased Power:

Debt Equivalent = $3,383,000* x 10% risk factor = $338,300

Interest Equivalent = $338,300 x 10% interest rate = $33,830

(*Net present value of future capacity payments discounted at 10%.)

There is no change in the internal funds ratio due to PPA debt equivalents.

Unlike the position taken by Duff & Phelps, S&P believes that "it is impossible to generalize about whether utility bond holders are better off if their utility buys or builds. The important thing is that both resource strategies have inherent risk." (PG&E-2, Mountcastle, Creditweek at 11.) S&P cites the following benefits of purchased power:

1. Avoidance of construction risk (significant cost overruns or failure to complete) since the purchasing utility only begins to pay for power once the non-utility generator (NUG) plant passes the hurdles outlined in the PPA;

2. Avoidance of financial deterioration typical in multi-year construction programs due to regulators' reluctance to allow full cash returns on construction in progress;

3. If timed correctly, a utility's rates will rise concurrent with or close to the time it actually commences purchased power payments, thus reducing regulatory lag, and recognizing that it is usually easier to recover purchased power expense than to rate base a new plant;

4. Power supply flexibility and diversity because NUG projects are generally small relative to a utility's total supply base resulting in little concentration risk; and

5. The avoidance of new investment in generating plant while continuing to depreciate existing plants shifts the asset mix so when combined with ongoing new investment in transmission and distribution, the proportion of total assets in the less risky segments of the business increases.

To the extent there are risks with purchased power, bond holders are directly threatened since they have no equity cushion to insulate them as do shareholders. At best, purchased power is recovered dollar for dollar as an operating expense with no markup to reward equity holders for taking the risk. S&P assesses market, operating, and regulatory risks associated with PPAs to arrive at the percentage risk factor it applies to the potential debt equivalent.

S&P identifies two PPA market risks. The first risk stems from the utility entering into long-term PPAs without assurance, due to forecast errors, that the utility will be able to sell the power. Since regulators do not like a utility to procure too much power, there is a major risk if demand falls short of expectations. The second risk is that the power under the PPA may not be economic over time. Due to increasing competition, a utility's cost of power is critical to its success. To the extent that the contracted power becomes uneconomic relative to other sources, the utility may suffer a loss of customers, sales, and earnings.

S&P cites four operating risks associated with PPAs. First, due to environmental concerns, erecting a power plant is more difficult which may mean that contracted NUG capacity may never come on line. S&P contends that utilities attempt to compensate by accepting excess bids for power. If a significantly greater percentage of the contracted power fails to materialize, due to its obligation to serve, the utility may be required to accelerate its own construction activities at a late date, resulting in greater costs and risk of regulatory disallowance. Second, there are questions whether NUG plants will operate well. Although data suggests that not much difference exists in availability between utility plants and NUG plants, there are lingering doubts because any discrepancy in quality may not be known until the plants begin to age. Third, the purchasing utility loses control over its supply sources because it may not control the NUG plant's operations, dispatch and take-downs for routine maintenance, thus influencing a utility's efficiency and reliability. Fourth, natural gas-fired NUGs will play an increasingly important role in electric generation but overreliance on any one fuel is a risk.

S&P believes there are two PPA regulatory risks. Although it agrees that the general one-for-one recovery of purchased power expense helps mitigate the risk, there still is a chance of prospective or retrospective disallowances. This risk of disallowance can be reduced by regulatory out clauses in PPAs, but the amount of protection depends on each contract's specific language and regulatory out provisions have not yet been tested in the courts. The second regulatory risk is the state's mechanics for recovery of purchased power expense. Disallowance risk is reduced when purchased power capacity charges are recovered from customers in a separate adjustment mechanism like a fuel clause rather than through base rates. This promotes little or no delay in recovery of charges and makes it easier to track expenses and ensures adequate revenues to cover them. A comprehensive integrated resource planning process also mitigates disallowance risk. Although this does not preclude cost overrun penalties, it mitigates the risk that capacity additions will be classified as unnecessary after the fact. In making its regulatory risk evaluation, S&P performs a state-specific overview encompassing the state's entire regulatory, legislative, and judicial arenas.

S&P cites two major financial risks to PPAs. The first is the potential for liquidating rate base, which is of particular concern to equity investors. Since utilities are allowed a return on depreciated investment, i.e., total investment less accumulated depreciation (or rate base), their earnings will decline to the extent that the rate base declines. Therefore, if a utility does not build new generating plant and continues to depreciate existing generation, then its depreciation will exceed its new capital investment and therefore rate base and earnings will decline. However, S&P believes that debt quality may not necessarily be affected by this scenario. There will be a gradual decline in rate base but spending on transmission and distribution will continue so that rate base will not totally disappear. Even if depreciation exceeds new investment, S&P believes this is not necessarily alarming because it means cash flow is strong relative to needs. The critical factor is what the utility does with its cash flow. A shrinking utility will not threaten bondholders if the utility reduces debt as its assets contract because, done in proportion, key relationships like cash flow to debt and cash flow coverage of interest will stay relatively constant. S&P's bigger concern with declining rate base is how management will react when faced with a scenario of slow earnings growth or declining earnings because typical management response is nonutility diversification.

The second and most important area of financial risk arises because the PPAs are long-term contracts with fixed cost components. For this reason, S&P believes that they are, at least in part, off-balance sheet debt equivalents. However, overall PPA financial risk will usually not be significant until purchased power exceeds 10 to 15% of a utility's capacity. Under PPAs, the fixed capacity payment covers the NUG's fixed costs, including its debt service, depreciation, and a return on equity. S&P believes that the total fixed capacity payment should be considered because the utility is obligated to pay the entire fixed capacity payment, not just the debt service portion. S&P does not focus on the extent to which the NUG is leveraged because this makes little difference in the capacity payments. Instead, there may be a difference in a NUG's financial viability since highly leveraged NUGs are inherently less creditworthy. This, in turn, raises reliability concerns to be analyzed under a utility's fuel and power supply risk, rather than in the financial analysis.

S&P quantifies the financial risk associated with the dollar value of the PPAs by the assignment of the percentage risk factor. This is based on the theory that different off-balance sheet obligations have different risks and some PPAs are more firm and therefore more debt-like than others. S&P uses a risk spectrum so that obligations with fewer debt-like characteristics are considered less firm than obligations with more debt characteristics. The place where the utility's PPA obligation falls on the risk spectrum scale determines the dollars of PPA debt equivalents S&P adds to the utility's reported debt. Sales/leasebacks of major plants are viewed as virtually the equivalent of debt. Take-or-pay obligations are considered quite firm since the utility is obligated to make capacity payments all the time whether or not the plant produces power. Take-and-pay contracts are considered the least debt-like of the PPAs because capacity payments are conditional on the power's availability. Also, the executory nature of a lease or contract may result in something short of a total debt equivalent.

When assessing take-and-pay contracts under the risk spectrum, the risk factor also depends upon a qualitative analysis of the PPA and the extent to which market, operating, and regulatory risks are borne by the utility, which may result in a relatively low risk factor. The risk factor is reduced to the extent that the power is economic relative to alternatives. The risk is lower if the project's energy rate is indexed to the purchasing utility's other sources of power so that the economics of the purchased power do not decline over time. The risk factor is also lower when a contract contains true performance standards, such as a minimum capacity factor of 80% and a total cutoff of capacity payments below a certain level of availability. Risk is lower if the utility retains control over the NUG's scheduling of maintenance and dispatch. Project diversity also lowers risk because S&P considers concentration of purchased power exposure more significant than aggregate exposure. Less regulatory risk is signaled by regulatory out clauses, complete recovery of the capacity charged to a fuel-cost type mechanism rather than base rates, and a state regulatory environment that supports and encourages purchased power. As a practical matter, the risk factor for take-and-pay obligations ranges between 10% to 50%. The risk factor for take-or-pay ranges from 40% to 80%. (PG&E-2, Mountcastle, Creditweek at 11-14.)

At the conclusion of its analysis of purchased power, S&P states:

> "Will S&P lower bond ratings to reflect its focus on the risk in purchased power? Going forward, S&P would expect some rating downgrades over the next couple of years. However, where purchases represent less than 10% to 15% of a utility's capacity, the quantitative adjustments will not make much difference to the ratios, and the incremental financial risk may be offset by the qualitative benefits of purchasing power.
>
> "Even where purchases are more significant, downgrades may or may not be appropriate, depending on the response to S&P's analysis by utilities and their regulators. It is not S&P's role to simply sit in judgement. Rather, it intends to work closely with both utilities and regulators to help identify the appropriate risk factor to apply to a utility's off-balance sheet obligations. Moreover, S&P will work with interested parties to design ways to offset purchased power risks." (PG&E-2, Mountcastle, Creditweek at 15.)

In the letter to Mountcastle, Ms. Richer, a director of S&P, relates its general policy to California. She references SDG&E's $25 million Southwest Powerlink (SWPL) disallowance, admittedly later modified, the DRA/Edison negotiated $250 million disallowance on Mission Energy Qualifying Facility (QF) contracts, and the DRA recommendation of a $7.3 million disallowance related to Edison's administration of QF contracts in 1989 through 1990 as suggesting PPA risks. S&P also contends that in California (1) the pricing of QF power, specifically for Standard Offer 4 contracts, is uneconomic; (2) many QFs are not dispatchable; (3) the prudence of capacity and energy costs is always subject to subsequent review in Energy Cost Adjustment Clause (ECAC) proceedings; and (4) there is a fixed financial charge associated with all purchases. However, S&P recognizes risk-mitigating factors for California PPAs which include: (1) QF contracts are take-and-pay; (2) capacity and energy payments are recovered in a timely fashion through the ECAC mechanism; (3) independent power production contracts will be pre-approved prospectively; and (4) the economics of QF power will improve as standard offer contracts convert to avoided energy pricing. Therefore, S&P arrives at a 10% risk factor, which is the lowest level risk factor assigned, for QF contracts in California. (PG&E-2, Mountcastle Letter at 2-3.) The letter does not address take-or-pay contracts.

b. Duff & Phelps

Since its May 1991 publication, Duff & Phelps has increased the amount of debt it imputes to a utility's balance sheet based on PPAs when computing the interest coverage ratio. Now Duff & Phelps reclassifies one-third of the capacity charges on all PPAs as an interest expense equivalent. Unlike S&P or Moody's, Duff & Phelps reclassifies one-third of the capacity charges as interest expense regardless of the specifics of the underlying PPAs when computing the interest coverage ratio. (Tr. Abrams at 901-902.) Duff & Phelps takes the straight dollar value of the PPAs, regardless whether they are long-term or short-term or whether they are take-or-pay and take-and-pay, and takes one-third of that. (Tr. Abrams at 948.) This results in more imputation of debt than under S&P's or Moody's methodology, when take-and-pay contracts only are involved. Abrams believes that imputing only one-third of the capacity payment as interest equivalent may actually understate the fixed obligations underlying the PPAs. (SCE-9, Abrams at 18.) In addition, the value of the assets providing capacity is added to the capitalization as a debt equivalent when computing the debt leverage, by capitalizing the annual capacity payments. (SCE-9 Abrams at 17.) This capitalization of the annual capacity payments can also be expressed by dividing the dollar amount of interest equivalents used in the interest coverage ratio by 0.10. (PG&E-1 Mountcastle at 1-9.) The financial adjustments "are not expected to be precise or have accounting reality. They can only be a reasonably close gauge of the effect of purchased power strategy on the company and, therefore, its investors. Where we have precise data, this, of course, will be used in our credit rating process." (SCE-9 Abrams Exhibit 1 at 7.)

Unlike Moody's or S&P, Duff & Phelps assesses the quantitative, financial risk of PPAs separately from all qualitative factors. For this reason Abrams believes that it is not possible that decreased regulatory risk can offset increased financial risk. (Tr. Abrams at 885.) Although Duff & Phelps does not apply qualitative factors to the debt equivalent dollars added to its financial ratio computations, it does apply them when making the final determination of the credit rating to assign. (Tr. Abrams at 940.) At this stage, qualitative factors may result in a lowering of the rating below what the numbers will suggest or a moderation of the numbers. (Tr. Abrams at 948-949.)

The Duff & Phelps ratio calculations for PPAs are as follows:

Duff & Phelps Method

(Illustrative Figures)

	Before PPA Adjustment		After PPA Adjustment	
Total Debt / Total Capital	$1,125,000 / 2,500,000	= 45%	($1,125,000+400,000) / (2,500,000+400,000)	= 53%
Pre-Tax Earnings / Total Interest Expense	350,000 / 100,000	= 3.5x	(350,000+ 40,000) / (100,000+ 40,000)	= 2.78x
Net Cash Flow / Capital Requirements	400,000 / 500,000	= 80%	400,000 / 500,000	= 80%

Purchased Power:

Total Annual Capacity Charges = $120,000
Interest Equivalent = 1/3 of $120,000 = $40,000
Debt Equivalent (capitalization of annual capacity payments at 10% cost) = $400,000 (SCE-9 Abrams at Exhibit 4.)

Duff & Phelps also compares the PPA scenario to a build scenario when making the ratio calculations, as follows:

	Without Adjustment		With Adjustment	
Total Debt / Total Capital	$1,125,000 / 2,500,000	= .45	$1,125,000 + 450,000 / 2,500,000 + 1,000,000	= .45
Pretax Earnings / Total Interest Exp.	350,000 / 100,000	= 3.5x	350,000 + 160,000 / 100,000 + 45,000	= 3.5x
Net Cash Flow / Capital Requirements	400,000 / 500,000	= .80	400,000 + 55,000 / 500,000	= .91

<u>Plant Construction requires</u>:
$160,000 in pretax earnings
$45,000 in interest expense
$450,000 in additional debt issued
$1,000,000 in additional capital
$55,000 in additional net cash flow
(SCE-9 Abrams at Exhibit 4.)

Abrams states that "you don't necessarily have to always lower the rating because you have purchased power." (Tr. Abrams at 866.) With one exception, Duff & Phelps has not downgraded a company solely because of the amount of purchased power. The exception is Central Maine Power Company whose bonds were downgraded from A- to BBB+ in June, 1992 because it was not recovering its purchased power expenses, which were being deferred and thus deteriorated its cash and increased its short-term debt. (Tr. Abrams at 867 and SCE-9 Abrams at Exhibit 5 p. 1.) However, we note the Duff & Phelps release also references the sluggish Maine economy and its Commission's rate design changes which have pressured earnings and slowed accounts receivable collection. (SCE-9 Abrams at Exhibit 5 p. 1.) Duff & Phelps has never downgraded a California utility's credit rating based solely on the risks associated with a large percentage of purchased power, but it has not raised the rating of SDG&E over the years because of its purchased power obligations and policy. (Tr. Abrams at 958.)

Duff & Phelps views a PPA as an obligation to make fixed payments very much like an obligation to make loan payments, with a financial impact which is the same as if the utility had taken a loan. (SCE-9 Abrams at 13.) Like S&P, Duff & Phelps believes when the amount of firm purchased capacity reaches 10 to 15% of the total generation resources available to a strong utility, the purchased power policy should receive close scrutiny. Weaker utilities cannot tolerate even the 10 to 15% level. Duff &

Phelps also believes that when a resulting interest coverage adjustment is more than 20 to 30 basis points, or when the total capacity charge associated with PPAs approaches or exceeds the total interest expense incurred by the utility, there is a significant level of purchased power. (SCE-9 Abrams at 14-15.)

Unlike S&P, Duff & Phelps views a company that owns its tools of production as being financially stronger than one that does not own those tools. (SCE 9, Abrams at 13-14.) When the capacity is owned, the ratio of pre-tax income to interest expense or debt to total capital remains steady and the ratio of cash flow to capital requirements is enhanced, since the equity earnings built into rates remain with the utility rather than being paid out to the capacity sellers. (SCE 9, Abrams at 17-18.) When a utility builds plant, it has a depreciation and return on equity which remains with the utility and can be used to build additional plant. However, when a utility buys capacity, it is making the equivalent depreciation payments to the NUG with the money not being necessarily available to the utility to build a new plant or to take down debt, pay dividends or invest in other operations. (Tr. Abrams at 909.) Depreciation cost recovery in the construction of generation assets is the single largest source of cash flow available to a utility to provide funds to invest in new facilities to serve its customers. Each increment of purchased power reduces the source of this cash flow resulting in an increased reliance on external financing to fund future construction requirements. (SCE-9 Abrams at 23-24.) Thus, when the cycle of cash flow is broken by reliance on purchased power, the cash flow support for future construction begins to decay and the ability of a utility to revert to construction and ownership of generation assets becomes progressively more risky and problematical over time. (SCE-9 Abrams at 24.)

Although S&P does not view purchase power providers' reliability as a PPA risk, Duff & Phelps does. Primary reliance on purchased power for new generation capacity can result in progressive liquidation of asset base with earnings and cash flow growth slowed or eliminated so that the ability of the utility to finance the construction of future facilities is severely impaired. There is no assurance that future expansion of independent power production can be counted on because independent power producers (IPPs) have no obligation to serve and will only remain in business as long as it is profitable. Therefore, it is necessary and prudent that the electric utility always stay in a position to build. (SCE-9 Abrams at 22.) Duff & Phelps' concerns about reliability arise from the fact IPPs are project-financed and do not have a tremendous amount of equity, and IPPs could walk away or go to more lucrative markets. (Tr. Abrams at 912-913.) He also states a lucrative avoided cost price can mitigate this concern and admits California avoided costs are high. (SEC-9 Abrams at 21 and Tr. Abrams at 911.) Abrams has heard of only one possible problem with a failure to deliver for a California IPP and was not sure of the nature of the problem, but asserts there are problems in other states. (Tr. Abrams at 954.)

Like S&P, Duff & Phelps admits that a slow-down or lack of rate base growth in and of itself does not greatly concern bond holders, as long as the utility's capital structure remains in balance. However, Duff & Phelps paints a gloomier picture and asserts lack of growth combined with the increased imputed financial obligation of power purchase contracts will increase risks. As assets decline relative to a utility's fixed charges, the utility will become less able to withstand any threats to its financial stability, whether these be economic events, natural disasters or prudency disallowances by regulatory commissions. Therefore, recognition of the financial obligations brought about by PPAs, in addition to more traditional obligations, is the best way to assure that the utility can fulfill its obligation to serve its customers into the future. (SCE-9 Abrams at 31.)

After computing the quantitative financial ratios including PPA debt equivalents, Duff & Phelps makes qualitative assessments before assigning a credit rating. A determination of credit quality includes a judgmental assessment of any and all qualitative circumstances which have a bearing on risk exposure, including the outlook for sales, competition, quality of management, the regulatory environment, the quality of reported earnings, and the quality of the balance sheet. (SCE-9 Abrams 10.) Qualitative factors specific to PPAs include: (1) take-or-pay versus take-and-pay arrangements; (2) the source of the capacity (whether a proven power technology facility); (3) dispatchability; (4) control of maintenance downtime; (5) fuel type and security of fuel supplies; (6) the payment structure divided between capacity and energy charges; (7) total costs per kilowatt-hours; (8) the regulatory mechanism to recover costs; (9) environmental considerations; (10) the financial stability of the operators; and (11) the utility's ability to take over the plant. (SCE-9 Abrams Exhibit 1 at 4.)

Duff & Phelps favors take-and-pay contracts over take-or-pay arrangements. However, Duff & Phelps still believes that the take-and-pay contracts have certain characteristics similar to take-or-pay arrangements and notes that control of the amount of dollars the utility pays still rests with the seller. (Id.) Dispatchability is viewed as a strength for take-and-pay arrangements since the utility has some operating flexibility to control the resource mix. Duff & Phelps notes that most PPAs lack dispatchability and these are considered a higher risk obligation. Also analyzed is whether the power technology utilized is a proven one and the operating success or failure of similar types of facilities. A diversified fuel supply is considered a strength. Although Duff & Phelps does not currently penalize a utility for heavy reliance on gas-fired generation, a diversified portfolio of power sources is preferred. Unusual fuels with limited availability and applicability are viewed with caution. The financial viability of the power producers to continue production as needed is considered vital in assessing the utility's power supply adequately. Even though NUG capacity can be taken over, the utility must have ready financial resources to exercise that option. Although recognizing that some investors view regulatory out clauses as virtually eliminating the risk, Duff & Phelps believes that they may only scale required payments to some lower level ordered by a future commission but do not totally abrogate a contract. It also has reservations about the fact that regulatory out provisions have not been tested in court. (SCE-9 Abrams Exhibit 1 at 4-5.)

Although Exhibit 1 to his testimony makes it appear that Duff & Phelps does a contract-specific analysis for each California utility, Abrams testified:

> "We do not take the position that we are smart enough or educated enough or have enough time to understand the intricacies of every purchased power contract."
>
> * * *
>
> "We do not have the staff, and we have more staff than most people, and our staff is highly qualified and highly educated in financial matters, but we do not have the staff that can look at those contracts and pretend to make a determination of each one of those contracts and relate it to some weighting of a financial ratio, and then come up with one magic number that is going to tell you what the rating is." (Tr. Abrams at 903.)

Instead, Duff & Phelps refers to the PPAs listed on the Federal Energy Regulatory Commission (FERC) Form F-1 and then discusses them and future power supply plans with the utility. (Tr. Abrams at 952.)

In assessing the California regulatory environment and the qualitative nature of California PPAs, Abrams recognizes that California's Standard Offer 4 contract is take-and-pay. (Tr. Abrams at 871.) Abrams admits that the ECAC, which passes through the costs of all prudent power purchases to customers, is a form of fuel clause which does reduce the risk and is one of the reasons Duff & Phelps values California regulation. (Tr. Abrams at 872.) Abrams recognizes that California is one of the leaders in the comprehensive integrated resource planning processes. (Tr. Abrams at 873.) However, California's resource planning process with fixed standard offers is one element of California's reduced risk profile, but it is a minor element. Abrams believes that it has caused some problems because it has caused some utilities to have more capacity than they need, so that there is a plus and a minus to the integrated resource planning process. (Tr. Abrams at 890.) Abrams asserts that these factors deal with regulatory risk and do not offset the financial risk of the contracts themselves as debt equivalents. This is because Duff & Phelps, unlike S&P and Moody's, does not consider any qualitative factors when it calculates the quantitative financial risk. Since one commission cannot bind a future commission, there is always the possibility that a future commission may have a different view of what was necessary or what price was proper and could disallow something previously considered prudent. While this does not dominate Duff & Phelps' risk analysis, it is there as a possibility. (Tr. Abrams at 883.)

Abrams defined regulatory risk as the quality of regulation, the ability to earn a fair return, the ability to recover costs, the stability of regulation, the recognition of changed conditions, the recognition of the utility's total obligations and its total liabilities. (Tr. Abrams at 887.) Among the determinants of regulatory climate is project and plant certification. Duff & Phelps has rated the quality of California regulation very high which is one reason it rates the California utilities as highly as it has. However, Duff & Phelps is still skittish about disallowances from future commissions whose mind set may differ from that of today's commission. (Tr. Abrams at 888.)

Although Abrams disagrees with some things that have been done in California, Duff & Phelps has recognized that California is one of the better regulatory climates, but it has gone through various cycles. In the last ten years it has been on a gradually upward cycle and, in the main, Duff & Phelps regards the Commission favorably. Duff & Phelps believes this Commission puts a lot of protection into the utilities, which is why the utilities are able to have the kind of ratings they do. However, Abrams cautions the Commission from relying on this favorable reputation to change policies on the theory that there is no risk of regulation in the rating agencies' minds. Such a change would be reflected in a change of regulatory risk assessment. (Tr. Abrams at 936-937.) A major regulatory risk would be in the Commission not recognizing the financial impact of the PPAs by not allowing a high enough common equity ratio or a low enough debt ratio and not allowing high enough returns to maintain the utility's financial integrity. (Tr. Abrams at 889-890.)

Exhibit 1, Duff & Phelps' Perspective, concludes that:

> "Just because the company increases its reliance on purchased power does not mean that debt protection measures will deteriorate and a downgrade is imminent. In many cases, various qualitative factors may outweigh the quantitative factors. More likely, we expect companies to raise their equity ratios to reflect the added liability and maintain higher reported coverages for a given credit rating. Also, the true cost of purchased power is increasingly being recognized by utilities in their pricing decisions.

> "From both the fixed income and equity investor's point of view, a heavy reliance on purchased power will ultimately lead to a tapering of rate base growth. This will diminish future earning power, dividend prospects and internal cash generation."
>
> * * *
>
> "Unless there are compensating returns, with rate base declining and the associated earnings lower, companies which pursue a power purchase strategy will ultimately have to slow dividend growth." (SCE-9 Abrams Exhibit 1 at 7.)

c. <u>Moody's</u>

Moody's takes a third approach to purchased power debt equivalents, which is more in line with S&P's than Duff & Phelps'. Moody's acknowledges both the benefits and the risks associated with PPAs. Like S&P, it believes their benefits vary, dependent largely on the type of contractual arrangements. Firm and near firm PPAs may gain a utility access to less expensive, competitively priced power. PPAs also reduce construction risks associated with a utility' own generation additions. Power purchases complementing a utility's existing capacity or fuel mix and sized to match the utility's growth in demand will make the purchases less likely to result in excess capacity. Rate shock associated with rate basing plants as well as the associated prudence, excess capacity, and used and useful issues surrounding capital recovery are also avoided. Competitive bidding and integrated resource planning using PPAs as one supply option have, at times, resulted in diminished regulatory volatility for the utilities.

Moody's also believes that, while construction and operating risk is often reduced by purchased power strategies, significant financing and regulatory risks remain which can reduce, offset or outweigh the benefits. Under either a build or buy scenario, the demand risk is retained by the utility. While Moody's believes the degree to which the financial flexibility of the utility is negatively impacted is a function of the inherent risk the utility has assumed, it is of particular concern if the company does not, when entering into the financial commitment, increase its equity to compensate for the risk. However, the degree to which equity should be allocated to offset the PPAs is to be determined by an analysis of the risk involved. Unlike S&P and Duff & Phelps, Moody's believes this determination is not formulaic. (SCE-9 Abrams Exhibit 3 at 2-3.) Therefore, no numerical example of the methodology can be set forth. In form, Moody's methodology appears to operate more in line with the S&P analysis.

Moody's methodology first identifies a spectrum of risk going between the two extremes, much like the S&P risk spectrum. Unlike S&P, it does not assign a specific risk factor percentage. Moody's merely identifies the key issues it qualitatively assesses in order to determine just where on the risk spectrum reality lies. Finally, it evaluates the quality of the asset being financed, which is an important consideration to mitigate the erosion of financial flexibility by the financing. Under this analysis, Moody's believes that at one extreme the risk of purchased power can be strongly discounted or ignored while on the other extreme financial risk can be weighed for all PPAs and added to the stand-alone debt of the utility dollar-for-dollar with an accompanying interest coverage and cash flow-to-total debt adjustment. In making its analysis, Moody's considers financial risk, demand risk, supply risk, construction risk, and operating risk. (SCE-9 Abrams Exhibit 3 at 3-4.)

In assessing financial risk, like S&P, Moody's addresses both quantitative and qualitative PPA attributes. Moody's concurs with S&P that the effect of the PPAs' financial risk on rate base is not of great concern to bond holders. As bond analysts, Moody's believes that monitoring cash flow relative to debt or fixed charges is the greater concern as rate base shrinks. There is a risk of lessened capital attraction, that is whether a company can attract material interest in the financial markets if required to do so. Management strategies to enhance slow-growing, flat, or decreasing earnings trends, such as business diversification, also could be of concern. However, build-some, buy-some, save-some type capacity planning strategies, which include moderate reliance on purchased power, may constructively address this issue while avoiding excessive financing needs. More significant to Moody's than the erosion of rate base is the second financial risk of the PPA's fixed payment stream. Take-and-pay contracts typically involve minimal use of a utility's financial flexibility, while take-or-pay contracts entail both demand risk that the power is not needed and operating risk that the facility has performance problems. Therefore, Moody's finds take-or-pay contracts often involve a significant use of a utility's financial flexibility. After analyzing the kind of PPA involved, Moody's includes the effective interest equivalent for capacity or fixed payment obligations associated with long-term PPAs in several of its financial coverage calculations, including interest coverage and leverage ratios and cash flow to total debt ratios. Moody's does not specify any particular formula to adjust these ratios. It also notes that these adjustments to the numbers represent the extreme of its risk continuum and provide only a framework upon which Moody's layers analysis of various qualitative factors. (SCE-9 Abrams Exhibit 3 at 4-5.)

Moody's appraises on a case-by-case basis whether or not there has been a real transfer of economic risk from the utility to a third party and then the degree to which the benefits mitigate these risks. Demand risk is the risk that purchased power is either not required or is uneconomic relative to other supply options. However, factors which limit or may offset these risks include: (1) regulatory mechanisms to pass through such costs; (2) unconditional take-and-pay contracts; (3) accurate demand forecasting, possibly as the result of a regulatory agency-approved integrated resource plan; (4) dispatchability of power; (5) market renegotiation provisions; and (6) termination payment provisions. Contracts which are take-or-pay exacerbate demand risk. Take-and-pay contracts carry a supply risk that the power is not available when needed, but the degree of utility harm is a function of how badly the power is needed. Concentration on one type of fuel, technology or asset is considered, and the absolute level of purchased power is gauged. Moody's pays particular attention to those utilities depending on purchases for over 10% of their power requirements. Other issues Moody's examines include: (1) the reliability of the providers; (2) the type of plant technology (unproven versus standardized/mature); (3) supply position of the utility power pool; and (4) the ability to pass replacement power costs through to ratepayers via adjustment clauses. Although supply risks can sometimes be offset by accepting more bids for power than actually needed, Moody's views regulatory response to this strategy as key. Moody's also considers what happens if plant construction is delayed or if plant is not built at all. (SCE-9 Abrams Exhibit 3 at 4-6)

Moody's looks at two factors under operating risk. The first factor is what happens if the plant does not operate reliably, since the utility retains an obligation to serve but may lose significant control over the purchased power supply. The second factor is how unexpected costs, both fuel and non-fuel, are handled. Moody's also looks to see who absorbs any regulatory lag if such costs can be passed through. Possible operating risk offsets focus on operating conditions specified in take-and-pay contracts, the utility's rights to intervene in failing projects, and the composition of the utility's portfolio of purchased power in relation to its total existing and target capacity mix. (SCE-9 Abrams Exhibit 3 at 7.)

In assessing regulatory risk, Moody's asks how insulated the purchasing utility is from regulatory disallowances. Its analysis examines the following factors: (1) economic market-based power seems less susceptible to regulatory scrutiny; (2) whether regulators get involved in supply decisions by preapproval of contracts or with competitive bidding which connotes a strong perception of prudency; (3) the ability to pass along capacity payments through an automatic adjustment clause offers protection against nonrecovery risks even though these costs may eventually be subject to review; and (4) whether regulatory out clauses exist because these could possibly offer a significant offset to regulatory risk. (SCE-9 Abrams Exhibit 3 at 7.)

Like S&P, Moody's concludes that it will not take sides in the buy versus build decision, but does recognize that PPAs have different risk factors. Nevertheless, it believes recovery on a one-for-one basis is thin protection. Thin coverage and high debt levels may be insufficient protection under times of adversity or unexpected financial stress. The critical issue for Moody's is whether utility customers and investors receive compensation for the risks they bear under any form the electric industry takes. Moody's believes that by reflecting PPA risks in its ratings, this will occur and capital markets will continue to operate efficiently. (SCE-9 Abrams Exhibit 3 at 7-8.) However, Moody's admits it takes a narrow perspective on managerial, financial and regulatory decisions that affect a company and influence business risk, and is therefore only interested in whether capacity planning decisions positively or negatively affect the prospective position of the bond holder. (SCE-9 Abrams Exhibit 3 at 1.)

2. Financial Impacts of the PPAs on the Utilities

a. In General

While the credit ratings granted by each agency are based on its own grading scale and nomenclature for the classification of credit quality, the ratings are generally comparable. (SCE-9 Abrams at 11.) Basically, the investment grade ratings run from BBB to A to AA to AAA, with plus and minus designations to show relative standing within the major rating categories. (Tr. Fohrer at 75.) However, under Moody's system, pluses and minuses are not used, but an AA- is about the same as Moody's Aa3. (SCE-9 Abrams at 11.) In 1989, we found that: "Among industrial firms with investment grade bonds, 46% have an A rating, whereas only 4.9% of such firms have AAA ratings and only 16.2% have AA ratings.... For electric utilities, ratings higher than single A are justified less than 15% of the time and have not been justified since the early 1980's." (33 CPUC 2d at 574 (1989).)

A downgrade can occur within the incremental steps in a ratings category (e.g. A+ to A) or between alphabetical categories themselves (e.g., AA- to A+). Movements downward have varying impacts. For example, it is a bigger step when a company drops from one alphabetical rating category to another (e.g., AA- to A+) than there is when a company moves within an alphabetical rating category (e.g., A+ to A). Abrams hopes, when looking at well-rated companies, one would not have to take a big step downward in the event of a downgrade. (Tr. Abrams at 925-926.) When asked by the ALJ whether he could assess what the impacts would be, dependent upon the outcome in this proceeding, Abrams responded, "I have not examined any of it. I have not studied the effects on the companies and all of that." (Tr. Abrams at 928.)

Abrams believes a credit rating is "a very-very important determinant" when investment decisions are being made because investors rarely purchase a bond or preferred stock without looking at the credit rating. (Tr. Abrams at 934.) FEA's witness Legler believes the investors basically take the ratings the agencies provide and do not do their own analysis. (Tr. Legler at 525.) However, Abrams admits investors will also listen to their own analysts, who have a narrower focus than the credit rating agencies do, because analysts are more sensitive to current developments. The analysts are also more sensitive to price changes near-term, whereas the credit rating agencies try to identify future trends. (Tr. Abrams at 934.) However, Abrams contends the investors will not listen to what a regulatory commission views as the investment risk. (Tr. Abrams at 933.).

Abrams cites three equally important reasons for a utility to defend and retain a strong credit rating. First, the utility needs borrowing reserve capability which is access to capital markets under the broadest circumstances. The borrowing potential of utilities may be restricted at times by either general market conditions or company-specific conditions. (SCE-9 Abrams at 11.) Market conditions can be unexpected inflation or a credit crisis. Company-specific conditions can be regulatory events, such as negative rate case decisions or prudency reviews. These have greater impacts on a company with a weak cash flow and lower earnings relative to the size of its operations. (Tr. Abrams at 28.) Abrams asserts that an inferior or reduced credit rating means the utility faces an increased risk that capital could be unavailable or more costly when needed. (SCE-9 Abrams at 11.) We believe the record does not prove a specific monetary link between increased costs of financing which negatively impact ratepayers and lack of borrowing reserve capability.

The higher the credit quality of a company, the more immune it is to restrictions of tight credit markets. Abrams foresees a volume of required new financings among better-rated electric utilities which will result in greater competition in the marketplace for funds. During the period from 1992 to 1994, Duff &

Phelps forecasts total capital requirements of $22 billion nationally to be financed externally by electric utilities it rates. Of this amount, $7 billion will be financed by AA rated companies and $12 billion financed by A rated companies. (SCE-9 Abrams at 11-12 and Tr. Abrams at 946-947.) This process has started already and will accelerate in 1993 and 1994. (Tr. Abrams at 925.) No California-specific financing numbers were provided. Abrams believes that the greater market pressure will widen the market spread between higher and lower rated credit standings: AA versus A and A versus BBB (SCE-9 Abrams at 12.), and that this means investors will have more opportunity to select among better credit risks, so they are going to be fussier. (Tr. Abrams at 925.)

Abrams also contends that the companies entering the market in these three years generally have been out of the construction business since 1985, so they have restored their financial ratios and are quality companies. PG&E and Edison have had to raise a lot of new money because they have large, ongoing construction needs beyond building generating plant. When they were raising money in the past, they were competing most often with poorly rated companies. PG&E and Edison looked pretty good to the market, because there was not as much better-rated paper available, except for refundings. Now, when competing with their peers in accessing the market, there will be greater competition over who looks better. (Tr. Abrams at 924.)

We find that Abrams' testimony is controverted by SoCalGas' recent market experience. In August 1992, Moody's downgraded its secured debt from A1 to A2 and unsecured debt from A2 to A3 and preferred stock from a1 to a2. Thereafter, both S&P and Duff & Phelps confirmed SoCalGas' current ratings. (Tr. Todaro at 425.) After the downgrade, SoCalGas issued $100 million of new first mortgage bonds, due in ten years, on a competitive bid basis. "[T]hey were very well received in the marketplace, they were very aggressively bid. The spread over the year--Treasuries as of that date was only 56 basis points, which would classify as very aggressive bidding for that issue." (Tr. Todaro at 423.) The downgrade did not really hurt SoCalGas' ability to make such issuances nor did it increase costs flowed through to ratepayers. (Id.) On the same date, SoCalGas had one of its regularly scheduled auctions of its auction preferred stock. The stock was auctioned at 2.5% which, when compared to the commercial paper rates, is roughly about 78% of commercial paper costs, "and that is the best that that auction issue has done in over a year." (Tr. Todaro at 424.)

Abrams' second reason for maintaining a good credit rating is that higher debt costs are associated with lower ratings. "All things equal, over time ratepayers of the better rated utilities will benefit from lower debt cost." (SCE-9 Abrams at 12.) When asked to quantify the dollar impact of a downgrade, in terms of financing costs or commercial paper rates to a utility, Abrams was unable to do so. The spreads between one credit rating and another, or the spreads between a specifically rated debt issue of a company relative to government securities, vary at different times. When total debt costs are low, then the spread tends to narrow because there is some floor. When interest rates go up, that spread widens. (Tr. Abrams 922.) Legler concurs that a rating's effect on the ability to attract capital depends on the rating assigned and the status of the capital markets. (Tr. Legler at 525.)

Legler believes some general differential in borrowing costs for rating classes can be ascertained by the spread between A and AA bonds over the years. (Tr. Legler at 557.) PG&E also cited this method. (Tr. Mountcastle at 201 and PG&E-1B Dore at 2-6.) While the differentials increase as interest rates go up, another factor is that the terms of an issue may vary according to the economic times. (Tr. Legler at 558.) For example, "when times are tight, companies experience difficulty. They have to be more generous in terms of call provisions to protect the investor. So the whole story is not told in the interest rates themselves." (Id.) Therefore, a specific number for the differential cannot be given. Whether the cost of capital is higher or lower depends on the extent of downgrading and whether the company subsequently goes to market with an issue. It might very well result in a higher cost of equity on a new common stock issue, but it does not change the cost of outstanding isssues. There "certainly may be" some detrimental effects on existing bondholders. (Tr. Legler at 524.)

We find that these statements must be assessed against SDG&E's actual experience. When SDG&E was a BBB company, it was much harder to access the financial markets and raise capital in times of high interest rates when there was a capital crunch. There were periods in 1978 and 1979 when SDG&E, as a BBB company, could not sell debt or, if they did sell debt, found "a very significant difference in cost" versus A or AA rated companies. However, at that time, people were worried about interest rates and what was happening in the economy and were looking for safer investments. Therefore, even though BBB was still investment grade, investors shied away from SDG&E's debt. By contrast, in today's environment, SDG&E's Malquist states, "I'm not aware of any BBB company who would have trouble attracting capital just based on their debt rating. There might be other things associated with the company that would cause them some problems. But just based on debt rating, a BBB today would not have any trouble financing." (Tr. Malquist at 303.) We concur with Malquist's assessment. We find that the utilities have not quantified any higher debt costs related to current economic environment.

Abrams asserts that other alleged costs, besides interest expense, when a downgrade occurs include an increase in the cost of purchased power, because the IPP takes its contract with the utility for project financing, and the bank looks at the underlying utility's credit. If the contract is with a utility rated BBB, the bank will likely mark up the underlying utility's borrowing cost 100 basis points to determine the IPP's borrowing costs. This in turn gets factored back into the capacity payment to be made by the utility. Therefore, IPPs like to deal with well-rated utilities so that they can obtain financing at lower costs. (Tr. Abrams at 922-923.) IPP financing will become more difficult and costly if the credit rating of the underlying utility erodes. (Tr. Abrams at 927.) However, the record contains no specific financial examples of this occurring, except a brief reference to Nevada Power by Fohrer. (Tr. Fohrer at 77.) We find insufficient evidence to assess the effect of utility credit ratings on IPPs.

Abrams' third reason for maintaining high credit ratings is the maintenance of operating and financing flexibility. A company that is able to maintain its credit rating is better able to take advantage of cost saving opportunities. A company with financial reserve can buy at will if a piece of equipment becomes available, since it either has funds on hand or has good access to capital markets. (SCE-9 Abrams at 12-13.) Utilities typically operate closely because they have relatively high debt ratios without large amounts of margin. Therefore, they do depend a great deal upon capital markets for financing. (Tr. Abrams at 967.) We believe this financial and operational flexibility must be shown to inure to the benefit of the ratepayers as well as the utility. The record again lacks a quantifiable showing of benefit to ratepayers.

Abrams asserts that allowing a high enough common equity ratio or low enough debt ratio and allowing high returns on equity in order to maintain a utility's financial integrity is not something that can be done overnight. Instead, it is a continuous, ongoing process. (Tr. Abrams at 890.) A company must not let the bond rating deteriorate and must improve it consistently to get to where it wants to be and then must work to hold it there. (Tr.

Abrams at 896.) A company can absorb more risk in its current rating category if there is an equity cushion. While Abrams states that raising the common equity ratio must be a gradual process because you cannot wait until you are about to be downgraded to sell enough stock to provide the equity support, he admits, in some cases, a company will be given more time to act on a commitment to take corrective action before a downgrade occurs. (SCE-9 Abrams at 26.) We observe that Edison was permitted to take such corrective action recently. "We don't pretend to control what a company does, but they want to maintain a certain credit profile. They know what they have to do to raise the money that they want to raise." (Tr. Abrams at 942.)

Abrams asserts that, usually, when a credit rating drops, it is hard to reverse it. Instead, once the company starts deteriorating, it is very hard for a regulatory commission to reverse the process and the tendency is to keep going downward in the ratings. (Tr. Abrams at 927.) No testimony related this to the specific experience of any California utility, which would be especially relevant in light of SDG&E's experience as a BBB, SoCalGas' recent downgrade by Moody's with confirmed ratings by S&P and Duff & Phelps, and Edison's recent upgrade by Duff & Phelps followed by a downgrade by Moody's. However, Abrams contends that the longer the Commission delays in permitting corrective measures, the harder it is for the utility to take them. If the utilities sell equity without the Commision's approval of the added equity in their capital structures, it will raise their equity ratio, but their earnings will not be raised, which is a problem for the rating agencies to consider. This would cause Duff & Phelps to relook at the California ratings and its favorable rating of California regulation. (Tr. Abrams at 945.)

When assigning the ratings, agencies take a long-term view. Ratings do not flip-flop when a company's numbers change from quarter to quarter or necessarily even from year to year.

Instead, the agencies talk to a company, and assess what the company is going to do about these changes and whether they can correct them over the long term. (Tr. Abrams at 898.) The rating agency considers the seriousness of the problem, whether it will be an ongoing problem, whether the company will correct it, and how much money that will cost. (Tr. Abrams at 935.)

The California utilities' high market-to-book ratios, in the 140% to 170% range, would not affect, except in some remote way, a credit analysis of their debt. However, when market-to-book ratios are over 100%, we concur with Abrams that it does mean that a company is readier to sell equity as necessary and would be able to realize more money from the equity's sale to support the debt ratio. (Tr. Abrams at 922.)

We find the record discloses a variety of ways to compensate for the rating agencies' treatment of the PPAs as off-balance sheet debt. Corrective actions to avoid a downgrade would include a promise to sell more equity and increase the equity ratio or cost-cutting, such as eliminating or re-examining a construction program and/or cutting back on repairs or other expenses. (Tr. Abrams at 942.) However, Abrams contends that everything that the utility can do to mitigate the financial risk of purchased power is then subject to Commission review, requiring the regulatory commission to be on board for the policy for the company to retain the benefits of its actions. (Tr. Abrams at 959.) Other ways to alleviate the PPA debt equivalents are an increase in the utilities' ROEs in this proceeding, or the combination of an increase in ROE and more equity cushion in the capital structure. (SCE-9 Abrams at 24-25 and Tr. Abrams at 907-908.) Increased preferred stock is another way to balance the capital structure. (Tr. Fohrer at 84.) Another method is a fee or mark-up on the PPAs, so that the investors earn the return for taking that risk through the contracts as opposed to through an adjustment to the utility's capital structure. (Tr. Mountcastle at 200.) S&P cites incentive return mechanisms and laws or regulations eliminating disallowance risk as possible solutions. (PG&E-2 Mountcastle, Creditweek at 15.) Open transmission access may alleviate the status of PPAs as debt equivalents. (SCE-9 Abriams Exhibit 1 at 7.) Also, moving asset and revenue mixes toward less risky transmission and distribution (SCE-9 Abrams Exhibit 3 at 1) or liquidating debt in proportion to decline in rate base (SCE-9 Abrams Exhibit 1 at 7) may lower risk profiles.

When asked by the ALJ whether the California utilities could conceivably be upgraded if they were given their requested returns on equity and extra equity cushions, Abrams responded: "That's an interesting concept. I think it is within the realm of possibility that there could be some movement upwards, or at least strengthening within a rating, assuming nothing else happened that was adverse..." (Tr. Abrams at 957.) However, as Abrams does not try to threaten downgrades, he also does not try to promise upgrades. His general impression is that it would be regarded as constructive and, while he could not promise an upgrade, it would be a favorable development. (Id.) Although we value being recognized as having a favorable regulatory climate, we are troubled that corrective measures might result in upgrades at the expense of ratepayers, rather than maintenance of current rating positions.

We now turn to the specific financial impacts of the PPAs on each of the utilities.

b. Edison

Edison's purchases from QFs have increased ten-fold since 1985 and are one-third of Edison's energy mix and over two-thirds of its fuel and purchased power budget. (SCE-1 Fohrer at 14.)[5] It has approximately 280 PPAs. (Tr. Abrams at 903.) Edison pays over $600 million annually in capacity charges. (Tr. Kahlon at 825.) We agree, however, with Kahlon that although these numbers, as well as those for PG&E and SDG&E, sound very significant, they are not necessarily significant for purposes of determining the requested increase in equity ratio. (Id.) It is necessary to assess these numbers in the proper context. We believe that context is lacking in the record due to the blending of the rating agencies' financial structure analysis with our ratemaking structure, and the failure to provide financial data to sort out the two.

Edison has been assigned $605 million of debt equivalents due to PPAs by S&P. (SCE-2 Simpson at 5-6.) These are the debt equivalents used in computing the debt leverage ratio. Even though Duff & Phelps assigns a higher dollar amount of debt equivalents in computing this ratio, Edison's presentation used the more conservative 10% assessment of S&P. (SCE-1 Fohrer at 5-6.) Like PG&E, Edison presented no analysis of the effect of the PPA/debt equivalents on its interest coverage ratios. Under the S&P method, 10% of the $605 million or $60.5 million would be used when calculating the interest coverage ratio. Under Edison's current financial capital structure, its total debt leverage is shown by way of bar chart at 53.4%, which includes 5.1% PPAs, 2.1% Palo Verde debt, 3.3% short-term debt,[6] and 43.0% other debt.[7]

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5 Simpson states QFs are over one-half of its fuel and purchase power budget. (SCE-2 Simpson at 4.)

6 Edison is also requesting, outside the PPA adjustment, increased equity for $390 million in fuel inventory short-term debt which is included in its bar graphs on debt leverage. See Section VI.B. infra.

7 We assume a rounding up of decimal points results in these figures totalling 53.5% while the chart shows 53.4%.

Another bar graph discloses that, if the ratemaking capital structure changes are granted, Edison's financial basis debt leverage would be 50.7%. (SCE-2 Simpson at Chart 2.) Edison admits some of the debt stress ($251 million) is attributable to the short-term Palo Verde deferred debit account, which we do not recognize in Edison's ratemaking capital structure, but contends it has not included this amount in its ratemaking capital structure request. (SCE-2 Simpson at 6-7.) We note it is included in the Chart 2 bar graphs showing the percentage leverage ratios on a financial basis before and after the equity increase. However, since no financial data is given, we cannot ascertain its effect, or the effect of the $390 million in fuel inventory debt.

Also reducing Edison's common equity and shaving away some of its equity ratio have been the write offs of a portion of San Onofre and the recent write off for the Mission Energy purchased power costs. (Tr. Abrams at 896.) The effect of these disallowances is not shown to be insulated from the effects of the PPA debt equivalents when calculating the equity increase.

Edison is still rated in the AA class by S&P even though its debt ratio is above S&P's 52% debt leverage maximum for A utilities. (SCE-1 Fohrer at 5.)[8] Edison has only recently been upgraded to AA by Duff & Phelps, having been an AA-. It could readily go back down into the A category. (Tr. Abrams at 876 and SCE-9 Abrams at Exhibit 6.) Abrams believes at one point Edison was rated A+ by Duff & Phelps. (Tr. Abrams at 929.) Prior to Duff & Phelps' November 1991 upgrade of Edison to AA, Edison committed to Duff & Phelps that Edison would raise its equity ratio and did in fact begin to sell additional shares. (Tr. Abrams at 895.) Last year Edison issued $200 million in additional equity. (Tr.

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8 While Edison cites 52% as S&P's maximum debt leverage, PG&E and SDG&E each declare the range to be from 44% to 54%. (PG&E-2 Dore at 2-4 and SDG&E-4 Montgomery at 5.)

Fohrer at 45.) Edison is currently rated Aa3 by Moody's (equivalent to AA-), and AA by Fitch Investors Service, Inc. (Fitch). (SCE-9 Abrams at 10.) During the last several years, Edison's financial capital structure has included substantially higher leverage than it carried for most of the 1980s, largely accounted for by PPAs, the fuel inventory short-term debt and Palo Verde (SCE-1 Fohrer at 4-5 and SCE-2 Simpson at 6-7), none of which is recognized by the Commission in the ratemaking capital structure. Yet, Edison attempts to pile the PPA debt equivalents on top of $390 million in short term debt and $251 million in Palo Verde deferrals in requesting us to take note of the high financial basis leverage caused by the PPAs. Therefore, we believe Edison's assertion that it is over S&P's limit for debt leverage must be assessed with this in mind. Without financial data to support the bar chart, we cannot assess the effect of past disallowances, Palo Verde and the short-term debt on the ratemaking equity request.

This year Moody's downgraded Edison to Aa3 from Aa2, (SCE-1 Fohrer at 5.) Edison contends Moody's debt leverage ratio for Edison is 55%, prior to consideration of the debt equivalence of the PPAs. (Tr. Fohrer at 51.) The February 17, 1992 Moody's Bond Survey states in its entirety:

> "Effective February 7, 1992, Moody's lowered the long-term credit ratings of Southern California Edison Company. The Prime-1 short-term debt rating remains unchanged. The company's new ratings reflect the expectation that financial flexibility will continue to be burdened by a high proportion of debt. Although on-balance-sheet leverage should decline modestly over the intermediate term, total leverage will remain high. In addition, reported leverage ignores significant large-scale purchased power commitments and their associated risk.
>
> "Southern California Edison maintains an on-balance-sheet capital structure with a total debt component that is expected to

> decrease only moderately over the next several years, a period of small but steady financing needs. Debt-protection concerns are magnified by substantial off-balance-sheet purchased-power commitments. Currently, SoCalEd's purchased power represents approximately 33% of its capacity and 43% of its energy. We recognize that sources of utility-owned generation and purchased power vary and that different levels of financial risks are associated with each source. We believe, however, that all sources of power, both those of a contractual nature or company-owned assets, require equity support to offset the financial risk assumed by the utility. At present, the risk factor in purchased-power commitment is not recognized by rate regulators. Where high levels of purchased power exists, as in the case of SoCalEd, added equity is appropriate, and rating pressure will be downward if regulators do not respond with supportive rate treatment.
>
> "Significant positive developments supporting the revised ratings are SoCal's much improved regulatory relations with the California Public Utilities Commission and common equity infusions. We believe that the 1992 general rate case decision and the agreements in principle dealing with the affiliated transaction issue (for parent SCEcorp's Mission Energy Group) as well as the San Onofre Nuclear Generating Station Unit 1 retirement may indicate a more balanced relationship with the commission in the future." (SCE-9 Abrams Exhibit 7.)

However, Edison's cash flow is strong and its quality of earnings is good. (Tr. Fohrer at 62.)

While Moody's downgraded the bond rating one level, it took the preferred stock rating down two levels to an A+. (Tr. Abrams at 927.) However, Abrams thought Edison was the only company through the 1980s that had the same rating, by Moody's and S&P, on its preferred stock as it had on its debt, which signals a very strong debt rating. (Tr. Abrams at 926.) Because Moody's took Edison's preferred rating down two levels when it took the debt rating down one level, it signals an even weaker AA- rating. Abrams assumes Edison went from the top of the AA category to closer to the bottom of the AA- category on its debt rating. (Tr. Abrams at 927.)

The February 17, 1992 Moody's Bond Survey also included a report on Edison's shelf sale of $200 million of 5.55% first and refunding mortgage bonds Series 92A, 2/1/1995. No testimony was presented by Edison regarding the impact of the lowered bond ratings on that financing. When asked by the ALJ whether Edison had any sort of calculation or study showing what financial differences the downgrade by Moody's would actually make in Edison's costs or what the overall result would be on costs if Edison were downgraded a step further, Fohrer stated that the impact of a downgrade could be calculated on the issuance Edison will make next year and that it would be "relatively small." (Tr. Fohrer at 76.)

But Fohrer contends the Commission should look at the broader picture because the investment and financial community do. Once a utility is downgraded it is very difficult to get the ratings back because the agencies are more concerned with the trends. (Tr. Fohrer at 76.) To back up this assertion, Fohrer cited the fact that when Edison's capital structure did not even support a BBB rating, during the construction of San Onofre and Palo Verde, and Edison had essentially junk bonds, the rating agencies kept its rating due to Edison's commitment to credit quality and the fact that it issued tens of millions of shares of stock below book value in order to support the credit rating in the best long-term interest of the company. (Tr. Fohrer at 76.) Since there appears to be so much elasticity in the analysis of the financial ratios, we view this as evidence which mitigates Edison's status as the highest leveraged AA in the country (Tr. Fohrer at

51) and contradicts the necessity for increasing the equity cushion to maintain Edison's rating.

Although Fohrer asserted that only a promise of adding additonal equity support averted a downgrade by S&P, he did not supply the reason for the threatened downgrade or the date this occurred. (SCE-1 Fohrer at 7.) We note it is not referenced in the Exhibit PG&E-2 letter from S&P which does reference two large regulatory disallowances. Exhibit 6 to Abrams testimony shows that on June 15, 1992, Edison was not under a ratings watch by S&P. On January 6, 1992, S&P stated as to Edison, "Given the company's extremely strong cash flow and manageable construction needs, the financial impact of [PPAs] is not substantial enough to impact ratings." (DRA-6 Kahlon at 3-16.)

Although Edison's high leverage continues to be of concern to Duff & Phelps, many factors are involved in the determination of its credit rating. In the past, Edison looked very good qualitatively to Duff & Phelps. It is Duff & Phelps' opinion that Edison is the least risky of the three large California energy utilities. (Tr. Abrams at 874.) The June 15, 1992 Duff & Phelps' rating report on Edison observes that the last Duff & Phelps' change in Edison's bond rating occurred in November 1991 when Duff & Phelps upgraded Edison's first and refunding mortgage bonds from AA- to AA and that Edison is not under a rating watch by Duff & Phelps. (SCE-9 Abrams at Exhibit 6.) The text of the report states in its entirety:

> "Reasons for Rating Edison is a well managed utility with a diverse service territory, a regulatory climate which generally has been constructive, good cash flow, and rate mechanisms that help stabilize the company's earnings and reduce regulatory lag. Management has demonstrated a commitment to maintaining the company's financial measures. Construction expenditures are expected to be stable and largely financed internally. Debt leverage is expected to improve as

> short term debt is reduced from recovery of Palo Verde deferrals. Major uncertainties are expected to be removed under settlements of purchased power contract disputes with an affiliate and the treatment of the early shutdown of San Onofre Unit 1. The settlements are subject to CPUC approval. Reported coverages are lower when adjusted for purchased power capacity payments. However, Edison is pursuing more adequate regulatory treatment to offset the risk of purchased power.
>
> "Current Developments In April, the CPUC issued a decision on the Company's Resource Plan. The decision was more advantageous to Edison in several areas (updating gas price assumptions and using environmental externalities based on point-of-production guidelines rather than point-of-consumption guidelines) than the ALJ had recommended. However, the 'Environmentally Sensitive Least Cost' Resource Plan requires Edison to bid on needed capacity ultimately resulting in higher cost to ratepayers. Our forecasted earnings in 1992 are under downward pressure. The Company is reducing costs to live within the level of operation and maintenance expenses authorized by the CPUC in the 12/91 general rate case.
>
> "Major Risks Major risks include a shift in regulatory treatment, customer bypass from high rates, and a reliance on purchased power." (Id.)

We observe that the analysis states that debt leverage will improve as the Palo Verde deferrals are recovered. It also references the pending settlement of disallowances on San Onofre and Mission Energy. We should not recognize PPAs as debt equivalents with impacts on the financial debt leverage ratios until we can be assured this does not undo our treatment of disallowances, Palo Verde and short-term debt.

Fohrer asserts that, if Edison does not have reasonable bond ratings, it would affect Edison's ability to issue commercial paper, upon which Edison relies heavily since it has a billion dollar commercial paper program. While bond ratings and commercial paper ratings do not go quite in lockstep, they are similarly affected. Thus, Edison cannot issue commercial paper into a market which will not accept the lower-rated paper. (Tr. Fohrer at 77.) Because no supporting figures accompanied this assertion, we reject this contention.

Edison contends that if the Commission fails to give Edison an equity cushion to offset the PPAs, the only thing Edison can do to preserve its bond rating and creditworthiness is to issue stock, have the shareholders take a diluted value, and transfer that money to the benefit of the bond holders. (Tr. Fohrer at 78.) Fohrer asserts this would also have adverse effects on Edison's stock price and would be viewed as a negative trend. (Tr. Fohrer at 79-80.) As interest rates and the rates of return have come down, Edison believes there is a perception of declining utility earnings. Edison's earnings per share in 1987 were $3.27 on the utility, whereas today they would be below $2.90. (Tr. Fohrer at 81.) Considering where the earnings are going and the expectations of the shareholders, Edison asserts it cannot keep spending shareholder money to support the credit rating if the Commission will not provide additional equity support. (Id.)

Fohrer states that Edison's shareholders have lost 6¢ in earnings per share this year in order to support credit quality, and if the Commission does not grant the 2 percentage point change in the equity ratio, there will be an additional 12¢ loss to the shareholders in 1993. (Tr. Fohrer at 81.) Therefore, if the Commission defers the decision of the PPA/debt equivalent issue until next year, Fohrer is not certain that management could issue stock in the interim due to the balancing act between shareholder earnings and credit quality. (Tr. Fohrer at 81.) Yet, we observe that Edison has done this in the past when it was a BBB and its current high market-to-book ratio must be considered when assessing Fohrer's contention.

Edison is the only utility which has already issued new common stock. Therefore, this also must be factored into Fohrer's claims of reduced earnings. Also, as observed by DRA, a portion of the $200 million equity offsets a $94 million charge to equity taken in 1991 to reflect Commission disallowances and an additional reserve for pending legal and regulatory matters which drove down Edison's common equity ratio. DRA disputes Edison's calculations for this reason and believes the net effect of the new issuance is really to restore the equity ratio to its authorized ratemaking level. (Tr. Quan at 720-722.) We concur with DRA's analysis.

While we applaud Edison's efforts to achieve or maintain AA status, we are troubled by the lack of specificity in proving that a rating within the AA range inures to the benefit of its ratepayers when evaluating its request that we facilitate maintenance of AA status. We have declared that our overriding concern is the equity ratios we adopt "are no greater than required to maintain reasonable credit ratings..." (D.91-11-059, mimeo. at 7.) Since Edison is the only utility in the AA category, absent more financial detail and demonstrable financial studies of the reasonableness of remaining in the AA range, versus the A range, we cannot at this time justify permitting the equity cushion increase to preserve AA status.

Based on the record, Edison has not carried its burden of proof on the necessity to remain in the AA range and the need to increase its ratemaking equity ratio in its authorized capital structure due to its PPAs.

c. <u>PG&E</u>

PG&E is currently rated A by Duff & Phelps, A by S&P, A1 by Moody's, and A by Fitch. It is not presently under a threat of downgrade due to the PPA/debt equivalents. (Tr. Mountcastle at

200.) PG&E has approximately 600 PPAs. (Tr. Abrams at 903.) PG&E's 1993 energy purchases from QFs are forecasted to be 24% of its total generation capacity, with capacity payments of over $400 million annually. (Tr. Kahlon at 825.) Under S&P's methodology, PG&E would have $354 million in increased debt due to the PPAs when computing its debt leverage ratio. Under the method employed by Duff & Phelps, based on a discounted net present value of PPAs of close to $4 billion, PG&E would have increased debt of $1.5 billion for calculation of debt leverage. (PG&E-1 Mountcastle at 1-10 and 1-11 and PG&E-1B Dore at 2-5 and Tables 2-5 and 2-6.) PG&E contends that under these analyses, its ratemaking equity ratios must be increased to between 48 and 52%, depending on the method used, in order to totally offset the effects of the PPAs as debt equivalents. (PG&E-1B Dore at 2-5) PG&E actually requests an increase to 49.50%. Based on the less draconian S&P calculation for the financial effect of PPAs, a 48% equity ratio would be the minimum increase that would at least partially compensate PG&E for that PPA financial risk. (Tr. Mountcastle at 203.) Although it was not stated in its application, at hearing PG&E declared it would issue additional common stock to match the equity increase granted in this proceeding. (Tr. Mountcastle at 169.)

Although PG&E provided some numbers to support its leverage calculations for ratemaking purposes, it fails to give financial data which discloses the amount of debt in its financial capital structure which is not recognized by us in our ratemaking capital structure. Dore's Tables 2-5 and 2-6 show the debt equivalents' effect on the ratemaking capital structure of PG&E. Using the S&P method, the debt leverage is shown at 49.23% when including the PPA debt equivalents in the ratemaking basis calculations, which will lower to 47.97% after an increase in common equity to 46.23% in the ratemaking capital structure. (PG&E 1B Dore at Table 2-6 and Chart 2-2.) The common equity ratio increases to 48.02% when taking out the debt equivalents in the ratemaking capital structure. (Id.) Under the Duff & Phelps method, the debt leverage is shown at 53.29% when including debt equivalents in the ratemaking basis calculations, which will lower to 48.30% after an increase in common equity to 46.73% in the ratemaking capital structure. (PG&E-1B Dore at Table 2-5 and Chart 2-2.) The common equity ratio increases to 52.20% when taking out the debt equivalents in the ratemaking capital structure. (Id.) Table 2-7 shows that if common equity is increased in the ratemaking capital structure to 49.50% with long-term debt leverage of 45%, then on a financial basis, the common equity will be 45.80% and debt leverage 49.11%.[9]

No interest coverage ratios were calculated by PG&E. The record does not contain sufficient data for us to calculate them. However, S&P's PPA adjustment would only be 10% of the $354 million or $35.4 million. Duff & Phelps' adjustment would be 1/3 of the annual capacity charges, but we do not have in the record the data to translate this into a dollar amount. The financial data we have also does not permit us to calculate these adjustments' effects on PG&E's coverage ratios.

PG&E's policy is to maintain at least an A bond rating on debt supporting non-Diablo Canyon utility assets. (PG&E-1B Dore at 2-3.) It did not identify how this equates to the analysis actually used by the credit rating agencies. S&P's most recent debt leverage benchmark for obtaining an A rating is between 44% and 54% for electric and combination utilities. (PG&E-1B Dore at 2-4.) PG&E's debt leverage was at 52.26% on a 1991 year-end financial basis, based on excluding Diablo Canyon and subsidiary capitalization, but including short-term debt and capitalized leases. (Id.) However, on March 2, 1992, S&P declared that the

9 It is unclear from the presentation whether these figures include the dollar impact of the actual issuance of new equity.

risks of purchased power and the resulting debt leverage adjustment are not material enough to impact PG&E's credit-worthiness. (DRA-6 Kahlon at 3-16.)

Duff & Phelps has talked with PG&E consistently about the need to gradually raise its common equity ratio, but some has been shaved away by the write-off of a portion of Diablo Canyon. (Tr. Abrams at 895-896.) Duff & Phelps regards PG&E as the riskiest of the three utilities. (Tr. Abrams at 874.) PG&E cites Duff & Phelps' assertion that a heavy reliance on purchased power ultimately leads to a tapering off of rate base growth which in turn diminishes future earnings power, dividend prospects, and internal cash generation, and unless debt is liquidated in proportion to the decline in rate base, debt protection measures for bond holders will diminish and risk will increase. (PG&E-1 Mountcastle at 1-12.)

We find that the erosion of protection for bondholders predicted by the Duff & Phelps report is only illusory as to PG&E. PG&E still is experiencing growth in transmission and distribution plant and overall there is growth in PG&E's rate base. (Tr. Mountcastle at 194.) Since PG&E's overall rate base is not actually declining, and PG&E manages its capital structure on the utility side so that its debt is approximately what PG&E has authorized in its capital structure, this Duff & Phelps' concern is not really applicable to PG&E. (Tr. Mountcastle at 193-194.) While Mountcastle claims shareholders are losing the ability to earn a return on rate base due to increased reliance on purchased power versus building new generation plant (Tr. Mountcastle at 193), PG&E is expanding its transmission and distribution plant which provides returns. While PG&E asserts that if third-party providers operate unreliably or abandon uneconomic plants, PG&E's planning risk increases, it admits, to date, this has not occurred that frequently. (Tr. Mountcastle at 198.)

PG&E contends that even though there is no downgrade threat, it still faces the same increased financial risk because the risk includes whether a company is downgraded or whether a company just moves down within its current ratings category. (Tr. Mountcastle at 200-201.) PG&E's policy is to be a strong A and the PPAs' effect on the financial ratios would move PG&E away from being a strong A and therefore closer to a BBB category. By maintaining an A rating, PG&E has a stabler financing cost because it retains financial flexibility which it would lose should it be downgraded to the BBB level. (Tr. Mountcastle at 201.) When asked by the ALJ whether PG&E had done any studies on borrowing costs that would be passed through to its ratepayers if it were downgraded, Mountcastle had no specifics on the difference between A and BBB, but "It would definitely cost us more to borrow. I don't have a specific number for how much more that would be." (Tr. Mountcastle at 202.) The only specific effect of an A- rating would be to leave PG&E less room if an unexpected event might result in a downgrade. (Tr. Mountcastle at 202.) We find this is an insufficient rationale for increasing the equity ratio.

Based on the record, PG&E has not carried its burden of proof on the necessity to increase its ratemaking equity ratio in its authorized capital structure due to its PPAs.

d. <u>SDG&E</u>

SDG&E requests an increase in its common equity ratio from 49.50% to 52.50% to compensate for the impact of its PPAs. Although not stated in its application, SDG&E presently intends to issue additional equity to increase its financial equity ratio to match any Commission-authorized increase. (Tr. Malquist at 250.) SDG&E is currently rated A+ by Duff & Phelps, A+ by S&P, Aa3 by Moody's, and A+ by Fitch. Because SDG&E's interest coverage is in the 4.0 to 4.1 range, SDG&E might be thought of as an AA utility, but was rated A+ by Duff & Phelps "reflecting its large purchased power burden and the expectation that purchased power will increase for the company over time." (SCE-9 Abrams at 20.) SDG&E has maintained higher coverages and a higher capital structure because of its purchased power strategy. (Tr. Abrams at 895.)

For SDG&E, purchase capacity represented 33% of total generation in 1991. (SCE-9 Abrams at 25.) For 1993, QF purchases are forecasted at 33% of total generating capacity with capacity payments of over $300 million annually. (Tr. Kahlon at 895.) It is the only utility with significant purchases from non-QF sources. (DRA-6 at 3-14.)

SDG&E's current financial objectives are to maintain a minimum 65% internal generation of funds for construction expenditures, a minimum 3.75x interest coverage ratio (including an allowance for funds used during construction) and a financial basis capital structure of:

Total debt	46-49%
Preferred stock	5-7%
Common equity	45-48%.

SDG&E has achieved its minimum level of internal generation since 1984. Interest coverage has been at or near its minimum target level since 1985. It has achieved the minimum level in its equity target range. (SDG&E-1 Malquist at 2.) One of the most commonly asked questions at investor presentations is whether and how SDG&E's present and future PPAs will affect the utility's financial strength. (Tr. Malquist at 264.)

S&P has currently assigned SDG&E a purchased power debt equivalent of roughly $300 million, and an interest expense equivalent of $30 million. (SDG&E-5 Montgomery at Exhibit L.) This S&P adjustment raises SDG&E's financial debt leverage ratio to the very top of the guideline range for single-A rated utilities. (SDG&E-2 Malquist at 1.) The requested 3% increase in SDG&E's authorized common equity ratio is allegedly just over half the impact of the S&P purchased power adjustment on the company's ratemaking debt ratio. (SDG&E-2 at 1.)

SDG&E's Exhibit L is not an S&P credit analysis of SDG&E. It is merely a letter from a director of the S&P ratings group, dated August 6, 1992, stating that at the request of SDG&E S&P has looked at the impacts of PPAs on the company's financial profile. It notes S&P has always factored the minimum capacity payments of take-or-pay contracts into SDG&E's ratings but now the Arizona Public Service Co. and Public Service Co. of New Mexico contracts look less restrictive than pure take-or-pay contracts. It also references S&P's new take-and-pay risk analysis. Ms. Richer concludes:

> "Adjustment of year-end 1991 statistical ratios results in roughly a 60 basis point decrease in pretax interest coverage, a 70 basis point decrease in funds from operations interest coverage, and a 500 basis point increase in total debt to total capital."

> "This preliminary analysis is subject to a full review and consensus of our utility group. Since the risk factors applied to each contract in determining the aggregate debt equivalent are somewhat are subjective, the final results may differ slightly from those indicated above."

This letter does not specify the take-or-pay risk factor, the overall weighted average of it and the 10% take-and-pay risk factor, or the dollar amount of non-QF contracts. Montgomery contends his calculations produce an overall weighted risk factor of 36% based on this letter. (SDG&E-5 Montgomery at 1.) No financial data accompanies this assertion. We also observe that SDG&E's brief cites the originally higher 40% weighted factor (a weighted average of an alleged 50% risk factor assigned by S&P to SDG&E's take-or-pay contracts and a 10% risk factor assigned for the take-and-pay contracts) which was superceded by SDG&E-5. (SDG&E-4, Montgomery at 3.)

On a financial basis, SDG&E's debt includes 3.3% which is short-term and 5.1% attributable to capital leases in addition to

40.9% long-term, for total debt leverage of 49.39% absent PPA debt equivalents. The 36% weighted risk factor of S&P results in a financial debt ratio of 53.9%. (SDG&E-5 Montgomery at Exhibit N.) S&P's guideline range for single-A rated utility debt ratios is 44 to 54%. (SDG&E-4 Montgomery at 5.) Were the Commission to grant the PPA equity cushion, and the non-PPA 50 basis point increase in long-term debt coupled with a 50 basis point decrease in preferred stock, after the 36% S&P PPA adjustment, SDG&E's financial debt ratio would be 51.2%.[10] (SDG&E-5 Montgomery at Exhibit N.)

Exhibit M performs a similar analysis on the ratemaking ratios. SDG&E's requested ratemaking long-term debt ratio (without a PPA equity cushion increase) of 45% is raised to 50.1% after the S&P adjustment. This calculation also reflects the non-PPA 50 basis point increase in debt and corresponding decrease in preferred stock which SDG&E requests. Similarly, if the Duff & Phelps' 33% risk factor adjustment were calculated into SDG&E's 1993 ratemaking capital structure, its debt leverage ratio would be 52.5% and its common equity ratio 42.8%. (SDG&E-5 Montgomery at Exhibit M.) There is also no information in the record as to Duff & Phelps' range for debt leverage of single-A utilities. If the PPA equity cushion is granted, Exhibit M does not cite what the actual ratemaking impact would be on the capital structure under either the S&P or Duff & Phelps analysis. Instead, it merely shows the SDG&E request for a 42% long-term debt ratio and 52.5% equity ratio. (SDG&E-5 Montgomery at Exhibit M.)

In 1991 SDG&E achieved an interest coverage level of 3.8x, which would fall to 3.0x using the Duff & Phelps' method.

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10 We find this table misleading because it presumes the non-PPA capital structure adjustment which has the effect of increasing debt 50 basis points, which adds to the debt leverage effect of the PPAs, and also posits an equity increase "comparable" to the 300 basis points required. (SDG&E-4 Montgomery at 4.)

(SDG&E-4 Montgomery at 4.) SDG&E, presuming a 40% weighted average risk factor from S&P, states that the 1991 interest coverage level of 3.8x would fall to 3.2x. (Id.) This coverage ratio was not recomputed using S&P's new 36% risk factor, but should be higher. The record contains no indication of the rating agencies' accepted ranges for coverage ratios.

SDG&E does not demonstrably screen out the effects of the SWPL disallowance, short-term debt, and capital leases in making its equity cushion request.

SDG&E asserts our current ratemaking mechanisms encourage utilities to build rather than purchase capacity, resulting in a one-sided rate structure which necessitates a leveling of the playing field between buy-or-build strategies by recognizing the PPAs as debt equivalents. (SDG&E-5 Malquist at 5.) However, Malquist agreed that the issue could be addressed in the currently pending incentive investigation (I.) 90-08-006 for the electric and gas utilities as well as it could in this proceeding. (Tr. Malquist at 292.) Therefore, ratemaking adjustments in I.90-08-006 are a possible solution to the problem. (Id.)

Although contending that purchasing versus building erodes rate base, SDG&E admits it may be increasing its plant in the future.[11] SDG&E will need additional capacity and will use a combination of repowered generating facilities and power purchases plus the return to service of existing plants to obtain it. (SDG&E-1 Malquist at 7.) SDG&E has not built plants since San Onofre was completed in 1983 and 1984, but hopes to build some plants if the Biennial Resource Planning Update (BRPU) will allow it. SDG&E will probably have to bid all 1600 megawatts, but to the

11 This new generation plant is later alleged to increase SDG&E's risk in the ROE assessment, while in arguing for more equity cushion, the PPAs are argued to be riskier than building plant.

extent repowering is cheaper, SDG&E will repower. Of the 1600 megawatts requested, on roughly 450 megawatts SDG&E has been given discretion whether to build or buy the power. Although it is uncertain whether SDG&E will be allowed to build another generating plant, it hopes to, especially because it foresees repowering being the cheapest source. However, even if SDG&E builds, over half of of the 1600 megawatts will be met through purchased power. (Tr. Malquist 293-294.) We believe SDG&E has not properly factored into its analysis of the financial impacts of the PPAs, the effect of a new building and/or repowering program on its financial ratios.

SDG&E is not under any threat of a downgrade from any of the rating agencies, but has not visited the rating agencies since August 1991. SDG&E will revisit them in November 1992, after it has completed its filing with DRA on incentive regulation so SDG&E may discuss that filing in detail at the annual meetings. Malquist opined, "I think that Standard & Poor's, the rating is fairly safe. I think that Moody's is starting to focus more on purchased power. Moody's has a AA-. S&P is A plus. So I'm a little concerned about Moody's....I'm not envisioning a downgrade pending from Duff & Phelps." (Tr. Malquist at 289-290.) The PPA/debt equivalent factor is not going to have a concrete downgrading effect, just for that alone, for SDG&E for 1993. (Tr. Malquist at 290.)

When asked by the ALJ whether SDG&E had performed any studies showing the correlation between the impact of a downgrade and increased costs of commercial paper and borrowing and how that would flow down to the ratepayers, Malquist replied:

> "We were a BBB company approximately eight years ago and we did a very detailed study at that time, as I recall, to justify an upgrade to a single-A as SDG&E worked with the Commission. That would have been in the early 80's we did the study. We have not since done our own study of bond ratings. I've read a number of different theses on this point of work that have been done by experts in the field, and you

> can find opinions on both sides about whether you should be AA or single-A. But I think it's very clear in people's minds that you want to be in the single-A or above category rather than BBB. But justifying between the grades, it's a very difficult proposition." (Tr. Malquist at 302.)

We note the absence in the record of a comparable current study by any of the utilities to support the need to increase equity to preserve current bond ratings.

Absent more equity cushion, if SDG&E were put on notice it was in jeopardy of being downgraded, SDG&E's only choice would be to sell additional equity without getting compensated for it in the ratemaking structure. (Tr. Malquist at 301.) However, Malquist observed, "I do not believe that our bond ratings are in jeopardy at this point in time. We are doing everything we can, anyway, to maintain our existing bond ratings." (Tr. Malquist at 301.) We find SDG&E is not currently in a posture to require the increased equity cushion, even though it may have more overall financial impacts from its PPAs due to its take-or-pay contracts.

Based on the record, SDG&E has not carried its burden of proof on the necessity to increase its ratemaking equity ratio in its authorized capital structure due to its PPAs.

3. Conclusion

We find that the main concern of the rating agencies in assessing PPAs is the effect on the utilities' bondholders on a generic nationwide basis under general principles of finance. This is not our narrow focus. Our concerns embrace not only the investor, but fairness to the utilities, their debt and equity holders, and California ratepayers under our California regulatory scheme for PPAs. This is a fundamental reason why our ratemaking capital structure does not recognize many risks that the financial industry and its markets do. We also recognize that, for this reason, threats of ratings downgrades may be related to other factors besides PPAs.

It is clear that the credit ratings agencies are now treating PPAs as debt equivalents. This does not mean we must do so as well, because our regulatory focus is broader than the focus of the rating agencies. We believe it is premature, based on the record before us, to determine now whether PPAs are debt equivalents in our ratemaking capital structures. The rating agencies cite the current ratemaking scheme as one reason for their treatment of PPAs as debt equivalents. In I.90-08-006, we are in the process of refining the ratemaking treatment that is an underpinning of the analysis of the financial impact of the PPAs. The ratemaking mechanisms which favor building over buying power are being reconsidered. The problem may be alleviated, or at least modified, by our decision in that proceeding. We urge the rating agencies to re-examine their policies at that time. We, in turn, are willing to then re-examine ours.

We also observe that Duff & Phelps admits open access to transmission may alleviate the status of NUG PPAs as debt obligations. Open access is also an issue we are currently examining in I.90-09-050 and may remove the financial ratio impacts of PPAs. Therefore, our long-term view embraces both of these possible solutions.[12] We urge the rating agencies to embrace them in their long-term view of California trends.

We appreciate the willingness of the rating agencies to work with regulators to refine their methodologies. We welcome their input in our proceedings. We are willing to work with them to bring their views before this Commission in a non-partisan

12 Since it is not ascertainable whether our final decisions in I.90-08-006 and I.90-09-050 will alter the rating agencies' treatment of PPAs, the utilities may attempt to convince us that changes to capital structures before the resolutions of these proceedings are not premature. But we express concern over the impact on a capital structure with increased equity due to the PPAs should the rating agencies cease to treat them as debt equivalents.

posture. We recognize that economic, financial, and business theory should mesh with regulatory policy in order to provide the best business environment for the state and the best service and rates for our ratepayers. We acknowledge the importance of rating agencies' decisions in achieving this mix.

We also believe that the rating agencies should reassess their philosophies as to the California utilities and PPAs under our current California regulatory climate, rather than relying on a national, generic view, as do Duff & Phelps and Moody's. While S&P does appear to use a more state specific analysis in assigning its percentage risk factor, it still bases its analytical construct on some generic assumptions.

The utilities have not cited another state regulatory commission decision granting PPA-related equity increases, based on hearing evidence on the need for increased equity in ratemaking capital structures due to the debt equivalence of PPAs. The utilities' citation to Opinion 92-8 of the New York Public Service Commission, issued April 14, 1992, in Consolidated Edison Company of New York's (Con Ed) general rate case (GRC) does not meet this criterion. Con Ed litigated its GRC with a capital structure of 50% equity, the level set in 1985. After hearing, the staff and the utility proposed a settlement with a 52% equity ratio and an ROE of 11.5% for the first year and 11.6% for the second and third years. The recitation of the positions of the parties shows that staff asserted the appropriate ROE was 10.5%, but agreed to the 100 basis point increase as a stay-out premium over the three future years. The utility contended that the actual ROE was closer to 11% due to other features of the settlement. The staff also argued that one of several reasons for the increase in equity was the fact credit rating agencies are looking hard at off-balance sheet obligations, such as PPAs and accounts receivable financing. Staff asserted the rating agencies use a lower equity ratio when purchased power was factored into their analysis. Thus, staff deemed a higher equity limit desirable to stave off a possible bond downgrading. (Opinion 92-8 mimeo. at 11.) However, these arguments are merely the Commission's statement of the settlement proponents' positions. The Commission proceeds to summarize the positions of many parties objecting to the settlement's equity increase. It declares no witness testified in favor of the 52% equity ratio and that, "as explained, infra, by itself the 52% equity ratio might be inadequately supported, but this is not a fatal defect in the settlement." (Id at 64.) The Commission later declares that "a conclusion to be drawn from the record is that a 50% equity ratio should be adequate to maintain Con Ed's financial integrity. But a 52% ratio is rational in the context of the overall settlement when coupled with the designated equity return allowance." (Id. at 90.) Therefore, the Commission accepted the GRC settlement, with a few modifications.

We do not find Opinion 92-8 persuasive precedent. First, and most importantly, the PPA debt equivalence issue was not litigated. Second, Con Ed's actual equity ratio was above the 50% regulatory cap, shown by Valueline to be 54.1% for 1989, 53.3% for 1990, and 53.5% for 1991, (DRA-8) and the new 52% equity ratio also appears to be lower than the actual ratio. Third, the ROEs tied to the equity increase are even lower than those we set today and are locked in for three years. Indeed, the Commission concluded that, but for the three-year scheme, Con Ed could be assigned an ROE of 10.5%. (Opinion 92-8, mimeo. at 89.) Fourth, the settlement also permitted Con Ed to retain earnings up to 25 basis points over the authorized ROE but required 50/50 sharing with ratepayers of any excess earnings over this dead band. (Opinion 92-8 mimeo. at 65.) Finally, Con Ed's market-to-book ratio of 1.29 (Id. at 56) is lower than Edison's, PG&E's, and SDG&E's.

The only other precedent cited is Order No. 25805 of the Florida Public Service Commission dealing with a determination of need for a proposed electrical power plant of Florida Power

Company. In that case, Abrams, the Duff & Phelps witness presenting testimony in this proceeding, testified on credit rating agencies' treatment of PPAs. The Florida Commission concluded that:

> "The increased reliance on [purchased] power does not have to portend lower credit ratings. Just because a utility increases its reliance on purchased power does not mean that debt protection measures will deteriorate and a downgrade is imminent. In many cases, various qualitative factors may outweigh the quantitative factors." (Order No. 25805 mimeo. at 72.)

The Commission also observed that purchased power is not without its risks, just as constructing a plant contains risks. (Id.) It found that "it is generally not possible to point to an increased reliance on purchased power as the sole reason for a change in credit rating." (Id. at 72-73.) The Commission found that each of the utilities downgraded by Duff & Phelps had demonstrated a pattern of deterioration in its financial ratios over a period of time preceding the downgrade action. (Id. at 73.) Since Florida Power had steadily improved its financial protection measures since its last growth cycle, the Commission concluded its claim that additional PPAs would result in a credit downgrade to be exaggerated. (Id.) Our view of purchased power, based on the record, leads us to conclusions similar to those of the Florida Commission.

While our regulatory climate does not totally eliminate the risk of PPAs, we agree with DRA that our ratemaking mechanisms offset most of the risks of purchased power, especially for take-and-pay contracts. Our Interim Standard Offer 4 contracts are take-and-pay. They are pre-approved and carry a presumption of reasonability that mitigates disallowance risk. Our BRPU proceeding is an integrated resource planning process that helps avoid overcapacity and disallowance risks for any future contracts.

Our ECAC balancing account treatment of fuel costs reduces regulatory lag in recovery of purchased power costs and mitigates financial risk. While the Interim Standard Offer 4 pricing is currently uneconomic, it will convert to avoided energy pricing. We also concur with DRA that disallowance risk is nothing unique to PPAs for which extra compensation is due.

We believe that QFs and IPPs are reliable. Because they bear more risk than regulated utilities, their incentive is to keep costs down and to burn 24 hours a day in order to earn higher unregulated returns. Even if a QF or IPP goes bankrupt, other investors are likely to step in to purchase the assets in an attempt to salvage profit from its failure. In any event, if a QF or IPP is unable to generate, it does not get paid, and the utility may use the funds to make other arrangements. Therefore, the performance risk falls on the QFs and IPPs, not the utility. We think the possible utility risks associated with questions as to reliability of purchase power producers are overstated.

We also believe any focus on eroding rate base is misplaced. A lower rate base does not equal more risk. If a utility no longer has generating plant, it no longer has the cost of operating that plant or the debt load that the depreciation on rate base funds. This avoids financial deterioration during construction programs. The financial impacts of the PPAs do not override this avoided deterioration. We also have found that there are benefits to third-party generation in the reduction of the utility's exposure to large baseload plant risks. (33 CPUC2d 525, 573 (1989).)

We also question the impact by PPAs, versus building generation plant, on debt quality based on this record which is also devoid of studies specific to the present economic environment. We are unable to ascertain on this record whether an increased coupon rate on downgraded bonds will cost the ratepayers more or less than an increase in equity ratio and/or ROE. This is a crucial factor to consider. At present, it appears that any impact of PPAs would be to equity investors due to possible decreased earnings. Yet, this impact can be controlled by proper cash flow usage. What is now emerging is a shift in the dynamics of the electric utility industry which may change to a more competitive profile. The asset mix is shifting into less risky transmission and distribution segments of the electric business. The markets may adjust to this more competitive profile as to electric utilities. While we do not wish our electric utilities' ratings to erode, to alter their equity structure at this time could prevent that natural market adjustment.

The record in this proceeding discloses several options to compensate for the risk of PPAs under current ratemaking mechanisms--by increased common equity ratios, by increased ROEs, by a combination of the two, by issuances of preferred stock, and by cost savings by the utility. Edison and SDG&E are planning preferred stock issuances in 1993. Edison has already issued more common stock. In this proceeding, the utilities are asking for both increased ROEs and increased equity ratios.

The utilities argue bondholders are penalized if the bond rating drops and that equity should not be diluted to avoid this devaluation. However, such an adverse effect, if proven, would be only on present bondholders who do not hold the bonds until maturity. New bondholders can be compensated for the ratings at issuance by higher interest and other provisions. The utilities presented no evidence regarding a secondary market in their bonds. Indeed, SDG&E states that most of its bondholders hold them to maturity. (Tr. Malquist at 287.) We also believe the utilities fail to consider the flip side of their argument, that is, bondholders are rewarded in the secondary market if ratings go up or are maintained, and new bondholders would get the benefit of past added equity support. The impact of ratings changes is simply part of an efficient market system. Especially because utilities typically have high debt ratios and low margin (Tr. Abrams at 967), we believe investors are aware of potential movements in the ratings during the life of utility bonds, just as they are aware that if interest rates rise, their payments remain fixed. We also believe the utilities' arguments about value to bondholders ignore the fact that bondholders are secured creditors, and equity holders are subordinated to their claims and more at risk when leverage is high. But shareholders correspondingly gain when utilities' returns are increased. Bondholders do not. That is one reason why equity is more risky than debt.

We believe any equity ratio increase due to PPAs is premature at this time, based on this record. Thus, we will not yet recognize the PPAs as debt equivalents for purposes of setting our ratemaking capital structures. But we also acknowledge that the rating agencies' treatment of PPAs affects investor perceptions of financial risk. Therefore, we do recognize an incremental increase in financial risk to investors on account of the credit rating agencies' increased recognition of PPA risks. Although we cannot quantify this increased risk, absent present economic conditions, we would increase ROEs to compensate for the added financial risk. Since we are making downward adjustments to this year's ROEs due to the recessionary climate, this potential increase in ROE translates into a mitigation of what would have been even lower ROEs.

This recognition, however, is tempered with the knowledge that returns on equity mean different things to different investors. As UCAN's Hill observes, utility stock is held largely by individuals and about 25% to 30% by institutions, but "the time that institutions will jump in is when a utility is in trouble. They will jump in because they know that the regulators are going to bail them out and they can make a big capital gain on these utilities." (Tr. Hill at 673.) Malquist's testimony concerning prior large institutional holdings of SDG&E stock supports this analysis. (Tr. Malquist at 287-288.)

In this proceeding, the utilities have not presented sufficient evidence to convince us to recognize PPAs as debt equivalents and therefore allow increases in their equity cushions. Like the rating agencies, we, too, must determine where on the risk spectrum reality lies. In our role as responsible and responsive regulators, we must make decisions, as do good businesspersons, based on a complete analysis of all relevant risk and benefit factors. Such informed decision-making is not possible based on the record before us. It is especially critical in a proceeding such as this one, which could prove precedential for other state commissions. The rating agencies set their ranges for leverage and coverage ratios based on the finances of the entire company. We set our ratemaking structure based on exclusion of some of this data. This creates problems in comparing the financial debt leverage ratio to the leverage ratio calculated under our ratemaking analysis, particularly when no financial data quantifies the dollar differences when computing the ratios under both schemes. We are also concerned that the financial leverage ratios include the effect of previous disallowances by this Commission. We have said before that we will not undo in the cost of capital proceeding the effects of such disallowances. (38 CPUC2d at 242.) We are troubled by requests to increase equity to preserve bond ratings based on claims of rate base erosion when Moody's and S&P admit this is not of much concern to bond holders. We question the necessity of maintaining high bond ratings during these times of low interest rates when there is no capital crunch. We are concerned by the reliance of the utilities on the effect of debt equivalents in only the debt leverage calculation when other important ratios are also considered by the agencies in arriving at a credit rating, and we are not provided data on these ratios. In order to properly assess our concerns in relation to the concerns of the utilities and the rating agencies, a more complete record is essential.

To conduct a complete analysis of the debt equivalence of PPAs in the future, we expect the record to contain at least the following information:

1. Studies, such as the one conducted in the past by SDG&E, to support the cost implications to ratepayers and the utility of downgrades in the presently prevailing market environment. The study should quantify, as much as possible, the differences between downgrades within a rating category and those between ratings categories. It should also include data on the increased financing costs of IPPs and how these are passed through to ratepayers.

2. Financial data, on both a ratemaking and financial basis, to support all dollar value and ratio calculations concerning both the interest rate coverage and debt leverage impacts of the PPAs.

3. The amount and date of new bond financings by the California utilities compared to nationwide figures for utilities accessing the financial markets with bond issuances.

4. Plans to issue new common equity and preferred stock, the timetable for its issuance and an affirmative statement in the application that such equity will be issued within the test year if the increased equity ratio is granted.

5. Data on the reliability of QFs and IPPs supplying California utilities.

6. Plans for future power purchases and repowering or building of generation plant by the utilities.

7. Details of the shift of asset mixes to transmission and distribution.

8. The ranges for maintaining coverage and leverage ratios by the major rating agencies, where the utility stands within each range on a financial basis and how the change in ratemaking capital structure will translate to a new position within these financial ranges. The utility should also present information concerning how

far it has been allowed to stray outside those ranges in the past and still maintain ratings higher than the ratio ranges would suggest.

9. Information concerning all threats of possible downgrade by rating agencies and a timetable for corrective action.

10. Details on the number of QF and non-QF contracts, the annual capacity payments thereunder and percentage of generation mix they represent.

11. A showing that cost savings cannot be employed to offset or mitigate the PPAs' effect on the financial ratios.

12. A showing that increased equity cushion does not compensate for a previous disallowance, short-term debt, or other items not recognized in our ratemaking capital structure.

13. Full copies of all credit rating agency rating reports for the last year.

14. An assessment of each utility's PPAs, both take-and-pay and take-or-pay, in regard to their benefits and risks and the mitigating effects on those risks of California mechanisms fitting the parameters of those recognized by the rating agencies. It should include evidence of the annual capacity charges of each kind of contract and the net present value of the contracts discounted at 10% as well as specific dollar values of debt equivalents assigned by rating agencies in computation of both debt leverage and interest coverage ratios.

15. Specifics on the assessment of the California regulatory climate by each agency and how it relates to a position on the scale each employs.

16. Specifics on how current ratemaking mechanisms negate or foster the debt equivalence treatment of PPAs by the rating agencies.

17. Any precedent from other state regulatory commissions regarding their treatments of PPAs in setting utilities' capital structures or ROEs.

18. Data regarding the number of utilities currently rated in the BBB, A, and AA categories.

19. Historical data profiling the extent to which there is a secondary market in the utilities' bonds.

20. Information as to whether the debt leverage is already reflected in the stock's market price, including data on earnings and earnings/price ratios.

We will reconsider the issue of the debt equivalence of PPAs when such a record is before us. The utilities may raise the issue in next year's ACC proceeding, based on such a record. However, the ALJ assigned thereto should have the discretion to expand the number of hearing days set forth in the modified rate case plan and to phase or advance the hearing dates and procedural schedule under that modified rate case plan. Because the utilities focus on long-term trends and whether problems will be ongoing, our willingness to reconsider the issue should be considered in these analyses.

B. Financial Models

We have often expressed our opinion that the financial models employed in our cost of capital proceedings should not be determinative and must be tempered with a great deal of judgment. (38 CPUC2d 233, 238 (1990).) The Discounted Cash Flow (DCF) Model, Risk Premium (RP) Model, and Capital Asset Pricing Model (CAPM) cannot be relied upon exclusively to develop a particular ROE, but may be helpful in developing a range of reasonable values. (Id.) "Our consideration of these three models has always been accompanied with considerable reservation." (Id.) First, "[t]he application and interpretation of these financial models may not accurately reflect all of the intricacies of the financial market." (26 CPUC2d 392, 426 (1987).) Second, "[a]lthough the quantitative financial models are objective, the results are dependent on subjective inputs." (D.91-11-059 mimeo at p. 25.) We have also recognized that the CAPM and RP models currently provide higher results than does the DCF model (33 CPUC2d 233, 238 (1990)). This continues to be true in this year's proceeding.

We have not given detailed guidance on the subjective inputs and have been generally permissive by not indicating what the limits to input subjectivity should be. (38 CPUC2d at 237.) The result of this, however, has been that over past few years we have received common equity ranges of such magnitude that the model results provide little guidance to the Commission in arriving at a reasonable return on common equity. (See, 38 CPUC2d at 237, citing 30 CPUC2d 506, 514 (1988).) In last year's attrition decision we again cautioned:

> "The wide range of returns on common equity recommended by the various parties preclude us from relying on a particular party's analysis. This is attributed to the subjective inputs to the models to which informed judgment is applied. For example, in this proceeding, the spread between the utilities' and interested parties' recommended returns averaged 129 basis points. We can only attribute this wide range to the utilities' pessimistic and the interested parties' optimistic view of risk. <u>We would hope that all parties would support a more realistic position in future proceedings</u>." D.91-11-059, mimeo at 20 (emphasis added).

This warning was ignored this year. Therefore, we must reconsider our permissive attitude.

In this year's proceeding, there has been an overemphasis on the models due to the use of basic models by the utilities that contain not only subjective inputs but methodological adjustments, the proposal of two new "corroborating" models plus use of the FERC generic benchmark methodology by UCAN, and UCAN's use of models without a comparable DRI forecast component. The record is replete with discussions of geometric versus arithmetic means, regression analyses, sustainable growth projections and the like, as each economist criticizes the others' inputs and methodology. For these reasons, we do not explore the detailed economic criticisms of the models.

To provide some level of consistency, during the course of the hearings, the ALJ required the utilities to submit bare-bones versions of the basic models without the methodological adjustments. We approve her actions in so doing. As we found in the test year 1990 proceeding, "The DCF, RPM and CAPM financial models are useful in establishing a range of required returns to consider in selecting the authorized return and in evaluating trends of investor expectations <u>when consistent assumptions and data sets are used in the analysis</u>." (33 CPUC2d 525, 574 (1989)(emphasis added).) However, this year we are confronted, as summarized in Appendix B, with different and largely inconsistent model formulations for each utility. This annual proceeding should not be an economic shell game in which we must guess where the rate of return pea lies. There are already enough input variables within the model formats to foster economic sleights of hand. We do not wish to encourage adding further numerical diversions.

The new adjustments and models, in addition to the myriad of already existing variables over which the parties routinely argue, resulted in a hearing that was largely a battle of the economic theorists and a stipulation not to address many of the issues during the compacted hearing schedule. That is not the purpose of this proceeding. Our aim is to use reasonably consistent models as a check against our analyses of the business, regulatory and financial risks specific to each utility. We are willing to fine tune our model analyses on the basis of evolving economic theory when pertinent. But this truncated annual proceeding is a cumbersome vehicle for such proper evaluation. Its short hearing time and compacted schedule under the modified Rate Case Plan are not conducive to extensive economic analysis. Therefore, in the future, requests to introduce new models or to make methodological adjustments in the DCF, RP, and CAPM models as we somewhat standardize them today must be clearly segregated from bare-bones computations.

Each year we expect the three models to be submitted in the bare-bones forms of a nominal yield annual compound growth version of the DCF model without other adjustments and one version each of the RP and CAPM models using the same April DRI Control Forecast for AA utility bonds, adjusted as required by 38 CPUC2d at 238. In the RP and CAPM models, either only the DRI Control Forecast or versions using each one of the four DRI forecasts must be used. (33 CPUC2d at 553.) We will then observe how many basis points higher or lower the October DRI Control Forecast is from the April forecast, as we did in 38 CPUC2d at 237-238, to make a judgment whether the results of the models would produce results lower or higher than those originally presented. We realize, as espoused by Legler and Hill, that the most technically accurate course would be to completely rerun all of the models, including the DCF which does not utilize the DRI Control Forecast, but believe this may be overly burdensome and could lead to problems if any parties believe other changes in inputs are inaccurate. When the RP model uses the DCF model as a base, we expect it to be the bare-bones annual model. There will still be room for subjectivity in inputs, such as the comparable group chosen, the Betas utilized, the growth rate employed and the like. Any requests to change methodology, rather than inputs, must be the subject of separate computation and will be referred to the Commission Advisory and Compliance Division (CACD) for workshops in the final decision, if the Commission deems it appropriate. After the receipt of recommendations arising from such workshops, then the issue can be brought before the Commission in the next attrition proceeding. We caution, however, that it is not our intent to search for the optimal financial model formulations or establish a proceeding like FERC's generic benchmark. Instead, we strive for reasonable and consistent forms of models that fairly reflect current economic conditions and theory. To this end, we will be selective in referring any new adjustments or models to workshops.

1. The Earnings-Price Ratio Model

The earnings-price ratio (EPR) model is the expected earnings per share divided by the current market price. TURN's Hill believes that this analysis is an accurate indicator of equity capital cost when the market price of a stock is near its book value. However, he admits that this model overstates the cost of capital when the market price of stock is below its book value and understates the cost of equity capital when the market price of a stock is above book value. (UCAN-4 Hill at 39.) Hill's Schedule 9 at page 1 shows market-to-book ratios of PG&E at 1.73, Edison at 1.68, and SDG&E at 1.87, but no documentary support accompanies these figures. His comparable groups have average market-to-book ratios from 1.62 to 1.76 and, therefore, the EPR model understates the cost of equity. (Id. at 39-40.) To correct this result, Hill has modified the standard EPR model by including a group-average expected return on equity as an uppermost limit and by considering the EPR result as the lowest limit. He then takes the midpoint between the average of all company EPRs and the average of all company expected returns on equity to arrive at his recommendation. (Id. at 40-41 and Schedule 8.)

The FERC has found that the EPR "provides insights as to the internal consistency of the [DCF] model's empirical results even though both the numerator and the denominator of the ratio may be employed elsewhere in the model." (51 Fed. Reg. at 363 (1986).) Hill also cites the reference to EPR in a brief excerpt from Roger Morin's 1984 text Utilities' Cost of Capital, but acknowledges that this reference states EPR is not used much in regulation anymore. (UCAN-4 Hill at 42.) The only other evidence of its use is a citation to a 1989 National Association of Regulatory Utility Commissioners (NARUC) survey which indicates seven regulatory bodies rely on EPR to estimate equity capital costs, which is the same number indicating use of CAPM in the 3-year-old survey. (Id.)

We find insufficient support in the record and in current economic methodology to permit our reliance on this modified EPR model or to refer it to a workshop. We particularly question the validity of taking an admittedly understated average ROE number from the model and picking midpoints between it and an average of Valueline current ROEs, that range from 9.0% to 15.0%, and an average of Valueline projected ROEs, that range from 10.50% to 19.50%, to arrive at recommendations in the 9% to 10% range. Therefore, the inclusion of this model in our tables of company-specific model results is for information only. We do not recognize it as a cost of capital estimator or a check on our approved methodologies.[13]

2. Market-to-Book Ratio Model

Hill also advocates a market-to-book (MTB) analysis which is a derivative of the DCF model and purportedly attempts to compensate the capital cost derived in that model for inequalities which may exist in the market-to-book ratio of the utility's stock. As with the EPR method, Hill believes this to be of corroborative use, rather than an independent check of the DCF method. (UCAN-4 Hill at 43.) He admits that the MTB is not a model that can stand on its own. (Tr. Hill at 678.) Hill contends that, in the DCF model, the data is "smoothed" to an extent in order to identify investors' long-term sustainable expectations. His MTB analysis relies on point-in-time data which is projected one year and then

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13 Although we may reject the methodology of UCAN's Hill, we in no way impugn his personal integrity and consider our conclusions to reflect only our opinion of his economic methodology. Based on our evaluation of his presentation in this proceeding, we repudiate the personal attacks made on Mr. Hill by the order of the Indiana Commission in its Indiana-American Water Company decision and echoed by Edison in this proceeding.

five years into the future. (UCAN-4 Hill at 43.) Speaking generally, FEA's Legler has difficulty with trying to drive allowed returns on equity by market-to-book ratios and has never testified about such adjustments. (Tr. Legler at 549.)

Hill first defines price from the standard DCF model as follows:

$$P(\text{price}) = \frac{D\ (\text{dividend})}{(k(\text{the ROE}) - g(\text{growth}))}$$

However, in Hill's formula, the dividend (D) is equal to the earnings (E) times the earnings payout ratio (which is expressed 1 minus the retention ratio (b)). The earnings (E) are equal to the return on equity (r) times the book value of that equity (B). Growth (g) is equal to the retention ratio of the company (b) times the expected return on equity (r) plus the funds raised from the sale of stock as a fraction of existing equity (s) times the fraction of new common stock sold that accrues to the current shareholder (v). Both sides of the equation are then divided by the book value (B) so that the final formula is expressed as:

$$k(\text{cost of capital}) = \frac{r(1-b)}{P/B} + br+sv$$

Hill's MTB model translates into the authorized cost of equity capital equaling the expected return on equity (i.e., Hill's market return) multiplied by the payout ratio, divided by the market-to-book ratio plus growth. (UCAN-4 Hill at 43-44.) However, Hill's model assumes a market ROE that is different from the authorized rate of return developed in the standard DCF model. The effect is to drive down stock prices. (Tr. Hill at 637-638.) Our purpose is to establish a rate of return that is supported by current and anticipated market data. It is not our intent to direct the market. Hill's model also produces a lower cost of capital when market-to-book ratios are large and a higher cost of capital when market-to-book ratios are small.

Hill has provided no reference to current economic theory or other regulatory bodies' cost of capital proceedings to support the use of this corroborative model, although he testified that it is based on other literature in the field. (Tr. Hill at 678.) He does provide references to financial literature in regard to his proposition that there is a relationship between a utility's market-to-book ratio and its expected book return and cost of equity capital. However, this testimony is support for his thesis that today's high market-to-book ratios for utilities cause their expected book equity returns to exceed the real cost of equity capital. (UCAN-4 Hill at 18 - 21.) It does not extrapolate into support for use of the new model. We believe this Commission sets the cost of capital so it equals the expected market return. Hill's MTB adjustments presume returns on equity we have set are inflated. We reject this assumption. Based on the record, we will not adopt the use of the MTB model in this proceeding or refer it to a workshop. Therefore, the inclusion of this model in our tables of company-specific model results is for information only. We do not consider it as a cost of capital estimator or check on our approved methodologies.

3. <u>The DRI Forecast</u>

UCAN also questions our decision in 38 CPUC2d 233 to accept the use of the DRI Control Forecast for use in this annual proceeding. Therefore, Hill did not provide any estimate using that DRI forecast in any model using interest rate forecasts. (Tr. Hill at 613-14.) Hill believes it is probable that DRI's forecasts are overstated or understated and are not very reliable, referring to a 55% probability that the forecast is accurate and a 45% probability that it is not. (Tr. Hill at 616 and Fohrer at 71.) Instead, Hill uses MMS International's interest rate forecast, which UCAN asserts is the most accurate of all the forecasts in the record. (Id.) FEA's Legler has also consistently questioned our use of the DRI Control Forecast and does so again this year.

In the 1991 test year attrition proceeding, we decided to utilize the DRI Control Forecast after workshops explored the issues surrounding the various forecasts. We agreed: 1) to use the DRI Control AA utility bond forecast adjusted to the utility's specific bond rating for the cost of debt and preferred stock over the rate period; 2) to use the weighted average of the most recent 36 months of Moody's recorded Aa-A data, ending with the first quarter of the filing year, rounded to the nearest five basis points for utilities which do not have an Aa bond rating and to use half of that spread for utilities with split ratings; 3) to use the latest DRI update (October) to finalize the embedded costs of debt; and 4) to not adopt a standard forecast for use in the development of the cost of equity, but to use DRI with one scenario in the models which use an interest rate forecast. (38 CPUC2d at 238.) In so doing we noted that "The agreement to use the DRI forecast greatly simplifies our determination of the cost of debt and improves, somewhat, the use of the various economic models by including a common assumption for comparison purposes." (Id.)

In the 1990 cost of capital decision, we also acknowledged that we still retained concerns over the level of accuracy of the DRI forecast, and we acknowledged that it has been shown that the DRI forecasts have varied from actual interest rates by an average of +/-1.81%. (38 CPUC2d at 239 at 269 footnote 2.) In 33 CPUC2d 525, this issue was litigated and we concluded that "DRI's forecast is subjective and subject to variations, and that greater reliance should be placed on other factors in determining returns on equity. While we agree there are shortcomings in the DRI Control Forecast, we do not believe that these shortcomings merit rejecting the forecast entirely." (33 CPUC2d at 536.) However, we convened a CACD workshop to explore suggestions for use of alternative methodologies. Those workshops resulted in the agreement to use DRI's Control Forecast. At this time we see no need to repeat this process. We continue to believe the agreement reached and adopted in 38 CPUC2d 233 is reasonable. We remain aware of the shortcomings of the DRI Control Forecast and will continue to use it as a subjective factor in our overall assessment of model results with the awareness of those shortcomings. We find that due to the 84 basis point drop in the October DRI Control Forecast shown in DRA-9, from the April forecast, the financial models utilizing it would produce lower ROE results than those reflected in the record.

4. <u>The Flotation Cost Adjustment</u>

The four large utilities' and SPPC's financial models include an adjustment for flotation costs. As shown by the non-adjusted models which the ALJ required to be submitted, this resulted in an average increase in ROE of 30 to 88 basis points. The basic argument is that in a bond issue, flotation costs are amortized over the life of the bond, rather than being expensed as in a stock issue, so that a compensating upward adjustment to the ROE is required to prevent the new issue from selling below book value and diluting the equity per share. DRA opposes this adjustment but concedes the adjustment could theoretically be made for past issuances. DRA asserts this would require that an adjustment be calculated for each past stock issue and then each individual adjustment must be weighted to arrive at the overall adjustment, which is not the method employed by the utilities. (DRA-6 Wong at 2-11.) FEA agrees that the adjustment is theoretically supported for the new issuances, but opposes it because it shifts the burden of stock transaction costs from the investor to the ratepayer. UCAN opposes the adjustment, claiming recent research has shown the adjustment is unnecessary and citing the FERC's rejection of the adjustment. (UCAN-4 Hill at 57-58.) In Order 420, the FERC "concludes that the evidence is inconclusive to support reflecting market pressure costs in the cost of common equity." (50 Fed. Reg. 21802, 21824 (1985).)

We believe that new adjustments to models require both a sound theoretical basis supported by practical experience and utility- and market-specific data which fit these parameters. The record contains theoretical and practical arguments on both sides of the issue but lacks the market- and utility-specific data necessary to a final position by this Commission. Based on the record, we conclude that any merit this flotation adjustment might have would apply only to existing stock at the time of actual new issuances and not to sales in the secondary market. While the utilities did not state in their applications that they intended to issue new common stock, at hearing PG&E, SDG&E, and Edison stated they would if we granted them increased equity in the capital structure. We also share the concerns of UCAN's Hill that the drop in the market price upon a new issuance may be only temporary and be erased by a subsequent price rise and that, in practice, some new issuances cause price rises. We agree with FEA's witness Legler that, even if we were to consider establishing such an adjustment, it is a highly complex problem, requiring an analysis of the current state of the stock market, the volatility of the specific utility's stock, the specific utility's growth rate, its current market-to-book ratio, how the company is financed, and whether new stock will be sold. (FEA-1 Legler at 33.) We do not have that information in the record before us. We also concur with Legler that any flotation adjustment would have to factor out general market decline when assessing the decline in stock at the time of the new issuance, and that the argument the shareholders need protection against dilution is less compelling where, as here, the stocks are selling above book value. (Id. at 34-35.) Legler stated, "I think the thrust of my argument is that when utility companies were selling below book value, there was more urgency, and I was perhaps more receptive to a flotation cost adjustment. I think with companies selling in a market-to-book ratio of, let's say 1.5, ... it is highly unlikely that a new issuance would result in company stock dropping below book value and thereby diluting the existing shareholders. So I think there is certainly less urgency for the consideration of flotation cost adjustment in an environment where the companies are selling at well above book." (Tr. Legler at 555.)

We conclude that a flotation adjustment is inappropriate as long as utility stocks are trading significantly above their book value. Therefore, we will not rely on the model results utilizing it. Any reconsideration of this adjustment in a future proceeding, in which the book values are closer to unity, will require a showing of the theoretical, practical, and utility- and market-specific data referenced above and a showing that the adjustment does not shift the burden of the transaction costs from the investors to the ratepayers. At such a time, we would consider referring the adjustment to a workshop, but do not do so today.

5. <u>Quarterly Compounding Adjustment</u>

In their DCF models, all applicants except Edison and SPPC adopted the quarterly compound version of the dividend yield component of the DCF model versus DRA's nominal yield annual compound growth version. As the unadjusted versions of the models disclose, this raises the ROE results approximately 35 to 65 basis points. The utilities contend that this more accurately reflects the amount and timing of the expected cash flows. DRA opposes the adjustment, because it assumes that the dividends are in fact reinvested, which is not necessarily true since they are paid out and left to the investor's discretion to reinvest. (DRA-6 Wong at 2-10.) DRA observes that "Regulators have long recognized that investors expect dividends quarterly. Regulators also recognize that allowing utilities to collect the quarterly effective rate would result in overcompensation." (DRA-5 Rosenberg and Lafferty, "The FERC's Discounted Cash Flow: The Right Direction Without Compromise," Public Utilities Fortnightly (February 4, 1988) at 46.) FEA and SPPC state that if the dividends are being reinvested this, in and of itself, provides additional compensation to investors independent of their ROE. (FEA-1 Legler at 23 and Tr. Olson at 442.) Legler contends that the DCF model must be viewed in the context of utility ratemaking use and notes that while dividends are not paid only at the end of the year, ratepayers also do not pay their bills at the end of the year. (Id.) He cites Linke and Zumwalt's "The Irrelevance of Compounding Frequency in Determining a Utility's Cost of Equity," 16 Financial Management No. 3 at 65-69 (Autumn 1987) in support of his argument. (Id. at 24.) Legler believes that it is not necessary to use the quarterly version of the model to provide investors with adequate returns, because if dividends were paid only annually at year-end, investors would react to this in terms of the stock's price. (Tr. Legler at 547.) However, Legler's version of the annual DCF model contains an adjustment to the dividend for a full year's growth as opposed to a half-year's growth and in some instances provides a higher expected return than the quarterly version of the model. (Id.) Hill cites Gordon, the developer of the DCF model, who states that the model is quarterly in that the dividend yield component is four times the value of the forecast dividend for the coming quarter divided by the current price, that is, the expected next quarter dividend, annualized. (UCAN-4 Hill at 38.) Therefore, Hill contends no further adjustment is needed.

We concur with these analyses of the inappropriateness of the quarterly compound model and will not refer this adjustment to a workshop. We also agree that using the expected next quarter dividend times four is the most realistic scenario due to the fact that dividends usually hold constant or move upward. Therefore, each year the utilities shall include in filed testimony a DCF model that is based on a dividend yield in which the expected next quarter dividend (relative to the application filing date) is multiplied times four. We will not rely on the results of the models using the quarterly compound growth. Its inclusion in the comparative tables is for information only. We do not refer it to a workshop for further study.

6. The Non-utility Adjustment

Edison does not utilize quarterly compounding in its DCF model, but presents a company-specific DCF model with an adjustment to data specific to SCECorp., Edison's parent, allegedly to remove the impact of Edison's unregulated subsidiaries. This was done by adjusting the market-to-book ratio to account for the unregulated Mission Companies. This resulted in a range of 11.63% to 12.13% when the flotation adjustment was removed and only the non-utility adjustment was made based on an annual DCF model. (SCE-6 Simpson.) The annual DCF model, run without either adjustment, resulted in a range of 10.93% to 11.43%, a 70 basis point decrease. (Id.) Therefore, contrary to Edison's contention in its brief, the results do not show that the non-regulated activities add value to the SCECorp stock price. Instead, the adjustment increases the ROE range.

Edison explained the adjustment as follows:

> "This modification, which is an extension of DCF theory, is based on an equation proposed by Richard Morin in his book Utilities' Cost of Capital. The underlying principle is that a utility's ROCE [return on common equity] should be set at a level which supports its target price to book ratio. For a regulated utility, this target price to book ratio must be at least 1:1 to maintain financial integrity and access to capital markets. By employing regression techniques, Edison was able to isolate the impact of its subsidiaries on its price to book ratio and by extension of its stock price.
>
> "The regression analysis to determine the market to book ratio uses four independent variables. These variables are: ROCE earned by subsidiaries, ROCE for the firm, dividend to book ratio, and percent of total assets employed in diversified activities. The input data were taken from published 1989 and 1990 year-end financial results. Once the

> regression equation was established, the coefficients for subsidiary ROCE and percent of asset were combined with the actual values to give the subsidiary effect. The regression results were then used to adjust the DCF model based on Morin's equation discussed above. This equation is:
>
> r = P/B (K-g) + g
>
> where: r = Allowed return on equity
> P/B = Target price to book ratio
> K-g = Dividend yield component from DCF model"

(SCE-2 Simpson at 13-14, footnotes omitted.)

UCAN questions the validity of this adjustment and its witness Hill asserted there was no support for the position in the financial literature. (UCAN-4 at 73.) But his assertion is merely that DCF is meant to apply to all types of stock, not just utility stock. (Id.) Hill also claims that Simpson misapplies the Morin analysis she cites. (Id at 74.) No other party addressed the adjustment in its briefs or direct testimony.

Because the effect of this adjustment is to inflate the model results on account of the nonregulated activities, we will not rely upon it. Its inclusion in the comparative tables is for information only. We do not believe it should be referred to a workshop for further study.

7. <u>The FERC Generic Benchmark</u>

UCAN also calculated the DCF model based on the methodology for the now discontinued FERC Generic Benchmark. The result is a return on equity of 11.09%. (UCAN-4 Hill at 16.) We have declared previously that the FERC Generic Benchmark ROE is a general guideline that does not apply specifically to individual utilities and is, therefore, an inappropriate reference and not to be relied upon in our ACC proceedings. 33 CPUC2d 525, 564. Therefore, we give no weight to this testimony.

8. Relative Ranking of Risk

As he has done in past attrition proceedings, FEA's witness Legler ranks every utility except SPPC according to its relative riskiness. His assessment of risk was based on an analysis of six indicators: proposed equity ratios, betas, bond ratings, long-term interest coverage, and Valueline safety and financial strength ratings. Legler concludes that Edison is the least risky of the five utilities and that Southwest is the most risky. SoCalGas and PG&E are somewhat more risky than SDG&E. He believes the risk rank ordering remains unchanged from last year. (FEA-1 Legler at 109-110.)

We have declared previously that:

> "[W]e believe there is merit in the overall approach taken by FEA in ranking the relative risk of the utilities. Despite the problems associated with any one risk indicator, it is noteworthy that six separate indicators were used. Further, FEA's ranking is generally consistent with our qualitative risk assessments. We conclude that FEA's ranking can appropriately be considered along with all of the other valid indicators of investors' required returns, but should not be relied on exclusively in the final analysis." (33 CPUC2d 525, 558 (1989).)

We will so utilize it.

C. Business and Regulatory Risks of the Electric Industry Restructuring

1. Biennial Resource Planning Update

PG&E declares that the BRPU proceeding, I.90-09-050, is a move towards expanded transmission access which adds further competitive threat to electric utilities. If the Commission's intention and investor expectations of the electric industry restructuring, transmission access, and competition are based on the precedent and experience of the gas industry, PG&E should be granted higher ROEs as are gas utilities. It cites the 1% differential in the comparable group analyses as appropriate.

SDG&E observes that D.92-04-045 in the BRPU requires it to solicit bids for 473 megawatts, which is 30% of its 1600-megawatt forecast. SDG&E contends this creates a substantial risk due to increased risks of initial delivery and availability from QFs and IPPs and the potential for increased costs to customers because of emission offset adjustments that may be required. The size of the resource bid will lead the rating agencies to impute more debt in the financial ratios. SDG&E believes that there is a high degree of uncertainty related to regulatory actions affecting the BRPU in 1992-1993.

Edison believes D.92-04-045 exacerbates many risks associated with purchased power and removes utility management flexibility from resource acquisition while saddling management with the risks of others' resource planning decisions. It believes Public Utility Holding Company Act (PUHCA) reform will increase risks by opening up the generation market to exempt wholesale generators which are not subject to regulatory constraints or the obligation to serve. SPPC contends that the fact it is not subject to BRPU means the salutary impacts cited by DRA are not received by it.

DRA believes that the alternative to BRPU bid solicitations for purchased power is construction, which also has its risks. It believes the elimination of construction risks, on balance, reduces risk to the utilities. It cites the recognition of purchased power risks in the 1991 test year attrition decision, in which the Commission stated that it had taken into account the substantial growth of QF-produced electric generation in the past decade in past cost of capital decisions. (38 CPUC2d 233, 241.) Therefore, DRA believes that there is no significant increase in risk.

2. Transmission Access

SDG&E and Edison cite pending federal and state regulatory review of transmission services and wheeling and our pending I.90-09-050 on transmission access as requiring both shareholders and QFs to assume new risks. SDG&E finds uncertainties arising therefrom, as to increased construction of new transmission facilities, proper allocation of their costs and adequate shareholder returns on them. SPPC raises uncertainties associated with its participation in Phase II of the transmission access proceeding.

DRA believes that the shift in existing cost allocation practices does not mean shareholders will bear additional risks for transmission upgrades. Instead, risks may shift away from ratepayers to QFs and transmission upgrades may be part of rate base. DRA also notes the earliest BRPU on-line date for QFs is SDG&E's, which is in 1995, and that transmission access may create a potential for increased revenues to shareholders. (Tr. Mountcastle at 156.)

3. Purchased Power

PG&E claims purchased power risks, due to the possibility of a future disallowance if there is ever a change in Commission policy. In addition to added off-balance sheet debt, SDG&E claims increased purchased power will deprive its shareholders of the benefits of construction, which is ratebased. Edison contends the Commission's acknowledgment of purchasesd power in prior attrition decisions has not translated into increased ROE. Though acknowledging benefits from purchased power, Edison does not believe they outweigh its risks. DRA believes that the regulatory risk of purchased power is minimal due to our ECAC and BRPU proceedings.

4. Incentive Ratemaking

PG&E contends that in our incentive ratemaking proceeding, I.90-08-006, increases risk since energy utilities are not technologically based and therefore do not have the opportunities incentive regulation has brought to telecommunications. This will increase investors' risk due to higher variability of earnings and the uncertainty of the bias of potential incentive schemes during the pendency of the proceeding. PG&E cites the loss of a portion of its shareholder incentive in the Demand-Side Management program as indicative of the uncertainty of incentives. SDG&E points to uncertainty over the future of the annual energy rate, cost of service ratemaking for non-fuel costs, and balancing account treatment for fuel costs as adding significant risk. It also believes the uncertainty creates additional risk in shareholders' minds. Edison mirrors PG&E and SDG&E's arguments and declares that, since investors will take on more risk under incentive ratemaking, movement toward it requires a higher return.

DRA believes the Commission has no plans to introduce incentive regulation, generally, for PG&E, SDG&E, and Edison in 1993. It asserts the Commission will be able to craft incentive plans to adequately protect against downside risks while permitting an opportunity for higher earnings. DRA asserts that incentive regulation will not be riskier than it is for telecommunications companies.

5. Conclusion

We do not believe that the electric industry restructuring risks have increased since the last two cost of capital proceedings. Indeed, the move to incentives may decrease risk for shareholders. The utilities' BRPU concerns over increased purchased power have been dealt with by our decision to consider PPAs as part of the utilities' financial risk. Our transmission access proceeding, I.90-09-050, has been considered in past ACC proceedings and no further increase in risk due to it will accrue in 1993. We continue to believe we can craft incentives for the energy utility to provide the opportunity for higher earnings with some floor on downside risks. On balance, we see no change in the risks relative to electric industry restructuring.

D. <u>Business and Regulatory Risks of the Gas Industry Restructuring</u>

PG&E points to a reduction in PG&E's procurement function under D.90-09-089, in conjunction with FERC Order 636 and federal changes thereunder, as increasing its risks. Litigation risk from the Commission's treatment of the Alberta & Southern (A&S) contracts is estimated at $430 million. The pending reasonableness review (A.91-04-033) creates increased risk, due to the $140 million DRA disallowance recommendation on the A&S contracts and fears of potential, unforeseen actions due to a possible change in Commission policy direction. Finally, PG&E cites the uncertainty created by federal industry restructuring under FERC Order 636.

Edison contends restructuring of gas has shifted risk to it as a major purchaser of gas. Therefore, it disagrees with PG&E's position that it is now riskier than electric-only utilities. Now that it must do its own procurement of gas for its generating plants, Edison believes it is at risk for disallowances over its procurement decisions on which there is no opportunity to earn a return. Edison contends the overall relative risks between gas and electric utilities have converged, with the balance of risk shifted more heavily to electric utilities.

SoCalGas cites a myriad of risks arising from the state and federal restructurings of the gas industry. Unbundling of interstate pipeline capacity into California and intrastate storage services makes the gas distribution business more complex. Financial and operating uncertainties accrue from loss of control of integrated gas delivery systems. Potential competitors are marketing non-utility storage services raising concern over excess storage capacity and stranded storage investment. The delay over our implementation of capacity brokering, due to Order 636, enhances investor uncertainty over recovery of authorized margin from non-core customers. The value of interstate capacity rights could fall below the demand charges once a capacity glut occurs, and there is no assurance non-core customers will pay their share. SoCalGas believes the 75% balancing account for the non-core does not offset the other aspects of the procurement decision, such as regulatory lag from the shift to biennial cost allocation proceedings (BCAPs), cash receipts' volatility from volumetric rates, and possible large undercollections not recoverable in non-core transmission rates. SoCalGas observes it still is operating under the procurement rules while facing $63 million in disallowances in its 1990 and 1991 reasonableness reviews on past procurement practices, which increases perceived risk by investors. The Commission's lack of specificity on procurement and our ongoing industry restructuring give rise to the concerns fostered by our allegedly vague, indefinite and conflicting procurement rules and objectives. Since SoCalGas is a gas-only utility, the concerns are magnified. Even though SoCalGas has fine tuned its procurement strategy beginning in 1991, both DRA and Commission response remains uncertain. This uncertainty was displayed in the four divergent concurring opinions on gas procurement policies in D.92-04-027.

SoCalGas also claims uncertainty exists over whether I.90-08-006 will consider gas industry incentives and the effect of the DRA/SDG&E incentive proposal on the gas industry. If telecommunications deregulatory structures were imposed, the variability of returns creates risk which must be rewarded by higher ROEs. SoCalGas also prophesizes a regulatory lag under the new incentive regulation, resulting in earnings above or below cost of capital for an extended period. The mere possibility of a return below cost of capital enhances uncertainty and increases investors' risk.

DRA believes the A&S litigation should have no effect on PG&E's ROE, since the contracts involve its unregulated affiliates.

It notes that if the contracts are found prudent in the reasonableness review, there will be no disallowance and, if they are imprudent, PG&E should not be rewarded for its imprudence by increased ROE. Similarly, DRA believes Edison's concerns are unfounded, because if it acts reasonably in procuring gas, no disallowance will accrue. DRA notes that in our capacity brokering implementation decision (D.92-07-025), we rejected proposals that shareholders bear risk for stranded interstate pipeline capacity, thus decreasing regulatory risk. Since Order 636 applies only to interstate pipelines, and not to the California local distribution companies (LDCs), DRA believes it does not increase risks to PG&E and SoCalGas, especially since it also shields shareholders from the risks of restructuring. Los Angeles contends the risks cited by SoCalGas are illusory. It believes that relative to the risks of nonregulated industries, the risks SoCalGas faces are not great which, in turn, increases SoCalGas' value in investors' eyes. Los Angeles believes that SoCalGas' proposal insulates its shareholders from all of the economic burden of unforeseen risks and places it on ratepayers.

We concur that the proposed disallowances facing SoCalGas and PG&E, and the spector of a future prudency review of Edison's gas procurement practices, are not regulatory risks requiring offsetting ROEs. If utilities act prudently, they will not incur the additional financial risk for their shareholders. The litigation risk of the A&S contracts mainly impacts A&S, PG&E's unregulated affiliate. While we do recognize that tactically PG&E may be brought into the litigation by some parties, it is our stated policy that PG&E's ratepayers should not assume the risks to PG&E for the acts of its unregulated affiliates.

We believe the risks of the federal and state gas industry restructurings, including the allegedly unclear procurement rules asserted by SoCalGas, have been taken into account in our past cost of capital proceedings and by the financial markets. We do acknowledge that the FERC's recent shift to a straight fixed variable rate will cause the fixed cost expenses of our LDCs to increase, with the potential for no ROE reductions for the interstate pipelines while our LDCs are experiencing reductions. This does impact SoCalGas and PG&E. Edison is impacted to some smaller degree as a holder of firm capacity on the El Paso Natural Gas Pipeline. But, due to its small volumes, SDG&E will not be impacted until the Pacific Gas Transmission (PGT) pipeline expansion goes on line in late 1993, more likely 1994. Even so, we also recognize that the increase in the reservation charges for the interstate pipelines is mitigated by our capacity brokering decision which passes through the demand charges for the volumes allocated to the core at the as-billed rate. This takes down the risk dramatically.

Our 100% core balancing account treatment also shifts more risk to the core than the utilities could shift previously. The 75% noncore balancing account is still a substantial risk modifier.

We do not recognize an increased risk of bypass because utilities may discount non-core rates prospectively, to prevent bypass and our discount adjustment mechanism is built into the BCAP revenue requirement. Its operation, in conjunction with the two balancing accounts, further reduces risk to shareholders. We also believe that competition with the interstate pipelines for bypass does not raise risk levels in 1993. The interstates do not have balancing account treatment for their transmission and storage functions while our LDCs do.[14] We believe that our LDCs have a

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14 We take official notice of FERC Orders 380, 436, 500, and 636 and our own Commission decisions under Rule 73 and Evidence Code § 452.

significantly lower risk of undercollection on a year-to-year basis than the interstate pipelines do.

Incentives for the gas industry will not begin in 1993. We concur with FEA that just because we are considering them, it does not increase the utilities' risks. Our long-run marginal cost proceeding should help the utilities address and fight bypass by sending a clear signal of cost causation and cost allocation. It should also provide efficient pricing information and move prices closer to actual costs, thus decreasing risks. Long-run marginal cost pricing is expected to go into place during 1993 and will lower the risk of economic bypass, decreased throughput, and customers generally leaving the system. We acknowledge that the proceeding to unbundle noncore storage could require more competition by SoCalGas and PG&E and might possibly remove the balancing account treatment. But, on balance, we believe the gas industry risks are no less and no greater than in past years.

B. California Regulation in General

Aside from controverting the specific allegations of regulatory risk made by applicants, DRA and FEA note that the record reflects that the rating agencies rate California regulation very highly, as set forth in Section III. A., supra. UCAN cites our "regulatory shock absorbers," such as BRPU, BCAPs, and balancing accounts, that are likely to extend into the future.

DRA contends regulatory risk should not depend on factors for particular proceedings, but is a comparison of our California regulatory climate versus those in other states. It notes California regulation is viewed as average or above-average by Valueline and Merrill Lynch. (DRA-6 Quan at 1-14.) FEA cites our annual ACC proceeding as reducing regulatory lag. It also believes that the Commission's mere consideration of a regulatory issue, such a incentives, does not, in and of itself, increase risk.

The utilities contend the change in composition of the Commission has led to regulatory uncertainty. SoCalGas cites

Duff & Phelps' July 1, 1992 Regulatory Fact Sheet stating, "we are watch listing California's regulatory environment with a direction down." (SCG-4 Todaro at 1.) Despite this contention, we believe the record amply supports the view that California regulation is regarded favorably by analysts and does not increase risk to the utilities on an overall basis.

F. Interest Rates and the Economy

UCAN asserts the Commission should take notice of long-term interest rates, which are at historic lows. (UCAN-4 Hill at 9-10.) It believes the U.S. economy may not be able to sustain recovery and points to the Federal Reserve's continual lowering of the discount rate over the last few years. DRA cites economic indicators that we are in a "triple-dip" recession. (DRA-3.) It believes that long-term interest rates are at their lowest levels since 1986 to 1987. For 1993, it posits slow economic growth, coupled with low relative interest rates, which portend a market environment characterized by lower investor expectations and modest returns on equity. FEA observes that in the last three years' cost of capital proceedings, the DRI forecast has been revised downward. UCAN requests we use the MMS International interest rate forecast, which at hearing showed the 30-year Treasury bond (T-bond) rate at 7.0% for the first quarter of 1993.

The utilities paint a scenario of a recovery in 1993, albeit a slow one, which will place upward pressure on interest rates and inflation. (SDG&E-1 Malquist at 15.) SPPC believes inflation is at about 4.5%, which is above the long-term historical average of about 3%. (Tr. Olson at 448.) DRA pegs it at 3% to 5%. (DRA-6 Quan at 1-16.) Edison declares inflation has remained relatively constant at approximately 3.4%, which will increase as the economic recovery continues. (SCE-1 Fohrer at 19.) SDG&E claims a substantial degree of uncertainty for 1993 interest levels because 1992 is a presidential election year. (Tr. Mountcastle at 185.) Edison believes the size of the deficit and political pressures from election year politics suggest the current interest rate forecasts are on the low side. (Tr. Fohrer at 73.) SoCalGas observes that, as of May 1992, while short-term interest rates were reduced over 240 basis points in the last 12 months, long-term interest rates fell only 20 basis points. It believes the long-term rates are the ones most relevant to utility investors. (SCG-1 Todaro at 4.) It cites the long-term rates as being 19% more volatile over the last 10 years, than their post World War II historical average. (SCG-1 Todaro at 5.) Continued rapid growth in the monetary supply and bank reserves may be laying the groundwork for a rebound of inflation and interest rates over the next 2 years. (Id.) Edison contends utility-authorized rates are generally more stable than market rates. Therefore, it asserts that a rapid reduction in return on common equity will negatively impact the utility's financial strength by lowering its interest coverage ratios. (Tr. Fohrer at 52.)

The October 1992 DRI Control Forecast for AA utilities for 1993 is 8.32% (DRA-9), 84 basis points lower than the April 1992 version of the same DRI Control Forecast of 9.16%. We conclude interest levels are at historically low levels, and although they may rise slightly in 1993, will still remain below the levels prevailing in 1991. We believe the recessionary period will extend through 1993 with prospects for only slow recovery.

In analyzing the impact of interest rates and inflation on the rates of return we set today, we are guided by the U.S. Supreme Court's declaration that, when establishing rates: "a state's decision to arbitrarily switch back and forth between methodologies in a way which required investors to bear the risk of bad investments at some times, while denying the benefits of good investments at others, would raise serious constitutional questions." (Duquesne Light Co. v. Barasch, 488 U.S. 299, 315 (1989).) While today's recessionary economic environment calls for lower returns, we must assess them against our past decisions to not let utility ROEs be driven in lock step with the interest rate. Since 1970, the highest energy utility ROE we have set is 16.20%, in inflationary 1982 (D.82-12-063). The present ROEs of 12.65% to 12.75% are somewhat above the lowest ever during that same time period of 11.65% for SoCalGas (74 CPUC 30 (1972)), 11.88% for PG&E (74 CPUC 487 (1972)), 11.90% for Edison (72 CPUC 282 (1971)), and 11.96% for SDG&E (74 CPUC 87 (1972)).[15] Shortly thereafter, during the recovery from the recession in the early 70s, we refused to set PG&E's return on common equity above 12% based on inflation. In doing so, the Commission reflected on D.78802's (72 CPUC at 293) 1971 admonition that we must do our best not to add to inflation and, to some extent, attempt to curb it. (78 CPUC 638, 717 (1975).) The converse is also true.

In 78 CPUC 638, TURN argued that it would be unwise for the Commission to grant an increase in the rate of return every time that inflation causes interest rates to rise and to reduce the rate whenever a showing of inflation causes interest rates to fall. (78 CPUC at 719.) TURN observed that the only effect would be to offer the owners of the utility "a windfall gain during periods of accelerating inflation and windfall losses during periods of slowing inflation." (Id.) In that decision, the Commission declared, "We agree... that it would be unwise to attempt to adjust rates every time interest rates rise or fall...." (78 CPUC at 722.) Thus, we found that we must set the rate of return at the lowest level that meets the test of reasonableness. (78 CPUC at 723.) Just as we have used caution in not setting the utilities' returns on common equity too high in inflationary times, we must balance this by refraining from setting them too low in today's recessionary economy.

15 Corresponding returns on rate base in these decisions were 8.0% for SoCalGas, PG&E, and SDG&E and 7.9% for Edison.

We believe that the interest rate decline must be viewed in context with our past cost of capital decisions. In 1989, we set ROEs varying from 12.85% to 13.05% for test year 1990. In 1990, in the face of over a 100 basis point increase in the DRI Control Forecast over the past year's, we maintained those ROEs for 1991. (38 CPUC2d at 238-239.) In 1991, with a 66 basis point decline over the previous year's DRI Control Forecast, we accepted a settlement of ROEs for 1992 of 12.75% and 12.65%, only 20 to 35 basis points lower than the previous year's. (D.91-11-059 mimeo. at 23.) Now we see another 78 basis point decline in this year's DRI Control Forecast over last year's. Due to their regulated status, utilities do not enjoy the benefits of high ROEs unregulated companies reap in times of a booming economy. Likewise, the utilities are traditionally provided some insulation from the ravages of a recessionary economy that the unregulated sector suffers in times such as these. We balance these concepts to arrive at returns that are fair in the long term. We recognize that utility stocks look good in today's recessionary market. Their present high market-to-book ratios reflect this fact. But we must also remember that in past inflationary times, utility stocks have looked bad to the market due to their lower regulated returns. This is all a part of the efficient operation of financial markets. We believe FEA's original recommendation in the low 12% range reflects this view. While we believe a downward revision is called for in today's economy, we do not believe the revision should be extreme. For this reason, we regard recommendations in the upper 11% range as more properly reflecting the lack of volatility within the extremes of the interest rate cycle that the regulated utilities traditionally experience. But we do so with the realization that ROEs in the upper 11% range are, by past years' standards, a large downward adjustment. Therefore, we must temper them with the knowledge that they will have repercussions in the financial markets for this reason.

Under the constitutional standard of Duquesne, and based on the record of this proceeding, including the impact of the PPAs on the utilities' ROEs, we believe that any adjustment of more than 75 to 100 basis points down from the 1992 returns is too precipitous a drop and would definitely fall into the category of windfall losses. Within that potential drop in returns, based on the recessionary climate, the model results and our judgment of financial, business, and regulatory risks, we believe that reasonableness lies somewhere in the range of 11.75% to 12.00% for returns on equity. While we observe that the Joint Recommendation of FEA, DRA, and Southwest (Joint Recommendation) recommends an ROE of 11.95%, which is within our range of reasonableness, we believe each utility should be evaluated on a case-by-case basis. Therefore, we will set each utility's cost of capital independently, within that range of reasonableness, based on its specific facts and circumstances without regard to the Joint Recommendation.

G. Cumulative Risk

Several utilities argue that the cumulative effect of the past few years' small changes in risk have caused an overall increase in risk to shareholders. We concur with FEA's argument that our efficient markets adequately reflect these changes in the perception of riskiness by reflecting them in market prices. We will not permit the risks too small to affect past equity costs to be accumulated over several years and rolled into the future returns on equity.

H. Updates

Both UCAN and SDG&E propose that the Commission render the decision based on economic conditions at the time the full Commission considers the ALJ's proposed decision. We have previously rejected this approach for statutory and practical reasons in 33 CPUC2d 525, 541 (1989).

IV. Southern California Gas Company

A. Background

By its application, SoCalGas requests an authorized return on equity of 13.10% (a 45 basis point increase) and an overall rate of return of 10.75% (a 25 basis point increase) for 1993. It estimates that the related revenue requirement increase is $15.774 million annually. An exhibit shows this equates to a 0.56% increase in the average residential rate. No overall percentage increase was given in the application. In future ACC proceedings, SoCalGas should state the overall percentage increase in the body of its application.

SoCalGas' presently authorized and requested rate of return, as well as DRA's, FEA's, UCAN's, and Los Angeles' recommendations, are depicted in the following tables. SoCalGas' and DRA's recommendations are updated to reflect DRA-9's effects, while the remaining tables are not.[16]

SoCalGas' Present Authorization
(D.91-11-059)

Component	Capital Ratio	Cost Factor	Weighted Cost
Long-Term Debt	43.80%	9.37%	4.10%
Preferred Stock	10.10	5.52	0.56
Common Equity	46.10	12.65	5.83
TOTAL	100.00%		10.49%

16 We follow this procedure throughout the remainder of the decision.

SoCalGas' Request*

Component	Capital Ratio	Cost Factor	Weighted Cost
Long-Term Debt	42.70%	9.04%	3.86%
Preferred Stock	10.80	5.55	0.60
Common Equity	46.50	13.10	6.09
TOTAL	100.00%		10.55%

* Updated to reflect DRA-9.

DRA's Recommendation*

Component	Capital Ratio	Cost Factor	Weighted Cost
Long-Term Debt	42.70%	9.04%	3.86%
Preferred Stock	10.80	5.55	0.60
Common Equity	46.50	11.55	5.37
TOTAL	100.00%		9.83%

* Updated to reflect DRA-9.

FEA's Recommendation

Component	Capital Ratio	Cost Factor	Weighted Cost
Long-Term Debt	42.70%	9.40%	4.01%
Preferred Stock	10.80	6.01	0.65
Common Equity	46.50	12.10*	5.63
TOTAL	100.00%		10.29%

* In light of the Southwest settlement, FEA recommends a reduction to 11.80%.

UCAN's Recommendation

Component	Capital Ratio	Cost Factor*	Weighted Cost
Long-Term Debt	42.70%		
Preferred Stock	10.80		
Common Equity	46.50	10.75-11.00%	
TOTAL	100.00%		

* UCAN presented only ROE testimony.

Los Angeles' Recommendation

Component	Capital Ratio	Cost Factor	Weighted Cost
Long-Term Debt	42.70 %	9.30%	3.97%
Preferred Stock	10.80	6.01	0.65
Common Equity	46.50	11.40	5.30
TOTAL	100.00%		9.92%

B. Capital Structure

SoCalGas proposes a capital structure which includes an increase in the equity ratio from the currently authorized 46.1% to 46.5% for 1993. DRA finds that the proposal is in line with the capital structures of the other utilities, although the level of preferred stock may be reaching the upper limits of what is reasonably considered optimal. We will adopt the proposed 1993 capital structure consisting of 42.7% long-term debt, 10.8% preferred stock, and 46.5% common equity.

C. Cost of Long-Term Debt and Preferred Stock

DRA agrees with the financing plans and calculations of SoCalGas for the cost of long-term debt. FEA, short of a change in our policy of using the October 1992 DRI Control Interest Forecast (DRI update), supports the updated costs. UCAN expects the DRI update to reflect reductions in embedded costs, as reflected in the hearings. Los Angeles does not object to the updated costs of long-term debt. DRA-9 shows SoCalGas' updated estimate of embedded long-term debt is 9.04%, which is 36 basis points lower than its original 9.40% estimate. (SCG-2 Balbien at 4-5.) We will adopt its 9.04% estimate of long-term debt costs for 1993.

SoCalGas will not issue new preferred stock in 1993. It intends to fix the cost of its Flexible Auction Rate Preferred Stock Series B this year to take advantage of current yields. (SCG-2 Balbien at 5-6.) SoCalGas originally requested an increase to 6.01%, up 49 basis points from 1992 costs. (SCG-2 Balbien at

6.) DRA-9 shows an updated cost of preferred stock at 5.55%, 3 basis points higher than 1992 levels. DRA, FEA, Los Angeles, and UCAN do not dispute these costs. We will adopt SoCalGas' 5.55% cost for preferred stock for 1993.

D. Return on Common Equity

The principal issue concerning SoCalGas' application is the appropriate ROE for SoCalGas in 1993. Below is the position of each party:

Party	Recommended Return
SoCalGas: With changed capital structure	13.10%
DRA: With changed capital structure	11.55%
Los Angeles: With changed capital structure	11.40%
FEA: With changed capital structure and prior to Southwest settlement	12.10%
FEA: With changed capital structure and post Southwest settlement	11.80%
UCAN: With changed capital structure	10.75-11.00%

SoCalGas, DRA, FEA, and UCAN submitted testimony on the results of various financial models which they considered in developing their ROE recommendations. As in prior cost of capital proceedings, Los Angeles' witness Kroman did not use these models in arriving at his recommended return, but did extensively analyze SoCalGas' use of the models.

Appendix B contains tables summarizing the model results presented by witnesses Todaro, Wong, Legler, and Hill. The DCF models range from 10.22% to 12.56%, the RP models from 11.8% to 13.82%, and the CAPM from 10.02% to 13.26%. UCAN's MTB model ranges from 9.00% to 12.55% and its EPR model estimates 9.26% (based on current ROEs) and 10.73% (based on projected ROEs).

SoCalGas also cites the severe recession in Southern California and resultant loss of commercial and industrial load as putting it at risk, pointing to a prospective of a 15% decline in that demand over the next 19 years. Since this is an annual proceeding, addressed to test year 1993 only, we view these figures with skepticism. SoCalGas also contends the South Coast Air

Quality Management District's (SCAQMD) market incentive program for emission reductions, which begins in two years, as translating, in conjunction with other environmental controls, into higher and more volatile costs of business. We regard this as too premature to assess as an increased risk for 1993. Likewise, we view the SCAQMD plan's long-range goals for 2010 as presenting negligible risk for 1993.

After considering all risks, market conditions, trends, and the quantitative models, we conclude that a 11.90% return on common equity is just and reasonable for SoCalGas in 1993. This return gives recognition to the overall level of business risk facing SoCalGas and the gas industry, and the overall levels of recession and interest rates.

E. Adopted Cost of Capital

The 11.90% adopted return on common equity produces an overall rate of return of 9.99% for 1993, as shown in the following table depicting the adopted cost of capital:

SoCalGas' Adopted Cost of Capital

Component	Capital Ratio	Cost Factor	Weighted Cost
Long-Term Debt	42.70%	9.04%	3.86%
Preferred Stock	10.80	5.55	0.60
Common Equity	46.50	11.90	5.53
TOTAL	100.00%		9.99%

F. Implementation

The proposed rates accompanying SoCalGas' application reflect the cost allocation proposed by the utility in its 1991 BCAP application (A.91-03-039). Under our modified Rate Case Plan, gas rate design and revenue allocation issues are addressed in BCAPs not in general rate cases or cost of capital filings.

SoCalGas will apply the actual cost allocation and rate design authorized by the Commission's final BCAP decision to the revenue requirement authorized in the proceeding. The original

BCAP decision, D.91-12-075, was subjected to limited rehearing which was resolved in D.92-09-055. The revenue requirements authorized herein will be incorporated in SoCalGas' 1993 attrition advice letter filing. Our order will provide for use of the BCAP rate designs and cost allocations in SoCalGas' 1993 attrition advice letter filing.

V. Pacific Gas and Electric Company

A. Background

At the time it filed its ACC application, PG&E requested an ROE of 13.00% (a 35 basis point increase) and a rate of return on rate base of 10.95% (a 19 basis point increase). The revenue requirement increase was estimated to be $48.730 million, or 0.64%, for the electric department, and $14.293 million, or 0.45%, for the gas department. The overall increase is 0.58% and results in an annual overall effect over present electric and gas rates of less than 1%. In order to get the same revenue requirement with no adjustments to the capital structure, PG&E would request a cost factor for common equity of 13.40% (Mountcastle, Tr. at 192). The application states that in accordance with the Diablo Canyon Settlement Agreement adopted in D.88-12-083, PG&E's analysis supporting its request excludes any consideration of the impact of the settlement on the required rate of return.

PG&E's presently authorized and requested rate of return, along with DRA's, FEA's, and UCAN's recommendations, are depicted in the following tables:

PG&E's Present Authorization
(D.91-11-059)

Component	Capital Ratio	Cost Factor	Weighted Cost
Long-Term Debt	47.50%	9.15%	4.35%
Preferred Stock	5.75	8.74	0.50
Common Equity	46.75	12.65	5.91
TOTAL	100.00%		10.76%

PG&E's Request*

Component	Capital Ratio**	Cost Factor	Weighted Cost
Long-Term Debt	45.00%	8.61%	3.87%
Preferred Stock	5.50	8.35	0.46
Common Equity	49.50	13.00	6.44
TOTAL	100.00%		10.77%

* Updated to reflect DRA-9.

** Including purchased power debt equivalents.

DRA's Recommendation*

Component	Capital Ratio**	Cost Factor	Weighted Cost
Long-Term Debt	47.50%	8.61%	4.09%
Preferred Stock	5.75	8.35	0.48
Common Equity	46.75	11.55	5.40
TOTAL	100.00%		9.97%

* Updated to reflect DRA-9.
** _Not_ including the purchased power debt equivalents.

FEA's Recommendation

Component	Capital Ratio*	Cost Factor	Weighted Cost
Long-Term Debt	47.82%	8.95%	4.28%
Preferred Stock	5.45	8.72	0.48
Common Equity	46.73	12.10**	5.65
TOTAL	100.00%		10.41%

* Not including purchased power debt equivalents.
** In light of the Southwest settlement, FEA recommends a reduction to 11.80%.

UCAN's Recommendation

Component	Capital Ratio*	Cost Factor**	Weighted Cost
Long-Term Debt	47.50%		
Preferred Stock	5.75		
Common Equity	46.75	10.50-10.75%	4.91-5.03%
TOTAL	100.00%		

* Not including purchased power debt equivalents.
** UCAN presented only ROE testimony.

B. Capital Structure

PG&E's proposed capital structure includes a 250 basis point decrease in its long-term debt ratio, a 25 basis point decrease in its preferred stock ratio and a 275 basis point increase in its equity ratio, compared to the currently adopted authorization. All changes are attributable to the PPAs, which we have not recognized as debt equivalents in Section III. A., *supra*. DRA opposes the PPA adjustments. FEA rejects any adjustment due to power purchase debt equivalents, and supports DRA's proposal, but suggests a 32 basis point increase in long-term debt ratio, a 30 basis point decrease in its preferred stock ratio and a 2 basis point decrease in its equity ratio. We will maintain the present capital structure for 1993, consisting of 47.50% long-term debt, 5.75% preferred stock, and 46.75% common equity.

C. Cost of Long-Term Debt and Preferred Stock

DRA agrees with PG&E's financing plans and calculations for long-term debt. Absent a change in our DRI update policy, FEA supports the updated costs. UCAN expects the DRI update to reflect reductions reflected in the hearings. DRA-9 shows PG&E's updated estimate of embedded long-term debt is 8.61%, 34 basis points lower than its original 8.95% estimate. (PG&E-1B Dore at 1-7.) We will adopt PG&E's 8.61% estimate of long-term debt costs for 1993.

PG&E forecasts no new preferred stock issues for 1992 or 1993, but does plan to continue sinking fund purchases of its 9.00 and 10.17 percent coupon issues in those years. This accounts for the slight decrease in its original embedded costs, down to 8.72% in 1993 from 8.74% in 1992. (PG&E-2 Dore at 2-7.) DRA, FEA, and UCAN are in agreement. DRA-9 shows an updated cost of 8.35%, a 37 basis point decrease from PG&E's original estimate. PG&E's 8.35% cost of preferred stock should be adopted for the 1993 test year.

D. Return on Common Equity

The remaining major issue in deciding PG&E's cost of capital is its appropriate ROE for 1993. The table below summarizes the position of each party:

Party	Recommended Return
PG&E: With changed capital structure	13.00%
PG&E: Without changed capital structure	13.40%
DRA: Without changed capital structure	11.55%
FEA: Without changed capital structure and prior to Southwest settlement	12.10%
FEA: Without changed capital structure and post Southwest settlement	11.80%
UCAN: Without changed capital structure	10.50-10.75%

PG&E, DRA, FEA, and UCAN submitted testimony on the results of various financial models, used in arriving at their ROE recommendations.

The table in Appendix B summarizes the model results presented by witnesses Dore, Wong, Legler, and Hill. The DCF models range from 10.07% to 12.62%, the RP models from 9.3% to 15.01%, and the CAPM from 10.10% to 13.43%. UCAN's MTB model ranges from 8.84% to 11.30% and its EPR model estimates 9.26% (based on current ROEs) and 10.88% (based on projected ROEs).

PG&E and DRA used only comparable group data in their financial model analyses, except for one DRA CAPM model. This is consistent with the Diablo Canyon Settlement Agreement, which precludes recognizing the impact of the settlement on future determinations of the utility's rate of return.

After considering all risks, market conditions, trends, and the quantitative models, we conclude that a 11.90% return on common equity is just and reasonable for PG&E in 1993. This return gives recognition to the overall level of business risk facing PG&E, as compbined elecrtric and gas utility, including such conditions in the electric industry as the credit rating agencies' treatment of PPAs, third party generation and bypass, and gas industry risks. In establishing this return, we are also recognizing the overall levels of recession and interest rates and that PG&E is the riskiest of the 3 large electric utilities.

E. Adopted Cost of Capital

The 11.90% adopted return on common equity produces an overall rate of return of 10.13% for 1993, as shown in the following table depicting the adopted cost of capital:

PG&E'S Adopted Cost of Capital

Component	Capital Ratio	Cost Factor	Weighted Cost
Long-Term Debt	47.50%	8.61%	4.09%
Preferred Stock	5.75	8.35	0.48
Common Equity	46.75	11.90	5.56
TOTAL	100.00%		10.13%

F. Implementation

PG&E proposes that the change in revenue requirement resulting from its cost of capital be allocated to rates by class and spread in a manner consistent with the revenue allocation and rate design principles adopted in its 1993 general rate case (A.91-11-036). PG&E proposes that the consolidated revenue requirement changes resulting from its requested cost of capital be allocated to gas rates by customer class according to its proposal in its latest BCAP (A.91-11-001), which is to use the BCAP-adopted cost allocation, discount adjustment, and rate design models. If that proposal is not accepted, PG&E requests that the changes be allocated in proportion to the gas base revenue allocation to each gas customer class in its latest BCAP as provided by D.89-04-094. In D.92-10-051, we adopted PG&E's proposal in A.91-11-001, with three minor modifications. We will provide in our order that the adopted cost of capital for PG&E's 1993 test year be implemented on the electric side pursuant to our decision in A.91-11-036 and on the gas side pursuant to D.92-10-051.

VI. Southern California Edison Company

A. Background

In its application, Edison requests a return on equity of 13.05% (a 40 basis point increase) and an overall rate of return of 10.72% (a 13 basis point increase). The estimated increase in the utility's base rate revenue under the ERAM incorporating the 10.72% rate of return is $55 million, or a probable 0.7% increase after the final ECAC decision is issued. In order to get the same revenue requirement with no adjustment to the capital structure, Edison would request a cost factor for common equity of 13.45%. (Tr. Simpson at 104.)

Edison requests a deferral of the revenue allocation and rate design issues associated with this application to its ECAC proceeding, A.92-05-047. In A.92-05-047, Edison stated that if its requested ECAC decrease is combined with other pending rate change proposals, the result will be a total rate decrease of $5.8 million, or 0.1%.

Edison's presently authorized and requested rates of return, along with DRA's, FEA's, and UCAN's recommendations, are depicted in the following tables:

Edison's Present Authorization
(D.91-11-059)

Component	Capital Ratio	Cost Factor	Weighted Cost
Long-Term Debt	48.00%	8.98%	4.31%
Preferred Stock	6.00	7.60	0.46
Common Equity	46.00	12.65	5.82
TOTAL	100.00%		10.59%

Edison's Request*

Component	Capital Ratio**	Cost Factor	Weighted Cost
Long-Term Debt	45.00%	8.53%	3.84%
Preferred Stock	7.00	6.96	0.49
Common Equity	48.00	13.05	6.26
TOTAL	100.00%		10.59%

* Updated to reflect DRA-9 forecast.
** Including purchased power debt equivalents.

DRA's Recommendation*

Component	Capital Ratio**	Cost Factor	Weighted Cost
Long-Term Debt	48.00%	8.53%	4.09%
Preferred Stock	6.00	6.96	0.42
Common Equity	46.00	11.55	5.31
TOTAL	100.00%		9.82%

* Updated to reflect the September 1992 DRI forecast.
** Not including the purchased power debt equivalents.

FEA's Recommendation

Component	Capital Ratio*	Cost Factor	Weighted Cost
Long-Term Debt	48.00%	8.78%	4.21%
Preferred Stock	6.00	7.33	0.44
Common Equity	46.00	11.80**	5.43
TOTAL	100.00%		10.08%

* Not including purchased power debt equivalents.
** In light of the Southwest settlement, FEA recommends a reduction to 11.50%.

UCAN's Recommendation*

Component	Capital Ratio*	Cost Factor**	Weighted Cost
Long-Term Debt	48.00%		
Preferred Stock	6.00		
Common Equity	46.00	10.25-10.50%	
TOTAL	100.00%		

* Not including purchased power debt equivalents.
** UCAN presented only ROE testimony.

B. Capital Structure

Edison's proposed capital structure includes a 300 basis point decrease in its long-term debt ratio, a 100 basis point increase in its preferred stock ratio, and a 200 basis point increase in its common equity ratio, compared to the currently adopted authorization. DRA opposes all changes to Edison's capital structure. FEA supports DRA's position.

Although Edison's brief makes it appear all changes are due to the debt equivalence of PPAs, a large portion of its equity increase is attributable to two other components. Edison also requests changes in its capital structure due to $390 million in short-term debt used to support fuel inventories. (SCE-2 Simpson at 6.) We note PG&E did not do so on the grounds it is premature because the result of a workshop on this topic is pending. (Tr. Mountcastle at 177.) FEA and DRA concur that Edison's attempt to obtain an adjustment in this proceeding is inappropriate. We agree. Edison also requests an adjustment to offset the impact of its Palo Verde deferred debit account, admitting "the rating agencies discount the Palo Verde debt to some degree...." (SCE-2 Simpson at 7.) DRA contends the rating agencies view the status of Palo Verde positively because as the revenue recovery has increased, this additional cash flow can be used to reduce debt levels supporting it. (DRA-6 Quan at 1-23.) FEA took no position. Based on the evidence before us and the balancing account treatment afforded the Palo Verde account, we do not believe including the Palo Verde short-term debt in Edison's capital structure determination is proper.

All other changes are attributable to the PPAs, which we have not recognized as debt equivalents in Section III., A., supra. We will adopt a 1993 capital structure consisting of 48.00% long-term debt, 6.00% preferred stock, and 46.00% common equity.

C. Cost of Long-Term Debt and Preferred Stock

Edison's estimate of 1993 long-term debt costs in its original testimony was 8.78%. (SCE-2 Simpson at 3.) Edison's updated cost of long-term debt at hearing was 8.55%. (SCE-3 Simpson at 1.) DRA agrees with the financing plans and calculations. FEA, short of a change in our policy of using the DRI update, supports the updated costs. UCAN expects the DRI update calculations to reflect reductions in embedded costs which are reflected in the hearing record. As shown in DRA-9, Edison's updated estimate of embedded long-term debt is 8.53%, 25 basis points lower than in its original estimate and 2 basis points lower than in its updated estimate at hearing. We will adopt Edison's 8.53% estimate of long-term debt cost for 1993.

Edison's estimate of 1993 preferred stock costs in its original testimony was 7.33%. (SCE-1 Simpson at 3.) Edison's updated cost of preferred stock at hearing was 7.02%. (SCE-3 Simpson at 1.) Edison issued $100 million of preferred stock in 1992 and plans to issue $100 million more by year end. Most of the new issue will replace shares retired to meet sinking fund requirements and to complete early retirement of Edison's 12.31% preferred stock. An additional $100 million preferred stock issuance is planned for 1993. (SCE-2 Simpson at 3-4 and SCE-3 Simpson at 1.) Edison also states its refunding activities in 1993, based on lower rates for debt and preferred stock, will result in $10 million more in savings for 1993. (SCE-3 Simpson at

1.) DRA, FEA, and UCAN are in agreement with the preferred stock costs, although UCAN believes the updated costs should be lower than the ones presented at hearing. DRA-9 shows an updated cost of preferred stock of 6.96%, a 37 basis point reduction from the original estimate and a 6 basis point reduction from the updated hearing estimate. Edison's 6.96% cost of preferred stock should be adopted for the 1993 test year.

D. Return on Common Equity

The major remaining issue involved in determining Edison's 1993 cost of capital is the appropriate ROE for Edison in 1993. The following table summarizes the position of each party:

Party	Recommended Return
Edison: With changed capital structure	13.05%
Edison: Without change capital structure	13.45%
DRA: Without changed capital structure	11.55%
FEA: Without changed capital structure and prior to Southwest settlement	11.80%
FEA: Without changed capital structure and post-Southwest settlement	11.50%
UCAN: Without changed capital structure	10.25-10.50%

Edison, DRA, FEA, and UCAN submitted testimony on the results of various financial models which they used in developing their return on common equity recommendations. The tables in Appendix B summarize the model results presented by witnesses Simpson, Wong, Legler, and Hill. The DCF models range from 9.51% to 12.53%, the RP models from 9.8% to 13.6%, and the CAPM from 9.50% to 13.37%. UCAN's MTB model ranges from 8.89% to 11.30% and its EPR model estimates 10.12% (based on current ROEs) to 10.90% (based on forecast ROEs).

We agree with DRA and FEA that it is appropriate to consider comparable utilities as well as company-specific information when applying the DCF model. However, as stated in Section III. B.6., supra, we do not support Edison's regression analysis.

Edison contends its construction expenditures for 1992 and 1993 will account for about $1 billion in both years and that it must maintain financial strength to have good access to financial markets. We believe that this argument has been more fully considered in our assessment of purchased power and that Edison is the least risky of the 3 large electric utilities.

After considering all risks, market conditions, trends, and the quantitative models, we conclude that a 11.80% return on common equity is just and reasonable for Edison in 1993. This return gives recognition to the overall level of business risk facing Edison, including such conditions in the electric industry as the credit rating agencies' treatment of PPAs, third-party generation, and bypass. We are also recognizing the overall levels of recession and interest rates. Although Edison has a more leveraged ratemaking capital structure than either PG&E's or SDG&E's, our determination of returns on equity is based on our assessment of overall levels of risk, including but not limited to financial risk. We believe that notwithstanding Edison's leverage, it is the least risky of the utilities.

E. Adopted Cost of Capital

The 11.80% adopted return on common equity produces an overall rate of return of 9.94% for 1993, as shown in the following table depicting the adopted cost of capital:

Edison's Adopted Cost of Capital

Component	Capital Ratio	Cost Factor	Weighted Cost
Long-Term Debt	48.00%	8.53%	4.09%
Preferred Stock	6.00	6.96	0.42
Common Equity	46.00	11.80	5.43
TOTAL	100.00%		9.94%

F. Implementation

Edison requests that the revenue changes associated with its cost of capital application be consolidated with the revenue change associated with Edison's pending ECAC proceeding (A.92-05-047). Pursuant to the Rule 23(b) and (c) waiver granted by the ALJ, present and proposed rate information was included in that application. We have consistently permitted such consolidations. (See D.92-01-018, D.90-12-067.) We will provide in our order that the revenue allocation associated with the revenue requirement established in this decision be addressed in A.92-05-047.

VII. San Diego Gas & Electric Company

A. Background

SDG&E requests adoption of a 13.00% ROE (a 35 basis point increase) for 1993. The utility also requests adjustments to its embedded debt and preferred stock costs and to its authorized capital structure. Based on the overall rate of return of 10.88% (a 13 basis point increase) sought in the application, SDG&E seeks a revenue requirement increase for 1993 of $13.427 million for its electric department, $2.030 million for its gas department, and $4 thousand for its steam department. The respective percentage increases are 1%, 0.4%, and 0.2%. The overall increase to base revenues is $15.461 million or 0.80%. In order to get the same revenue requirement with no adjustment to the capital structure, SDG&E would request a cost factor for common equity of 13.45%. (Tr. Malquist at 301.)

SDG&E's presently authorized and requested rate of return along with DRA's, FEA's, and UCAN's recommendations are depicted in the following tables:

SDG&E's Present Authorization
(D.91-11-059)

Component	Capital Ratio	Cost Factor	Weighted Cost
Long-Term Debt	44.50%	9.09%	4.05%
Preferred Stock	6.00	7.31	0.44
Common Equity	49.50	12.65	6.26
TOTAL	100.00%		10.75%

SDG&E's Request*

Component	Capital Ratio**	Cost Factor	Weighted Cost
Long-Term Debt	42.00%	8.22%	3.45%
Preferred Stock	5.50	6.90	0.38
Common Equity	52.50	13.00	6.83
TOTAL	100.00%		10.66%

* Updated to reflect DRA-9.
** Including purchased power debt equivalents.

DRA's Recommendation*

Component	Capital Ratio**	Cost Factor	Weighted Cost
Long-Term Debt	44.50%	8.22%	3.66%
Preferred Stock	6.00	6.90	0.41
Common Equity	49.50	11.55	5.72
TOTAL	100.00%		9.79%

* Updated to reflect DRA-9
** Not including purchased power debt equivalents.

FEA's Recommendation

Component	Capital Ratio*	Cost Factor	Weighted Cost
Long-Term Debt	44.50%	8.70%	3.87%
Preferred Stock	6.00	7.30	0.44
Common Equity	49.50	12.00**	5.94
TOTAL	100.00%		10.25%

* Not including purchased power debt equivalents.
** In light of the Southwest settlement, FEA recommends a reduction to 11.70%.

UCAN's Recommendation

Component	Capital Ratio*	Cost Factor**	Weighted Cost
Long-Term Debt	44.50%		
Preferred Stock	6.00		
Common Equity	49.50	10.50-10.75%	
TOTAL	100.00%		

* Not including purchased power debt equivalents.
** UCAN presented only ROE testimony.

B. Capital Structure

SDG&E's proposed capital structure includes a 250 basis point decrease in its long-term debt ratio, a 100 basis point decrease in its preferred stock ratio, and a 300 basis point increase in its common equity ratio, compared to the currently adopted authorization. As we noted in Section III. A., in addition to PPA adjustments, SDG&E requests a reduction of 50 basis points in its preferred stock and a corresponding 50 basis point increase in its long-term debt. Although SDG&E asserts these changes are reasonable, it will accept the DRA/FEA position if no PPA adjustment is granted. DRA asserts there should be no changes in SDG&E's capital ratios from 1992 authorized levels. FEA rejects any adjustment due to power purchase debt equivalents and also believes there should be no changes compared to the currently authorized capital structure. All other changes are attributable to the PPAs, which we do not recognize as debt equivalents in Section III. A., supra. We will not authorize the 50 basis point changes in preferred stock and long-term debt ratios, since we have not granted the PPA adjustment. We will adopt a 1993 capital structure consisting of 45.50% long-term debt, 6.00% preferred stock, and 49.50% common equity.

C. Cost of Long-Term Debt and Preferred Stock

SDG&E's estimate of long-term debt is 8.70% (SDG&E-4 Montgomery at 7.) SDG&E plans an $85 million issuance of first mortgage bonds in 1993 at a 9.30% interest rate. It will call two existing $150 million issues of Industrial Development Bonds (IDBs) along with offering two new replacement IDB issues of $150 million each at lower interest rates. DRA agrees with the financing plans and calculations. FEA, short of a change in our policy of using the DRI update, supports the updated costs. UCAN expects the DRI update calculations to reflect reductions in embedded cost reflected in the hearing record. As shown in DRA-9, SDG&E's updated estimate of embedded long-term debt is 8.22%, 48 basis points lower than its original estimate. We will adopt SDG&E's 8.22% estimate of long-term debt cost for 1993.

SDG&E's estimate of 1993 preferred stock costs is 7.30%. (SDG&E-4 Montgomery at 7.) This includes a $25 million issuance in 1993 at 9.30%, using the forecasted bond rate applicable to SDG&E. (SDG&E-4 Montgomery at 7.) DRA believes the forecasted bond rate inflates the outcome by 100 basis points. (DRA-6 Wong at 2-21 - 2-22.) DRA, in its brief, acknowledges that the use of the SDG&E forecasted bond rate only results in an insignificant difference (1 basis point) in the overall rate of return.

FEA and UCAN are in agreement with the preferred stock costs, although UCAN believes the update should be lower than the original cost estimate. DRA-9 shows an updated overall cost of preferred stock of 6.90%, a 40 basis point reduction. SDG&E's 6.90% cost of preferred stock is adopted for the 1993 test year.

D. Return on Common Equity

The remaining major issue is the appropriate ROE for SDG&E's 1993 attrition year. The following table summarizes the position of each party:

Party	Recommended Return
SDG&E: With changed capital structure	13.00%
SDG&E: Without changed capital structure	13.45%
DRA: Without changed capital structure	11.55%
FEA: Without changed capital structure and prior to Southwest settlement	12.00%
FEA: Without changed capital structure and post-Southwest settlement	11.70%
UCAN: Without changed capital structure	10.50-10.75%

SDG&E, DRA, FEA, and UCAN submitted testimony on the results of various financial models which they analyzed in developing their recommended ROE. The tables in Appendix B summarize the model results presented by witnesses Montgomery, Wong, Legler, and Hill. The DCF models range from 9.1% to 12.23%, the RP models from 9.9% to 13.3%, and the CAPM from 9.65% to 13.26%. UCAN's MTB model ranges from 8.84% to 11.30% and its EPR model estimates 10.62% (based on current ROEs) to 11.09% (based on forecast ROEs).

SDG&E cites its 5-year construction forecast of $2.4 billion as adding significant construction risk. (SDG&E-1 Malquist at 8.) We concur with DRA that normal, planned construction for new generation is well publicized and expected by investors in regulated utilities, unless it is of such major significance as a Diablo Canyon. We find also that the testimony reflects that much of SDG&E's power needs will be subject to bids by IPPs and QFs. To the extent bids are accepted, it will negate the need to build new plant. We do not find the possible new construction to be a financial risk to be reflected in SDG&E's ROE. Much like SoCalGas, SDG&E also argues new air emission standards in Southern California add risk. We agree with DRA that the total costs of $94 million over five years is insufficient to warrant any adjustment for 1993. Similarly, the new ocean discharge limitations by the California Water Resources Control Board will not affect costs in 1993. (SDG&E-1 Malquist at 9.) Therefore, we will not consider them in this year's proceeding. Although SDG&E asserts that the SONGS I settlement permits them only a partial rate of return on the plant (SDG&E-1 Malquist at 12), DRA correctly observes that usually our policy is to permit no return on prematurely retired facilities. We hardly view this more generous exception to our policy as a risk to SDG&E. Since we have not acted on the DRA recommendation in A.91-04-044 for 10% sharing by shareholders of SoCalGas' hazardous substance cleanup, we do not find this to be a realistic risk for SDG&E shareholders of a change in regulatory policy.

After considering all the risks, market conditions, trends, and the quantitative models, we conclude that a 11.85% return on common equity is just and reasonable for SDG&E in 1993. This return gives recognition to the overall level of business and financial risk facing SDG&E, as a combined electric and gas utility, including such conditions in the electric industry as the credit rating agencies' treatment of PPAs, third-party generation, and bypass, its relative gas industry risks, and the prevailing levels of recession and interest rates. Because of its take-or-pay PPAs, we regard SDG&E as more risky than Edison, but do not believe it is as risky as PG&E.

E. Adopted Cost of Capital

The 11.85% adopted return on common equity produces an overall rate of return of 9.94% for 1993, as shown in the following table depicting the adopted cost of capital:

SDG&E's Adopted Cost of Capital

Component	Capital Ratio	Cost Factor	Weighted Cost
Long-Term Debt	44.50%	8.22%	3.66%
Preferred Stock	6.00	6.90	0.41
Common Equity	49.50	11.85	5.87
TOTAL	100.00%		9.94%

F. Implementation

SDG&E proposes to implement the cost of capital authorized in this proceeding in conjunction with its 1993 operational attrition advice letter filing. The proposed rate changes submitted with the application were developed using the currently adopted rate design and revenue allocation procedures. SDG&E is currently in a general rate case (A.91-11-036) whose interim rates go into effect January 1, 1993. We will provide in our order that the adopted cost of capital for SDG&E's 1993 test year be implemented pursuant to the interim rates in A.91-11-036.

VIII. Southwest Gas Corporation

A. Background

In its application, Southwest requests no increase in its currently authorized return on equity of 12.75%. It has requested a 10.77% overall return on rate base, which is a decrease of 49 basis points over last year. This would result in a reduction of the annual revenue requirement by $351,621 or a 0.50% decrease. Southwest's presently authorized and requested rate of return, and DRA's and FEA's recommended rates of return, are depicted in the following tables:

Southwest's Present Authorization
(D.91-11-059)

Component	Capital Ratio	Cost Factor	Weighted Cost
Long-Term Debt	50.00%	10.08%	5.04%
Preferred Stock	5.00	9.57	0.48
Common Equity	45.00	12.75	5.74
TOTAL	100.00%		11.26%

Southwest's Request*

Component	Capital Ratio	Cost Factor	Weighted Cost
Long-Term Debt	50.00%	8.49%	4.25%
Preferred Stock	5.00	9.57	0.48
Common Equity	45.00	12.75	5.74
TOTAL	100.00%		10.47%

* Updated to reflect DRA-9.

DRA's Recommendation*

Component	Capital Ratio	Cost Factor	Weighted Cost
Long-Term Debt	50.00%	8.49%	4.25%
Preferred Stock	5.00	9.57	0.48
Common Equity	45.00	11.65	5.24
TOTAL	100.00%		9.97%

* Updated to reflect DRA-9.

FEA's Recommendation

Component	Capital Ratio	Cost Factor	Weighted Cost
Long-Term Debt	50.00%	9.09%	4.55%
Preferred Stock	5.00	9.57	0.48
Common Equity	45.00	12.25	5.51
TOTAL	100.00%		10.54%

At hearing, Southwest, DRA, and FEA jointly recommended Southwest's cost of capital for 1993. The Joint Recommendation is depicted in the following table:

Southwest/DRA/FEA Joint Recommendation*

Component	Capital Ratio	Cost Factor	Weighted Cost
Long-Term Debt	50.00%	8.49%	4.25%
Preferred Stock	5.00	9.57	0.48
Common Equity	45.00	11.95	5.38
TOTAL	100.00%		10.11%

* Updated to reflect DRA-9.

This Joint Recommendation results in a $520,000 revenue requirement reduction from what is requested in Southwest's application, for a total reduction of approximately $900,000. (SWG-3 Laub at 2 and Schedules 5 and 6.) This will lower residential rates by 1.3% and 3.7%, respectively, in its northern and southern California operating divisions. (Tr. Laub at 704.) Southwest, DRA, and FEA declare that this recommendation shall not provide any precedential value for subsequent filings by Southwest. UCAN, SDG&E, and SPPC oppose the ROE set in the Joint Recommendation. This will be further addressed in Section VIII. D, infra.

B. Capital Structure

In both the application and the Joint Recommendation, Southwest requests no changes to its authorized capital structure from that established for 1992. Both DRA and FEA agree with the requested capital structure. We will adopt a 1993 capital structure consisting of 50.0% long-term debt, 5.0% preferred stock, and 45.0% common equity.

C. Cost of Long-Term Debt and Preferred Stock

Southwest's cost of fixed rate long-term debt, including the effective cost of its Series F Debentures, which were issued after these proceedings commenced, is 10.70%. (SWG-2, Laub at ABL-1 Sheet 2 of 11.) The 1993 cost of Southwest's variable rate long-term debt at the time its application was filed was projected to be 6.85% and is subject to adjustment based on the October DRI 1993 interest rate forecast. (SWG-1 Milanowsky at 11.) Combining the cost of both fixed and variable rate debt results in a weighted cost of debt of 9.09% in the application. (Exhibit SWG-2, Laub at ABL-1 Sheet 2 of 11.)

FEA accepted Southwest's projected cost of long-term debt, recognizing that the variable rate component of the company's debt and any new issues would be subject to the DRI Update. DRA undated the cost of Southwest's variable rate debt cost, using a later DRI forecast. The net effect of using a more current cost of fixed and variable rate long-term debt results in an overall cost of long-term debt of 8.79%, the rate reflected in the Joint Recommendation, which is subject to adjustment based on DRA-9. (SWG-3, Laub at 3.) The DRA-9 adjustment produces an overall cost of long-term debt of 8.49%, which is 60 basis points lower than the original estimate. It is not disputed. We will adopt the 8.49% estimate as Southwest's cost of debt for 1993.

Southwest proposes a cost of preferred stock of 9.57%, which is its actual cost. Southwest does not propose to issue any additional preferred stock for the remainder of 1992 through test year 1993. No party contests this cost. We will adopt Southwest's estimate of preferred stock cost at 9.57% for the 1993 attrition year.

D. Return on Common Equity

The only remaining issue is the appropriate ROE for Southwest's 1993 attrition year. The following table summarizes the position of each party prior to and after the Joint Recommendation:

Party	Recommended Return
Southwest:	12.75%
DRA:	11.65
FEA:	12.25
Southwest/DRA/FEA:	
Joint Recommendation	11.95

UCAN opposes the Joint Recommendation, but acknowledges that its prepared testimony did not include Southwest. However, it contends its witness Hill established a "scope of reasonableness" and the settlement ROE exceeds it. We have already set a scope of reasonableness higher than that of UCAN. UCAN also acknowledges the record does support a higher ROE for Southwest than for the four large utilities, citing its markedly lower BBB- rating (Tr. Laub at 698), which is two steps below investment grade, a considerably higher current debt ratio of 60% (Id.) and its small size and absence of economics of scale. We also observe Southwest has only 100,000 customers in California. (Tr. Laub at 699.) UCAN contends these factors support an ROE in the 11% range. Because we set each utility's return on a case-by-case basis, we believe UCAN's argument to reject the ROE in the Joint Recommendation, based on its model analyses of the four large utilities, is inappropriate.

DRA argues that, since Southwest is the riskiest of the applicants and has the lowest bond rating, the Commission should consider this factor in setting the remaining ROEs at lower levels. FEA concurs with DRA and takes the position that it wishes to lower its other ROE recommendations by 30 basis points because the stipulated ROE is 30 basis points below what it originally proposed for Southwest. SPPC, SDG&E, and SoCalGas and Edison all object to using the Joint Recommendation as a benchmark for the other ROEs, alleging that DRA targeted Southwest as leverage against the other utilities and that using 11.95% as a benchmark violates Rule 51.8. SoCalGas and SDG&E argue that they are each riskier than Southwest. SDG&E points to Southwest's 95% core load which SDG&E contends makes Southwest virtually risk-free.

We find the Joint Recommendation is not a settlement or stipulation under Rule 51.8. It is merely a contested Joint Recommendation, which we have reviewed as part of the entire record on Southwest when analyzing Southwest on a par with our previous evaluations of the large utilities. Because each utility's specific facts and circumstances are evaluated to arrive at its return, a Joint Recommendation for one utility should not serve as a benchmark for setting any other utility's return.

Southwest, DRA, and FEA submitted testimony on the results of various financial models which they used in developing their original recommended returns on common equity. The tables in Appendix B summarize the model results presented by witnesses Milanowski, Wong, and Legler. Although UCAN presented no model results, it posits an ROE of 11%. The DCF models range from 8.94% to 13.5%, the RP models from 12.04% to 14.82%, and the CAPM from 10.57% to 13.86%. Southwest's company-specific DCF model is 11.62% and FEA's is 10.1%-11.0%. DRA and Southwest make no company-specific analysis. FEA makes only a company-specific RP model which produces 10.9% to 11.8%. Southwest's company-specific CAPM is 13.62% to 13.86%, FEA's is 12.77% to 13.13% and DRA's is 11.05%. We do not place much reliance on company-specific model results from Southwest, due to its diversification (33 CPUC 2d 525, 567 (1989)). However, we do note that the CAPM and DCF results as to Southwest are the highest ranges in this proceeding, and its RP results are lower than all but SPPC's. We believe Southwest's bond rating is reflective of its diversified operations.

Southwest believes it is riskier than the comparable group companies because procurement has changed its status as a full requirements customer of PG&E. Now, it relies on PG&E for 65% of its load and identifies for purchase by PG&E approximately 35% of its requirements. It contends once capacity brokering under FERC Order 636 begins, it will face increased exposure to potential imbalance fees, use-or-pay charges, and spot market price fluctuations. Southwest fails to assess the effects of procurement on the cost of gas supplies. Without this information in the record, we cannot balance the benefits of the new gas program against the risks asserted. We also recognize that if Southwest procures gas prudently, its risk will not increase. Therefore, we will not recognize increased risk. We also do not recognize any effects of the startup of the Kern River pipeline in Southwest's territory absent proof that actual bypass is occurring. The mere fact the line is within five miles of some of Southwest's largest customers does not mean they will bear the costs of interconnect fees to utilize the pipeline.

We believe that Southwest's overall business and financial risk has changed very little since its last cost of capital review and that the prevailing economic conditions warrant a lower return on equity.

After considering all risks, market conditions, trends, and the quantitative models, we conclude that an 11.95% return on common equity is just and reasonable for Southwest in 1993. We are recognizing Southwest's business and financial risks, including its lower bond rating, and the state of the economy.

E. Adopted Cost of Capital

The 11.95% adopted return on common equity produces an overall rate of return of 10.11% for 1993, as shown in the following table depicting the adopted cost of capital:

Southwest's Adopted Cost of Capital

Component	Capital Ratio	Cost Factor	Weighted Cost
Long-Term Debt	50.00%	8.49%	4.25%
Preferred Stock	5.00	9.57	0.48
Common Equity	45.00	11.95	5.38
TOTAL	100.00%		10.11%

F. Implementation

Southwest will implement the cost of capital authorized in this proceeding in conjunction with its 1993 operational attrition advice letter filing. Our order will so provide.

IX. Sierra Pacific Power Company

A. Background

SPPC requests capital structure adjustment and a 13.0% return on equity (a 25 basis point increase) and a gross revenue requirement increase of $410,000, or 1.15%, for 1993. In order to obtain the same revenue requirement with no change to the capital structure, SPPC would request an ROE of 13.61%. (Tr. Olson at 453.) SPPC's presently authorized and requested rate of return, with DRA's recommendations, are depicted in the following tables:

SPPC's Present Authorization
(D.91-11-059)

Component	Capital Ratio	Cost Factor	Weighted Cost
Long-Term Debt	50.91%	8.07%	4.11%
Preferred Stock	5.97	7.74	0.46
Common Equity	43.12	12.75	5.50
TOTAL	100.00%		10.07%

SPPC's Request*

Component	Capital Ratio	Cost Factor	Weighted Cost
Long-Term Debt	47.76%	8.12%	3.88%
Preferred Stock	5.73	7.74	0.44
Common Equity	46.51	13.00	6.05
TOTAL	100.00%		10.37%

* Updated to reflect DRA-9.

DRA's Recommendation*

Component	Capital Ratio	Cost Factor	Weighted Cost
Long-Term Debt	49.00%	8.12%	3.98%
Preferred Stock	6.00	7.74	0.46
Common Equity	45.00	11.65	5.24
TOTAL	100.00%		9.68%

* Updated to reflect DRA-9.

B. Capital Structure

SPPC's capital structure proposal includes an increase of 339 basis points in its equity ratio from the currently authorized 43.12% to 46.51%, and reductions in its long-term debt and preferred stock ratios from 50.91% and 5.97% to 47.76% and 5.73%, respectively. Approximately 150 basis points results from equity additions, and the remainder of the increase results from a modification to the way the weighted average cost of capital is calculated for each of SPPC's operating divisions (gas, water, and electric) by the Nevada Public Service Commission (Nevada). Nevada now looks at divisional capital structures, rather than a consolidated capital structure. DRA believes that, although SPPC's request is based on a change in policy in another jurisdiction, this change is too large to make in one year. Therefore, DRA recommends a capital structure with a modest increase in equity ratio (188 basis points) to 45% which DRA feels is in line with the capital structures of other California utilities yet gives reasonable recognition to Nevada's change in ratemaking. (DRA-6 Quan at 1-21.) UCAN supports the DRA recommendation. In the past, since both Nevada and California followed a consolidated ratemaking approach, DRA did not object to Nevada's approach, because its overall results were reasonable. (DRA-6 Quan at 1-21.)

Quan cites no precedent for his conclusion that a 339 basis point increase is in and of itself imprudent or unreasonable. Quan believes increases that significant, which are merely the result of a change in regulatory action outside California, are not appropriate. Since this annual proceeding began, generally, the Commission has not authorized changes in capital structures that vary significantly from year to year. (Tr. Quan at 763.) Without the Nevada change in allocation, DRA would be looking at a capital structure of approximately 44.5% equity under the prior methodology we have followed. (Tr. Quan at 767.) After reviewing the workpapers, Quan admitted his attribution of the entire increase to the Nevada change was in error and that 150 basis points of it was attributable to increased actual equity. (Tr. Quan at 767-768.) However, he believes that California's electric-only operations should not subsidize SPPC's Nevada gas and water service and that the increase must be viewed from the standpoint of California regulation. (Tr. Quan at 771.) Quan also observes that Nevada does its ratemaking on a historical test year, while California ratemaking is on a forecast test year. (Id.)

SPPC believes its increase is in line with its actual projected equity ratio and the DRA proposal will result in a lower

ROE. (Tr. Atkinson 375.) SPPC contends that under In re Illinois Power Co., 113 PUR 4th 106 (1990) and In re AT&T Communications of the South Central States Inc., 107 PUR 4th 381 (1989), a utility's actual capital structure should be adopted for ratemaking purposes unless it is imprudent or unreasonable. SPPC believes its equity ratio request is in line with the presently authorized equity ratios of the large utilities which range from 46 to 49.5%. Only the Southwest equity ratio is 45%. (Id.) SPPC notes that, even with the increase in equity, its ROE request only requires a 1.15% rate increase.

Our reading of Illinois Power discloses that it holds a hypothetical capital structure can also be rejected if it burdens ratepayers unfairly. (113 PUR4th at 207.) Here the actual capital structure unduly burdens ratepayers. In AT&T, the Commission substituted a hypothetical capital structure, because the actual capital structure, as here, was unreasonable. (107 PUR4th at 388.)

We cannot adopt a 339 basis point increase based on an actual capital structure which is calculated in a method so different from California's, and under which our electric ratepayers, who receive no gas or water service from SPPC, would subsidize the divisional ratemaking of Nevada electric, water, and gas customers. It therefore burdens our ratepayers unfairly and is unreasonable. We would be willing to re-examine this issue next year, if SPPC can clearly show no such subsidization exists after filtering out the impacts of the Nevada ratemaking employing a historical test year and divisional accounting. Therefore, we will adopt a 1993 capital structure consisting of 49.00% long-term debt, 6.00% preferred stock, and 45.00% common equity.

C. Cost of Long-Term Debt and Preferred Stock

SPPC's estimate of long-term debt is 8.20% (SPP-1 Atkinson at Exhibit 3). Due to the Nevada divisional ratemaking, more debt has been assigned to the electric division which serves California. Its increase is attributable to a $25 million issue of new tax-exempt variable rate debt and draw downs of the tax-exempt construction trusts. Three first mortgage bond issues will be refunded during 1992. DRA agrees with its financing plans and calculations. FEA, short of a change in our policy of using the DRI update, supports the updated costs. UCAN expects the DRI update calculations to reflect reductions in embedded costs reflected in the hearing record. As shown in DRA-9, SPPC's updated estimate of embedded long-term debt is 8.12%, 8 basis points lower than its original estimate. We will adopt SPPC's 8.12% estimate of long-term debt cost for 1993.

SPPC's estimate of 1993 preferred stock costs is 7.74%. (SPP-1 Atkinson at Exhibit 3.) No new issues are forecast. DRA, FEA, and UCAN are in agreement. As shown in DRA-9, SPPC's updated estimate of embedded long-term debt is 7.74%. We will adopt SPPC's 7.74% estimate as its cost of preferred stock for the 1993 test year.

D. Return on Common Equity

The remaining major issue is the appropriate ROE for SPPC in 1993. The following table summarizes the position of each party:

Party	Recommended Return
SPPC: with changed capital structure	13.00%
SPPC: without changed capital structure	13.61
DRA: with partial changes to capital structure	11.65

SPPC and DRA submitted testimony on the results of various financial models which they used in the development of their recommended ROEs. The tables in Appendix B summarize the model results presented by witnesses Olson and Wong. FEA and UCAN presented no testimony on SPPC's ROE.

SPPC's DCF range without flotation is 11.05% to 11.57%; DRA's is 9.83% to 10.92%. No company-specific analyses were made. SPPC's RP result is 15.3%, while DRA's is 10.66% to 12.0%. No company-specific analyses were made. SPPC did no CAPM analysis. DRA's CAPM group analysis is 11.03% and its company-specific version is 11.22%. Since SPPC is so diversified, we do not rely on company-specific analyses.

In its opening brief, SPPC contends that its 3-year electric resource plan, filed with Nevada on July 1, 1992, calls for $371 million in new construction from 1992 to 1996. SPPC contends this electric generation will be used to serve California customers. However, nowhere in the application or hearing exhibits is the filing cited or are the figures found. In general testimony, Olson merely referred to his model analysis and stated that it must be assessed with specific factors such as "the scope of the construction program." (SPP-2 Olson at 17.) It was only upon cross-examination of DRA's Quan that the construction program was mentioned. We find this insufficient evidence upon which to base an assessment of whether risk is increased. We believe that the level of financial risk facing SPPC has not changed significantly.

After considering all risks, market conditions, trends, and the quantitative models, we conclude that a 11.95% return on common equity is just and reasonable for SPPC in 1993. As we have done in the past, by setting a return on equity which is higher than the return generally indicated by the results of the financial models, we are also recognizing SPPC's relative risk compared to the other electric utilities and the disparate jurisdictional ratemaking treatment.

E. Adopted Cost of Capital

The 11.95% adopted return on common equity produces an overall rate of return of 9.82% for 1993, as shown in the following table depicting the adopted cost of capital:

SPPC's Adopted Cost of Capital

Component	Capital Ratio	Cost Factor	Weighted Cost
Long-Term Debt	49.00%	8.12%	3.98%
Preferred Stock	6.00	7.74	0.46
Common Equity	45.00	11.95	5.38
TOTAL	100.00%		9.82%

F. Implementation

Our order will provide that the adopted cost of capital for SPPC's 1993 test year will be implemented by operational advice letter filing, but it shall be modified as required in SPPC's general rate case, A.92-05-040.

X. Proposed Decision

The proposed decision of the ALJ was filed with the Commission and served upon all parties to the proceeding on October 23, 1992, in accordance with § 311(d) of the Public Utilities Code, and Rule 77.1 of the Commission's Rules of Practice and Procedure. Comments to the ALJ's proposed decision were received on November 12, 1992 from PG&E, Edison, SDG&E, SoCalGas, FEA, DRA, and UCAN. Southwest and SPPC did not comment on the proposed decision.

Reply comments were received on November 17, 1992, from PG&E, DRA, and Edison.

Rule 77.3 requires comments to the proposed decision to focus on factual, legal, or technical errors in the proposed decision and in citing such errors requires the party to make specific references to the record. Rule 77.4 requires comments proposing specific changes to the proposed decision to include supporting findings of fact and conclusions of law.

We have carefully reviewed and considered all comments filed by the parties to this proceeding that focused on factual, legal, or technical errors in the proposed decision. To the extent that these comments required discussion, or changes to the proposed decision, the discussion or changes have been incorporated into the body of this order. Those comments that did not comply with Rules 77.3 and 77.4 were not considered.

Findings of Fact

1. By D.89-01-040 we removed consideration of cost of capital issues from general rate cases filed by SoCalGas, PG&E, Edison, SDG&E, Southwest, SPPC, and Pacific, and established a separate, generic ACC proceeding.

2. The plan for ACC proceedings provides that the new rates will be implemented in conjunction with the utility's pending general rate case or its attrition rate adjustment filing as applicable.

3. By a letter request to the Executive Director, Pacific requested an exemption from participation in the 1992 ACC proceeding. That request was granted by the Executive Director's letter dated May 8, 1992.

4. Pacific will not seek a price increase based on any attrition, whether it be financial or operational, for 1993. Pacific will make a filing stating it will seek no increase. DRA does not object to this procedure.

5. Pacific will accept a ROE below 9.25% if such is set by the Commission for small utilities for 1993.

6. On September 17, 1992, PG&E filed a motion to strike Appendix B of UCAN's opening brief. Edison also filed a motion to strike UCAN's Appendix B and the addendum brief attachments to PWP's September 10, 1992 addendum brief. Edison also requested both PWP and UCAN be sanctioned. No responses to either motion were received. The materials sought to be stricken are various newspaper articles, published after the close of hearings.