BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

Order Instituting Rulemaking to Establish Policies and Cost Recovery Mechanisms for Generation Procurement and Renewable Resource Development.	)))))	Rulemaking 01-10-024

COMMENTS OF SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E) CONCERNING DISCUSSION ON MARKET PRICE REFERENTS

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COMMENTS OF SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E) CONCERNING DISCUSSION ON MARKET PRICE REFERENTS

Southern California Edison Company ("SCE") submits these comments concerning the Discussion on Market Price Referents ("Discussion") distributed by the Energy Division and the Strategic Planning Division of the California Public Utilities Commission ("Commission") on March 22, 2004. SCE appreciates the effort exhibited in the Discussion, and welcomes this opportunity to provided comments in anticipation of the workshop on April 15, 2004.

1. Introduction

SB 1078 requires the Commission to develop a methodology for determining "the market price of electricity for terms corresponding to the length of contracts with renewable generators . . . ." Pub. Util. Code Section 399.15(c). This market price is frequently referred to as a "market price referent" or MPR. As succinctly stated by the authors of the Discussion, "MPRs will be used to establish the maximum price at which an RPS-obligated utility can be compelled to purchase renewable energy, up to its Annual Procurement Target (APT), and to determine whether Supplemental Energy Payments (SEPs) are applicable to bids that result from RPS solicitations." Discussion at 3, footnotes omitted. As recognized by the authors of the Discussion, the MPR is not intended to fix a minimum price for renewable energy, but merely to define the boundary between payments made to an

RPS project by means of utility contracts and those, if any, made to the project via SEP funding administered by the California Energy Commission.[1] Nor does the MPR structure determine whether renewable bidders win or lose in a particular solicitation. Discussion, at n. 2.

The RPS legislation itself provides general guidance to the Commission concerning the source of data to be considered in developing MPRs, but gives very little detail concerning the methodology to be used for calculating MPRs. Pub. Util. Code Section 399.15(c). In its decisions implementing Section 399.15 to date, the Commission has indicated that it will give little weight to market data such as broker quotes and that, in the absence of executed, long term contracts, it will rely principally on the long term operating costs associated with a new fossil fuel fired plant to develop an MPR. D.03-06-071, *mimeo*, at 15-18; *see also*, D.03-12-065, *mimeo*, at 24-25. Broker quotes may, however, be used to validate MPRs. *Id.*

Section 399.15(c) also directs the Commission to consider the "value of different products including baseload, peaking, and as-available output" in establishing MPRs. Although the Commission has indicated that it will take up the issue of as-available capacity in a separate rulemaking, neither the Commission nor the authors of the Discussion attempt to differentiate between as-available and firm resources for the purpose of implementing an MPR methodology. Discussion, at 10-12. As discussed below, the RPS Legislation requires the Commission to account for differences in value between as-available and firm resources. Failing to address this fundamental issue as part of the Commission's implementation of Section 399.15 could potentially result in the IOU paying the same price to firm and as-available projects;[2] such a result is clearly contrary to the stated purpose of SEP funding – to insure that the IOUs never pay more than market for renewable

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1 As SCE has noted in prior filings, the setting of an MPR may actually establish a single price for the utility-paid portion of all RPS contracts resulting from a particular solicitation. For example, if all bids in a solicitation exceed the MPR, then the MPR would effectively set a single rate for the utility-paid portion of any RPS contracts resulting the particular solicitation cycle.

2 This would be the situation if the winning bid prices for both projects exceed the MPR.

energy – because the firm project obviously provides greater ratepayer value. The Commission cannot simply ignore the issue. Therefore, SCE proposes a methodology to account for the differing values associated with firm and as-available obligations in these comments.

Before turning to general comments concerning the Discussion's proposed methodology and specific comments concerning various input values, SCE believes that it is also important to address a matter of considerable concern: process. There is a fundamental tension between getting the MPR methodology done and getting it done right. Neither legislative intent nor compliance with Federal law will be achieved by a methodology that routinely generates MPRs that are "too high" or "too low." In the former case, ratepayers will effectively shoulder a double subsidy by absorbing above-market costs which they have already subsidized through the collection of SEP funds. In the latter case, SEP funding will be allocated improperly and depleted prematurely. In either case, some stakeholders are likely to be dissatisfied. This tension is exacerbated by the legislative mandate that the MPR associated with any particular RPS solicitation cannot be determined or revealed until after the closing date of the solicitation. Pub. Util. Code Section 399.14(a)(2)(A).

SCE desires to avoid an endless and volatile debate concerning methodology and input values. This desire is certainly shared by other stakeholders. In recent months, notwithstanding the success of interim solicitations by RPS-obligated utilities, many interested parties have begun to voice concerns that RPS implementation is not proceeding quickly enough. Regardless of whether this concern is well-founded, it does not warrant a rush to judgment.

These concerns underscore the need for a clearly defined process by which the Commission will determine the MPR methodology, obtain input values, and calculate MPR output values. In Section VII of the Discussion, the authors attempt to outline such a "process." However, assuming that no consensus is reached at the workshop, the Commission should provide a clear explanation of how it intends to decide key issues before proceeding to establish an MPR methodology. The

Discussion describes a sequence of tasks to be undertaken, such as "establish[ing] power plant proxy cost components," and "collect[ing] input from parties on long-term fuel price assignments." Discussion at 22. However, the Discussion does not explain whether an evidentiary record will be established, and if so, how it will be made. The Discussion only states, rather cryptically, that comments submitted in response to the Discussion "may become part of the record in the future." Discussion at 4. Further, the Discussion does not indicate a manner in which MPRs will be adopted and disclosed or the process by which parties may seek modification or review of the MPR methodology or specific MPR values determined in any solicitation cycle.

Reaching a common understanding of a clearly defined process should be a paramount concern for all parties. Evidentiary hearings are one means of ensuring that all parties are heard and a record developed that is subject to review. SCE does not necessarily advocate evidentiary hearings either with respect to methodology or specific input values. However, SCE strongly recommends that the workshop should commence with a discussion of process, with a view towards achieving clear definition and broad consensus.

In defining this process, SCE believes that Commission staff and decision-makers should be guided by the following principles:

1. The initial MPR methodology should reflect, as accurately as possible, the *actual* cost associated with running a power plant. Thus, for example, the methodology should account for tax implications, such as accelerated depreciation and interest deductibility, as proposed by SCE.
2. The initial MPR methodology should be internally consistent.
3. All assumptions underlying variables or input values used in the initial MPR methodology should be clearly identified.
4. Specific MPRs for a solicitation should employ input values based on market facts for a project that is to be developed in the near-term and whose on-line date is roughly comparable to those being bid.

5. Any MPR methodology should recognize and account for situations in which there is a wide divergence of opinion concerning key input values, such as fuel cost.
7. The MPR methodology must consider the relative value of firm and as-available capacity.
6. The input values for specific MPRs should be disclosed publicly.
7. A process for seeking review of specific MPR values should be established.
8. A clearly defined and broadly accepted process should be established for reviewing, updating and refining the MPR methodology over time.

SCE believes that, whatever process is ultimately adopted by the Commission, adherence to these principles will result in a workable methodology that meets the expectations of all stakeholders.

2. General Comments Concerning Proposed Methodology.

a. A Cash Flow Simulation Model is Preferable to the Closed Form Model Proposed in the Discussion.

SCE has previously recommended use of a cash flow simulation model and continues to advocate using this analytic approach as the preferred methodology for determining MPR values. SCE believes that the cost analysis performed by the CEC was based on a cash flow simulation approach.[3]

[3] Comparative Cost of California Central Station electricity Generation Technologies, Final CEC Staff Report June 5, 2003, 100-03-001F.

The closed form model proposed in the Discussion appears to use levelized input values to derive a levelized MPR. A cash flow simulation model is analytically superior because it can more accurately account for the actual timing of cash flows and, consequently, the return on equity realized. For example, a cash flow simulation model permits a proper accounting of tax deductibility of interest on debt by reflecting large interest payments early in the debt term. Moreover, as discussed below, a cash flow simulation model provides a more robust method for calculating the debt and equity recovery costs for the proxy plant. The Excel "goal seek" function can be used to determine the fixed contract price that generates the target return on equity.[4]

Calculation of a 10-year and 15-year MPR based on full recovery of debt and equity in the 10 year or 15 year contract period, as proposed by in the Discussion, improperly ignores the residual value of the proxy plant at the end of 10 or 15 years. A new fossil fuel fired plant has an asset life of at least 20 years. To account for the asset life beyond the contract terms, the closed form model proposed in the Discussion requires an estimate of the residual value of the 20-year asset at the end of 10 and 15 years. The cash flow simulation model avoids the issue of estimating residual values by assuming that debt and equity will be recovered over 20 years and calculating a 10-year and 15-year MPR by levelizing the first 10 or 15 years, respectively, of annual cash flows.[5]

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[4] Input data include kWh production over time, capital costs, percentage of debt and percentage of equity, cost of debt and term of debt, fixed O&M costs over time, variable O&M costs over time, heat rate over time, forward gas prices over time, property taxes, etc. A first-year price of electricity can be assumed and each subsequent year can be assumed to be equal to that first year price or to escalate at a rate tied to the change in gas prices. Pre-tax cash flows are determined. Taxable incomes and associated state and federal taxes are determined. After-tax cash flow in each year equals the pre-tax cash flow in that same year minus the taxes due in that same year. The internal rate of return of the stream of after-tax cash flows is calculated. The EXCEL goal seek function is used to determine that first year price which yields the target IRR (i.e., the target return on and of equity).

[5] Under this approach, the capacity component of the MPR (i.e., the fixed costs) is the same for all three contract terms.

Use of a cash flow simulation model is also consistent with SB 1078, which calls for the determination of the levelized cost of a greenfield plant. The RPS legislation does not expressly provide for the use of variable lifespans for the proxy greenfield plant, and it is reasonable to assume that the Legislature intended the Commission spread the costs of the greenfield plant over the project's asset life, not over varying contract terms. Should the Commission elect the closed form model approach, however, it must account for the residual value remaining at the end of the contract term and provide parties the opportunity to comment on how such residual value should be derived.

b. The MPR Methodology Needs to Account For Significant Divergence In the Range of Input Values.

The proposed methodology appears to assume that there is a single value or array for each input datum, resulting in a single output value. However, most, if not all, of the input data for the variables identified by the Discussion are likely to occupy a range or spectrum representing different markets, geographic locations, access to capital markets, competitiveness and a host of other factors that depend on the specific variable. As a result, polling the market at any given time will generate a bandwidth of values for each variable rather than a single value (as will likely be amply demonstrated at the upcoming workshop). In turn, utilization of the range of values for each variable will generate a bandwidth for the resulting MPR. Some input variables, the price of natural gas being the most salient example, will have a disproportionate effect on the final value.

For the parameters that most influence the MPR, it is important to consider whether there is a range of legitimate opinions and, if so, the deviation of legitimate opinions or market reference points within that range. If the deviation among data points is relatively minor, the range of resulting MPR values will presumably likewise be relatively narrow. Under such circumstances, there is a reasonable probability that interested parties will accept the average of those MPR values as the MPR, that the legislative policy concerning the allocation of direct contract payments and SEP funding will be fulfilled and, ultimately, that the ratepayer interest will be protected. By contrast, if staff encounters a significant deviation among data inputs, the deviation in the range of MPR outputs will presumably be significant, as well. In that circumstance, using the high end of the MPR would be inappropriate and the use of a simple average would likewise be questionable. If this occurs, the Commission may wish to exercise its discretion to find reasonable consensus among independent experts with market-based experience or suspend or delay an auction, rather than establish an MPR.

c. The Assumptions Concerning Capital Cost Should Be Identified.

SCE agrees that "It can be very difficult to obtain reliable information about the actual installed costs of individual power generation projects and care should be taken to ensure that publicly available data results in an 'apples-to-apples' comparison among projects." Discussion at 14. SCE also agrees that "A potentially more reliable source for actual cost of completed projects is from information provided to project lenders (and their advisors) in conjunction with financing of individual projects." *Id.*, at 15. However, this source of data may be difficult to tap, given the confidentiality restrictions that typically surround project financing and lender relationships. One possible means of discernment would be to engage experts from the investment banking community familiar with greenfield generation project finance terms and current market conditions, who could provide expert opinions without disclosing specific deal points and project financing terms.

Regardless of the source of input data, the methodology must recognize that the cost of capital is a dependent variable and not an input value. Specifically, determining the cost of capital depends on assumptions concerning the cost and term of debt, the cost and term of equity and the relative amounts of debt and equity, as well as the quality of the borrower as determined by debt rating agencies. The Discussion is silent concerning these variables, opting instead to treat the cost of capital parametrically. Capital-related data inputs to a cash flow simulation model would include the term and cost of debt and the relative amounts of debt and equity. The after-tax cash flow generated represents the return on and of equity.

In determining the cost of debt and equity, the Commission must be very clear about the context for determining the assumptions underlying capital cost input values – a long-term power purchase agreement with an investment-grade buyer. In today's market, there is a dearth of long-term contracts and a plethora of would-be project developers that would beat a path to the door of any IOU offering one. The capital cost methodology should recognize this phenomenon, as well as its consequence: low debt and equity costs in comparison to those associated with a merchant plant.

d. The Methodology Should Ensure Consistent Assumptions Concerning Input Variables.

Referring to D.03-06-071, the Discussion indicates that "location-specific" referents may not be practical. SCE agrees that it is both unnecessary and undesirable to develop a "potentially infinite number of market price referents," in order to account for "each project location and configuration." Discussion at 18, quoting D.03-06-071 at 71. The proposed methodology fails to address, however, a means of ensuring that the input parameters used to develop an MPR are internally consistent. For example, the methodology must ensure that the MPR does not assume both a remote location for the purpose of quantifying transmission costs and an in-basin location for the purpose of quantifying emissions costs. It would be equally illogical to use commodity forward prices from early in a solicitation year to establish an MPR late in a solicitation year. The Commission obviously need not develop multiple MPRs to reflect the location of RPS bidders; the statute contemplates that the MPR will be based on a proxy gas fired plant, not on the location of the RPS project. SCE's principle concern is that the methodology not result in a "Mr. Potatohead" proxy with no real-world analog.

To address this problem, SCE proposes that the MPR should be site-specific – *i.e.*, that the MPR ultimately selected use input values determined with respect to a specific project site. The MPR should be selected based on the location that generates the most competitive overall project cost for the simple reason that if a utility were either to build the proxy plant or to conduct a competitive solicitation for projects intended to be built in various locations, the utility would select the most competitive overall cost. Such a cost is necessarily location-specific. That plant, whether hypothetical or real, would be sited in one place, not multiple locations. This approach does not require the Commission to develop multiple MPRs, only to determine the lowest MPR based on the various sets of consistent input values.

e. The Requirements to Qualify As a Peaking Product Should Be Established.

Pub. Util. Code Section 399.15(c) directs the Commission to consider the value of different products, including baseload and peaking products. The statute does not define either of these terms.

In the Discussion, the authors propose to assign a 92% capacity factor to baseload products and a 10% capacity factor to peaking products. Although the factor for baseload products appears reasonable and consistent with baseloaded delivery profiles, SCE questions whether a 10% capacity factor for peaking products is reasonable in the context of the RPS. The only renewable technology that typically provides a peaking product is solar. However historical experience shows that such projects typically deliver in about 30% of the hours, not in a typical peaking profile of about 10%, as assumed by the Discussion for purposes of establishing a peaking MPR. Additionally, a typical peaking resource is fully dispatchable at the discretion of the procuring utility and a peaking resource does not produce energy during periods when it is not required to do so by the utility. Failing to recognize the disparity between a true "peaking" product and the typical solar production profile will result in an inappropriate use of "peaking" MPR for a resource that is not truly a peaking product.

f. The Commission Must Address The Difference In Value Between Firm And As-Available Output.

Pub. Util. Code Section 399.15(c) clearly directs the Commission to consider the value of different products and specifically refers to as-available output. The Discussion, however, does not propose a methodology for accounting for differences in value between as-available and firm products. As discussed briefly here, it is inappropriate to use the same MPR for a firm and as-available resources.

To a certain extent, the statute itself creates confusion. It identifies three "products" the value of which the Commission must consider in establishing an MPR: baseload, peaking and available output. "As-available" is not, properly understood, a different product from baseload and peaking products, in that both baseload and peaking projects can provide either as-available output or firm output depending on the contract terms for the project. In either case, however, as-available output would undeniably have considerably less value to the purchaser than firm output from the same project. Therefore, it does not make sense to think of "as-available" output in terms of a third "product" as to which a separate MPR must be developed. Instead, it makes sense to consider the value of "as-available" (as opposed to firm) output in terms of a factor to be applied to the capacity component of the baseload and peaking MPRs.

The authors of the Discussion indicate that six MPRs must be developed. The relative value of "as-available" output can be taken into account by determining the effective load carrying capacity ("ELCC") for a particular technology or type of facility that proposes to contract on an as-available basis. It is a relatively simple matter, once the six MPRs identified by the Discussion have been quantified, to disaggregate the capacity value in the MPR from the energy value by subtracting the values associated with variable operating costs (essentially fuel cost multiplied by heat rate plus variable O & M) in order to derive a "capacity-only" value. Once that value is determined, application of the ELCC factor to the "capacity-only" value will yield a revised capacity value that will account for the relative firmness of various project types, including those which propose to contract for "as-available" output. This revised capacity value can then be added to the "energy-only" value to derive technology specific MPRs that account fully for the relative firmness of deliveries.

This methodology will cause the MPR for less firm proposals to be lower than more firm proposals. As recognized by the authors of the Discussion, however, the MPR itself will not affect whether a particular project wins or loses in a solicitation, nor will it impact the all-in payment received by the project if it wins. This process will merely ensure that procuring utilities receive equivalent value on a cents/kWh basis for as-available and firm products. It will in no way disadvantage project developers proposing to contract for as-available output.

3. <u>Comments Concerning Specific Input Values:</u>

a. Fuel Price

i. Commodity

Participants in the futures market for natural gas have earned positive returns on average, which implies that forward prices of gas are less than unbiased forecasts of the corresponding spot prices. Hence, insofar as forward prices of gas represent fixed fuel prices, as required by SB1078, the appropriate gas price input into the modeling effort, when the relevant forward prices are not observable and cannot be estimated by more reliable procedures, should be an unbiased forecast of spot prices with a discount applied for the risk premium in gas forward markets. There are numerous companies which provide such data, and the Commission can subscribe to one or more of these. In SCE's experience, one can obtain forecasts at Topock. In order to generate the requisite burnertip gas price, one would have to add intrastate tariff costs to these forecasts.

ii. Gas Hedge Value:

Many parties have referred in this rulemaking to a paper authored by Bolinger, Wiser and Golover, "Quantifying the Value That Wind Power Provides As a Hedge Against Volatile Natural Gas Prices," published in June 2002. That paper presented analyses which the authors claimed supported a finding that consumers have had to pay a premium of $0.75/MMBtu for natural gas (equivalent to about $0.50/kWh at a 7,000 heat rate) to lock in natural gas prices. The authors reached this conclusion based on (1) a comparison of a small sample of natural gas swap prices to EIA price "forecasts" and (2) estimates of "beta" coefficients for (the systematic risk of) natural gas prices. The authors went on to conclude that "this hedging cost should either be added to the cost of variable-price gas contracts or credited as a benefit to fixed-price renewable energy investments." As demonstrated by SCE and others at hearings last summer, this analysis contains a number of serious flaws and has largely been discredited.

Perhaps in recognition of this critique, a subsequent, revised version of the paper, "Accounting for Fuel Price Risk: Using Forward Natural Gas Prices Instead of Gas Price Forecasts to Compare Renewable to Natural Gas-Fired Generation," was circulated in August 2003. In the revised paper, Bolinger *et al.* emphasized that natural gas forward prices rather than price forecasts should be used as a basis for comparing alternative types of generation. That conclusion, by itself, is reasonable. The problem, however, is that forward gas prices are directly observable only over a limited time horizon - about six years in the NYMEX market for Henry Hub contracts and perhaps ten years, at most, in OTC markets. In contrast, the planning horizon for long-term resource decisions is often 25-plus years; the RPS legislation and implementing decisions of the Commission, for example, contemplate contract terms of 10, 15 and 20 years. This leaves the question: What should planners use for long-term gas prices? Although the revised paper includes the new conclusion that forward prices rather than price forecasts should be used for planning purposes, the revised version of the paper still contains the same flawed analysis presented in the original, tempting readers to estimate long-dated (unobservable) gas forward prices by adding a premium to gas price forecasts.

Two types of analysis can be undertaken to shed light on the relationship between natural gas forward and spot prices. One is to calculate the returns realized historically in the gas futures market ("historical risk premiums on gas"). The other is to estimate the systematic risk of natural gas using futures (rather than spot) prices ("systematic risk of gas"). SCE has engaged an outside consultant to perform this analysis using settlement prices for Henry Hub gas futures contracts observed from April 1990 through December 2003. The findings of SCE's consultant conflict directly with Bolinger's work and lead to the conclusion that, if anything, a premium should be deducted from price forecasts to estimate unobservable forward prices.

Specifically, SCE's consultants have found that the natural gas futures contracts provided positive returns on average during the 1990-2003 period. This implies that forward prices of gas are less than unbiased forecasts of the corresponding spot prices. Bolinger *et. al.* conclude that forward prices are greater than spot price forecasts based on a comparison of swap prices (OTC forward prices for a calendar block) to EIA price "forecasts." EIA personnel queried on this approach have repudiated that the EIA values are "forecasts."

Bolinger *et al.* also claim to have found evidence of a negative beta (systematic risk) coefficient for natural gas, but that analysis is also flawed. In particular, it relied entirely on gas spot prices, whereas the gas prices that are germane to the problem at hand are long-dated forward prices. SCE's consultants estimated the systematic risk of natural gas using futures rather than spot prices and found beta coefficients close to zero.[6]

SCE intends to make an interim report on these findings available to interested parties prior to the workshop on April 15.

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6 If the Capital Asset Pricing Model is a good description of market risk-return tradeoffs and an index of common stocks is a satisfactory proxy for the market portfolio, then a negative beta would imply that forward prices are greater than corresponding spot price forecasts (as proposed by Bolinger's group), whereas a positive beta would imply the opposite result, namely, that forward prices are less than unbiased spot price forecasts.

b. Heat Rate:

The 7400 Btu/kWh heat rate value proposed for discussion is excessive. It represents the highest value claimed by any party at hearings in 2003. The appropriate source of such data is the CCGT industry. The literature quotes a new and clean value for an intercooled LMS 100 MW gas turbine in combined cycle configuration at 6320 LHV or 6983 HHV. *Gas Turbine World*, January, 2004, at 18.

A conversion factor must be applied to obtain a long term average heat rate from available industry data for new equipment. In its 2003 testimony, CEERT proposed a 2.2% conversion factor based on a publication from the Northwest Power Planning Council. CEERT, Prepared Direct Testimony of William Monson, April 1, 2003, at n. 33. Application of this factor to 6983 Btu/kWh yields 7137 Btu/kWh, or 96% of the 7400 offered by CALWEA. CALWEA's witness, R. Thomas Beach, justified this higher value by referring to the impact of startups, ramping, and degradation on hot days. For a CCGT operating in a must-run fashion, however, there are very few startups, little ramping and the dollars spent on inlet air cooling can easily be recovered many times over to offset any heat degradation effects. The MPR methodology should also take into account technological innovation and advances as a consideration in developing heat rate values. Over the past 10 years, turbine manufacturers have introduced new designs and better materials into rotors and other turbine components as part of routine upgrading during scheduled maintenance and overhauls. Upgrades and technological innovation tend to increase or, at the very least, maintain heat rate efficiency over time (such as by decreasing blowby through closer blade/casing tolerances or increasing firing temperature by using better materials) and to decrease variable O&M cost (such as by reducing labor costs through automation or by reducing lube cycles). In developing long-term average heat rate values, it is reasonable to assume that these trends will continue.

c. Return on Equity:

Cost pressures in the current market should be taken into account. The market is very "hungry" for projects that can be constructed using the project finance model that was used in the 1980s, which was based on the availability of long-term PPAs. This demand is expected to depress prices, resulting in project developers being willing to accept reduced equity returns. SB 1078 does not contemplate a gold-plated plant, disconnected from current market fundamentals. At a time when investors are fleeing the stock market for the security of 5% pre-tax bonds, after-tax equity returns anywhere near the 16% upper bound suggested by the CEC, are more a developer wish than a market reality.

4. Conclusion

SCE appreciates this opportunity to provide comments concerning the Discussion.

Respectfully submitted,

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CERTIFICATE OF SERVICE

I hereby certify that, pursuant to the Commission's Rules of Practice and Procedure, I have this day served a true copy of the COMMENTS OF SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E) CONCERNING DISCUSSION ON MARKET PRICE REFERENTS on all parties identified on the attached service list. Service was effected by means indicated below:

☒ Placing the copies in properly addressed sealed envelopes and depositing such envelopes in the United States mail with first-class postage prepaid (Via First Class Mail);

☐ Placing the copies in sealed envelopes and causing such envelopes to be delivered by hand to the offices of each addressee (Via Courier);

☒ Transmitting the copies via facsimile, modem, or other electronic means (Via Electronic Means).

Executed this 9th day of April **2004**, at Rosemead, California.

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