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**BEFORE THE PUBLIC UTILITIES COMMISSION OF THE**

**STATE OF CALIFORNIA**

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| Order Instituting Rulemaking To Examine The Commission's Post-2008 Energy Efficiency Policies, Programs, Evaluation, Measurement And Verification, And Related Issues. | ) ) ) ) | Rulemaking 09-11-014 (Filed November 20, 2009) |

# <u>SOUTHERN CALIFORNIA EDISON COMPANY'S (U 338-E) RESPONSE TO ADMINISTRATIVE LAW JUDGE'S RULING SEEKING POST-WORKSHOP COMMENTS ON DEMAND-SIDE COST-EFFECTIVENESS ISSUES</u>

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# SOUTHERN CALIFORNIA EDISON COMPANY'S (U 338-E) RESPONSE TO ADMINISTRATIVE LAW JUDGE'S RULING SEEKING POST-WORKSHOP COMMENTS ON DEMAND-SIDE COST-EFFECTIVENESS ISSUES

## I.
## INTRODUCTION

The California Public Utilities Commission (Commission or CPUC) held a two-day workshop in June 2012 to discuss Demand Side Management (DSM) Cost-Effectiveness issues. The workshop is a result of the 2012-2014 DR Application Final Decision (D.12-04-045), which ordered the Energy Division to hold workshops to address and develop deficiencies in cost-effectiveness calculations. DSM resources under discussion included Energy Efficiency (EE), Demand Response (DR), and Distributed Generation (DG). Parties at the workshop discussed the following issues:

- Generation related avoided cost
- Transmission and distribution avoided cost
- Discount rate
- Schedules to update cost-effectiveness assumptions
- Consistency across demand-side proceedings
- Standard Practice Manual tests

After the workshop, the Administrative Law Judge issued a ruling on August 14, 2012 (ALJ Ruling) seeking post-workshop comments. The ALJ Ruling asks a series of 36 questions based on the cost-effectiveness topics mentioned above. SCE's answers to these questions are below.

## II.
## RESPONSES TO QUESTIONS IN THE ALJ RULING

### 1. When Is It Appropriate To Use Long-Term Avoided Costs, And When Is It Appropriate To Use Short-Term Avoided Costs?

SCE supports using the long-run cost of generation capacity for DSM evaluation because it provides the proper stable economic signal for investments with long asset life-spans. If prices fluctuate frequently, then customers may fail to invest in energy efficiency (EE) during periods when market capacity prices fall below the cost of new capacity resources. The use of short-run costs creates unstable decision making for customers' capital investments. However, if excess capacity exists for an extended period, then consideration should be given to adjusting long-run prices to reflect the value of continued excess capacity in economic decision-making. The use of short-run costs is best for sending a price signal for the variable operation of equipment, such as natural gas prices for the dispatch of generating units.

### 2. Assuming The Resource Balance Year (RBY) Calculation Will Continue To Be Used To Distinguish Between Long- And Short-Term Costs, Are There Modifications That Could Be Made To The RBY Calculation To Make It More Accurate?

The appropriate balance year is highly debatable as the basis can be meeting peak load, local reliability, or flexibility needs in intrgrate variable generation. Each basis has a different year, so the appropriate basis for DSM would need to be determined. In addition, impacts of Once Through Cooling (OTC) policy create substantial uncertainties regarding the potential retirement of existing resources. The identification of any needs for new physical generation is performed in the Long Term Procurement Plan (LTPP) proceedings.

The RBY could be used to determine the level of program marketing or the allowance for new customers to sign-up. If the RBY year is far into the future, then marketing for certain demand side programs could be reduced and/or limit the number of new customers that can sign-up for the program. When the time to the RBY is lessened, full marketing and new customer acceptance can resume.

**3. <u>Is It Appropriate To Have Different RBYs For Different Demand-Side Programs, Given The Inherent Differences Among Them, Or Should There Be A Consistent RBY?</u>**

No, it is not appropriate to have different RBYs for different demand-side programs. It does not make sense to have different resource balance years when evaluating the benefit of DR, EE, or DG as it sends inconsistent price signals between resource options.

**4. <u>Should The RBY Be Updated Periodically, And, If So, What Is An Appropriate Process?</u>**

Yes, the RBY should be updated periodically. The LTPP proceeding seems the most appropriate forum for the determination of need. However, for a variety of reasons including the uncertainties described in response to question 2, there may not be a clear identification of a RBY in this proceeding.

**5. <u>Is It Still Appropriate To Model Avoided Costs On Natural Gas Generation, Given That Renewable Generation Will Comprise The Bulk Of New Additions?</u>**

Yes, it is still appropriate to model avoided costs on natural gas generation. The CT proxy for capacity value has a long history with CPUC ratemaking and CE. Its continued use provides consistency between proceedings of EE, DG, DR, and ratemaking. While renewable generation is growing, it is still a must-take resource. The marginal or avoided energy resource will still be predominately based upon natural gas. Due to the Renewable Portfolio Standard (RPS) compliance, programs that affect sales do avoid an RPS obligation as it is based upon retail sales. Thus, depending on the compliance year, 20-33 percent of the avoided energy sale would be based upon the marginal cost of RPS compliance.

**6. <u>Does The Addition Of The Avoided RPS Cost Properly Account For The Change In The Generation Mix? Explain Why Or Why Not.</u>**

SCE assumes this question relates to how the the marginal resource and RPS requirements impact the avoided cost. As mentioned in SCE's response to question 5, most of the avoided energy cost will be based upon the marginal resource, and another portion will be the energy associated with RPS compliance.

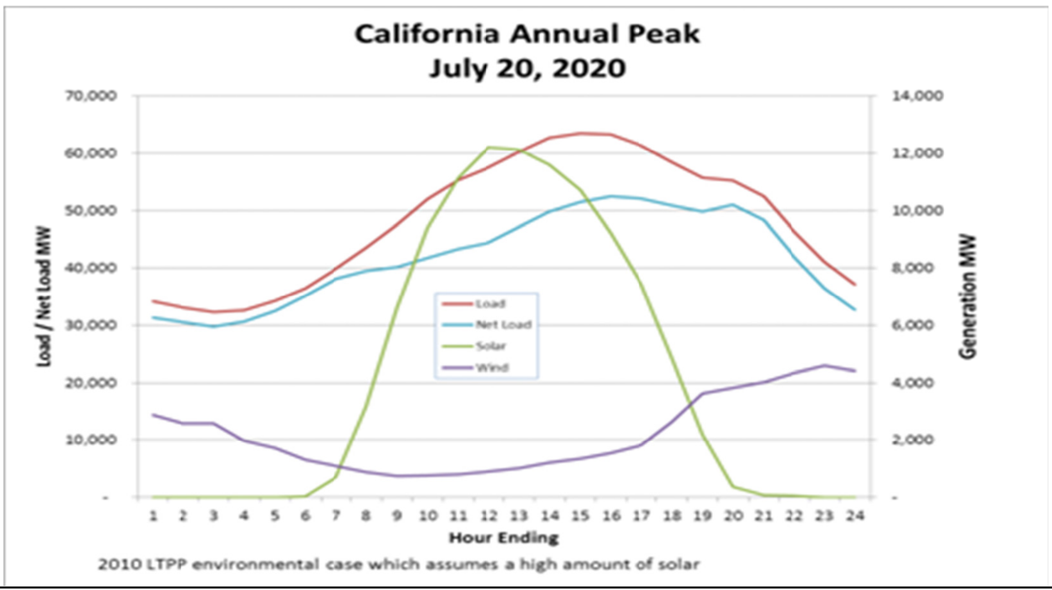
**7. <u>Should The Allocation Method For Generation Capacity Be Changed? What Are The Reasons To Use Any Of The Various Methods Listed Above, Or Another Method? (Please focus your answer on concrete suggestions of how to allocate generation capacity costs, rather than criticisms of existing methods.)</u>**

The CPUC-approved protocols on cost-effectiveness recognized that Loss Of Load Expectation (LOLE)[1] is the theoretically correct method to allocate the need for additional capacity. The reason LOLE is superior is because it is a stochastic look at both load and available capacity. As acknowledged in the protocols, the preferred method of the top 250 hours is a simple proxy that only looks at load. While the top 250 hour proxy produces reasonable results for the current Time of Day (TOD) distribution, it may not be a reasonable proxy in the future due to California's renewable polices. Currently, peak sales and peak need for dispatchable generation are correlated resulting in the highest LOLE occurring at the time of peak demand. However, in a future with a 33% renewables, such as solar and wind, the net load shape is changing, and the net-peak is occurring

[1] Also referred to as Loss of Load Probability (LOLP). LOLP is the probability of outage and the LOLE is when an outage is most likely to occur.

later in the day. Because of high amounts of solar power, there may no longer be a need for additional generation during the mid-afternoon to improve reliability, as shown Figure II-1, as it may shift later in the day. A LOLE study will capture the impact caused by the change in resource mix with more non-dispatchable variable generation such as wind and solar.

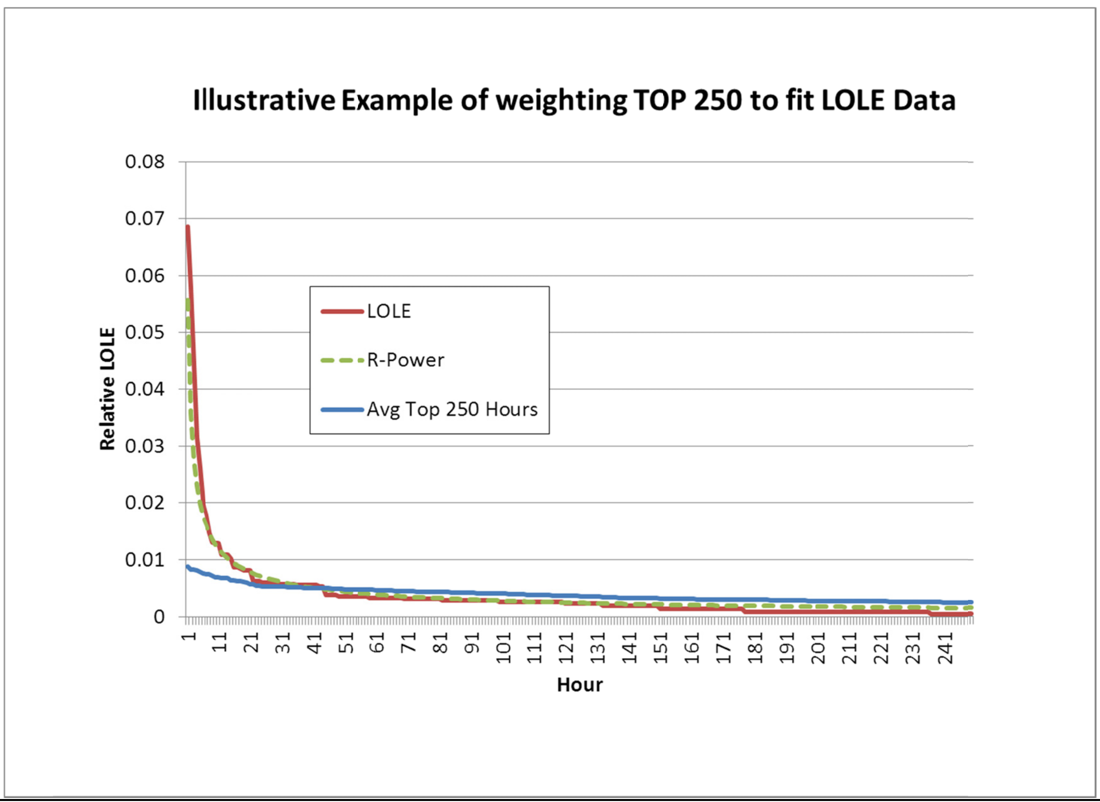
***Figure II-1***




The only way to determine when additional capacity, or DR programs, can improve the reliability of the system is through LOLE studies, which are confidential but more accurate than the public model preferred by the Commission. Proprietary models are available to anyone willing to pay a fee for their use; however, the investor-owned utilities (IOUs) consider the results confidential because this information would be potentially valuable for marketers to maximize their offering price for capacity. The Commission will have to decide between the impact of inaccuracy from using the simplified proxy and the reliability studies used to develop accurate LOLE. If the proxy is inaccurate there is a risk that programs may not have the intended impact to improve reliability. SCE presents its LOLE studies as the basis of rate design in their Phase 2 of General Rate Cases, and they are generally vetted by residential, commercial, and agricultural advocates, as well as the CPUC's Division of Ratepayer Advocates.

Currently, the top 250 load hour proxy under-values DR programs with limited hours (25 or less) because the weight for the highest load hours is significantly lower than allocation from the LOLE results. This makes programs such as Capacity Bidding Program appear less cost effective. A temporary solution is to give the higher load hours a higher weight through the use of a functional form which will give the top 25 hours more weight[2]. In Figure II-2, a power function is usedused to convert the top 250 hours to fit illustrative LOLE data.[3] The proposed adjustment would still give more benefit to programs that are available more than 100 hours. See Table II-1 for a comparison of the cumulative allocation for various methods.

***Figure II-2***




[2] However, as mentioned previously this would not solve the future problem of properly allocating generation need to the time of day or months of year.

[3] The results from the power function are then adjusted so that the 250 hours sum to 100%.

***Table II-1***

| Cummulative Allocation | | | |
|---|---|---|---|
| Hours | Top 250 | rPower | LOLE |
| 50 | 30% | 51% | 57% |
| 100 | 53% | 69% | 73% |
| 150 | 71% | 81% | 85% |
| 200 | 86% | 91% | 91% |
| 250 | 100% | 100% | 95% |

## 8. Would Changing The Step Function To A Linear Function, Such That Value Of RPS Energy Reductions Increases Linearly Between Interim Goal Years, More Accurately Reflect The Utility Procurement Costs That Will Be Avoided?

Changing the step function to a linear function would make analysis easier than trying to forecast step functions and would not negatively impact the precision of cost-effectiveness.

## 9. After 2013, Will There Still Be A Need For An Additional Greenhouse Gas (GHG) Avoided Cost Adder Beyond The California Carbon Allowance Price?

The need of a GHG adder is dependent on the method to determine the energy price forecast as GHG may already be embedded in the value.

A *GHG* adder *is **not required*** if the forecasted energy is:

- Based upon market quotes for a delivered energy in the future, in which case the cost of GHG compliance (just as fuel cost) is imbedded in the energy price. The use of New York Mercantile Exchange (NYMEX) futures is an example;or,
- Based upon a production cost model when GHG is included as an input cost.

A *GHG* adder *is **required*** if the forecasted energy is:

- Based upon historical energy prices prior to 2013; or,

- Based upon natural gas prices and a heat rate, provided the GHG cost is not embedded into the gas price

**10. How Do The Avoided Costs Of GHG And RPS Affect Each Other? How Should That Relationship Be Accounted For In The Avoided Cost Model?**

Renewables purchases directly offset GHG emissions. Therefore, avoided RPS purchases should reduce avoided carbon emissions costs by the percentage share of renewables in the generation mix. For example, for each kWh of avoided energy, if 33% is assumed renewable and an RPS adder (i.e., 33%*Renewables premium) is added to the avoided cost of energy, then 33% of the GHG emission costs for the kWh in question should be subtracted from the avoided cost of energy to avoid double counting.

**11. Describe In Detail The Analysis That Was Used To Determine The Current Transmission & Distribution (T&D) Avoided Costs For Your Utility.**

SCE based its avoided T&D cost on the marginal cost study presented in the marginal cost exhibit for the 2006 General Rate Case, Phase 2. The study used a combination of historical and forecast expenditures on growth related T&D costs to measure the additional cost incurred by adding a new customer, which adds new access and transformer demand cost. However, the determination of avoided T&D for cost-effectiveness analysis is different from the marginal T&D included the GRC Phase 2. For avoided cost, SCE did not include the capital costs related to poles, wires, and substation structures and related equipment, as those items are not avoided by DR or EE since the customer is still served by the utility. The remaining capital costs are for transformer equipment, as that is the investment that can be deferred through the use of DR or EE. The maintenance of poles, wires, and substations, including the transformer, is not avoided;therefore, operations & maintenance (O&M) was also excluded in the avoided cost determination.[4]

[4] In the data requested provided to E3, SCE removed the O&M component from avoided T&D cost; however, E3 independently added it back as an avoided cost for their E3 model.

The avoided T&D study reflects expenses associated with Federal Energy Regulatory Commission (FERC) uniform system of accounts 353 and 262 which are associated with station equipment for T&D.[5] Transmission account 353 is further adjusted to remove FERC jurisdictional transmission, so only sub-transmission costs remain.[6] For the forecast data, five years of forecasted load growth expenditures are taken from studies that support Phase 1 of SCE's GRC. Since the forecast data is on a cash flow basis, it is adjusted to be consistent with the historical closed to plant basis, which includes capitalized allowance for funds used during construction and administrative and general overhead.

A regression analysis is used to derive a trend between substation expense and load growth using 10 years of historical and 5 years of forecast data. For load growth over time, historical planned capacity and forecast annual peak load for the A-Bank (sub-transmission) and B-Bank (distribution) is used in the regression. For the 2006 study, a regression best fit line was calculated using ordinary least squares.[7] A regression is performed separately for sub-transmission and distribution. The slope coefficients are annualized using the real economic carrying charge to calculate the annual deferral value of avoided T&D.

**12. Are The Current T&D Avoided Costs Appropriate For Demand-Side Programs? Do They Accurately Reflect The Marginal Cost Of Adding T&D Capacity In Response To Demand? Explain.**

For SCE, except for the addition of O&M cost, which is not avoided, the current T&D avoided costs are appropriate for demand-side programs, as the avoided costs only reflect those

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5 Substation equipment also includes switching gear which would not be avoidable; however, SCE does not have a separate estimate of non-transformer related equipment in these FERC accounts.

6 The CAISO related transmission is generally not avoidable as the system is used to move bulk power. Peak transmission flows may not occur during times of system peak. In addition, most of the future transmission investments are to import renewables or maintain reliability.

7 Future studies will use Maximum Likelihood Estimate (MLE) method is used for the regression to account for serial correlation of the input data.

components of T&D marginal costs that are avoided by DSM load reductions. To clarify, SCE assumes avoidable T&D costs to only include transformer capacity.

Furthermore, the avoided T&D cost is subject the principles of right place and right certainty:

*Right Certainty*. For a DSM program to be able to avoid sub-transmission and distribution investment, the utility must be able to call the program to reduce circuit loading which may or may not occur at times when the system is experiencing a generation peak event. In addition, the DSM program must be capable of being dispatched at a specific location in SCE service area, as opposed to all customers within the program or on a wide geographic area.

*Right Place.* An existing customer selecting a DSM program in an area that is fully developed will not avoid T&D investment because the investment has already been made to serve the customers in that area.

**13. What Are The Component Costs Of The Existing Avoided T&D Costs (e.g., Replacing/Upgrading Poles, Wires, Hardware, Transformers, Air Switches; Building New Transmission, Sub-Transmission, Distribution, Substations)? To What Extent Do Each Of These Cost Components Represent Routine Replacement, And To What Extent Are They Each Load-Driven?**

The separation of load-related and access-related equipment for the addition of new customer is difficult as the connection with a customer's respective loads is added to the system simultaneously. However, since the customer is already in place, there is a distinct difference between marginal and avoided T&D cost. All the equipment needed to deliver power to the customer will remain in place and will not be impacted due to a reduction in customer load. In SCE's experience, transformer capacity can be "reassigned" to customers in an adjacent area experiencing load growth by reconfiguring distribution circuits, so that it is sometimes possible for DSM to reduce transformer capacity in an area. In addition, as discussed in more detail in question 12, the upgrade of a transformer of a circuit with rapid load growth can be deferred to a later time.

Avoided T&D costs should include:

- Costs associated with incremental transformation requirements

Avoided T&D costs should exclude:

- Land
- Substation structures to locate transformers, switches, etc.
- Poles, wires, switches
- O&M to patrol and inspect T&D facilities

**14. <u>What Is The Appropriate Method Of Determining The Marginal Cost Of T&D? Participants Suggested Using Historical Data In A Multi-Variable Regression Analysis To Determine T&D Avoided Cost Functions And Then Isolating The Marginal Cost Attributable To Increased Demand. Is This A Reasonable Approach? Why Or Why Not?</u>**

SCE's regression, discussed in the response to question 11, is an appropriate method to determine avoided T&D costs associated with DR. The use of multi-variable regression to attempt to isolate customer access versus load related costs is problematic due to regression multi-colinearity. This occurs because an adding a customer results in additional load, so the separate effects of the customer and the associated load cannot be discerned. That is, the regression's explanatory variables move in the same direction and often by the same magnitude. When a regression formula is affected by multi-colinearity, the estimators are inefficient and it is not possible to determine accurately which behaviors are actually impacting the coefficient of the estimates.

**15. <u>What Is The Appropriate Level Of Disaggregation For T&D Avoided Costs, And Should It Differ For Energy Efficiency, Demand Response, And Distributed Generation?</u>**

T&D avoided costs should be evaluated at the systems level. While evaluating T&D avoided cost at a more detailed level is useful for program administrative and marketing purposes, it is not practical and may not even be feasible for cost-effectiveness analysis.

**16. The Feed-In Tariff Proceedings Have Considered Identifying Specific Locations Or "hotspots" Where Distributed Generation Will Provide Higher Avoided T&D Cost Savings. Should Those Location-Specific Avoided Costs Be Adopted For Demand-Side Programs? Why Or Why Not?**

Providing locational benefits via administratively priced feed in tariffs is problematic, because such "locational adders" commonly are not avoided cost based, and the factors which lead to locational premium occurring are not stable over the term of a feed in tariff agreement. The identification of locations where DSM programs can create deferral benefits may be useful in managing the T&D system in the short term. SCE has identified these impacted areas in the circuit saver study, which is then used to market DSM programs in those specific areas to capture deferral benefits. It is not necessary to develop specific location avoided cost to perform cost-benefit analysis. The cost savings will trend to the system average because of a mix of various circuits over time.

**17. Assuming That The Weighted Average Cost Of Capital (WACC) Will Continue To Be Used For At Least Some, Although Not Necessarily All, Cost-Effectiveness Analyses Of Demand-Side Resources, Is The After-Tax WACC The Appropriate Discount Rate To Use Or Would The Before-Tax WACC Be More Appropriate?**

Between the before-or after-tax view of capital cost, the before tax rate is a better choice as it reflects the cost paid by customers. WACC is flawed.

The proper discount rate should be from the point of view of the customer, because utility investments are incurred on behalf of customers and because customers are obligated to compensate the utility for these investments. However, the current WACC is a short-term measure of capital cost and it is a measure of IOU financing, not customer financing. In addition, IOUs cannot get current WACC over the long-term, so it is inappropriate for discounting long-term costs and benefits. (The authorized WACC is determined every three years.) The discount rate should be consistent between generation capital projects, transmission and distribution projects, and DR, EE, and DG products.

SCE's practice has been to use a measure of long-term incremental cost of capital, currently 10%, for discounting for capital projects such a steam generators and transmission projects. In our view, this is best representation of a customer discount rate.

The after-tax view of WACC is a SCE shareholder view of investment because interest on debt is tax deductible. However, the tax deductible portion of the debt still has to be paid by customers and/or society through higher tax collections. Therefore, the after-tax WACC is inappropriate for discounting investments from the viewpoint of the customers as they cannot benefit from the tax deduction. This point is acknowledged in E3's write-up on discount rates included in attachment 3: "If, on the other hand, the cash flows ignore the tax benefits of debt financing, as in Table 2, then the higher before tax discount rate should be used." Between the two WACCs, the before-tax WACC should be used for discounting.

**18. Should A Societal Discount Rate Be Considered For Any Part Of The Current Cost-Effectiveness Analysis? When, If Ever, Is It Appropriate To Use A Societal Discount Rate?**

The term societal discount rate is not well defined. If this means a discount rate to measure private investments, then the private investment rate used by the Federal Office of Management and Budgets (OMB) – the private real discount rate of seven percent[8] – could be used as a societal measure. To convert to a nominal discount rate, long term gross domestic product implicit price deflator (GDP-IPD) rate should be added.[9]

Sometimes the term societal discount rate is used to refer to the risk-free rate, with suggested a value of 3% . There is no economic basis for applying such a rate to utility capital investments, which necessarily have associated risks.

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[8] This rate approximates the marginal pretax rate of return on an average investment in the private sector in recent years. *See* OMB Circular A-94, p. 9. OMB Circular A-94 is *available at* http://www.whitehouse.gov/omb/circulars_default; a direct link to the text of OMB Circular A-94 in PDF format is *available at* http://www.whitehouse.gov/sites/default/files/omb/assets/a94/a094.pdf.

[9] Currently this is about 1.7-1.8%.

The evaluation of utility service related costs and benefits should use discount rates consistent with the parties paying for those assets in rates. A societal measure would be a weighted average mix of all financial investments in the economy. A societal rate would be applicable for macroeconomic analysis involving the entire economy.

**19. Should A Consumer Discount Rate Be Considered For Any Part Of The Current Cost-Effectiveness Analysis? When, If Ever, Is It Appropriate To Use A Consumer Discount Rate? How Should The Consumer Discount Rate Be Determined? How Many Different Consumer Discount Rates (For Different Types Of Consumers) Would Be Needed?**

See the response to question 17. Some parties have suggested customer discount rates of 3%, which is inappropriate as individuals could not finance utility assets at that very low discount rate. Some parties have suggested using home mortgages rates, which is also inappropriate as banks would not be offer this rate to utility type investments. This is because a homeowner must make an equity contribution in the form of a down payment or by having equity in the home in the case of a refinancing. The home mortgage rate does not take this into account, since it is only a debt rate, and it excludes the homeowner's expected return on their equity portion. (The homeowner cost of capital would include both the home mortgage rate plus their expected increase in value of their equity portion.) Other consumer discount rates that do not require an equity contribution, such as a credit card with a revolving line of credit, carry rates that are considerably higher.

**20. Some Participants Suggested Using Different Discount Rates For Different Cost-Effectiveness Tests, Or Different Discount Rates For Different Cost-Effectiveness Inputs. Is This Appropriate, And Is This Feasible? How?**

Using a different discount rate for the different inputs included in each participant cost-effectiveness test would add unnecessary tedious complication to an already complex analysis. For each test, a dollar is a dollar regardless of its source. As for applying a different discount rate for the four cost-effectiveness tests, it is unnecessary as it would have little impact on the difference in the resulting cost to benefit ratio as the discount rate would apply both to the numerator and denominator. It would never be appropriate to apply a different discount rate to benefits and costs.

## 21. Should The Input Data Be Updated Regularly?

SCE supports "planned" updates to the required demand-side program inputs. These planned updates should include cost effectiveness inputs as well as updates required by program planners so program plans can be efficiently implemented.

In 2015, the program cycles for EE, DR, and Energy Savings Assistance are in alignment and are on track to start new program cycles in 2015:

- Energy Efficiency: 2013-2014 programs proposed
- Demand Response: 2012-2014 programs adopted by the CPUC
- Energy Savings Assistance: 2012-2014 programs adopted by the CPUC
- California  Solar Initiative: ongoing
- Self-Generation Incentive Program: ongoing

The decision providing guidance on 2013-2014 EE portfolios[10] provided, in one document, much of the required input/decisions necessary to start the EE program planning process. Avoided costs, Database for Energy Efficient Resources (DEER) and Goals were updated, and guidance was supplied on the use of spillover values, discount rates and other things. However, one critical item was not ready for the start of the 2013-2014 program planning process – the E3 calculator. The E3 calculator was revised multiple times, stifling program planning efforts that had the potential to delay the submission of the 2013-2014 application. Therefore, it is critical that all inputs are in place and ready for 2015-2017 program planning to effectively begin. SCE suggests that the 2015-2017 planning process start now. This includes identifying program planning inputs that require updating and the collection of that data.

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[10] D.12-05-015.

## 22. **<u>What Process And Timeline Should Be Implemented To Allow Parties And The Commission To Examine The Input Data Before Updates Are Adopted?</u>**

As evidenced in the ALJ Ruling, updating just a portion of the required cost-effectiveness inputs is a complex and time consuming endeavor. SCE suggests that a holistic plan for continuous improvement of all data needed to start the 2015-2017 DSM program cycle should be developed. As indicated in SCE's 2013-2014 program testimony,[11] SCE proposes staging Evaluation, Measurement, & Verification (EM&V) activity to provide for continuous program measurement and real-time updated to EE potential, goals, and program assumptions.

To implement this change, during their development of the 2013-2014 EM&V research plan, the Energy Division and utility EM&V teams should agree to a suite of staged research studies, thereby levelizing the workload across a longer timeframe. As indicated in the graphic blow, this staged approach would prioritize studies to make the right information available at the right time, thereby maximizing the value of EM&V expenditures.

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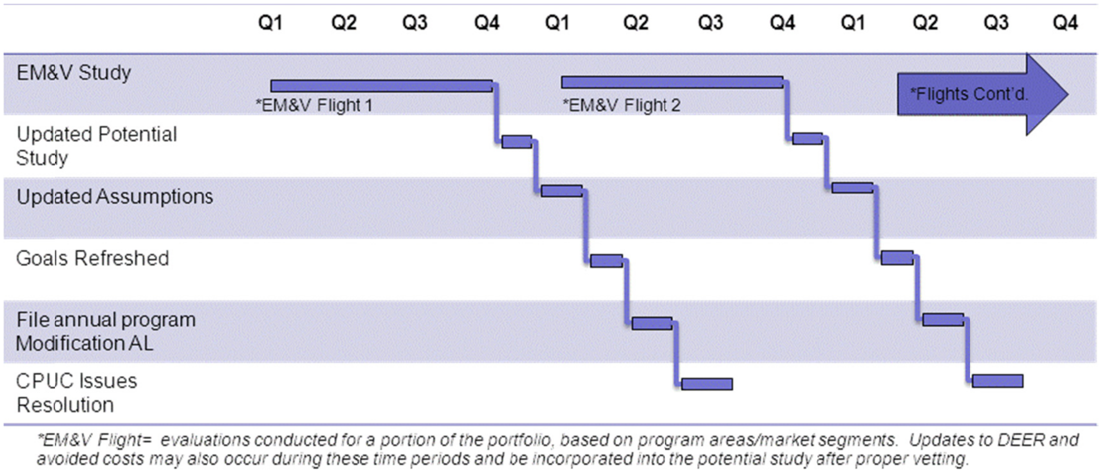
[11] Testimony of Southern California Edison Company in Support of its Application for Approval of its Energy Efficiency and Demand Response Integrated Demand Side Management Programs and Budget for 2013-2014, dated July 2, 2012, served in proceeding A.12-07-004, pp. 114-115. [*Available at* http://www3.sce.com/sscc/law/dis/dbattach4e.nsf/0/BA8D06C0F086A3B488257A4000839CC6/$FILE/A.12-07-004_+SCE+2013-2014+EE+Application+-+SCE-1+EE+and+DR+Application+Testimony_REVISED.pdf].

*Figure II-3*

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**23. <u>What Relationship Should the Existing Demand –Side Cost-Effectiveness Efforts Have To One Another? Is It Feasible To Have One Basic Framework For All Demand-Side Programs, With Only Minor Variations Or Additions For Each Resource, Or Should Separate Methods And Models Continue To Be Developed For Each Resource?</u>**

The Standard Practice Manual should continue to be the basic framework applicable to evaluating the cost effectiveness of EE, DR, and DG resources. There may need to be separate methods and models developed for each resource as each demand-side resource has its own unique set of inputs and assumptions. For instance, allocating of capacity value to "dispatchable" demand response programs raises issues that are not present in the evaluation of energy efficiency programs.

**24. <u>Should The Commission Continue To Separately Address Cost-Effectiveness For Each Demand-Side Resource In Different Proceedings, Or Can Consistency Only Be Accomplished If Cost-Effectiveness Is Addressed In One Proceeding? What Are The Pros And Cons Of Having Aan Over-Arching Demand-Side Cost-Effectiveness Proceeding? Are There Any Regulatory Barriers Or Policy Concerns?</u>**

If the CPUC seeks to develop common avoided cost assumptions that will be used across all demand-side resources, such an effort will need to be timely and subject to frequent updates, since underlying assumptions (e.g., natural gas price forecasts) can change significantly in a short period of time. Each demand-side resource has unique inputs and assumptions that favor a flexible process where each proceeding should allowspecific cost-effectiveness issues and assumptions to be addressed. In any case, parties to a DSM proceeding should be permitted to present cost effectiveness based on what they considers to be reasonably assumptions, in instances where underlying assumptions differ materially for any standard values adopted by the CPUC staff.

Having one over-arching demand-side cost-effectiveness proceeding may be useful in addressing common concerns, but has the potential to turn into an unwieldy and protracted effort that does not produce timely results and risks delaying DSM proceedings that have tight deadlines for reaching funding decisions. As seen from the DSM Cost-Effectiveness Workshop in June 2012, many discussion topics needed to be separated because they are not applicable to all demand-side resources, so separate proceedings for EE, DR, and DG cost-effectiveness would be more useful in addressing different cost-effectiveness issues and concerns. The current process of the SPM definition of TRC to include the utility and its customers is an appropriate scope for cost-effectiveness.

**25. What Are The Pros And Cons Of Using The PAC, Rather Than The TRC, As The Primary Test Of Cost-Effectiveness? Option (2) In Question 24 Above Leads To An "energy only" TRC, Where Non-Energy Impacts Are Excluded, Whereas Option (3) Above Leads To A TRC Which Includes Non-Energy Impacts. Which Is More Appropriate For The TRC Test?**

The Program Administrator Cost (PAC) is not appropriate as a primary test of cost effectiveness.

As described in the California Standard Practice Manual (SPM):[12]

- The Total Resource Cost (TRC) test measures the net costs of a demand-side management program as a resource option based on the total costs of the program, including both the participants' and the utility's costs. This measure combines the costs and benefits of participants, non-participants, and the program administrator so it is a wide viewpoint. However, because costs of incentives to non-participants are cancelled by benefit received by participants, it does not measure the amount of wealth transfer between the two parties.
- The Program Administrator Cost (PAC) test measures the net costs of a demand-side management program as a resource option based on the costs incurred by the program administrator (including incentive costs) and excluding any net costs incurred by the participant.
- The Rate Impact Measure (RIM) test measures what happens to customer bills or rates due to changes in utility revenues and operating costs caused by the program due to participation in a program.
- The Participant test is the measure of the quantifiable benefits and costs to the customer due to participation in a program.

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[12] California Standard Practice Manual, Economic Analysis of Demand-Side Programs and Projects, October 2001 [*available at* http://www.energy.ca.gov/greenbuilding/documents/background/07-J_CPUC_STANDARD_PRACTICE_MANUAL.PDF].

All cost-effectiveness tests serve their own perspective and have their own purpose. As a result, the Commission should review all cost-effectiveness tests and understand their individual effects. More importantly, it is important not to give a particular test more weight over another or cherry pick different tests for different proceedings because a certain test provides a better cost-effectiveness ratio than another test.

The reliance on the PAC test as a primary measure of cost effectiveness is flawed, since it would ignore any costs not paid by the administrator. As such, it is better to consider the PAC as a test of program leverage – it captures the amount spent by program administrators to induce customer spending for DSM. As mentioned in the SPM manual because rate impacts are a transfer, the reliance on the PAC test would ignore the impact to non-participants that is measured in the RIM test. This is the same weakness as relying only on the TRC test.

The ALJ ruling suggested the following remedies to correct this perceived asymmetry of costs and benefits: "(1) either replacing or putting more focus on the Program Administrator Cost (PAC) test, instead of the TRC; (2) ensuring that the participant costs are adjusted to remove costs associated with non-energy benefits (NEBs); or (3) adding NEBs to the TRC."

SCE assumes that remedy 2 above means part of the participant's cost would be allocated to NEB. For example, if 50% of a solar system was counted as the customer's non energy costs to advertise themselves as being "green." This would artificially make the installation of solar panel appear cheaper which would inpact the cost effectiveness test. The impact of this would be programs incentives would go toward the customer desire to advertise themselves as being green while the solar system is not cost effective. Customer funded DSM programs should not fund the marketing campaigns of participants.

Remedy 3, including NEBs to the TRC, would become a societal measure, which is beyond the scope of utility programs. SCE does not recommend the calculation of a societal TRC due to the broad-nature of the inputs as it would be a never ending list of inputs and wide disagreements.

**26. Currently, In Energy Efficiency Cost-Effectiveness Calculations, The Effect Of NEBs Is Intended To Be Minimized By Applying A Net-To-Gross Ratio To The Participant Costs. Does The Net-To-Gross Formulation Provide An Accurate Accounting Of Participant Costs? Should A Similar Process Be Used For Demand Response And/Or Dstributed Generation?**

SCE does not have a response for this question.

**27. In The Demand Response Context, Participant Costs Include Value Of Service Lost And Transaction Costs. Are These Costs Relevant For Any Other Demand-Side Resources?**

Participant costs in the demand response context include value of service lost and transaction cost because customers have to function with less electricity when a demand response event is called. These costs are not relevant in EE or DG because these customers are not losing any service. Therefore, these participant costs are not applicable in the EE and DG context.

**28. Assuming NEBs Were Added To The TRC (Or Another Cost-Effectiveness Test), Is The NEB Research That Has Been Done In The Low Income Proceeding On Participant And Utility NEBs Applicable To Other Resources? If So, Which NEBs Should Be Included? If Not, How Should The Value Of NEBs Be Determined For The Cost-Effectiveness Framework?**

Non-energy costs and benefits are difficult to quantify, and research into the non-energy benefits and costs of utility programs is still preliminary. Because of these reasons, non-energy costs and benefits should be excluded from the TRC and other cost-effectiveness tests.

The statewide study of NEBs commenced with a kickoff meeting for all interested parties in August 2009. The purpose of the study was to research the available literature on NEBs and provide a recommended methodology for updating the current NEB values used for testing the cost-effectiveness of the Energy Savings Assistance Program. The work scope consisted of an extensive literature review and synopsis of relevant ranges of values used in other programs. The results of the study showed that the current NEB values used by the utilities for the most part fall within the range of values reported from other programs.

EE program non-energy benefit and costs should be studied further and possibly reported on in ex-post qualitative program evaluations, but not included in program cost-effectiveness evaluations.

If non energy benefits and costs (NEBC) are included, they should be part of a qualitative perspective.

**29. <u>Are There Societal NEBs (Beyond GHGs) That You Believe Should Be Fit Into The Cost-Effectiveness Framework? If So, How (i.e., via Which Test Or Tests) Should They Be Handled?</u>**

NEBs and non energy costs (NECs) should not be included in the cost-effectiveness framework for utility ratepayer-funded EE programs, because NEBs are not the primary goals of these programs. If there is a desire among stakeholders to estimate NEBs and NECs of EE programs, evaluation of NEBs and NECs should be done through qualitative program evaluations – but given the inherent difficulty of measuring NEBs and NECs, including them in EE program cost-effectiveness evaluations would result in highly questionable in results.

**30. <u>Are There Cost And Benefit Inputs (Other Than Participant Costs) To The TRC That Should Be Updated, Redefined, Or Calculated Differently? Are Current Methodologies Over- Or Under-Estimating Some Benefits And Costs? If So, Which Ones?</u>**

For DR, avoided capacity costs are overestimated and the A-factor is underestimated for programs with a few call hours. The avoided capacity cost is overstated as the CT proxy, which is based upon an advanced turbine that has a low heat rate which provides energy benefits. There are cheaper turbines that can provide capacity value that would result in lower net capacity value than the methodology used by the E3 avoided cost calculator. For the A-factor, see response to question 7.

The updated E3 avoided cost model included in attachment A has the following problems:

- Page A3, gas prices are based on those from December 2010. Gas prices have dropped significantly in the last year and half. We need to address the process of updating inputs in a timely manner.
- Page A24, SCE's avoided T&D capacity is wrong. The updated E3 model misses the assumption of right place and right certainty, which should be included as a test for DSM programs before assigning T&D benefits. (See our answer to question 12 above.)
- Page A26, the allocation of avoided T&D. SCE's circuit study for the rate making in the GRC does not support TOU-based T&D charges, so the treatment of T&D benefits should be on a similar basis. The use of temperature to allocate avoided T&D is a poor method because temperature is only good at explaining air-conditioning based load. The relationship between temperature and load breaks down when the temperature is lower, such as coastal areas that have night-time peaks due to lighting. If avoided T&D is allocated, then it should be based upon load.
- Page A32, The updated E3 model uses the most expensive Fairmont California Renewable Energy Zone as a proxy for marginal RPS, which lacks support. If no contracts are being signed in this zone, then it is not a marginal source.

For EE, please see answers to question 21 and 22. In addition, there are several cost and benefit inputs to the TRC and other tests of EE programs that SCE will address during the upcoming EE-specific workshops.

**31. <u>Are There Any Other Impacts, Such As The Rebound Effect Or Long-Term Impacts, That Need To Be Accounted For In The TRC? (Note That Spillover And Market Transformation Effects Are Being Addressed In Other Proceedings.)</u>**

SCE does not have a response for this question.

32. **Many Parties In The Energy Efficiency Proceeding Have Suggested That The Avoided Costs Of Embedded Energy In Water Be Added To The TRC. Should The Commission Add The Avoided Costs Of Embedded Energy In Water To The TRC, And, If So, What Is The Best Approach?**

No, SCE does not believe that embedded energy in water should be added to the TRC as the current avoided costs adequately recognize energy savings associated with embedded water efficiency measures. The embedded energy costs associated with delivery and processing of water is internalized in the cost of water paid by consumers. Thus, the cost of water consumption that is avoided by, for instance a low water use washer, will be reflected in operating cost savings. This principle generally applies to any other products that are require energy for their manufacture or delivery.SCE does not see a reason to treat embedded water-energy savings differently than any other EE measure as embedded water energy savings results in reduced energy consumption, which are captured in the current avoided costs.

33. **What Is The RIM Test Useful For? How Should It Be Weighted In Cost-Effectiveness Analysis? Does The Current RIM Formula Need To Be Revised To Accurately Reflect Programs Involving Long-Term, Capital-Intensive, Customer Funded Projects (e.g., Permanent Load Shifting)?**

The RIM test measures what happens to customer bills or rates due to changes in utility revenues and operating costs caused by the program due to participation in a program.[13] The RIM test helps show the impact of various DSM policies on non-participants.

As described in the response to question 25, all cost-effectiveness tests serve their own perspective and have their own purpose. As a result, the Commission should review all cost-effectiveness tests and understand their individual effects. More importantly, it is important not

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[13] California Standard Practice Manual, Economic Analysis of Demand-Side Programs and Projects, October 2001, p. 13 [*available at* http://www.energy.ca.gov/greenbuilding/documents/background/07-J_CPUC_STANDARD_PRACTICE_MANUAL.PDF].

to give a particular test more weight over another or cherry pick different tests for different proceedings because a certain test provides a better cost-effectiveness ratio than another test.

The RIM test formula does not need to be adjusted for the participants's capital expenses as those costs are not included in the RIM test. Any incentives or rate shifting impacts that occur over the lifespan of Permanent Load Shifting (PLS) used in the analysis should be included to get an accurate measure of the RIM.

**34. <u>Would Additional Cost-Effectiveness Tests, Or Alternative Forms Of The Existing Tests (e.g., A Societal TRC Test), Be Useful? Explain.</u>**

The current tests (TRC, PAC, RIM, and Participant) provide a sufficient range of perspectives of cost-effectiveness. It is not necessary to include additional or alternative forms of existing tests. A societal TRC test includes NEBs, which are qualitative in nature. Unless these types of benefits can be accurately quantified, vague speculations and estimates should not be used to quantify these benefits. The current process of the SPM definition of TRC to include the utility and its customers is an appropriate scope for cost-effectiveness.

**35. <u>Would A Societal TRC Test (i.e., A TRC Which Included Non-Energy Costs And Benefits) Be Useful For Measuring The Value Of Demand-Side Programs? If There Was A Societal TRC, How Should It Be Used To Determine The Program Design And The Content Of The Portfolio Of Demand-Side Programs?</u>**

The inclusion of non-energy costs and benefits allows for a never-ending scope of issues to be evaluated. The boundaries need to be defined and also accurately quantified. Unless these types of benefits can be accurately quantified, vague speculations and estimates should not be used to quantify these benefits. Qualitative benefits and costs should be evaluated outside the cost-effectiveness framework. Note that under a societal test framework, taxes and tax credits would be considered transfers, not costs and benefits, respectively, which raises numerous issues as well.

**36. <u>In Past Proceedings, The Commission Has Relied Primarily On The TRC To Determine The Cost-Effectiveness Of Demand-Side Programs. Should The Commission Continue To Rely Primarily On The TRC, Or Could The Method Of Determining Program Offerings, Program Design, Incentive Levels, Or Other Decisions About Demand-Side Programs Be Improved By Giving More Prominence To Different Tests Or Other Methods? For Example, Workshop Participants Suggested That The Commission Pay More Attention To The RIM Test; That Different Tests Be Used At Different Levels (i.e., Measure, Program, And Portfolio); That Having Positive Net Benefits According To The PAC Be Used As A Minimum Criterion Of Cost-Effectiveness; And That The Various Tests Be "Weighted."</u>**

As described in the response to question 25, all cost-effectiveness tests serve their own perspective and have their own purpose. As a result, the Commission should review all cost-effectiveness tests and understand their individual effects. More importantly, it is important not to give a particular test more weight over another or cherry pick different tests for different proceedings because a certain test provides a better cost-effectiveness ratio than another test.

# <u>III</u>.

## <u>CONCLUSION</u>

SCE appreciates the opportunity to respond to this question and to improving demand-side cost effectiveness analysis.

Respectfully submitted,

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