UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

California Independent System Operator Corporation	)))	Docket No. ER00-2019-006, ER01-819-002, and ER03-608-000

PREPARED REBUTTAL TESTIMONY OF
JOHANNES P. PFEIFENBERGER
ON BEHALF OF THE
CALIFORNIA INDEPENDENT SYSTEM
OPERATOR CORPORATION

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In his rebuttal testimony, Mr. Pfeifenberger observes that the efficiency claims made for TOU and coincident-peak pricing by SWP and SWC are based primarily on the assumption that peak transmission use occurs during the peak hours of total end-use energy consumption. However, Mr. Pfeifenberger explains that a careful review and analysis of the ISO's congestion data shows that significant transmission congestion occurs during off-peak hours. Indeed, he shows that at some of the major transmission interfaces, such as Path 15, which connects northern and southern California, congestion has occurred more frequently during off-peak hours than on-peak hours. Hence, Mr. Pfeifenberger concludes that, rather than improving economic efficiency, TOU or coincident-peak pricing of transmission access may provide perverse price signals to transmission customers to increase their usage of an already congested transmission grid. In that case, he explains, the TAC would be working at cross purposes with any current or future congestion charges set by the ISO's congestion management system.

Mr. Pfeifenberger also disputes related and unsupported assertions by SWP witness Wilson that coincident-peak (e.g., 12-CP) pricing would be more consistent with long-run marginal cost pricing principles, and hence would be more economically efficient than the ISO's TAC design. He shows that 12-CP is a way of recovering embedded transmission costs that is very similar to the ISO's volumetric access charge. Just like the ISO's volumetric charge, he explains, a 12-CP pricing does not, in and of itself, indicate the marginal cost of transmission usage—either long- or short-term. He demonstrates that it is the ISO's congestion charges that indicate the short-run marginal cost of using constrained paths or interfaces in the ISO-controlled grid.

Mr. Pfeifenberger also shows that assertions by SWC witness Russell and SWP witness Wilson that the ISO's congestion prices provide an inadequate incentive for efficient expansion of the ISO Grid are overstated at best. He explains that congestion prices reflect the marginal cost of relieving a constraint and thus efficiently ration scarce transmission capacity between zones. He points out that the ISO's congestion prices enable market participants to identify the location and direction (as well as the cost and persistence) of congestion and therefore signal the potential value of expanding transmission capacity (or generating capacity) to mitigate the constraint. Mr. Pfeifenberger observes that the ISO's congestion management system highlighted the fact that constraints on

Path 15 often caused the Northern California zone to separate from Southern California and spurred support for the Path 15 expansion.

Mr. Pfeifenberger also exposes as unsupported claims that TOU or coincident-peak pricing of transmission service are more consistent with cost causation and well-established ratemaking principles than the ISO's Access Charge. He explains that the TAC's flat, volumetric rate appropriately recovers fixed transmission costs from all users of the grid. Mr. Pfeifenberger shows that the ISO's access charge is consistent with its provision of firm hourly transmission service, pointing out that even under the prior utility-specific access charges, the ISO recovered its directly-assessed transmission access charges (i.e., for wheeling services) on a volumetric basis.

Next, Mr. Pfeifenberger finds several errors and omissions in Mr. Hansen's estimate of the benefits from increased ISO participation that results in a serious underestimate of those benefits.. Most significantly, he shows that Mr. Hansen seriously understates the benefits resulting from a reduction in "phantom" transmission congestion. Mr. Pfeifenberger explains that Mr. Hansen's estimate (of only $7 million/year) should be disregarded, in part, because, as ISO witness Keith Casey explained in his rebuttal testimony, it completely overlooks the impact that reduced congestion will have on competition and suppliers' bidding behavior. Mr. Pfeifenberger also observes that Mr. Hansen too readily dismisses other efficiencies from reduced transmission "seams" that the ISO would likely achieve through expanded membership simply because they are difficult to quantify and that Mr. Hansen ignores the Commission's clear recognition of the importance of scope and configuration and the benefits of reducing "seams" between transmission operators.

Finally, Mr. Pfeifenberger explains how the modified methodology for calculating cost shifts and Transition Charges proposed in Amendment No. 49 improves upon the ISO's previous TAC methodology. Amendment No. 49, he observes, excludes the costs of New High Voltage ("New HV") transmission facilities from the determination of the cost shifts and Transition Charges, while the allocation of the cost of new transmission investments among Participating Transmission Owners could vary significantly and unpredictably under the Amendment No. 27 methodology because of the impact of New HV facilities on the Transition Charge. Under Amendment No. 49, the cost of new transmission investments are recovered on an ISO-wide basis in proportion to gross load, which, Mr. Pfeifenberger concludes, facilitates transmission construction and allows participation by Transmission Owners without gross load, such as Transelect.

Q1. PLEASE STATE YOUR NAME.

A1. My name is Johannes P. Pfeifenberger.

Q2. ARE YOU THE SAME JOHANNES PFEIFENBERGER WHO PREVIOUSLY FILED TESTIMONY ON BEHALF OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION ("ISO")?

A2. Yes.

Q3. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A3. My rebuttal testimony first responds to proposals to modify the ISO's transmission Access Charge ("TAC") from its proposed rate design—a single price, volumetric rate—to a time-of-use ("TOU") or 12-month coincident peak (also known as "12-CP") rate design. I then respond to the testimony by Mr. Hansen (Exh. No. SCE-5) regarding his estimate of the benefits associated with the proposed TAC methodology and increased ISO participation. Finally, I address the treatment of New High Voltage ("HV") Transmission Facilities in the calculation of cost shifts and Transition Charges as proposed by the ISO in Amendment No. 49.

I. TOU AND COINCIDENT-PEAK PRICING

Q4. WHO IS PROPOSING TO CHANGE THE ISO ACCESS CHARGE TO A TOU OR COINCIDENT-PEAK RATE DESIGN?

A4. The proposed changes in the TAC rate design are advocated only by the witnesses for the California Department of Water Resources/State Water

Project ("SWP") and the State Water Contractors/Metropolitan Water District of Southern California ("SWC") through the testimony of Dr. John Wilson (Exh. No. SWP-65, his Cross-Answering Testimony, and Exh. No. SWP-67, the portion of the Initial and Answering Testimony of Harrison Call Jr. sponsored by Dr. Wilson) and Whitfield Russell (Exh. No. SWC-1, his Direct Testimony and Exhibits). Contrary to the testimony of these two witnesses, however, neither the economic efficiency nor the equity of the ISO's TAC likely would be improved by changing to TOU or coincident-peak pricing.

Q5. BEFORE YOU RESPOND TO THESE PROPOSED CHANGES IN THE TAC, PLEASE BRIEFLY EXPLAIN THE NATURE OF TRANSMISSION COSTS.

A5. The primary cost of transmission service is the fixed cost of transmission equipment, such as lines, poles, transformers, and substations. These costs are fixed because they do not vary in the short-term with usage of the transmission system. Transmission-related operations and maintenance costs also are largely fixed. Line losses and congestion constitute the variable costs of transmission service. Losses reflect the portion of electrical energy that is dissipated as it travels over transmission lines and congestion cost is the cost imposed on the system when the transmission grid is unable to accommodate all requested transactions. While line losses and congestion essentially are determined by generation-related costs, they are viewed as transmission costs because they are caused by underlying limitations in the transmission grid. Congestion costs can be quite significant if constrained transmission paths separate a relatively low-cost generation market from a relatively high-cost generation market. However, where congestion costs are less of a problem, almost all transmission cost (other than losses) will be fixed.

Q6. HOW DOES THE ISO CURRENTLY RECOVER THE COSTS OF TRANSMISSION SERVICE ON BEHALF OF THE OWNERS OF TRANSMISSION FACILITIES AND ENTITLEMENTS?

A6. The ISO recovers the cost of transmission service through three charges: a charge for transmission losses, a congestion charge, and a transmission access charge. The first two charges are based on the short-run marginal costs of losses and congestion, with the latter determined by the marginal bids accepted to resolve transmission constraints. The access charge is used to recover the residual cost of the ISO-controlled Grid—which, under the proposed access charge methodology, is the Grid's net transmission revenue requirement. As explained in previous testimony, the proposed TAC consists of a Low Voltage Access Charge collected by the individual Participating Transmission Owners ("PTOs") and a High Voltage Access Charge ("HVAC") collected by the ISO on a TAC-area and Grid-wide basis. The ISO's HVAC is a flat volumetric ($/MWh) rate.

Q7. WHAT TYPE OF RATE DESIGN DO DR. WILSON AND MR. RUSSELL SPECIFICALLY RECOMMEND THE COMMISSION REQUIRE FOR THE ISO'S HIGH VOLTAGE ACCESS CHARGE?

A7. SWC's witness Russell recommends that the ISO's Access Charge rate structure be changed to a 12-CP methodology (Exh. No. SWC-1 at 60), but notes that he could also support a TOU rate, such as the time-differentiated rate proposed by SWP's witness (Exh. No. SWC-1 at 71). SWP's witness Wilson similarly finds that a 12-CP or TOU rate structure would be preferable over the current Access Charge rate design (Exh. No. SWP-65 at 15), and specifically recommends that the ISO's High Voltage Access Charge rate design be changed to TOU pricing (Exh. No. SWP-67 at 34). Dr. Wilson testifies that, although a 12-CP methodology could be used, a TOU rate design is preferable (Exh. No. SWP-67 at 38).

Q8. WHAT IS TOU PRICING?

A8. Broadly speaking, TOU pricing refers to a pricing structure in which rates vary according to the time-of-day. Typically, TOU pricing features two rates: a rate for peak hours and a rate for off-peak hours, with peak and off-peak hours defined based on peak and off-peak electricity consumption by end users. However, TOU pricing also could feature several different rates throughout the day or seasonally-differentiated rates.

Q9. WHAT IS COINCIDENT PEAK OR 12-CP PRICING?

A9. Coincident peak rates are a form of demand-based charge that allocates costs based on customer loads that are coincident with the system's peak load in a billing period (usually a month). This is why it is referred to as a coincident peak or "CP" rate. The most common rate, a 12-CP rate, reflects the 12 month average of a customer's monthly coincident peak load, hence 12-CP. Other CP cost allocations have been used as well, such as a 1-CP rate, which reflects the customer's coincident peak load for the entire year.

For the purpose of transmission pricing, 12-CP pricing has been used widely for network transmission service (in contrast to point-to-point service). Network service enables transmission-dependent load-serving entities embedded within larger transmission-owning utilities to integrate their own generation resources. Network service effectively allows an entity to purchase use of a "slice" of a transmission provider's system.

Q10. ACCORDING TO SWP'S AND SWC'S WITNESSES, WHAT ARE THE BENEFITS OF CHANGING THE ISO'S FLAT VOLUMETRIC ACCESS CHARGE TO A TOU OR 12-CP RATE STRUCTURE?

A10. Mr. Russell and Dr. Wilson provide two principal rationales for TOU and CP pricing. First, the witnesses claim that TOU/CP pricing would be more economically efficient than the ISO's proposed TAC because TOU/CP pricing would discourage transmission use during on-peak periods and encourage use during off-peak periods (Exh. Nos. SWP-65 at 6-7 and 11-12, SWP-67 at 22-23, SWC at 40). They argue that providing such incentives is appropriate because the need for transmission capacity is driven by peak end-use load (Exh. Nos. SWP-65 at 20, SWP-67 at 22 and SWC-1 at 19-20).

Second, SWC and SWP claim that TOU/CP pricing better reflects the long-term costs of transmission expansion and is more compatible with cost causation and well-established ratemaking principles. In addition, they contend that TOU/CP pricing of transmission service is a "fairer" way of recovering the fixed costs of transmission (Exh. Nos. SWC-1 at 10-12, SWP-65 at 11-12).

Q11. DO YOU AGREE WITH SWC AND SWP THAT TOU/CP PRICING WOULD BE A MORE EFFICIENT RATE DESIGN THAN THE ISO'S VOLUMETRIC CHARGE?

A11. No. I do not believe that TOU/CP pricing would be a more efficient rate design than the ISO's volumetric Access Charge. SWC witness Russell and SWP witness Wilson's conclusions are based largely on the erroneous premise that peak transmission usage and peak load energy consumption of end users (to which I here refer as "peak end-use load") necessarily coincide. This erroneous premise leads to the equally flawed conclusions (1) that TOU/CP pricing (based on peak end-use load) is more economically efficient than the ISO's proposed volumetric TAC because it sends more appropriate price signals to transmission users; and (2) that the need for transmission investments is driven primarily by peak end-use load (e.g., Exh. No. SWP-67 at 22).

A. PEAK TRANSMISSION USAGE V. PEAK END-USE LOAD

Q12. WHAT DO YOU MEAN BY YOUR STATEMENT THAT PEAK TRANSMISSION USE AND PEAK END-USE LOAD DO NOT NECESSARILY COINCIDE?

A12. I mean that peak transmission use (*i.e.*, congestion) often is not directly related to (or driven by) peak end-use loads. Regional transmission congestion often is lower during peak load conditions when all generating units are in service, because when all units are operating in each region, less power tends to be transferred between regions. As a result, and contrary to the implicit assumption of witnesses Wilson and Russell (Exh. Nos. SWP-67 at 22, SWC-1 at 18), peak transmission usage may not be correlated with peak energy consumption. While such correlations might exist in some regional power markets, one generally needs to distinguish peak transmission usage from peak end-use loads.

Q13. DOES THE ISO'S HISTORICAL EXPERIENCE SHOW THAT PEAK TRANSMISSION USAGE COINCIDES WITH PEAK END-USE LOADS IN CALIFORNIA?

A13. No, it does not. The ISO provided me with hourly data for day ahead ("DA") and hour ahead ("HA") congestion for its five-year operational history from April 1998 through March 2003. I used this data to calculate the incidence and value of congestion during hours of peak and off-peak loads for seven major transmission paths in California: (1) the California-

Oregon Intertie ("COI"); (2) Eldorado; (3) Mead; (4) the Nevada-Oregon Border; (5) Palo Verde; (6) Path 15; and (7) Path 26. I use the standard definitions of "peak" and "off-peak" hours as the 16-hour period from (the hours ending) 7 a.m. to 10 p.m., Monday through Saturday, excluding Sundays and holidays. The results of this analysis are summarized in Tables 1a, 1b, 2a, and 2b of Exhibit No. ISO-36.

The top set of rows in Tables 1a and 2b of Exhibit No. ISO-36 shows on an annual basis the percentage of hours in which these paths were congested on a DA and HA basis during peak and off-peak periods. The bottom set of rows shows the average congestion price on these transmission paths during the congested peak and off-peak hours. I have shaded the time periods for which congestion on these transmission interfaces has been more frequent, more costly, or both during off-peak hours.

Tables 2a and 2b of Exhibit No. ISO-36 provide additional detail on when congestion occurred during *peak* hours—showing the frequency and value of peak-hour congestion during the peak Summer season (*i.e.*, the 2nd and 3rd quarters of each year) and the off-peak Winter season (*i.e.*, the 1st and 4th quarters of each year). Again, I have shaded the periods for which congestion was more frequent, more costly, or both during off-peak seasons.

Q14. WHAT DO THESE DATA SHOW WITH RESPECT TO TRANSMISSION CONGESTION IN CALIFORNIA DURING PEAK AND OFF-PEAK PERIODS?

A14. As is evident from Tables 1a and 1b of Exhibit No. ISO-36, not only does congestion frequently occur during off-peak hours, but on some paths congestion occurred more often during off-peak hours than during peak load hours. Notably, on Path 15, the primary path connecting Northern and Southern California, congestion in the South-to-North direction has been more prevalent during off-peak hours than on-peak in both the DA and HA market throughout the operational history of the ISO. Eldorado, Path 26, and Palo Verde are other examples of transmission paths on which congestion has occurred more frequently in off-peak hours.

Tables 1a and 1b also show that congestion prices frequently were higher during off-peak hours than during peak load hours. For example, in the HA market, the average price of off-peak congestion consistently has exceeded the average price of on-peak congestion on Path 15. Over the past operating year (April 2002 through March 2003) the average price of off-peak congestion also was greater than the average price of on-peak congestion at COI and Palo Verde.

The prevalence of these patterns over the last five years also makes it clear that one cannot attribute off-peak congestion to market dysfunction during the power crisis. For example, over the period April 1999 through March 2000, when the California market was functioning relatively well, Path 15 was congested about 40% of the time during off-peak hours but only 24% of the time during on-peak hours in the DA market. More recently, from April 2002 through March 2003, DA congestion on Path 15 occurred during off-peak hours about 14% of the time but only 1% of the time during on-peak hours.

In summary, these data demonstrate that on a number of critical transmission interfaces, congestion has been more of an off-peak phenomenon than an on-peak phenomenon.

Q15. WHAT DO THE DATA SHOW WITH RESPECT TO CALIFORNIA'S SEASONAL PATTERN OF CONGESTION DURING PEAK LOAD HOURS?

A15. Tables 2a and 2b of Exhibit No. ISO-36 show that transmission congestion during peak load hours often was more pronounced during the off-peak/Winter season than during the peak/Summer season. This pattern of higher congestion frequency and higher congestion prices during off-peak seasons affects almost all of the seven major transmission paths and is apparent in both the DA and HA market. Thus, even when transmission congestion occurs during peak load hours, it often is more frequent during off-peak seasons.

Q16. WHAT DO YOU CONCLUDE FROM YOUR ANALYSIS OF THIS CONGESTION DATA?

A16. I conclude that transmission congestion in California is not primarily a peak load phenomenon. On some critical paths, congestion consistently has occurred more frequently during off-peak hours than during peak load hours. In addition, the average price of congestion often has been greater during off-peak hours as well. So both the cost and frequency of congestion have been greater during off-peak hours on several major transmission paths during significant portions of the five-year operational history of the ISO. The data thus establish that peak transmission usage on many of the major transmission paths does not coincide with peak load energy consumption in California.

In addition, I conclude that the ISO's congestion prices provide a stronger incentive than the TAC to influence customer behavior and shift transmission use to times when the grid is less congested. As Exhibit No. ISO-36 shows, the average congestion price in both peak and off-peak periods frequently exceeds the TAC—often by a wide margin.

B. ECONOMICALLY EFFICIENT RATE DESIGN AND PRICE SIGNALS

Q17. WHAT DO YOUR OBSERVATIONS IMPLY FOR THE ALLEGED EFFICIENCY BENEFITS OF CHANGING THE ACCESS CHARGE TO TOU OR CP PRICING?

A17. The pervasiveness of congestion during off-peak hours implies that the assertions by Dr. Wilson and Mr. Russell that TOU or CP pricing would enhance economic efficiency is based on faulty logic and is inconsistent with actual peak transmission usage. Moreover, in contrast to the witnesses' claim that TOU/CP pricing would complement the ISO's congestion pricing, just the opposite is true. Based on their own rationale, the proposed TOU/CP pricing would encourage more transmission use during off-peak periods over major interfaces, such as Path 15, on which there already is more congestion during off-peak periods than during peak load conditions. In these cases, a TAC based on TOU/CP pricing would more likely work at cross purposes with the ISO's congestion management process and reduce the efficiency with which the grid is used and expanded.

Q18. HAS IT ALSO BEEN RECOGNIZED IN ACADEMIC RESEARCH THAT TOU-BASED TRANSMISSION CHARGES MAY BE INEFFICIENT AND COUNTER-PRODUCTIVE?

A18. Yes. The potential conflict between TOU access charges and congestion pricing was noted by Dr. Steven Stoft, a professor of economics at the University of California, Berkeley, who previously held positions at FERC, the University of California Energy Institute, and the Lawrence Berkeley National Laboratory. In his recently published book *Power System Economics: Designing Markets for Electricity*, Dr. Stoft explains that the ideal pricing structure for transmission service has two elements: an efficient price equal to short-run marginal costs (congestion and losses) and an access charge, which Dr. Stoft also refers to as a "tax," to raise the remaining revenue necessary to cover the fixed cost of transmission service. In Dr. Stoft's view, there is little chance for improvement over a "flat energy charge" in combination with efficient congestion pricing and any attempts to improve on transmission pricing by means of the access charge likely would result in reduced efficiency. Dr. Stoft specifically disputes (at 413) the alleged efficiency benefits of TOU pricing of transmission service by noting that:

> if efficient congestion pricing is already in place, time-of-use charges can only interfere with it and reduce the efficiency with which the grid is used.

Q19. IS THE ISO'S TRANSMISSION PRICING DESIGN CONSISTENT WITH THE PRICING STRUCTURE RECOMMENDED BY DR. STOFT?

A19. Yes. The ISO's combination of charges for the short-run marginal costs of losses and congestion, and a flat, volumetric TAC to recover fixed transmission costs is consistent with the pricing methodology recommended by Dr. Stoft. As Mr. Hansen also explains in his cross answering testimony, the ISO's market redesign will further improve the scope and accuracy of the ISO's existing price signals for congestion and losses (Exh. No. SCE-29 at 12-13).

Q20. MR. RUSSELL NEVERTHELESS CLAIMS THAT A 12-CP RATE WOULD PROVIDE PRICE SIGNALS THAT ARE CONSISTENT WITH, AND REINFORCE, THE PRICE SIGNALS SENT BY A PROPER FORMULATION OF THE CONGESTION CHARGE (EXH. NO. SWC-1, P. 70). DO YOU AGREE?

A20. No. The ISO's congestion charges reflect the marginal cost of using constrained transmission paths and thus provide efficient price signals. Moreover, they appropriately reflect the cost of transmission congestion *during any given hour.* The primary purpose of a transmission access charge, regardless of whether it uses a 12-CP, TOU, flat volumetric, or some other rate design, is to recover fixed costs and do so in a way that minimizes distortion in the wholesale power market. Contrary to Mr. Russell's assertions, switching to a 12-CP rate would not "improve upon" the transmission price signals provided by the ISO's congestion management system. 12-CP pricing is simply an alternative way of recovering embedded or fixed costs.

Moreover, given that a significant portion of peak transmission usage in California occurs during off-peak hours and off-peak seasons, coincident peak or TOU pricing would appear to be less consistent with congestion pricing and the fair and economically efficient recovery of fixed costs than the ISO's current volumetric Access Charge. Under coincident peak or TOU pricing, California market participants with substantial transmission usage during off-peak hours and off-peak seasons would pay below-average access charges even though they may over-proportionately contribute to transmission congestion and the need for transmission upgrades. Under these circumstances, the ISO's preexisting flat volumetric access charge likely represents the more equitable and more efficient rate structure to recover embedded transmission costs.

Q21. MR. RUSSELL AND DR. WILSON ARGUE THAT THE PROPOSED TAC IS NOT CONSISTENT WITH "COST CAUSATION" AND RELATED

RATEMAKING PRINCIPLES (EXH. NOS. SWC-1 AT 16; SWP-65 AT 8). DO YOU AGREE?

A21. No. Mr. Russell and Dr. Wilson offer little evidence to back their assertion that the proposed TAC is inconsistent with cost causation (*i.e.*, fails to allocate costs in a way that reflects responsibility for the costs the ISO incurs). As I have shown, the advocates of TOU/CP pricing incorrectly assume that utilization of the transmission system in California, and hence congestion, is greatest during hours of peak end-use loads when, in fact, a very significant amount of congestion can and does occur during off-peak hours.

Mr. Russell also is incorrect when he claims that "[t]he cost of rendering off-peak transmission service is essentially zero, but the current MWh-based TAC charges off-peak customers at full average cost [while] the on-peak customer is charged a rate that is much lower than the marginal cost it causes" (Exh. No. SWC-1 at 21). Under the ISO's congestion charges, all transmission customers face the marginal cost of using a constrained interface and all contribute to the recovery of the residual fixed costs. Ultimately, neither Mr. Russell nor Dr. Wilson offers support for his contention that an "on-peak customer" (a term they do not define) pays less than its fair share of the ISO's transmission costs.

C. TRANSMISSION EXPANSION

Q22. WHAT ARE THE IMPLICATIONS OF THE ISO'S PATTERN OF CONGESTION FOR THE TESTIMONY PRESENTED BY SWP AND SWC ON TRANSMISSION EXPANSION?

A22. Contrary to the fundamental assumption on which Dr. Wilson and Mr. Russell rely, the need for transmission upgrades is not driven primarily by peak energy consumption. This is particularly true for transmission upgrades that are motivated by economic considerations, such as reducing the costs associated with congestion. This is demonstrated by the most significant transmission expansion within the ISO's footprint, the Path 15 upgrade, which is in response to transmission congestion.

Q23. WHAT IS THE BASIS FOR YOUR STATEMENT THAT THE RATIONALE FOR THE PATH 15 EXPANSION IS A RESPONSE TO TRANSMISSION CONGESTION?

A23. The rationale for upgrading this path is, for example, set forth in an August 2003 Staff Report of the California Energy Commission. The Report emphasizes that Path 15 has played a major role in the seasonal power exchanges that take place between Northern and Southern California and California and the Pacific Northwest. The report notes that, at its current rated capacity, Path 15 often limits south-to-north power transfers within California—which, in addition to creating congestion costs, facilitates the exercise of market power. The Report (at 15) further notes:

> The Path 15 upgrade is an important solution to a backbone system bottleneck, which will have benefits to nearly everyone affected by California's electricity market. From a qualitative perspective, one would expect the expansion to provide increased competition, reduced price variation, north-to-south, and reduced opportunities for the exercise of market power and resulting price spikes.
>
> Studies conducted by the CA ISO during the past two years show that Path 15 constraints impede competitive market function and impose additional costs to loads in Northern California. There are two major problems, one is congestion cost, south-to-north, and the second is market power.

Q24. ARE YOU SAYING THAT PEAK LOAD IS NOT A FACTOR IN TRANSMISSION PLANNING?

A24. No. Peak load clearly is a factor in grid reliability studies conducted by transmission planners, including the ISO, but it is not the only factor. Reliability assessments typically are performed for a variety of load conditions, not just peak load and coincident peak load, and the results of such assessments depend on a host of factors other than the level of loads, including generation availability and the location of loads relative to generation. Moreover, reliability assessments are only part of the transmission planning process and hence only part of what determines the need for transmission upgrades. As we have seen with Path 15, major transmission upgrades can be and are driven largely by economic considerations.

Q25. NEVERTHELESS, WITNESSES RUSSELL AND WILSON CLAIM THAT THE ISO ITSELF HAS ACKNOWLEDGED THAT ITS TRANSMISSION

SYSTEM PLANNING IS DRIVEN BY PEAK LOAD (SWC-1 AT 28; SWP-67 AT 37). HOW DO YOU RESPOND?

A25. This assertion misstates the ISO's responses to three data requests (Exh. Nos. SWP-34 and SWP-35). In one response (SWP-ISO-214) the ISO acknowledges that it uses its peak demand (but not coincident peak demand) for system planning purposes. However, this does not mean that transmission expansion is driven primarily by peak loads, which is the logical leap that witnesses Russell and Wilson are making. This critical distinction is confirmed by the ISO's response to SWP-ISO-215, stating that ISO grid plans depend on the load forecasts prepared by individual utilities and the utilities use both coincident and non-coincident load forecasts depending on the type of transmission planning studies being done. In this response, the ISO also notes that projects are approved if the ISO determines there is a reliability or economic need, and that the proposed project is the best alternative to solve the problem—which involves factors that go well beyond peak load.

Finally, both Mr. Russell and Dr. Wilson identify the Southern Tri-Valley expansion project as evidence of the fact that transmission planning is driven by peak load (Exh. No. SWP-35). However, this project is a low-voltage, local project that would not even be part of the ISO's High Voltage Access Charge. Moreover, even if this project was specifically constructed based on peak load considerations, it would only prove that some transmission upgrades are driven by peak loads. This finding is consistent with the congestion data, which shows that on some transmission interfaces congestion is more prevalent during peak periods. However, the Tri-Valley project clearly is not representative of all transmission projects underway or under consideration in California and it does not prove that transmission expansion is driven primarily by peak load. In fact, my analysis of congestion data and the fact that congestion is the primary factor of the Path 15 upgrade shows that this is not the case.

Q26. DR. WILSON AND MR. RUSSELL SUGGEST THAT A SWITCH TO TOU OR 12-CP PRICING WOULD IMPROVE PRICE SIGNALS FOR LONG-TERM GRID EXPANSION IN CALIFORNIA. DO YOU AGREE?

A26. No. As I have shown, TOU or 12-CP pricing would not reflect peak transmission usage on a number of the major transmission paths in California. As a result, and if one were to accept the proposition that congestion charges provide inadequate long-term signals for transmission expansion, the pattern of peak transmission usage clearly suggests that TOU or 12-CP pricing would not be the solution. TOU or 12-CP pricing is simply an alternative way of recovering embedded transmission costs. Embedded costs reflect past investments that, by definition, cannot change—pricing and usage cannot affect sunk cost in any particular transmission system. Mr. Russell himself acknowledges this in his testimony:

> A transmission facility has no component of its total cost that varies with the number of hours it is used (as measured by MWH). Once a facility is constructed, using it for more hours or at higher levels closer to its rated capability will not increase the cost of providing transmission service, and using it for fewer hours or at lower levels will not reduce the cost of providing transmission service.

Exh. No. SWC-1 at 22. Mr. Russell also contends that the 12-CP methodology will "promote the efficient location of generation and loads over the long term…" (Exh. No. SWC-1 at 63). However, he does not explain how his proposed 12-CP access charges, which do not vary by geographic location, would help promote the efficient "location" of generation and loads. In contrast, the ISO's congestion prices identify the location and direction (as well as the cost and persistence) of congestion in the ISO Grid and thus more accurately promote the efficient location of generation and loads.

Q27. BUT DON'T MR. RUSSELL AND DR. WILSON ASSERT THAT CONGESTION PRICING PROVIDES AN INADEQUATE INCENTIVE FOR EFFICIENT TRANSMISSION GRID EXPANSION?

A27. Yes. According to Dr. Wilson and Mr. Russell, congestion pricing such as that currently used by the ISO or the locational marginal pricing method that the ISO plans to implement in the new market design provides an inadequate economic incentive for efficient long-term transmission system design and expansion (Exh. Nos. SWP-65 at 24, SWC-1 at 39). In their view, supplementing congestion pricing with 12-CP pricing for the access charge would provide a more meaningful price signal for economically efficient grid expansion.

Q28. DO MR. RUSSELL AND DR. WILSON EXPLAIN WHY THEY BELIEVE THAT CONGESTION PRICING PROVIDES AN INADEQUATE PRICE SIGNAL FOR EFFICIENT TRANSMISSION GRID EXPANSION?

A28. Yes. The primary drawback of congestion pricing, in Mr. Russell's view, is that it only provides "short-term" price signals and these short-term signals are deemed inadequate to influence new investment in transmission or generation (Exh. No. SWC-1 at 39). In addition, Mr. Russell questions the accuracy of the prices yielded by the ISO's congestion management system (Exh. No. SWC-1 at 34). Dr. Wilson's reasons for believing that congestion pricing provides an inadequate long-term price signal are less clear. His primary concern appears to be that congestion pricing does not reflect transmission system investment costs and, thus, does not tie rates to transmission system cost causality (Exh. No. SWP-65 at 14-15).

Q29. DO YOU AGREE THAT CONGESTION PRICING SUFFERS FROM THESE DEFECTS?

A29. No. First, while it technically is true that congestion is a short-term (*e.g.*, hourly) price, this does not mean that congestion prices cannot inform decisions about investments in new transmission and generating capacity. The persistence of congestion over a period of time between two points on the transmission grid will signal the potential value of expanding transmission capacity (or generating capacity) to mitigate the constraint.

Conversely, if congestion occurs infrequently on a given path, market participants will recognize that expansion of the path is unlikely to be economical. Trends in congestion prices thus provide critical input to an ISO's long-term planning process.

Moreover, market participants will take short-term energy, capacity, ancillary service and congestion prices into account when making their investment decisions. The expectation of these short-term price signals in the future will influence any longer-term decisions by market participants. Mr. Hansen also appears to agree with this point when he testifies that congestion charges "[n]o matter how stable or volatile, ... provide signals that influence current and future decisions" (Exh. No. SCE-29 at 34).

Importantly, the ISO's congestion management system already allows market participants to purchase Firm Transmission Rights ("FTRs") as a financial hedge against the uncertain cost of congestion charges. FTRs are sold at prices that reflect the market's estimate of annual congestion costs over the major transmission paths. A rational buyer will not pay more for an FTR than his discounted, present value estimate of the expected cost of future congestion. Thus, the market is already setting such longer-term congestion prices through the value of FTRs.

Q30. HOW DO YOU RESPOND TO MR. RUSSELL'S CONTENTION THAT THE ISO'S CONGESTION MANAGEMENT SYSTEM DOES NOT PRODUCE ACCURATE PRICES (EXH. NO. SWC-1 AT 34-36)?

A30. The ISO's current congestion management system may not be ideal, but Mr. Russell provides or cites no evidence showing that the prices yielded by the ISO's congestion management system are systematically biased or inaccurate. Mr. Russell cites a Commission order on the ISO's intra-zonal management scheme but fails to note that intra-zonal congestion accounts for a relatively small portion of total congestion costs. As Mr. Hansen notes "over 90% of the ISO's congestion costs are inter-zonal" (Exh. No. SCE-29 at 24). Thus, the ISO's congestion prices indicate the marginal cost of mitigating most of the congestion that occurs in the ISO grid and efficiently ration scarce transmission capacity between zones. Moreover, the ISO's congestion management system will accurately price both intra- and inter-zonal congestion when the ISO implements its new market design based on locational marginal pricing.

Thus, concerns about the accuracy of the ISO's congestion prices are either unsupported or overstated. Even to the extent that the ISO's current congestion management system might not be perfect, it should also be clear that the current congestion charges will be considerably more accurate than a simplistic differentiation of transmission access prices based on TOU periods or coincident peak loads.

Q31. IS THERE ANY EVIDENCE THAT CONGESTION PRICING IS IN FACT RELEVANT TO LONG-TERM TRANSMISSION EXPANSION PLANNING?

A31. Yes. The ISO's congestion management system—congestion prices and FTRs—highlighted the fact that constraints on Path 15 often caused the Northern California zone to separate from Southern California. The Path 15 constraint created significant congestion costs and generally reduced competition in California. Recognition of this constraint created significant stakeholder and political support for upgrading Path 15, which in fact is happening. Thus, contrary to the assertions of Dr. Wilson and Mr. Russell, the ISO's congestion management system provided "price signals" that spurred support for the Path 15 expansion. The Path 15 experience suggests that Mr. Russell's concern that congestion prices are too "short-term" to spur economically efficient transmission investment is overstated at best. Mr. Russell overlooks the fact that a time-series of congestion prices provides valuable insight into the economic value of mitigating a transmission constraint.

Q32. IF ONE NEVERTHELESS CONCLUDED THAT THE ISO'S CURRENT TRANSMISSION PRICING STRUCTURE PROVIDED INADEQUATE LONG-TERM PRICE SIGNALS, COULD AN ACCESS CHARGE BE DESIGNED TO PROVIDE BETTER LONG-TERM PRICE SIGNALS FOR EFFICIENT EXPANSION OF THE TRANSMISSION SYSTEM?

A32. Yes, but the access charge would have to, in some way, accurately reflect the long-run marginal cost ("LRMC") of expanding the transmission grid rather than be based simply on the grid's embedded cost. The revenues raised by such an LRMC-based charge may then need to be reconciled with the overall revenue requirement, which could dilute the LRMC price signal.

Importantly, considering an LRMC-based access charge would only make sense *if* one could conclude that congestion prices, by themselves, did not provide a sufficient price signal to foster efficient transmission expansion and generation location. In such a scenario, a carefully-designed access charge possibly could be used to “enhance” and “supplement” the hourly congestion prices. I see no basis to reach such a conclusion at this time.

Moreover, a simple, fixed price would not capture in any meaningful way the marginal cost of transmission on a short- or long-term basis. Congestion varies greatly over time, with grid location, and the direction of power flows. A fixed congestion charge is more likely to harm than help the market to the extent it does not correctly track the actual short- or long-run marginal costs of mitigating congestion in various parts of the Grid.

D. OTHER CONSIDERATIONS

Q33. WOULD COINCIDENT DEMAND-BASED PRICING REQUIRE CHANGES IN HOW THE ISO PROVIDES TRANSMISSION SERVICE?

A33. Yes. If one were to change the ISO's Access Charge to a 12-CP design, this pricing method would require a change in the type of transmission service currently provided by the ISO. The ISO's preexisting flat volumetric charge, denominated in MWh, is consistent with the ISO's hourly firm transmission service. In contrast, 12-CP pricing usually is offered in conjunction with long-term (firm) network service. Because of this long-term nature of 12-CP pricing, it would not be practical for short-term transmission service, such as the ISO currently provides. Thus, 12-CP pricing would require the creation of a new type of transmission service. SCE's witness, Mr. Hansen, makes a very similar point (SCE-29, p. 29), testifying that a CP pricing structure for the ISO's TAC would be incompatible with the basic nature of the transmission service offered by the ISO.

Q34. MR. RUSSELL CLAIMS THAT DEMAND-BASED RATES USED FOR POINT-TO-POINT TRANSMISSION SERVICE UNDER THE COMMISSION'S *PRO FORMA* TARIFF PROVIDE ADDITIONAL SUPPORT FOR HIS PROPOSAL TO CHANGE THE ISO'S ACCESS CHARGE TO A 12-CP BASED RATE (SWC-1, P. 52). IS THIS CORRECT?

A34. No. Under the *pro forma* tariff, a point-to-point transmission customer purchases or reserves the right to use a specified amount of transmission capacity from one point to another. The charge for this service equals the tariff rate for point-to-point service multiplied by the amount of capacity reserved. The cost that the customer incurs generally has little to do with the coincident peak usage of the system. In fact, the customer may incur exactly the same cost if he uses his maximum reservation during peak hours or off-peak hours. Hence, the wide-spread use of demand-based rates for point-to-point transmission service provides no further support to justify a switch from the ISO's volumetric charge to a 12-CP based transmission access charge.

Q35. SWP AND SWC ALSO CLAIM THAT TOU AND DEMAND BASED RATES WERE NOT SERIOUSLY EXAMINED BY THE ISO WHEN IT DEVELOPED THE TAC (SWP-67 AT 18-19;SWC-1 AT 44). DO YOU AGREE?

A35. No. As Mr. Hansen also explains (SCE-29 at 27-28), there is no basis for this conclusion. Such alternative rate designs were considered, analyzed, and discussed in the stakeholder process leading up to the ISO's filing of the proposed Access Charge before the Commission. This is also documented in Exhibit ISO-5, which shows that, based on the TAC Working Group discussions and the specific analysis of a TOU rate structure, ISO Management recommended to its Board in the Fall of 1999 that a volumetric, commodity-based access charge should be adopted in favor of TOU or demand-based pricing for the following reasons:

- The ISO's "new market structure (including congestion pricing) is entirely commodity based and all wheeling is also commodity based." (Exh. ISO-5 at 6)
- While "[s]ome Stakeholders favor a peak/off peak structure" (at 8), there was "little stakeholder support for anything other than a volumetric charges" (*id.* at 6)

- "[T]he appropriateness and effectiveness of time-of-use pricing is questionable given that 1) a significant portion of the experienced congestion occurs during off-peak hours and off-peak months; and 2) congestion charges already provides market incentives for transmission demand." (Exh. ISO-5, Att. A at 6)
- "Given current congestion patterns, [a peak/off peak rate structure] is not appropriate." The question can be revisited after a "critical mass" of new PTOs have joined, "when congestion patterns could change." (*id.* at 8)

Q36. WHAT OVERALL CONCLUSION DO YOU DRAW WITH RESPECT TO WHETHER IT WOULD BE APPROPRIATE TO SWITCH FROM THE ISO'S FLAT VOLUMETRIC ACCESS CHARGE TO TOU OR 12-CP BASED CHARGE?

A36. Major paths on California's transmission grid are more congested during off-peak periods than during periods of peak end-use loads. As a result, rather than improving economic efficiency, a switch to a TOU or coincident peak rate design for the TAC likely would degrade existing price signals to transmission customers and induce them to increase their usage of an already congested transmission grid. In such cases, the TAC would be working at cross purposes with any current or future congestion charges set by the ISO's congestion management system.

Assertions that coincident-peak pricing would make the TAC more consistent with LRMC pricing principles, and hence would be more economically efficient than the ISO's TAC design, are also unsupported. Coincident peak pricing, like the ISO's volumetric charge, recovers net transmission revenue requirements from end-use load but does not, in and of itself, indicate the marginal cost of transmission usage—either long- or short-term. It is the ISO's congestion charges that indicate the short-run marginal cost of using constrained portions of the ISO-controlled grid—and the expectations of these congestion charges will influence long-term decisions by market participants. Claims that a change to TOU or coincident-peak pricing of transmission service would make the TAC more consistent with cost causation and related ratemaking principles are similarly unsupported.

II. MR. HANSEN'S BENEFIT CALCULATION

Q37. MR. HANSEN ESTIMATES THAT THE BENEFITS ASSOCIATED WITH EXPANDED ISO PARTICIPATION WOULD NOT EXCEED $22.6 MILLION A YEAR EVEN AT FULL ISO PARTICIPATION BY ALL CALIFORNIA TRANSMISSION OWNERS (SCE-4 AT 40). IS MR. HANSEN'S ESTIMATE OF THESE BENEFITS REASONABLE?

A37. No. Mr. Hansen's approach to estimating the benefits of expanded ISO participation contains several errors and omissions. If these errors and omissions are addressed, the estimated benefits increase substantially.

Mr. Hansen specifically recognizes four factors as potential benefits of increased ISO participation: (1) the reduction of phantom congestion;

(2) the reduction of Ancillary Service and Energy costs that would occur due to increased supply; (3) the reduction in the ISO's GMC rates; and (4) the value of the transmission capacity brought to the ISO Controlled Grid by New PTOs (SCE-5 at 13).

With respect to the benefits from the reduction of phantom congestion, Mr. Hansen recognizes that "[p]hantom congestion affects spot market electricity prices in the same manner as congestion" (SCE-5 at 18) and estimates that the benefits of eliminating phantom congestion would have been $82 million in 1999. This estimate, which excludes entirely the impact of congestion on Path 15, understates the total benefit of eliminating phantom congestion.

Q38. WHY DOES MR. HANSEN'S ESTIMATE UNDERSTATE THE TOTAL BENEFIT OF ELIMINATING PHANTOM CONGESTION?

A38. As Dr. Casey explains in his rebuttal testimony (ISO-30 at 14-16), Mr. Hansen's estimate ignores the competitive benefits of reduced congestion. Mr. Hansen's estimate implicitly assumes that, even if phantom congestion had been eliminated in 1999, market participants nevertheless would have submitted exactly the same bids they actually submitted in the presence of phantom congestion. However, because reduced congestion will expand the relevant market in which sellers compete, Mr. Hansen's implicit assumption is unreasonable and understates the benefits associated with a reduction or elimination of phantom congestion.

Q39. MR. HANSEN ESTIMATES THAT THE EXPIRATION OF EXISTING CONTRACTS WILL REDUCE THE COST OF PHANTOM CONGESTION BY APPROXIMATELY 20% (EXH. NO. SCE-5 AT 22). IS THAT A REASONABLE ASSUMPTION?

A39. It is reasonable to recognize that the expiration of some of the existing contracts most likely will reduce the pre-existing amount of phantom congestion. If Mr. Hansen's 20% estimate of that effect is applied to his $80 million estimate of 1999 phantom congestion costs, this would yield a residual benefit of $66 million annually. Dr. Casey, who has explicitly modeled the effects of phantom congestion after the upgrade of Path 15 and considering ETC expirations through 2007, estimates that the expected benefits of relieving phantom congestion on Path 15 alone are between $46 and $89 million annually, depending on whether it is a normal or low-hydro year (ISO-30 at 18). Since Mr. Hansen's estimate excludes any benefits of eliminating phantom congestion on Path 15 and also excludes benefits of increased competition associated with the elimination of phantom congestion on other transmission paths, it would appear that the elimination of phantom congestion on all transmission paths would at least double Mr. Hansen's estimate. Simply adding up Mr. Hansen's $66 million estimate of benefits on transmission paths other than Path 15 and Dr. Casey's $46-$89 million estimate of benefits on Path 15 means that the annual benefits of eliminating phantom congestion on all transmission paths could be in the $110 million to $150 million range, even when ignoring the additional competitive benefits associated with eliminating congestion on transmission paths other than Path 15.

Q40. MR. HANSEN ALSO NOTES THAT HIS 1999 ESTIMATE OF PHANTOM CONGESTION COSTS NEEDS TO BE REDUCED BY 90% TO REFLECT THE FACT THAT, UNLIKE IN 1999, THE ORIGINAL PTOS NOW PURCHASE ONLY APPROXIMATELY 10% OF THEIR ENERGY NEEDS IN THE SHORT-TERM ENERGY MARKETS (EXH. NO. SCE-5 AT 21-22). THIS REDUCES MR. HANSEN'S ESTIMATED BENEFIT TO $7 MILLION PER YEAR. DO YOU AGREE WITH THIS STEP IN MR. HANSEN'S ANALYSIS?

A40. As Dr. Casey has already pointed out in his testimony (ISO-30 at 16-17), Mr. Hansen assumes that a reduction of congestion in the spot electricity markets will have absolutely no effect on the Original PTOs' long-term purchases. However, this assumption is unreasonable because: (1) market participants will take congestion into account in their forecasts of future energy prices (hence, congestion will be an important factor in the negotiation of new long-term contracts as well as in any renegotiations of existing long-term contracts); and (2) even under the PTO's long-term supply contracts, congestion costs may be the responsibility of the buyer, not the seller. Mr. Hansen himself implicitly recognizes these points when, in the context of congestion charges, he stresses that such short-term prices "provide signals that influence current and future decisions" (Exh. No. SCE-29 at 34). As preexisting longer-term contracts roll over, all of a

PTO's power purchases would be expected to benefit from the elimination of phantom congestion. Taking the $150 million/year estimate from above and assuming that the Original PTOs' power purchases would supply approximately 50% of their load, the benefit from elimination of phantom congestion would still be at least $75 million per year—ten times Mr. Hansen's estimate even without considering any costs that phantom congestion may impose on the Original PTOs' own generation.

Q41. WILL EXPANSION OF THE ISO PARTICIPATION PROVIDE BENEFITS IN ADDITION TO THOSE YOU HAVE ALREADY CITED?

A41. Yes. First, increased ISO participation will likely provide indirect competitive benefits from new PTOs' increased participation in the ISO's energy and ancillary services markets—a source of benefits that Mr. Hansen addresses but then mostly dismisses. While I agree that these benefits are very difficult to quantify, I believe Mr. Hansen's estimated annual benefit of zero to $0.7 million per year (the latter only under full ISO participation) substantially understates the competitive benefits that increased ISO participation would offer to the ISO's energy and ancillary service markets.

Second, enhancing the ISO's scope and configuration should yield transmission operations and planning efficiencies, particularly because non-PTOs own (or have contractual rights to) critical transmission facilities that are not currently under the ISO's control. As Mr. Hansen explains (SCE-5 at 35), these transmission assets include several key transmission projects in California, such as the California-Oregon Transmission Project ("COTP"), the Mead-Phoenix and Mead-Adelanto Transmission Projects, and the Southern Transmission System (connecting the transmission networks in Utah to Southern California). These transmission projects account for a significant proportion of the transmission capacity between California and surrounding regions. For example, the COTP is a 500 kV line that provides 1,600 MW of transfer capacity—or one third of the total transfer capability of the California-Oregon Intertie—between California and the Pacific Northwest.

However, despite acknowledging that these transmission facilities are not currently integrated with ISO operations, Mr. Hansen rejects attribution of any benefits associated with the full or partial integration of these transmission assets into the ISO by claiming that "there is no sound empirical basis … to place a value on this potential benefit" (SCE-5 at 37) and "whatever the benefits are, they will accrue to the OPTOs and the New PTOs proportionately." I agree with Mr. Hansen that it might be difficult to estimate the benefits that would accrue from the elimination of these current "seams" between the ISO's transmission facilities and the transmission projects operated by the potential new PTOs. However, as the Commission has recognized, such "seams" between transmission operators can create significant operational and economic inefficiencies. Given the significance of the California transmission projects that are currently outside the ISO's operational control, one would need to assume that the benefits of seamless transmission operations, which would include these facilities, would likely be significant in terms of increased reliability, reduced congestion and resulting competitive benefits. When considering the benefits that Dr. Casey has estimated with respect to eliminating phantom congestion on Path 15 alone, it would appear likely that the benefits flowing from the integration of these transmission projects could easily exceed several tens of millions of dollars a year. The fact that these benefits "accrue proportionally" to both Original and New PTOs is no justification for dismissing the value of this benefit.

While it is difficult to estimate the overall benefits that the Access Charge methodology and increased ISO participation may generate, these benefits are substantially larger than Mr. Hansen has estimated in his testimony. The fact that the end-user representatives considered the benefits that the Access Charge methodology and potential future ISO participation might offer when they agreed to increase the cost shift cap to $72 million ($32/$32/$8 million) strongly suggests that the expected benefits are sufficient to accept this level of cost shift. Ms. Le Vine's rebuttal testimony addresses this point in greater detail.

III. TREATMENT OF "EXISTING FACILITIES" IN AMENDMENT NO. 49

Q42. VERNON AND SOUTHERN CITIES DISAGREE WITH THE MODIFICATION IN AMENDMENT NO. 49 TO EXCLUDE THE COSTS

OF NEW HV FACILITIES FROM THE DETERMINATION OF COST SHIFTS AND TRANSITION CHARGES (VER-1, AT 5-6; SC-1 AT 24). HOW DO YOU RESPOND?

A42. Aside from Vernon and Southern Cities, all interveners and FERC Staff appear to support (or do not oppose) the proposed Amendment No. 49 modification to exclude New HV Facilities from the determination of cost shifts and Transition Charges. As explained in my direct testimony, the revised treatment is necessary and reasonable because it facilitates the financing and construction of new transmission facilities by new PTOs without gross load (e.g., Trans-Elect's upgrade of Path 15) and avoids speculation as to how the new HV Transmission Facilities would have been financed under the old utility-specific access charges (Exh. No. ISO-1 at 78 and ISO-18 at 9-10).

Financing and construction of New HV Transmission also is facilitated by the fact that the cost of the new facilities will be borne in proportion to ISO Grid-wide gross load regardless of who finances and constructs the new HV Transmission upgrades. Under the methodology originally specified in Amendment No. 27, which included the costs of New HV Transmission in the determination of cost shifts and Transition Charges, the costs of New HV Transition would not generally be borne in proportion to Gross Load, but would greatly depend on who constructs the new facilities and the size of the overall cost shifts. In essence, under the Amendment No. 27 methodology, the cost of New HV Transmission facilities would have interfered with the calculation of the Transition Charge such that the Transition Charge counter-acted the immediate ISO-wide roll-in of transmission upgrades in often unpredictable ways.

Q43. HAVE YOU PREPARED AN EXHIBIT TO ILLUSTRATE THESE UNDESIRABLE FEATURES OF THE METHODOLOGY ORIGINALLY SPECIFIED IN AMENDMENT NO. 27?

A43. Yes, I have. Table 1 of Exhibit No. ISO-37 compares cost allocations for new transmission facilities under the Amendments No. 49 and No. 27 methodologies for a number of hypothetical transmission financing scenarios. This exhibit is based on the current ISO configuration with three Original PTOs (SCE, PG&E, SDG&E) and five New PTOs (Vernon and the four Southern Cities). The cost allocations are shown for the Original PTOs as a group, the New PTOs as a group, and PG&E and Anaheim as examples of individual PTOs building new transmission. In a nutshell, the right set of columns in Table 1 of Exhibit No. ISO-37 shows that under Amendment No. 49 the costs of New HV Transmission Facilities are borne in proportion to Gross Load irrespective of who builds the transmission upgrade. In contrast, the left set of columns in Table 1 shows that the allocation of New HV Transmission costs under Amendment No. 27 varies greatly depending on (1) who builds the facilities and (2) the overall size of the cost shift burdens and benefits.

Q44. WHAT IS SHOWN IN THE VARIOUS ROWS OF YOUR TABLE?

A44. These rows show the new transmission cost allocations resulting from the Amendments No. 27 and No. 49 methodologies under five different scenarios. The first row shows the cost allocations under the assumption that transmission is financed and constructed by PG&E in a scenario where total cost shifts are below the cap. The second row shows cost allocations for a PG&E transmission investment for a hypothetical scenario where total cost shifts exceed the cap. The third row shows cost allocations for a hypothetical transmission investment by Anaheim in a scenario where cost shifts are below the cap. The fourth row shows cost allocation for a transmission investment by Anaheim where prior to the upgrade cost shifts are below the cap, but where the transmission upgrade increases cost shifts to exceed the cap under Amendment No. 27. Finally, the fifth row shows cost allocations for a hypothetical transmission investment by Anaheim where, even prior to the upgrade, cost shifts exceed the cap.

Q45. HOW HAVE YOU CALCULATED THESE COST ALLOCATIONS SHOWN ON TABLE 1 OF EXHIBIT NO. ISO-37?

A45. As shown in Tables 2a through 2e of Exhibit No. ISO-37, I have calculated for each of these scenarios the sum total High Voltage Access Charges and Transition Charges paid by the various customer groups with and without the hypothetical transmission upgrade under both the Amendments No. 27 and No. 49 methodologies. These tables show that charges to gross load vary greatly by scenario under Amendment No. 27.

This variation is caused by the impact of new HV Transmission Facilities on the Transition Charges calculated for the various transmission investment scenarios under Amendment No. 27.

Q46. HOW DO THE COST ALLOCATIONS OF THE HYPOTHETICAL NEW HV TRANSMISSION FACILITY VARY ACROSS THESE SCENARIOS?

A46. The right set of columns in Table 1 shows the cost allocations under the Amendment No. 49 methodology (which excludes the cost of new HV Transmission Facilities from the determination of cost shifts and Transition Charges). It shows that for each of the transmission investment scenarios, costs are allocated in proportion to Gross Load—which means that the costs of the transmission upgrade is truly recovered on an ISO-wide basis. For example, since PG&E accounts for 43.4% of Gross Load, PG&E's customers bear 43.4% of the new facility's transmission costs regardless of who builds the new facility or the level of total cost shifts.

The left set of columns shows that just the opposite is the case under the Amendment No. 27 methodology. As is shown, the percentage of New HV Transmission costs paid by the New PTOs as a group varies from 0% in Scenario 2 (PG&E construction, cost shifts above the cap) to 100% in Scenario 5 (Anaheim construction, cost shifts above the cap). Similarly, the percentage of New HV Transmission costs paid by the Original PTOs as a group varies from 100% in Scenario 2 to 0% in Scenario 5—and various values in between for the other scenarios.

Q47. WHAT DO THESE RESULTS DEMONSTRATE?

A1. These results illustrate the inappropriateness of potential transmission cost allocations under the original Amendment No. 27 methodology. These allocations could create significant barriers to the efficient upgrade of the transmission system—providing disincentives for transmission investments by PTOs with a disproportionately high allocation of the costs, while not providing proper incentives for PTOs with an under-proportionate (or even zero) allocation of new transmission costs to make efficient transmission upgrades.

In short, the Amendment No. 49 modification to exclude the costs of New HV Transmission Facilities in the determination of cost shifts and Transition Charges is reasonable and desirable. Moreover, as was explained in previous testimony—and in contrast to Amendment No. 27, which would need to be modified—Amendment No. 49 specifically addresses and facilitates transmission construction by entities without their own gross load, such as Trans-Elect.

Q48. THANK YOU, I HAVE NO MORE QUESTIONS.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

California Independent System Operator Corporation	)))	Docket No. ER00-2019-006, ER01-819-002, and ER03-608-000

DECLARATION OF WITNESS

I, Johannes P. Pfeifenberger, declare under penalty of perjury that the statements contained in my Prepared Rebuttal Testimony on behalf of the California Independent System Operator Corporation filed in this proceeding are true and correct to the best of my knowledge, information, and belief.

Executed in Washington, D.C.
on this 2nd day of October, 2003.

DISTRICT OF COLUMBIA SS:
WASHINGTON DC

Johannes P. Pfeifenberger

SUBSCRIBED AND SWORN TO BEFORE ME
THIS 2ND DAY OF OCTOBER 2003,
D.B.

Deborah Bailey
Notary Public District of Columbia
My Commission Expires: April 14, 2008

Deborah Bailey
otary Public District of Columbia
Expires: April 14, 2008

Table 1a
Peak vs. Off Peak Congestion Summary
Day Ahead

Percent of Hours Congested

		4/98 - 3/99		4/99 - 3/00		4/00 - 3/01		4/01 - 3/02		4/02 - 3/03	
Branch	Direction	Peak	Off Peak	Peak	Off Peak	Peak	Off Peak	Peak	Off Peak	Peak	Off Peak
COI	Import	28.7%	8.6%	38.9%	27.7%	3.1%	1.0%	2.2%	0.5%	24.4%	6.0%
	Export	-	-	-	-	8.0%	9.8%	1.0%	0.9%	-	-
ELDORADO	Import	10.6%	8.5%	10.5%	15.9%	3.0%	10.7%	1.7%	2.8%	1.4%	0.5%
	Export	-	-	-	-	-	-	-	-	-	-
MEAD	Import	0.0%	0.1%	2.6%	0.2%	3.8%	1.5%	-	0.2%	0.2%	-
	Export	0.1%	-	0.2%	-	0.8%	0.6%	0.3%	-	0.2%	0.1%
NOB	Import	14.7%	1.8%	9.2%	5.3%	5.2%	0.2%	0.3%	-	26.4%	4.6%
	Export	-	-	-	0.9%	15.2%	30.8%	5.0%	11.1%	-	-
PALOVERDE	Import	7.0%	4.5%	12.7%	13.6%	3.7%	10.2%	1.4%	7.0%	4.5%	1.3%
	Export	-	-	-	-	-	-	0.0%	-	-	-
PATH15	Import	3.2%	26.9%	24.4%	39.9%	41.1%	60.2%	16.9%	62.4%	1.1%	14.2%
	Export	2.8%	0.4%	0.6%	0.2%	4.5%	1.5%	-	-	0.5%	-
PATH26	Import	-	-	-	0.1%	0.1%	1.8%	0.3%	7.8%	0.0%	1.1%
	Export	-	-	3.1%	0.3%	15.4%	1.3%	0.6%	0.3%	7.6%	0.2%

Average Price ($/MWh)

		4/98 - 3/99		4/99 - 3/00		4/00 - 3/01		4/01 - 3/02		4/02 - 3/03	
Branch	Direction	Peak	Off Peak	Peak	Off Peak	Peak	Off Peak	Peak	Off Peak	Peak	Off Peak
COI	Import	$6.2	$4.7	$10.7	$5.9	$1.1	$7.6	$30.7	$1.6	$8.1	$8.4
	Export	-	-	-	-	$59.8	$47.2	$100.4	$62.2	-	-
ELDORADO	Import	$6.6	$6.5	$7.5	$7.1	$22.4	$29.7	$1.5	$5.6	$55.8	$53.1
	Export	-	-	-	-	-	-	-	-	-	-
MEAD	Import	$4.0	$50.0	$8.4	$20.0	$17.1	$22.1	-	$7.7	$1.7	-
	Export	$10.4	-	$55.6	-	$75.9	$57.3	$30.0	-	$20.7	$20.0
NOB	Import	$7.1	$3.0	$2.8	$5.3	$13.9	$0.3	$0.0	-	$0.5	$0.0
	Export	-	-	-	$26.3	$45.2	$42.2	$19.0	$48.7	-	-
PALOVERDE	Import	$6.6	$4.0	$8.6	$7.0	$73.6	$43.2	$112.7	$45.5	$7.5	$33.6
	Export	-	-	-	-	-	-	$30.0	-	-	-
PATH15	Import	$7.8	$9.6	$14.6	$8.4	$39.1	$44.5	$0.2	$0.1	-	-
	Export	$10.8	$2.4	$8.9	$9.7	$33.9	$50.0	-	-	$13.8	-
PATH26	Import	-	-	-	$0.5	$76.2	$36.2	$23.5	$49.4	$0.0	$17.3
	Export	-	-	$6.8	$2.6	$50.6	$28.9	$26.1	$25.6	$9.5	$0.0

Source: CAISO DMA's SI database, Branch Group table.

Notes
Shading indicates off peak percentage (price) is greater than peak percentage (price).
Annual totals calculated using hourly data. Peak hours are HE 7:00 - HE 22:00, Monday - Saturday, excluding NERC holidays.
Path 15 & Path 26 Import is S to N; Path 15 & Path 26 Export is N to S.

Table 1b
Peak vs. Off Peak Congestion Summary
Hour Ahead

Percent of Hours Congested

Branch	Direction	4/98 - 3/99 Peak	4/98 - 3/99 Off Peak	4/99 - 3/00 Peak	4/99 - 3/00 Off Peak	4/00 - 3/01 Peak	4/00 - 3/01 Off Peak	4/01 - 3/02 Peak	4/01 - 3/02 Off Peak	4/02 - 3/03 Peak	4/02 - 3/03 Off Peak
COI	Import	7.6%	1.8%	30.0%	11.0%	3.5%	1.0%	3.9%	0.3%	14.5%	5.5%
	Export	-	-	-	-	1.8%	3.2%	0.4%	0.9%	-	-
ELDORADO	Import	2.0%	0.8%	6.6%	4.8%	2.5%	5.0%	1.4%	3.4%	0.9%	1.0%
	Export	-	-	-	-	-	-	-	-	-	-
MEAD	Import	0.1%	-	4.2%	0.2%	3.5%	2.1%	0.9%	0.5%	0.8%	0.9%
	Export	0.0%	-	0.3%	0.1%	0.1%	0.1%	0.3%	0.1%	0.2%	0.1%
NOB	Import	5.1%	1.2%	8.2%	3.6%	10.9%	0.7%	0.2%	-	10.5%	2.9%
	Export	-	-	-	0.2%	13.5%	29.2%	7.2%	15.7%	-	-
PALOVERDE	Import	3.1%	0.5%	10.3%	10.0%	3.6%	8.7%	4.8%	8.5%	3.0%	0.9%
	Export	-	-	-	-	-	-	-	-	-	-
PATH15	Import	0.3%	1.0%	9.2%	9.5%	28.2%	51.4%	10.0%	23.6%	0.3%	2.7%
	Export	0.7%	0.1%	0.2%	0.1%	2.4%	1.0%	-	-	0.0%	0.1%
PATH26	Import	-	-	-	0.1%	0.1%	1.0%	0.1%	5.0%	0.0%	0.8%
	Export	-	-	1.4%	0.1%	10.2%	0.8%	0.6%	0.2%	3.7%	0.1%

Average Price ($/MWh)

Branch	Direction	4/98 - 3/99 Peak	4/98 - 3/99 Off Peak	4/99 - 3/00 Peak	4/99 - 3/00 Off Peak	4/00 - 3/01 Peak	4/00 - 3/01 Off Peak	4/01 - 3/02 Peak	4/01 - 3/02 Off Peak	4/02 - 3/03 Peak	4/02 - 3/03 Off Peak
COI	Import	$116.8	$150.4	$42.8	$66.6	$57.1	$46.1	$44.5	$23.9	$30.0	$31.4
	Export	-	-	-	-	$62.4	$132.8	$28.5	$61.1	-	-
ELDORADO	Import	$58.4	$154.6	$32.2	$45.7	$67.7	$53.2	$38.9	$20.2	$26.2	$21.0
	Export	-	-	-	-	-	-	-	-	-	-
MEAD	Import	$14.4	-	$22.4	$26.3	$55.1	$71.1	$53.9	$60.0	$34.9	$26.1
	Export	$125.0	-	$62.0	$6.5	$99.6	$173.8	$222.1	$30.0	$15.1	$42.9
NOB	Import	$117.0	$66.0	$29.3	$49.3	$81.2	$65.8	$65.4	-	$34.3	$31.5
	Export	-	-	-	$13.6	$64.4	$69.9	$20.5	$22.1	-	-
PALOVERDE	Import	$143.8	$211.8	$11.7	$23.2	$57.2	$45.3	$15.6	$25.7	$21.4	$33.7
	Export	-	-	-	-	-	-	-	-	-	-
PATH15	Import	$217.2	$223.4	$81.3	$65.5	$53.6	$57.5	$40.6	$45.6	$24.5	$37.0
	Export	$135.8	$88.7	$91.8	$49.4	$65.6	$54.1	-	-	$1.0	$18.0
PATH26	Import	-	-	-	$15.5	$16.7	$24.2	$32.6	$37.8	$125.4	$17.6
	Export	-	-	$9.1	$10.5	$78.2	$39.6	$44.9	$37.0	$34.2	$21.2

Source: CAISO DMA's SI database, Branch Group table.

Notes
Shading indicates off peak percentage (price) is greater than peak percentage (price).
Annual totals calculated using hourly data. Peak hours are HE 7:00 - HE 22:00, Monday - Saturday, excluding NERC holidays.
Path 15 & Path 26 Import is S to N; Path 15 & Path 26 Export is N to S.

Table 2a
Peak Hour Congestion Summary by Season
Day Ahead

Percent of Hours Congested

Branch	Direction	4/98 - 3/99 Summer	4/98 - 3/99 Winter	4/99 - 3/00 Summer	4/99 - 3/00 Winter	4/00 - 3/01 Summer	4/00 - 3/01 Winter	4/01 - 3/02 Summer	4/01 - 3/02 Winter	4/02 - 3/03 Summer	4/02 - 3/03 Winter
COI	Import	21.1%	36.4%	35.9%	41.8%	0.8%	5.4%	2.5%	2.0%	39.9%	8.8%
	Export	-	-	-	-	4.8%	11.2%	2.0%	-	-	-
ELDORADO	Import	0.7%	20.5%	9.3%	11.6%	0.3%	5.6%	0.3%	3.1%	0.7%	2.1%
	Export	-	-	-	-	-	-	-	-	-	-
MEAD	Import	-	0.0%	2.0%	3.2%	4.0%	3.5%	-	-	-	0.4%
	Export	0.2%	-	0.5%	-	1.5%	-	0.7%	-	0.4%	-
NOB	Import	11.1%	18.3%	13.6%	4.7%	10.3%	-	-	0.5%	50.9%	1.8%
	Export	-	-	-	-	2.8%	27.6%	10.1%	-	-	-
PALOVERDE	Import	0.9%	13.2%	4.4%	21.0%	0.0%	7.3%	-	2.9%	2.1%	6.9%
	Export	-	-	-	-	-	-	0.0%	-	-	-
PATH15	Import	1.7%	4.8%	11.4%	37.3%	13.5%	69.0%	19.1%	14.8%	1.5%	0.8%
	Export	4.7%	1.0%	1.0%	0.3%	9.0%	-	-	-	0.7%	0.2%
PATH26	Import	-	-	-	-	0.1%	0.1%	-	0.7%	0.0%	-
	Export	-	-	-	6.3%	28.5%	2.1%	-	1.1%	8.7%	6.5%

Average Price ($/MWh)

Branch	Direction	4/98 - 3/99 Summer	4/98 - 3/99 Winter	4/99 - 3/00 Summer	4/99 - 3/00 Winter	4/00 - 3/01 Summer	4/00 - 3/01 Winter	4/01 - 3/02 Summer	4/01 - 3/02 Winter	4/02 - 3/03 Summer	4/02 - 3/03 Winter
COI	Import	$9.6	$4.2	$13.1	$8.7	$3.1	$0.8	$53.5	$1.3	$9.7	$0.9
	Export	-	-	-	-	$54.3	$62.2	$100.4	-	-	-
ELDORADO	Import	$1.8	$6.8	$8.2	$6.9	$33.7	$21.8	$9.3	$0.8	$15.8	$69.9
	Export	-	-	-	-	-	-	-	-	-	-
MEAD	Import	-	$4.0	$6.1	$9.9	$6.2	$29.7	-	-	-	$1.7
	Export	$10.4	-	$55.6	-	$75.9	-	$30.0	-	$20.7	-
NOB	Import	$16.7	$1.2	$3.4	$1.2	$13.9	-	-	$0.0	$0.4	$2.3
	Export	-	-	-	-	$31.0	$46.7	$19.0	-	-	-
PALOVERDE	Import	$4.2	$6.8	$12.1	$7.8	$32.9	$73.8	-	$112.7	$1.7	$9.2
	Export	-	-	-	-	-	-	$30.0	-	-	-
PATH15	Import	$4.8	$8.9	$16.3	$14.0	$27.0	$41.5	$0.4	$0.0	-	-
	Export	$12.3	$3.4	$9.5	$7.1	$33.9	-	-	-	$18.2	$1.4
PATH26	Import	-	-	-	-	$6.2	$146.2	-	$23.5	$0.0	-
	Export	-	-	-	$6.8	$53.2	$16.3	-	$26.1	$9.9	$9.0

Source: CAISO DMA's SI database, Branch Group table.

Notes
Shading indicates off peak season/winter percentage (price) is greater than peak season/summer percentage (price).
Annual totals calculated using hourly data. Peak hours are HE 7:00 - HE 22:00, Monday - Saturday, excluding NERC holidays.
Seasons: Summer=Q2 & Q3, Winter Q4 & Q1 of following year.
Path 15 & Path 26 Import is S to N; Path 15 & Path 26 Export is N to S.

Table 2b
Peak Hour Congestion Summary by Season
Hour Ahead

Percent of Hours Congested

Branch	Direction	4/98 - 3/99 Summer	4/98 - 3/99 Winter	4/99 - 3/00 Summer	4/99 - 3/00 Winter	4/00 - 3/01 Summer	4/00 - 3/01 Winter	4/01 - 3/02 Summer	4/01 - 3/02 Winter	4/02 - 3/03 Summer	4/02 - 3/03 Winter
COI	Import	5.0%	10.2%	27.1%	32.8%	4.7%	2.4%	2.3%	5.6%	22.4%	6.6%
	Export	-	-	-	-	0.1%	3.6%	0.8%	-	-	-
ELDORADO	Import	0.2%	3.9%	3.9%	9.3%	0.6%	4.4%	0.6%	2.2%	0.3%	1.5%
	Export	-	-	-	-	-	-	-	-	-	-
MEAD	Import	-	0.2%	2.0%	6.4%	2.6%	4.5%	-	1.8%	0.1%	1.4%
	Export	0.1%	-	0.6%	-	0.3%	-	0.5%	-	0.4%	-
NOB	Import	3.2%	7.0%	9.5%	6.9%	21.6%	-	-	0.5%	18.3%	2.7%
	Export	-	-	-	-	3.8%	23.2%	14.4%	-	-	-
PALOVERDE	Import	-	6.2%	3.4%	17.2%	0.1%	7.1%	0.7%	8.8%	0.9%	5.1%
	Export	-	-	-	-	-	-	-	-	-	-
PATH15	Import	-	0.6%	4.0%	14.4%	11.4%	45.1%	18.4%	1.6%	0.2%	0.3%
	Export	0.9%	0.5%	0.3%	0.0%	4.8%	-	-	-	0.1%	-
PATH26	Import	-	-	-	-	0.1%	0.1%	0.1%	0.0%	0.0%	0.0%
	Export	-	-	-	2.7%	19.8%	0.5%	0.5%	0.7%	4.3%	3.0%

Average Price ($/MWh)

Branch	Direction	4/98 - 3/99 Summer	4/98 - 3/99 Winter	4/99 - 3/00 Summer	4/99 - 3/00 Winter	4/00 - 3/01 Summer	4/00 - 3/01 Winter	4/01 - 3/02 Summer	4/01 - 3/02 Winter	4/02 - 3/03 Summer	4/02 - 3/03 Winter
COI	Import	$185.9	$82.4	$49.3	$37.5	$54.5	$62.3	$85.4	$27.3	$34.7	$14.1
	Export	-	-	-	-	$22.5	$63.3	$28.5	-	-	-
ELDORADO	Import	$100.0	$56.7	$50.9	$24.3	$33.6	$72.4	$31.6	$40.8	$16.0	$28.4
	Export	-	-	-	-	-	-	-	-	-	-
MEAD	Import	-	$14.4	$46.4	$15.0	$24.5	$73.3	-	$53.9	$13.0	$36.2
	Export	$125.0	-	$62.0	-	$99.6	-	$222.1	-	$15.1	-
NOB	Import	$190.9	$82.8	$27.8	$31.3	$81.2	-	-	$65.4	$36.6	$18.0
	Export	-	-	-	-	$53.4	$66.3	$20.5	-	-	-
PALOVERDE	Import	-	$143.8	$18.4	$10.3	$10.9	$58.0	$11.7	$15.9	$16.9	$22.1
	Export	-	-	-	-	-	-	-	-	-	-
PATH15	Import	-	$217.2	$112.5	$72.7	$41.9	$56.6	$39.9	$48.7	$38.7	$15.6
	Export	$182.2	$57.4	$97.8	$49.9	$65.6	-	-	-	$1.0	-
PATH26	Import	-	-	-	-	$4.5	$35.0	$30.0	$37.9	$231.9	$19.0
	Export	-	-	-	$9.1	$77.9	$89.7	$54.3	$38.6	$36.7	$30.6

Source: CAISO DMA's SI database, Branch Group table.

Notes
Shading indicates off peak season/winter percentage (price) is greater than peak season/summer percentage (price).
Annual totals calculated using hourly data. Peak hours are HE 7:00 - HE 22:00, Monday - Saturday, excluding NERC holidays.
Seasons: Summer=Q2 & Q3, Winter Q4 & Q1 of following year.
Path 15 & Path 26 Import is S to N; Path 15 & Path 26 Export is N to S.

Table 1
Percentage of Additional TRR for New HV Transmission Facilities Paid for by Various Customer Groups

			Under Amendment 27				Under Amendment 49			
	Owner of New HV Facility	**Cost Shift Cap Exceeded**	**PG&E**	**Original PTOs**	**Anaheim**	**New PTOs**	**PG&E**	**Original PTOs**	**Anaheim**	**New PTOs**
1	PG&E	No	98.6%	96.9%	1.4%	3.1%	43.4%	96.9%	1.4%	3.1%
2	PG&E	Yes	100.0%	100.0%	0.1%	0.0%	43.4%	96.9%	1.4%	3.1%
3	Anaheim	No	43.0%	96.9%	1.4%	3.1%	43.4%	96.9%	1.4%	3.1%
4	Anaheim	Partial*	28.3%	63.8%	26.0%	36.2%	43.4%	96.9%	1.4%	3.1%
5	Anaheim	Yes	0.0%	0.0%	76.2%	100.0%	43.4%	96.9%	1.4%	3.1%
Share of Gross Load			43.4%	96.9%	1.4%	3.1%	43.4%	96.9%	1.4%	3.1%

Sources
Scenario 1: See Table 2a.
Scenario 2: See Table 2b.
Scenario 3: See Table 2c.
Scenario 4: See Table 2d.
Scenario 5: See Table 2e.

Notes
* This scenario shows cost allocation for a transmission investment by Anaheim where prior to the upgrade cost shifts are below the cap, but where the transmission upgrade increases cost shifts to exceed the cap under Amendment 27.

Scenario 1: Additional New TRR of $51.1 million was added to PG&E New TRR.
Scenario 2: Additional New TRR of $51.1 million was added to PG&E New TRR.
Original PTO cost shift caps were reduced to $16/$16/$4 from $32/$32/$8 so that the cap would be exceeded.
Scenario 3: Additional New TRR of $30 million was added to Anaheim's New TRR.
Scenario 4: Additional New TRR of $50 million was added to Anaheim's New TRR.
In this scenario, the cost shift cap is not exceed before the $50 million addition.
After the addition, the cap is exceeded by $17 million under Amendment 27.
Scenario 5: Additional New TRR of $50 million was added to Anaheim's New TRR.
Original PTO cost shift caps were reduced to $16/$16/$4 from $32/$32/$8 so that the cap would be exceeded.

Table 2a

Comparison of the Impact of New Transmission Investment: Amendment 27 vs. Amendment 49

Assumes $51.1M new TRR added by PG&E; Cost shift cap is not exceeded

	Amendment 27			Amendment 49		
	Case A	Case B	Difference	Case A	Case B	Difference
TRR of PG&E Existing Facilities ($)	154,837,354	154,837,354	-	154,837,354	154,837,354	-
TRR of PG&E New Facilities	48,896,007	100,000,000	**51,103,993**	48,896,007	100,000,000	**51,103,993**
TRR PG&E Total	203,733,361	254,837,354	51,103,993	203,733,361	254,837,354	51,103,993
TRR of OPTO Existing Facilities ($)	366,105,334	366,105,334	-	366,105,334	366,105,334	-
TRR of OPTO New Facilities	56,773,705	107,877,698	**51,103,993**	56,773,705	107,877,698	**51,103,993**
TRR OPTO Total	422,879,039	473,983,032	51,103,993	422,879,039	473,983,032	51,103,993
TRR of Anaheim Existing Facilities ($)	23,665,095	23,665,095	-	23,665,095	23,665,095	-
TRR of Anaheim New Facilities	-	-	-	-	-	-
TRR Anaheim Total	23,665,095	23,665,095	-	23,665,095	23,665,095	-
TRR of New PTO Existing Facilities ($)	56,397,722	56,397,722	-	56,397,722	56,397,722	-
TRR of New PTO New Facilities	-	-	-	-	-	-
TRR New PTO Total	56,397,722	56,397,722	-	56,397,722	56,397,722	-
PG&E Gross Load (MWh)	82,761,368	82,761,368		82,761,368	82,761,368	
OPTO Gross Load (MWh)	184,820,051	184,820,051		184,820,051	184,820,051	
Anaheim Gross Load (MWh)	2,589,830	2,589,830		2,589,830	2,589,830	
New PTO Gross Load (MWh)	5,993,549	5,993,549		5,993,549	5,993,549	
ISO-wide Gross Load (MWh)	190,813,600	190,813,600		190,813,600	190,813,600	
PG&E Share of ISO-wide Gross Load	43.4%	43.4%		43.4%	43.4%	
OPTO Share of ISO-wide Gross Load	96.9%	96.9%		96.9%	96.9%	
Anaheim Share of ISO-wide Gross Load	1.4%	1.4%		1.4%	1.4%	
New PTO Share of ISO-wide Gross Load	3.1%	3.1%		3.1%	3.1%	
Total Charges to PG&E load ($)	221,565,728	271,956,298	**50,390,570**	198,086,689	220,251,966	**22,165,277**
Total Charges to OPTO load ($)	463,001,864	512,500,655	**49,498,791**	463,001,864	512,500,655	**49,498,791**
Total Charges to Anaheim load ($)	7,032,431	7,726,043	**693,612**	7,032,431	7,726,043	**693,612**
Total Charges to New PTO load ($)	16,274,897	17,880,099	**1,605,202**	16,274,897	17,880,099	**1,605,202**
Percentage of additional new facilities paid for by PG&E's load			**98.6%**			**43.4%**
Percentage of additional new facilities paid for by OPTOs' load			**96.9%**			**96.9%**
Percentage of additional new facilities paid for by Anaheim's load			**1.4%**			**1.4%**
Percentage of additional new facilities paid for by New PTOs' load			**3.1%**			**3.1%**

Sources
Based on TRR and Gross Load data in the CAISO TAC Informational Filing, September 17, 2003 (Docket No. ER03-1357).
Amendment 27 - Case A: See Workpaper 1 to Table 2.
Amendment 27 - Case B: See Workpaper 2 to Table 2.
Amendment 49 - Case A: See Workpaper 8 to Table 2.
Amendment 49 - Case B: See Workpaper 9 to Table 2.

Notes
Case A represents the "filed" case in which PG&E adds $49 million of New Facility TRR.
Case B represents the "revised" case in which PG&E adds $100 million of New Facility TRR.
Assumes cost shift cap of $32/$32/$8.
Under the Amendment 27 methodology, the TRR of New Facilities is included in cost shift and transition charge calculations.
Under the Amendment 49 methodology, the TRR of New Facilities is excluded in cost shift and transition charge calculations.
Total charges reflect High Voltage Access Charge and Transition Charge applied to Gross Loads.

Table 2b
Comparison of the Impact of New Transmission Investment: Amendment 27 vs. Amendment 49
Assumes $51.1M new TRR added by PG&E; Cost shift cap is exceeded

	Amendment 27			Amendment 49		
	Case A	Case B	Difference	Case A	Case B	Difference
TRR of PG&E Existing Facilities ($)	154,837,354	154,837,354	-	154,837,354	154,837,354	-
TRR of PG&E New Facilities	48,896,007	100,000,000	**51,103,993**	48,896,007	100,000,000	**51,103,993**
TRR PG&E Total	203,733,361	254,837,354	51,103,993	203,733,361	254,837,354	51,103,993
TRR of OPTO Existing Facilities ($)	366,105,334	366,105,334	-	366,105,334	366,105,334	-
TRR of OPTO New Facilities	56,773,705	107,877,698	**51,103,993**	56,773,705	107,877,698	**51,103,993**
TRR OPTO Total	422,879,039	473,983,032	51,103,993	422,879,039	473,983,032	51,103,993
TRR of Anaheim Existing Facilities ($)	23,665,095	23,665,095	-	23,665,095	23,665,095	-
TRR of Anaheim New Facilities	-	-	-	-	-	-
TRR Anaheim Total	23,665,095	23,665,095	-	23,665,095	23,665,095	-
TRR of New PTO Existing Facilities ($)	56,397,722	56,397,722	-	56,397,722	56,397,722	-
TRR of New PTO New Facilities	-	-	-	-	-	-
TRR New PTO Total	56,397,722	56,397,722	-	56,397,722	56,397,722	-
PG&E Gross Load (MWh)	82,761,368	82,761,368		82,761,368	82,761,368	
OPTO Gross Load (MWh)	184,820,051	184,820,051		184,820,051	184,820,051	
Anaheim Gross Load (MWh)	2,589,830	2,589,830		2,589,830	2,589,830	
New PTO Gross Load (MWh)	5,993,549	5,993,549		5,993,549	5,993,549	
ISO-wide Gross Load (MWh)	190,813,600	190,813,600		190,813,600	190,813,600	
PG&E Share of ISO-wide Gross Load	43.4%	43.4%		43.4%	43.4%	
OPTO Share of ISO-wide Gross Load	96.9%	96.9%		96.9%	96.9%	
Anaheim Share of ISO-wide Gross Load	1.4%	1.4%		1.4%	1.4%	
New PTO Share of ISO-wide Gross Load	3.1%	3.1%		3.1%	3.1%	
Total Charges to PG&E load ($)	219,733,361	270,837,354	**51,103,993**	195,461,749	217,627,027	**22,165,277**
Total Charges to OPTO load ($)	458,879,039	509,983,032	**51,103,993**	457,095,749	506,594,540	**49,498,791**
Total Charges to Anaheim load ($)	8,741,522	8,767,865	**26,344**	9,485,186	10,178,799	**693,612**
Total Charges to New PTO load ($)	20,397,722	20,397,722	-	22,181,012	23,786,214	**1,605,202**
Percentage of additional new facilities paid for by PG&E's load			**100.0%**			**43.4%**
Percentage of additional new facilities paid for by OPTOs' load			**100.0%**			**96.9%**
Percentage of additional new facilities paid for by Anaheim's load			**0.1%**			**1.4%**
Percentage of additional new facilities paid for by New PTOs' load			**0.0%**			**3.1%**

Sources
Based on TRR and Gross Load data in the CAISO TAC Informational Filing, September 17, 2003 (Docket No. ER03-1357).
Amendment 27 - Case A: See Workpaper 5 to Table 2.
Amendment 27 - Case B: See Workpaper 6 to Table 2.
Amendment 49 - Case A: See Workpaper 12 to Table 2.
Amendment 49 - Case B: See Workpaper 13 to Table 2.

Notes
Case A represents the "filed" case in which PG&E adds $49 million of New Facility TRR.
Case B represents the "revised" case in which PG&E adds $100 million of New Facility TRR.
Assumes cost shift cap of $16/$16/$4 for illustrative purposes.
Under the Amendment 27 methodology, the TRR of New Facilities is included in cost shift and transition charge calculations.
Under the Amendment 49 methodology, the TRR of New Facilities is excluded in cost shift and transition charge calculations.
Total charges reflect High Voltage Access Charge and Transition Charge applied to Gross Loads.

Table 2c

Comparison of the Impact of New Transmission Investment: Amendment 27 vs. Amendment 49

Assumes $30M new TRR added by Anaheim; Cost shift cap is not exceeded

	Amendment 27			Amendment 49		
	Case A	**Case B**	**Difference**	**Case A**	**Case B**	**Difference**
TRR of PG&E Existing Facilities ($)	154,837,354	154,837,354	-	154,837,354	154,837,354	-
TRR of PG&E New Facilities	48,896,007	48,896,007	-	48,896,007	48,896,007	-
TRR PG&E Total	203,733,361	203,733,361	-	203,733,361	203,733,361	-
TRR of OPTO Existing Facilities ($)	366,105,334	366,105,334	-	366,105,334	366,105,334	-
TRR of OPTO New Facilities	56,773,705	56,773,705	-	56,773,705	56,773,705	-
TRR OPTO Total	422,879,039	422,879,039	-	422,879,039	422,879,039	-
TRR of Anaheim Existing Facilities ($)	23,665,095	23,665,095	-	23,665,095	23,665,095	-
TRR of Anaheim New Facilities	-	30,000,000	**30,000,000**	-	30,000,000	**30,000,000**
TRR Anaheim Total	23,665,095	53,665,095	30,000,000	23,665,095	53,665,095	30,000,000
TRR of New PTO Existing Facilities ($)	56,397,722	56,397,722	-	56,397,722	56,397,722	-
TRR of New PTO New Facilities	-	30,000,000	**30,000,000**	-	30,000,000	**30,000,000**
TRR New PTO Total	56,397,722	86,397,722	30,000,000	56,397,722	86,397,722	30,000,000
PG&E Gross Load (MWh)	82,761,368	82,761,368		82,761,368	82,761,368	
OPTO Gross Load (MWh)	184,820,051	184,820,051		184,820,051	184,820,051	
Anaheim Gross Load (MWh)	2,589,830	2,589,830		2,589,830	2,589,830	
New PTO Gross Load (MWh)	5,993,549	5,993,549		5,993,549	5,993,549	
ISO-wide Gross Load (MWh)	190,813,600	190,813,600		190,813,600	190,813,600	
PG&E Share of ISO-wide Gross Load	43.4%	43.4%		43.4%	43.4%	
OPTO Share of ISO-wide Gross Load	96.9%	96.9%		96.9%	96.9%	
Anaheim Share of ISO-wide Gross Load	1.4%	1.4%		1.4%	1.4%	
New PTO Share of ISO-wide Gross Load	3.1%	3.1%		3.1%	3.1%	
Total Charges to PG&E load ($)	221,565,728	234,480,254	**12,914,527**	198,086,689	211,098,555	**13,011,866**
Total Charges to OPTO load ($)	463,001,864	492,059,549	**29,057,685**	463,001,864	492,059,549	**29,057,685**
Total Charges to Anaheim load ($)	7,032,431	7,439,607	**407,177**	7,032,431	7,439,607	**407,177**
Total Charges to New PTO load ($)	16,274,897	17,217,212	**942,315**	16,274,897	17,217,212	**942,315**
Percentage of additional new facilities paid for by PG&E's load			**43.0%**			**43.4%**
Percentage of additional new facilities paid for by OPTOs' load			**96.9%**			**96.9%**
Percentage of additional new facilities paid for by Anaheim's load			**1.4%**			**1.4%**
Percentage of additional new facilities paid for by New PTOs' load			**3.1%**			**3.1%**

Sources
Based on TRR and Gross Load data in the CAISO TAC Informational Filing, September 17, 2003 (Docket No. ER03-1357).
Amendment 27 - Case A: See Workpaper 1 to Table 2.
Amendment 27 - Case B: See Workpaper 3 to Table 2.
Amendment 49 - Case A: See Workpaper 8 to Table 2.
Amendment 49 - Case B: See Workpaper 10 to Table 2.

Notes
Case A represents the "filed" case in which PG&E adds $49 million of New Facility TRR.
Case B represents the "revised" case in which a New PTO (Anaheim) adds $30 million of New Facility TRR.
Assumes cost shift cap of $32/$32/$8.
Under the Amendment 27 methodology, the TRR of New Facilities is included in cost shift and transition charge calculations.
Under the Amendment 49 methodology, the TRR of New Facilities is excluded in cost shift and transition charge calculations.
Total charges reflect High Voltage Access Charge and Transition Charge applied to Gross Loads.

Table 2d

Comparison of the Impact of New Transmission Investment: Amendment 27 vs. Amendment 49

Assumes $50M New TRR added by Anaheim; Cost shift cap is exceeded after addition but not before

	Amendment 27			Amendment 49		
	Case A	**Case B**	**Difference**	**Case A**	**Case B**	**Difference**
TRR of PG&E Existing Facilities ($)	154,837,354	154,837,354	-	154,837,354	154,837,354	-
TRR of PG&E New Facilities	48,896,007	48,896,007	-	48,896,007	48,896,007	-
TRR PG&E Total	203,733,361	203,733,361	-	203,733,361	203,733,361	-
TRR of OPTO Existing Facilities ($)	366,105,334	366,105,334	-	366,105,334	366,105,334	-
TRR of OPTO New Facilities	56,773,705	56,773,705	-	56,773,705	56,773,705	-
TRR OPTO Total	422,879,039	422,879,039	-	422,879,039	422,879,039	-
TRR of Anaheim Existing Facilities ($)	23,665,095	23,665,095	-	23,665,095	23,665,095	-
TRR of Anaheim New Facilities	-	50,000,000	**50,000,000**	-	50,000,000	**50,000,000**
TRR Anaheim Total	23,665,095	73,665,095	50,000,000	23,665,095	73,665,095	50,000,000
TRR of New PTO Existing Facilities ($)	56,397,722	56,397,722	-	56,397,722	56,397,722	-
TRR of New PTO New Facilities	-	50,000,000	**50,000,000**	-	50,000,000	**50,000,000**
TRR New PTO Total	56,397,722	106,397,722	50,000,000	56,397,722	106,397,722	50,000,000
PG&E Gross Load (MWh)	82,761,368	82,761,368		82,761,368	82,761,368	
OPTO Gross Load (MWh)	184,820,051	184,820,051		184,820,051	184,820,051	
Anaheim Gross Load (MWh)	2,589,830	2,589,830		2,589,830	2,589,830	
New PTO Gross Load (MWh)	5,993,549	5,993,549		5,993,549	5,993,549	
ISO-wide Gross Load (MWh)	190,813,600	190,813,600		190,813,600	190,813,600	
PG&E Share of ISO-wide Gross Load	43.4%	43.4%		43.4%	43.4%	
OPTO Share of ISO-wide Gross Load	96.9%	96.9%		96.9%	96.9%	
Anaheim Share of ISO-wide Gross Load	1.4%	1.4%		1.4%	1.4%	
New PTO Share of ISO-wide Gross Load	3.1%	3.1%		3.1%	3.1%	
Total Charges to PG&E load ($)	221,565,728	235,733,361	**14,167,633**	198,086,689	219,773,133	**21,686,444**
Total Charges to OPTO load ($)	463,001,864	494,879,039	**31,877,175**	463,001,864	511,431,339	**48,429,475**
Total Charges to Anaheim load ($)	7,032,431	20,039,265	**13,006,834**	7,032,431	7,711,059	**678,628**
Total Charges to New PTO load ($)	16,274,897	34,397,722	**18,122,825**	16,274,897	17,845,422	**1,570,525**
Percentage of additional new facilities paid for by PG&E's load			**28.3%**			**43.4%**
Percentage of additional new facilities paid for by OPTOs' load			**63.8%**			**96.9%**
Percentage of additional new facilities paid for by Anaheim's load			**26.0%**			**1.4%**
Percentage of additional new facilities paid for by New PTOs' load			**36.2%**			**3.1%**

Sources
Based on TRR and Gross Load data in the CAISO TAC Informational Filing, September 17, 2003 (Docket No. ER03-1357).
Amendment 27 - Case A: See Workpaper 1 to Table 2.
Amendment 27 - Case B: See Workpaper 4 to Table 2.
Amendment 49 - Case A: See Workpaper 8 to Table 2.
Amendment 49 - Case B: See Workpaper 11 to Table 2.

Notes
Case A represents the "filed" case in which PG&E adds $49 million of New Facility TRR.
Case B represents the "revised" case in which a New PTO (Anaheim) adds $50 million of New Facility TRR.
Assumes cost shift cap of $32/$32/$8.
Under the Amendment 27 methodology, the TRR of New Facilities is included in cost shift and transition charge calculations.
Under the Amendment 49 methodology, the TRR of New Facilities is excluded in cost shift and transition charge calculations.
Total charges reflect High Voltage Access Charge and Transition Charge applied to Gross Loads.

Table 2e

Comparison of the Impact of New Transmission Investment: Amendment 27 vs. Amendment 49

Assumes $50M New TRR added by Anaheim; Cost shift cap is exceeded

	Amendment 27			Amendment 49		
	Case A	Case B	Difference	Case A	Case B	Difference
TRR of PG&E Existing Facilities ($)	154,837,354	154,837,354	-	154,837,354	154,837,354	-
TRR of PG&E New Facilities	48,896,007	48,896,007	-	48,896,007	48,896,007	-
TRR PG&E Total	203,733,361	203,733,361	-	203,733,361	203,733,361	-
TRR of OPTO Existing Facilities ($)	366,105,334	366,105,334	-	366,105,334	366,105,334	-
TRR of OPTO New Facilities	56,773,705	56,773,705	-	56,773,705	56,773,705	-
TRR OPTO Total	422,879,039	422,879,039	-	422,879,039	422,879,039	-
TRR of Anaheim Existing Facilities ($)	23,665,095	23,665,095	-	23,665,095	23,665,095	-
TRR of Anaheim New Facilities	-	50,000,000	**50,000,000**	-	50,000,000	**50,000,000**
TRR Anaheim Total	23,665,095	73,665,095	50,000,000	23,665,095	73,665,095	50,000,000
TRR of New PTO Existing Facilities ($)	56,397,722	56,397,722	-	56,397,722	56,397,722	-
TRR of New PTO New Facilities	-	50,000,000	**50,000,000**	-	50,000,000	**50,000,000**
TRR New PTO Total	56,397,722	106,397,722	50,000,000	56,397,722	106,397,722	50,000,000
PG&E Gross Load (MWh)	82,761,368	82,761,368		82,761,368	82,761,368	
OPTO Gross Load (MWh)	184,820,051	184,820,051		184,820,051	184,820,051	
Anaheim Gross Load (MWh)	2,589,830	2,589,830		2,589,830	2,589,830	
New PTO Gross Load (MWh)	5,993,549	5,993,549		5,993,549	5,993,549	
ISO-wide Gross Load (MWh)	190,813,600	190,813,600		190,813,600	190,813,600	
PG&E Share of ISO-wide Gross Load	43.4%	43.4%		43.4%	43.4%	
OPTO Share of ISO-wide Gross Load	96.9%	96.9%		96.9%	96.9%	
Anaheim Share of ISO-wide Gross Load	1.4%	1.4%		1.4%	1.4%	
New PTO Share of ISO-wide Gross Load	3.1%	3.1%		3.1%	3.1%	
Total Charges to PG&E load ($)	219,733,361	219,733,361	-	195,461,749	217,148,193	**21,686,444**
Total Charges to OPTO load ($)	458,879,039	458,879,039	-	457,095,749	505,525,224	**48,429,475**
Total Charges to Anaheim load ($)	8,741,522	46,852,180	**38,110,658**	9,485,186	10,163,815	**678,628**
Total Charges to New PTO load ($)	20,397,722	70,397,722	**50,000,000**	22,181,012	23,751,537	**1,570,525**
Percentage of additional new facilities paid for by PG&E's load			**0.0%**			**43.4%**
Percentage of additional new facilities paid for by OPTOs' load			**0.0%**			**96.9%**
Percentage of additional new facilities paid for by Anaheim's load			**76.2%**			**1.4%**
Percentage of additional new facilities paid for by New PTOs' load			**100.0%**			**3.1%**

Sources

Based on TRR and Gross Load data in the CAISO TAC Informational Filing, September 17, 2003 (Docket No. ER03-1357).
Amendment 27 - Case A: See Workpaper 5 to Table 2.
Amendment 27 - Case B: See Workpaper 7 to Table 2.
Amendment 49 - Case A: See Workpaper 12 to Table 2.
Amendment 49 - Case B: See Workpaper 14 to Table 2.

Notes

Case A represents the "filed" case in which PG&E adds $49 million of New Facility TRR.
Case B represents the "revised" case in which a New PTO (Anaheim) adds $50 million of New Facility TRR.
Assumes cost shift cap of $16/$16/$4 for illustrative purposes.
Under the Amendment 27 methodology, the TRR of New Facilities is included in cost shift and transition charge calculations.
Under the Amendment 49 methodology, the TRR of New Facilities is excluded in cost shift and transition charge calculations.
Total charges reflect High Voltage Access Charge and Transition Charge applied to Gross Loads.