PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Investigation into implementation of Assembly Bill 970 regarding the identification of electric transmission and distribution constraints, actions to resolve those constraints, and related matters affecting the reliability of electric supply.	)))))))	I.00-11-001
Conditional Application of Pacific Gas and Electric Company (U 39 E) for a Certificate of Public Convenience and Necessity Authorizing the Construction of the Los Banos-Gates 500 kV Transmission Project	))))))	A. 01-04-012

OPENING BRIEF OF THE
CALIFORNIA INDEPENDENT SYSTEM OPERATOR
ON PATH 15 BENEFITS

Charles F. Robinson, General Counsel
Jeanne M. Solé, Regulatory Counsel
California Independent System Operator
151 Blue Ravine Road
Folsom, CA 95630
Telephone: 916-351-4400
Facsimile: 916-608-7222

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I. INTRODUCTION AND SUMMARY

In accordance with California Public Utilities Commission Rule 75 and the oral ruling of Administrative Law Judge (ALJ) Gottstein, the California Independent System Operator Corporation (CA ISO) respectfully submits its opening brief in the above captioned case. In this phase of the proceeding, the California Public Utilities Commission (CPUC) is assessing the benefits from upgrading Path 15 by adding approximately 1500 MW of transfer capability.

Based on a $300 million cost estimate by Pacific Gas and Electric Company (PG&E), the CA ISO strongly believes that the Path 15 upgrade should be undertaken in order to support a workably competitive wholesale electricity market.[1] First, the CA ISO considers that, given the experience of the California electricity markets over the past two years, and the severe and rapid manner in which the exercise of market power can destabilize the wholesale electricity markets and cause significant consumer harm, it is imperative that aggressive progress be made on all the key fronts that affect the ability of suppliers to exercise market power. Key actions include putting into place the necessary transmission infrastructure, assuring adequate supplies, developing demand response, and putting into place adequate long-term contracts. Each of these actions is important and has been adopted by the CA ISO as part of its ongoing Market Design 2002 effort. Moreover, each of these actions taken alone is less likely to be effective than a comprehensive approach. Accordingly, there should be an aggressive effort to pursue all actions needed to support a workably competitive market. Further, the CA ISO considers that it would be risky and short-sighted to rely, on an on-going basis, on effective regulatory intervention and price mitigation by the Federal Energy Regulatory Commission (FERC) as an alternative to a

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[1] Although the Path 15 upgrade has not been presented to the CA ISO Governing Board, the position of the CA ISO as set forth in its testimony was shared with the Governing Board on September 30, 2001. Exh. 200, Testimony of Perez, Greenleaf and Casey, at 4: 24. The Path 15 upgrade has not be presented to the CA ISO Governing Board because the details and technical specifications of the project are not yet final. Tr. (Greenleaf) at 535: 27-28; at 536:1-6.

comprehensive effort to put into place the structural elements necessary to support a competitive market. As the CA ISO has stated repeatedly, collective and timely action by state and federal policymakers is necessary if California is to remedy identified problems in the electricity markets.

Second, although the market power mitigation benefits are sensitive to a number of key factors, the record indicates that under the scenario that is currently most plausible, a $300 million Path 15 upgrade cost could easily be recovered within four years, even after reducing the benefits in the most likely scenario by 25% to account for the uncertainty associated with the key parameters and biases in the analysis. The CA ISO has revised its initial conclusions about the most realistic scenario: in the case of its assessment of new generation development in California, based on new information; and in the case of assumptions about the availability in 2005 of capacity subject to Existing Transmission Contracts (ETCs) and the level of protection afforded by the California Department of Water Resources' (CDWR) long term electricity contracts, based on a more accurate assessment of these factors developed during the course of the hearings. These revisions further highlight the potential benefits of a Path 15 upgrade.

Finally, the CA ISO notes that in less likely, but still possible scenarios, the benefits of the upgrade exceed the entire upgrade cost in one year; or put another way, the cost to consumers of not upgrading Path 15 could be very substantial; whereas the maximum total cost to consumers of going forward with the upgrade is the upgrade cost. Thus, the risks of not upgrading the Path versus the risks of going forward are far from symmetrical.

In sum, the CA ISO considers that upgrading Path 15 is an important component to support a workably competitive wholesale electricity market, and well worth the $300 million estimated project cost.

II. THE PATH 15 UPGRADE IS ONE OF SEVERAL KEY STRUCTURAL ELEMENTS THAT SHOULD BE PUT INTO PLACE TO SUPPORT A WORKABLY COMPETITIVE MARKET.

The CA ISO supports upgrading Path 15, as one of several key structural elements to create a workably competitive wholesale electricity market. An underlying theme that has emerged in this proceeding is whether a transmission project of the magnitude of the Path 15 upgrade should be undertaken primarily to reduce the ability of suppliers to exercise market power, and support a workably competitive wholesale market. The CA ISO considers that the answer to this question is a firm "yes" for a number of reasons:

- It is risky to rely on a continued effective market power mitigation program on the part of FERC in lieu of correcting the structural deficiencies that enable suppliers to exercise market power.
- To adequately mitigate the ability of suppliers to exercise market power, actions to correct all the key structural deficiencies in the market should be pursued aggressively, as an exclusive focus on one or another of the structural deficiencies is unlikely to be as effective as a combination of strategies.
- The Path 15 upgrade would address a constraint in the backbone transmission system with statewide and regional significance.

As stated by witness Casey, the CA ISO acknowledges that in determining what actions to take to mitigate market power, it is appropriate to review the market power benefits of the actions versus their cost. Tr. (Casey) at 557: 24-28; at 558: 1-10. The issue of benefit-cost is reviewed in the following section. As a general matter, however, as described in further detail below, the CA ISO strongly believes that the addition of critical transmission infrastructure, such as upgrading Path 15, is among the key strategies that should be assessed and, where cost-effective, undertaken to mitigate the ability of suppliers to exercise market power and to provide the structural framework for a workably competitive wholesale electricity market.

A. It is Risky to rely on Continued FERC Effective Market Power Mitigation Programs Without Taking Steps to Address Structural Market Deficiencies.

The Office of Ratepayer Advocates (ORA) has questioned the value of upgrading Path 15 to mitigate the ability of suppliers to exercise market power, arguing that, absent the State undertaking the structural changes within its purview that are necessary to support a workably competitive wholesale electricity market, FERC will maintain in place the market power mitigation mechanisms necessary to prevent suppliers from exercising market power. Exh. 217, ORA Report on Path 15, at 10: 1-10. As an initial matter, it is important to recognize that FERC has indicated clearly that it remains committed to the objective of a competitive wholesale electricity market. Exh. 202, Rebuttal Testimony of Perez, Greenleaf and Casey, at 5: 5-6. In this context, the CA ISO believes that an approach on the part of the CPUC to eschew structural changes that support a workably competitive wholesale electricity market relying instead on FERC to maintain effective market power mitigation measures would be short sighted and highly risky.

In Spring and Summer 2001, after much prodding from California state agencies and the CA ISO, FERC instituted a package of market power mitigation measures that were extended to cover the entire West. See 95 FERC ¶ 61,115 and 95 FERC ¶ 61,418. In adopting the package, FERC stressed that the measures are temporary in nature; are intended to give time to California to put into place structural improvements that will support a workably competitive electricity market; and will expire on September 30, 2002. Exh. 202, Rebuttal Testimony of Perez, Greenleaf and Casey, at 4: 5-28, at 5:1-4. In an April 26, 2001 order, FERC stated explicitly:

"Reliance on mitigation should not supplant or slow down efforts to add generation as well as to develop more effective market mechanisms, and terminating this mitigation plan in a year will help ensure that all parties work to achieve these goals." 95 FERC ¶ 61,115 (slip op.) at 25.

Since issuing these market power mitigation orders, FERC has continued to insist that the current market power mitigation measures will expire on September 30, 2002. For example, on December 19, 2001, FERC once again denied requests for rehearing of the September 30, 2002 sunset date for the mitigation measures, 97 FERC ¶ 61,275 (slip op.) at 61-62; Exh. 220, and ordered the CA ISO to incorporate the September 30, 2002 termination date into its Tariff, 97 FERC ¶ 61,293 (slip op.) at 23; Exh. 220. In addition, as recently as mid-February, FERC Chairman Wood indicated that it was his position that the mitigation measures should terminate on September 30, 2002, since the State had been given ample opportunity during the years in which the measures were in effect, to reduce both the infrastructure and market design deficiencies that exist in California. Tr. (Greenleaf) at 565: 2-11.

Thus, a rejection of the Path 15 upgrade relying on FERC to indefinitely maintain effective market power mitigation measures would be contrary to FERC's explicitly articulated intent. Such a strategy would be highly risky and could in one year cost consumers far more than upgrading Path 15.

In its market redesign program, the CA ISO intends to propose a further package of market power mitigation measures to FERC to take the place of the current broad West-wide program. Exh. 228, Third Quarterly Report of the CA ISO, at 98. However, there is significant resistance on the part of other entities in the West, to an on-going West-wide mitigation approach, and FERC, which has been pressured by these entities, has indicated clearly that the current West-wide approach will terminate on September 30, 2002. Tr. (Casey) at 775: 1-28; at 776: 1-24. If after September 30, 2002, mitigation measures are once more limited to California, their efficacy will likely diminish significantly. Id. California depends on the broader regional market for imports, and without a West-wide mitigation program in-state suppliers can sell to the Southwest or Northwest to avoid mitigation measures that are in effect only in California. Id. Thus, an effective market power mitigation approach requires a program that is West-wide in its application, but West-wide application is unlikely to survive beyond September 30, 2002. Tr. (Casey) at 775: 1-28; at 776: 1-24.

In sum, it is highly risky to rely on existing market power mitigation measures to prevent the exercise of market power by suppliers in the long-term. FERC has clearly and repeatedly indicated that the current package of measures will expire on September 30, 2002, and has been subject to significant pressure by Western entities to eliminate the current West-wide approach. While even the current package of measures has not fully eliminated the ability of suppliers to exercise market power, see Exh. 228, Third Quarterly Report of the CA ISO, at 26-30, a California only approach would be much less effective. Tr. (Casey) at 775: 1-28; at 776: 1-24.

B. Action Should be Pursued to Address All the Key Structural Deficiencies That Permit Suppliers to Exercise Market Power.

The CA ISO supports aggressive action to redress all the key structural deficiencies that allow suppliers to exercise market power. The record is clear that while a Path 15 upgrade would significantly reduce that ability, it will not on its own eliminate the ability of suppliers to exercise market power. There is no evidence to suggest that other strategies would be completely successful individually either, particularly as each of the alternative strategies to reduce market power has its own benefit-cost limitations. Rather, the record illustrates how actions taken in concert can support and complement each other. Thus, to correct the significant market power problems that have existed in California over the past few years, a concerted, multi-pronged effort is required.

The key components of a multi-pronged effort to reduce the ability of suppliers to exercise market power, in addition to providing for adequate transmission infrastructure, were listed by CA ISO witness Casey at various times during the hearings. They include: increasing demand responsiveness, improving supply adequacy (keeping in mind the concentration of market share by particular suppliers); and encouraging utilities to enter into long-term contracts for supply. Tr. (Casey) at 581: 19-28; at 582: 1-14; at 769: 12-28; at 770: 1-17.

The CA ISO's Department of Market Analysis (DMA) study of the benefits of a Path 15 upgrade, "Potential Economic Benefits to California Load from Expanding Path 15 -- Year 2005 Prospect", Exh. 201, Attachment 4 (DMA study) indicates the level of market power that would exist with and without the Path 15 upgrade in a number of scenarios. The DMA study shows that while upgrading Path 15 will significantly reduce the ability of suppliers to exercise market power in all cases, the upgrade will not, in itself, entirely eliminate the ability of suppliers to exercise market power in any case. Exh. 201, Attachment 4, Tables 3 and 4, lines A and B; Tr. (Casey) at 769: 1-8. There is no evidence to suggest that the other measures available to address structural deficiencies in the market would, in isolation, cost-effectively eliminate all ability on the part of suppliers to exercise market power.

In fact, although there is no discussion of the relative benefits and costs of alternatives to reduce supplier market power[2], it is reasonable to conclude that each alternative has associated costs that would limit the extent to which it could be used cost-effectively to mitigate the ability of suppliers to exercise market power. For example, demand responsiveness has costs associated with the customer behavioral changes that are required; long-term contracting can have costs

[2] In its responses to CA ISO data requests, ORA witness Scott Logan listed ongoing FERC mitigation measures as low cost alternatives to transmission upgrades to curb market power, although he could not quantify the costs of these "low cost measures". Exh. 218, ORA Responses to CA ISO DR, Answer to Question 14. The risks associated with relying on FERC action are described in section II, A above. Mr. Logan did not address any other "low cost" measures.

both in terms of the risk of locking in a price that over time proves to be uneconomical and locking in the effect of market power if these effects are prevalent at the time the contracts are signed; new generation development also has associated costs, particularly if significant excess capacity is required to mitigate the market power of a supplier that already controls a significant proportion of available supplies.

While the record does not explore the benefit-cost of alternatives, it does illustrate how, undertaken in concert, these measures can be more successful than in individual application. For example, CA ISO witness Casey explained that long-term contracts ultimately reduce the ability and incentive of suppliers to exercise market power by reducing 1) the level of load exposed to short term price volatility and 2) the benefit suppliers obtain from exercising market power. Tr. (Casey) at 769: 24-28; at 770: 1-17. However, Mr. Casey explained that, if conditions prevail in which suppliers know they can exercise market power, and believe they will continue to be able to do so, these circumstances will be factored into the negotiations for the long-term contracts, and the long-term contract prices will themselves reflect market power. Tr. (Casey) at 598: 16-28; at 599: 1-2. If suppliers are aware however, that steps are underway that will reduce their ability to exercise market power, such as the expansion of transmission capacity or programs to increase demand response, these circumstances too will be factored in the contract negotiations and the contracts are more likely to reflect reasonable prices. Thus, different strategies applied in concert can have a complementary effect.

In sum, there is no evidence in the record that any of the alternatives available to address structural deficiencies that permit suppliers to exercise market power would be cost-effective to the exclusion of other strategies in single-handedly creating a workably competitive market in California. Rather, a concerted, multi-pronged effort that includes upgrading Path 15 should be pursued.

C. The Path 15 Upgrade Would Address a Constraint in the Backbone Transmission System with Statewide and Regional Significance.

In the face of the extreme distortions in the California and Western electricity markets during the past year and a half, policy-makers at the state and federal level have begun to focus on the need for a robust transmission system to support a reliable, workably competitive wholesale electricity market. Exh. 200, Testimony of Perez, Greenleaf and Casey, at 18: 1-15. For example, the California Legislature in AB 970 charged the CPUC and the CA ISO to work together to "[i]dentify and undertake those actions necessary to reduce or remove constraints on the state's existing electrical transmission ... system" and to "give first priority to those geographical regions where congestion reduces or impedes electrical transmission and supply." California Public Utilities Code §399.15. To support these objectives, the CA ISO has begun developing a vision of an adequate 500 kV backbone transmission system. Exh. 200, Testimony of Perez, Greenleaf and Casey, at 19: 10-11. Upgrading Path 15 is one of the highest priority projects in that plan. Exh. 200, Testimony of Perez, Greenleaf and Casey, at 19: 11-12.

Path 15 does now, and has historically, played a major role in the seasonal exchanges that take place between Northern and Southern California and California and the Pacific Northwest. Exh. 200, Testimony of Perez, Greenleaf and Casey, at 3: 9-10. The Path supports seasonal exchanges of thermal and hydro generation, with power typically flowing from south to north during late summer through winter periods to enable northern hydroelectric resources to restock and conserve their water suppliers for critical peak periods. Exh. 200, Testimony of Perez, Greenleaf and Casey, 3: 10-16. Because Path 15 has often been limited by its operating capacity, it has been, since the commencement of CA ISO operations, an Inter-Zonal Interface, and hence transmission customers that submit schedules over Path 15 must pay a usage charge to use the scarce capacity available. Exh. 200, Testimony of Perez, Greenleaf and Casey, 3: 17-24. Thus, Path 15 can be considered a significant backbone transmission constraint that can affect the operation of the competitive market on a statewide and even regional basis. See Exh. 202, Rebuttal Testimony of Perez, Greenleaf and Casey, at 5: 18-19.

The CA ISO recognizes that in addressing market power concerns, a balance must be struck between regulatory intervention and adding transmission infrastructure, as it would be uneconomic to upgrade the transmission system to address all cases and all levels of market power. Exh. 202, Rebuttal Testimony of Perez, Greenleaf and Casey, at 5: 18-19. For example, the CA ISO has supported limited, on-going mechanisms such as the Reliability Must Run contracts to address transmission constraints that are local in nature. Exh. 202, Rebuttal Testimony of Perez, Greenleaf and Casey, at 5: 10-17. In the case of a significant regional constraint such as Path 15, however, broad on-going, market-wide mitigation would be necessary to address market power concerns. Exh. 202, Rebuttal Testimony of Perez, Greenleaf and Casey, at 5: 22-25. Therefore, in the case of a significant statewide and regional constraint like Path 15, an upgrade that would significantly reduce market power concerns is more prudent than relying on on-going and prevalent regulatory intervention in the market. Id.

Moreover, and for similar reasons, in the case of transmission projects of the magnitude, and state and regional significance of the Path 15 upgrade, relying on generation alternatives can be problematic. As Mr. Greenleaf explained on the stand, it is difficult to rely on generation alternatives because there is no assurance that they will be there when needed, since the availability of generation depends on market signals. Tr. (Greenleaf) at 608: 23-26. Further, a "tremendous" level of generation is required to obtain the benefits of a Path 15 upgrade. This is particularly true as to market power mitigation benefits since a limited amount of generation built as an "alternative" to the upgrade could be in a position to exercise market power. Tr. (Greenleaf) at 608: 15-28; at 609: 1-12.

In sum, upgrading Path 15 to reduce market power is appropriate because Path 15 is a significant state and regional path for important electricity transfers, and the alternative would be ongoing broad and pervasive regulatory intervention in the market.

III. UPGRADING PATH 15 IS VERY COST EFFECTIVE IN THE MOST LIKELY SCENARIO AND PROVIDES INSURANCE AGAINST THE CONSEQUENCES OF EXTREME SCENARIOS.

The record in this proceeding demonstrates that the Path 15 upgrade is very cost effective in the most likely scenario; the costs of the upgrade could be recovered within four years. Even deducting 25% from the projected benefits to account for substantial uncertainty associated with a number of key factors and biases in the analysis, the project costs can be recovered within four years. The record demonstrates that the upgrade also provides substantial insurance against the risk of potentially very high costs in less likely scenarios, while negative risks are capped at the relatively modest project cost of $300 million. In these circumstances, the CA ISO considers that the record provides strong justification for going forward with the upgrade.

A. The Methodology Used by the CA ISO to Assess the Benefits of Upgrading Path 15 While Innovative is Well Founded and Adequately Validated.

The CA ISO's evaluation of the benefits of upgrading Path 15 in terms of reducing market power impacts is one of the first of its kind performed in the United States. Exh. 200, Testimony of Perez, Greenleaf and Casey, at 17: 16-18. Accordingly, there were questions during the hearings about the legitimacy of the methodology used. The CA ISO is currently engaged in an exercise with the California investor-owned utilities and relevant California state agencies to develop a methodology to assess the economic benefits of proposed transmission upgrades. Exh. 200, Testimony of Perez, Greenleaf and Casey, at 17: 20-22. This methodology was not developed in time for the CA ISO to perform its Path 15 assessment. Nonetheless, the

CA ISO considers that the methodology used to assess the market power benefits of a Path 15 upgrade is sound, founded on a solid theoretical basis, and validated by the statistical relationship demonstrated between the key parameters, and its ability to accurately predict prices, except in highly anomalous situations.

The methodology employed to assess the market power benefits of the Path 15 upgrade uses the relationship between a Residual Supply Index (RSI), system load and Lerner Indices to predict the percent that suppliers will be able to increase prices above the prices that would exist in a competitive market. Exh. 201, Testimony of Casey and Willis, at 9: 16-26; Tr. (Casey) at 676-680. The methodology is based on a supply function equilibrium methodology used by Green and Newbery in an economic model of the England and Wales electricity market, and confirmed in competitive electricity markets around the world, including the New England electricity market, and the PJM electricity market. Exh. 206, CA ISO Response to Energy Division DR, Answer to Question 1. The methodology has been applied to the California electricity markets by key academics such as Borenstein, Bushnell, Wolak, Joskow and Kahn. Id. A similar but simplified methodology, the Supply Margin Assessment methodology, was proposed by FERC in a November 20, 2001 Order. Id.

A regression analysis undertaken for the DMA study established that there is a strong statistical relationship between Lerner Indices, RSIs and CA ISO system loads. Exh. 221, Further Testimony of Keith Casey, at 2: 10-16. The results of this regression analysis are set forth in Table 2, Exh. 201, Attachment 4. These results indicate that there is a statistically significant relationship between RSI, system load and Lerner Indices in all four periods studied, with the one exception: system loads were not a statistically significant explanatory variable for Lerner Indices during the Off Peak Season Peak hours. Tr. (Casey) at 908: 27-28; at 909: 1-9.

At the request of the judge, the CA ISO undertook an exercise to further validate the statistical relationship between Lerner Indices, RSIs and CA ISO system loads. Using data from two different time periods, the CA ISO used the Lerner Index regression estimates established in the DMA study to estimate prices, and compared the estimated prices to the actual prices. The two time periods used were the year 2001, and the period between November 1998 to October 1999. This exercise further validated the methodology used by the CA ISO to estimate the market power benefits from upgrading Path 15.

In the validation exercise using the period between November 1998 to October 1999, predicted prices closely matched actual prices for 9 of the 12 months assessed (November 1998, January 1999 through July 1999 and September 1999). Exh. 221, Further Testimony of Keith Casey, at 7: Figure 3. Only in three months, December 1998, August 1999 and October 1999, were results appreciably different. Id. Given the numerous factors that could be expected to affect the ability of suppliers to exercise market power, in addition to RSIs and system load, these results provide a very strong validation of the methodology used by the CA ISO to assess the market power benefits of upgrading Path 15. Exh. 221, Further Testimony of Keith Casey, at 7: 18-21.

In the validation exercise using year 2001 data, there was far more variation between predicted prices and actual prices than in the exercise for the November 1998 to October 1999 period. This result, however, is not surprising. Even before undertaking the validation exercise requested by the judge, CA ISO witness Casey testified that he had concerns about using 2001 data for validation purposes due to a number of anomalous conditions that year. Tr. (Casey) at 623: 17-28; at 624: 1-7. Mr. Casey's concerns were borne out by the 2001 analysis, since the actual price-cost markups significantly exceeded predicted price-cost markups January through May, and were significantly below predicted price-cost markups in June through August. Exh.

221, Further Testimony of Keith Casey, at 4: Figure 1. However, there are a number of clearly identifiable factors that help explain the anomalies.

First, the market was in disarray in the first half of 2001 because the California Power Exchange ceased operations, it took some time for the California Energy Resource Scheduler (CERS), the scheduler for CDWR, to assume the role of purchasing on behalf of two of California's utilities, and natural gas prices were unprecedently high. Exh. 221, Further Testimony of Keith Casey, at 5: 19-25; Tr. (Casey) at 940-943. None of these conditions is likely to recur. Id. In the second half of the year, price-cost markups lower than expected can be explained by sales of excess power on the part of CERS and the imposition of an increasingly more stringent package of market power mitigation measures by FERC starting in April. Exh. 221, Further Testimony of Keith Casey, at 5: 26-28; at 6: 1-21.

In sum, the methodology used by the CA ISO to assess the benefits of upgrading Path 15, while innovative, has a sound theoretical basis and has significant empirical validation.

B. Upgrading Path 15 is Highly Cost-Effective in the Most Likely Scenario.

The judge asked the parties to indicate in their briefs a reasonable range of benefits that would result from the Path 15 upgrade. The CA ISO considers that using reasonable assumptions, the estimated $300 million cost of the Path 15 upgrade could be easily be recovered in four years. Based on the record that has been developed, the CA ISO's initial view of how some of the key factors should be assessed has changed; resulting in even higher benefits from the upgrade than initially projected. In light of the record, the CA ISO considers that there is a very strong basis for going forward with the upgrade.

The CA ISO's assessment of each of the key assumptions is discussed below. The discussion below also addresses biases that result in under and over estimates of the benefits. Because there are biases that operate in either direction, and because it is not possible to quantify these biases, the CA ISO believes that it is appropriate to rely on the outcome of the assessment without a quantitative modification. Instead to acknowledge that there are significant uncertainties associated with the key parameters, and biases that have not been quantified, the CA ISO believes it is appropriate to consider a range of benefits applying a plus or minus 25% factor to the results in the most likely scenario. The results of this exercise are set forth in section III, B, 6, below.

1. It is reasonable to assume that a one in ten year drought will continue to take place every one in ten years.

The CA ISO considers that it is reasonable to assume that a one in ten year drought will continue to occur at least once every ten years. See Exh. 200, Testimony of Perez, Greenleaf and Casey, at 9: 9-14. There does not appear to be much controversy about this assumption. Rather, there were questions about the CA ISO's four year scenario that assumed one drought year and three normal years. This scenario was premised on the fact that droughts do occur in California with a one-in-ten years frequency, and that accordingly a drought could easily occur within a few years of a Path 15 upgrade. In any event, the revised benefits figures indicate that the upgrade could pay for itself within four normal hydro years.

Further, it is worth pointing out, as Mr. Casey testified, that a one-in-ten year drought probability does not preclude a sequence of more than one dry year in a row, even though a drought of equal severity two years in a row would not be expected. Tr. (Casey) at 561: 9-18. Since benefits are particularly high in drought years, the upgrade could also serve as insurance against the ability of suppliers to exercise a high degree of market power in consecutive dry years.

2. The CA ISO's initial assumption of continued unavailability in 2005 of 50% of ETC capacity reserved in 2000is unduly pessimistic; 29% is a more reasonable number.

The record indicates that it is unduly pessimistic to assume, as the CA ISO did in its opening testimony, that in 2005, 50% of the capacity subject to ETCs that was reserved in 2000 would remain unavailable and unused in the forward electricity markets in 2005. Instead, the CA ISO concedes that 29% would be a better number. The rationale and effect of this change follow.

Before describing CA ISO's view about appropriate ETC assumptions, it is important to describe ETCs, the problems they create for the CA ISO, why these are likely to persist in 2005, and how the CA ISO modeled ETC capacity in the DMA study. ETCs are transmission contracts between certain parties and Participating Transmission Owners (Participating TOs) that were in effect at the time the CA ISO began operations on March 31, 1998. FERC required the CA ISO and Participating TOs to honor these contracts. Exh. 200, Testimony of Perez, Greenleaf and Casey, at 9: 17-19.

Many of these contracts allow ETC rights-holders to schedule up to 20 minutes prior to transaction times. Exh. 200, Testimony of Perez, Greenleaf and Casey, at 9: 18-20; Exh. 206, CA ISO's Response to Energy Division DR, Answer to Question 8. (In fact, all ETC contracts over Path 15 allow for scheduling up to 20 minutes before the Trading hour. Exh. 222, March 21 Response of CA ISO to Certain Questions of Judge Gottstein, Answer to Question 1; Tr. (Le Vine) at 848: 20-28; at 849: 5.) In contrast, the CA ISO scheduling procedures require that Market Participants submit their schedules in the Day-Ahead scheduling process, by 10:00 A.M. on the day before the operating day, or in the Hour-Ahead scheduling process, two hours prior to the operating hour. Exh. 206, CA ISO Response to Energy Division DR, Answer to Question 8. The CA ISO's congestion management process calculates applicable congestion charges that are applied in the Day-Ahead process, with an ability on the part of Market Participants to amend their schedules to avoid Congestion Charges, and in the Hour-Ahead process, with no further ability to make scheduling adjustments. Exh. 206, CA ISO Response to Energy Division DR, Answer to Question 8.

Generally, to reconcile these timelines, the CA ISO reserves the capacity subject to ETCs for ETC rights-holders in the Day-Ahead and Hour-Ahead scheduling processes. See Exh. 206, CA ISO Response to Energy Division DR, Answer to Question 8. However, in the case of Path 15, the process is a little bit different. Pursuant to a February 1999 agreement negotiated in response to a FERC Order, in the case of ETC capacity over Path 15, PG&E conveys to the CA ISO an ETC reservation amount by 8:30 A.M. of each weekday prior to the start of a Trading Day, which can be revised by PG&E by 4:30 PM of the weekday prior to the start of the Trading Day. Exh. 222, March 21 Response of CA ISO to Certain Questions of Judge Gottstein, Answer to Question 1. PG&E determines the reservation amount based on prescheduled amounts submitted to PG&E by some of the ETC rights-holders, on the previous day's schedules and on PG&E's view of the capacity that will be used by such ETC rights-holders, with an additional amount of margin to ensure that sufficient capacity is available to ETC rights-holder that wish to modify their pre-scheduled use. Id. (While the reservation amount can be decreased, it cannot be increased. Tr. (Casey) at 21-24. Thus, in the case of Path 15, the amount of ETC capacity that the CA ISO makes unavailable in the Day-Ahead and Hour-Ahead scheduling processes is not the full ETC capacity but rather the ETC capacity reserved by PG&E and Southern California Edison. Exh. 222, March 21 Response of CA ISO to Certain Questions of Judge Gottstein, Answer to Question 1.

As a result of the scheduling times-lines described above, there has been ETC capacity that was set aside for use by the ETC rights-holder that is never used in the forward electricity markets, even by the ETC rights-holders. Exh. 200, Testimony of Perez, Greenleaf and Casey, at 9: 27-28; at 10: 1-2.

Whether it is reasonable to assume that ETC capacity will continue to be underutilized in forward electricity markets in 2005 is the seminal question in determining appropriate ETC capacity assumptions for purposes of analyzing the Path 15 upgrade. The CA ISO considers that it is reasonable to make this assumption. As noted in the CA ISO rebuttal testimony, the CA ISO has advocated and will continue to advocate before FERC for adoption of a mechanism to make available in the forward electricity markets unused transmission capacity subject to ETCs; however, notwithstanding these efforts, the ETC problem has persisted since startup. Exh. 202, Rebuttal Testimony of Perez, Greenleaf and Casey, at 7: 23-28. Mr. Greenleaf explained that ETC rights-holders consider their flexible scheduling rights to have considerable value. Tr. (Greenleaf) at 642: 9-11. Further, Mr. Greenleaf testified that the New York Independent System Operator, which also faces ETC related problems, has not been able to resolve the problems even after five years of negotiations and litigation. Tr. (Greenleaf) at 668: 18-24. In fact, after initially minimizing the ETC problem, even ORA witness Scott Logan recognized that there are more ETC arrangements than he suspected when writing his testimony, and that it is difficult for the CA ISO to, as Mr. Logan characterized it, do battle with the ETC rights-holders. Tr. (Logan) at 831: 5-20.

In sum, the record supports the view that it would be optimistic to merely assume that there will be no further ETC related issues in 2005, particularly as two ETC contracts associated with Path 15, the CDWR Comprehensive Agreement and TANC SOTP Contract, extend beyond 2005 and well into the future. Exh. 222, March 21 Response of CA ISO to Certain Questions of Judge Gottstein, Answer to Question 1. The question then becomes what is a reasonable assumption about the magnitude of the underutilized ETC problem in 2005.

In the DMA study, the CA ISO provided two possible "bookends" for the ETC capacity use spectrum:

- in cases labeled "including ETC" in tables 3 and 4 of Exh. 201, Attachment 4, the CA ISO assumed that all ETC capacity would be available to the market during all time frames in 2005 (TTC scenario). Exh. 222, March 21 Response of CA ISO to Certain Questions of Judge Gottstein, Answer to Question 2.
- in cases labeled "excluding ETC" in tables 3 and 4 of Exh. 201, Attachment 4, the CA ISO assumed, on an hour-by-hour basis, that all of the ETC capacity that was reserved by PG&E and SCE in 2000 would be unavailable and unused in the forward electricity markets in 2005 (ATC scenario). Exh. 222, March 21 Response of CA ISO to Certain Questions of Judge Gottstein, Answer to Question 2.

In its opening testimony, the CA ISO acknowledged that some ETCs that were in effect in 2000 will expire by 2005, and that it is reasonable to assume that some reserved ETC capacity will be used. Exh. 200, Testimony of Perez, Greenleaf and Casey, at 11: 20-28; at 12: 1-2. Accordingly, the CA ISO argued that a reasonable assumption would be that 50% of the ETC capacity reserved in 2000 would remain unavailable and unused in 2005. As the record on ETCs has developed, the CA ISO considers the 50% figure to be unduly elevated and that 29% is a better founded number[3].

In 2000, the following ETCs over Path 15 were in effect: CDWR EHV Agreement (300 MW); SCE CCPIA (580 MWs sold to other entities); CDWR Comprehensive Agreement (810 MW); TANC SOTP (300 MW); SMUD TRS (400MW); TID IA (32MW), for a total of

[3] Technically, in estimating the ATC and TTC values used in the Year 2005 analysis, DMA conducted 100 Monte Carlo draws for each hour from ATC and TTC data for Path 15 for each corresponding month in 2000. Exh. 201, Attachment 4 at 13. However, given that these are random draws, the average ETC usage assumed unavailable for use in the forward markets in 2005 should approximate the average hourly amount of ETC reserved in 2000.

2422MW. Exh. 222, March 21 Response of CA ISO to Certain Questions of Judge Gottstein, Answer to Question 1. In 2000, 45.7% of total ETC capacity over Path 15 was reserved. Thus, on average, the DMA study assumed that 1100 MW of ETC capacity was unavailable for use in the forward markets in 2005[4].

The SMUD TRS contract expired on December 31, 2000. Id. The CDWR EHV Agreement will expire on December 31, 2004. Thus, neither of these agreements which were in place in 2000 will be in place in 2005 and this change should affect the analysis. Moreover, the SCE CCPIA will expire on July, 31, 2007, and although according to PG&E responses to CA ISO queries there is some uncertainty as to whether it can be renewed. The CA ISO concedes that it would be appropriate, absent further information, to assume that the contract will not be in effect after 2007. This results in the elimination in the next five to six years of 1,280 MW of capacity subject to ETC from 2000, leaving a total ETC figure of 1142MW by 2008.

It was established during the hearings that, since final scheduled usage numbers are unavailable, the best information on ETC capacity that is reserved but not used, would be the ETC reservation minus the ETC capacity scheduled in the Hour-Ahead scheduling process. Tr. (Casey) at 955-956. On Path 15, 45.7% of the total ETC capacity was reserved in the Hour-Ahead market in 2000. Of that 45.7% reserved, 38.3% was scheduled, which means that 61.7% of amount reserved was unscheduled in the Hour-Ahead market. Thus, a good proxy for the amount of unavailable and unused ETC in 2005 would be 1142 MW (total remaining ETC capacity over Path 15 in 2005) x 28.2% (45.7%*61.7%), or 322 MW. 322 MW is approximately 29% of 1100 MW, the approximate average hourly amount of ETC capacity that was assumed to be unavailable and unused in 2005 in the DMA study. Thus, extrapolating within the bookends established in the DMA study, the CA ISO would add to the excluding ETC cases, 29% times

[4] 45.7% * 2422 = 1106.9.

the difference between the excluding ETC and including ETC cases to arrive at a reasonable benefits number.

In sum, the problems associated with capacity subject to ETC are real and should not be assumed away. While the CA ISO has tried and will continue to try to reduce the level of capacity that remains unused in forward electricity markets due to ETCs, the record demonstrates that merely assuming that the problem will cease to exist in 2005 would be overly optimistic. However, the CA ISO acknowledges that based on the record, a more appropriate estimate of the ETC capacity that will remain unused in 2005 is 29% of the amount reserved in 2000.

3. A mid-point between the medium and low new generation scenarios is most reasonable.

In its written testimony, the CA ISO testified that a medium new generation scenario was the most reasonable. However, since that time, conditions in the market have changed and a significant number of projects have been cancelled or put on hold. Tr. (Casey) at 655: 7-28; at 656: 1-4; Exh. 228, Third Quarterly Report of the CA ISO, at 62-68. Accordingly, the CA ISO now believes that a medium to low new generation scenario is the most reasonable.

As noted by Mr. Casey, the DMA study is most sensitive to assumptions about new generation development North of Path 15. Tr. (Casey) at 656: 16-22. Accordingly, the assumptions about new generation development North of Path 15 will be discussed first. Three scenarios were modeled for generation North of Path 15: Scenario 1, Scenario 2 and Scenario 3. In Scenario 1 (the medium scenario), the CA ISO assumed that all generating plants approved by the California Energy Commission (CEC) or with approval from the CEC pending, and 291 MW of peakers would be built. In Scenario 2 (the low scenario), the CA ISO assumed that all generating plants approved by the CEC and 291 MW of peakers would be built. In Scenario 3 (the high scenario) the CA ISO assumed that all approved, pending, and announced plants would be built, as well as 291 MW of peakers. Exh. 201, Attachment 3, at 21-22.

In their opening testimony, the CA ISO policy witnesses testified that it is plausible to assume a medium new generation build out in California. Exh. 200, Testimony of Perez, Greenleaf and Casey, at 7: 21-22. On the stand, however, Mr. Casey noted that since the opening testimony was written, his opinion about the most reasonable assumption for new generation had changed. Mr. Casey noted that changes in the economic conditions in California coupled with anecdotal information raise questions about the extent to which pending and announced projects would be built. Mr. Casey noted that he now believes a more plausible scenario to be somewhere between the medium and low generation scenarios. Tr. (Casey) at 727: 4-11.

Mr. Casey's opinion is supported by information in the March 26, 2002, Third Quarterly Report of the CA ISO, Exh. 228. That report indicates that 1) the probability of completing new generation projects that are scheduled to be online by August 2002 and that are only in the permitting or study stage is uncertain; and 2) developers have already cancelled approximately half of the generating projects expected to go online between August and December 2002. Exh. 228, Third Quarterly Report of the CA ISO, at 64-5. The report further indicates as considerations for the likelihood of future new generation development that: 1) in the wake of the Enron bankruptcy, many companies have recently chosen to either delay, place on hold, or withdraw projects to try to strengthen balance sheets and reduce debt loads; 2) credit-rating down-grades due to the Enron bankruptcy, weakening energy prices and poor economic conditions could result in higher costs of capital for new generation and reduce the ability of developers to obtain financing; 3) higher California costs associated with the production of energy could also negatively impact investment decisions. Exh. 228, Third Quarterly Report of the CA ISO, at 66-7. Finally, the report notes that 1,773 MW of planned generation was cancelled in 2001, and 2,888 MW of planned generation has been cancelled so far in 2002. Exh. 228, Third Quarterly Report of the CA ISO, at 68.

In light of these factors, the CA ISO considers that a more likely scenario for new generation in Northern California, is 100% of approved projects, 50% of projects with approval pending and 100% of peaker projects. Since Scenario 1 includes all approved, pending and peaker projects, and Scenario 2 includes all approved and peaker projects, the mid-point between Scenarios 1 and 2 is a reasonable approximation of the revised most plausible new generation scenario. Conversely, the high generation Scenario 3 has become even less likely.

These conclusions are supported by the response of ORA witness Logan to the CA ISO data requests. Asked about the new generating plants ORA expected to be on line in 2005 North of Path 15, Mr. Logan listed four new plants providing a total additional 2970 MW of capacity. Exh. 218, ORA Responses to CA ISO DR, Answer to Question 3. The 2,970 MW figure is still significantly below the LOW generation figure assumed in the DMA study of 4,590 MWs. Further Mr. Logan acknowledged that "what was termed the 'low' generation scenario in September may become the 'medium' scenario in at the present time". Exh. 218, ORA Responses to CA ISO DR, Answer to Question 17.

The same analysis applies in the case of Southern California new generation development. However, in terms of considering the impact of revised new generation assumptions on the likelihood of particular scenarios assessed in the DMA study, it is important to recognize two distinctions with regards to new generation assumptions for North of Path 15 and South of Path 15. First, with regards to new generation South of Path 15, Scenario 1 is the medium generation scenario; Scenario 2 is the high generation scenario and Scenario 3 is the low generation scenario. Exh. 201, Attachment 3, at 22. Second, the South of Path 15 new generation figures are lower than those used in scenarios developed to assess the reliability need for a second link between Southern California and the Southwest (SWPL scenarios), and could thus be argued to somewhat lower than appropriate. See Exh. 222, March 21 Response of CA ISO to Certain Questions of Judge Gottstein, Answer to Question 4.

These two factors combined indicate the following. Scenario 3, the low generation South of Path 15 scenario, may include unduly pessimistic assumptions about new generation development South of Path 15; however Scenario 3 is unlikely in any event because it likely overstates potential new generation development North of Path 15. Scenario 1 (the low SP 15 scenario) is lower than the SWPL middle or low scenarios, and thus arguably unduly low; whereas Scenario 2 (the high SP 15 scenario) is somewhat, but not much, above the SWPL middle scenario, and thus likely overly high. However, the mid-point between Scenarios 1 and 2 would reflect a generation scenario for South of Path 15 between 4,813 MW and 6894 MW ≈ 5,853; this mid-point is not substantially different from the mid-point between the medium and low cases in the SWPL scenarios, 5766 MW (the mid-point between 6487 MW and 5045 MW). Thus, a mid-point between Scenario 1 and Scenario 2 would incorporate a realistic assessment of likely new generation South of Path 15.

As Mr. Casey testified, assumptions about new generation South of Path 15 affect the DMA study only to the extent they affect the competitive base-line price to which any price-cost markup would be applied. Thus, even a significant error in assumptions about new generation South of Path 15 would likely have a small impact on the market power benefits analysis. Tr. (Casey) at 727: 14-28; at 728: 1.   Nonetheless, if South of Path 15 generation is underestimated, the result is that market power benefits may be somewhat overstated, although the impact should be small. Id. The converse is also true. Thus, Scenario 1, which likely understates SP 15 new generation, likely overstates market power benefits, and Scenario 2, which likely overstates new generation, likely slightly understates market power benefits. In a case taking the mid-point benefits between these cases, these errors would likely cancel out.

In sum, because new information suggests that projections of new generation should be reduced downward, the CA ISO considers the more reasonable assumption to be that new generation development would be a mid-point between Scenarios 1 and 2 for both North of Path 15 and South of Path 15.

<u>4. The record supports a scenario in which half the State long term contracts are considered to reduce the impacts of supplier market power.</u>

The CA ISO has acknowledged that to the extent that utility customer load can be met through existing long-term power contracts, this load would be shielded from the effects of supplier market power. Accordingly, in assessing the market power benefits of a Path 15 upgrade, the CA ISO assessed two set of cases, one which assumed the ongoing existence of the long term contracts negotiated by CDWR on behalf of utility customers, and one that excluded these contracts.

In its opening testimony, the CA ISO listed as the most reasonable case, one in which 100% of the existing CDWR contracts remain in effect in 2005; and assumed that all load backed by such contracts would be shielded from the exercise of market power. Exh. 200, Testimony of Perez, Greenleaf and Casey, at 7. Given further development of the record, the CA ISO now believes that it is unduly optimistic to consider that 100% of the load that can be met by existing CDWR contracts will be shielded from supplier market power, since over 50% of these contracts are not firm in 2005. Accordingly, the CA ISO considers a more plausible scenario to be one in which only 50% of the load subject to CDWR long-term contracts is shielded from the ability of suppliers to exercise market power.

In its opening testimony, the CA ISO acknowledged that it is plausible to assume that 100% of the CDWR contracts would remain in effect and mitigate the ability of suppliers to exercise market power in 2005. Exh. 200, Testimony of Perez, Greenleaf and Casey, at 7: 19-27. The CA ISO also noted that the Path 15 upgrade would provide insurance against the possibility that some of the existing CDWR contracts could be modified or cancelled prior to 2005, since in such scenarios the upgrade benefits would be even more substantial. Exh. 200, Testimony of Perez, Greenleaf and Casey, at 12: 16-21. The CA ISO noted that if the contract prices are deemed to be higher than prevailing market prices over the next few years, the State may seek to terminate or renegotiate the terms of the contracts. Id.

As the record has developed, the CA ISO considers that assuming that 100% of load covered by the CDWR contracts would be shielded from the impacts of supplier market power is unduly optimistic. During the hearings, Mr. Casey explained that non-firm contracts provide less protection against the exercise of market power than firm contracts. Tr. (Casey) at 912: 2-21. The shortcomings of non-firm, non-dispatchable long-term contracts in shielding load from supplier market power are discussed in further detail in the CA ISO's March 26, 2002 quarterly report, Exh. 228, Third Quarterly Report of the CA ISO, at 90-96. Nonetheless, when it calculated the MW of load subject to CDWR contracts in 2005, for cases "Including Long-term Contracts" (Table 4 of Exh. 201, Attachment 4), the CA ISO included all CDWR contracts, including firm and non-firm contracts. This can be confirmed by reviewing Exh. 225, Summary of Long-term Contracts in 2002, which sets forth the MWs subject to CDWR contracts that were assumed DMA study, and comparing the numbers to Exh. 228, Third Quarterly Report of the CA ISO, at 92, figure 24, which sets forth year by year the MW of CDWR contracts through 2014.

Exh. 228, Third Quarterly Report of the CA ISO, at 92, Figure 24 illustrates that in 2005, at least 50% of the MWs available from the CDWR contracts are both non-firm and non-dispatchable, and a further 10% of the MWs available from the CDWR contracts are non-firm but dispatchable. Exh. 228, Third Quarterly Report of the CA ISO, at 92, Figure 24. Since non-firm contracts do not provide the same level of protection against the exercise of market power as firm contracts, the CA ISO considers that it is more reasonable to assume that loads equal to 50% of the MWs available under the CDWR contracts would be shielded from market power impacts in 2005.

Suggestions have been made that the existing long-term contract coverage for load could be improved in the CPUC's proceeding relating to utility procurement. Some may argue that the DMA study overstates the harm from the exercise of market power to load (and hence the benefits of the upgrade) because it neglects to account for subsequent long-term contracts between utilities and suppliers. Nonetheless, the CA ISO considers it appropriate in determining the impacts of market power in 2005, to consider the long-term contracts that are in effect now. This is because although long-term contracts reduce the load subject to further market power once they are in place, they can themselves reflect market power if suppliers can predict that they will be able to exert market power in the future. Tr. (Casey) at 598: 20-28.

This effect can be reduced if utilities negotiate long-term contracts several years in advance, particularly to the extent suppliers are uncertain about the extent to which they will be able to exercise market power in the future. Tr. (Casey) at 600: 6-23. Thus a comprehensive strategy to address market power concerns can be more effective than relying on one strategy alone. As discussed earlier, utilities may be able to obtain better long-term contracts, if suppliers understand that Path 15 will be upgraded and their ability to exercise market power in the future reduced.

In sum, the CA ISO considers that in assessing the market power benefits of a Path 15 upgrade it is most plausible to assume that 50% of the load covered by CDWR contracts will be shielded from the exercise of market power in 2005.

5. Additional biases in the analysis do not justify a departure from the study results.

In determining a reasonable range of benefits from the Path 15 upgrade it is appropriate to review factors in the analysis that may have biased the results to either overstate or understate the benefits of the upgrade. The CA ISO acknowledges that there are such factors and will discuss each such factor below. However, for a number of reasons, the CA ISO considers that these factors do not provide an adequate basis to revise the estimate of benefits. First, as will be illustrated below, there are factors that would result in both slight over and understatements of the Path 15 upgrade benefits. Second, there is little quantitative information on the record as to the potential magnitude of the biases relative to each other.

Without more precise information, there is no basis to conclude that the estimated benefits numbers should be revised. Rather, a plus or minus 25% factor can be applied to the benefits in the most likely scenario to capture the uncertainty associated with key parameters and the lack of quantitative information on the biases discussed below. The CA ISO notes moreover, that significant additional work to quantify the likely impact of the bias factors is unlikely to be productive, since further precision on some of these more subtle influences would likely be outweighed by the level of uncertainty associated with the key factors that have been quantified.

a. Factors that result in an understatement of upgrade benefits in the DMA study.

- The DMA study does not quantify or consider the market power benefits South of Path 15. As Mr. Casey testified, the addition of transfer capability reduces the ability of suppliers North and South of Path 15 to exercise market power. Tr. (Casey) at 662: 5-12; Exh. 221, Further Testimony of Keith Casey, at 8-10. Nonetheless, the DMA study does not quantify the benefits to load in Southern California from the reduction in the ability of suppliers to exercise market power South of Path 15. Tr. (Casey) at 662: 5-12. This omission results in an understatement of the Path 15 upgrade benefits to California consumers.

- The DMA study assumed that the proportion of operational transfer capability (OTC) to total transfer capability (TTC) that was in place in 2000 would be the same in the case of an upgrade to Path 15 in 2005. That is, in 2005 there would be the same level of OTC as in 2000 for the existing transfer capability, and the proportion of OTC to TTC for added transfer capability from the Path 15 upgrade would be the same as the proportion of OTC to TTC in 2000. Exh. 222, March 21 Response of CA ISO to Certain Questions of Judge Gottstein, Answer to Question 2. This assumption is incorrect.

There is a simultaneous interaction between Path 15 and West of Borah that is expressed in a nomogram. Exh. 214, PG&E's Opening Testimony, Tab 6 at 4. The current interaction is described in the nomograms that comprise Exhibit 226. On the stand, Mr. Perez explained that a Path 15 upgrade would affect the simultaneous interaction between Path 15 and West of Borah and decrease the extent to which Path 15 transfer capability would have to be reduced due to interactions with West of Borah. Tr. (Perez) at 884: 12-20. Thus, OTC would increase proportional to TTC after a Path 15 upgrade, and hence the benefits of the upgrade would be greater than those reported in the DMA study.

It is also true that the proportion of OTC to TTC could increase in 2005 over what occurred in 2000, if there are upgrades made West of Borah that affect the Path 15-West of Borah nomograms. Tr. (Perez) at 884:12-20. However, neither the CA ISO nor other California entities can control whether and if upgrades West of Borah will in fact be made. Moreover, as discussed earlier, an upgrade to Path 15 would not single-handedly eliminate the effects of market power in any of the cases studied. Thus, even if an upgrade West of

Borah assists in mitigating the ability of suppliers to exercise market power in California, there would likely still be significant additional benefits from undertaking a Path 15 upgrade that increases the transfer capability over the Path a full 1500MW.

- The DMA study assumed that a Path 15 upgrade would add 1400 MW of transfer capability to the Path. In fact, however, the upgrade is projected by PG&E to add 1500 MW of transfer capability to Path 15. As a result the DMA study understates the benefits of the upgrade, although Mr. Casey testified that, given the limited nature of the difference, he would not expect a significant difference in results. Tr. (Casey) at 590: 1-8.
- The DMA study calculated RSI values in a period in which price caps were in effect. Tr. (Casey) at 924: 8-28; at 925: 1-7; at 928-930. Accordingly, the price-cost markups were likely less than they would be in an unconstrained market. Id. To the extent that price caps are no longer in effect in 2005, the DMA study would likely understate the level of price-cost markups that could be expected and hence the benefits from a Path 15 upgrade.

b. Factors that result in an overstatement of upgrade benefits in the DMA study.

- The DMA study assumed that there would always be sufficient excess power South of Path 15 to fill the capacity of Path 15 and contest the ability of suppliers North of Path 15 to exercise market power. Tr. (Casey) at 656: 26-28; at 657: 1-26. To the extent that there are hours in which there is insufficient capacity South of Path 15 to contest the ability of suppliers North of Path 15 to exercise market power, the DMA study overstates the benefits of the upgrade. Id. This is particularly so if suppliers North of Path 15 are aware of the deficiency.
- The DMA study did not assess the extent to which a supplier's existing and future long-term contracts might reduce its incentive to exercise market power. Tr. (Casey) at 909-910. Incorporating this assessment is a significant undertaking that could not be performed given

resource constraints. Tr. (Casey) at 914-917. To properly asses the degree of change in 2005, it would be necessary to determine a likely difference between the level of long term contracts in effect in 2000, the effects of which are captured in the DMA study, and the level of long-term contracts likely to be in effect in 2005. Id. To the extent that the level of supply capacity of pivotal suppliers subject to long-term contracts in 2005 is higher than the level in 2000, the DMA study would overstate the benefits of a Path 15 upgrade. The CA ISO believes that this bias could be balanced by biases that understate the benefits as described above.

c. Other uncertainty factors.

- The DMA study did not assume that there would be more demand response in 2005 than that in place in 2000. The study does incorporate the level of demand response in place in 2000. Tr. (Casey) at 700-703. It is difficult to determine whether this factor results in an overstatement or an understatement of benefits since there is little information on the extent of demand response that will be in place in 2005. Mr. Casey testified that efforts to include additional demand response in 2001 in the California electricity markets has met with limited success. Tr. (Casey) at 701-702. Nonetheless, the CA ISO certainly hopes that progress can be made going forward. In any event, as discussed above, the CA ISO supports a comprehensive strategy to address structural factors that provide the basis for supplier market power since there is no evidence that any one strategy alone will cost-effectively and adequately mitigate the ability of suppliers to exercise market power.
- There is evidence in the record that the level of congestion over Path 15 was less in 2001 than in 2000. Exh.215, Late-Filed Graph of Path 15 Congestion. However, Mr. Casey testified that this reduction was due to the fact that CDWR, which stepped in to buy on behalf of customers in 2001, had the ability to buy power after the close of the Hour-Ahead markets

and undertook this responsibility in a manner that would reduce congestion over Path 15. Tr. (Casey) at 572: 11-21. This situation is no longer available to any entity, Tr. (Casey) at 575: 5-18. Thus, there is no reason to suspect that the anomalous congestion pattern of 2001 will be present in 2005. Moreover, the fact that CDWR was able to manage its purchases to avoid congestion over Path 15, does not mean that there were no costs associated with the limited transfer capability over Path 15 in 2001. This is because, to prevent causing congestion over Path 15, CDWR may have had to buy more expensive contracts or energy North of Path 15 since buying less expensive power South of Path 15 would not have been feasible without causing congestion. Tr. (Casey) at 575: 22-28; at 576: 1-10; and at 577: 14-23. Thus, the CA ISO does not consider that there is evidence to support a conclusion that there will be less congestion, and less costs from congestion over Path 15 in 2005 than in 2000.

- The study undertaken of historic costs associated with congestion over Path 15 indicated possible costs of up to $220 million, a figure substantially higher than a study undertaken by FERC and reported in IEEE. Exh. 213, IEEE Spectrum Article, Feb. 2002. Questions may arise about whether these inconsistent results should undermine confidence in the DMA study. However, the historic study, Exh. 203, was an independent exercise from the DMA study, and the CA ISO did not rely significantly on the historic study in determining on a prospective basis the market power benefits of upgrading Path 15. Tr. (Casey) at 613: 24-28; at 614: 1-3. In fact, the historic study did not include any consideration of the costs associated with Path 15 congestion due to the ability of suppliers to exercise market power. Tr. (Casey) at 615: 16-28; at 616: 1-8.

Moreover, the CA ISO historic study and the FERC study were designed to measure separate aspects of the impacts of Path 15 congestion. The CA ISO historic study attempted to assess the cost impact of congestion to load. Tr. Tr. (Treinen) at 961: 18-21. The FERC study assessed the difference between what the load paid and what generators got paid, or the flow times the congestion price. Tr. (Treinen) at 962: 21-27. In other words, the FERC study ignores a transfer of wealth from load to generators from congestion, which is reflected in a study that quantifies, as the CA ISO's study did, the cost impact to load.

In sum, there are biases that both understate and overstate the benefits of a Path 15 upgrade in the DMA study. Without further information about the quantitative impact of these biases, the CA ISO considers that they are best addressed by applying a plus or minus 25% factor to the results in the most plausible scenario to develop a reasonable range of probable benefits.

6. The revised estimate of benefits.

This section sets forth an analysis of how the updated CA ISO assumptions impact a conclusion that the upgrade would pay for itself in one drought and three normal years. As will be demonstrated below, the CA ISO considers that this conclusion still holds, even applying a plus or minus 25% factor to account for uncertainties. In fact, the revisions further highlight the benefits of the upgrade.

As described above, based on new information and the record developed, the CA ISO considers that the following are the most reasonable assumptions as to the key factors underlying the DMA study:

- a one-in-ten drought hydro scenario remains appropriate, supporting consideration of a case that includes one drought hydro year and three normal years;
- a mid-point generation scenario between Scenarios 1 and 2 is appropriate since it reflects an increased uncertainty as to the construction of new generators that have not been permitted by the CEC and corrects for any overly conservative estimates of new generation in Southern California;

- an assumption that 29% of the ETC capacity reserved in 2000 will remain unavailable and unused in the forward electricity markets in 2005 is more accurate than a 50% assumption, given the historic scheduling pattern and the contracts that expire by 2008;
- an assumption that 50% of the load backed by CDWR long-term contracts will be shielded from the exercise of market power is more realistic than a 100% assumption, given that more than half the CDWR contracts in effect in 2005 are non-firm in nature.

Attachment A sets forth the calculations for determining the upgrade benefits given these revised assumptions. As a result of these assumptions, projected benefits from the upgrade in a normal year would be $104 M, whereas projected benefits from the upgrade in a drought year would be $305M. As demonstrated in the chart below, with these revised numbers, the upgrade would easily pay for itself in one drought and three normal years, and would in fact pay for itself within four normal years, even applying a 25% plus or minus factor.

Four Year Benefits Assessment[5]

	Simple Figures	+ 25%	- 25%
Normal (A)	$ 104 M	$130	$78
Drought (B)	$ 305	$381	$228
3 (A) + 1 (B)	$ 617	$771	$462
4 (A)	$ 416	$520	$312

[5] The CA ISO selected the four year benefits assessment approach, because it highlights the fact that the upgrade could easily pay for itself within a relatively small number of years and because it avoids the need to extrapolate assumptions made for 2005 for an extensive number of years. Tr. (Casey) at 680: 12-19. Nonetheless, if the CPUC believes that one annualized number is better than the four year analysis approach, the numbers can easily be converted to an annualized number that reflects a one-in-ten year drought hydro scenario as follows: [.9 X $104M] + [.1 X $305 M] = $124M. Applying a 25% plus or minus factor to account for uncertainty results in an annual benefits range of $93 to $155 M.

7. The upgrade provides cost effective insurance against unlikely but costly scenarios.

A final and important consideration in the evaluation of the Path 15 upgrade is the relative risks to consumers should the upgrade be undertaken or not. This consideration is compelling. Consumers will bear high risks if the project does not proceed and relatively contained risks should the upgrade be constructed. This risk assessment clearly provides substantial additional justification for upgrading Path 15.

In the most pessimistic of scenarios evaluated in the DMA study, the benefits of upgrading Path 15 (and conversely the cost to consumers of not upgrading Path 15) exceed one billion dollars in a single year. Exh. 201, Testimony of Casey and Willis, Attachment 4 at 19, Table 3. Even adjusting this figure for a more realistic view with regards to ETC (29% of the ETC reserved in 2000 will be unavailable and unused in the electricity forward markets in 2005), the benefits are close to twice the cost of the project upgrade ($600 million)[6]. Accordingly, the risks to consumers from failing to upgrade the Path are significant. Conversely, even in the most optimistic scenarios evaluated in the DMA study, upgrading Path 15 has some benefits. Since the cost of upgrading the Path is limited to $300 million, the total risk to consumers from upgrading Path 15 is less than $300 million. The asymmetry of risks is a further substantial argument in favor of the Path 15 upgrade.[7]

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6 The figure is calculated as follows: [29% of ($1,304.07 M - $289.19 M)] + $289.19 M = $ 583 M. The figures 1,304.07 and 289.19 are from Exh. 201, Attachment 4, at 19 Table 3, Bad Hydro Year scenarios.

7 It is worth noting moreover, that in the event that the most optimistic scenarios do come to pass, and the direct economic benefits of the Path 15 upgrade are substantially less than those currently projected, the Path 15 upgrade could nonetheless be used to provide important reliability benefits. As set forth in PG&E's Plan of Service for the Path 15 upgrade, the current 3900 MW Path rating has been made possible by the establishment of remedial action schemes (RAS). Exh. 214, Opening Testimony of Pacific Gas and Electric Company, Tab 6, at 7. These RAS schemes are summarized in Table 4 of the Plan of Service and were discussed by Mr. Morris on the stand. Exh. 214, Opening Testimony of Pacific Gas and Electric Company, Tab 6 at 7-8. The RAS summaries and Mr. Morris' testimony demonstrate that the 3900 MW path rating is maintained by allowing for the possibility of substantial generation and load outages in the event of highly unlikely but possible events. The Path 15 upgrade would provide an additional 1500 MW of added transfer capability with somewhat increased levels of RAS. Exh. 213, Opening Testimony of Pacific Gas and Electric Company, Tab 6 at 7-8. However, if the additional capacity is not entirely required to reduce the ability of suppliers to exercise market power, it may be possible to use the upgrade to reduce the likelihood of operating the RAS; thus improving reliability.

In sum, the substantial risk associated with not upgrading Path 15 coupled with a contained risk in the case of going forward argue strongly for proceeding with the upgrade.

IV. CONCLUSION.

The record strongly supports proceeding with the Path 15 upgrade. By reducing the ability of suppliers to exercise market power, the upgrade would pay for itself within four years in the most likely scenarios. Moreover, the upgrade provides a cost-effective hedge against significant consumer harm in less likely but still plausible worst-case scenarios.

Respectfully submitted this 10th of April, 2002 by:

Jeanne M. Solé
Regulatory Counsel
California Independent System Operator
151 Blue Ravine Road
Folsom, CA 95630
(916) 608-7144