CALIFORNIA ISO

California Independent
System Operator

February 28, 2003

Attn: Commission's Docket Office
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102

RE: Docket # I.00-11-001, 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

Dear Clerk:

Enclosed for filing please find an original and eight copies of the California Independent System Operator Update on a Methodology to Assess the Economic Benefits of Transmission Upgrades in Docket # I.00-11-001. Please date stamp one copy and return to California ISO in the self-addressed stamped envelope provided.

Thank you.

Sincerely,

Jeanne M. Solé
Jeanne M. Solé
Regulatory Counsel

Cc: Attached Service List

PROOF OF SERVICE

I hereby certify that on February 28, 2003, I served by electronic and U.S. mail the California Independent System Operator Update on a Methodology to Assess the Economic Benefits of Transmission Upgrades in Docket # I. 00-11-001.

DATED at Folsom, California on February 28, 2003.

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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

THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR UPDATE ON A METHODOLOGY TO ASSESS THE ECONOMIC BENEFITS OF TRANSMISSION UPGRADES

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Dated: February 28, 2003

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

THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR UPDATE ON A METHODOLOGY TO ASSESS THE ECONOMIC BENEFITS OF TRANSMISSION UPGRADES

In accordance with the Administrative Law Judge's ("ALJ") January 29, 2003 Ruling and Notice of Evidentiary Hearings on Tehachapi Transmission Project ("January 29 Ruling"), the California Independent System Operator ("CA ISO") respectfully submits a report on "A Proposed Methodology for Evaluating the Economic Benefits of Transmission Expansions in a Restructured Wholesale Electricity Market" ("Report"). Consistent with the January 29 Ruling, the CA ISO will be prepared to discuss the report in a workshop to be organized by Pacific Gas and Electric Company ("PG&E") currently scheduled for March 14, 2003.

The report describes the methodology developed by the CA ISO jointly with London Economics International LLC ("LE") with input and review provided by an external steering committee -- comprised of representatives from the California Public Utilities Commission ("CPUC"), the California Electricity Oversight Board ("EOB"), the California Energy Commission ("CEC"), PG&E, Southern California Edison Company ("SCE"), and San Diego Gas and Electric Company ("SDG&E") – and the CA ISO Market Surveillance Committee. The report does not contain the results of illustrative simulations of the estimated benefits of a Path 26 expansion, because some additional work is required to finalize this information. The CA

ISO expects to disseminate this information to the service list prior to the March 14 workshop.

February 28, 2003

Respectfully Submitted:

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A Proposed Methodology for Evaluating the Economic Benefits of Transmission Expansions in a Restructured Wholesale Electricity Market

Prepared by

The California ISO and London Economics International LLC

February 28, 2003

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Executive Summary

Since September 2001, the CAISO has been working jointly with London Economics International LLC (LE) to develop a comprehensive methodology for evaluating the economic benefits of transmission investments in a restructured electricity market. Unlike the prior vertically integrated regime, the restructured wholesale electric market involves a variety of parties making decisions that affect the utilization of transmission lines. This paradigm shift requires a new approach to evaluating the economic benefits of transmission expansions. Specifically, a new approach must address the impact a transmission expansion would have on increasing transmission users' access to generation sources and demand areas, the impact on incentives for new generation investments, and the impact on increasing market competition. It must also address the inherent uncertainty associated with other critical market drivers such as future hydro conditions, natural gas prices, and demand growth as well as capture the dispatch capability of hydroelectric generation and the availability of import supplies. These last two factors are particularly critical in modeling the California market given its heavy dependence on hydroelectric generation and imports. Integrating all of these critical modeling requirements into a comprehensive methodological approach has been extremely challenging.

The methodology presented in the document, which represents the culmination of over a year of joint research between the CAISO and LE with input and review provided by an external steering committee[1] and CAISO Market Surveillance Committee, integrates all of these critical modeling requirements into a single comprehensive methodology and demonstrates aspects of the methodology using a proposed expansion of Path 26 as an illustrative case study[2]. We believe the methodology provided here far exceeds anything that has been done to date in the area of transmission planning studies and that this modeling framework can provide a template for the basic components that a transmission study should address. While much of the focus of this paper is on modeling California transmission projects, the basic approach could be easily adopted to study the benefit of upgrades in other areas of the Western Interconnect.

Major Challenges and Solutions

This evaluation method was developed to capture the benefits of transmission expansion in the current restructured environment. It reflects the transformation

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1 The external steering committee consisted of representatives of the investor owned utilities (SDG&E, SCE, and PG&E) and various state agencies (CPUC, CEC, and the Electricity Oversight Board (EOB))

2 Various components of this methodology are applied using a proposed expansion of Path 26 as an illustrative case study. However, illustrative simulations of the estimated benefits of the Path 26 expansion are not provided and will instead be provided prior to the PG&E workshop scheduled for March 14, 2003 It is important to note that the information provided for Path 26 is for illustrative purposes only. Some limited scenarios of a Path 26 expansion are evaluated to demonstrate how the methodology works More scenario analysis and possibly a more detailed model of the transmission network would be required for a definitive assessment of a Path 26 expansion.

of decision making as to transmission expansions and generation additions. In the past, such decision making was dominated by a few large utilities who could consider trade-offs between building power plants, purchasing power, or adding transmission to transport power to meet their native load under cost-of-service regulation. Now, decision making is more decentralized. As to transmission facilities, it is necessary to consider the needs of many parties for non-discriminatory access to the transmission grid and the fact that there is no requirement for power suppliers to bid their costs. In such a decentralized – market oriented environment one must consider the risk of market power and how a transmission expansion can serve to reduce this risk. A transmission expansion can provide market power mitigation benefits through enlarging the market and thereby reducing the concentration that any one supplier may have.

Under the vertically integrated paradigm, utilities planned for <u>both</u> transmission and generation to meet their native load requirements and focused primarily on reliability impacts and savings from contract purchases and sales. In the restructured environment, ISOs/RTOs have the responsibility to provide non-discriminatory access to all parties, and must undertake transmission evaluations and planning for transmission augmentations consistent with this objective. However, investments in new generation resources are made in the market place by private companies or by utilities subject to regulatory oversight. Planners at an ISO or RTO must also consider broader objectives functions that value the benefits to all participants in the region including retail customers, generation owners, and transmission owners.

Finally, different market conditions such as demand levels, hydro conditions, availability of imports, and new generation entry levels can have significant impacts on the economic benefits of a transmission expansion to different parties and regions. Therefore, it is critical that a valuation methodology explore the economic value of a transmission expansion under a number of different assumptions about future market conditions, particularly extremely adverse market conditions (e.g. high demand and low hydro).

To address these challenges, the new transmission valuation methodology proposed here offers four major changes from traditional transmission evaluations:

(1) Provides policy makers with several options for measuring the benefits of a transmission expansion that address the distributional impacts a transmission expansion can have between consumers and producers and between regions.

(2) Provides a simulation method that incorporates the impact of strategic bidding (i.e. market power) to reflect the fact that the benefits of transmission expansions are not limited to reduced production cost of electricity but also include consumer benefits from reduced market power.

(3) Captures the interaction between generation and transmission investment decisions in recognition that a transmission expansion can

impact the profitability of new generation investment and incorporates the different objectives of generator investors (private profits) and the transmission planner (societal net-benefits) into a single methodology.

(4) Addresses the uncertainty about future market conditions by providing a methodology for selecting a representative set of market scenarios to measure benefits of a transmission expansion and provides a methodology for assigning weighting factors to different scenarios so that the expected benefit of a transmission expansion can be determined.

In addition, this comprehensive methodology provides a number of important enhancements to evaluating the economic benefits of transmission expansions that would be useful under any regulatory environment. These include methodologies for modeling imports, and the dispatch and availability of hydroelectric generation.

Key Modeling Methods

A more detailed summary of major components of this methodology is provided below. It should be noted that while this methodology lays out the basic components of a comprehensive transmission study, it makes no specific recommendation on a particular software product to use in applying this methodology. It does, however, provide guidelines on the desired functional requirements of the modeling software.

Network Representation and Modeling Time Horizon

Perhaps the most fundamental aspect of a transmission expansion study is how one models the transmission network The appropriate scale and scope of the network representation depends on the type of transmission expansion project being considered. For large transmission projects (e.g. 230-500 kV) a broad regional network representation is appropriate since the expansion is likely to have implications throughout the Western Interconnect, particularly in adjacent control areas. A comprehensive assessment should attempt to capture the broader regional benefits and costs of a major transmission expansion, even if the primary interest is in how the expansion benefits California consumers. Smaller transmission expansion projects (e.g. sub-transmission projects at voltage levels less than 230 kV) tend to have more localized benefits, which can be better captured through a more detailed network representation in the electrical vicinity of the project that is more limited in its regional scope. In addition to capturing thermal limits, smaller projects could also capture local voltage security limits and nomogram constraints[3]. A detailed network representation for smaller transmission expansions would also allow for evaluating the potential substitutability between reliability must run generation and the transmission expansion.

[3] The emphasis here is on the local nature of voltage security (static) and nomogram constraints In general, voltage stability (dynamic) and system-wide nomograms should be modeled beyond the local scope.

Determining an appropriate modeling time horizon is also an important consideration in transmission expansion valuation studies. From a practical standpoint, long-run forecasts covering periods in excess of 8-10 years are subject to substantial forecast error. Because the accuracy of the base-line input assumptions used in the model diminish significantly for long-term projections, it is critical that the benefits of the transmission expansion be evaluated under a number of different input assumptions (i.e. scenarios). Assessing the benefits under a variety of input assumptions can compensate for the inherent uncertainty of these parameters and allow for the estimation of a reasonable range of expected values. In determining an appropriate study period, one needs to also consider when the transmission expansion can be completed. Most transmission projects typically take several years to complete. We believe a study period in the range of 12-15 years, beginning with the next full calendar year is a reasonable time horizon for a transmission expansion study. Benefit estimates beyond this range would be highly speculative due to the uncertainty of future system conditions. Assuming an average transmission development time of 6 years, a time horizon of 12-15 years would provide 6-9 years of annual benefit estimates. However, a shorter time horizon can be appropriate if a transmission project can be shown to be economically viable within a shorter time frame.

Critical Inputs to the Model

Assumptions about future gas prices, demand, near-term new generation entry, available transmission capacity[4], and the degree that buyers are hedged through long-term energy contracts have a significant impact on the estimated economic benefits of a transmission expansion. This document provides some specific recommendations for determining these input data and describes the methodology and data sources used in the illustrative Path 26 expansion analysis. The basic criteria used to select input data is to select the most plausible series of inputs to use as a "base-case" scenario; and to supplement the base-case assumptions with a number of plausible extreme scenarios (e.g. extremely high demand, extremely high gas prices). Capturing extreme scenarios is important because the benefits of a transmission expansion are often greatest under extreme conditions.

Innovative Modeling Components

The major modeling components of a transmission expansion study include, simulating the availability of imports and exports, modeling the availability and optimal dispatch of hydroelectric and thermal generation, modeling long-term new generation entry, and modeling market power. This document provides methodological approaches to modeling each of these critical components and demonstrates each using a Path 26 expansion as an illustrative case study.

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[4] Specifically, assumptions about the future utilization of existing transmission contracts (ETCs) can have significant implications on the amount of transmission capacity that is assumed "available" to the market.

Simulating the availability of imports to California must recognize the fundamental characteristics of the two major regions that export to California, the Pacific Northwest, and the Desert Southwest. Generation in the Pacific Northwest is predominately hydroelectric and is therefore highly variable from year to year, depending largely on snow-pack and reservoir storage conditions. Also, unlike California, demand for electricity in the Pacific Northwest peaks in the winter months and is generally moderate in the summer months. Because of these characteristics, the Pacific Northwest typically has surplus generation available to export to California during summer and early fall periods but the amount of this supply is extremely variable from year to year. In contrast, the Desert Southwest is predominately thermal based generation and its peak demand tends to coincide with California's peak demand. As a consequence, during summer months, the availability of imports from the Desert Southwest is often inversely related to the level of demand in California. This document provides methodologies for capturing the unique supply attributes of each of these two regions.

How one models the availability and optimal dispatch of hydroelectric generation within California can have important implications on the model results. A methodology for modeling hydroelectric generation must recognize that these resources are typically energy limited (i.e. energy production is limited by the availability of water) and as a consequence, the optimal dispatch must reflect inter-temporal opportunity costs (i.e. the cost of the energy produced today should reflect the foregone market opportunity of selling that energy in some future period). An opportunity cost approach to dispatching hydroelectric supply will optimize the value of hydroelectric production by dispatching it in the highest priced periods. In modeling hydroelectric dispatch one must also recognize that the maximum production capabilities of these resources in any particular hour often depends on the overall hydrology conditions. In very dry years, the maximum hourly production capabilities of some facilities is limited due to a lack of river flow or pond storage. This document provides an opportunity cost approach for modeling hydroelectric dispatch and a methodology for matching the maximum output of hydroelectric resources with overall hydrology conditions.

Modeling the availability and dispatch of thermal resources is relatively straightforward compared to hydroelectric resources. However, a sound methodology for modeling and dispatching thermal generation should include random plant outages and a unit commitment program (i.e. large thermal units with long and expensive start-up costs are only turned on (committed) if market revenues over a 24-hour period are sufficient to cover the unit's start-up and other operating costs). The frequency and duration of plant outages should be calibrated to be historically consistent the class and vintage of the units (i.e. 40-year old steam units would be expected to experience higher outage rates of longer duration than a new combined cycle unit). It should also be capable of incorporating energy limitations associated with environmental restrictions.

One of the more challenging aspects of developing a methodology for evaluating the economic benefits of transmission expansions concerns the interdependence of new generation and new transmission facilities. The benefits of a transmission investment depend on uncertain future demand for transmission services and this demand in turn depends on the expected pattern of new generation investment. To determine the benefits of a transmission investment it is therefore necessary to take account of the incentives to invest in generation. This problem is further complicated by the fact that the relationship between demands for transmission and generation services varies over time and space. In some cases generation and transmission are substitutes for each other: a generation asset produces power at a specific location, while transmission delivers power to a specific location. However, under other conditions, generation and transmission projects are also complementary investments: a transmission line expansion may improve the profitability of a generator that is exporting power, as it increases the volume of power that the exporting generator can sell and cause to be delivered. Therefore, a comprehensive methodology needs to be able to anticipate potential investment in generation in response to transmission investment and incorporate the interdependence of transmission and generation into the valuation process for transmission. This document provides a methodological approach for accomplishing this. Specifically, for each transmission upgrade option, a pattern of *long-term* new generation *entry is* derived for each congestion zone such that new entry will be just sufficient to maintain prices at the appropriate remunerative levels for both peaking and base-load thermal units.

The final modeling component addresses modeling market power. In a restructured electricity market, transmission expansions can provide significant consumer benefits by improving the competitiveness of a transmission-constrained region. A transmission expansion can increase market competitiveness by increasing the amount of supply available to serve load in a constrained area. Of course, a transmission expansion is just one of several structural options for improving market competitiveness. The addition of new generation capacity, increased levels of forward energy contracting, or the development of price responsive demand can also significantly reduce the ability of suppliers to exercise market power. Therefore, a comprehensive transmission expansion study should explore the market power mitigation benefits of a transmission upgrade under a variety of plausible new generation entry, forward contracting levels, and price responsive demand scenarios.

Some have argued that it is inappropriate to include in an assessment of transmission facility benefits, the market power mitigation benefits of a transmission expansion and that market power is more appropriately addressed through effective regulation. The CAISO believes that trusting that regulators will have the political will and/or ability to effectively enforce regulations to eliminate market power is a high risk strategy that could have enormous consequence to consumers if it should turn out to be false. The California experience in year 2000 is a case in point We also believe that in the long run, the most effective way to mitigate market power is to correct the structural deficiencies that enable suppliers to exercise market power (e.g. lack of supply, lack of forward contracting, and lack of price responsive demand).

This document provides two approaches to modeling strategic bidding behavior (e.g. the exercise of market power) in transmission valuation studies. The first approach involves developing a game theoretic model of strategic bidding. The second approach involves capturing strategic bidding through estimated historical relationships between certain market variables and a variable that captures a measure of market power. Each modeling approach has its advantages and disadvantages and these are discussed in detail. Given that both approaches have complementary strengths and weaknesses and that work in this area is relatively new, we have developed versions of both approaches and applied them in the illustrative case study of Path 26.

Scenario Selection and Probability Assignments

In order to provide a comprehensive and accurate assessment of the economic benefits of a transmission expansion, the benefits must be examined under a wide range of system conditions. As noted above, assumptions about natural gas prices, demand levels, hydro conditions, and new generation entry can have significant impacts on the economic benefits of a transmission expansion. The benefits of a transmission expansion should be examined under different plausible combinations of these system variables In choosing scenarios, it is particularly important to capture extreme scenarios, such as combinations of high demand and low hydro conditions, because the benefits of a transmission expansion can often be derived mostly or entirely from low likelihood but extreme system conditions. It is also important to choose a sufficient number of more moderate scenarios to ensure the benefits are accurately captured under more likely scenarios. These more likely scenarios are also useful in ensuring adequate representation of the system in the simulation models (i.e. ensuring the optimal dispatch and path flows comport with historical patterns). There is no hard rule on the number of scenarios that ought to be considered other than "more is always better". Ultimately, the number of scenarios considered is likely to be driven by practical issues such as the amount of the time one has to undertake a study and the speed at which scenarios can be run and results compiled. In this document, we provide a two-step methodology for selecting scenarios that ensures extreme scenarios are included in the assessment and that a representative sample of more moderate scenarios are also selected.

Having evaluated a transmission expansion under a number of different scenarios, the next methodological step relates to the weighting factors that need to be applied to each scenario modeled in order to determine the "expected benefit" of the transmission expansion. A two-stage approach has been adopted to deal with this issue. In the first stage, joint probabilities are derived for the various combinations of gas price and demand levels. These joint probabilities are then used in a second stage to determine the joint probability of the pairs of gas price and demand levels and the new generation entry scenarios. This two-stage approach was driven by the fact that we have much better information on the probability distributions of demand and gas prices (i.e. based on historical data) than we do on the level of new generation entry. Given this, the best alternative is to consider the sensitivity of the study's conclusion under a range of plausible distributions that satisfy certain reasonableness constraints. This can be done through an optimization that chooses, first, a set of joint probabilities of demand, gas price, and new entry scenarios that maximize the expected benefits of a transmission expansion and second, another set of joint probabilities that minimize the expected transmission expansion benefits. This Min-Max optimization approach will then produce a range of potential benefits (lowest to highest) rather than a single expected value. However, it is possible to narrow the range of estimated benefits by imposing further constraints on the optimization such as requiring that certain scenarios be considered more likely than others.

Measuring Net Benefits

The benefits of a transmission expansion can accrue to both suppliers and consumers and can involve significant welfare transfers between these groups or between locations. Therefore, it is important to measure producer and consumer benefits on a regional basis and to understand how the welfare of these groups shifts under a transmission expansion. For example, a transmission expansion that has a significant impact on reducing market power will, for the most part, simply shift welfare from producers to consumers. A conventional social welfare objective in which producer and consumer welfare are given equal weights would show very little net benefit because such a criteria does not consider the distribution effects. It only measures the net effect. However, public policy makers generally do care about distributional effects and therefore benefit measures that reflect the distributional effects are essential to the methodology. This document sets out the principles of cost benefit analysis and provides three benefit measures for policy makers to consider in evaluating a transmission expansion; 1) an approach that gives equal weight to both consumer and producer surplus (i.e. the conventional social welfare objective), 2) an approach that gives equal weight to consumer benefits and the competitive portion of producer benefits (i.e. ignores any benefits that accrue to suppliers from market power), and 3) an approach that only looks at benefits to consumers. Since different decision makers can take different views of the merits of these measures, the most useful output from the transmission valuation methodology will be the building blocks necessary to evaluate the given transmission investment project under all three different objective functions.

An Illustrative Example using Path 26

Various components of this methodology are applied using a proposed expansion of Path 26 as an illustrative case study. However, illustrative simulations of the estimated benefits of the Path 26 expansion are not provided and will instead be provided prior to the PG&E workshop scheduled for March 14, 2003. It is important to note that the information that will be provided regarding Path 26 does not constitute a definitive assessment of the value from expanding Path 26 rather it will merely serve to demonstrate how the methodology can be carried out and applied in practice. A definitive assessment of Path 26 would require assessing the benefits under more scenarios and possibly require a more detailed transmission network representation than was used in this study. Nonetheless, this illustrative case study will demonstrate that the methodology is practical and can produce sensible results.

Introduction

Since September 2001, the CAISO has been working jointly with London Economics International LLC (LE) to develop a comprehensive methodology for evaluating the economic benefits of transmission investments in a restructured electricity market. In a market oriented restructured environment, a comprehensive approach must address the impact a transmission expansion would have on market competition and new generation investment. It must also address the inherent uncertainty associated with other critical market drivers such as future hydro conditions, natural gas prices, and demand growth as well as capture the dispatch capability of hydroelectric generation and the availability of import supplies. This last two factors are particularly critical in modeling the California market given its heavy dependence on hydroelectric generation and imports. Integrating all of these critical modeling requirements into a comprehensive methodological approach is extremely challenging

The methodology presented in the document, which represents the culmination of over a year of joint research between the CAISO and LE with input and review provided by an external steering committee[5] and CAISO Market Surveillance Committee, integrates all of these critical modeling requirements into a single comprehensive methodology and demonstrates aspects of the methodology using a proposed expansion of Path 26 as an illustrative case study[6]. We believe the methodology provided here far exceeds anything that has been done to date in the area of transmission planning studies and that this modeling framework can provide a template for the basic components that a transmission study should address. While much of the focus of this paper is on modeling California transmission projects, the basic approach could be easily adopted to study the benefit of upgrades in other areas of the Western Interconnect.

This paper describes each of the critical components of a comprehensive transmission valuation modeling approach, offers a number of methodological approaches for addressing each of them, and demonstrates aspects of the methodology using a Path 26 expansion as an illustrative case study. The first section identifies some important factors one should consider in deciding two fundamental aspects of a transmission study: the transmission network representation and the modeling time horizon. Section II identifies the critical input data for a transmission valuation study such as natural gas prices, demand forecasts, near-term new generation energy, transmission transfer capabilities

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[5] The external steering committee consisted of representatives of the investor owned utilities (SDG&E, SCE, and PG&E) and various state agencies (CPUC, CEC, and the Electricity Oversight Board (EOB)).

[6] Various components of this methodology are applied using a proposed expansion of Path 26 as an illustrative case study However, illustrative simulations of the estimated benefits of the Path 26 expansion are not provided and will instead be provided prior to the PG&E workshop scheduled for March 14, 2003. It is important to note that the information on the Path 26 expansion will be for illustrative purposes only. Some limited scenarios of a Path 26 expansion are evaluated to demonstrate how the methodology works More scenario analysis and possibly a more detailed model of the transmission network would be required for a definitive assessment of a Path 26 expansion

before and after the expansion, and assumptions about the level of long-term forward energy contracting. The latter is particularly important in assessing the extent to which market power can be exercised. Section III provides specific methodologies for critical modeling components. These include assumptions and methodologies for modeling the following components; imports to the CAISO control area, CA hydrology, optimal dispatch of thermal and hydro generation resources, demand price responsiveness, long-term new generation entry, and market power. To provide a comprehensive and accurate assessment of a transmission expansion, it is critical that the expansion be evaluated under a wide range of system conditions (e.g. demand levels, gas prices, hydro conditions etc.). Section IV provides a methodology for selecting various scenarios of system parameters to ensure a comprehensive and representative set of plausible scenarios. Evaluating the benefits of a transmission expansion under a number of scenarios raises the next methodological issue of how to assign probabilities to these scenarios in order to determine the "expected value" of the project. Section V provides a methodology for assigning probabilities to each of the scenarios. Finally, Section VI provides the basic framework for computing the net-present value of a transmission expansion. The benefits of a transmission expansion can accrue to both consumers and producers. This section provides a methodology for calculating the different benefit components and provides recommendations on the appropriate benefits to consider. A summary of the methodology is provided in Section VII.

I. Network Representation and Modeling Time Horizon

Transmission Network Representation

Perhaps the most fundamental aspect of a transmission study is how one models the transmission network and determines an appropriate modeling time horizon for evaluating the potential benefits of a transmission expansion.

The appropriate scale and scope of the network representation really depends on the type of transmission expansion project being considered. For large transmission projects (e.g. 230 – 500 kV) a broad regional network representation is appropriate since the expansion is likely to have implications throughout the Western Interconnect, particularly in adjacent control areas. When modeling major transmission projects, the need for a detailed network representation is less critical. Moreover, a large overly complex regional model will make it more difficult to incorporate critical modeling components such as strategic bidding and may make the model result generally less tractable. The degree of regional network representation for large transmission projects also depends on the focus of the benefit measures. For example, if the focus of studying a particular large transmission expansion in the CAISO control area is to measure how such an expansion would benefit California consumers, the need for modeling the major transmission lines outside of the CAISO control area is less critical provided there is adequate representation of the major inter-ties between the CAISO control area and adjacent control areas. However, as a general matter, a comprehensive assessment should attempt to capture the broader regional benefits and costs of a major transmission expansion, even if the primary interest is in how the expansion benefits California consumers.

Smaller transmission expansion projects (e.g. sub-transmission projects at voltage levels less than 230 kV) tend to have more localized benefits, which can be better captured through a more detailed network representation in the electrical vicinity of the project that is more limited in its regional scope. In addition to capturing thermal limits, smaller projects could also capture local voltage security limits and nomogram constraints[7]. A detailed network representation for smaller transmission expansions would also allow for evaluating the potential substitutability between reliability must run generation and the transmission expansion.

An import consideration in determining the appropriate level of network detail is ensuring that the model remains tractable. As discussed throughout this document, a comprehensive modeling approach should incorporate many components including modeling long-term new generation entry and strategic (versus cost-based) bidding behavior. The more complex the network

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[7] The emphasis here is on the local nature of voltage security (static) and nomogram constraints. In general, voltage stability (dynamic) and system-wide nomograms should be modeled beyond the local scope

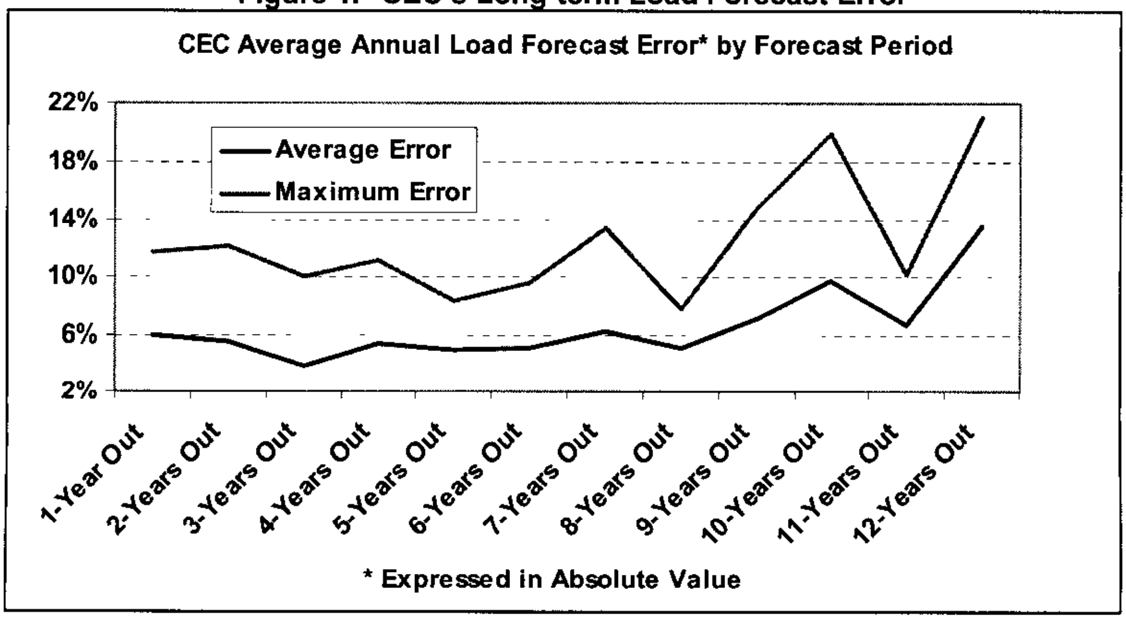
representation, in terms of its scope and scale, the more difficult it is to determine whether the model is behaving as expected.

In the illustrative analysis provided in this document, a simplistic network representation was used consisting of the three internal ISO zones (NP15, ZP26, SP15), the internal paths connecting them (Path 15 and Path 26), and external injections from the Desert Southwest and Pacific Northwest. Because the case study considered here involved the expansion of a major 500 kV line (i.e. expanding Path 26), it was important to model the major importing regions into California.

Modeling Time Horizon

Another fundamental issue in transmission studies is determining an appropriate modeling time horizon. From a practical standpoint, the accuracy of the model is apt to diminish significantly the further out one forecasts. Predictions of gas prices, demand levels, and generation levels become highly speculative beyond 8-10 years. For example, Figure 1 shows the average and maximum annual load forecast errors of the California Energy Commission's long-term base demand projections[8] for California as a function of the number of years out the projection was made.

Figure 1. CEC's Long-term Load Forecast Error



This figure indicates that the average forecast error for 1-8 year out demand projections are fairly stable and generally below 6%. The maximum forecast error is also fairly stable within an 8-year out projection period. However, average and maximum forecast errors tend to increase significantly for 9-12 year out projections. A similar trend is also observed for natural gas price forecasts.

[8] These data were derived from CEC Electricity Outlook Reports from 1988 to 2000

Because the accuracy of the base-line input assumptions used in the model is apt to diminish significantly for projections out beyond 8-years, it is critical that the benefits of the transmission expansion be evaluated under a number of different input assumptions (i.e. scenarios). Assessing the benefits under a variety of input assumptions can compensate for the inherent uncertainty of these parameters and allow for the estimation of a reasonable range of expected values.

In determining a study period, one needs to also consider when the transmission expansion can be completed. Most transmission projects typically take several years to complete. Given this, if one establishes a 13-year study period with the first year being the current year, the first several years will not produce any benefits or costs since the project would not be on-line until several years out. However, modeling the first few years is still a good practice as it will help to calibrate the model. The initial years prior to expansion can also serve as a benchmark for the net benefit analysis in that if the model is functioning appropriately it should produce zero net-benefits in these years.

Given these considerations, a study period in the range of 12-15 years, beginning with the next full calendar year is a reasonable time horizon for a transmission study. Benefit estimates beyond this range would be highly speculative due to the uncertainty of future system conditions. Assuming an average transmission development time of 6 years, a time horizon of 12-15 years would provide 6-9 years of annual benefit estimates. However, a shorter time horizon can be appropriate, if a transmission project can be shown to be economically viable within the shorter time frame.

II. Critical Input Components

Modeling Gas Prices

Fuel price variation can have a material impact on the benefits of transmission because the CAISO system comprises different technologies and different regional distribution of those technologies. Changing relative fuel prices can be expected to change the relative short-run costs of these technologies which, in some cases, may result in changed patterns of utilization. The changes in utilization will be affected by transmission capacity. Hence, for example:

1. The incremental heat rates of gas fired units are highly non-linear and vary significantly depending on whether the unit is a base load combined cycle or a peaking CT (i.e. combustion turbine) unit. Because of the non-linearity of the incremental heat rates, assuming a different gas price can have a significant impact on the price differentials of the no-expansion and expansion scenarios.
2. If units are dispatched based on a daily commitment process, a higher gas price may result in more base-load units being committed rather than dispatching CTs.
3. Higher gas prices may result in more hydroelectric generation being dispatched.

Furthermore, the relativity of producer and consumer surplus is directly affected by changes in relative fuel prices; thus, depending on the choice of objective function, fuel price assumptions can significantly change the magnitude and distribution of social welfare. Therefore, it is important to assess the benefits of a transmission expansion under a number of plausible gas price scenarios and to capture potential regional variations in gas prices

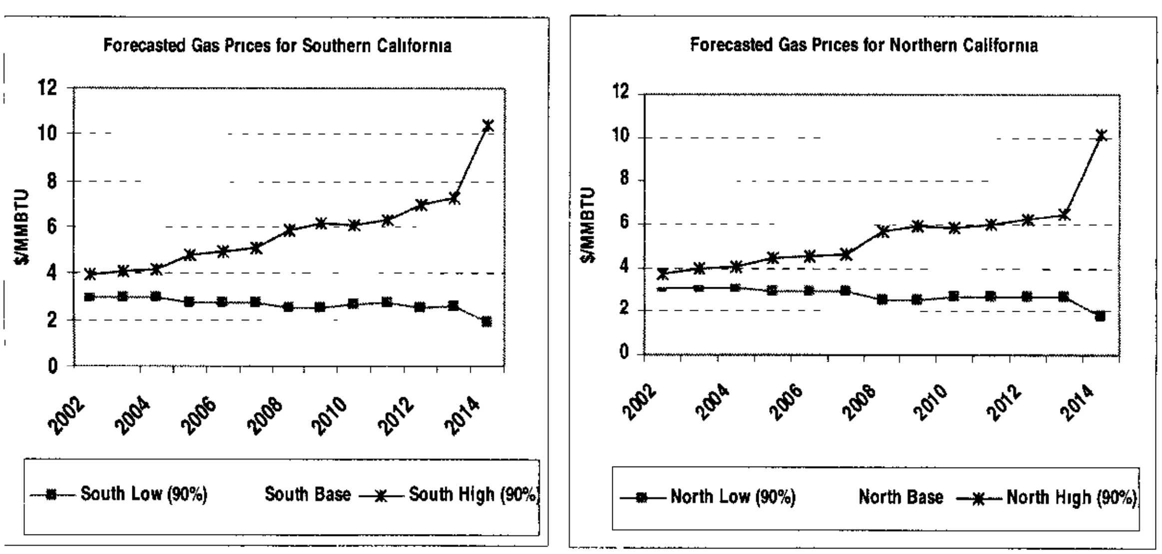
In the illustrative analysis of Path 26, base-line gas price forecasts for 2002-2014 were derived from the CEC's June 2002 unpublished forecast of annual natural gas prices and monthly natural gas price multipliers, which was very similar to that published in CEC's *2002-2012 Electricity Outlook Report, February 2002.* These forecasts are on an all-in delievered cost basis (burner tip) to electric generators in 2000 dollar terms. We have converted the CEC forecast to 2002 dollar terms, using the deflation index provided by the CEC in their 2002-2012 Electricity Outlook Report. Due to the similarity in the SoCal Gas and SDG&E forecasts, we decided to use SoCal Gas price forecasts for gas-fired generation in the SP15 zone and the PG&E gas price forecasts for gas-fired generation in the NP15 region.

Alternative gas price scenarios can be derived based on CEC's historical gas price forecast errors following the procedures described below:

1. Actual and forecasted gas prices can be assumed to have a lognormal distribution to reflect the fact that gas prices are asymmetrically distributed about their mean. (i.e. gas prices cannot be negative). Forecast errors are calculated by taking the log of actual and forecasted gas prices (i.e. converting them to a normal distribution) and taking the difference between these values. More specifically, gas price forecast error = 1 – LN(Forecast Gas Price)/LN(Actual Gas Price), where Actual Gas Price is the historical gas price and Forecast Gas Price is the CEC forecasted value.
2. Since CEC forecast errors tend to be larger the further one projects out, the mean and standard deviation of forecast errors can be calculated separately for different CEC forecast outlooks (e.g. 1-3 year outlooks, 2-5 year outlooks, 6-7 year outlooks, etc.]
3. Confidence intervals can be derived for each forecast outlook category based on the desired extremeness of the scenario (e.g. a 90% confidence interval would reflect low and high gas price scenarios where the probability of having actual prices below or above these levels, respectively, is only 5%).
4. The derived confidence interval can then be applied to the log of baseline gas price forecast values to derive high and low LN(gas prices).
5. Finally, high and low LN(gas price) scenarios are converted into high and low log-normal gas price scenarios.

Note that any number of gas price scenarios can be derived following the above procedures. This approach was applied in the illustrative Path 26 analysis to derive high and low gas price scenarios that reflect a 90% confidence interval. These scenarios are shown graphically below for Southern and Northern California

Figure 2. Forecasted Gas Prices for Southern and Northern California



Modeling Demand Forecasts

Forecasted demand levels can have significant impacts on the benefit results. Generally speaking, the higher the demand in the importing zone of a constrained transmission interface, the greater the benefit of the expansion. Demand levels impact the benefit of a transmission project in several respects.

1. Higher demand levels will result in higher cost resources being dispatched and extremely high demand levels may also result in the dispatch of curtailable load, which, depending on how curtailable load is modeled, can have a significant impact on the price forecast results.
2. Higher demand levels will tend to increase market power. The ability of a supplier to exercise market power depends largely on the degree to which the supplier is "pivotal" in the sense that demand could not be met absent the supplier's capacity. In general, higher demand levels result in suppliers being more pivotal and thus being better able to exercise market power.
3. Since the benefits of transmission project are typically measured by changes in producer and/or consumer surplus and both of these measures are based on the amount of load served, the assumed level of load will have a significant multiplier effect on the estimated social benefits.

Given these impacts, it is important to utilize the best available forecasts on future demand levels and to conduct multiple modeling runs under different demand scenarios to capture the uncertainty.

In the illustrative Path 26 analysis, base-line demand forecasts for 2002-2014 were derived from the CEC's long-term base demand projection published in CEC's *2002-2012 Electricity Outlook Report* CEC derived its baseline scenario of demand forecasts for 2002-2012 under the following three assumptions:

a) Annual average energy consumption forecast based on normal economic growth trends in the 2002-2012 period;[9]

b) Annual statewide peak demand forecast based on temperature conditions that have a 1-in-2 probability of occurring; and

c) A 50% probability of persistence of 2001 demand reduction effect.

Demand forecasts for 2013 and 2014 were calculated by linearly extrapolating the CEC's 2012 growth rate forecast for both peak demand and energy consumption. This approach yielded base demand cases that assume a 1.9% average annual growth over forecast time horizon in peak demand and total energy The resulting annual peak demand and energy consumption figures, along with the CEC's target assumption on levels of conservation, was applied to

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[9] The normal economic growth trend does not include the economic downturn in 2001 or any of the effect of the September 11th, 2001 tragedy

the regional synthetic hourly load shapes[10] (which were also provided by the CEC and had been utilized in their long-term load projections) to derive a 13-year hourly load forecast (2002-2014). High and low demand cases were developed off the base case using CEC's historical forecast error (deviation between forecast and actual demand) and a tailored outlook based on the potential persistence of conservation. These high and low demand scenarios were compared with high and low demand scenarios derived from historical forecast errors based on a 90% confidence interval and were found to match quite well. Therefore, the high and low demand scenarios considered in this study approximate a 90% confidence interval. This assessment resulted in the forecasted peak demand and consumption levels shown in Figure 3 and Figure 4, respectively.

Figure 3. Forecasted Peak Demand Levels (MW)

		2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Very Low	NP15	18,862	19,107	20,095	20,728	21,171	21,564	21,945	22,218	22,365	22,558	22,399	22,284	22,060
	ZP26	1,364	1,393	1,459	1,508	1,541	1,568	1,606	1,616	1,629	1,644	1,631	1,623	1,606
	SP15	25,098	26,046	26,855	27,598	28,125	28,503	29,255	29,419	29,607	29,860	29,529	29,392	29,125
	SW	3,250	3,250	3,250	3,250	3,250	3,250	3,250	3,250	3,250	3,250	3,250	3,250	3,250
Base	NP15	20,161	20,541	21,607	22,404	22,977	23,411	23,718	24,301	24,760	25,170	25,596	25,983	26,376
	ZP26	1,458	1,498	1,569	1,630	1,672	1,702	1,736	1,767	1,803	1,834	1,864	1,892	1,921
	SP15	26,633	27,791	28,665	29,603	30,285	30,703	31,392	31,914	32,476	32,993	33,343	33,804	34,272
	SW	3,250	3,250	3,250	3,250	3,250	3,250	3,250	3,250	3,250	3,250	3,250	3,250	3,250
Very High	NP15	22,224	22,439	23,401	24,072	24,693	25,214	25,598	26,522	27,300	28,082	29,106	30,103	31,122
	ZP26	1,607	1,636	1,699	1,751	1,797	1,833	1,874	1,928	1,988	2,046	2,120	2,192	2,266
	SP15	29,069	30,099	30,811	31,597	32,336	32,850	33,656	34,573	35,518	36,484	37,530	38,718	39,934
	SW	3,250	3,250	3,250	3,250	3,250	3,250	3,250	3,250	3,250	3,250	3,250	3,250	3,250

Figure 4. Forecasted Annual Consumption Levels (GWh)

		2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Very Low	NP15	94,421	97,032	101,266	104,858	107,214	109,114	111,461	112,430	113,255	114,146	112,914	112,270	110,024
	ZP26	6,850	7,042	7,374	7,652	7,829	7,967	8,139	8,210	8,279	8,356	8,277	8,229	8,065
	SP15	134,030	138,697	142,548	146,614	149,380	152,093	154,900	156,179	157,162	158,343	157,042	156,283	153,539
	SW	4,456	4,456	4,456	4,456	4,456	4,456	4,456	4,456	4,456	4,456	4,456	4,456	4,456
Base	NP15	100,869	104,179	108,755	113,129	116,093	118,189	120,270	122,778	125,186	127,246	128,913	130,861	132,839
	ZP26	7,318	7,561	7,919	8,255	8,476	8,629	8,783	8,965	9,150	9,315	9,449	9,592	9,737
	SP15	141,592	147,216	151,381	156,364	159,852	162,820	165,327	168,425	171,279	173,847	175,991	178,298	180,639
	SW	4,456	4,456	4,456	4,456	4,456	4,456	4,456	4,456	4,456	4,456	4,456	4,456	4,456
Very High	NP15	110,664	113,360	117,479	121,363	124,573	127,071	129,544	133,730	137,753	141,660	146,287	151,299	156,429
	ZP26	8,027	8,228	8,553	8,855	9,095	9,277	9,460	9,764	10,068	10,369	10,721	11,089	11,465
	SP15	153,109	158,211	161,691	166,070	169,847	173,319	176,315	181,393	186,158	190,928	196,580	202,515	208,589
	SW	4,456	4,456	4,456	4,456	4,456	4,456	4,456	4,456	4,456	4,456	4,456	4,456	4,456

[10] It is important to note that the regional synthetic hourly load shapes and the peak demand projections are all based on the CAISO control area definitions as of March 2002, at which time the CEC had provided LE such data. Recently, certain municipalities, such as SMUD, have exited the CAISO system. However, for consistency with the inputs, our modeling includes them both on the demand and supply side

Modeling Near-term New Generation Entry and Retirements

The modeling approach for new generation entry is an important component of a transmission valuation methodology. Near-term new generation entry (e.g. two to three years out) can be determined through evaluating publicly available data on plant licensing. In the case of California, such information is readily available on the California Energy Commission's website and is updated frequently. Plants that are under construction or that have received all the necessary permitting and approvals should be included as a base-case in the transmission study, unless there is substantial information that supports not including such plants. Moreover, recent history has shown that even projects permitted and or under construction can be cancelled or significantly delayed. To capture this uncertainty, additional scenarios should be performed where some of this generation is assumed delayed or canceled. Given the required lead time in plant siting and construction, and the duration of the approval process, we believe that the majority of the announced capacity which has not been approved but is in the process of filing with the CEC will likely be delayed or canceled and therefore should not be included explicitly in the transmission study. Additional new generation entry under a longer time horizon is best addressed through the addition of generic new generation as a function of expected profits (see section on Modeling Long-term New Generation Entry).

In the illustrative Path 26 analysis, in addition to the new plants in 2002 that are already on-line, the following new generation facilities, which are currently either under construction or have received full CEC approval, were assumed available in this study.

Figure 5. Assumed Near-term New Generation Entry

Ownership	Name	Region	DNC	Year in	Unit Type
CPCO	Feather River	NP15	45	2002	Peaker
CPCO	Goosehaven Energy Center	NP15	49	2002	Peaker
CPCO	Lambie Energy Center	NP15	49	2002	Peaker
CPCO	Los Esteros	NP15	195	2003	CCGT
MISC	Tracy Project	NP15	169	2003	Peaker
CPCO	Wolfskill Energy Center	NP15	49	2003	Peaker
		NP15 Total	555		
MISC	Huntington Beach	SP15	225	2002	CCGT
MISC	Springs	SP15	40	2002	Peaker
MISC	Blythe Energy Project	SP15	517	2003	CCGT
MISC	Central La Rosita I	SP15	160	2003	CCGT
MISC	Central La Rosita II, Phase 2	SP15	155	2003	CCGT
MISC	High Desert	SP15	850	2003	CCGT
CPCO	Pastoria Power Project	SP15	755	2003	CCGT
CPCO	Pastoria Project	SP15	750	2003	CCGT
MISC	Termoelectrica De Mexicali	SP15	600	2003	CCGT
MISC	Wind Project (Windridge)	SP15	20	2003	Wind
		SP15 Total	4,072		
SDGE	Elk Hills Power Project	ZP26	530	2003	CCGT
SCEC	Sunrise Power Project, Phase II	ZP26	200	2003	Peaker
		ZP26 Total	730		
		Grand Total	5,357		

In addition, the following retirements were assumed based on information provided by the CAISO Operations Engineering & Maintenance Department

Figure 6. Near-term Plant Retirements

Plants	*Size*	*Zone*	*Date of Retirement*
Alamitos 7	134 MW	SP15	12/31/2003
El Segundo1 & 2	339 MW	SP15	12/31/2002
Etiwanda 5	130 MW	SP15	12/31/2003
Huntington Beach 5	128 MW	SP15	12/31/2002
San Bernardino 1 & 2	126 MW	SP15	12/31/2002

Modeling Long-term Energy Contracts

The extent to which buyers and sellers are hedged through long-term contracts will have important implications on the ability and incentives for exercising market power in future periods. If buyers are mostly hedged, the spot market will be relatively small which will make it more difficult for any single supplier to exercise market power. In addition, if a seller has pre-sold most of its capacity through long-term contracts, the potential profits from exercising market power are relatively small since only a small portion of the supplier's portfolio can benefit from a strategy to raise spot prices. Because the potential pay-off will be smaller, suppliers will have less of an incentive to exercise market power.

Some have argued that if hedging through long-term energy contracts is an effective strategy for mitigating market power than directing load serving entities to hedge most of their load in future periods is a more cost-effective strategy for mitigating market power than building additional transmission. This argument fails to recognize that if a lack of transmission expansion increases market power in the spot market, this market power will be reflected in the long-term energy market as well since suppliers will reflect the expected spot market opportunities in the price at which they are willing to provide a long-term energy contract.

Figure 7 below provides a summary of the long-term contracts assumed in this study. These contracts will be assigned to the generator owners (e.g. CPCO = Calpine Corporation, WESC = Williams) for the purposes of determining strategic bidding. The contracts will also be assigned to load serving entities for the purposes of determining their residual net-demand in the empirical based market power simulations.

Figure 7. Assignment of CDWR Long-term Contract

Owner	Price Region	Start Month	Start Year	Stop Month	Stop Year	MW Amount	Exercise Price
MISC	SP15	10	2001	12	2011	1000	61
CPCO	NP15	10	2001	9	2005	1000	59
CPCO	NP15	8	2001	7	2009	495	164
CPCO	NP15	7	2001	6	2009	1000	60
CPCO	NP15	5	2002	4	2011	225	110
MISC	NP15	5	2001	8	2014	400	60
MISC	SP15	7	2003	9	2014	175	60
MISC	NP15	7	2002	6	2012	100	60
MISC	SP15	7	2004	6	2012	175	60
MISC	SP15	1	2002	12	2004	800	120
MISC	SP15	2	2001	2	2006	50	120
Pacificorp	NP15	7	2001	6	2011	300	70
PGEC	SP15	10	2001	6	2011	66.6	59
SCEC	SP15	4	2002	9	2011	920	85
SCEC	SP15	6	2002	9	2011	220	110
WESC	SP15	6	2001	11	2005	600	63
WESC	SP15	4	2001	3	2010	300	87
WESC	SP15	6	2001	11	2010	400	63
WESC	SP15	1	2003	12	2011	500	63

Modeling Transmission Limits for Path 15 and Path 26

Assumptions about the available transmission capacity of Path 15 and Path 26 are important input components to the transmission valuation model. The nominal transfer capabilities of Path 15 and Path 26 are shown in Figure 8 below in each direction. The proposed Path 26 expansion contemplates two upgrades: a 400 MW upgrade in 2003-04 and a 600 MW upgrade in 2005 (for both directions).

Figure 8. Nominal Transmission Limits for Path 15 and Path 26

Year	Path 15		Path 26 No-Expansion		Path 26 Expansion	
	S -> N	N->S	S -> N	N->S	S -> N	N->S
2002	3,900	1,275	3,000	3,000	3,000	3,000
2003-04	3,900	1,275	3,000	3,000	3,400	3,400
2005-13	3,900	1,275	3,000	3,000	4,000	4,000

While a review of the nominal transmission capabilities is informative, in practice, not all of this capacity is made available to the market. Historically, a significant portion of this capacity is unavailable due to market participants reserving existing transmission rights in the day-ahead market but never fully utilizing those rights in real-time. Since many of the existing ETCs on Path 15 and Path 26 will remain through year 2014 and beyond, it is important to consider the impact of unscheduled ETC in determining "available" transmission capacity during the study period. The following methodology was used to make this determination:

1. Historical data was reviewed to determine for each path and each direction the average percent of ETC rights that were reserved but not scheduled in the day-ahead market.
2. The quantity and timing of any ETC expirations on Path 15 and Path 26 were determined and those quantities were subtracted from the total ETCs on each Path.
3. The percentages derived in Step 1 were applied to the estimated remaining ETCs during each year of the study period (i.e. Step 2) to determine an estimate of the amount of ETCs that would not be available to the market for each path and direction and in each year of the study period.
4. Available transmission capacities were derived by subtracting the estimated unavailable ETCs (Step 3) from the nominal transmission capacities shown in Figure 6.

This procedure resulted in the ETC adjusted limits for Path 15 and Path 26 shown below in Figure 9.

Figure 9. ETC Adjusted Limits for Path 15 and Path 26

Year	Path 15		Path 26 No-Expansion		Path 26 Expansion	
	S -> N	N->S	S -> N	N->S	S -> N	N->S
2002	3,230	806	2,035	2,552	2,035	2,552
2003	3,230	806	2,035	2,552	2,435	2,952
2004	3,340	806	2,630	2,742	3,030	3,142
2005	3,423	806	2,720	2,742	3,720	3,742
2006	3423	806	2,720	2,742	3,720	3,742
2007	3584	806	2,820	2,742	3,820	3,742
2008-13	3593	806	2,820	2,742	3,820	3,742
2014	3817	806	2,820	2,742	3,820	3,742

III. Critical Modeling Components

Modeling Imports

When modeling the benefits of a major transmission expansion within the CAISO control area, it is important to have a good representation of the availability and cost of import supplies from both the Desert Southwest and the Pacific Northwest so that these supply sources can be incorporated into the optimal dispatch. Ideally the network representation used for evaluating a major transmission project within the CAISO control area would include a representation of significant generation, transmission, and load resources outside the ISO control area. The representation does not need to be extremely detailed but should instead capture the major load areas, generation resources, and transmission constraints. These components would be integrated into a regional model and the dispatch algorithm would minimize production cost for the entire region. However, acquiring the necessary data to develop such a regional model and the calibration of that model would be a significant undertaking. One would need cost information on major power plants, the capacity values of major hydro resources, regional load forecasts, and anticipated new power plants throughout the WECC interconnect. If one were to obtain all the necessary data and incorporate into a regional dispatch model, extensive testing would be necessary to ensure the model is producing results consistent with observed historical patterns. One area that would be extremely challenging is calibrating the dispatch of hydroelectric resources in the Pacific Northwest. For example, environmental and alternative use constraints on the utilization of hydro resources in the Pacific Northwest would be difficult to incorporate into the modeling process.

The difficulties in developing a broad regional model are not insurmountable – indeed, commercial models exist that do this - but the incorporation of the wider WECC representation into the strategic bidding representations used in this analysis would require a collaborative effort between all the major control areas that comprise the WECC interconnect. In the interim, it will be necessary to adopt a more stylized representation of external areas From California's standpoint, there are two major importing regions, the Pacific Northwest and the Desert Southwest, both of which have very different characteristics that must be reflected in their representation. The Pacific Northwest load is greatest during the winter months and its generation base is almost entirely hydroelectric. The implications of this to California is that imports from the Pacific Northwest are greatest in the late Spring and Summer but diminish significantly through the Fall and Winter. Other important implications to California are that summer availability of Pacific Northwest imports can vary dramatically depending on the overall hydro storage and snow pack conditions.

The availability of imports to California from the Desert Southwest has very different characteristics. In the Desert Southwest seasonal demand patterns tend to coincide with California's seasonal demand and the generation base in the Desert Southwest is largely thermal The implications of this to California is that during Summer high load periods, there is generally less import supply available from the Desert Southwest.

In the illustrative analysis of Path 26, a stylized representation of these two importing regions was developed that captures the basic characteristics of each region.

Modeling Southwest Imports

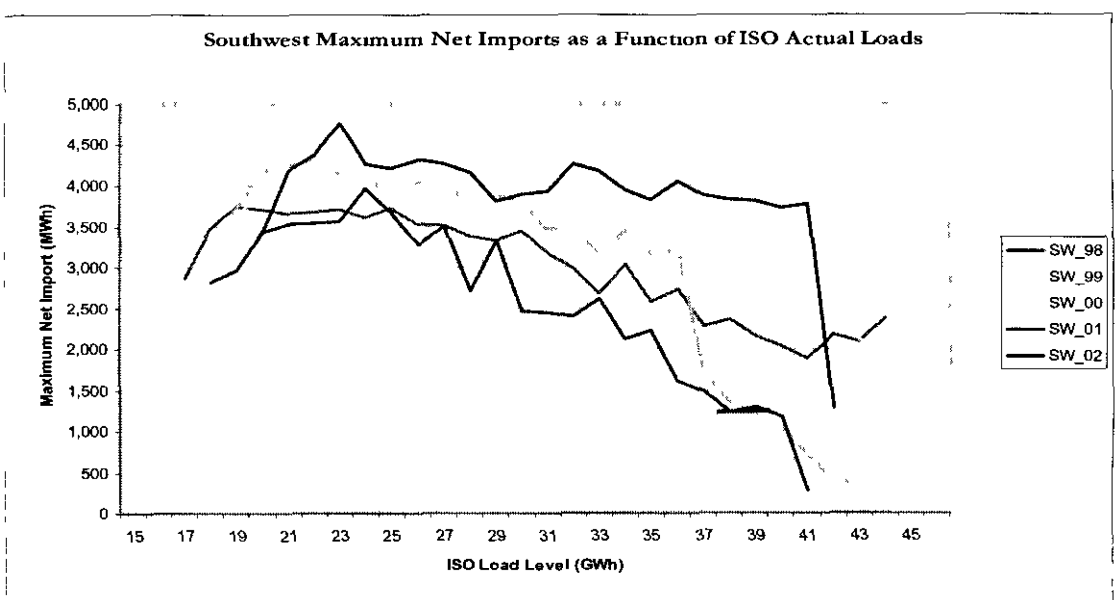
Observed import patterns

To capture the relationship between California load levels and the availability of imports from Desert Southwest, an analysis of historical data was first conducted. The analysis included the imports through the interfaces, Eldorado, Four Corners, Moenkopi, Mead, and Palo Verde through North Gila and Devers to the SP15 region of California for the summer months of July through September for the years 1998 through 2002. The following graph in Figure Figure 10 shows the historical trend.

The hourly load in California varied from 15 GWh to 45 GWh during this time period between the on peak and off peak hours. The imports increased slowly until the hourly load reached the range of 23 GWh to 25 GWh. When the hourly load increased above 25 GWh, imports start declining.

During the years when hydro conditions were relatively wet (1999, 2002), imports declined at a slower pace between the hourly loads of 25 GWh to 40 GWh, but declined significantly when the hourly load increased above 40 GWh. During relatively dry years (2000 and 2001) however, the imports declined more sharply between the hourly loads of 25 GWh to 35 GWh and in some cases switched to a net-export from California to the Desert Southwest when the hourly loads increased above 35 GWh

Figure 10. Relation of Southwest Imports to CAISO Loads



This trend shows that the hourly loads in California are not directly proportional to the imports from the Desert Southwest, but are contingent on peak load and hydrology conditions.

The basic model

The historical patterns identified above are captured in a stylized southwest (SW) zone. This zone is connected to SP15 through a one-way interconnect (no exports from CAISO are allowed) with a maximum capacity of 4,500MW. The stylized SW zone contains:

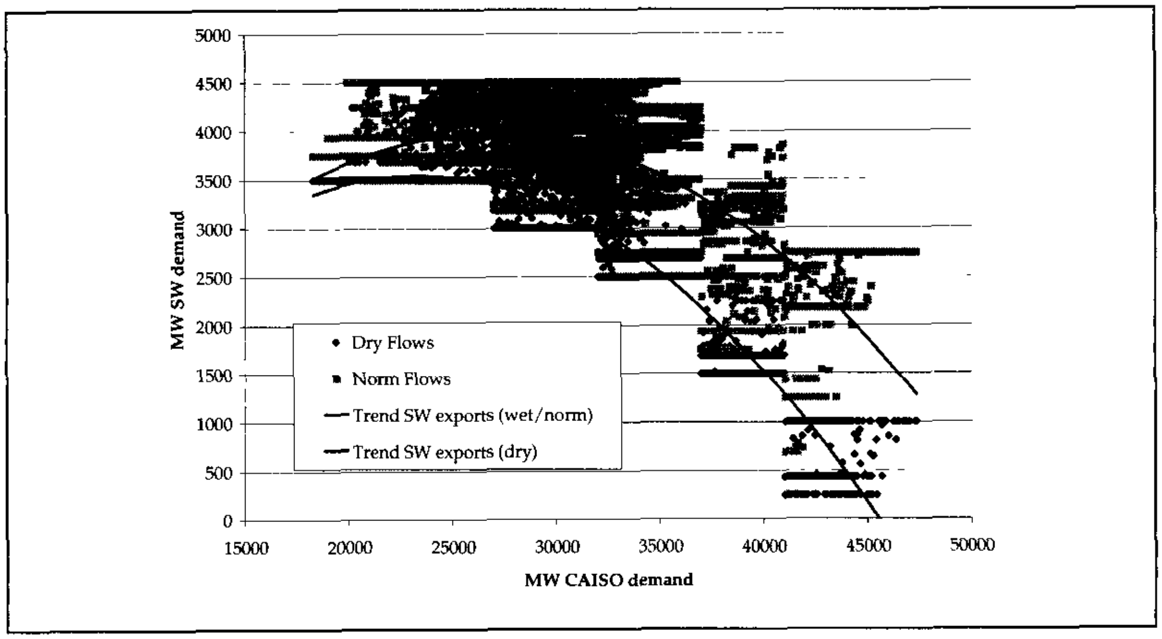
- A pseudo demand component, which is expressed as a function of CAISO demand — the demand in the SW region is fixed across hydrology conditions and time;
- 4,250MW of thermal supply which is assumed to have unlimited fuel availability, and which is independent of hydrology. In the analysis, this was separated into two blocks of 3,500MW and 750MW, both of which were assumed to operate as base-load levels (i.e. with a zero marginal cost); and
- 1,750MW of hydro resources[11], but only in medium and wet hydrology cases, separated into three blocks: a 250MW run-of-river block with sufficient energy to run base-load; 2 x 750MW blocks with sufficient energy to run with a capacity factor of approximately 25%. There are no hydro resources in the dry periods.

The characteristics of resources in the SW zone were selected so as to deliver a pattern of imports that fitted with observed patterns of imports. They did not accord with any specific resources located in the SW.

[11] It should be noted that there are few real hydro resources in the SW Rather, the modeling should be interpreted as in terms of thermal resources in the SW allowing the redeployment of CAISO hydro resources within the CAISO control area

The results of modeling the SW zone are shown in Figure 11, which can be compared directly to the data shown in Figure 10 above.

Figure 11. Estimated SW Imports versus CAISO Load

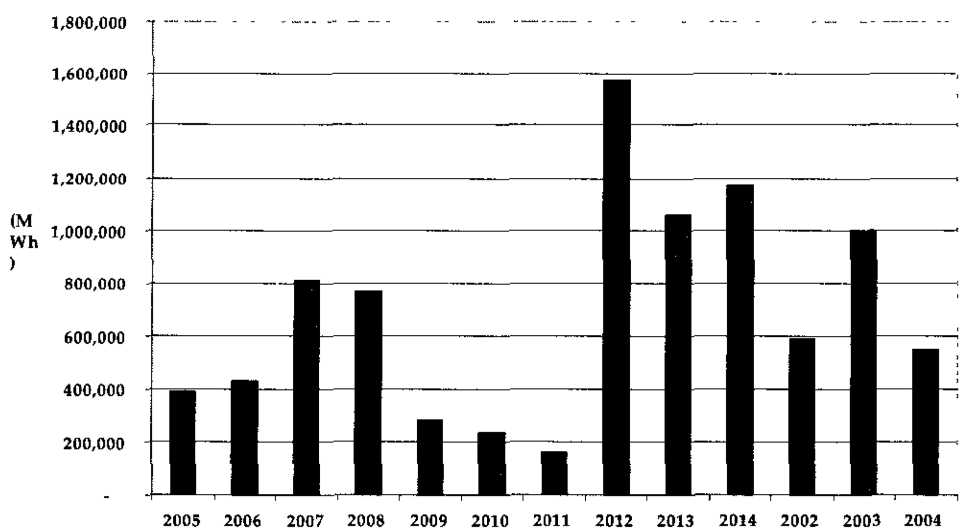


Modeling Northwest Imports

Basic assumptions

Given that a substantial portion of the Pacific Northwest (NW) production capacity is hydro-based, imports from that region into the CAISO control area are modeled as virtual hydro plants in the NP15 region. These modeled imports from the Pacific Northwest[12], are assumed to have a maximum hydro capacity of 4,500MW, based on observed historical flow patterns and the transmission transfer capability between the Pacific Northwest and CAISO. The Pacific Northwest import group is separated out into three blocks (or virtual hydro plants) of 1,500MW, each mainly consisting of run-of-river units with annual load factors ranging from 100% (during wet years) down to 0% (under extremely dry conditions). The underlying data for the Pacific Northwest imports is in the form of actual hourly path flows into the CAISO control area, which were then used to determine the final daily energy budgets per month (MWh per day in a given month) and available capacity schedules (peak MW available in a given month) for these imports into California. Calibrating the pseudo Pacific Northwest imports to match historical import patterns implicitly incorporates to some extent the environmental limitations of Pacific Northwest hydro production. The figure below shows the annual hydro energy budget profile for the modeled period based on an actual thirteen year hydrological cycle of 1988-2000, which is shown in chronological order below but converted to the study period years, where 1998 actual hydro data was assumed for year 2002, 1999 actuals for 2003, 2000 actuals for 2004, 1988 actuals for 2005 etc.).

Figure 12. Annual NW Energy Budgets (MWh/Year)



[12] For purposes of our analysis and in consideration of the historical data used to develop the assumptions, the Pacific Northwest region consists of the following states: Oregon, Washington, Montana, Wyoming and Idaho

In Figure 12, 1998 (shown as 2002) was selected as the starting point for the 13-year hydro cycle because it was determined that the historical hydro production for 1998-2000 would most closely match expected hydro conditions in 2002-2004, as we discuss further below on 'Modeling California Hydrology'. The 13-year series covers 1988-2000 rather than 1990-2002 because the analysis originally began in the Fall of 2001 and there was not sufficient time to update the analysis to the most recent 13-year hydro cycle (i.e. 1990-2002).

The maximum committable level of NW hydro capacity to California is dependent upon observed annual hydro conditions (i.e. wet, dry or medium) using a similar methodology as that which was used to develop the hydro generation schedules for those plants internal to the California ISO control region (see next section). Each year's hydrology profile is sculpted into month-specific daily energy budgets to reflect the historically observed monthly profile of NW imports, but thereafter committed and dispatched in the same way as hydro resources located within NP15. The maximum output from these pseudo NW resources was set by reference to import constraints from the NW. Exports from the California ISO to the Pacific Northwest are included as a portion of the total projected demand for the NP15 region, based on the stylized representation of flows in the transportation model (i.e., this approach basically assumes that all the export capacity flows directly from the NP15 region, though in reality, some exports from the South (SP15 and other control areas south of Path 15) can occur through the Pacific DC Intertie) [13]

[13] It should also be noted that at times these exports from CAISO to the NW can be curtailed The ability to curtail exports in this manner was represented through notional generation resources in the CAISO termed 'export release' resources

Modeling California Hydrology

How one models the availability of hydroelectric generation within California can have important implications on the model results. A methodology for modeling hydroelectric generation must recognize that these resources are typically energy limited (i.e. energy production is limited by the availability of water) and as a consequence, the optimal dispatch must reflect inter-temporal opportunity costs (i.e. the cost of the energy produced today should reflect the foregone market opportunity of selling that energy in some future period). An opportunity cost approach to dispatching hydroelectric supply will optimize the value of hydroelectric production by dispatching it in the highest priced periods. In modeling hydroelectric dispatch one must also recognize the maximum production capabilities of these resources in any particular hour often depends on the overall hydrology conditions. In very dry years, the maximum hourly production capabilities of some facilities is limited due to a lack of river flow or pond storage conditions. This section describes a methodology for matching the maximum output of hydroelectric resources with overall hydrology conditions. The methodology for optimally dispatching California hydroelectric resources is described in the next section.

The underlying data for the California hydrology assumptions came from CEC historical hydro monthly output data (1984-2000). This publicly-available data set was used as the basis for the construction of the 13-year California hydro scenario. This data set comprises actual monthly hydro generation output on a per unit basis, along with the nameplate capacities for each unit. Plant capacity data was cross-referenced with data from the EIA and FERC Form 1 for certain plants, in order to identify and correct any inconsistency in the data or clarify ambivalent capacities in the CEC database.

The hydrology data was also benchmarked against actual metered production figures compiled by the CAISO from the last few years of operation. The simulation model used in this analysis seeks to optimize the use of hydro resources by scheduling its use for peak periods where prices are expected to be highest. The results of the simulation studies and, in consequence, the benefits of a transmission expansion are highly sensitive to assumptions on the ability of NP15 hydro resources to schedule their production in this way. The initial modeling allowed hydro resources to schedule to their maximum capacities (their published P_{MAX} figures), but this was found to give patterns of use substantially different from observed patterns, and patterns of transmission use that differed from observed patterns. After several iterations of the modeling, more realistic[14] outcomes were achieved by adjusting hydro peak capacity by their monthly energy availability.

[14] In the sense that the 'more realistic' modeling parameters gave a pattern of transmission flows and hydro use that most closely matched actual historical observations

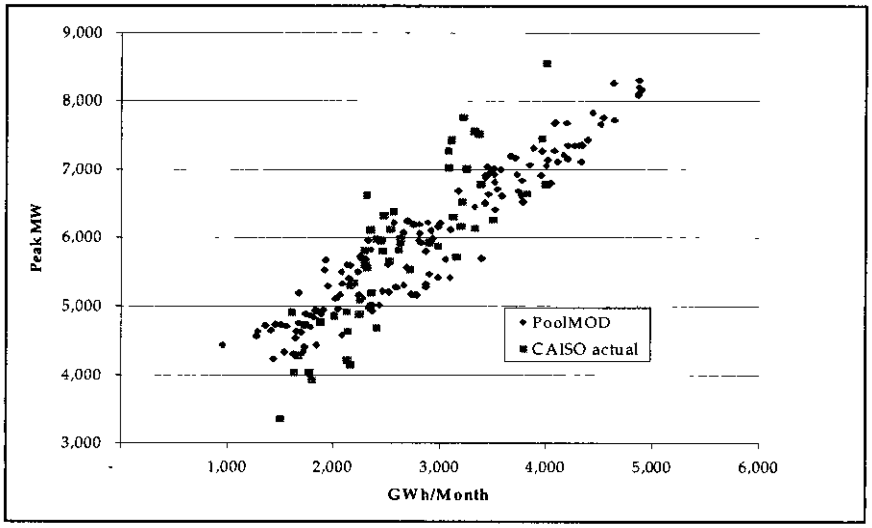
Specifically, an assessment of historical data revealed a strong positive correlation between the monthly maximum output of California hydroelectric resources and their total hydro production for that month (see Figure 13 below). This analysis is based on CAISO data from April 1998 to December 2002.

Figure 13. Regression Results of Monthly Maximum Hydro Production

Dependent Variable = Monthly Maximum Hydro Output in NP15		
Explanatory Variable	Parameter Estimate	t-statistic
Intercept	1,937.50	284 63
Dummy Variable for Summer Months	705 14	153.08
Monthly Total Hydro Energy Production in NP15	0.00140	0.00011
R-Squared		.81
Number of Observations		54

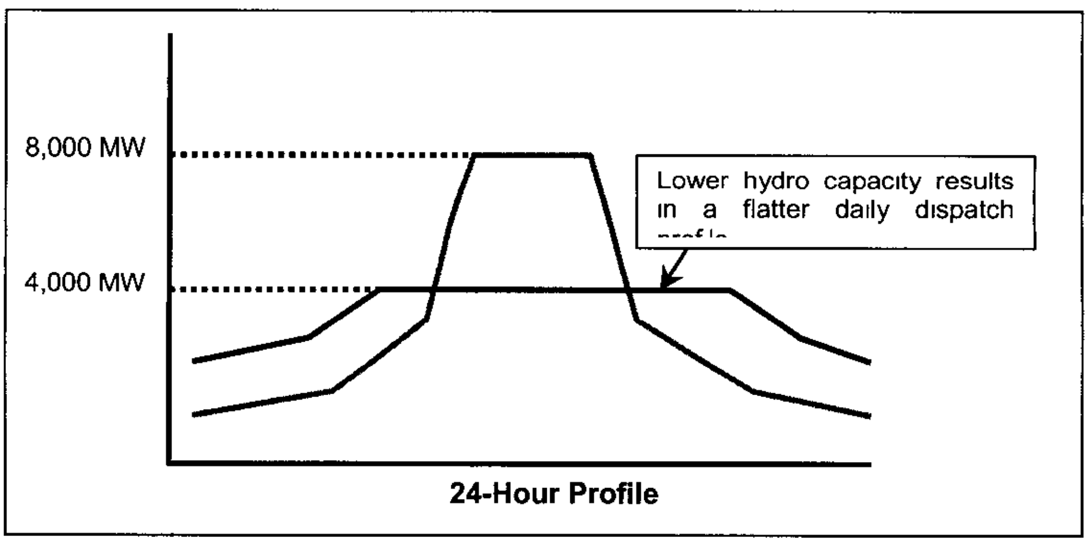
The regression results shown in Figure 13 were used to calculate the maximum monthly hydro capability for each zone in the study period (2002-2014) based on the monthly hydro energy budgets assumed in the study period. The results of these calculations are shown in Figure 14 and compared against historical actual values. This comparison shows that computed values for the study period are very consistent with the historical relationship.

Figure 14. Maximum Hydro Output versus Monthly Hydro Production (NP15)



This adjustment to the monthly maximum hydro capabilities has significant ramifications for the model results because it determines the extent to which daily hydro dispatch can be sculpted to meet peak demand. This effect is illustrated in Figure 15. By assuming a lower maximum hydro capacity value for hydro production in NP15, hydro production profiles become flatter with more energy being provided in the shoulder hours and less in the peak hours. This will result in generally higher prices in the peak hours and lower prices in the shoulder hours.

Figure 15. Impact of Assuming Lower Hydro Capacity



This analysis has two important implications. First it underscores the importance of calibrating hydro dispatch to comport with historical patterns rather than simply assuming the units are always capable of producing at their reported capacity or P-max. Secondly, it provides a vivid insight as to the impact of constraints on hydro operation on system performance.

These calibrations resulted in the energy and capacity patterns shown in Figure 16. The only modification made to the hydro-based import schedule from the Pacific Northwest (as compared to previous databases) was to de-rate the *capacity* broadly in line with the patterns observed in Figure 16; monthly energy was not affected. The CEC data shown in Figure 16 refers to the annual energy reported by the CEC. All the data is net of imports from the Desert Southwest or the Pacific Northwest.

Figure 16. Hydrology assumptions by year (GWh top table, MW bottom table)*

Study	Actual	CEC	Total	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2002	1998	49,126	48,479	2,700	4,069	4,337	4,199	4,639	4,867	4,887	4,865	3,995	3,093	3,052	3,777
2003	1999	38,947	40,642	3,162	3,512	3,735	3,514	3,948	3,955	4,008	3,840	2,914	2,870	2,600	2,585
2004	2000	38,031	41,017	2,364	2,982	4,040	3,764	4,324	4,261	4,104	3,765	2,864	2,785	2,867	2,898
2005	1988	24,495	25,064	1,838	1,503	1,877	2,015	2,079	2,348	3,001	2,806	2,149	2,000	1,638	1,810
2006	1989	30,610	29,235	1,139	1,357	2,511	2,826	2,928	2,882	3,324	3,167	2,256	2,338	2,269	2,239
2007	1990	24,093	23,991	1,372	1,287	1,825	1,900	2,060	2,246	2,748	2,683	2,127	2,366	1,726	1,651
2008	1991	21,733	22,485	1,066	954	1,448	1,554	2,140	2,322	2,755	2,567	2,298	2,075	1,614	1,692
2009	1992	19,889	20,745	1,274	1,409	1,737	1,669	2,151	1,915	2,076	1,923	1,668	1,711	1,430	1,783
2010	1993	39,515	37,745	2,068	2,625	3,539	3,719	4,070	4,085	3,702	3,489	2,799	2,763	2,364	2,522
2011	1994	23,347	23,673	1,399	1,274	1,823	1,773	2,228	2,463	2,655	2,703	1,948	1,833	1,533	2,040
2012	1995	48,401	44,891	2,845	3,501	4,196	4,535	4,859	4,631	4,434	4,184	3,419	3,394	2,431	2,462
2013	1996	45,043	42,139	2,198	3,570	4,388	4,161	4,509	3,877	3,511	3,427	2,809	2,727	2,661	4,303
2014	1997	40,762	38,666	3,649	3,660	3,579	3,093	3,456	3,443	3,448	3,422	2,915	2,982	2,329	2,690

Study	Actual		Max	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2002	1998		8,293	5,409	7,666	7,363	7,160	7,722	8,293	8,160	8,195	7,054	5,420	5,692	6,536
2003	1999		7,274	5,729	6,820	6,683	6,421	6,913	7,274	7,151	7,069	5,953	5,272	5,271	5,278
2004	2000		7,351	4,905	6,163	6,798	6,620	7,121	7,351	7,116	6,841	5,801	5,169	5,325	5,472
2005	1988		6,223	4,452	4,742	4,887	5,112	5,328	5,828	6,223	6,197	5,605	4,877	4,534	4,843
2006	1989		6,693	4,064	4,721	5,624	5,927	5,991	6,226	6,458	6,693	5,706	5,020	5,118	5,168
2007	1990		6,251	4,226	4,644	4,948	4,949	5,170	5,732	6,181	6,251	5,616	5,021	4,406	4,632
2008	1991		6,214	4,046	4,441	4,739	4,714	5,408	5,964	6,204	6,214	5,691	4,582	4,308	4,627
2009	1992		5,674	4,076	4,647	4,891	4,758	5,306	5,537	5,505	5,674	5,194	4,334	4,237	4,702
2010	1993		7,684	4,688	5,902	6,712	6,930	7,279	7,684	7,172	6,971	5,958	5,171	4,935	5,209
2011	1994		6,243	4,087	4,567	4,942	4,873	5,505	5,969	6,076	6,243	5,294	4,435	4,340	4,968
2012	1995		8,251	5,619	7,015	7,352	7,762	8,081	8,251	7,828	7,679	6,514	5,703	5,020	5,221
2013	1996		7,661	4,822	7,007	7,431	7,224	7,661	7,317	6,935	6,882	6,058	5,178	5,313	7,354
2014	1997		7,199	6,477	7,199	6,619	6,125	6,639	7,044	6,929	6,912	6,100	5,416	4,976	5,579

*Excludes COI imports

Figure 17 below, shows the historical annual hydro energy budgets (labeled as the "CEC") over the entire 13-year cycle compared to those used in the modeling process (labeled as "Total"), while Figure 18 shows the monthly energy budgets from April 1998-December 2000.

Figure 17. Comparison of CEC Annual Hydro Production to Simulation Quantities

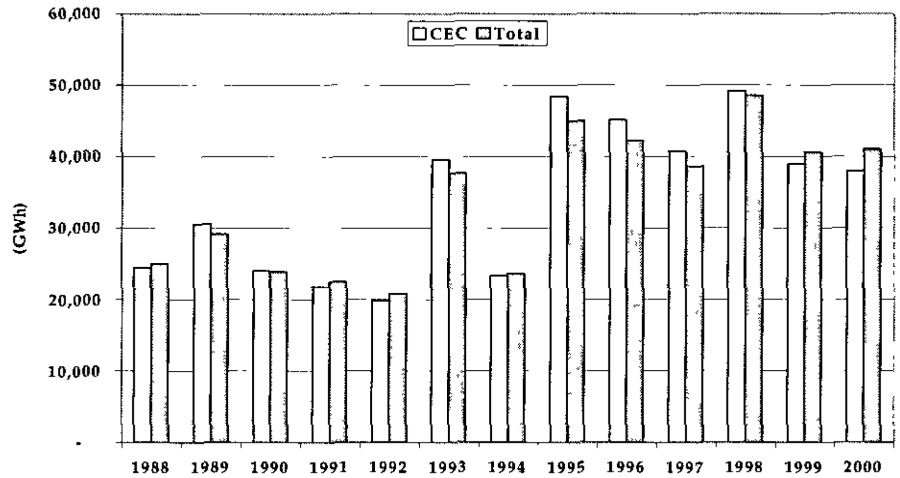
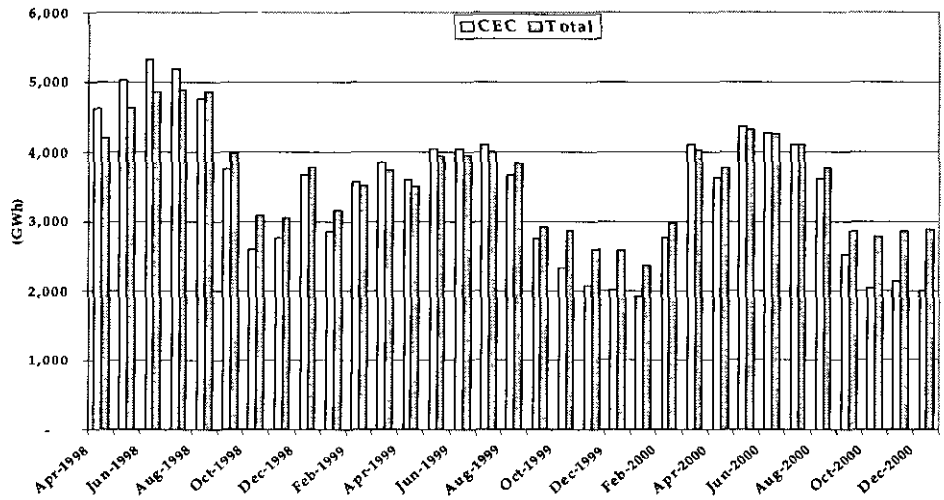


Figure 18. Monthly Energy Budgets from April 1998-December 2000



The minor differences between CEC data and the data used in this study (which can be seen in both charts) reflect two factors: first, the CEC data covered a slightly different mix of units than those used in the study; and second, we did not have access to release schedules for some plant and therefore imposed typical regional capacity factors on them.

Modeling Optimal Generation Dispatch

A sound methodology for modeling and dispatching generation should include random plant outages and a unit commitment program (i.e. large thermal units with long and expensive start-up costs are only turned on (committed) if market revenues over a 24-hour period are sufficient to cover the unit's start-up and other operating costs). The frequency and duration of plant outages should be calibrated to be historically consistent the class and vintage of the units (i.e. 40-year old steam units would be expected to experience higher outage rates of longer duration than a new combined cycle unit). It should also be capable of incorporating energy limitations of both hydroelectric facilities and thermal resources that are subject to environmental restrictions and should include an opportunity cost approach for dispatching these resources. This section describes the modeling methodology used to incorporate these components in the illustrative Path 26 analysis.

London Economics' proprietary electricity market simulation software, PoolMOD, was used to demonstrate the methodology in the illustrative Path 26 case study. PoolMOD determines a 'near' optimal maintenance schedule on an annual basis having regard for the need to preserve regional and zonal reserve margins. Based on the resultant schedule of available plant (net of planned outages), PoolMOD then allocates forced (unplanned) outages randomly across the year based on the forced outage rate specified for each resource. PoolMOD then commits and dispatches plant on a daily basis.[15]

Commitment is based on the schedule of available plant net of maintenance. Hence, plant that may experience a forced (unplanned) outage on the scheduled day will appear in the commitment order. Plant is committed in ascending order of commitment cost starting in the lowest demand period in each day and finishing in the highest demand period in the day.

The commitment price is the total short run operating costs of the unit across the scheduled period of operation in that day including any specified start costs and no-load heat costs. Units that run for 24 hours do not incur a start cost in their commitment price. Hence, start costs become an increasingly large component of commitment price as the period of expected operation in the day reduces. No unit is allowed to incur two starts on a scheduled day. Rather, they are part-loaded in the periods between starts. In addition, no unit is committed for a period less than their specified minimum on time. If they are required for shorter periods, then they are required to run for at least their minimum on time. Sufficient plant is committed to meet demand plus a region specific reserve margin. During the commitment procedure, hydro resources are scheduled according to the optimal duration of operation in the scheduled day. They are

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[15] Commitment algorithms in other models often use a weekly schedule, which tends to result in a more accurate representation of commitment decisions by certain types of conventional thermal plant However, the distortion introduced by a daily commitment algorithm in a large system such as the CAISO is small

then given a shadow price just below the commitment price of the resource that would otherwise operate to that same schedule (i.e., the resource they are displacing). Commitment takes account of transmission constraints. A unit is not committed if running that unit at its minimum stable generation would violate a transmission limit. All committed plant in any half-hour period is then deemed to run in that period at its minimum stable generation.

Dispatch is based on the foregoing commitment order. Resources are dispatched to operate above their minimum stable generation based on their incremental heat rates. No other short-run costs are included in the dispatch price. Units on forced outages are not dispatched. No unit is dispatched at a level that would violate a transmission constraint. Units are dispatched to meet demand (in contrast to commitment, which utilizes demand plus reserves).

The zonal marginal price is then set equal to the dispatch price of the most expensive dispatched resource in that zone or any electrically interconnected zone not subject to a binding transmission constraint (i.e. power must be able to flow from the second zone to the first zone – directly or indirectly - in order for a unit in the second zone to set price in the first).

In the current modeling, several simplifying assumptions were made (although PoolMOD does not force these assumptions). Units were assumed to have constant incremental rates across their whole output, and no start costs or no-load heat costs were included.

Finally, both commitment and dispatch prices were adjusted to take account of bid markups from strategic behavior. The mark-ups applied only to incremental output above a threshold output level.

Modeling Demand Price Responsiveness

Assumptions about demand side price responsiveness in market simulations can have significant implications on forecasted prices and the ability of suppliers to exercise market power. If demand is assumed to be unable to reduce consumption in the face of higher prices, suppliers will have a greater ability to exercise market power and consequently prices will be generally higher. While the development of price responsive demand is a high priority for most restructured electricity markets, these efforts have to date yielded only nominal results. Given the importance of this component, a transmission valuation study should examine the sensitivity of the benefit results to different assumptions about price-responsive demand.

There are two approaches to incorporating price responsive demand into a transmission valuation model: the demand curve can be modeled as a function of price (i.e. a price responsive demand curve is assumed rather than a vertical inelastic demand curve) or price responsive demand could be incorporated into the supply function as curtailable demand (i.e. demand that is willing to curtail once prices reach a certain level(s)). These two approaches are very different in that under the first approach, load reduces consumption to "avoid" having to pay higher prices but under the second approach load is "paid" to reduce consumption. From a policy standpoint, some have questioned the efficiency of the latter approach because it requires verification that curtailments actually took place. However, from a modeling standpoint, both approaches produce the same effect (i.e. consumption goes down when prices go up). In addition, the latter approach is advantageous because it simplifies the benefit calculations for determining consumer surplus. This issue is discussed in greater detail in Section VI – Measuring Net-Benefits.

In the illustrative Path 26 analysis, demand side responsiveness is modeled as dispatchable demand. Hence, these resources are committed and dispatched in the same manner as, for example, a peaking gas turbine. It is assumed that NP15 contains 256MW of curtailable demand in six blocks, ranging in price from $250/MWh to $650/MWh. SP15 contains similar resources, but the block size is 174MW (giving a total of 1,043MW). ZP26 contains 4 blocks of 11MW of curtailable demand priced from $250/MWh to $650/MWh. The price range and level of curtailable demand used in this analysis is roughly commensurate with the prices and level of participation observed in the day-ahead load curtailment programs implemented by the California UDCs in Summer 2000. Under these programs, the UDCs paid customers to reduce consumption when prices in the day-ahead PX Market exceeded $250/MWh.

Under this approach, sensitivity analysis could be performed for this modeling component by assuming different quantity and price levels of curtailable demand in each zone. However, time did not permit for such analysis under the illustrative Path 26 study.

Modeling Long-term New Generation Entry

There are many uncertain elements to consider when conducting a cost benefit analysis for a transmission investment project, but by far, the most challenging uncertainty revolves around the interdependence of generation and transmission assets. The benefits flowing from a transmission investment depend on uncertain future demand for transmission services, and this demand in turn depends on the expected pattern of new generation investment. To determine the optimal transmission investment schedule it is therefore necessary to take account of the incentives to invest in generation. This problem is further complicated by the fact that the relationship between the demand for transmission and the demand for generation services varies over time and space. In some cases generation and transmission are substitutes for each other: a generation asset produces power at a specific location, while transmission delivers power to a specific location. However, under other conditions, generation and transmission projects are also complementary investments: a transmission line expansion may improve the profitability of a generator that is exporting power, as it increases the volume of power that the exporting generator can sell and cause to be delivered.

Additional power requirements in any particular region can be satisfied by investment in generation in that region, or by grid augmentation investment that allows a higher volume of imported power to be delivered. If a single entity with appropriate incentives were responsible for both generation and transmission investment then, faced with additional demand, it would seek the least cost form of supply; trading off the costs and benefits of transmission and generation investment.[16] However, with restructuring, the decision-making capabilities of the transmission planner are no longer integrated with that of generation. While publicly accountable for the efficient and reliable delivery of power, the CAISO only has control over one of the two means by which capital allocations can advance this goal. Thus, in order to optimize transmission investment, the CAISO needs to be able to anticipate potential investment in generation in response to transmission investment and incorporate the interdependence of transmission and generation into the valuation process for transmission.

A methodology for incorporating new generation investment under different transmission expansion options is described below.

Entry Decision

For each transmission upgrade option, a pattern of *long-term* new generation *entry is* derived under the assumptions that, (i) new entry are independent and non-strategic; (ii) new entry will be just sufficient to maintain prices at the appropriate remunerative levels. These appropriate remunerative levels are defined as a benchmark annual revenue requirement, also called "entry trigger

[16] Demand side management is obviously also an option that needs to be considered, but this does not affect the fundamentals of the argument.

price". It is assumed that over the long-term, the two most likely technologies for new generation will be either peaking gas-fired units (SCGTs) or base load advanced combined cycle units CCGTs. The levelized annual revenue requirement for a typical new entrant is set at a level for each technology to recover (a) capital cost; (b) operating cost; (c) debt financing cost (interest and principle repayment); and (d) a 20% (after tax) rate of return on investment for the equity portion for a CCGT (and a 25% after tax return for a SCGT).

These calculations were based on the data shown in Figure 19 and Figure 20, which was derived by London Economics based on announced new California plants whose projected capital costs had been reported publicly. Due to lack of sufficient evidence, investment costs were assumed constant across regions (i.e. SP15, NP15, ZP26). A review of a CEC report on the regional siting costs of new generation revealed no significant difference in siting costs across regions. A summary of this analysis is provided as Appendix B.

Figure 19. Capital Cost of Base Unit (CCGT)

Baseload Unit (CCGT)

	2005	2014
capital cost - real $/kW	$600	$565
average heat rate - Btu/kWh	7,300	6,259
indicative load factor	85%	85%
variable O&M - real $/MWh	$1 5	$1 5
fixed O&M - real $/kW/year	$17 1	$17 1
leverage	70%	70%
debt rate	10%	10%
after-tax required equity return	20%	20%
corporate income tax rate	35%	35%
debt financing lifetime (yrs)	10	10
capital recovery lifetime for equity portion (yrs)	20	20

Figure 20. Capital Cost of a Peaking Unit (SCGT)

Peaking Unit (SCGT)		
	2005	2014
capital cost - real $/kW	$350	$329
average heat rate - Btu/kWh	11,000	9,631
indicative load factor	10%	10%
variable O&M - real $/MWh	$1 9	$1 9
fixed O&M - real $/kW/year	$8.0	$8 0
leverage	30%	30%
debt rate	10%	10%
after-tax required equity return	25%	25%
corporate income tax rate	35%	35%
financing lifetime (yrs)	10	10
capital recovery lifetime for equity portion (yrs)	10	10

Given the capital costs cited above, entry trigger prices are calculated for each year and each zone, based on the capacity factors derived by PoolMOD for each new unit type (SCGT, CCGT). In addition PoolMOD calculates the average unit revenue (AUR) for each new unit type. The addition of new units is then based on a comparison of AUR and trigger prices until the model converges to a point where it is no longer profitable for new entry. Long-term new generation entry was derived separately for each transmission option to reflect the potential substitutability of new generation for new transmission Entry decisions were based on the predicted market clearing prices (i.e. prices that reflect the impact of strategic bidding behavior) rather than competitive prices.

Entry decisions were based on a probability-weighted average of prices under low, medium, and high demand scenarios, assuming normal gas prices, to reflect the fact that entry decisions are based on expected profits under a variety of system conditions. Ideally, one would want to consider expected profits under alternative hydro and gas price scenarios as well. However, because new generation entry is added incrementally in an iterative process, it was not practically feasible to consider more scenarios than the three demand scenarios described above.

Modeling Market Power

In a restructured electricity market, transmission expansions can provide significant consumer benefits by improving market competitiveness. A transmission expansion can increase market competitiveness by increasing both the number of suppliers available to serve load and the total available supply. The number of suppliers is of particular importance because as more suppliers are able to compete for demand, the market becomes less concentrated and more competitive. Of course, a transmission expansion is just one of several structural options for improving market competitiveness. The addition of new generation capacity, increased levels of forward energy contracting, or the development of price responsive demand can also significantly reduce the ability of suppliers to exercise market power in the spot market. However, a transmission expansion has the additional benefit of improving the competitiveness of not just the spot market but also the longer-term forward energy market. This occurs because the transmission expansion creates greater access to a broader regional market and thereby increases the number of sellers that could offer long-term energy contracts. A comprehensive transmission expansion study should explore the market power mitigation benefits of a transmission upgrade under a variety of plausible new generation entry, forward contracting levels, and price responsive demand scenarios.

Some have argued that it is inappropriate to include the market power mitigation benefits of a transmission expansion in an assessment of the benefits of a transmission expansion and that market power is more appropriately addressed through effective regulation. The CAISO believes that trusting that regulators will have the political will and/or ability to effectively enforce regulations to eliminate market power is a high-risk strategy that could have enormous consequence to consumers if regulators are unable or unwilling to control market power. The California experience in year 2000 is a case in point. We also believe that in the long run, the most effective way to mitigate market power is to correct the structural deficiencies that enable suppliers to exercise market power (e.g lack of supply, lack of forward contracting, and lack of price responsive demand).

This section examines two approaches to modeling strategic bidding behavior (e.g. the exercise of market power) in transmission valuation studies. The first approach involves developing a game theoretic model of strategic bidding. The second approach involves capturing strategic bidding through estimated historical relationships between certain market variables and a variable that captures a measure of market power such as the difference between estimated competitive prices or bids and actual prices and bids (i.e. price-cost markups and bid-cost markups, respectively). Each modeling approach has its advantages and disadvantages.

The advantage of the game theoretic approach is that because it is derived independent of observed historical behavior, it can simulate market power under a variety of future market conditions without the potential bias of having been based on observed historical behavior. This could be particularly important if the market conditions assumed in the model study period are very different than past historical conditions. For example, if a study assumed a much higher level of forward energy contracting or price responsive demand than existed historically, a game theoretic model that explicitly incorporates these elements in determining strategic bidding may be able to better simulate market power than an empirical approach that is based on a period where there was very little forward contracting. However, the game theoretic model's independence from observed historical relationships between market power and specific market conditions raises a significant risk in that if the model is not tested and calibrated to replicate historical bidding practices, there is no guarantee that it will be able to accurately predict strategic bidding in the future. Moreover, it may simply not be possible to calibrate a game theoretic model to match actual market outcomes given that there are a limited number of instruments one can incorporate and adjust in such a model. Another risk in simulation-based game theoretic models is that the converged solution may not be truly converged or represent a true equilibrium. This can happen if the strategy space is too narrowly defined or if the limit on the maximum number of iterations is set too low. It may also happen if the model is simply too complicated to converge to a solution. In order for a game theoretic model to solve in a tractable and timely manner, the model must be fairly simplistic in terms of network representation and the types of bidding strategies. Such simplifications may make the model too abstract to reasonably capture market power.

The advantage of modeling market power through an empirical approach where estimates of historical relationships between market power (as expressed through bid-cost or price-cost markups) and certain market variables (such as load levels and supply margins) are applied prospectively in the transmission study is that the approach has a strong historical basis. Another advantage is that this approach could be applied to a more detailed transmission network representation provided the model can produce the required explanatory variables (i.e. the variables contained in the regression equation(s)) at a more granular level. A potential disadvantage of this approach is that because it is based on estimated historical relationships, its predictive capability may be limited if applied under very different market conditions.

Given that both approaches have complementary strengths and weaknesses and that work in this area is relatively new, we have developed versions of both approaches and applied them in the illustrative case study of Path 26. Each of these approaches is discussed in greater detail below.

Game Theoretic Models

Game theoretic models typically consist of several strategic suppliers with each player seeking to maximize its expected profits by changing its bidding strategy in response to the bidding strategies of all other players. An equilibrium is attained when no player can increase its expected profits given the bidding strategies of all other players. In very simplistic game theoretic models, an equilibrium can be solved for mathematically. In more complicated models, an equilibrium cannot be solved directly but must instead be derived through an iterative process where each player's bid is adjusted based on the observed bidding behavior of all other players in the previous iteration. The model converges when no player wants to change its bid strategy, given the bid strategies of all other players in the previous iteration. A meaningful model of strategic bidding in a transmission study must recognize the major constraints in the transmission network and the location of each player's supply within the network. These requirements generally make the model too complex for determining a solution mathematically and thus an iterative convergence approach is necessary.

An iterative model of strategic bidding, "ConjectureMod", was developed by London Economics and applied in the illustrative case study of Path 26. The term "ConjectureMod" (CM) is derived from the central tenet of the model, namely that strategic behavior is simulated through an iterative process in which participants conjecture that their competitor bids are some function of their profit maximizing bids in previous iterations. The model then produces details of each iteration, which include bid markups on players' marginal costs, portfolio average unit revenue and regional prices.

The starting point of this iterative procedure is that each bidder *i* predicts that each other bidder *j* is bidding its marginal cost at output level q_j, i.e., $P_j(q_j) = MC_j(q_j)$. Then, for each demand level *D* bidder *i* chooses its offered bid pair $(P_i(q_i;D), q_i)$ according to an assumed supply function form (see discussion in below) to maximize its net profit in view of its residual demand function given *D* and its prediction of other bidders' supplies. For the iterative procedure thereafter, each firm conjectures that each players bid is their profit maximizing bid from the previous iteration.

The discontinuous nature of the supply curve and the solution methodology underlying production-cost simulation and traditional transport models does not allow specification of a continuous strategy space. Rather, each player's supply function is assumed to take the following form:

$$B_{jZ}(q_{jZ}) = [MC_{jZ}(q_{jZ}) - k]\mu + k, \qquad b_{jZ}(q_{jZ}) \leq 1000$$

where $MC_{jZ}(q_{jZ})$ is the marginal cost of generator j in zone k at output q_{jZ}, k is a constant which could be considered similar to the intercept used in linear SFE models and μ is a discrete strategy choice $\in$ (1, 1.1, 1.3, 1.5, 2, 3, 4, 5, 10, 15, 20, 25, 30, 35, 40). Furthermore:

- k was indexed against prevailing gas prices to ensure that the mix of strategic plant is not affected by the gas price assumption in the model; and
- units that bid strategically are assumed to bid marginal costs on their capacity up to elbow point 1 (typically the first third of their total capacity), and strategically only on capacity in excess of this figure.[17]

Convergence rules were set such that the model was deemed to have converged if the profits of each and every player do not diverge across the last two iterations by more than 1%, or when 50 iterations are complete.

The profit for each player is based on the relevant zonal prices having regard to any transmission constraints, and also takes into account the revenue impacts of any long-term contracts that may apply to that player.

ConjectureMOD is closely integrated with PoolMOD. It estimates markups for all resources based on the same schedule of resources used by the PoolMOD commitment algorithm, and uses the same algorithm to determine transmission constraints.

[17] The assumption closely follows observed behavior in markets such as E&W and SE Australia

Empirical Approach

An empirical approach to modeling market power was developed in this study through estimating the historical relationships between certain market variables and observed price-cost markups. The basic approach involved developing historical measures of price-cost markups as a function of system conditions and utilizing those estimated relationships to model market power prospectively under the various system conditions assumed in a transmission valuation study.

The approach entails four major steps.

1. Complete a price-cost markup regression analysis using historical data (Nov 99 – Oct 00) where the hourly price-cost markup in each zone (j) is regressed against a residual supply index ($RSI_{i,j}$) – a measure of the extent to which the largest supplier is "pivotal" in the market, Uncommitted Capacity of the largest single supplier in the zone ($TUC_{i,j}$), the total zonal load ($LD_{i,j}$), a dummy variable for whether it is a summer month ($SP_{i,j}$), and a dummy variable for whether the zone is NP15 or SP15 ($NS_{i,j}$).
2. Under the various supply and demand scenarios considered in the prospective transmission valuation study, determine for each hour (i) and zone (j):
    - Residual Supply Index ($RSI_{i,j}$)
    - Identity of Largest Single Supplier ($LSS_{i,j}$)
    - Total Uncommitted Capacity of $LSS_{i,j}$ ($TUC_{i,j}$)
    - Zonal Load ($LD_{i,j}$)
3. Apply the regression equation(s) in Step 1 to the values derived in Step 2 to estimate the price-cost markups in each zone and apply the estimated price-cost markups to the competitive based MCPs in each zone to compute market-clearing prices under the various supply and demand scenarios.
4. Calculate new generation investment for the base case scenarios through iterations between competitive PoolMOD and the application of the estimated price-cost markups.

Each of these steps is described in greater detail below.

Step1: Price-cost Markup Regression Analysis

Definition of Regression Equation

The regression analysis for determining the relationship between price-cost markups and certain market conditions is based on data for Nov 99 – Oct 2000[18]. Specifically, the following regression equation is estimated:

$$PMU_{i,j} = a + b\,RSI_{i,j} + cTUC_{i,j} + d\,LD_{i,j} + eSP_{i,j} + fNS_{i,j}$$

Where

$PMU_{i,j}$	=	The price-cost markup for hour (i) in zone (j).
$RSI_{i,j}$	=	Residual Supply Index in hour (i) for zone (j)
$TUC_{i,j}$	=	Total Uncommitted Capacity of largest single supplier in hour (i) for zone (j)
$LD_{i,j}$	=	Actual load in hour (i) for zone (j)
$SP_{i,j}$	=	Dummy for summer periods (May-Oct)
$NS_{i,j}$	=	Dummy for whether the zone is NP15 or SP15

The price-cost markup, RSI, and largest single supplier variables are described in greater detail below.

[18] This 12-month period was selected because it provides a broad range of market conditions and bid-cost markups. In prior periods, the market was generally workably competitive (e.g. very low bid-cost markups) and post periods have varied from extremely dysfunctional (Dec 00 – Apr 01) to extremely moderate (May 01 – Current). Moreover, with the demise of the PX, the post period does not have a DA energy market and has been essentially a market with a single buyer (State of California) that buys predominately through bilateral arrangements Consequently, the real-time market prices during the post periods may not necessarily reflect the market outcomes that would arise under a market setting with multiple buyers.

Definition of Variables

Price-Cost Markup (PMU)

The Price-Cost Markup is actually expressed as the Lerner Index, which is equal to the following:

$$\text{Lerner Index} = ((P_{i,j} - C_{i,j})/P_{i,j})$$

Where

$P_{i,j}$	=	Actual price in hour (i) and zone (j)
$C_{i,j,}$	=	Estimated competitive price in hour (i) and zone (j)

This specification implies that the explanatory variables in the regression equation have a non-linear relationship with actual market clearing prices. This is important because historically market prices tend to increase exponentially when market power is being exercised.

Residual Supply Index (RSI)

The Residual Supply Index ($RSI_{i,j}$) in each hour (i) and for each zone (j) will be calculated according to the following formula:

$$RSI_{i,j} = \frac{TS_{i,j} - Max(TUC_{i,j})}{RND_{i,j}}$$

Where,

$TS_{i,j}$	=	Total Available Supply (available imports + the uncommitted capacity of independent generator owners)
$Max(TUC_{i,j})$	=	Total Uncommitted Capacity of Largest Single Supplier
$RND_{i,j}$	=	Actual zonal demand less utility owned generation output - QF generation - Long-term Contracts[19].

The RSI measures the extent to which the largest supplier is "pivotal" in meeting demand. The largest supplier is pivotal if the Residual Net Demand (RND) cannot be met absent the supplier's capacity and such a case would translate to an RSI value less than 1. When the largest suppliers are pivotal (an RSI value less than 1), they are capable of exercising market power.

[19] For the period under study, long-term contracts will be comprised of any PX Block Forward Energy contracts Also for the NP15 region, RND is adjusted downward by the net energy production of PG&E's resources in zone ZP26 [PGE_Gen_{ZP26} - PGE_Load_{ZP26}] to reflect the fact that a portion of the NP15 load is served by the PG&E's generation capacity in the ZP26 zone.

Total Uncommitted Capacity of Largest Supplier

Total uncommitted capacity for each supplier (i) for each zone (j) is comprised of the uncommitted capacity the supplier has physically located in the zone ($UC_{j,i}$) plus any imports to the zone that the supplier can physically control (Controllable Transmission Capacity (CTC)).

Determining the Total Uncommitted Capacity of the Largest Single Supplier is complicated by the fact that one significant generator owner owns substantial capacity in all three zones (SP15, NP15, and ZP26) and consequently may be able to strategically withhold supply to one zone through withholding generation in another zone. Thus a measure that simply looked at the uncommitted capacity of this supplier in a particular zone (e.g. NP15) may understate this supplier's ability to manipulate prices in NP15. Hypothetically speaking, by withholding its generation portfolio in ZP26 and SP15, this supplier may have been able to reduce the total imports supplied to NP15 via Path 15. Whether this supplier is capable of reducing imports from Path 15, depends on whether Path 15 could be congested absent this supplier's supply (i.e. whether there is uncommitted capacity from other suppliers south of Path 15 in excess of the Path 15 rating). Thus, the appropriate measure of the total amount of strategic capacity that this supplier has available in NP15 should included its uncommitted capacity in NP15 as well as any portion of the import capacity on Path 15 that it could control through withholding its supply portfolio in ZP26 and SP15. A general methodology for calculating the total strategic capacity of each generator owner is described in Appendix A.

Total Available Supply

Capacity on Major Inter-Ties

The determination of total supply for each zone must include an assessment of how much energy is actual available at the inter-ties. The critical term here is "available" because from a market power standpoint, the ability of a market to compete away any attempt to exercise market power stems from the amount of supply capacity available as opposed to what was actually generated. When there is an abundance of capacity in the market, suppliers will bid aggressively (i.e. close to their actual marginal cost) since they know if they bid too high, they will not be selected.

Modeling the amount of "available supply" on the Pacific Northwest inter-ties is complicated by the fact that actual scheduled flows in any hour may not be indicative of the total available supply Moreover, using the total import transmission capability may overstate the actual available supply, particularly during dry periods. An alternative is to base the available import capability on schedules and submitted RT bids. However, this approach would tend to understate the available supply if participants tend not to offer into the real-time market in hours when prices are expected to be relatively low. Given these difficulties, the following approach was used for determining the available supply on the major Northwest path into California (COI).[20]

Available Transmission Capacity on COI (Import Direction):

$$ATC\_COI_i = \text{Min}[\text{Max}[0, \text{Maximum hourly flow for operating day})], Grp\_lmt_i]$$

Under this formulation, the assumed available supply in each hour is set to the lower of the maximum hourly scheduled net-imports for that operating day and the transmission import limit for that hour. The transmission import limit (Grp_lmt_i) is the total transmission capability less any unused ETC reservations[21]. This approach assumes that the maximum hourly schedule for each operating day represents the maximum supply available for each hour of that day. While this is not a perfect measure, it strikes a reasonable compromise between assuming the hourly scheduled flow as the total available capacity, which would tend to understate the total available supply, and assuming the hourly transmission limit ($Grp\_lmt_{i,j}$), which would tend to overstate the total available supply.

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[20] A similar approach could be adopted for the Pacific Northwest DC line into Southern California. However, this path was not modeled in the market simulation software and therefore was not included in the regression. Ideally, the Pacific Northwest DC line (NOB) would be modeled in both the regression analysis and in the prospective transmission valuation methodology.

[21] Capacity for Existing Transmission Contracts (ETCs) are often reserved in the day-ahead market but never utilized Since this unscheduled ETC capacity is not available to the market, it is subtracted from the total transmission capability

Measuring the available supply for each hour on the southwest inter-ties is also challenging. As with the Pacific Northwest inter-ties, using the hourly net-import schedules on the Desert Southwest inter-ties as the measure will tend to underestimate the total available supply. Using the total transmission limit (Grp_lmt_i) may be appropriate during off-peak periods but could significantly over-state available supply during summer peak periods when scheduled imports from the southwest are fairly low. As was previously discussed, during the summer peak periods, the available supply from the Desert Southwest tends to be inversely related to load levels in California. This occurs because California's summer peak loads are highly correlated with the Desert Southwest peak loads. Thus during simultaneous peaks, there is less supply available from the Desert Southwest for import into California. To capture this phenomenon, the following approach was used to determine the available supply on southwest paths to California:

Available Transmission Capacity on the major Southwest Interfaces (Palo Verde, Mead, Eldorado, Silver Peak):

ATC_SW_i = the lowest of the following:

1. Max[0, maximum hourly flow for operating day)],
2. Grp_lmt_i, and
3. Maximum import capability for the load category (L) (this 3rd term only applies in Jun-Sep in hours where hourly CAISO loads exceed 38,000 MW).

   The maximum import capability for load category L, is computed as:

   $$Max[0, \sum_{x=1}^{X} ActualFlow_L]$$

   Where the load category is defined in 1 GWh increments from 38-46 GWh and "X" represents the different inter-ties between southwest and CAISO control area.

   For instance, maximum import capacity for the load category between 38,000 MW and 39,000 MW would be the largest import quantity recorded where the load is between 38,000 MW and 39,000MW in the summer months. This third term is included to reflect the fact that during high load periods, the amount of supply available on the SW branch groups typically declines because CAISO summer peak loads are highly correlated with the Desert Southwest peak loads leaving less supply available for import into California.

Another important import supply for the CAISO control area are the inter-ties connecting to the Los Angeles Department of Water and Power (LADWP). Since LADWP's loads are also highly correlated with loads in the CAISO control area, the same approach used to determine available supply for the southwest inter-ties was used for the inter-ties with LADWP.

Available Transmission Capacity for the inter-ties connecting to LADWP (Sylmar, Mccullgh, Inyo, andVictvl):

$$ATC\_LA_t = \text{Same approach as } ATC\_SW_t$$

Capacity on internal paths:

Since price-cost markups are estimated on a zonal basis, it is also necessary to make certain assumptions about the amount of available supply on the two major internal paths (Path 15 and Path 26) that define the three major internal zones in the CAISO control area (NP15, ZP26, and SP15). The available supply on the internal paths was determined by taking the lower of the total uncommitted supply in exporting zones and the path limit (Grp_lmt). For example if in a particular hour, the total supply in NP15 that could be exported to ZP26 ($TS_{N\text{-}Z}$) is 700 MWh and the Path 15 limit for that hour in the north-south direction is 806 MW ($Grp\_lmt_{N\text{-}Z}$) then the available supply on Path 15 north to south ($ATC_{N\text{-}Z}$) would be set equal to 700 MW. This value would then be combined with the total uncommitted supply in ZP26 to determine the maximum amount that could be exported to SP15.

Path 15 north to south:

$$ATC_{N\text{-}Z} = \text{Min } [TS_{N\text{-}Z}, Grp\_lmt_{N\text{-}Z} \text{ of Path 15}]$$

Where,

$$TS_{N\text{-}Z} = ATC\_COI + \Sigma UC_{NP15} + \text{Other Generation}$$[22]

Path 26 north to south:

$$ATC_{Z\text{-}S} = \text{Min } [TS_{Z\text{-}S}, Grp\_lmt_{Z\text{-}S} \text{ of Path 26}]$$

Where,

$$TS_{Z\text{-}S} = ATC_{N\text{-}Z} + \Sigma UC_{ZP26}$$

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[22] Other generation includes generation from facilities other than the five new generation owners (Dynegy, Duke, AES/Williams, Mirant, and Reliant), UDC owned facilities, and qualifying facilities (QFs) Calpine was not included because their gas-fired capacity was not on-line during the study period used in this regression analysis.

Path 26 south to north:

ATC_{S-Z} = Min [TS_{S-Z}, Grp_lmt_{S-Z} of Path 26]

Where

TS_{S-Z} = $ATC_{SW} + ATC_{LA} + \Sigma UC_{SP26}$ + Other Generation

Path 15 south to north:

ATC_{Z-N} = Min [TS_{Z-N}, Grp_lmt_{Z-N} of Path 15]

Where

TS_{Z-N} = $ATC_{S-Z} + [PGE\_Gen_{ZP26} - PGE\_Load_{ZP26}] + \Sigma UC_{ZP26}$

The total supply available from ZP26 to NP15 (TS_{Z-N}) includes the available transmission capability from SP15 to ZP26 (ATC_{Z-N}), the net PG&E generation (i.e. Diablo generation less PG&E load in ZP26), and the total uncommitted capacity of all other suppliers in ZP26 (ΣUC_{ZP26})

Total available supply in NP15:

Total Available Supply in NP15 is defined as follows:

$$TS_{NP15,t} = \sum_{m=1}^{M} UC_{m(NP15),t} + (\mathrm{ATC}_{z\text{-}n,t} - [\mathrm{PGE\_GenZP26 - PGE\_LoadZP26}]) + ATC_{COI,t}$$
$$+ \textit{Metered Generation From Other Generators Other than NGOs, UDC, and QFs}$$

Where,

$\sum_{m=1}^{M} UC_{m(NP15),t}$ = the sum of the uncommitted capacity[23] of the two major independent generator owners in NP15 (Duke and Mirant).

The Capacity of Path 15 from south to north is further reduced by [PGE_Gen_{ZP26} - PGE_Load_{ZP26}] to reflect the fact that most of energy generated by the PG&E owned Diablo facility in ZP26 zone serves load in NP15. Diablo's net of load generation in ZP26 is also subtracted from the NP15 Residual Net Demand (RND_{NP15}) in the RSI calculation (i.e. counted as utility owned generation output).

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[23] Uncommitted capacity for each generator owner is equal to the total available capacity less any capacity committed under long-term contracts

Total Supply in SP15

The Total Supply for SP15 will be calculated as follows:

$$TS_{SP15,i} = \sum_{m=1}^{M} UC_{m(SP15),i} + ATC_{ZP26,i} + ATC_{SW,i} + ATC_{LA,i}$$

Where,

$\sum_{m=1}^{M} UC_{m(SP15),i}$	=	the sum of the uncommitted capacity of the three major independent generator owners in SP15 (Williams, Dynegy, Reliant)

Summary of Estimation Methodology

In summary, the computation of the variables described above will result in a data set having 4 variables for each hour (i) and zone (j) ($PMU_{i,j}$, $RSI_{i,j}$, $UC_{i,j}$, and $LD_{i,j}$) for all 8,765 hours from Nov 99 – Oct 00. These data will be used to estimate the regression equation based on the following relation:

$$\mathrm{PMU}_{i,j} = \mathrm{a} + \mathrm{b}\,\mathrm{RSI}_{i,j} + \mathrm{c}\mathrm{TUC}_{i,j} + \mathrm{d}\,\mathrm{LD}_{i,j} + e\mathrm{S}P_{i,j} + \mathrm{f}\mathrm{NS}_{i,j}$$

Where

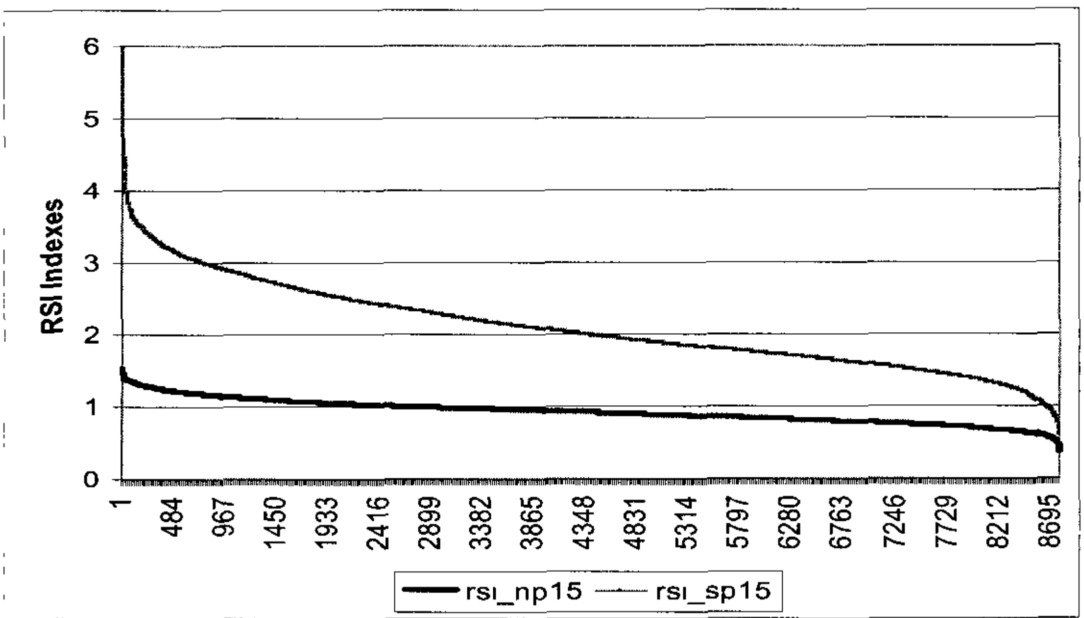
$PMU_{i,j}$	=	Price-Cost Markup for hour (i) in zone (j).
$RSI_{i,j}$	=	Residual Supply Index in hour (i) for zone (j)
$TUC_{i,j}$	=	Total Uncommitted Capacity of largest single supplier in hour (i) for zone (j)
$LD_{i,j}$	=	Actual load in hour (i) for zone (j)
$SP_{i,j}$	=	Dummy for summer periods (May-Oct)
$NS_{i,j}$	=	Dummy for whether the zone is NP15 or SP15

Estimation Results

RSI and Markup

Figure 21 shows the RSI duration curve for the period from November 1, 1999 to October 31, 2000. We can see that RSI indexes are consistently higher in the SP15 zone than NP15 zone, indicating that supply in SP15 is more adequate to meet its load. For the NP15 region, the RSI index is less than 1 for about two-thirds of hours during the period, indicating that there might be potential for exercising market power in NP15 region for significant number of hours in the study period.

Figure 21. RSI Duration Curve for NP15 and SP15 (Nov99–Oct00)



Regression Results

The regression results for the study period November 1999 to October 2000 are shown below in Figure 22.

Figure 22. Price-cost Markup Regression Results

Dependent Variable· Lerner Index		
Explanatory Variables	**Parameter Estimate**	**t-Statistics**
RSI	-0 26	[41 11]***
Zonal Load	4 55*E-5	[54.88]***
Uncommitted Supply of the Largest Supplier	1 35*E-4	[22 90]***
Dummy for Summer Months	0 22	[62 27]***
Dummy for Two Zone (NP15=1, SP15=0)	0 16	[14.49]***
Intercept	-0 84	[26 97]***
R Squared		0 62
Number of Observations		16,378

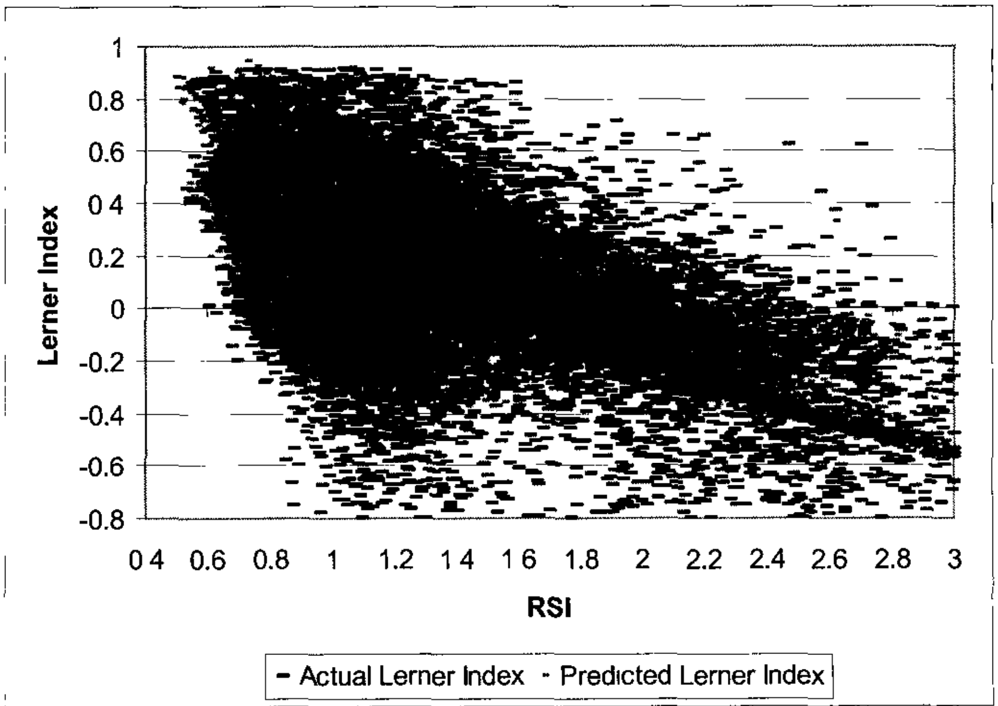
Source data in CAISO Market

**** Significant at 1% level.

The regression results indicate that there is a statistically significant relationship between the Lerner Index and RSIs and other explanatory variables. The included variables explain over 62% of the variation in the Lerner Indexes during the study period (see R-Squared values in the table above). Moreover, the signs of the estimated coefficients are as expected. A negative coefficient on RSIs indicates that smaller RSIs (i.e. a more dominant market share by the largest supplier) correspond to higher Lerner Indexes (i.e. higher price-cost markup). On average, an increase in the RSI index of .10 would decrease the Lerner index by 0.026 percent. A positive coefficient value for zonal load in each zone indicates that Lerner Indexes increase when zonal demand is higher. Similarly, the capacity of the largest supplier has a positive effect on Lerner index, indicating that if the largest supplier has more capacity, it would have a greater incentive to bid higher since it would reap a larger portfolio benefit if selected. Finally, the effects of two dummy variables also have expected signs. The Lerner index would be larger in summer months when the demand is higher or in the NP15 region.

Figure 23 compares the actual hourly Lerner Indexes to the predicted values and further indicates that the regression analysis produces a good prediction of price-cost markups. One interesting observation of Figure 23 is that there are 2 distinct clusters of observations, a rounded cluster on the right of the graph and a longer sweeping cluster on the left of the graph. These clusters largely reflect data points for NP15 and SP15, respectively. Recall, that NP15 had predominately low RSI values while SP15 had a much wider range of RSI values, with a particular large amount of observations in the higher RSI ranges. There is also a significant overlap in the two clusters, where for a given RSI value (e.g. 1.2), a higher price-cost markup would be predicted for SP15 compared to NP15, which is why a dummy variable for whether the zone is NP15 or SP15 was included in the regression.

Figure 23. Comparison of Actual and Predicted Lerner Indexes



Step 2: Calculate system variables for the prospective study period

This step involves calculating the necessary hourly variables for determining the price-cost markups to be used in the prospective production cost simulations. The specific hourly data that will need to be calculated for each simulation scenario are the following:

$RSI_{i,j}$ = Residual Supply Index in hour (i) for zone (j)

$TUC_{i,j}$ = Total Uncommitted Capacity of largest single supplier in hour (i) for zone (j)

$LD_{i,j}$ = Zonal load in hour (i) for zone (j)

The last two values ($TUC_{i,j}$, $LD_{i,j}$) can be determined under each of the various scenarios (e.g. gas prices, demand growth, new generation expansion) without actually running the production cost model. However, calculating the RSI values will require running the production cost model to determine the optimal dispatch of hydro generation.

Recall the formula for the RSI calculation:

$$RSI_{i,j} = \frac{TS_{i,j} - Max(TUC_{i,j})}{RND_{i,j}}$$

Where,

$TS_{i,j}$ = Total Available Supply (available imports + the uncommitted capacity of independent generator owners)

$Max(TUC_{i,j})$ = Total Uncommitted Capacity of the Largest Single Supplier

$RND_{i,j}$ = Residual Net Demand – Actual zonal demand less utility owned generation output, less QF generation, less Long-term Contracts.

The first component of the RSI calculation ($TS_{i,j}$) is defined by the following equations:

$$TS_{NP15,i} = \sum_{m=1}^{M} UC_{m(NP15),i} + ATC_{P15,i} + ATC_{COI,i}$$

Where,

$\sum_{m=1}^{M} UC_{m(NP15),i}$	=	The sum of the uncommitted capacity[24] of the three major independent generator owners in NP15 (Duke, Mirant, Calpine) plus any uncommitted capacity from other new generation additions.
$ATC_{P15,i}$	=	Available Transmission Capacity south to north on Path 15 (TTC_i-Unused ETC_i)
$ATC_{COI,i}$	=	Available Transmission Capacity on COI (Import Direction) = Min[Max[0, maximum hourly flow for operating day)], TTC_i-Unused ETC_i][25]

[24] Uncommitted capacity for each generator owner is equal to the total available capacity less any capacity committed under long-term contracts.

[25] This approach recognizes that there is not always enough available generation in the Pacific Northwest to congest COI, particularly during the late summer, and that in any given hour, the actual flow for that hour may not reflect what was actually available

The Total Supply for SP15 will be calculated as follows:

$$TS_{SP15,i} = \sum_{m=1}^{M} UC_{m(SP15),i} + ATC_{ZP26,i} + ATC_{SW,i} + ATC_{LA,j},i$$

Where,

$\sum_{m=1}^{M} UC_{m(SP15),i}$	=	The sum of the uncommitted capacity of the three major independent generator owners in SP15 (Williams, Dynegy, Reliant) plus any uncommitted capacity from other new generation additions.
$ATC_{ZP26,i}$	=	Available Transmission Capacity south to north on Path 26 (TTC_i-Unused ETC_i)
$ATC_{SW,i}$	=	Min[SW import limit, Estimated available SW supply][26]
$ATC_{LA,i}$	=	Available Transmission Capacity for the inter-ties connecting to LADWP (Sylmar, Mccullgh, Inyo, andVictvl). Same approach as $ATC_{SW,i}$

[26] As previously discussed, available SW import supply is modeled as a function of CAISO system loads such that as CAISO system load increases, available SW imports decline. This approach was adopted to reflect the fact that peak demand in Arizona and Nevada often coincides with peak demand in California On this basis, the availability of SW imports during the summer months are contingent on the level of CAISO system loads such that available imports from the Desert Southwest decline with increasing CAISO system loads in a manner consistent with historical patterns.

Determining the Total Uncommitted Capacity of each generator owner in each zone ($TUC_{i,j}$) is, as discussed in the previous section, complicated by the fact that the generation owned in one zone can be withheld to manipulate prices in another zone. The general methodology described in Appendix A will be used to address this important issue.

Calculating the Residual Net Demand ($RND_{i,j}$) will be based on the following equation:

$RND_{i,j}$ = Zonal demand - utility owned generation output - QF generation - Long-term Contracts.

Where,

Term		Definition/Computational Approach
Zonal Demand	=	Simulation projected demand in hour (i) for zone (j)
Utility Owned Generation Output	=	Available capacity of utility non-hydro generation + output of utility hydro resources. Output of utility hydro resources will be based on the optimal dispatch as determined by PoolMOD.
QF Generation	=	Generation output from Qualifying Facilities.
Long-term Contracts	=	Utility long-term contract coverage – based on existing DWR contracts.

Summary

The calculations described above will result in a final dataset containing the variables necessary for calculating the price-cost markups. This will result in 76 data sets (2-zonal data sets for each of the 38 scenarios considered in the illustrative Path 26 analysis) comprised of the following variables:

NP15 Data Set:

Variable		Definition
Opr_dt	=	Operating Date
Opr_hr	=	Operating Hour
$Max(TUC_{i,j})$	=	Total Uncommitted Capacity of the Largest Single Supplier in NP15 (see Appendix A)
$LSS_{i,j}$	=	Name of the largest single supplier in NP15
$LD_{i,j}$	=	Hourly Load in NP15
$\sum_{m=1}^{M} UC_{m,i,j}$	=	The sum of the uncommitted capacity of NGO's and other new generation in NP15
$ATC_{P15,i}$	=	Available Transmission Capacity south to north on Path 15 (TTC_i-Unused ETC_i)
$ATC_{COI,i}$	=	Available Transmission Capacity on COI (Import Direction) = Min[Max[0, maximum hourly flow for operating day)], TTC_i-Unused ETC_i]
$UOG\_NH_{i,j}$	=	Available capacity of PG&E non-hydro generation
$UOG\_H_{i,j}$	=	PG&E hourly hydro production
$QFG_{i,j}$	=	PG&E QF hourly generation output
$LTC_{i,j}$	=	PG&E Long-term Contracts

SP15 Data Set:

Variable		**Definition**
Opr_dt	=	Operating Date
Opr_hr	=	Operating Hour
Max($TUC_{i,j}$)	=	Total Uncommitted Capacity of the Largest Single Supplier in SP15
$LSS_{i,j}$	=	Name of the largest single supplier in SP15
$LD_{i,j}$	=	Hourly Load in SP15
$\sum_{m=1}^{M} UC_{m,i,j}$	=	The sum of the uncommitted capacity of NGO's and other new generation in SP15
$ATC_{ZP26,i}$	=	Available Transmission Capacity south to north on Path 26 (TTC_i-Unused ETC_i)
$ATC_{SW,i}$	=	Min[SW import limit, Estimated available SW supply
$ATC_{LA,i}$	=	Available Transmission Capacity for the inter-ties connecting to LADWP (Sylmar, Mccullgh, Inyo, andVictvl). Same approach as $ATC_{SW,i}$
$UOG\_NH_{i,j}$	=	Available capacity of SCE & SDGE non-hydro generation
$UOG\_H_{i,j}$	=	SCE hourly hydro production
$QFG_{i,j}$	=	SCE & SDGE QF hourly generation output
$LTC_{i,j}$	=	SCE & SDGE Long-term Contracts

Step 3: Estimating the price-cost markups

This step involves estimating hourly Lerner indexes based on the input data derived in Step 2 and applying the estimated markups in each zone to the competitive prices produced by PoolMOD to derive the estimated actual market prices. Recall that the dependent variable in the regression equation is the Lerner Index, which is defined as:

$$\text{Lerner Index} = ((P_{i,j} - C_{i,j})/\mathbf{P_{i,j}})$$

Where

$P_{i,j}$	=	Actual price in hour (i) and zone (j)
$C_{i,j}$,	=	Estimated competitive price in hour (i) and zone (j)

To derive actual market clearing prices, the estimated Lerner Indexes must first be converted to price-cost markups (PMU):

$$PMU_{i,j} = ((P_{i,j} - C_{i,j})/\mathbf{C_{i,j}})$$

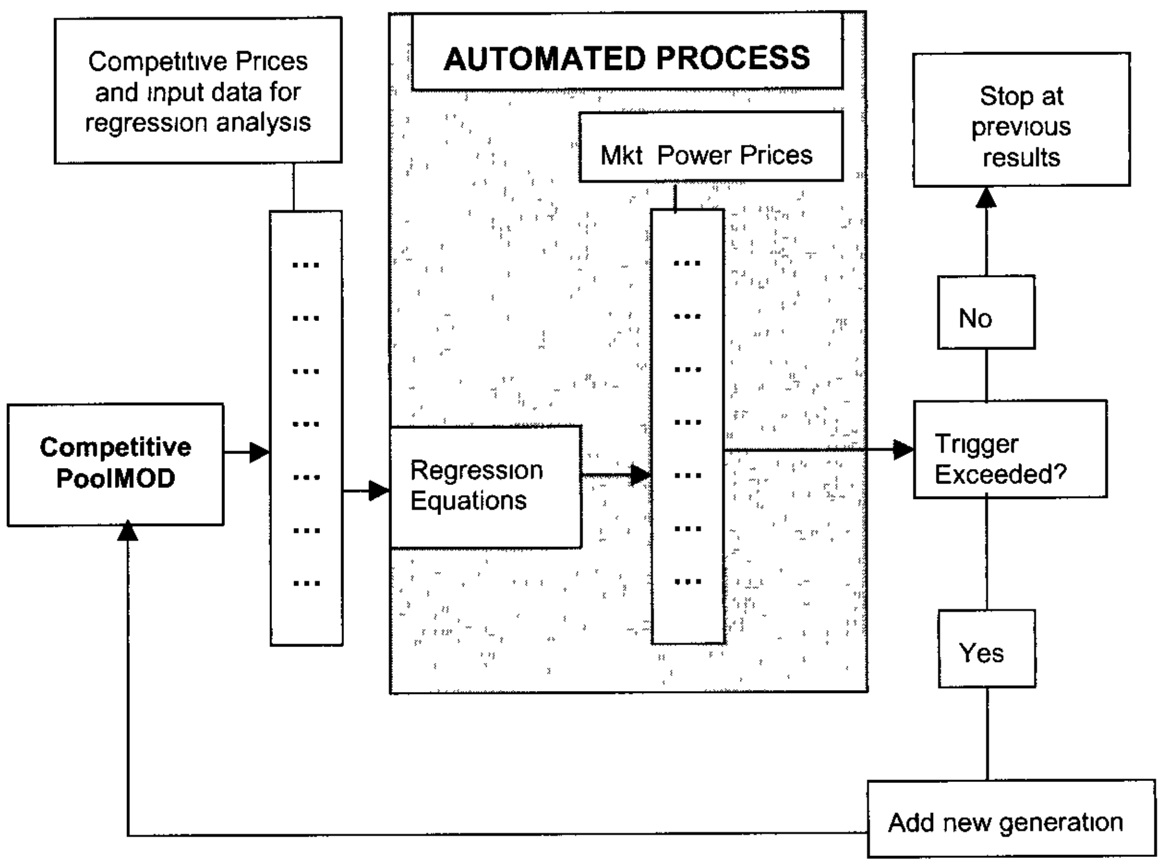
Actual market prices are then estimated by multiplying the estimated price-cost markups by the competitive prices produced in PoolMOD ($C_{i,j}$).

$$P_{i,j} = (1+PMU_{i,j})*C_{i,j}$$

Step 4: Calculating new generation investment

An equilibrium new generation entry level will need to be calculated for the base case scenarios using the estimated actual market prices derived from the price-cost markups. This will be done by comparing the annual average unit revenues for a new combined cycle unit based on the prices derived in Step 3 to entry trigger prices that reflect the revenue requirements for a new combined cycle unit. If the annual average unit revenues exceed the trigger price, new generation will be added and steps 2, 3, and 4 will be repeated until no further entry is called for, as shown in Figure 24 below.

Figure 24. Process for Modeling New Generation Entry



IV. Selection of Scenarios

In order to provide a comprehensive and accurate assessment of the economic benefits of a transmission expansion, the benefits must be examined under a wide range of system conditions. As discussed in previous sections, assumptions about natural gas prices, demand levels, hydro conditions, and new generation entry can have significant impacts on the economic benefits of a transmission expansion. The benefits of a transmission expansion should be examined under different plausible combinations of these system variables. In choosing scenarios, it is particularly import to capture extreme scenarios, such as combinations of high demand and low hydro conditions, because the benefits of a transmission expansion can often be significantly higher under extreme system conditions. It is also important to choose a sufficient number of more moderate scenarios to ensure the benefits are accurately captured under more likely scenarios. There is no hard rule on the number of scenarios that ought to be considered other than "more is always better". Ultimately, the number of scenarios considered is likely to be driven by practical issues such as the amount of the time one has to undertake a study and the speed at which scenarios can be run and results compiled.

In this section we provide a two-step methodology for selecting scenarios that provides a means for ensuring extreme scenarios are included in the assessment and that a representative sample of more moderate scenarios are also selected. In the first step, the most likely as well as some extreme scenarios are pre-selected. In addition, scenarios are selected where only on for different values of a particular market variable holding all other choice variables constant. This sampling technique allows one to isolate the effects a single variable has on the estimated benefits. In the second step, additional scenarios are randomly selected using a technique referred to as "Latin Hypercube Sampling". The first step ensures the more interesting and important scenarios are considered (e.g. extreme and most likely). The second step ensures a representative sample of all possible scenarios.

This two-step approach was used to select scenarios for demand levels and natural gas prices in the illustrative analysis of Path 26 and is described in detail below. The methodology used to select long-term new generation entry scenarios and hydro scenarios is also discussed.

Selection of Demand and Natural Gas Price Scenarios

Step 1 – Importance Sampling of 13 Joint Demand/Gas Price Scenarios

In this step we try to capture both the most likely as well as the most extreme possible combinations of demand levels and natural gas prices. Figure 25 lists all possible combinations of demand and gas prices assuming each variable at 5 discrete levels. The five discrete levels are *very high, high, base, low,* and *very low.* As discussed in previous sections these discrete levels of gas prices and demand were determined through statistical confidence intervals derived from an assessment of CEC forecast errors. Under this approach, scenarios that define a 90% confidence interval about the base case forecast are considered extreme (very low, very high) in that the probability of realizing one of those extreme conditions is only 5% (e.g. probability of a very high demand scenario). More moderate high and low demand and natural gas price levels could be derived based on a 75% confidence interval, for example.

Figure 25. Demand and Gas Price Combinations

		Demand Scenario				
		Very High	*High*	*Base*	*Low*	*Very Low*
Gas Price Scenario	*Very High*	X		X		X
	High					
	Base	X		X		X
	Low					
	Very Low	X		X		X

The 9 scenarios selected in Step 1 are marked with an "X" in the above table. Extreme or bookend cases are represented by the 4 corner scenarios: D_{vh}/G_{vh}, D_{vl}/G_{vl}, D_{vl}/G_{vh}, and D_{vl}/G_{vl}. The 3 additional cases (D_{vh}/G_b, D_b/G_b, and D_{vl}/G_b) capture the most likely scenario of base case gas prices and demand levels but also capture how the benefits change with different demand levels, holding gas prices constant at the base level. These three scenarios are also used in determining long-term new generation entry. The other 2 cases (D_b/G_{vh} and D_b/G_{vl}) capture the variation in gas prices when demand is base. These 9 scenarios capture extreme, most likely, and interesting combinations of scenarios but may not adequately represent the entire sample space (i.e. the 25 different possible combinations of gas price and demand levels shown above). Step 2 is designed to ensure better sample representation.

Step 2: Latin Hypercube Sampling for Additional Demand/Gas Scenarios

In this step, a Latin Hypercube Sampling technique is used to randomly select additional scenarios. The essence of Latin Hypercube sampling is to pick one and only one value of each variable. Once a value is chosen, it cannot be picked again. Suppose again that each variable (demand and gas price) take five discrete values (see Figure 26), the Latin Hypercube sampling is to sample without replacement from the Demand and Gas price bins separately. Two different examples of Latin Hypercube sampling are provided in Figure 26 and denoted as "X" and "O". The critical feature of the Latin Hypercube sampling approach is the sampling is done without replacement. For example, in the random sample denoted as "X" in Figure 26, suppose in the first draw a "Very High" gas price scenario is randomly selected and paired with a randomly selected Very High demand scenario then those two scenarios will be excluded from the sample in all subsequent draws. The implication of this sampling technique is that it minimizes the number of draws necessary for ensuring a selection is made in every column and in every row of the sample space (i.e. provides a representative sampling with a minimum number of draws).

Figure 26. Latin Hypercube Sampling of Demand and Gas Price Scenarios

		Demand Scenario				
		Very High	*High*	*Base*	*Low*	*Very Low*
Gas Price Scenario	*Very High*	**X**		**O**		
	High		**X**		**O**	
	Base		**O**	**X**		
	Low				**X**	**O**
	Very Low	**O**				**X**

Given that we already selected some scenarios in Step 1, the Latin Hypercube sampling technique is modified slightly to ensure duplicative scenarios are not selected.

For example, the Latin Hypercube sampling could produce the following 5 cases:

***Db/Gh*, *Dh/Gl*,** *Dvh/Gvl*, ***Dl/Gb*,** *Dvl/Gvh.*

Since *Dvh/Gvl* and *Dvl/Gvh* are already selected in Step 1, we now only have 3 distinct samples (shown in bold above). However, we can repeat the procedure until we get 2 more distinct samples. For example a repeat of the sampling procedure could produce the following:

Dvl/Gh, *Dh/Gl, Dvh/Gb, Db/Gvh,* ***Dl/Gvl***.

So together we can obtain 5 additional distinct samples:

Db/Gh, Dh/Gl, Dl/Gb, Dvl/Gh, Dl/Gvl.

Note that the above set includes replications of a demand scenario (***Dl/Gb, Dl/Gvl***) and replications of a Gas Price scenario (***Db/Gh, Dvl/Gh)***. However, the combined sampling approach of Step 1 and Step 2 still ensure that every row and column has "at least" one selection (denoted respectively as "X" and "L", in Figure 27).

Figure 27. Demand and Gas Price Combinations (Steps 1 and 2 Combined)

		Demand Scenario				
		Very High	*High*	*Base*	*Low*	*Very Low*
Gas Price Scenario	*Very High*	X		X		X
	High			L		L
	Base	X		X	L	X
	Low		L			
	Very Low	X		X	L	X

Selection of Generation Entry and Retirement Scenarios

As previously discussed, the base case new generation entry levels are determined in the near-term based on CEC plant licensing data and in the long-term by adding generic new generation to the model until it is no longer profitable to enter. Base case unit retirements are determined only in the near-term based on publicly available data. Because the level of future new generation entry and unit retirements is highly uncertain and can have a significant impact on the estimated benefits, it is critical that the transmission expansion benefits are estimated under a range of new generation entry and unit retirement scenarios. Unfortunately, unlike gas price and demand forecasts, there is no good historical basis for determining what constitutes a reasonable range of potential new generation entry scenarios (e.g. historical data to derive distribution for forecast errors for new generation entry by zone).

Given the lack of historical data, it is important to conduct sensitivity analysis for a wide range of new generation entry scenarios. In the illustrative Path 26 analysis, sensitivity analysis was conducted around the base case "long-term" new generation entry level[27] using approximately +/- 50 % of baseline annual incremental entry levels to capture over and under entry conditions. Under this approach 3 possible new generation entry scenarios were considered for each zone (Over-entry = "O", Normal or base-case entry = "N", and Under-entry = "U"). With three zones and three possible entry scenarios for each zone, a total of 27 different entry combinations are possible. Combined zonal new generation entry scenarios are labeled in the following order (NP15, ZP26, SP15). For example, a new generation entry scenario labeled "ONU" would represent over-entry in NP15, normal entry in ZP26, and under-entry in SP15.

Ideally, the 2-step sampling approach described above for sampling demand and natural gas price scenarios should be applied to the 27 new generation entry scenarios. Under this approach, interesting new generation entry scenarios, such as the most likely scenarios and the scenarios that are likely to minimize or maximize the benefits of a transmission expansion would be pre-selected and then additional scenarios would be selected using the Step 2 Latin Hypercube sampling approach. The approach would be exactly analogous to the demand and gas price scenario selection except that instead of the sample space being 2-dimensional, it would be 3-dimensional (i.e. a 3X3 cube where each zone is a dimension consisting of 3-categories (over-entry, normal entry, under-entry). Applying the Latin Hypercube sampling approach to a 3X3 cube would result in 9 unique scenarios (i.e. there would be a unique selection from every row and column in the entire cube). These 9-scenarios would then be combined with the interesting scenarios selected in Step 1.

While this would be the preferred approach to sampling new generation entry scenarios, given the time limitations and the practical necessity of needing to limit the sample selection to a manageable size only some interesting new generation entry scenarios were considered in the illustrative Path 26 analysis. Specifically, three scenarios were considered, the most likely scenario of normal entry in all three zones (NNN), a scenario of under-entry in NP15 and SP15 and over-entry in ZP26 (UOU), and a scenario of over-entry in NP15 and SP15 and under-entry in ZP26 (OUO).

The various selected demand, gas price, and new generation entry levels results in a total of 84 scenarios (2-transmission investment options ("Path 26 expansion" and "No expansion"), 14-demand and gas scenarios, and 3-zonal new generation entry scenarios). Given the time limitations and the practical necessity of needing to limit the sample selection to a manageable size, a subset of 38 scenarios (19 for each transmission expansion option) was selected. This subset, which is shown below in Figure 28, was selected to capture both

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[27] The base case level is the level derived from iteratively adding block increments of generic new generation to the model in each zone until market revenues were insufficient to support any additional entry.

moderate and extreme system conditions and is sufficiently large for an adequate demonstration of the methodology. However, we do not believe it is sufficiently large enough to be a representative sample. As noted above, the preferred approach would be to model all the interesting new generation scenarios plus additional new generation entry scenarios selected through the Latin Hypercube sampling technique.

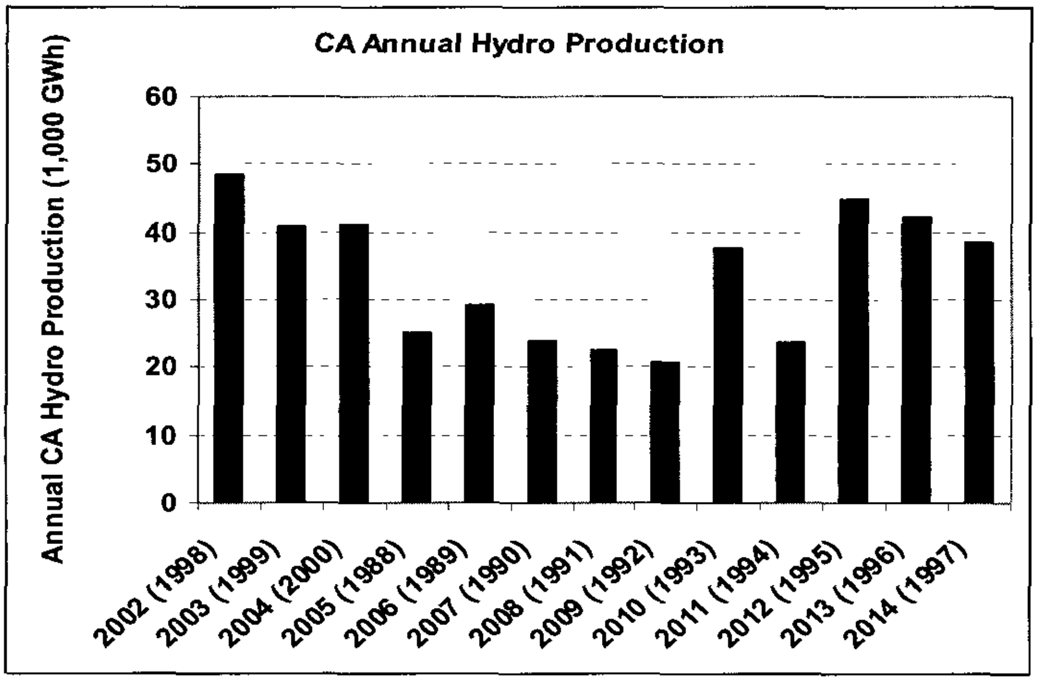
Figure 28. Final Set of Scenarios used in the Illustrative Assessment of Path 26

Scenario	Demand	Gas	Generation Entry
1	*Very high*	*Very high*	*NNN*
2	*Very high*	*Base*	*NNN*
3	*Very high*	*Very low*	*NNN*
4	*Base*	*Very high*	*NNN*
5	*Base*	*Base*	*NNN*
6	*Base*	*Very low*	*NNN*
7	*Very low*	*Very high*	*NNN*
8	*Very low*	*Base*	*NNN*
9	*Very low*	*Very low*	*NNN*
10	*Very high*	*Very high*	*OUO*
11	*Very high*	*Very low*	*OUO*
12	*Base*	*Base*	*OUO*
13	*Very low*	*Very high*	*OUO*
14	*Very low*	*Very low*	*OUO*
15	*Very high*	*Very high*	*UOU*
16	*Very high*	*Very low*	*UOU*
17	*Base*	*Base*	*UOU*
18	*Very low*	*Very high*	*UOU*
19	*Very low*	*Very low*	*UOU*

Selection of Hydrology Scenarios

Assumptions about California hydro conditions can have substantial impacts on the benefit estimates. Therefore, it is very important to compute benefit estimates under a variety of hydro assumptions. As previously discussed, California hydrology in this study was based on the actual annual hydro production for the period 1988-2000 and this 13-year cycle was applied to the study period 2002-2014. Since, the hydro was compiled and calibrated to PoolMOD during year 2002, there was not sufficient time to update the database with a more recent 13-year cycle (e.g. 1990-2002). Moreover, the most recent 13-year cycle may not be the most appropriate series for a base-case analysis if that series is highly anomalous (e.g. consisting of an inordinate amount of exceptionally dry years or exceptionally wet years). In applying the 1988-2000 annual hydro production cycle prospectively, it was determined that starting the series with some relatively wet years would more closely match expected hydro production in years 2002 and 2003. As a result, 1998 was used as the starting point for the 13-year series (e.g. 1998=2002, 1999=2003, 2000=2004, 1988=2005, 1989=2006 etc.) as indicated below in Figure 29.

Figure 29. Study Assumptions on Annual CA Hydro Production



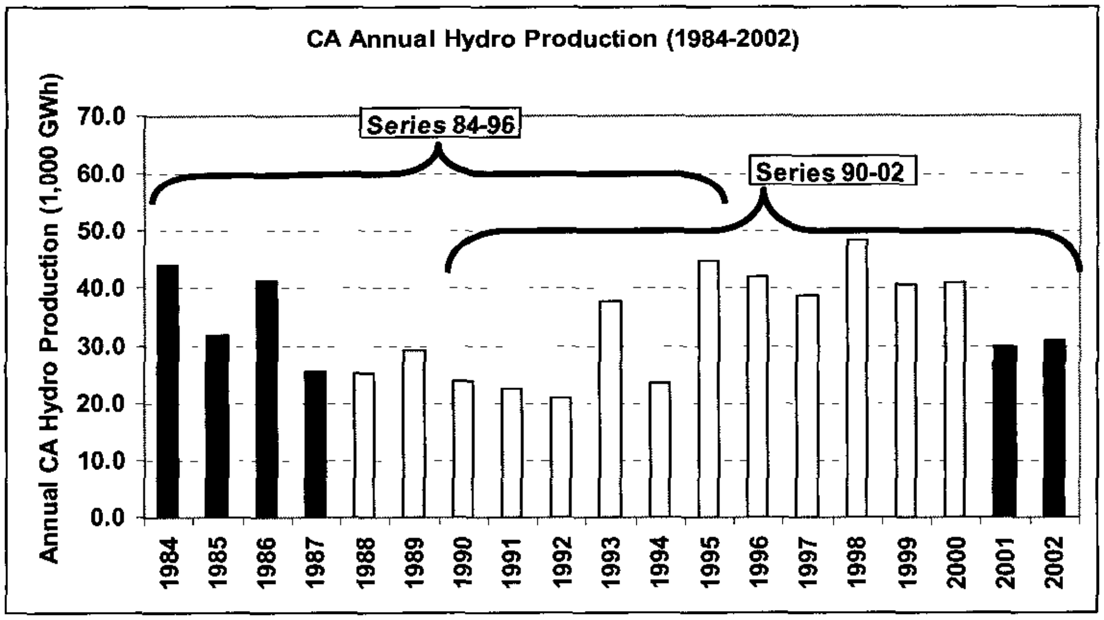
It is important to note that the 13-year CA hydro cycle used in this analysis contains a combination of relatively normal, wet, and dry years. Thus the annual estimated benefits of a transmission expansion within this 13-year study period capture to some extent the impact that different hydro conductions have on the estimated benefits. For example, comparing the estimated benefits between year 2009 and 2010 or between 2011 and 2012 will provide an indication of how the benefits change in moving from a dry to a wet hydro year. However, given the significance that hydro assumptions have on the study results, exploring the transmission benefits under different 13-year hydro scenarios is critical. Though there was not sufficient time to examine alternative 13-year hydro scenarios in the illustrative Path 26 study, an approach to selecting alternative scenarios is discussed below.

To get some indication of how annual hydro production varies over a longer cycle, Figure 30 shows annual hydro production for the CAISO control area over a 19-year period (1984-2002). The columns highlighted in yellow indicate the 13-year cycle used in this study. Several important observations can be drawn from Figure 30.

1. The selected study period (1988-2000) appears to include a reasonable proportion of dry, normal, and wet years and therefore is a reasonable "base-case" 13-year hydro cycle.
2. The 1984-1996 series contains an inordinate amount of normal to dry years and very few wet-years relative to the selected series of 1988-2000 as well as for the series 1990-2002. Therefore, the 1984-1996 series could serve as a reasonable 13-year "dry-hydro" scenario.

3. The 1990-2002 series could serve as a "wet-hydro" scenario by replacing production in years 2001-2002 with year 2000 production.

Figure 30. CA Annual Hydro Production (1984-2002)



While the discussion of hydro scenarios has focused on the proportion of dry, wet, and normal hydro years in each 13-year cycle, the sequence in which these events occur can also have a significant impact on the benefit results. For example, if one modeled the selected 13-year cycle of 1988 to 2000 in chronological order (e.g. 1988=2002, 1989=2003, 1990=2004 etc.), the study would be front-loaded with relatively dry hydro years and back-loaded with relatively wet-hydro years, which could produce very different benefit results than if the annual hydro was modeled in the reverse order (i.e. 2000-1988 instead of 1988-2000). On a discounted, net present value basis, such a dynamic would have a substantial impact on the optimal decision vis-à-vis the investment. Therefore, it would be important to undertake additional hydro scenarios that vary the sequence of annual hydro conditions.

V. Assigning Probabilities to Scenarios

One of the more challenging aspects of this project has been determining an appropriate methodology for assigning probabilities to the selected scenarios. As discussed above, transmission expansion benefits were evaluated under 19 different scenarios. To determine the expected benefits of each expansion option, weights need to be assigned to each scenario that represent the joint probability of realizing a particular combination of new generation entry, demand levels, and gas prices. If we had perfect knowledge about the marginal probabilities of each variable, along with their correlations, and a much larger and representative sampling of each variable then determining the joint probabilities of realizing particular combinations of these variables would be very straightforward. Unfortunately, we do not have perfect knowledge about the marginal probabilities of each variable nor do we have a sufficient sample size to claim that we have representative sampling. Consequently, an alternative approach to determining the joint probabilities of each scenario is needed.

The approach adopted here is a 2-stage approach that consists of an approach advocated by Ben Hobbs (Stage 1) and an approach advocated by Frank Wolak (Stage 2), both of whom are members of the ISO Market Surveillance Committee. In the first stage, joint probabilities are derived for the various combinations of gas price and demand levels. These joint probabilities are then used in a second stage to determine the joint probability of the pairs of gas price and demand levels and the new generation entry scenarios[28]. This 2-stage approach was driven by the fact that we have much better information on the probability distributions of demand and gas prices than we do on the level of new generation entry. Each of these stages is described in greater detail below.

[28] The second stage could also be used to assign probabilities to various hydro scenarios This was not done in this study because time did not permit the evaluation of alternative hydro scenarios

Stage 1: Determining joint probabilities for demand and gas price scenarios

Description of methodology

The approach used in this stage is based on recommendations provided by Benjamin Hobbs and involves choosing joint probabilities for each selected scenario that match the estimated probability distributions of gas prices and demand levels. This is accomplished by using a simple linear programming (LP) algorithm to select joint probabilities that match the moments (e.g. mean, variance, and skew) of the estimated probability distributions[29] of gas prices and demand levels. This moment consistent LP approach for determining probabilities is based on established approaches in the statistical literature.[30]

The estimated probability distribution of gas prices and demand prices is derived from comparing their historical values to CEC forecasted values. As discussed previously, normal demand is based directly on CEC's baseline forecasts. Very high and very low demand scenarios are derived by multiplying the base scenario by (1 + a 90% confidence interval of demand forecast error). In other words, we have a 90% confidence that the actual demand in the modeling time horizon will be between the selected high and low demand scenarios. A similar approach is used in deriving very high and very low gas price scenarios, except that we assume that gas price has a lognormal distribution. In other words, we have a 90% confidence that the actual gas prices in the modeling time horizon will be between the selected very high and very low gas scenarios. Out of the total possible combinations of gas prices and demand values, nine were considered in this study (see Figure 31).

Figure 31. Demand and Gas Price Scenarios from Step 1 of Scenario Selection

Scenario	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**
Demand	VH	VH	VH	B	B	B	VL	VL	VL
Gas Prices	VH	B	VL	VH	B	VL	VH	B	VL

After deriving the very high and very low scenarios, we use the assumed distributions of demand and gas prices, which are based on estimated distributions derived from CEC forecast errors, to perform a moment consistent

[29] The probability distribution of a random variable (x) is typically described by its central moments. The first moment is the mean (u), second moment is the variance ($v=E((x-u)^2)$), third moment is represented by skewness ($E((x-u)^3/(V^{1.5}))$), and the fourth moment is represented by kurtosis ($E((x-u)^4/(V^2))$) Variance measures the dispersion of the distribution Skewness measures the asymmetry of a distribution. For asymmetric distributions the skewness will be positive if the distribution has a long tail in the positive direction. Kurtosis is a measure of the thickness of the tails of a distribution

[30] See Pearson E.S. and Tukey J W., Approximate means and standard deviations based on distances between percentage points of frequency curves Biometrica (1965), 52, 3 and 4, p 533

LP approach to derive the joint probabilities of demand/gas prices by minimizing the sum of the squared joint probabilities[31] and the sum of the squared third moments of the marginal demand and gas price distributions subject to the constraints of matching the mean and variance of these distributions and that the joint probabilities sum to 1. More specifically, we solve the following LP problem, supposing there are *m* unique demand/gas price scenarios:

[31] Minimizing the joint probabilities subject to the constraint that they sum to one mitigates against extreme solutions where some scenarios have a weight close to zero and other scenarios have a weight close to 1

Figure 32. Formulation of Moment Consistent LP Approach

$$\min_{p_1, p_2, \ldots, p_m} \sum_{i=1}^{m} p_i^2 + [\sum_{i=1}^{m} p_i (D_i - \hat{\mu}_D)^3]^2 + [\sum_{i=1}^{m} p_i (G_i - \hat{\mu}_G)^3]^2$$

st

$$\sum_{i=1}^{m} p_i D_i = \hat{\mu}_D \quad \ldots\ldots \quad (1)$$

$$\sum_{i=1}^{m} p_i G_i = \hat{\mu}_G \quad \ldots\ldots \quad (2)$$

$$\sum_{i=1}^{m} p_i (D_i - \hat{\mu}_D)^2 = \hat{\sigma}_D^2 \quad \ldots\ldots \quad (3)$$

$$\sum_{i=1}^{m} p_i (G_i - \hat{\mu}_G)^2 = \hat{\sigma}_G^2 \quad \ldots\ldots \quad (4)$$

$$\sum_{i=1}^{m} p_i (D_i - \hat{\mu}_D)(G_i - \hat{\mu}_G) = \hat{\sigma}_{DG} \quad \ldots\ldots \quad (5)$$

$$\sum_{i=1}^{m} p_i = 1 \quad \ldots\ldots \quad (6)$$

$$p_i \geq 0 \quad \ldots\ldots \quad (7)$$

Where $\hat{\mu}_D$ and $\hat{\mu}_G$ are the estimated means of historical demand forecast error and historical gas price forecast error respectively, $\hat{\sigma}_D$ and $\hat{\sigma}_G$ are the estimated variances, and $\hat{\sigma}_{DG}$ is the estimated covariance between historical demand forecast error and gas price forecast error. Constraints (1) and (2) simply state that the sum of the joint probability-weighted demand and gas price forecast errors have to match their respective estimated mean forecast errors, which are derived from historical CEC forecasts. Similarly, constraints (3) and (4) specify that the joint probability-weighted variances have to match the estimated variance from historical CEC forecasts, while constraint (5) states that the covariance between two forecast errors has to be matched. In this particular LP for the illustrative Path 26 study, the correlation constraints between demand and gas prices are not imposed[32]. Constraint (6) is the sum of probabilities has to equal to 1 and constraint (7) is a non-negativity constraint.

[32] Correlation constraint can be specified and imposed if historical data indicates strong correlation between demand and gas prices.

Application of Methodology

As discussed in Section II, historical CEC demand and gas price forecast errors can be used to estimate, for each year, the mean and variance of forecast errors. These are estimated separately for each year because the mean and variance of the forecast errors of these variables tends to increase the larger the forecast outlook (e.g. 1-year outlook, 2-year outlook, .. 13-year outlook) The estimated means and variances were then used to derive a forecast error for each year outlook that reflects a 90% confidence interval. Given this information, one could apply the above probability methodology in each year to derive the joint probabilities of selected demand and gas price scenarios. However, it is not necessary to do so for each year. Instead, we can standardize each year's forecast error by subtracting the mean of forecast error for that year and dividing the difference by the standard deviation of forecast error for that year. Using the moment consistent linear program approach, described above, for estimating the joint probabilities of demand and gas price scenarios in each year using these standardized forecast errors would produce the same set of joint probabilities for each year. Therefore, it is only necessary to run the moment consistent LP approach once using the standardized forecast error for any representative year.

Figure 33 lists the standardized forecast errors, for a representative year (year 4), that were used to derive each of the 9 selected demand/gas price scenarios.

Figure 33. Demand and Gas Price Estimated Forecast Errors

Order	Scenario		Confidence Interval		Standardized Estimated Forecast Error	
	Demand	Gas	Demand	Gas	Demand	Gas
1	VH	VH	90%	90%	1.734	1.740
2	VH	B	90%	50%	1.734	0 000
3	VH	VL	90%	90%	1.734	-1.740
4	B	VH	90%	90%	0.000	1.740
5	B	B	50%	50%	0.000	0.000
6	B	VL	50%	90%	0.000	-1.740
7	VL	VH	90%	90%	-1.734	1.740
8	VL	B	90%	50%	-1.734	0.000
9	VL	VL	90%	90%	-1.734	-1.740

Applying the LP approach defined in Figure 32 to the representative standardized values of demand and gas price forecast errors shown in Figure 33 results in the estimated joint probabilities shown in Figure 34[33]. This LP problem was formulated and solved in an Excel Spreadsheet using Excel Solver.

Figure 34. Estimated Joint Probabilities of Demand and Gas Prices

Scenarios	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**
Demand	VH	VH	VH	B	B	B	VL	VL	VL
Gas Price	VH	B	VL	VH	B	VL	VH	B	VL
Joint Probability	0 0121	0.1606	0 0121	0.1606	0 3092	0 1607	0 0121	0 1606	0 0121

[33] Since there are only a small number of CEC forecasts to calculate means and standard deviations of demand and gas price forecast errors, the variance constraints in the LP are adjusted to reflect standard variation in standard t-distribution Also note that to guarantee strictly positive probability solutions, the methodology imposed constraints $p_i \geq$ 0 001 in the LP, although these strictly positive constraints are not binding.

Stage 2 - Assigning Joint Probabilities to Demand/Gas Price and New Generation Entry by LP

Stage 2 involves assigning the joint probabilities of the pairs of demand and gas price scenarios and the new generation entry scenarios. The approach is based on the fact that we have poor information about the marginal probability distribution of new generation entry and thus would have very little basis for assuming a particular marginal distribution. Given this, the best alternative is to consider the sensitivity of the study's conclusion under a range of plausible distributions that satisfy certain reasonableness constraints. This can be done by choosing, first, a set of joint probabilities of demand, gas price, and new entry scenarios that maximize the expected benefits of a transmission expansion and second, choosing another set of joint probabilities that minimize the expected transmission expansion benefits. This approach will then produce a range of potential benefits (lowest to highest) rather than a single expected value. It is possible to narrow the range of estimated benefits by imposing constraints on the plausible distributions

For a generalized approach with *k* joint scenarios of demand/gas price/new generation, the objective is to determine the range of the expected transmission benefit by first maximizing and then minimizing expected benefit subject to some prior constraints on marginal or joint probabilities of demand, gas prices, and new generation. The objective function in this second stage of the LP approach is shown in Figure 35.

Figure 35. Objective Function for Second Stage LP

$$\underset{f_1, f_2, \dots, f_k}{Max} \sum_{j=1}^{k} f_j B_j \quad or \quad \underset{f_1, f_2, \dots, f_k}{Min} \sum_{j=1}^{k} f_j B_j$$

Where f_j (j = 1, 2, .., k) denotes the joint probability of the *jth* demand/gas/new generation scenario, B_j denotes the transmission benefit of the *jth* scenario. The constraints include the following:

Constraint Set 1:

$$\sum_{j=1}^{k} f_j * INT_j[(D_j / G_j) = (D/G)_i] = p_i^* \quad \text{for } i = 1, 2, \dots, m$$

Constraint set 1 requires that the joint probabilities of demand/gas prices derived from stage 1 be observed in the Stage 2 LP. INT_j is a binary variable, taking the value of 1 when demand and gas price in *jth* demand/gas/new entry scenario in stage 2 is the same as the *ith* demand/gas scenario in Stage 1, and otherwise taking the value of 0. The term p_i^* is the estimated probability for the joint demand/gas price scenario derived in stage 1. For example, in the Stage 1 estimations, the base demand and base gas scenario (*Db/Gb*) has a joint probability 0.3092 and the *Db/Gb* scenario appears in the 5th, 12th, and 17th

combined scenarios of new generation entry, demand, and gas prices (see Figure 28). Thus for the *Db/Gb* scenario, the constraint is that the sum of the joint probabilities of realizing scenarios 5, 12, and 17 is equal to .3092 ($f_5 + f_{12} + f_{17} = 0.3092$). Similar constraints will exist for the other 8 selected demand and gas price scenarios[34].

Constraint Set 2:

$$\sum_{j=1}^{k} f_j * INT_j(newgen_j = NNN) \geq \sum_{j=1}^{k} f_j * INT_j(newgen_j = OUO)$$
$$\sum_{j=1}^{k} f_j * INT_j(newgen_j = NNN) \geq \sum_{j=1}^{k} f_j * INT_j(newgen_j = UOU)$$

Constraint Set 2 imposes constraints on the relative probabilities of certain new generation entry scenarios. The term INT_j is a binary variable, taking a value of 1 if the *jth* new generation pattern is as the pattern identified in the parenthesis and otherwise taking a value of 0. This set of constraints simply imposes a requirement that the estimated joint probabilities must result in the base case new generation entry scenario (NNN) being more likely than the extreme patterns of over-entry (*OUO*) and under-entry (*UOU*).

Constraint Set 3

$$f_j \geq 0 \ \forall j.$$

Constraint Set 3 is simply a non-negativity constraint.

The Stage 2 results provide the final probabilities to assign to the transmission expansion benefits estimated under each scenario . If the resulting range of benefits is very wide, then it may be desirable to consider tightening the above constraints, or adding additional ones.

Since the probabilities are based on the estimated transmission expansion benefits, a different benefit measure (i.e. Net Social Surplus, Consumer Benefit) will require estimating a new set of joint probabilities. Since a set of estimated benefits is necessary to compute the joint probabilities in this optimization, the application of this optimization to the illustrative Path 26 analysis is deferred to the Path 26 illustrative presentation.

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34 Note that in this LP the constraint that sum of probabilities equals to 1 is redundant to Constraint Set 1, thus should be omitted.

VI. Measuring Net-Benefits

Introduction

In this section, we review the theory that underpins investment project evaluation, with a view to identifying the appropriate objective function or functions for the transmission valuation methodology. The section commences with a brief description of the optimal investment rule. It then sets out the principles of cost benefit analysis.

The optimal investment rule

The optimal investment rule requires that in order to recommend a particular transmission investment, the ISO must ensure that each candidate investment satisfies a two-part test, namely:

- social benefits of the transmission investment outweigh the social costs of the investment; and
- the transmission investment delivers the highest net social surplus, being the ratio of social benefit to social cost.

The second part of the test implies that social welfare will only be maximized if the CAISO reviews the range of alternative projects that could substitute for the proposed transmission project, and rejects the proposed project if any one of them yields a greater social surplus. As a matter of practice, the CAISO can only address the second part of the test somewhat narrowly by reviewing:

- alternative timing choices or other transmission projects that might substitute for the proposed project; and
- whether generation or demand side management measures might negate the social benefits of the project.

Hence, as a practical matter, the CAISO will generally need to confine its analysis to the first part of the test (whether the project yields net benefits), and address the second part of the test in the development of future market forecasts including the evaluation of the impacts of uncertainty therein. The remainder of this section proceeds on the basis that the principal task is to determine whether or not candidate transmission projects yield positive net benefits. This question is normally addressed through cost-benefit analysis.

Overview

Cost-benefit analysis (CBA) is a widely used procedure for investigating whether a proposed project is desirable from a societal welfare standpoint. In customary practice, CBA implies approval of the project if its net present value exceeds zero, with all relevant benefits and costs over the project's lifetime factored into the calculation.[35] This can be expressed mathematically as:

$$NPV = \frac{B_0 - C_0}{(1+d)^0} + \frac{B_1 - C_1}{(1+d)^1} + ... + \frac{B_t - C_t}{(1+d)^t} > 0$$

where the subscripts represent periods from project initiation, *d* embodies a social discount rate and B and C represent benefits and costs respectively.

Alternatively, net benefits can be conceptualized as the summation across market participants of their willingness to pay for the project, less the opportunity cost that reflects the benefits foregone due to implementing the project. Since most projects will enhance the welfare of some market participants while diminishing the welfare of others, practitioners of CBA often employ the Kaldor-Hicks criterion to judge the acceptability of an undertaking's impact on society in aggregate. This principle holds that a project is supportable if the winners could theoretically compensate the losers for their decreased utility while maintaining a net welfare gain for themselves. In other words, the project must be Pareto-improving[36] when the potential for transfer payments is factored in. Note that this criterion does not imply that redistribution must occur in reality, and in fact such transfers could modify the behavior of individual agents such that the efficiency gains resulting from the project would be partially offset.

Producer and consumer surplus as measures of benefit

The Kaldor-Hicks criterion introduces the idea of winners and losers. Consumers win if they receive a lower price, which translates into an increased consumer surplus (being the difference between their willingness to pay and the price of the good). Producers win if they increase profits, which translates into an increased producer surplus (being the difference between the price of the good and the cost of its production). This is illustrated in Figure 36. Hence, if the sum of the changes in consumer and producer surplus consequent on the investment is in excess of the cost of the investment, then the project must be (potentially) Pareto-improving and it should go ahead. The sum of the producer and consumer surplus in each period corresponds to the term (B-C) in equation (1) above.

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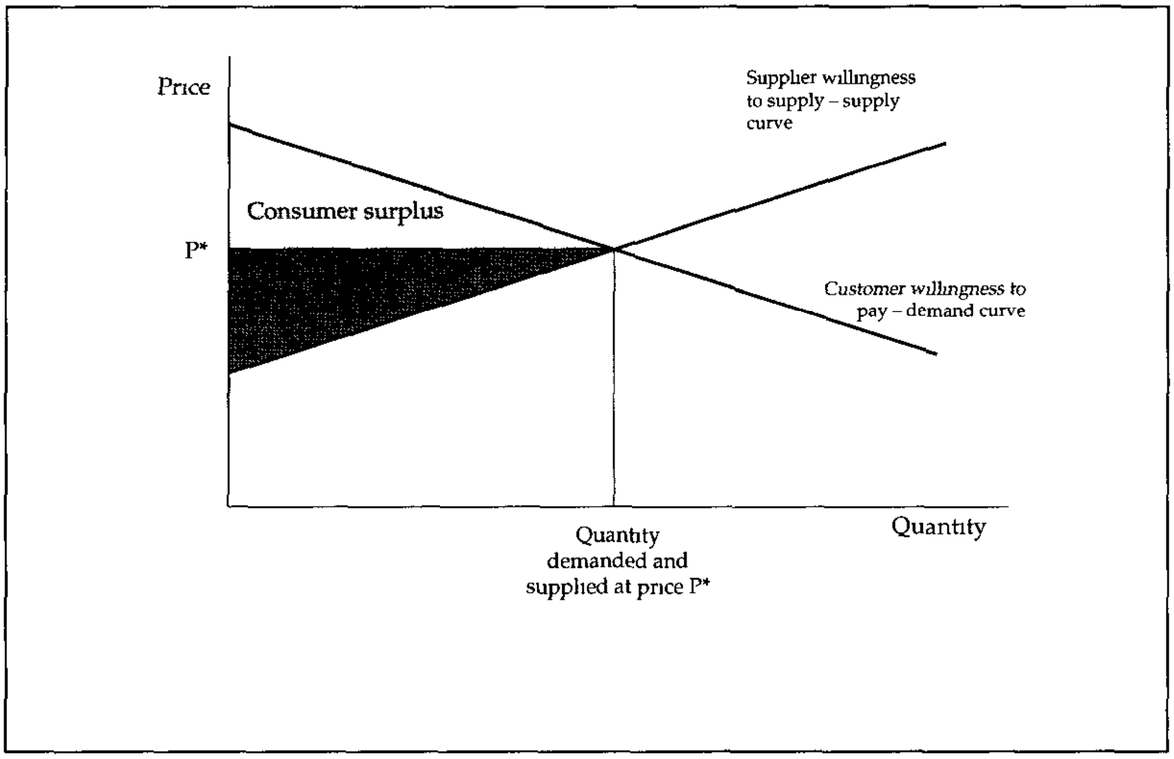
[35] Another approach developed by Keynes involves determining the economic rate of return (ERR) that equates the initial project cost with the sum of discounted future net benefits. This method will deliver similar results when the input assumptions are similar

[36] A change is regarded as 'Pareto-improving' if no one is made worse off but at least one person is better off

Figure 36. Consumer and producer surplus



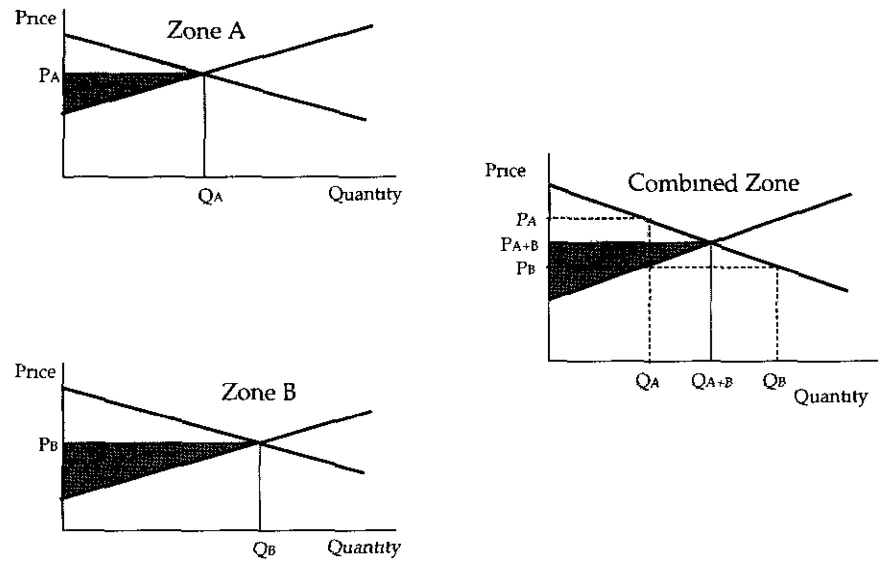
Application to transmission investment

The impact of transmission investment can be described in the following terms. Take, for example, a transmission line constructed between a zone with high cost supply (Zone A) and a zone with low cost supply (Zone B) which can be expected to result in the following changes (absent strategic behavior):

- prices fall in Zone A and rise in Zone B;
- customers in Zone A see a rise in consumer surplus, customers in Zone B see a fall in consumer surplus;
- suppliers in Zone A see a fall in producer surplus, suppliers in Zone B see an rise in producer surplus.

The last point indicates that some suppliers in Zone A that were previously required to meet demand in Zone A are displaced by generators in Zone B supplying across the interconnect. This is illustrated in Figure 37.

Figure 37. Impact of a transmission link between zones



In the classical cost benefit analysis, the aggregate change in the surpluses is compared with the cost of the investment.

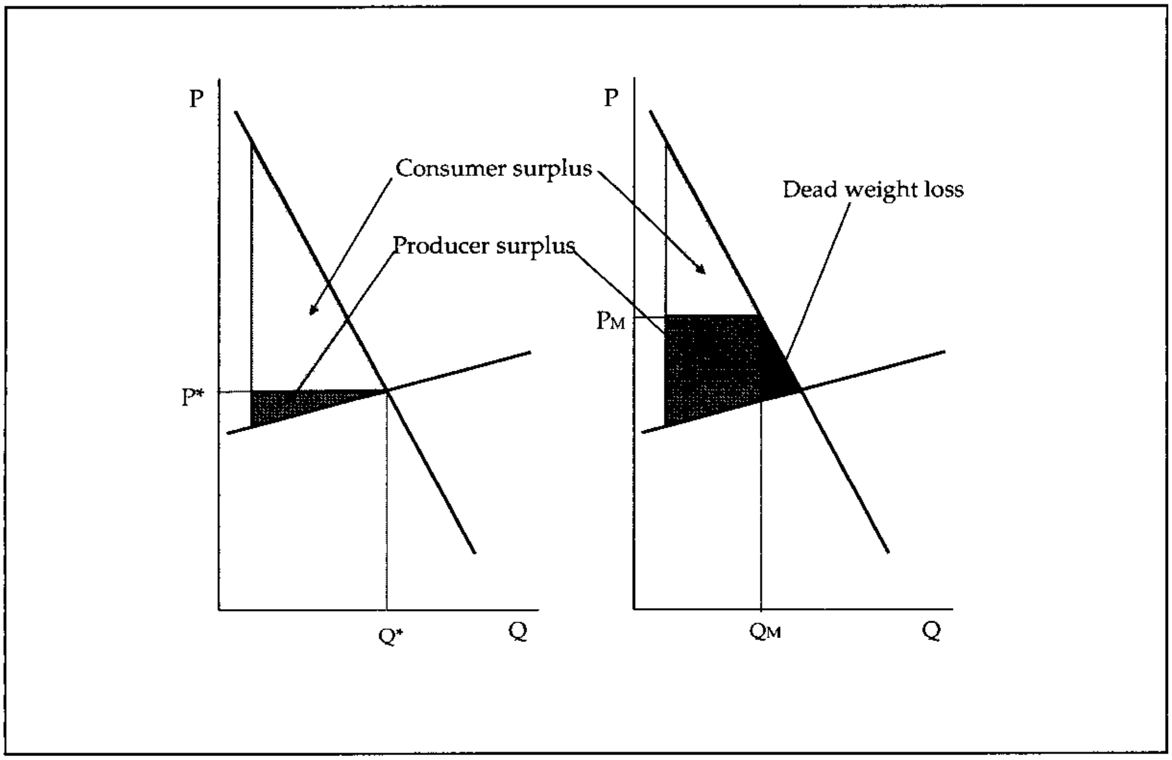
Distributional effects

The foregoing makes no distinction (from the perspective of social welfare) between producer and consumer surpluses or regional shifts in surpluses within each of these groups. This has an important consequence: that transfers between customers and suppliers that are not associated with any reduction in demand result in no welfare losses.[37] Figure 38 shows the impact of a supplier with market power raising price above the competitive level. In this example, demand is inelastic (i.e., demand changes very little as prices rise). The consequence of the rise in price is therefore:

- a decrease in quantity consumed;
- an absolute efficiency loss (termed the dead-weight loss); and
- a transfer from customers to suppliers.

[37] A monopolist that can perfectly price discriminate can achieve this outcome.

Figure 38. Impact of monopoly pricing



The welfare losses (i.e., the dead weight) are likely to be small in markets where demand is unresponsive to price (such as electricity as it currently stands), but the transfers from customers to suppliers can be large. Since the foregoing approach makes no distinction between consumer and producer surpluses, it ascribes very little welfare loss to monopoly pricing in markets with relatively unresponsive demand. As a practical matter, transmission evaluation under this approach will not consider reduced scope for monopoly pricing to be a significant source of benefits.

Distributional issues are often important, however. Even when a rigorous CBA indicates that a particular project is welfare-enhancing in the aggregate, it may be considered undesirable if its benefits are disproportionately skewed toward particular groups. This suggests two potential courses of action:

- after approving a project with adverse welfare effects on certain groups, establish a formalized mechanism whereby gains are redistributed; or
- explicitly integrate distributional effects into the CBA such that only an undertaking whose *distribution-adjusted* net social value is positive will be implemented.

The former is not a realistic proposition for the CAISO, and is beyond the scope of this study, although it is noteworthy that there are regulators in this market that explicitly take account of distributional questions in controlling prices.

The second approach factors distributional effects into the computation of net social value, and hence may reject projects that would have been accepted on an unadjusted basis. Formally, the revised decision rule is to approve projects if.

$$\sum_{i=1}^{n} \alpha_i * (B_i - C_i) > 0$$

where the α represent the 'marginal social value' of each individual i relative to the population of n individuals.[38] The development of suitable weights for each individual or group in society (e.g., consumers, traders, private transmission operators (PTOs), and out-of-state interests) presents significant difficulties and will depend upon the political objectives of the decision-making body.

The example shown in Figure 38 is directly pertinent to the transmission valuation question in California, since mitigation of the pricing consequences of market power is one of the objectives of transmission investment. As noted above, the net social gains from this are small if producer and consumer surplus are considered equivalent. However, if this is not so (perhaps because marginal social value of producer surplus is deemed to be less than that of consumer surplus), then the transfers will have a significant effect on the social value of the project. There are, we believe, three reasonable cases to consider. These are shown in Figure 39

Figure 39. Benefit Objective Functions

Objective Function	Description
1. Change in Social Welfare	This approach equally weights consumer and producer benefit
2. Change in Consumer Benefit plus Change in Competitive Producer Surplus	This approach considers the change in Consumer Surplus plus any changing in Producer Surplus associated with the competitive component of market clearing prices (i e. excludes any Producer Surplus associated with changes in the Price-cost markups).
3. Change in Consumer Benefit	This approach only looks at changes in Consumer Surplus.

[38] For simplicity of presentation, we have represented the discounted stream of benefits and costs as B_i and C_i.

The first might be considered more consistent with a fully deregulated market where there is considerable customer choice and competition. The second might be considered more consistent with a market in which a regulator of final prices has an objective to ensure ongoing supply to customers at lowest sustainable price. Under this measure, no marginal social value is ascribed to positive economic profits by generators derived from strategic bidding behavior (i.e. market power). The third approach focuses exclusively on consumer surplus with no consideration for producer surplus. Since competitive producer surplus (i.e. producer surplus devoid of market power rents) is not apt to change much under most transmission expansions due to the homogeneity of thermal production costs throughout the western interconnect, there may not be much discernable difference between the second and third approach.

Since different agents can take different views of the marginal social value of different surpluses, the most useful output from the transmission valuation methodology will be the building blocks necessary to evaluate the given transmission investment project under all three different objective functions. Appendix C provides a detailed methodology for how to estimate each of these benefits.

Measuring Costs

As noted above measuring the Net-Present Value of a transmission project can be expressed mathematically as:

$$NPV = \frac{B_0 - C_0}{(1+d)^0} + \frac{B_1 - C_1}{(1+d)^1} + \ldots + \frac{B_t - C_t}{(1+d)^t} > 0$$

where the subscripts represent periods from project initiation, *d* embodies a social discount rate and B and C represent benefits and costs respectively. The annual costs of a transmission project should reflect the estimated annual revenue that a transmission owner would require to undertake the project Besides the capital costs of a project, these costs typically include a return on capital, federal and state taxes, and operation and maintenance costs (O&M). If no detailed cost estimates of these additional components are available at the time the project is being evaluated, they could be estimated using general utility standard (e.g. previously approved rates or return on equity and debt for previous projects and estimated taxes and O&M).

For the illustrative Path 26 analysis, only the estimated capital cost of the proposed expansion was available. These are shown below in Figure 40 below. The exposed expansion consists of a short-term upgrade of 400 MW and two potential long-term upgrade options that would add an additional 600 MW of capacity in both directions. Option 1 was assumed as the long-term expansion option in the illustrative Path 26 analysis.

Figure 40. Path 26 Expansion Capital Costs

		Long-term	
	Short-term	**Option 1**	**Option 2**
Capital	$2,100,000	$138,750,000	$143,000,000
Upgrade	400 MW	600 MW	600 MW
On-line Dates	2003	2005	2005

Social Discount Rate

An important component of the NPV calculation is determining an appropriate social discount rate (d). There is no definitive source or method for determining an appropriate social discount rate. However, as a practical matter, regulators have already determined what they consider to be an appropriate rate of return on transmission assets, and have presumably taken into account all relevant considerations. Given this, the regulated rate of return approved for pervious transmission projects should serve as an appropriate discount rate. It should be noted that this rate may not necessarily correspond with the rate of return a transmission provider may be requesting to undertake a transmission project and it need not be. For example, an independent transmission company may offer to build a transmission expansion provided they can earn a 12% return on capital and the social discount rate, which is an average of the regulated rate of return of previously approved projects, may be 9%. In such a case, the 12% return will be reflected in the annual revenue requirements (C_i) but the social discount rate will be 9%. In other words, the social discount rate should reflect the societal opportunity cost of money not the transmission investor's.

It is important to note that if the benefits of a transmission expansion are adjusted for inflation (i.e. expressed in real dollars versus nominal dollars) then the social discount rate should also be adjusted for inflation in order to reflect the inflation-free results; such an adjustment could be made by comparing the yield on long-term US Treasury Bonds with the yield on an Inflation-indexed Treasury security.

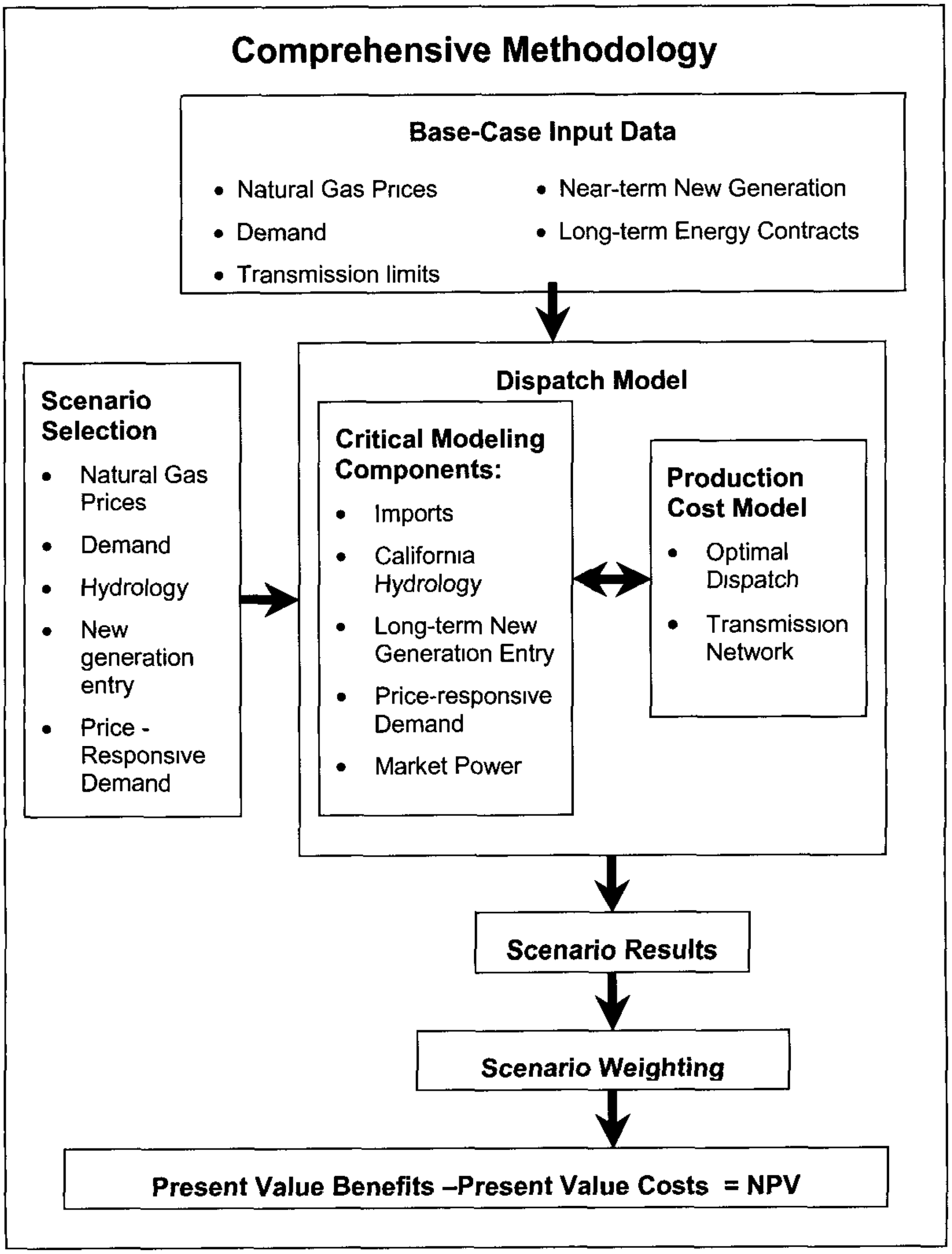
VII. Summary of Methodology

This document provides a comprehensive methodology for evaluating the economic benefits of transmission expansions. Specifically, this study addressed the following elements:

- Provides guidelines for determining the appropriate level of network representation and modeling time horizon.
- Describes the critical input data to a transmission valuation methodology and provides recommendations on the factors one should consider in choosing the appropriate values of these data.
- Identifies the major modeling components that a comprehensive valuation methodology should include and provides specific methodologies for developing each of them.
- Emphasizes the importance of estimating the benefits of a transmission expansion under multiple scenarios and provides a methodologies for selecting scenarios and assigning weights to each scenario in order to estimate the expected benefits of the expansion.
- Provides an overview of the theory and methodology for measuring the net-benefits of a transmission expansion and provides recommendations for specific benefit measures and methodologies for calculating these benefits

A summary of this comprehensive approach is provided in Figure 41

Figure 41. Schematic of Methodology



Appendix A

Methodological Approach for Calculating Residual Supply Indexes (RSIs) in a Three Zone Model

Residual Supply Index (RSI)

$RSI_N = (TS_N - Max(TUC_{N(i)})/RND_N$

$RSI_S = (TS_S - Max(TUC_{S(i)})/RND_S$

Where,

N, S	=	Zones (NP15, SP15), respectively
TS_j	=	Total Available Supply in Zone j
$TUC_{j,i}$	=	Total Uncommitted Capacity of Supplier i in Zone j
RND_j	=	Residual Net Short in Zone j

Total Uncommitted Capacity (TUC)

Total uncommitted capacity for each supplier (i) for each zone (j) is comprised of the uncommitted capacity the supplier has physically located in the zone ($UC_{j,i}$) plus any imports to the zone that the supplier can physically control (Controllable Transmission Capacity (CTC)).

$TUC_{N(i)} = UC_{N(i)} + CTC_{(Z\text{->}N)(i)}$

$TUC_{Z(i)} = UC_{Z(i)} + CTC_{(N\text{->}Z)(i)} + CTC_{(S\text{->}Z)(i)}$

$TUC_{S(i)} = UC_{S(i)} + CTC_{(Z\text{->}S)(i)}$

Controllable Transmission Capacity (CTC)

Controllable transmission capacity for each supplier (i) in each zone (j) is determined by taking the total available import capability for a particular transmission path (e.g. Path 15 and Path 26) and subtracting from that value the total available imports less the imports available from supplier (i). If this value is negative (e.g. total available imports less supplier (i)'s available imports exceeds the import capability of the path), supplier (i) cannot control the amount of imports provided on that path. However, a positive value would represent the amount of imports that supplier (i) would be capable of withholding.

$CTC_{(Z->N)(i)} = Max[0, [ATC_{Z->N} – (TS_{(Z->N)} – UC_{Z(i)} - CTC_{(S->Z)(i)})]]$

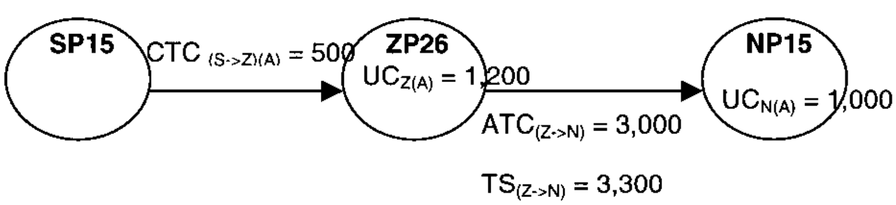
$CTC_{(N->Z)(i)} = Max[0, [ATC_{N->Z} – (TS_{(N->Z)} – UC_{N(i)})]]$

$CTC_{(S->Z)(i)} = Max[0, [ATC_{S->Z} – (TS_{(S->Z)} – UC_{S(i)})]]$

$CTC_{(Z->S)(i)} = Max[0, [ATC_{Z->S} – (TS_{(Z->S)} – UC_{Z(i)} - CTC_{(N->Z)(i)})]]$

Note, calculating the controllable transmission capacity of each supplier for imports into NP15 and SP15 from ZP26, via Path 15 and Path 26, respectively is more complicated in that one must also account for the transmission capacity the supplier controls from SP15 to ZP26 and from NP15 to ZP26. An example using $CTC_{(Z->N)(i)}$ will help illustrate the point.

Figure A-1:



In Figure A-1 assume that the south to north available transmission capability on Path 15 is 3,000 MW, Supplier A controls 500 MW of south to north flows on Path 26 and has 1,200 MW of uncommitted capacity in ZP26, and that the total supply available to import into NP15 (Path 26 S->N ATC plus all uncommitted generation capacity in ZP26 is 3,300 MW. Under this example, if Supplier A withheld its 500 MW of imports on Path 26 and its 1,200 MW of generation in ZP26, only 1,600 MW would be available for import into NP15, which means that Supplier A can effectively withhold 1,400 MW of imports on Path 15 (e.g. $CTC_{(Z->N)(A)} = 1,400$)

Appendix B

Regional Cost Differences in Siting New Power Generation in California

This Appendix provides a summary and assessment of a draft report prepared for the CEC on the regional cost differences of siting new generation in California[1]. The analysis in the report is divided into two phases. The report outlined a 2-Phase research approach to assessing regional cost difference that would include the costs associated with the following regional siting constraints.

Figure B-1. New Generation Siting Cost Components

Phase 1	***Phase 2***
• Air quality offsets • Water resources • Biological resources • Land use issues • Infrastructure upgrades, such as transmission lines (230 and 500 kv), substations, natural gas pipelines, water lines, reclaimed water lines etc.	• Additional details on Phase 1 factors • Efficiency and reliability (plant performance based on the meteorological conditions) • Public involvement and controversy • Environmental justice • Noise • Transportation and circulation • Recreation • Cultural resources • Visual resources • Environmental contamination.

However, the report only included cost information on the Phase 1 elements. For the purpose of the analysis, a base load combined cycle plant of size 500MW is considered for comparison. The plant has the following features.

⇒ Combined Cycle of nominal output of 500 MW
⇒ Two Frame 7F technology Combustion Turbines (CTs) manufactured by GE and one Steam Turbine (ST).
⇒ Each of these turbines has a nominal capacity of 175 MW each.
⇒ The capital cost of construction is assumed to be in the range of $400 - $500 Million.
⇒ All of the costs are in 2003 dollars.

[1] This is a draft report titled "Regional Cost Differences- Siting New Power Generation in California" prepared for the California Energy Commission by Aspen Environmental Group, December 2002.

Figure B-2. Air Quality Offset Summary

CAISO Zone	Air Basin	Air Quality Offset	
		District	Cost
NP15	San Francisco Bay	Bay Area	$ 5,748,500
NP15	Sacramento Valley	Butte County	$ 6,378,000
NP15		Colusa County	$ 6,378,000
NP15		Glenn County	$ 6,378,000
NP15		Feather River	$ 6,378,000
NP15		Tehama County	$ 6,378,000
NP15		Placer County	$ 8,065,000
Outside CAISO		Sacramento Metropolitan	$ 8,065,000
NP15		Yolo-Salono	$ 8,065,000
NP15		Shasta County	$ 5,759,500
All Zones	San Joaquin Valley	San Joaquin Valley Unified	$ 5,129,500
NP15	North Central Coast	Monterey Bay Unified	$ 7,960,000
ZP26	South Central Cost	San Luis County	$ 3,980,000
ZP26		Santa Barbara County	$ 5,970,000
SP15		Ventura County	$ 5,006,000
SP15	Mojave Desert	Antelope County	$ 4,922,000
SP15		Kern County	$ 4,776,000
SP15		Mojave Desert	$ 4,922,000
SP15		South Coast	$ 20,061,800
SP15	South Coast	South Coast	$ 20,061,800
SP15	San Diego	San Diego County	$ 5,868,000
Outside CAISO	Salton Sea	Imperial County	$ 4,776,000
SP15		South Coast	$ 20,061,800

From Figure B-2 above the following costs are summarized for each of the CAISO zones.

Figure B-3. Air Quality Offset Summary by CAISO Zones

Zones	NP15	ZP26	SP15
Maximum	$8,065,000	$5,970,000	$20,061,800
Average	$6,601,591	$5,026,500	$10,089,878
Minimum	$5,129,500	$3,980,000	$4,776,000

Figure B-4. Estimated Water Supply Costs and Capital Costs Associated with Cooling and Wastewater Discharge Systems

CAISO Zone	Air Basin	Estimated Costs		
		Water Supply (M$/year)	Cooling System (M$)	Wastewater System (M$)
NP15	San Francisco Bay	$3.10	$10	Minimal
NP15	Sacramento Valley	$1.10	$15	$10
All Zones	San Joaquin Valley	$0.80	$25	$10
NP15	North Central Coast	$1.70	$25	$10
ZP26/SP15	South Central Cost	$1.60	$25	Minimal
SP15	Mojave Desert	$0.06	$40	None
SP15	South Coast	$2.50	$20	Minimal
SP15	San Diego	$2.00	$5	Minimal
SP15	Salton Sea	$0.08	$40	None

The costs shown in Figure B-4 are summarized for each of the CAISO zone in Figure B-5.

Figure B-5. Summary of Water Supply, Cooling System and Waste Water System Cost

	Water Supply Costs (M$/Year)			***Cooling System (M$)***			***Waste Water System (M$)***		
Zones	**NP15**	**ZP26**	**SP15**	**NP15**	**ZP26**	**SP15**	**NP15**	**ZP26**	**SP15**
Maximum	$3 1	$1.6	$2.5	$25.0	$25.0	$40.0	$10 0	$10 0	$10 0
Average	$1.7	$0 8	$0.8	$18 8	$25.0	$25 0	$10 0	$10.0	$10.0
Minimum	$0.8	$0.8	$0 1	$10 0	$25.0	$5.0	$ -	$ -	$ -

Figure B-6. Example of Biological Mitigation/Requirements Costs

CAISO Zone	Air Basin/ Study Region	Power Plant	Costs
NP15	San Francisco Bay	Russell City Energy Center	$ 300000 for the first year and additional annual payments
		Delta Energy Center	$ 5,000
		Metcalf Energy Center	$ 412,500
		Los Esteros Critical Energy Facility	$ 517,929
NP15	Sacramento Valley	Sutter Energy Center	$ 10,000 - 40,000
All Zones	San Joaquin Valley	La Paloma Power Project	$ 233,000
		Elk Hills Project	$ 143,983
		Midway Sunset Project	$ 942,302
		Henrietta Peaker	$ 28,750[2]
NP15	North Central Coast	Moss Landing Power Project	$ 7,000,000
ZP26/SP15	South Central Cost	None	
SP15	Mojave Desert	High Desert Power Project	$ 2,200,000
		Blythe energy Center	$ 93,000
SP15	South Coast	Huntington Beach Repower Project	$ 1,500,000
SP15	San Diego	Otay Mesa	$ 305,016
SP15	Salton Sea	None	

Adding the zonal siting costs shown in Figure B-3 and Figure B-5 to a $450 Million average capital cost of construction results in the zonal $/kW siting costs shown in Figure B-7. These costs do not include the data from Figure B-6 given that the biological mitigation/requirement costs depends highly on the site-specific conditions and therefore an accurate comparison is not possible.

Figure B-7. CCGT Prices by CAISO Zone ($/kW)

	NP15	ZP26	SP15
Maximum	$ 634	$ 597	$ 651
Average	$ 593	$ 578	$ 583
Minimum	$ 549	$ 565	$ 527

The average cost difference in Figure B-7 is not significant enough to differentiate the costs between the CAISO zones. The current assumption for all zones is $ 600/kW, reduced by 2% every 5th year to accommodate the cost reduction due to technology improvements.

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2 Cost of land not available

APPENDIX C

Defining Welfare Components and Transmission Benefits In the Transmission Evaluation Methodology

This Appendix describes the general approach used to calculate changes in consumer and producer welfare, and ISO congestion charges. A simple two-zone example illustrates the approach. In Section I, we define the components of the welfare calculations without and with the transmission addition. Then in Section II, we describe the calculation of welfare changes resulting from the transmission expansion. Finally, in Section III, we discuss the modifications made to make the actual calculations using output of production costing simulation software.

I. Define Welfare Components

Without Transmission Expansion

Competitive Case

Figure C-1 illustrates a snap shot of supply and demand balance in a 2-zone, 1-way transmission system where Zone *A* is the importing zone and Zone *B* is the exporting zone, with a certain level of transmission capacity *T* connecting the two zones. Zone *A* is short of generation, while *B* has a surplus of cheap generation. Suppose all generators bid their marginal costs and market clearing prices are settled at P_{0c}^{A} and P_{0c}^{B} where $P_{0c}^{A} > P_{0c}^{B}$ due to congestion on the transmission line[1]. Line *CA* in the left panel represents the stack of the marginal costs of the generation units at *A*. The zonal demand in Zone *A* is represented by line V^ABD^A where V^A denotes the value of lost load in Zone *A*. Similarly in the right panel for the exporting zone, line V^BFD^B denotes the zonal demand curve where V^B denotes the value of lost load in Zone *B*, and line *GE* denotes the stack of the marginal costs of units located in Zone *B*. Note that there is excess supply of amount *T* in Zone *B*; this represents exports to Zone *A*, which are used to meet the excess demand in Zone *A*.

[1] Note the notation convention is that superscript "*A*" and "*B*" denote zones, subscript "*c*" denotes competitive solution, and subscript "*0*" denotes solution in the absence of transmission expansion

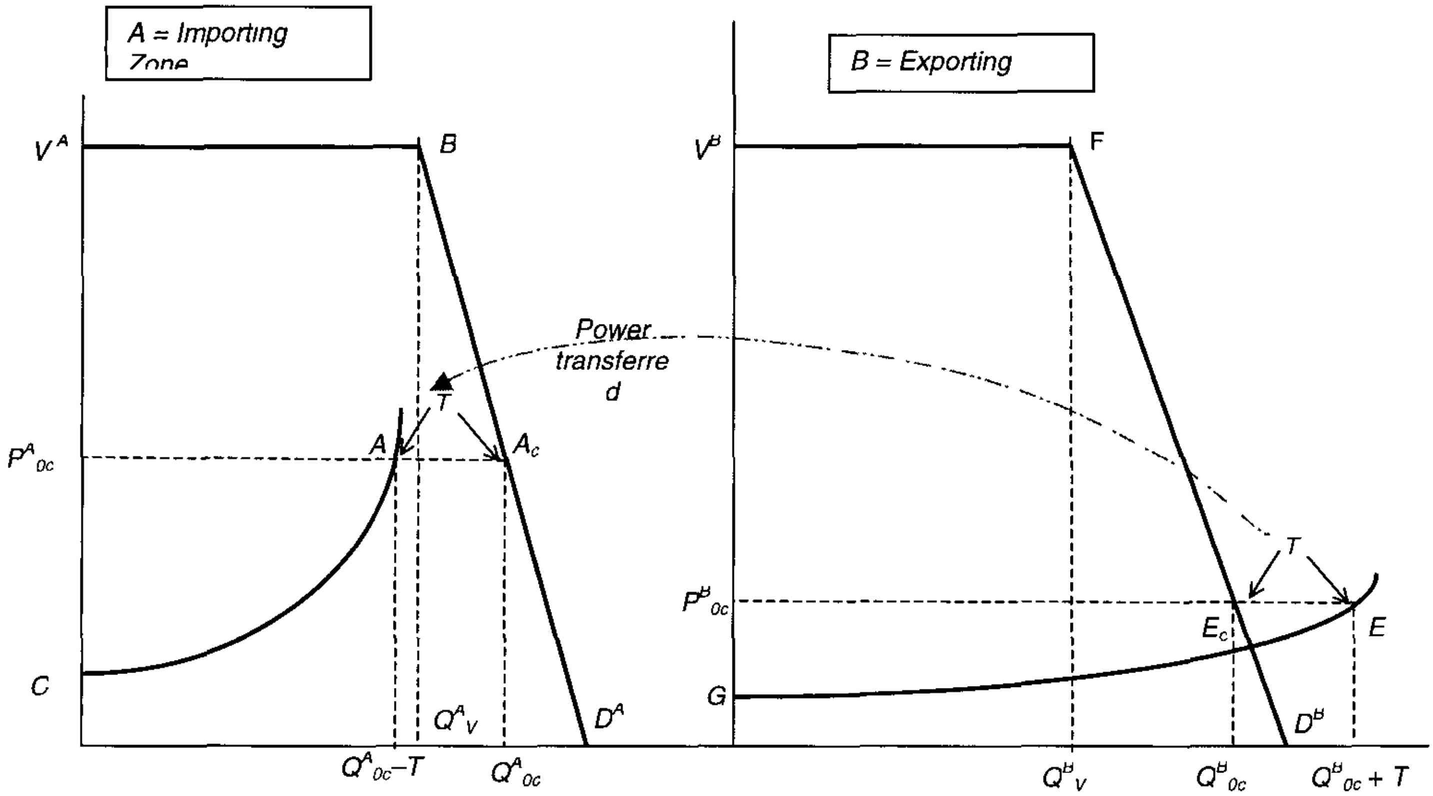

Figure C-1: Illustration of a 2-Zone System Under Competitive Assumption

Let Q^A_{0c} and Q^B_{0c} denote the competitive zonal consumption in *A* and *B* respectively. One commonly defined component of economic welfare is producer surplus:

Producer Surplus for Zone *A* Producers = *Area* $CAP^A_{0c} \approx 0.5(P^A_{0c} - C)(Q^A_{0c} - T)$,

Producer Surplus for Zone *B* Producers = *Area* $GEP^B_{0c} \approx 0.5(P^B_{0c} - G)(Q^B_{0c} + T)$,

where *C* and *G* are the marginal cost of the least expensive unit in the respective zone. Producer surplus measures generators' gain by producing power.

Another commonly defined component is ordinary (Marshallian) consumer surplus. Consumer surplus is an approximation of the difference between the price consumers actually pay for power and the amount they are willing to pay. Let Q^A_V and Q^B_V denote the consumption level associated with V^A and V^B respectively. Thus consumer surplus can be defined as:

Consumer Surplus in Zone *A* = *Area* $P^A_{0c}A_cBV^A = 0.5(V^A - P^A_{0c})(Q^A_V + Q^A_{0c})$,

Consumer Surplus in Zone *B* = *Area* $P^B_{0c}E_cFV^B = 0.5(V^B - P^B_{0c})(Q^B_V + Q^B_{0c})$.

Furthermore the ISO as the system operator collects the following congestion rent:

$$\text{Congestion Rent } = (P^A_{0c} - P^B_{0c})T \,.$$

Note that if flow is less than T, then the prices are equal under competitive conditions, and there is no such rent.

Market Power Case

When market power exists, prices are often set at levels higher than marginal costs. Let P^A_{0m} and P^B_{0m} in Figure C-2 denote the zonal prices and Q^A_{0m} and Q^B_{0m} denote the zonal consumptions[2]. Let MC^A_{0m} and MC^B_{0m} denote the marginal costs of the units that set zonal prices[3]. Thus producer surplus in Zone *A* is now the area $CHRP^A_{0m}$ and it can be decomposed to producers' competitive rent, the area $CHMC^A_{0m}$, and producers' market power rent, the area $MC^A_{0m}HRP^A_{0m}$. Consumer surplus in Zone *A* is now the area $P^A_{0m}R_mBV^A$. Welfare measures for Zone *B* can be similarly defined.

Thus we have the following welfare measures for Zone *A*:

$$\begin{aligned}
&\text{Producer Surplus } = \text{Competitive Rent + Market Power Rent}\\
&\text{Competitive Rent } = \textit{Area } CHMC^A_{0m} \approx 0.5(MC^A_{0m} - C)(Q^A_{0m} - T)\,,\\
&\text{Market Power Rent } = \textit{Area } MC^A_{0m}HRP^A_{0m} = (P^A_{0m} - MC^A_{0m})(Q^A_{0m} - T)\,,\\
&\text{Consumer Surplus } = \textit{Area } P^A_{0m}R_mBV^A = 0.5(V^A - P^A_{0m})(Q^A_V + Q^A_{0m})\,,
\end{aligned}$$

Note that we are defining "competitive rent" as the rents that would be earned if price instead equaled marginal cost at the quantity supplied by producers at *A*. Market Power Rent is therefore calculated as the difference between producer surplus and the competitive rent.

[2] Subscript "*m*" denotes market power solution.

[3] Note that in general a supply curve does not exist under market power conditions, although we have shown a stack of generation units' marginal costs (i.e., line *CH* and line *GI*). This is because imperfectly competitive generators may withhold output, and so their cheap generators might be dispatched after more expensive generators owned by other firms in the same zone. However, for the purposes of this explanation, we define line *CH* as the generation-cost ordered stack of units that are actually dispatched. In the actual calculations performed in PoolMOD, generation costs are based on the actual expenses incurred by dispatched generation units, rather than a supply curve

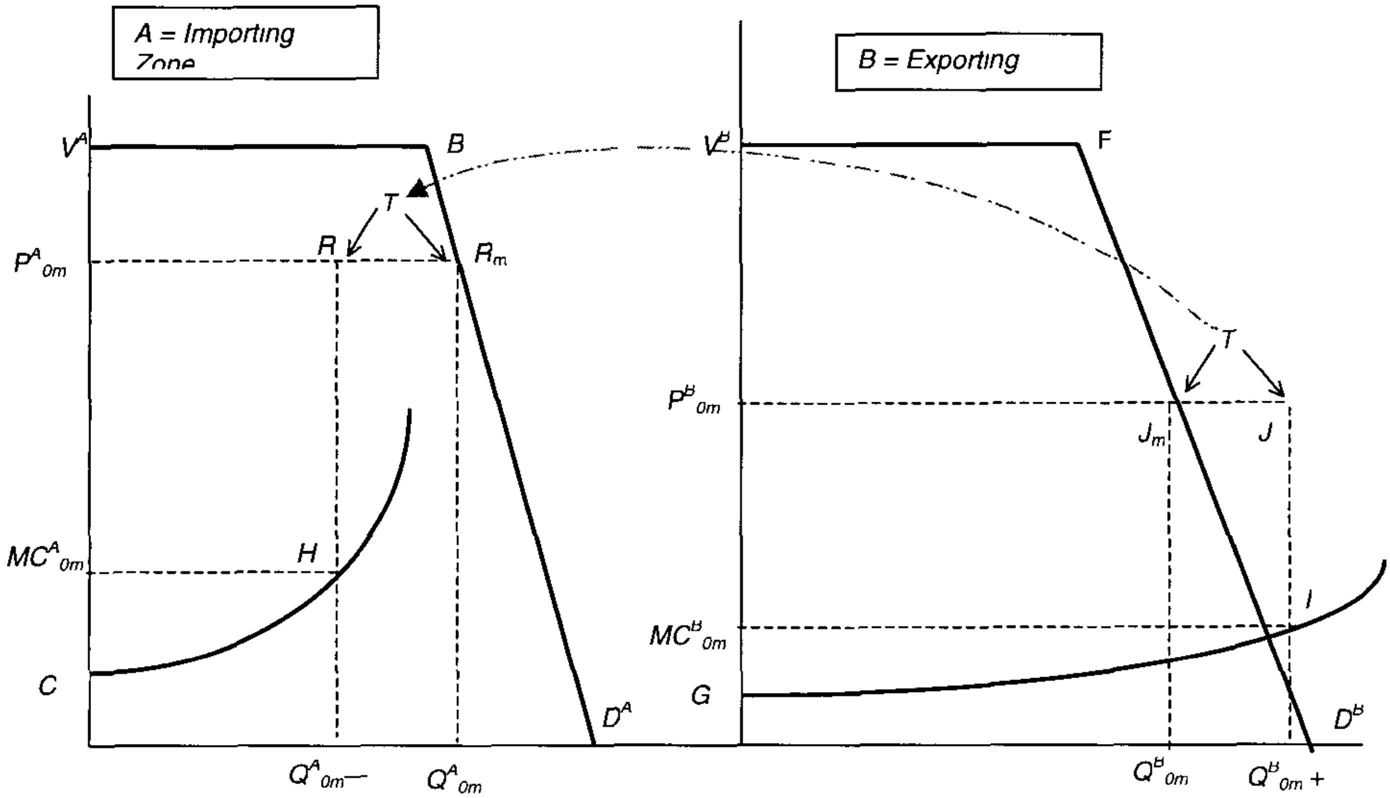

Figure C-2: Illustration of a 2-Zone System Under Market Power Assumption

For Zone *B*, we have the following:

Producer Surplus = Competitive Rent + Market Power Rent,
Competitive Rent = *Area* $GIMC^B_{0m} \approx 0.5(MC^B_{0m} - G)(Q^B_{0m} + T)$,
Market Power Rent = *Area* $MC^B_{0m}IJP^B_{0m} = (P^B_{0m} - MC^B_{0m})(Q^B_{0m} + T)$,
Consumer Surplus = *Area* $P^B_{0m}J_mFV^B = 0.5(V^B - P^B_{0m})(Q^B_V + Q^B_{0m})$,

And the ISO collects the following congestion rent:

Congestion Rent = $(P^A_{0m} - P^B_{0m})T$.

The dead weight loss due to market power can then be calculated as the difference between the sum of producer and consumer surpluses plus congestion rent between the competitive and imperfectly competitive cases.

With Transmission Expansion

Competitive Case

Suppose the transmission capacity between Zones *A* and *B* is upgraded to a higher level ($T+\Delta T$). In this case more cheaper power could flow from Zone *B* to Zone *A* to substitute for the more expensive units in Zone *A*. Suppose the line is still congested even though it is expanded. Assume generators are competitive and they always bid their marginal costs.

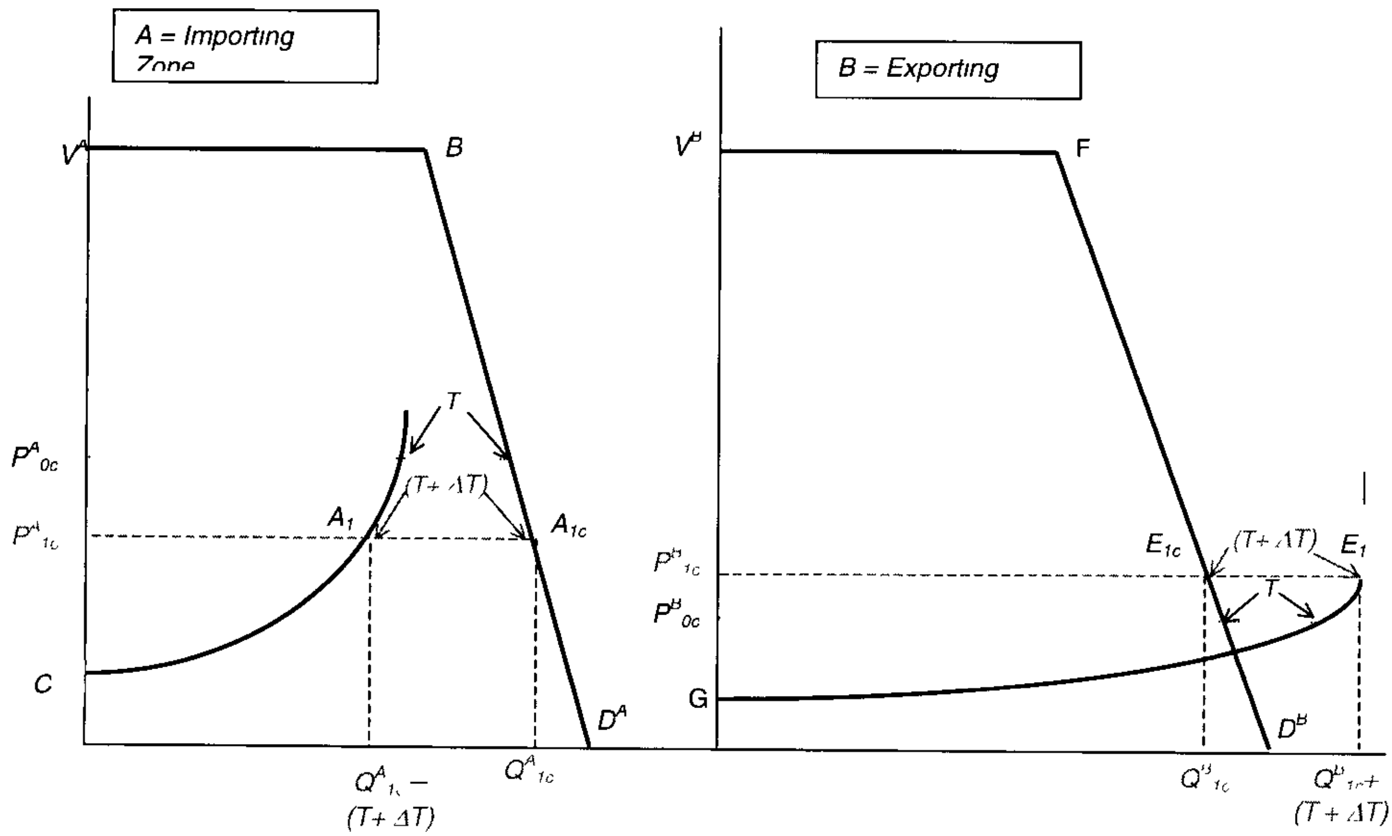

Figure C-3: Illustration of the Impact of Transmission Expansion Under Competitive Assumption

Figure C-3 compares the new and old competitive price equilibria. Let P^A_{1c} and Q^A_{1c} denote the market price and consumption in Zone *A*, and let P^B_{1c} and Q^B_{1c} denote the market price and consumption in Zone *B*[4]. With transmission expansion, we would expect price in Zone *A* to be lower than without expansion (i.e., $P^A_{1c} < P^A_{0c}$), and price in Zone *B* to be higher than without expansion (i.e., $P^B_{1c} > P^B_{0c}$) in general. As the figure shows, the excess supply in Zone *B* has increased (to the new line capacity $T + \Delta T$), matching the increase in excess demand in Zone *A*.

[4] Subscript "*1*" denote solution with transmission expansion.

Under the competitive assumption, we have the following welfare measures:

Producer Surplus in Zone A = Area $CA_I P^A_{Ic} \approx 0.5(P^A_{Ic} - C)[Q^A_{Ic} - (T + \Delta T)]$,
Producer Surplus in Zone B = Area $GE_I P^B_{Ic} \approx 0.5(P^B_{Ic} - G)[Q^B_{Ic} + (T + \Delta T)]$,
Consumer Surplus in Zone A = Area $P^A_{Ic} A_{Ic} BV^A = 0.5(V^A - P^A_{Ic})(Q^A_V + Q^A_{Ic})$,
Consumer Surplus in Zone B =Area $P^B_{Ic} E_{Ic} FV^B = 0.5(V^B - P^B_{Ic})(Q^B_V + Q^B_{Ic})$,
Congestion Rent $= (P^A_{Ic} - P^B_{Ic})(T + \Delta T)$.

Market Power Case

When market power exists, prices are again set at levels higher than marginal costs, although perhaps less so than before transmission capacity was expanded. Let P^A_{Im} and P^B_{Im} denote the zonal prices and Q^A_{Im} and Q^B_{Im} denote the zonal consumptions. Let MC^A_{Im} and MC^B_{Im} denote the marginal costs of the units that set zonal prices in each zone respectively. Figure C-4 illustrates the resulting equilibrium, and calculations of welfare measures.

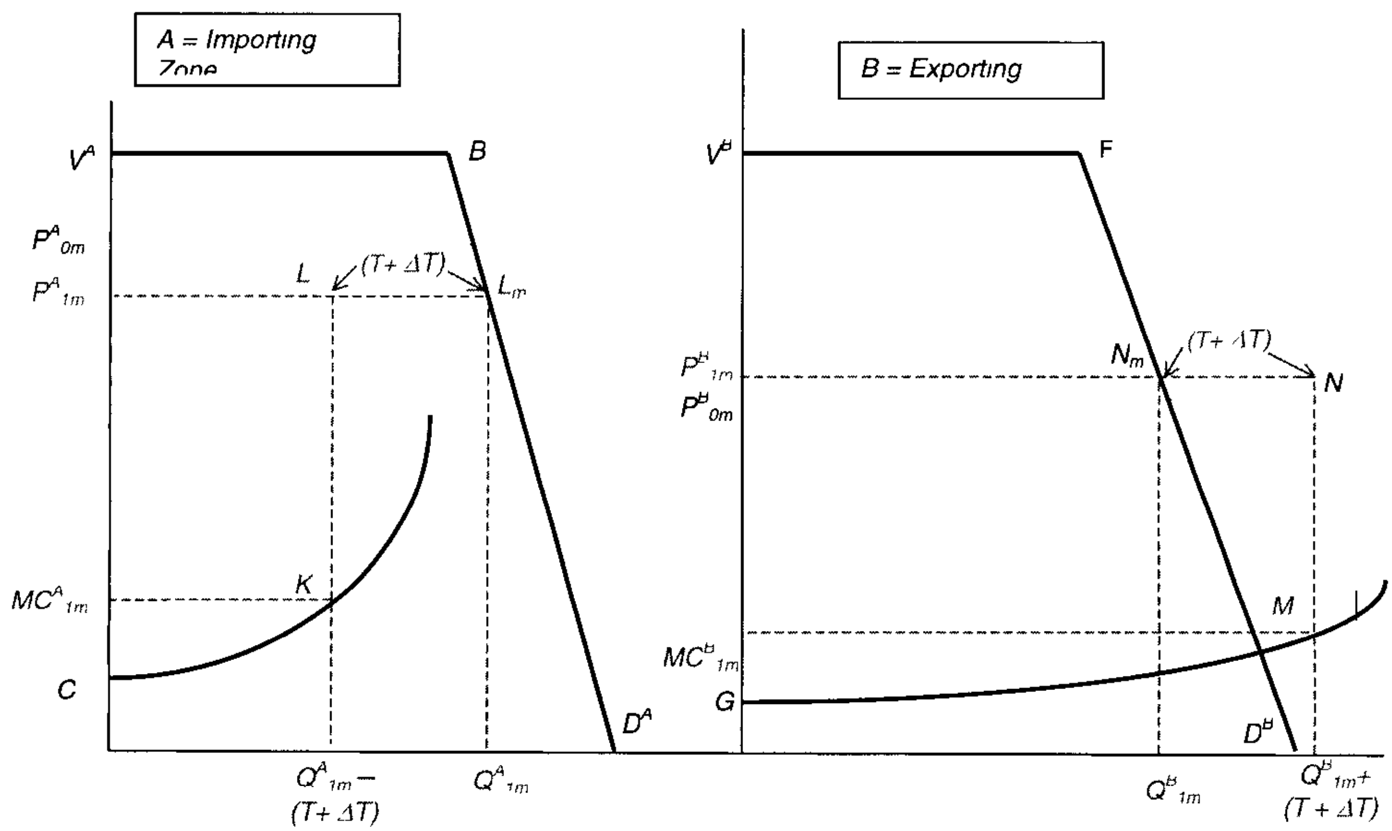

Figure C-4: Illustration of the Impact of Transmission Expansion Under Market Power Assumption

Welfare measures with transmission expansion under market power assumption can be defines as follows:

For Zone *A*:

Producer Surplus = Competitive Rent + Market Power Rent,
Producer Competitive Rent = $Area\, CKMC_{1m}^{A} \approx 0.5(MC_{1m}^{A} - C)[Q_{1m}^{A} - (T + \Delta T)]$,
Producer Market Power Rent = $Area\ MC_{1m}^{A}KLP_{1m}^{A} = (P_{1m}^{A} - MC_{1m}^{A})[Q_{1m}^{A} - (T + \Delta T)]$,
Consumer Surplus =$Area\ P_{1m}^{A}L_{m}BV^{A} = 0.5(V^{A} - P_{1m}^{A})(Q_{V}^{A} + Q_{1m}^{A})$.

For Zone B:
Producer Surplus = Competitive Rent in + Market Power Rent'
Producer Competitive Rent = $Area\, GMMC_{1m}^{B} \approx 0.5(MC_{1m}^{B} - G)[Q_{1m}^{B} + (T + \Delta T)]$,
Producer Market Power Rent = $Area\ MC_{1m}^{B}MNP_{1m}^{B} = (P_{1m}^{B} - MC_{1m}^{B})[Q_{1m}^{B} + (T + \Delta T)]$,
Consumer Surplus =$Area\ P_{1m}^{B}N_{m}FV^{B} = 0.5(V^{B} - P_{1m}^{B})(Q_{V}^{B} + Q_{1m}^{B})$.

For the ISO:

Congestion Rent = $(P_{1m}^{A} - P_{1m}^{B})(T + \Delta T)$.

II. Define Transmission Benefit Components

Each individual group's transmission benefits can be obtained by simply comparing its welfare with and without transmission expansion. Suppose market is imperfectly competitive, transmission benefits can be defined as:

For Zone A:
Consumer Benefit = Consumer Surplus with ΔT – Consumer Surplus Without ΔT

$$= 0.5(V^{A} - P_{1m}^{A})(Q_{V}^{A} + Q_{1m}^{A}) - 0.5(V^{A} - P_{0m}^{A})(Q_{V}^{A} + Q_{0m}^{A})$$

$$= 0.5(P_{0m}^{A} - P_{1m}^{A})(Q_{0m}^{A} + Q_{1m}^{A}).$$

Producer Benefit (Competitive Rent Portion)
= Competitive Rent with ΔT – Competitive Rent Without ΔT

$$\approx 0.5(MC_{1m}^{A} - C)[Q_{1m}^{A} - (T + \Delta T)] - 0.5(MC_{0m}^{A} - C)(Q_{0m}^{A} - T).$$

Producer Benefit (Market Power Rent Portion)
= Market Power Rent with ΔT – Market Power Rent Without ΔT

$$= (P_{1m}^{A} - MC_{1m}^{A})[Q_{1m}^{A} - (T + \Delta T)] - (P_{0m}^{A} - MC_{0m}^{A})(Q_{0m}^{A} - T),$$

Total Producer Benefit = Competitive Rent Portion + Market Power Rent Portion

In this simple 2-zone, 1-way transmission model, for importing Zone A, transmission expansion will generally reduce zonal prices comparing to the situation without expansion. Thus consumers in Zone A will generally benefit from transmission expansion. Producers in importing zone are generally harmed by transmission expansion due to less competitive rent and market power rent.

For Zone B:

Consumer Benefit = Consumer Surplus with ΔT – Consumer Surplus Without ΔT

$$= 0.5(V^B - P^B_{1m})(Q^B_V + Q^B_{1m}) - 0.5(V^B - P^B_{0m})(Q^B_V + Q^B_{0m})$$

$$= 0.5(P^B_{0m} - P^B_{1m})(Q^B_{0m} + Q^B_{1m}).$$

Producer Benefit in Competitive Rent Portion)

= Competitive Rent with ΔT – Competitive Rent Without ΔT

$$\approx 0.5(MC^B_{1m} - G)[Q^B_{1m} + (T + \Delta T)] - 0.5(MC^B{}_0 - C)(Q^B{}_0 + T).$$

Producer Benefit in Market Power Rent Portion)

= Market Power Rent with ΔT – Market Power Rent Without ΔT

$$= (P^B{}_1 - MC^B{}_1)(Q^B{}_1 + (T + \Delta T)) - (P^B_{0m} - MC^B_{0m})(Q^B_{0m} + T).$$

Total Producer Benefit = Competitive Rent Portion + Market Power Rent Portion

Consumers in exporting zone B are generally harmed by transmission expansion due to prices increase in Zone B. However, producers generally benefit from expansion since more power are produced and traded at higher prices than without expansion.

ISO Benefit:

Benefit in Congestion Rent = Congestion Rent with ΔT + Congestion Rent without ΔT

$$= (P^A_{1m} - P^B_{1m})(T + \Delta T) - (P^A_{0m} - P^B_{0m})T .$$

Generally the ISO benefit of transmission expansion is negative, due to primarily two factors: (1) the transmission line will be congested in less hours with expansion than without expansion; (2) the price difference between two zones are likely reduced with expansion than without expansion.

The total social benefit of the transmission line is sometimes defined as the change in the sum of producers', consumers', and the ISO's benefit across zones. This is also equal to the change in value received by consumers (integrals of the demand curve) minus the change in generation costs.

III. Calculation Method

In the above we have defined welfare components and transmission benefits for a single time period of a 2-zone, 1-way transmission system. Note in the real world, the import-export direction (thus net power flow direction) can be easily reversed depending on instantaneous supply and demand balance in each zone and the transfer capability in both directions between zones. Thus ideally for long-term transmission expansion modeling, we should model a transmission network hourly or half-hourly and calculate welfare components and transmission benefits based on hourly or half-hourly market outputs, then aggregate to monthly or annual level to obtain transmission benefit for a given long-term time horizon.

Most production cost models can simulate hourly or half-hourly supply-demand balances, so does PoolMod. However, calculating welfare components by hourly or half-hourly intervals then aggregate is very time consuming. An alternative approach is to use the quantity weighted average annual market prices and average generation costs with and without expansion to calculate annual welfares and benefits. We have experimented both approached and found out the second approach could generate reasonably good approximation for long-term transmission evaluation purposes.