**ATTACHMENT 3**

# PATH 15 Expansion Economic Benefit Study: Phase II -Year 2005 Prospect

## September 24, 2001

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# 1 Executive Summary

This report provides the results from the second phase of the study on the economic benefit of a Path 15 expansion. In the first phase of the study (issued February 2001), historical bid data were used to estimate the economic benefit that the Path 15 expansion could have brought in retrospect.

The second phase of the study is aimed at projecting future economic benefit that the Path 15 expansion could bring in a fully competitive electricity market in the year 2005. For this analysis, a transmission constrained economic dispatch algorithm (modeled by a DC optimal power flow) is used to simulate a set of study hours for which the year 2005 load is input. The other inputs to this algorithm are generation (existing and new generation that will be available in the year 2005), imports and exports (including new generation, external to the control area, that will be available in the year 2005) and constraints on the existing Inter-Zonal Interface (in which Path 15 is included).

To address uncertainties in the input of the forecasted new generation expansion, and hydro conditions, several scenarios are used to present a spectrum of possibilities. It is assumed that there exists competitive generation bidding and consequently the supply bids used in this study are constructed based on their variable costs (i.e., heat rates, gas prices and variable operation and maintenance costs.) Moreover, the study assumes a market model that uses zonal marginal pricing based on the cost-based energy bids. Other assumptions used in this study include retirement of older thermal and combustion turbine generating units. Note that the data used in this study are from the California Energy Commission (CEC) and the CAISO.

The objective of the study is to assess the economic benefit of constructing a new 500 kV transmission line parallel to Path 15 assuming a fully competitive market. The cost of adding such a line is evaluated separately by Pacific Gas and Electric (PG&E). The economic benefit is evaluated by comparing an economic indicator calculated for the status quo situation, i.e., the current limit of Path 15, with the economic indicator calculated for the situation after the upgrade (an additional 500 kV line that will provide an estimated 1400 MW of additional capacity). There are two economic benefit indicators used in this study:

**Re-dispatch Cost** - the objective function of the optimal generation dispatch problem minimizes the production costs of generators and imports and maximizes the benefits of serving load and exports. This indicator is equivalent to the concept of social surplus in economics.

**Energy Cost to Load** - calculated as the product of the control area loads and zonal prices produced under the aforementioned marginal pricing model. This indicator represents the actual money transferring from energy consumers (loads) to energy producers (generators).

The findings of this study as calculated over the different scenarios are as follows:

1. The economic benefit of Path 15 expansion in terms of re-dispatch cost ranges from $0.33 million to $9.02 million dollars per year. The $9.02 million re-dispatch cost difference came from a scenario where NP15 is very deficient in generation stemming from modeling a dry hydro year (approximately a one in ten year) and low new generation build out in NP15 and the Pacific Northwest.

2. The economic benefit of Path 15 expansion in terms of energy cost to California load ranges from -$7.47 million dollars to $83.05 million dollars per year. Again, the $83.05 million came in the same case described in (1) above.

3. Sensitivity studies performed by varying the hydro conditions on the worst case scenario, i.e., the $83.05 million case with low NP15 and Pacific Northwest new generation, shows that the hydro condition has a large impact on the results. With a hydro condition varying from approximately a one in ten year drought to an average condition, the condition that falls in the middle of these in terms of energy shows that the cost to load difference is only $14.0 million and the re-dispatch is only $2.4 million. Thus, only when the hydro condition approaches more of a drought condition is when the economic indicators start to rise significantly.

Note the following relationship between the two economic benefit indicators: for the re-dispatch economic indicator, increasing the Path 15 will keep this indicator the same or decrease it. However, for the cost to load economic indicator, the total energy cost to load may increase or decrease resulting from Path 15 expansion and this is seen from one end of the range indicated by (2) above with a negative $7.47 million.

# 2 Introduction

## 2.1 Background

As is shown in Figure 2.1, Path 15 is a transmission interface located in the southern portion of the Pacific Gas & Electric's (PG&E) service area that is in the middle of the California Independent System Operator's (CAISO) control area. The majority of the flow of power from southern California to northern California and to the Pacific Northwest flows through Path 15; the remaining small percentage (loop flow) goes through Arizona, Nevada, Utah and Idaho.

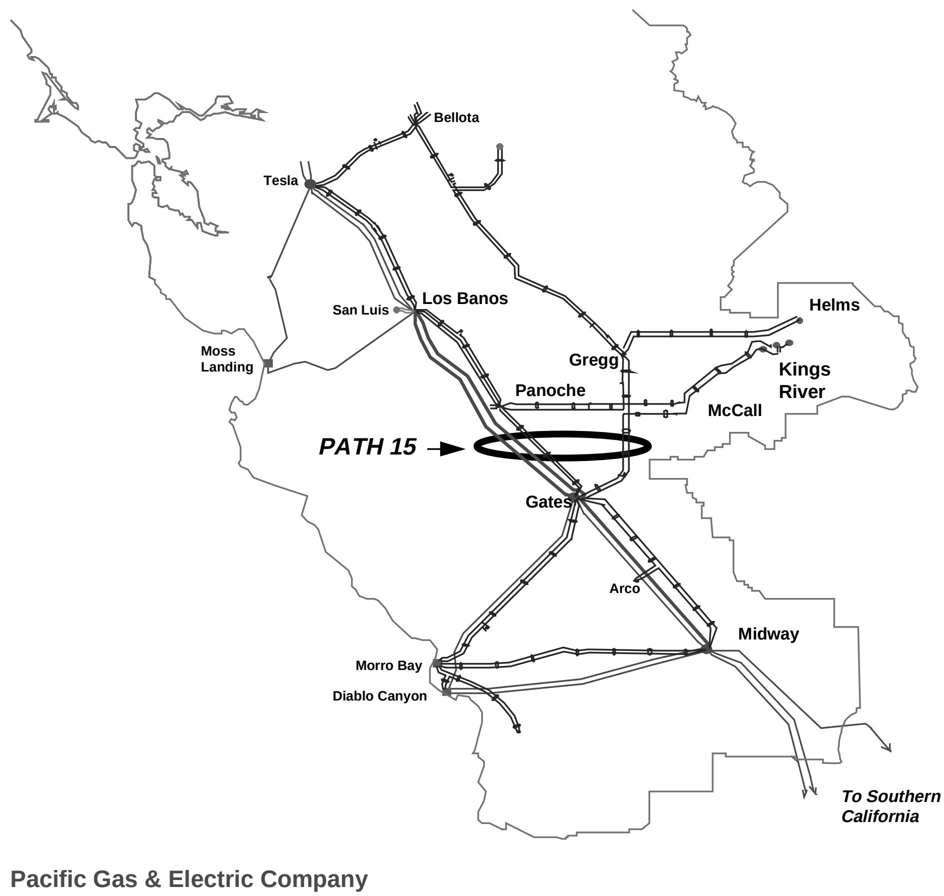


Figure 2.1. Location of the Path 15 Branch Group

Typically in the past, before the California electric utility restructuring of 1998, power flowed from the south to north during winter off-peak hours (as a payback for summer power, for example). This also held true after the restructuring because there was available power in southern California to serve northern California load. Since these power flows were often limited by the operating capacity of Path 15, it was defined to be an Inter-Zonal Interface (now connecting the Zones NP15 and ZP26) in the CAISO's Congestion Management process where transmission capacity is made available to the entity that values the capacity the most. Moreover, the congestion on Path 15 also gave rise to strategic bidding behaviors such as under-scheduling that undermined the reliability of the CAISO Controlled Grid.

Consequently, there is a proposal to upgrade Path 15 by an additional 1400 MW of capacity, i.e., by adding a third 500 kV line. The CA ISO has worked cooperatively with PG&E, and state and federal agencies to assess the economic benefits of upgrading Path 15.InFebruary, the CA ISO completed an analysis of the cost of congestion over Path 15 from September 1999 to December 2000. This report provides an assessment of the economic benefit of a Path 15 upgrade in 2005.

In the Phase I report, historical bid data (9/1/99 – 12/31/00) were used in the analysis. It was assumed that an upgrade to Path 15 would create a sufficient amount of transmission capacity such that congestion would never occur. Based on California Power Exchange unconstrained Market Clearing Prices (in the Day-Ahead and Hour-Head markets), the cost to load under the upgrade scenario was determined and then was compared to the cost originally incurred by the load. Also, an estimation of the Real-Time benefit of the upgrade was calculated based on Real-Time cost to load. In addition, Ancillary Services and Out-of-Market calls (requests for energy outside of the market) were included in the analysis.

## 2.2 Phase II Analysis

Phase II, in contrast to the Phase I report which used historical data, presents the results and analysis of the economic benefit in the year 2005. The analysis is set in the year 2005 because if the upgrade project were to begin construction in the years 2001-2002, the additional 500 kV line is estimated to be operational for the entire year 2005.

The economic benefit analysis is based upon simulating a cost-based transmission constrained economic dispatch (TCED), which is similar to the CAISO Congestion Management tool if the Market Separation Rule is neglected, over every hour of the study year. The TCED is actually a DC Optimal Power Flow (DCOPF) algorithm.

For each hour and each different scenario, there is one simulation with the rating as it is now (the status quo case) and one simulation with the rating at the value determined with the additional line. After the simulations are complete, economic indicators are calculated and the difference is take by the status quo indicator minus the new rating indicator.

### 2.2.1 High Level Overview of Assumptions, Forecasts and Scenarios

In order to perform a cost-based TCED analysis for the year 2005 all the input data needed for the simulations need to be projected for the year 2005. In doing so, many forecasts and assumptions are required. In addition, since one cannot predict the values for some of these inputs to an accurate level, scenarios are required in which the inputs in question are varied over a range. Although all of these forecasts, assumptions, and scenarios are described in detail in this report (as well as a description of the cost-based TCED), they are provided below at a high level.

1. Market Structure: the assumption is that there is a spot energy market similar to the California Power Exchange with a Zonal Market Clearing Price (i.e., a model that uses Zonal marginal pricing).

2. Competitive market: the major assumption of this study is that there is competitive generation bidding in the year 2005 and no market power exists. This study did not assess whether this would be the case in 2005, it took a fully competitive market as a given. Under the competitive bidding assumption, all generation will bid into the market at their true marginal cost. Thus, cost-based bidding will be used and based on incremental heat rates, forecasted fuel prices (for the gas-fired generators) and variable operation and maintenance costs.

3. Load forecast: the load is forecast for the year 2005 and is based on year 2000 actual load with California Energy Commission (CEC) provided load growth factors. All load is inelastic in the simulations.

4. Existing internal generation: internal generation used as inputs for a particular hour in the simulation are based on the availability of this generation via non-zero metered data from the year 2000. This method allows for the implicit incorporation of scheduled and forced outages of the existing generation. Only gas-fired, hydro and the Geysers generation will be allowed to bid and as noted, the bids are cost based.

5. New internal generation: new internal generation will be modeled in the simulations. The capacity totals for the new generation are from the CEC and the CAISO, but it is not known exactly how much of this generation capacity will actually be built and on-line in the year 2005. Thus, three scenarios are used in the simulations. An average scenario where the same percentages of total capacity in each zone are assumed to be built. A NP15 low scenario in which less of a percentage of generation is built in NP15 and more in ZP26 and SP15. Finally, a NP15 high scenario in which a larger percentage is built in NP15 as compared to SP15 and ZP26. This set of scenarios is very important since Path 15 connects ZP26/SP15 to NP15 and the flow on this path is impacted by the amounts of new generation on either side.

6. Imports and exports: imports and exports will be based on metered data from the year 2000. The imports will be given decremental bids of $0/MWh and the exports will be given decremental bids of $2499/MWh.

7. New external generation: it is assumed that new generation external to the CAISO control area in the northwest and southwest will also be built by 2005. The new external generation will be a part of the three scenarios for new internal generation. The data for the new external generation is from the CEC.

8. Retirements: It is assumed that by the year 2005 some internal generation will be retired. A list was provided by the CEC and these units will not be included in the simulation.

9. Hydro: the hydro is part of the existing internal generation as noted above as well as part of the imports. However, since it is difficult to predict hydro conditions, a scenario will be used based on the year 2000 metered data and this scenario is approximately 100% of average hydro conditions. For the extreme hydro conditions, another scenario is also simulated in which internal hydro generation, California-Oregon Interface (COI) imports and imports over the DC are all reduced to represent drought conditions in California and the Pacific Northwest. Three sensitivity simulations are also performed on the scenario of low NP15 and northwest new

generation. These three sensitivities simulate hydro conditions between the average year and the drought year.

10. Heat-Rates, gas prices and variable operation and maintenance (O/M): As noted, all bidding will be competitive and thus all generation will bid in at their marginal costs. For gas fired units, incremental heat rates and forecasted gas prices along with variable O/M will be used to create the bid. For the hydro and Geysers, their variable O/M will be used as their bid. The heat rates and gas price forecast for the year 2005 are from the CEC.

11. Constraints: a simple network model will be used in this analysis in which all Intra-zonal Congestion is ignored. The interfaces that will be constrained are the existing inter-tie connections along with Path 15 and Path 26. The Path 15 rating will be the Hour-Ahead (HA) hourly rating from the year 2000 and this rating will have the unscheduled Existing Transmission Contracts (ETCs) released as NFU. Thus, the assumption is that unscheduled ETCs will be able to be used in the market. However, since it is not fully known what will happen in the year 2005 with the ETCs, an additional sensitivity on one of the scenarios is created in which the unscheduled ETC capacity is not released as NFU.

12. Reliability Must-Run (RMR): RMR units will be dispatched at a minimum reliability level based on the existing requirements of the local areas.

### 2.2.2 Economic Indicators

The economic indicators that are calculated for each hour and each scenario for both the status quo case and the upgrade are listed below and are described in detail in a later section.

- Generation re-dispatch costs; and

- Energy cost to load.

# 3 Path 15 Transmission Interface Upgrade Background

Path 15 is located in the southern portion of the PG&E service area and in the middle of the California Independent System Operator (CAISO) Control Area. This path consists of the following transmission lines:

- Los Banos - Gates 500 kV
- Los Banos - Midway 500 kV
- Gates - Panoche #1 230 kV
- Gates - Panoche #2 230 kV
- Gates - Gregg 230 kV
- Gates - McCall 230 kV

The present maximum south-to-north limit for this path is 3950 MW, and the critical outages are:

- the simultaneous loss of the two 500 kV lines south of Los Banos (Los Banos South Double Line Outage (DLO)) listed in the above table
- the Los Banos - Midway 500 kV Single Line Outage (SLO),
- the Los Banos North DLO (Los Banos – Tesla and Los Banos – Tracy 500 kV lines), and
- the Midway North DLO (Midway – Gates and Midway – Los Banos 500 kV lines).

The preliminary plan of service for increasing the path rating is as follows:

- Construct an uncompensated, single circuit 500 kV transmission line between Los Banos and Gates substations.
- Install voltage support facilities at Los Banos and Gates substations (250 MVArs of shunt capacitors on the Los Banos and Gates 230 kV buses).

This upgrade is expected to provide approximately 1400 MW of additional Path 15 transfer capability. The WSCC three phase rating process has been initiated for this project and the Phase 1 studies are in progress to evaluate the above plan of service and the incremental capability that would be provided.

# 4 Methodology

The purpose of the study is to determine the benefit of constructing an additional 500 kV transmission line parallel to Path 15. The cost of such a line is out of the scope of this study and is performed by PG&E. The benefit in terms of economics, however, is the focus of this study. The benefit will be determined by comparing an economic indicator calculated for the status quo situation, i.e., the current limit of Path 15, with the economic indicator calculated for the upgrade.

## *4.1 Simulation Tool*

In order to evaluate these economic indicators, the CAISO developed a software tool that mimics and expands the functionality of the existing Congestion Management software (CONG) used daily in the CAISO DA and HA markets. The objective function of this DCOPF problem is the minimization of the re-dispatch cost over all of the resources that are assigned cost-based energy bids. Specifically, the objective function is the minimization of the production costs due to generators and imports and the maximization of the benefits of serving load and exports. The constraints of this problem formulation include the DC load flow equations and the inter-zonal branch group limits. The solution to this optimization problem provides the optimal dispatch of the resources and the zonal energy prices. The re-dispatch cost is available as the objective function. Based on the optimal load schedule and the zonal prices, the cost to load is calculated.

The energy bid price has to be within the range of zero and a prescribed price cap; bids with prices beyond this range will be considered price takers. The simulation tool will not produce a solution when firm load has to be curtailed; the tool will simply log this case as unsolved. In this analysis, the unsolved cases are excluded from the calculation of the economic indicators. However, the number of hours of load shedding is reported for each scenario.

The tool was developed following the same methodology and modeling assumptions used in CONG. The new software uses a linear DCOPF formulation that ignores power losses, reactive power flows, and voltage constraints. The DC approximation is derived from the AC real power flow equations by assuming negligible line resistances and small voltage angle differences. The mathematical formulation of the problem is provided in Appendix A.

## *4.2 Application of the Simulation Tool*

Although the simulation tool that was developed can handle the Market Separation Rule (MSR), this rule is not enforced in this study. In other words, the net of the generation and the load in a Schedule Coordinator's portfolio are not enforced to be constant before or after the simulation. Consequently, the application of this software produces an optimal dispatch of the energy schedules rather than an optimal pricing of transmission interfaces as the current CONG would produce. If, for example, in 2005 the market structure was similar to the PX and the CAISO still ran a transmission auction via CONG (MSR enforced), then the assumption is that there would be a robust secondary market for generators to optimally trade energy so that the outcome would be the same as if the MSR was not enforced.

The current CONG software is executed in both the CAISO DA and the HA markets because it conducts bid-based transmission auctions. The new software in this analysis is not executed according to such market timelines because the assumption is just one market that includes the overall effect of Path 15 congestion without artificially attributing the effect into DA, HA and Real-Time Markets.

## *4.3 Economic Indicators*

There are two benefit economic indicators used in this study.

### A. Re-dispatch Cost

The first benefit indicator is the re-dispatch cost. This is the objective function of the DC Optimal Power Flow (DCOPF), which is the simulation used in this study. This objective function minimizes the production costs of generators and imports and maximizes the benefits of serving load and exports based on the bids submitted by these resources (see below and in Appendix A for a complete description). With the addition of another 500 kV line, the value of the limit on the flow of power across Path 15 will be increased and thus this constraint in the optimization formulation will be relaxed. In any optimization problem, the objective function will be equal to or will be reduced when a constraint is relaxed. Thus, one can say that as compared to the status quo situation, the re-dispatch costs (i.e., objective function) will be equal to or reduced with the addition of the upgrade and most probably, a positive benefit will be seen from the upgrade of the path.

### B. Energy Cost to Load

The second benefit economic indicator is the cost to the CAISO control area load under a marginal pricing structure (a Zonal market clearing price is produced). As a by-product of minimizing the objective function, the DCOPF will produce the zonal prices and the loads will be charged at the zonal prices. This is similar to the methodology that was used by the California Power Exchange. If there is no congestion internal to the control area, there will be one clearing price applicable to the entire load. However, under the conditions of congestion, there will be potentially different clearing prices in different zones. In this study, the only internal interfaces that are enforced are Path 15 and Path 26, which then lead to the formation of the NP15, ZP26 and SP15 zones. Thus, there may be three different market clearing prices under the conditions of congestion.

In contrast to the re-dispatch indicator, the energy cost to load may increase or decrease resulting from the upgrade of Path 15. With a south to north congestion on Path 15, resources in the north need to increase generation by some amount while generation in the south need to decrease by the same amount. The price in the north will remain constant or increase while the price in the south will remain constant or decrease. In Appendix E, an example is provided that shows both a potential increase in cost to load and a decease in cost to load along with a simple formula, knowing the zonal price changes and load amount, for determining if the total costs will increase or decrease.

## 4.4 Scenarios

As noted earlier, due to the assumptions of various input data, scenarios will be set up and simulated. For this study, there are a total of three high level input parameters that are varied to create a total of twelve scenarios and in addition eight more sensitivity cases will be simulated. The three input parameters are:

- Path 15 limit (2 values): the status quo limit and the upgrade limit;

- New internal and external generation (3 values): an average scenario where the same percentages of total capacity in each zone is assumed to be built; an NP15 low scenario in which less of a percentage of generation is built in NP15 and more in ZP26 and SP15; and an NP15 high scenario in which a larger percentage is built in NP15 as compared to SP15 and ZP26; and

- Hydro conditions (2 values): an average hydro year and a drought hydro year.

Thus, the approach consists of simulating a total of twelve cases (=2 x 3 x 2). Each case is simulated for each hour of the year (total of 8784 hours due to leap year).

In addition to the twelve cases, two sensitivities of retaining the Path 15 unscheduled ETCs will be performed on the scenario with low NP15 new generation and the drought hydro year for Path 15 status quo and upgrade ratings. Another six sensitivities will also be performed by varying the amount of available hydro generation in California and from the Pacific Northwest.

The economic evaluation criteria are computed annually for each of the cases.

## 4.5 Reserve Capacity Requirements

The evaluation criteria used in this study are based on energy cost only, i.e., re-dispatch and cost to load. However, the cost of the ancillary services (A/S) (Upward Regulation, Downward Regulation, Spinning Reserve, Non-spinning Reserve, and Replacement Reserve) is not included in the evaluation criteria for the following reasons:

- Assigning a meaningful cost to the unused capacity of a generator is difficult because this study is based on the variable costs (O & M, heat rates, and the gas prices).

- Instead of assigning an explicit cost to the unused capacity, one could attempt to calculate the opportunity cost of the capacity. However, this requires estimation of other costs such as start-up cost, shut-down cost, no-load cost and etc., which are unavailable especially for the new generators.

- One could apply generic cost characteristics to the generators whose cost characteristics are unknown. However, the inaccuracy introduced by such estimation may greatly undermine the objective of increasing the accuracy of the study by adding the A/S costs.

- Moreover, the consideration of the start-up cost, shut-down cost, no-load cost and O&M costs leads to the use of a transmission constrained unit commitment and economic dispatch software program for dispatching the resources. Using a software program like this would implicitly assume a specific market model for 2005 in California, which is out of the scope of this study.

With the new capacity scheduled to be on-line by the year 2005, A/S costs should be a small percentage of the energy costs. Given the uncertainties embedded in the estimate of the new generation capacity and their geographical distribution, the internal and external load forecasts, and the import and export volume, the incorporation of the A/S cost in the evaluation criteria will not improve the accuracy of the study.

# 5 Detailed Modeling and Assumptions

## 5.1 Market Structure

For the year 2005, the assumption is a Zonal marginal pricing market structure (i.e., the determination of a market clearing price) with competitive generation bidding. In order to simulate competitive bidding, all energy bids will be derived from incremental heat rate data when applicable, forecasted gas prices, and variable operation and maintenance costs.

## 5.2 Study Period

The study set consists of simulating the 8784 hours of the year 2000. However, the load for each of these hours is the load forecast for that hour in the year 2005.

## 5.3 Network Model

The network model used is a simplified model shown below in Figure 5.1. There are only three internal nodes that represent the three existing active zones, NP15, ZP26 and SP15. All internal generation and load will be mapped back to one of these three corresponding nodes. Also, all the ties go directly into either NP15 or SP15. Since this system is radial, there is no loop flow; and the reactances of each line will be set at 5% per unit. Because of this simplified model, Intra-Zonal constraints are not considered.

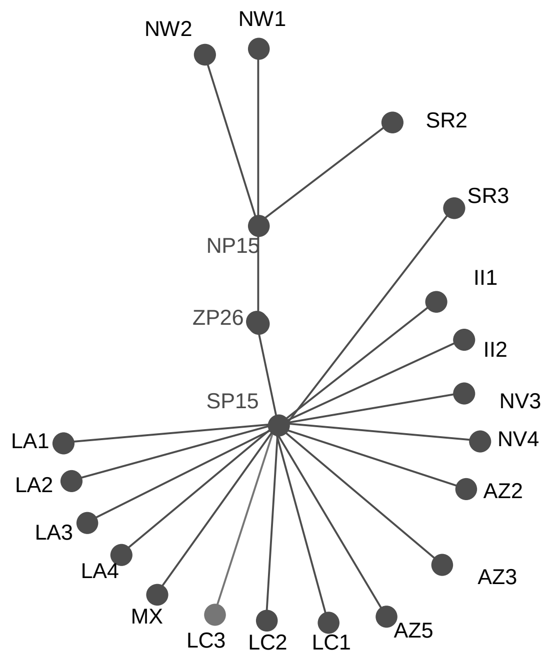


Figure 5.1. Simplified network model

Note that the Pacific DC line is not present. Energy from the Pacific DC line is included in the metered data of the flow between CAISO and Los Angeles Department of Water and Power (LADWP).

## 5.4 Resources

The resources used in the study consist of:

- Load resources: Demand Zones, Load Groups, and Load Points (which includes pumps);
- Exports, imports, and new external generation that will be assumed to be on-line by the year 2005;

- Internal Generation: Renewables (Geothermal, Wind, Small Hydro), QFs, Hydro, Nuclear and Gas generation (also the coal fired Majove plant) plus new generation that will be assumed to be on-line by the year 2005.

The manner in which these resources are modeled is elaborated below.

## 5.5 Load and Pumps

The load for the three internal Zones NP15, ZP26 and SP15 will be based on forecasted loads for the year 2005. The load growth will be based on the CEC forecasted peak load growth of approximately 1.5% to 2% per year for on-peak and a reduced percentage for off-peak. Hourly actual PG&E, SCE, and SDG&E 2000 data will be used to project these 2005 loads. NP15 and ZP26 load will be derived using a ratio calculated from a snapshot of PG&E load data. The forecasting methodology along with the exact load growth ratios are presented in Appendix B.

The pump load for SP15 is included in the initial load calculation. The pump load, including pump/generation resources, for NP15 is explicitly included and is based on 2000 metered data.

The Zonal load and pump load are set to be non-adjustable, i.e., not given an adjustment bid. The reason is that the bulk of the zonal load cannot react to market prices and the assumption is that this is still true in 2005. Pump load and pump/generation on the other hand can have adjustment bids. However, these adjustment bids are generally based on the forecast next-day MCP and since these scenarios are run in batch mode, there is presently no feedback to incorporate a MCP into a adjustment bid calculation for these resources.

With regard to transmission losses, the DCOPF that is used in the simulations does not take into consideration transmission losses. In turn, the sum of the generation and import will equal load plus export. In actual operation, the generation and import need to increase output to account for these losses and this is accounted for in the settlement by the Generator Meter Multiplier (GMM) and the Tie-point Meter Multiplier (TMM). However, the load forecast for the year 2005 is based on control area load and already takes into account the transmission losses.

The peak load for the three zones for the year 2005 are 23168 MW, 1989 MW and 25507 MW for NP15, ZP26 and SP15 respectively.

## 5.6 Existing Internal CAISO Control Area Generation

### 5.6.1 Non-Dispatchable Units

The non-dispatchable resources will consist of the Renewables (except Geysers), QFs and nuclear units.

For the Renewables, QFs and nuclear resources, the schedules used in the simulations will be based on meter data from the year 2000. If there is no meter data or the resource has a meter value of zero, it will not be included in the simulation.

### 5.6.2 Dispatchable Units

The dispatchable resources will consist of the Geysers, gas-fired (both existing and new generation), and Hydro generation. For these resources, a starting non-zero schedule is not provided; rather adjustment bids are provided and the optimization algorithm will dispatch them.

For the Geysers and Hydro, an adjustment bid with one segment will be used and this will range from zero MW to the meter data value. The price will be set to the corresponding resource's variable operation and maintenance (O/M) costs. The variable O/M for hydro will be set at $0.33/MWh, which is derived from CAISO Reliability Must-Run (RMR) contracts and the variable O/M for the Geysers will be set at $19.84/MWh, which is also derived from CAISO RMR contracts.

For the rest of the dispatchable resources, which are the gas-fired generators, the presence of non-zero meter data will determine if these resources will be included in the simulations. If they are included, their adjustment bid will be based on their incremental heat-rate curve (along with the appropriate fuel price) plus a variable O/M, and the adjustment bid will range from zero to Pmax. The variable O/M costs are derived from CAISO RMR contracts. For units that did not have a contract, the variable O/M value was selected, based on similar sized capacity, from those units that did have a variable O/M value. The variable O/M for peaker units is $0.00/MWh and for other gas-fired generation, the variable O/M ranged from $0.73/MWh to $3.92/MWh. However, two NP15 resources have a variable O/M of $31.09/MWh.

The incremental heat rate data is from the CEC. The forecasted gas prices are provided in a section below.

### 5.6.3 Retirement of Units

Certain generators will be assumed to be retired by the year 2005 and will not be included in the simulation. The retirements are provided by the CEC. The total generation retirement is summarized in the table below.

Table 5.6.1 MWs of retirement in each zone

| **Zone** | **Total MW Retirement** |
|---|---|
| NP15 | 1580 |
| ZP26 | 15 |
| SP15 | 2378 |

If one of these units has non-zero metered data for a certain hour, it will not be used in the simulation.

## 5.6.4 Re-powering of Units

The only re-powering considered in this study is for the Morro Bay generating units 1-4. These will be re-powered with each unit having a maximum power output of 265 MW and an average heat rate of 9815 BTU/kWh at 66.25 MW; 7590 BTU/kWh at 132.5 MW; 7054 BTU/kWh at 198.75 MW and 6816 BTU/kWh at 265 MW. From these average heat rates, the incremental heat rates were derived and used as the cost based bids along with the applicable variable O/M cost.

## 5.6.5 Hydro Year

There are two high-level values used for hydro in this analysis. The first is to use the year 2000 hydro metered data. The second is to create a drought hydro scenario.

For an indication of the hydro conditions for the year 2000, i.e., hydro metered data from the year 2000, the period of January through July 2000 was 99.25% of average and the period of August to December 2000 was 64% of average for the utilities involved with the Pacific Northwest Coordination Agreement which includes water from Canada that feeds into the Pacific Northwest. In addition, the flow at The Dalles for October 1999 through September 2000 was 97% of average and the flow at Grand Coulee for the same period was 102%.

As for Northern California, the year 2000 was 97% of average for the PG&E hydro, and 101% of average for the Irrigation Districts and Water Agencies under contract to PG&E.

### 5.6.5.1 Drought Hydro Conditions

Because it is difficult to predict hydro conditions in the year 2005, a case was developed to model a drought hydro scenario. This drought hydro scenario affects the NP15, ZP26 and SP15 (although very little hydro) hydro resources energy output, the import of energy over the California-Oregon Border (COI) and the import of energy from the Pacific DC Intertie (PDCI). Although there is more energy in the average year, the shape of the hydro output is also different as compared to a dry year. For a dry year, there is still a relatively high output during the peak hours to cover load, but in the partial-peak and off-peak hours, the output is much less than for an average year due to water conservation.

A one in ten drought year was considered sufficient to determine the impact on the economic indicators. Based on hydro generation output data provided by PG&E over the last twenty years for Northern California, it was determined that approximately a one in ten hydro year has an annual energy output equivalent to 64% of an average annual year. PG&E also provided total hydro watershed output for an average year and a dry year over four different seasons and the time periods of peak, partial- peak and off-peak. Factors were developed by taking the ratio of the dry year watershed output to the average year watershed output for all seasons and all periods. Since the year 2000 was considered an average hydro year, these factors were applied (correspondingly with the season and period of the day) to the hydro metered data to arrive at a scaled profile that approximates a dry year output. After the factors were applied, it was determined that the annual energy output was approximately 58.5% of the average year. A factor of 1.094 (= 64/58.5) was applied to all of the scaled profile to adjust it upward so that the total annual energy was approximately 64%, which as noted above is approximately a one in ten hydro year. Note that the

Helms hydro/pump storage plant was not included in this analysis because it is pump storage. Helms generation or load was taken from the 2000 metered data for the drought year scenario.

For similar hydro conditions of approximately a one in ten hydro year, BPA provided COI import/export data that modeled this condition and was from the hydro year 1993 to 1994. For this data, approximately a one in ten hydro year was determined to be 71% of the 30-year average. The year 2000 hydro data, which in terms of BPA hydro calendar year extends from August 1999 through July 2000, is 92.5% of the 30-year average. However, a calendar year, not hydro year, of 2000 was used in the simulations. This calendar year is composed of the partial 2000 hydro year and partial 2001 hydro year. The 2001 hydro year was 54.9% of the 30-year average.

Because the CAISO does not have PDCI metered data, the metered tie data from the intertie between Sylmar and LADWP was used. If this metered data indicated an import, then the assumption is that this energy came from hydro generation in the Pacific Northwest. To model the drought year for the energy on the PDCI, the metered data that indicates an import is scaled by 71% to be consistent with the COI data.

### 5.6.5.2 Additional Hydro Sensitivities

Three additional hydro conditions are modeled and simulated as sensitivities with low NP15 new generation. These three hydro conditions are bound on one side by the average year and the other side by the drought year, in other words three hydro conditions were modeled that fell between the average year of 2000 and the approximate one in ten drought year. The California Hydro, COI imports/exports and Sylmar imports are modeled as described below.

**California Hydro**

Because the California hydro drought year was about 64% of average in terms of total energy, the total amount of energy was scaled up from 64% of average to 73%, 82% and 91% to arrive at three additional California hydro conditions. The actual profile (hourly MWh values) were scaled to arrive at these values.

**COI Import/Export**

A plot of the COI import and exports for the year 2000 and the hydro year 1993/1994 is shown in Figure 5.2. Note that positive values are imports into California. The graph shows that in the drought year (1993/1994) the amount of imports and exports are comparable over the months of May through September. However, in the months of January through April and October through December, there are imports in the year 2000 and correspondingly exports in the year 1993/1994.

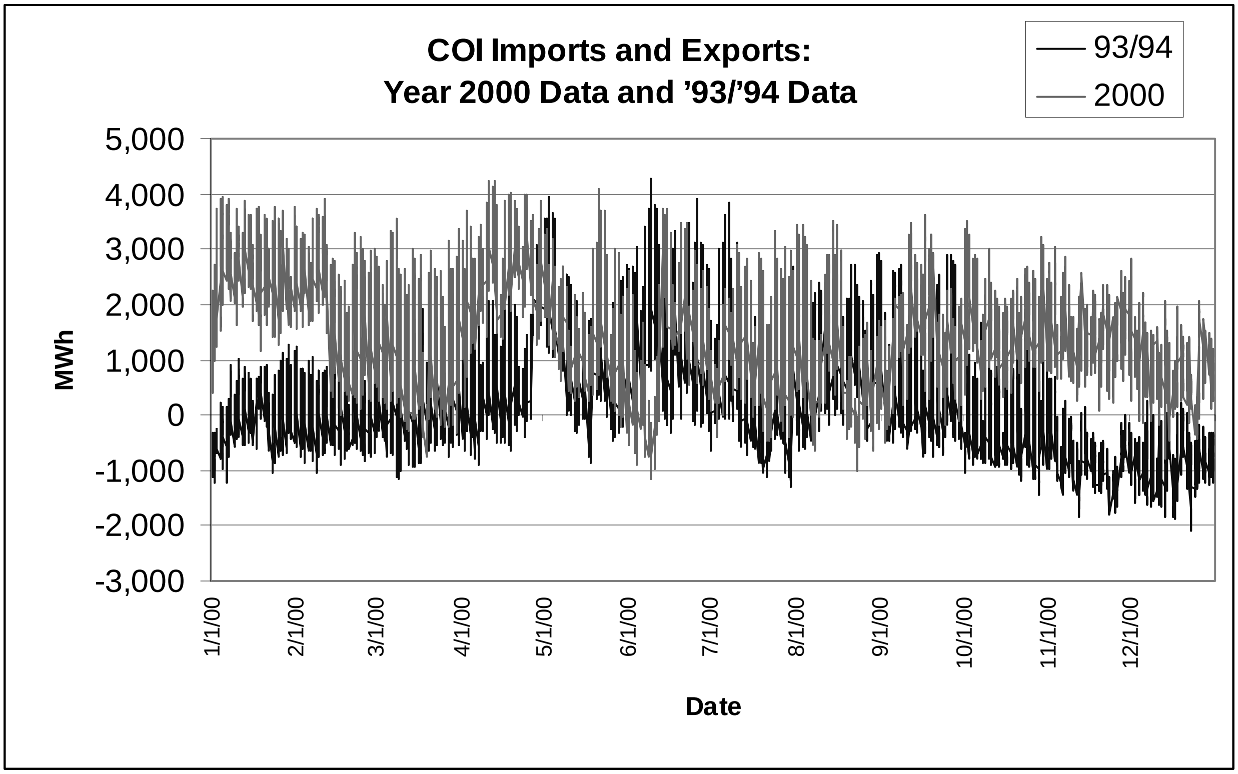


Figure 5.2 COI imports and exports: year 2000 and '93/'94

In order to derive conditions between these two import/export profiles, three new profiles were created. The new profiles were created for each hour of the year by taking the points that were 25%, 50% and 75% between the data for the year 1993/1994 and the year 2000. For example, for January 1, hour-ending 1, for the year 1993/1994 there is an export of 782 MWh and for the year 2000 there is an import of 540 MWh. The three new points for this hour are -782 + .25 * (540 - (-782)) = -451 MWh, -782 + .5 * (540 - (-782)) = -121 MWh and -782 + .75 * (540 - (-782)) = 209 MWh, respectively.

**Sylmar Import**

In the drought year, the Sylmar import is scaled by 71%. For the three new sensitivities, this import is scaled by 78.25%, 85.5% and 92.75%, respectively.

The following table shows the scaling factors used to derive the three hydro sensitivity cases and note that these cases are also ranked in order of increasing amount of hydro generation, i.e., Hydro Sensitivity 1 provides the least, while Hydro Sensitivity 3 provides the most.

Table 5.6.2 Scaling factors used to develop three additional hydro condition sensitivities

| | Hydro Sensitivity Scaling Factors | | |
|---|---|---|---|
| **Hydro Sensitivity Cases** | **California Hydro** | **COI** | **Sylmar** |
| Hydro Sensitivity 1 | 73% | 25% | 78.25% |
| Hydro Sensitivity 2 | 82% | 50% | 85.5% |
| Hydro Sensitivity 3 | 91% | 75% | 92.75% |

## 5.7 New Internal CAISO Control Area Generation

For the year 2005, there are several thousands of MWs of new generation under development within the CAISO control area. The data that was used in this study was given by the CEC. At this time, all new generation under consideration is at some stage in its development. The CEC provided two different sets of stages along with estimated capacity due to data availability.

The first set is for the generation in SP15 and was provided in March 200 and is in the Table 5.7.1:

Table 5.7.1 Stages of development for SP15 new generation

| Stage | Stage Description | Capacity (MW) |
|---|---|---|
| 1 | Under construction or recently completed | 0 |
| 2 | Regulatory approval received | 1,470 |
| 3 | Application under review | 2,922 |
| 4 | Starting application process | 6,598 |
| 5 | Press release only | 4,909 |
| | **Totals** | 15,899 |

The second set is for new generation in NP15 and ZP26, and is in Table 5.7.2. The stages in this table are different than the stages in the table above in that Stage 1 from below is equivalent to Stages 1 and 2 above. Stage 3's are equivalent and Stages 4 and 5 above are equivalent to Stage 3 below. Also in this table, peaker units are identified.

Table 5.7.2 Stages of development for NP15 and ZP26 new generation

| Stage | Stage Description | NP15 Capacity (MW) | ZP26 Capacity (MW) |
|---|---|---|---|
| 1 | Approved | 4,299 | 2,547 |
| 2 | Pending | 2,800 | 0 |
| 3 | Announced | 2,382 | 0 |
| 4 - Peakers | | 291 | 98 |
| | **Totals** | 9,772 | 2,645 |

Since it is difficult to accurately predict the new capacity that will be on-line in 2005, three scenarios are created that will provide a range of new capacity and then used in the simulations. Three scenarios are created.

New Generation Scenario 1: an average scenario where not all new forecasted generation is built and approximately the same percentages from each zone are assumed to be on-line in the year 2005.

New Generation Scenario 2: an SP15 and ZP26 biased scenario where more of the new forecasted generation is assumed to be on-line in 2005 in SP15 and ZP26 as compared to NP15.

New Generation Scenario 3: an NP15 biased scenario where more of the new forecasted generation is assumed to be on-line in 2005 in NP15 as compared to SP15 and ZP26.

Note that the bias is grouped by the generation on either side of Path15, i.e., NP15, and SP15 plus ZP26.

<u>The scenarios are created by taking percentages of the capacity for each of the stages listed above. For SP15 these percentages are</u>:

SP15 new generation scenario 1: 100%, 60%, 50%, 30% and 10% for stages 1 to 5, respectively.

SP15 new generation scenario 2: 100%, 70%, 60%, 40% and 30% for stages 1 to 5, respectively.

SP15 new generation scenario 3: 100%, 40%, 30%, 20% and 0% for stages 1 to 5, respectively.

<u>For NP15 and ZP26 new generation scenarios the following percentages are used</u>:

NP15 and ZP26 new generation scenario 1: 100%, 100%, 0% and 100% for stages 1 to 4, respectively.

NP15 and ZP26 new generation scenario 2: 100%, 0%, 0% and 100% for stages 1 to 4, respectively.

NP15 and ZP26 new generation scenario 3: 100%, 100%, 100% and 100% for stages 1 to 4, respectively.

The three generation scenarios are given in the following table.

Table 5.7.3 Available new internal capacity

| Scenario | NP15 New Generation (MW) | ZP26 New Generation (MW) | SP15 New Generation (MW) |
|---|---|---|---|
| Scenario 1 | 7,390 | 2,645 | 4,813 |
| Scenario 2 | 4,590 | 2,645 | 6,894 |
| Scenario 3 | 9,772 | 2,645 | 2,784 |

Note that the peakers are always assumed to be built by 2005 for NP15 and ZP26. For SP15, based on CEC data, 6% of the new generation for each scenario are modeled as peakers.

## 5.7.1 New Generation Incremental Heat Rates and Variable O/M

The price of the new generation is cost-based. The cost-based data is derived from generic average heat-rate data for new combined cycle technology provided by the CEC.

These average heat-rate data are:

- 7843 BTU/kWh at 50% of rated capacity;
- 7248 BTU/kWh at 75% of rated capacity; and
- 7027 BTU/kWh at 100% of rated capacity.

Given the average heat rates, the shape of the input/output curves can be determined. From this curve, the numerical derivative can be determined and this is the incremental heat rate. Note that this input/output curve would not have no-load costs included. Including the no-load cost is equivalent to adding a scalar quantity to the input/output curve. By taking the derivative of the input/output curve, the scalar addition is neglected, and thus the incremental heat rate curve is independent of the no-load costs.

The incremental heat-rate of the new generation, derived from the average heat-rate data, is set at:

- 5766 BTU/kWh from 0 to 50% of rated capacity,
- 5858 BTU/kWh from 50% to 75% of rated capacity, and
- 6364 BTU/kWh from 75% to 100% of rated capacity.

Based on similar units for which there exists variable O/M costs (based on CAISO RMR contracts), the variable O/M for the new generation is set at $1.50/MWh.

Based on heat-rates provided by the CEC, the peakers are given a single segment incremental heat-rate from 0 MW to Pmax at 12,000 BTU/kWh. The maximum power output in this case are 291 MW for NP15, 98 MW for ZP26 and the 6% of the new generation for each scenario for SP15.

## *5.8 Imports and Exports*

Import and Export energy schedules that are used in these simulations will be based on historical metered data from the year 2000. Since these are based on metered data, there will be a net quantity (either import or export) for each scheduling point for each hour.

If the metered data indicates an export, these exports will have a decremental adjustment bid with the following two attributes:

- There will be only one segment in the adjustment bid and that segment will range from zero MW to the corresponding metered data value; and

- The price of that one segment will be $2499/MWh.

The $2499/MWh price on the exports is arbitrary to a certain point. This price was set at some level that is larger than any cost-based price for internal (including new) or new external generation. This way the internal or new external generation would be fully adjusted if necessary to relieve internal congestion. The only impact this price would have on the results is if the exports were cut to alleviate internal congestion, then the zonal price would be set at $2499/MWh.

If the metered data indicates an import, these imports will have a decremental adjustment bid with the following two attributes:

- There will be only one segment in the adjustment bid and that segment will range from zero MW to the corresponding metered data value; and

- The price of that one segment will be $0/MWh.

The reason for the import price being at zero is that internal generation, on those generators that have adjustment bids, will be decremented before the imports for any potential congestion relief.

### 5.8.1 New External Generation

New generation for the year 2005 will also be located outside of the CAISO control area and this generation can be used to supplement imports. A percentage of this external generation as it relates to external load growth forecasts in the corresponding area of the new external generation will be available for use as imports on an hourly basis.

The new external generation is provided at COI, Eldorado, Palo Verde and Miguel (from Mexico). This new generation has the same heat-rate structure as the new internal generation.

The scenario uses actual hourly external generation capacity taking into account hourly variations in external area load. The methodology used to determine the hourly amount of external generation is provided in Appendix C.

## 5.9 Availability of New Internal and External Generation

### 5.9.1 Existing Generation

Since the existing generation is used within the simulation only if there is non-zero metered data from the year 2000; the availability of the generation is based on the actual availability from the year 2000.

### 5.9.2 New Internal and External Generation

Due to scheduled outages and forced outages, which are normal in network operations, an average availability rate of 89.7% is used for new internal generation. This average availability is based on the forced outage rate (4.5%) and maintenance rate (5.8%) of new combined cycle generation and is from the CEC.

## 5.10 Gas Prices

The gas prices used with the heat-rates for the dispatchable units are based on forecasted gas prices for the year 2005 from the CEC. These prices are for the burner tip in the Zones; NP15, SP15, ZP26, NW and SW (this includes Mexico). The base gas prices are listed below and are by month.

Table 5.10.1 Gas prices

| | ($/MMBtu) | | | | |
|---|---|---|---|---|---|
| **Month\Region** | **Northwest** | **NP15** | **ZP26** | **SP15** | **Southwest** |
| January | 4.80 | 4.89 | 4.89 | 4.73 | 4.09 |
| February | 4.63 | 4.77 | 4.77 | 4.62 | 3.99 |
| March | 4.44 | 4.64 | 4.64 | 4.49 | 3.86 |
| April | 4.13 | 4.42 | 4.42 | 4.27 | 3.65 |
| May | 4.11 | 4.41 | 4.41 | 4.26 | 3.64 |
| June | 4.17 | 4.44 | 4.44 | 4.29 | 3.68 |
| July | 4.24 | 4.49 | 4.49 | 4.34 | 3.72 |
| August | 4.24 | 4.49 | 4.49 | 4.35 | 3.73 |
| September | 4.26 | 4.50 | 4.50 | 4.36 | 3.74 |
| October | 4.30 | 4.52 | 4.52 | 4.38 | 3.76 |
| November | 4.50 | 4.66 | 4.66 | 4.52 | 3.90 |
| December | 4.71 | 4.81 | 4.81 | 4.67 | 4.04 |

## 5.11 NOx Costs

Emission related NOx costs are not included in this study because at this time it is very difficult to predict if any gas-fired generation would incorporate any emission reducing procedures within their plants.

## 5.12 Constraints

Path 15, Path 26 and all tie-point Branch Groups are enforced. The simplified model used can accommodate these branch groups.

The limit for Path 15 will be derived from the Hour-Ahead (HA) Branch Group data limits (both the S to N and N to S directions) from the year 2000. Since this is based on actual historic data, this limit takes into account Path 15 Internal Remedial Action Schemes (IRAS) availability, Gates substation temperature and time of day; loop flow, and scheduled clearances. As noted, the unscheduled ETCs will be released as NFU, but there will be one sensitivity with the low NP15 generation and hydro drought condition in which the unscheduled ETCs are retained and not released as NFU. (Note: PG&E is the Path Manager for the ETC allocation.)

The HA Branch Group will use the existing limit, while the upgrade will add 1400 MW of capacity.

The limit for Path 26 will be bi-directional at 3000 MW for all hours in the study set.

The limit for the Tie interfaces will be the WSCC ratings. This data will remain static throughout the study period.

## 5.13 RMR with Minimum Reliability Energy

The modeling of Minimum Reliability Energy (MRE) from Reliability Must Run (RMR) units will be a part of this simulation. A list of RMR units with MRE values will be compiled with the values given seasonally for the existing local areas based on existing local area procedures of the CAISO.

These units will always be dispatched at the MRE level and will have cost-based adjustment bids that will range from the MRE to Pmax.

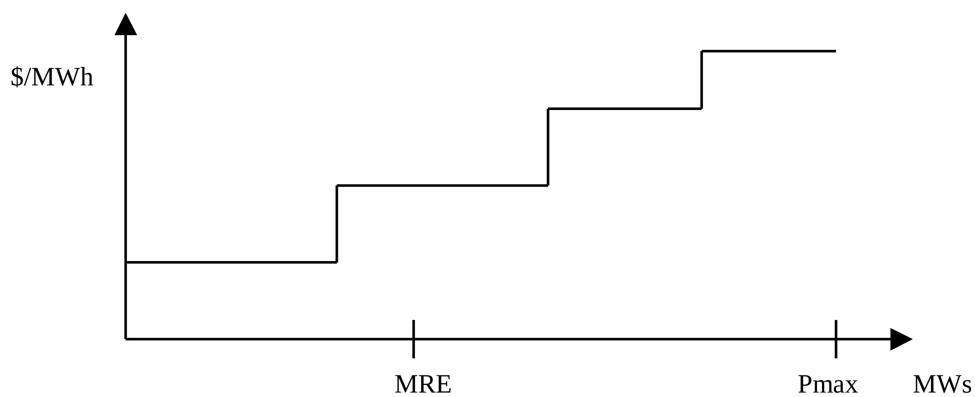


Figure 5.13.1. Cost-based Adjustment bid of RMR unit

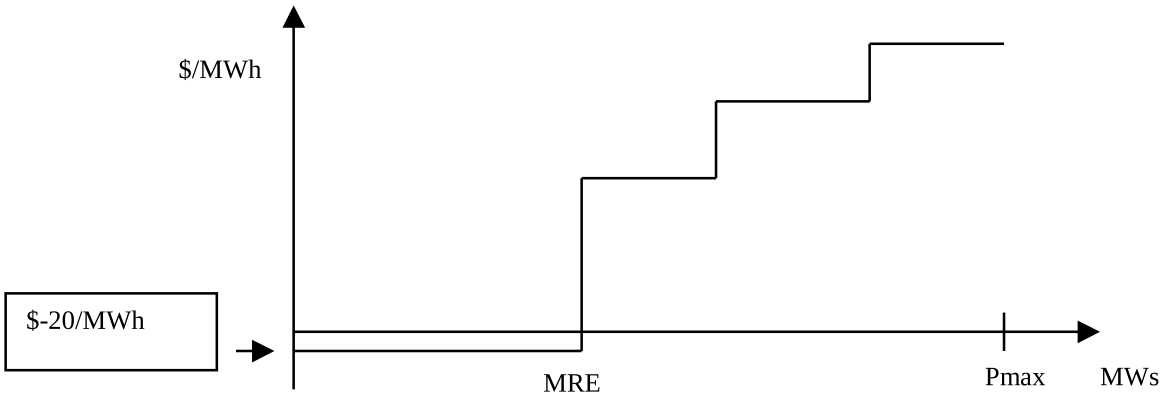


Figure 5.13.2. Cost-based Adjustment bid of RMR unit after addition of MRE

Figure 5.13.1 shows a typical cost-based adjustment bid for a thermal RMR unit. This adjustment bid will be modified to look as Figure 5.13.2; here, the unit is unable to be adjusted below the MRE level, but is able to be adjusted up to the Pmax.

# 6 Economic Indicator Results

The economic indicator results are given in this section. As noted in the Section 4.4 above, a total of twenty yearly cases were simulated. Twelve cases were simulated with the parameters being the hydro condition, new generation levels and the Path 15 path rating. In addition, eight sensitivity cases were simulated. Two cases were simulated which retained the unscheduled ETCs and released them as NFU for the drought hydro year with low NP15 new generation. In addition, six cases were simulated with low NP15 new generation, the release of unscheduled ETCs as NFU, and varying the hydro conditions.

The economic benefit indicators are determined as the difference between a particular scenario (and sensitivity) with and without the Path 15 upgrade.

The results are provided below in Tables 6.1A, Table 6.1B and Table 6.1C. Table 6.1A presents the results for the twelve scenario cases. These are shown as six cases, A through F, with the difference in the economic indicator provided due to the upgrade of Path 15. Note that the results are sorted in order of decreasing cost to load. Table 6.1B provides the results the additional sensitivity pertaining to retaining the unscheduled ETCs in the drought hydro condition and with low new NP15 generation. Table 6.1C provides the results of the hydro generation sensitivity conditions with low new NP15 generation. Because Case A below shows the largest results, the sensitivities are based on this case.

Table 6.1A Simulation results sorted by cost to load difference

| | **Scenarios** | | **Economic Indicator Differences ($ Millions) Path15 Rating: Status Quo minus Upgrade** | |
|---|---|---|---|---|
| Case ID | New Generation Scenario | Hydro Year Scenario | Re-dispatch Costs Difference | Cost to Load Difference |
| A | 2 | Drought | $9.02 | $83.05 |
| B | 2 | Average | $0.93 | $2.09 |
| C | 1 | Average | $0.44 | $(2.44) |
| D | 3 | Average | $0.33 | $(2.86) |
| E | 1 | Drought | $1.14 | $(7.43) |
| F | 3 | Drought | $0.51 | $(7.47) |

Table 6.1B Sensitivity results for Case A with unscheduled ETCs retained and not released as NFU

| | **Scenarios** | | **Economic Indicator Differences ($ Millions) Path15 Rating: Status Quo minus Upgrade** | |
|---|---|---|---|---|
| Case ID | New Generation Scenario | Hydro Year Scenario | Re-dispatch Costs Difference | Cost to Load Difference |
| G* | 2 | Drought | $16.42 | $118.55 |

* Note that in Case G, there are 8 hours for which exports in the Northwest were curtailed resulting in NP15 prices to be $2499/MWh (i.e., the decremental adjustment bid of the exports). These hours were omitted from the results for this case because the price for curtailing exports cannot be quantified. Thus, the cost differences for Case G can be considered as a lower bound. The exports were curtailed to in order to balance out generation and imports against load and exports. The number of north bound congestion hours for case G are: status quo (5,881), with Path 15 upgrade (2,986).

Table 6.1C Sensitivity results for varying hydro conditions with low new NP15 generation

| | **Scenarios** | | **Economic Indicator Differences ($ Millions) Path15 Rating: Status Quo minus Upgrade** | |
|---|---|---|---|---|
| Case ID | New Generation Scenario | Hydro Sensitivity | Re-dispatch Costs Difference | Cost to Load Difference |
| H | 2 | 1 | $4.60 | $41.70 |
| I | 2 | 2 | $2.41 | $14.01 |
| J | 2 | 3 | $1.35 | $4.10 |

For the three hydro sensitivity cases, the number of north bound congestion hours are: Case H, status quo (4,072), with Path 15 upgrade (1,389), Case I, status quo (3,523), with Path 15 upgrade (942), and Case J, status quo (2,890), with Path 15 upgrade (565).

The hours of Path 15 south to north congestion are given in Table 6.2 in the same case order as Table 6.1.

Table 6.2: Summary of Congestion Hours

| | **Scenarios** | | **Congestion hours for northbound congestion** | |
|---|---|---|---|---|
| **Case ID** | **New Generation Scenario** | **Hydro Year Scenario** | **Status Quo** | **Plus 1400 MW** |
| A | 2 | Drought | 4,606 | 1,982 |
| B | 2 | Average | 2,429 | 206 |
| C | 1 | Average | 1,182 | 48 |
| D | 3 | Average | 710 | 7 |
| E | 1 | Drought | 2,279 | 576 |
| F | 3 | Drought | 1,047 | 148 |

## 6.1 Discussion of Results

### 6.1.1 Trend of Congestion Hours in the Results

A clear trend for the number of congestion hours for scenario 2 (low NP15 new generation and high SP15 new generation) appears. The maximum number of congestion hours occurs when there is the least amount of NP15 generation (the drought under scenario 2) and the path rating is the lowest (status quo). As the generation is increased by going to the average scenario (scenario 1) and then to the high NP15 new generation scenario (scenario 3), the number of congestion hours decreases. The results for the hydro condition sensitivities also follow this trend.

Table 6.3 has the case IDs listed by order of the number of congestion hours in the status quo case. Note that for each new generation scenario (1, 2 or 3), the drought in the status quo rating always precedes the average.

Table 6.3 Congestion hours sorted by number of hours in Status Quo case

| | **Scenarios** | | **Congestion hours for northbound congestion** | |
|---|---|---|---|---|
| Case ID | New Generation Scenario | Hydro Year Scenario | Path15 Status Quo | Path15 Plus 1400 MW |
| A | 2 | Drought | 4,606 | 1,982 |
| B | 2 | Average | 2,429 | 206 |
| E | 1 | Drought | 2,279 | 576 |
| C | 1 | Average | 1,182 | 48 |
| F | 3 | Drought | 1,047 | 148 |
| D | 3 | Average | 710 | 7 |

### 6.1.2 Economic Indicators

#### 6.1.2.1 Re-dispatch Costs

The re-dispatch cost differences vary from a high of $9.02 million to a low of $0.33 million. The high cost occurs in the most extreme case, Case A, with the drought hydro conditions and low NP15 new generation (and with low new Pacific Northwest external generation). The low cost occurs in Case D with high new NP15 generation and an average hydro year. This is the case with the least number of congestion hours both in the status quo and upgrade conditions.

For the majority of the cases other than Case A, all the re-dispatch cost difference tends to lie in a small range.

#### 6.1.2.2 Cost to Load

The cost to load differences vary from a high of $83.05 million to a low of a negative $7.47 million. The high difference occurs, similar to the re-dispatch costs, in Case A, the most extreme case. The low difference occurs in Case F, which includes the drought hydro conditions, and high new NP15 and new Pacific Northwest generation.

#### 6.1.2.3 Sensitivities

Based on the worst case, which occurred with low new NP15 and Pacific Northwest generation and drought conditions, a sensitivity was performed by retaining the unscheduled ETCs and not releasing them as NFU. By not releasing the ETCs, the path rating is further reduced and more congestion will occur as noted in the number of congestion hours. For the status quo case, there are 5,881 hours northbound for retaining the ETCs as compared with 4,606 hours by releasing the ETCs. The cost to load differences increased from $83.05 million to $118.55 million and the re-dispatch cost differences increased from $9.02 million to $16.42 million. Thus, retaining the ETCs increases the economic indicators.

Also based on the low new NP15 and new Pacific Northwest generation scenario, hydro conditions were varied from the drought condition to the average condition. These three sensitivities were created because of the sudden large cost to load differences as shown in Case A from Case B in which the variable that changed was the hydro condition. The economic indicator results for these three sensitivities and Cases A and B are given in the following table.

Table 6.4 Hydro sensitivity results

| | **Scenarios** | | **Economic Indicator Differences ($ Millions) Path15 Rating: Status Quo minus Upgrade** | |
|---|---|---|---|---|
| Case ID | New Generation Scenario | Hydro Scenario / Sensitivity | Re-dispatch Costs Difference | Cost to Load Difference |
| A | 2 | Drought | $9.02 | $83.05 |
| H | 2 | 1 | $4.60 | $41.70 |
| I | 2 | 2 | $2.41 | $14.01 |
| J | 2 | 3 | $1.35 | $4.10 |
| B | 2 | Average | $0.93 | $2.09 |

Figure 6.1 shows the cost to load and re-dispatch cost differences for these five cases as the hydro conditions vary from a drought to an average year.

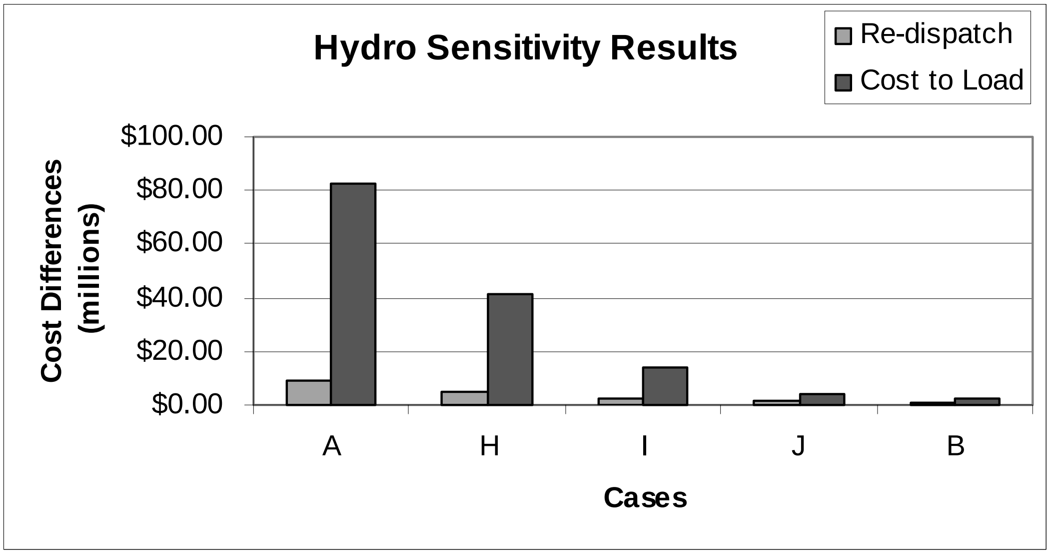


Figure 6.1 Hydro sensitivity results

As the hydro conditions are varied linearly from the average year condition to the drought condition, the cost to load differences starts to increase between Cases I and H.

### 6.1.2.4 Probability of Scenarios

In this study, different scenarios were simulated to cover situations that cannot be accurately predicted for the year 2005. The results for both the re-dispatch cost differences and the cost to load differences do not vary greatly over the span of the cases except for the one case, Case A.

The probability of a certain generation build-out scenario is not known at this time, because the major variable are those generators who have not started construction as of yet and can still go forward or discontinue the process due to the current situation in the market (i.e., forecasted market prices, price mitigation, etc.). However, the probability of the drought is one occurrence in ten years based on historical data.

# 7 Conclusions

This study presented an economic benefit analysis for an upgrade of Path 15 of approximately 1400 MW in the year 2005.

The simulation tool used was a transmission constrained economic dispatch (using a DC optimal power flow), with cost-based resource bidding. One year's worth of data was used in the simulations with the year 2005 load forecast along with, generation levels and availability from the year 2000, and import and export levels from the year 2000. Retirement of existing units and the addition of new generation for the year 2005 were modeled in the analysis.

Because of the uncertainty in some of the data forecasted for the year 2005, scenarios were simulated that included varying the amount of new generation, both internal and external to the

CAISO control area, and a drought hydro year. Based on the worst case, additional sensitivities were simulated that varied the hydro conditions and the ETC release.

The economic indicator results consisted of re-dispatch costs and the corresponding cost to load. The results show that in the worst case scenario an increase in the cost to load can rise to about $83.05 million and about $9.02 million in re-dispatch costs over the year. This occurs in the low new NP15 and Pacific Northwest generation and drought hydro conditions. These two conditions more heavily limit the amount of generation in NP15 and tend to create more flow northbound on Path 15 and thus more congestion.

The hydro condition sensitivities show that even in a hydro condition that lies nearly between a drought year and a average year, the cost to load is only approximately $14 million, it is only when the hydro condition is close to the drought condition that the costs start to rise significantly.

The sensitivity for retaining the ETCs on Path 15 shows a large increase in the cost differences.

# 8 Appendix A: DC Optimal Power Flow Formulation

In this section the mathematical formulation for the calculation of the Re-dispatch Cost and the Energy Costs to load are presented.

## 8.1 Nomenclature

| | |
|---|---|
| $A$ | the set of all the resources that are assigned energy bids |
| $A_g$ | the set of generators and imports that are assigned energy bids |
| $A_d$ | the set of load and exports that are assigned energy bids |
| $\mathbf{B}$ | the bus admittance matrix for the DC power flow model, $B_{ii} = \sum_j \frac{1}{x_{ij}}$, for $j$ over all lines connected to bus $i$ |
| $B_{ij} = -\frac{1}{x_{ij}}$ | |
| | where $x_{ij}$ is the reactance of the line connecting buses $i$ and $j$ |
| $c_i(p_i)$ | the dispatch-cost of resource $i$ |
| $dc_i(p_i)$ | the re-dispatch-cost of resource $i$ |
| $\delta_k$ | the phase angle of bus $k$ |
| $D$ | the set of all loads |
| $F_b^{\max}$ | the flow limit on branch group $b$ |
| $\mathbf{H}$ | the matrix that maps phase angles to Branch Group flows: $H_{bk}$ = the sensitivity of power flow on Branch Group $b$ with respect to phase angle at bus $k$ |
| $\lambda_j$ | the nodal price at bus $j$ |
| $L$ | the Lagrangian function |
| $\mu_b$ | the congestion (shadow) price for branch $b$ |
| $m$ | the total number of branch groups |
| $mc_i(p_i)$ | the staircase adjustment-bid curve for resource $i$ |
| $n$ | the total number of buses |
| $obj(p_1,\ldots, p_r)$ | the objective function |
| $p_i$ | the output (or consumption) of resource $i$ |
| $p_i^{\min}, p_i^{\max}$ | the lower and upper bounds of the adjustment bids respectively for resource $i$ |
| $R$ | the set of all the resources in the system |
| $R_j$ | the set of resources connected at bus $j$ |
| $s$ | the total number of schedule coordinators |
| $SC_k$ | the set of resources scheduled by Schedule Coordinator $k$ |
| $SC_{PX}$ | the set of resources scheduled by the PX |

## 8.2 Problem Formulation

The congestion management problem is formulated as a linear programming problem as follows:

Minimize

$$obj(p_1, p_2, ..., p_r) = \sum_{i \in A} c_i(p_i) \tag{1}$$

Subject to the constraints:

$$\sum_{k=1}^{n} B_{jk}\delta_k - \sum_{i \in R_j} p_i = 0 \qquad \text{for } j = 1, 2, \ldots, n \tag{2}$$

$$\sum_{k=1}^{n} H_{bk}\delta_k - F_b^{\max} \le 0 \qquad \text{for } b = 1, 2, \ldots, m \tag{4}$$

$$p_i^{\min} \le p_i \le p_i^{\max} \qquad \text{for all } i \in A \tag{5}$$

The objective function of the congestion management is aimed at minimizing the total re-dispatch cost based on the energy bid prices when schedules of resources are adjusted to alleviate congestion. The equations in (2) represent the DC power flow model. The equations in (4) represent the power flow constraints on the branch groups. The equations in (5) represent the range of the energy bids.

## 8.3 Re-Dispatch Cost

The dispatch-cost curve of a resource is formally defined as follows:

$$c_i(p_i) = \int_{p_i^{\min}}^{p_i} mc_i(p)dp \qquad \text{for } i \in A_g \tag{6}$$

$$c_i(p_i) = \int_{p_i^{\max}}^{p_i} mc_i(p)dp \qquad \text{for } i \in A_d \tag{7}$$

The adjustment-bid curves are staircase functions that are positive and monotonically non-decreasing:

$$mc_i(p_i) \ge 0 \qquad \text{for } i \in A \tag{8}$$

$$mc_i(p_i + \Delta p_i) \ge mc_i(p_i) \qquad \text{if } \Delta p_i > 0, \text{ for } i \in A \tag{9}$$

The adjustment range for a generator or import is positive. The adjustment range for a load or export is negative. In other words,

$$0 \le p_i^{\min} \le p_i \le p_i^{\max} \qquad \text{for } i \in A_g \tag{10}$$

$$p_i^{\min} \le p_i \le p_i^{\max} \le 0 \qquad \text{for } i \in A_d \tag{11}$$

The definite integral in (6) is positive and the definite integral in (7) is negative. Minimizing the negative cost function of a load is equivalent to maximizing the benefit of serving the load.

The re-dispatch cost for resource *i* when the schedule is changed from $p_i^{preferred}$ to $p_i$ is defined as follows:

$$dc_i(p_i) = c_i(p_i) - c_i(p_i^{preferred}) \tag{12}$$

The re-dispatch cost is zero for a resource that does not have energy bids because its schedule is not adjusted. Therefore, the total re-dispatch cost over all the resources is:

$$\sum_{i \in R} dc_i(p_i) = \sum_{i \in A} c_i(p_i) - \sum_{i \in A} c_i(p_i^{preferred}) \tag{13}$$

Since the preferred schedules are constant, the second term in (13) is a constant. Consequently, minimizing the total re-dispatch cost over all the resources is equivalent to minimizing the objective function in (1).

*Example A – Re-dispatch cost for generation and import*

The set of energy bids for each resource defines a monotonically increasing staircase-function consisting of 10 segments at maximum. In other words, the set of energy bids consist of up to 11 MW values and 10 prices. Figure 3 shows a typical bid curve for generators or imports.

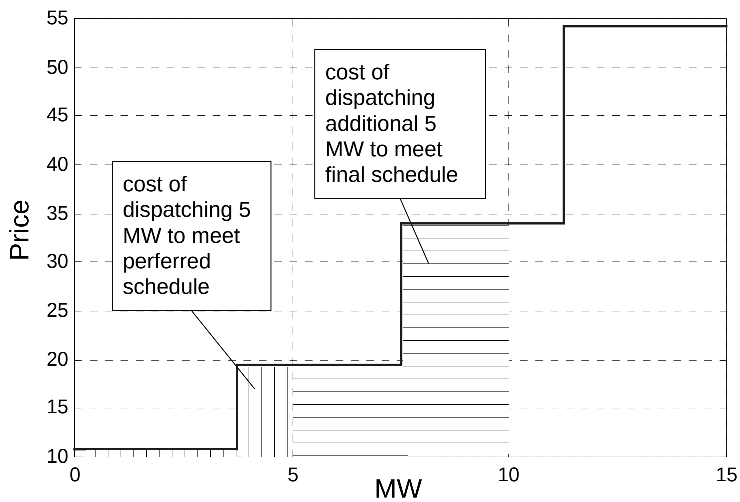


Figure 3- A typical energy-bid curve for generators and imports;

MW values = [0, 3.75, 7.5, 11.25, 15]; Prices = [10.75, 19.45, 33.96, 54.28]

This bid curve has 4 segments. The five MW values, i.e. [0, 3.75, 7.5, 11.25, 15], define the five junction points on the horizontal axis. The four prices, i.e. [10.75, 19.45, 33.96, 54.28], define the 4 price levels for the four segments. The cost of dispatching this resource is the area under the bid curve. For example, suppose the preferred schedule of this resource is 5 MW; the cost of dispatching 5 MW of this resource to meet the preferred schedule is the area shaded by vertical strips, which amounts to $65, i.e., (3.75-0)*10.75+(5-3.73)*19.45 = 65. Furthermore, suppose the final schedule of this resource is adjusted to 10 MW as a result of the congestion management. The cost of dispatching 10 MW of this resource is the total area shaded by both the vertical strips and the horizontal strips, which amounts to $199, i.e., (3.75-0)*10.75+(7.5-3.73)*19.45+(10-7.5)*33.96 = 199. The re-dispatch cost is the difference between the cost to meet the final schedule and the cost to meet the preferred schedule. In this example, the re-dispatch cost is $199-$65 = $134 which is represented by the area shaded by the horizontal strips.

*Example B – Re-dispatch cost for load and export*

Figure 4 shows a typical adjustment-bid curve for loads and exports.

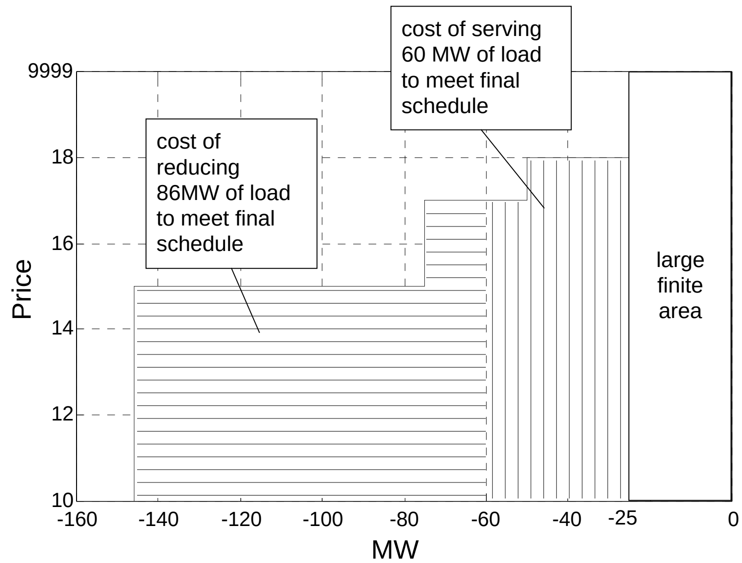


Figure 4- A typical adjustment-bid curve for loads and exports;

MW values = [-146, -75, -50, -25]; Prices = [15, 17, 18].

This bid curve has 3 economic segments in the range of –146 MW to –25 MW. The negative sign indicates negative injection to the bus, i.e., a load or an export. The range between –25 MW to 0 MW is non-economic range, meaning that the load is willing to be a price taker for the first 25 MW to be served. In practice, the non-economic range is indicated by a predefined high price, e.g. $9999/MW.  The four MW values at the junction points are [-146, -75, -50, -25]. The three prices are [15, 17, 18]. Suppose the preferred schedule of this load is 146 MW; the cost of serving this load to meet the preferred schedule is the area shaded by both the vertical strips and the horizontal strips, which amounts to -$1940, i.e., (75 - 146)*15+(50-75)*17+(25-50)*18 = -1940. The negative sign indicates that the load is willing to pay $1940 to have the 146 MW of load served. Suppose the final schedule of this resource is adjusted to 60 MW as a result of the congestion management; the cost of serving 60 MW of load is the area shaded by the vertical strips, which amounts to -$620, i.e., (50-60)*17+(25-50)*18 = -620. The large finite area in the non-economic range is not included in the above calculation because it does not affect the objective of minimizing the re-dispatch cost. Even if the large finite area (denoted by LFA) were included, the *re-dispatch cost* would still be the same. Specifically,

re-dispatch cost = (-$620  - LFA) – (-$1940 - LFA) = $1320

The positive re-dispatch cost of $1320 indicates the loss of revenue when load is not served.

## 8.4 Zonal Price

The nodal price is calculated based on the LaGrange multipliers. The LaGrangian function for the congestion management problem formulated in (1)-(5) is as follows:

$$L = \sum_{i \in A} c_i(p_i) + \sum_{j=1}^{n} \lambda_j \left( \sum_{k=1}^{n} B_{jk}\delta_k - \sum_{i \in R_j} p_i \right) + \sum_{b=1}^{m} \mu_b \left( \sum_{k=1}^{n} H_{bk}\delta_k - F_b^{\max} \right)$$

$$+ \sum_{i \in A} \pi_i^{\min}(p_i^{\min} - p_i) + \sum_{i \in A} \pi_i^{\max}(p_i - p_i^{\max}) \qquad (14)$$

The nodal price at bus $j$ is defined to be the LaGrange multiplier $\lambda_j$. Since the congestion management uses a radial network model, all the nodal prices within a congestion zone are equal. Therefore, the zonal price of a congestion zone equals to any nodal price in the zone. In fact, since a simplified network model is used where each zone and tie point is a node, the nodal price is the zonal price.

## 8.5 Energy Cost to Load

The energy cost for resource $i$ is different from its dispatch cost. The former is calculated based on marginal nodal price, and the latter is calculated based on bid prices. Energy costs can be calculated for all resources regardless of whether the resource has been assigned energy bids. Dispatch costs can only be calculated for resources that have submitted adjustment bids. The total energy cost for loads is calculated as follows:

$$\sum_{j=1}^{n} \sum_{i \in R_j \cap D} \left( \lambda_j \cdot p_i \right) \qquad (15)$$

# 9 Appendix B: Hourly Load Forecast Methodology

The load forecast for the year 2005 is based on the year 2000 with and annual load growth for the *peak* hourly load for the three internal zones as:

NP15 1.56% / year

ZP26 1.59% / year

SP15 2.08% / year

For all other hour besides the peak, these load growth ratios are scaled by the ratio of the load for that hour to the peak load. The following formula illustrates the forecast:

$$ZonalLoad_{2005}(h) = ZonalLoad_{2000}(h) \cdot \left(1 + G \cdot \frac{ZonalLoad_{2000}(h)}{ZonalLoad_{MAX}}\right)^5$$

Where G is the load growth factor.

Note that the load growth multiplier, $\left(1 + G \cdot \frac{ZonalLoad_{2000}(h)}{ZonalLoad_{MAX}}\right)$, is applied five times to the year 2000 load to yield the year 2005 load.

The year 2000 load data are based on metered UDC hourly loads. From the UDC area loads the Zonal load area calculated as follows:

NP15 load = .921 * PG&E UDC load.

ZP26 load = .079 * PG&E UDC load.

SP15 load = SCE UDC load + SDG&E UDC load.

# 10 Appendix C: External Generation

Similar to the new internal generation situation, there are several thousands of MWs of new generation under development outside of the CAISO control area that could be available to serve California load. New external generation is provided at COI, Eldorado, Palo Verde and Miguel (from Mexico).

The scenario is to use actual hourly external generation capacity taking into account hourly variations in external area load.

The total external capacity under development as of June 2001 is shown in Table 10.1

Table 10.1

| Stage | NW | SW | Mexico |
|---|---|---|---|
| Stage 1 | 2,884 | 4,447 | 640 |
| Stage 2 | 3,309 | 5,600 | 765 |

All generation projects currently under construction are Stage 1 and generation projects that have obtained a construction permit are Stage 2.

The different percentages applied to each Stage are given in the following table. As with the internal generation there will be 3 different scenarios produced by varying the amount of percentages.

Table 10.2

| Scenario | Stage | NW | SW | Mexico |
|---|---|---|---|---|
| 1 | 1 | 100% | 100% | 100% |
| 1 | 2 | 80% | 80% | 80% |
| 2 | 1 | 100% | 100% | 100% |
| 2 | 2 | 60% | 90% | 90% |
| 3 | 1 | 100% | 100% | 100% |
| 3 | 2 | 90% | 60% | 60% |

Scenario 1 is an average scenario in that the percentages are the same over all the regions. Scenario 2 is biased with toward more generation in the Southwest part and Scenario 3 is biased with more generation in the Northwest part.

The forecasted peak load increase between the years 2000 and 2005 in the Northwest, Southwest and Mexico are 4327 MW, 4262 MW and 497 MW, respectively. The load growth data is from the Western Systems Coordinating Council (WSCC). Taking the above percentages applied to the expected capacity and subtracting out the peak load growth results in the net external generation used in this study (Table C3).

Table C3

| Scenario | NW | SW | Mexico |
|---|---|---|---|
| 1 | 1,204 | 4,665 | 755 |
| 2 | 542 | 5,225 | 831 |
| 3 | 1,535 | 3,545 | 602 |

Note that the Southwest generation was evenly split between the Eldorado and Palo Verde tie points.

For the hourly new external generation the load growth is now set to vary hourly and the net generation is calculated based on the generation calculated from the data in table 10.1 and 10.2. The following formula illustrates how the hourly external generation is calculated for a given area (NW, SW or Mexico).

$$GenHourly(h) = GenMin + (GenMax - GenMin) \cdot \left(1 - \frac{AIL(h) - AILMin}{AILMax - AILMin}\right) - X$$

Where,

GenMin is the net new generation when load is at its peak.

GenMax is the total expected new generation when there is no load growth.

AIL is the adjacent internal load which is used as a proxy for the load shape of the external area. For SW and Mexico, the SP15 load is used. For NW, the NP15 load is used.

AILMax is the maximum load out of AIL

AILMin is the minimum load out of AIL

X is an offsetting factor for summer and winter peaking periods. This offsetting factor is necessary because the NW peaks in the winter and this winter peak exceeds the summer peak by about 1100 MW for the load growth from the year 2000 to 2005. Thus, X is set at 1100 MW for the NW for the periods of January 1 to January 31 and from October 15 to December 31. For all other hours of the year, X is set at zero and is also set at zero for all hours of the year for SW and Mexico.

# 11 Appendix D: Market Power

The CAISO Department of Market Analysis will perform a study of market power within each of the three internal zones.

# 12 Appendix E: Cost to Load Example and Analysis

In this section a simple three-part example is given below to show how the total cost to load may increase or decrease with the expansion of Path15 capacity. In these examples and in this study, the assumption is that the load does not submit any adjustment bids to resolve congestion.

**(1) No congestion with project:** Suppose that with the Path 15 upgrade there is no congestion and the three internal zonal prices are the same at $30/MWh. Assume the NP15 load to be 10,000 MWh and the SP15 plus ZP26 load to be 12,000 MWh. The total cost to load is 30*10,000 + 30*12,000 = $660,000.

**(2) Congestion without project:** Now assume that the upgrade is not in place and there is congestion in the south to north direction. Assume that after congestion management the south price is now $25/MWh and the north price is $40/MWh. The new cost to load is 25*12,000 + 40*10,000 = $700,000.

**(3) Congestion without project:** Now assume when there is congestion similar to part 2 of this example, but now assume that a different unit is the marginal unit in the north that is dispatched to relieve this congestion. Let the south price stay the same at $25/MW, but let the north price be only $32/MWh instead of $40/MWh as in part 2. The total cost to load is 25*12,000 + 32*10,000 = $620,000.

This example illustrates the point that the upgrade can either increase total cost to load or decrease total cost to load. In part 3 the cost to load is $620,000 and this is without the upgrade, while with the upgrade the cost to load rose by $40,000 to $660,000. However, in part 2 of this example, the cost to load decreased with the upgrade from $700,000 to $660,000. The key factors in determining if there is an increase or decrease in the cost to load are the zonal marginal prices and how much they vary, under the congested case, from the unconstrained price.

A more analytic approach is the following. Let $L_N$ and $L_S$ be the NP15 and SP15+ZP26 load, respectively. Let $\lambda_N$ and $\lambda_S$ be the marginal prices of NP15 and SP15 (and ZP26), respectively. Assume the project to be complete and there is no congestion. Under this scenario, there is one MCP (the unconstrained price) over the three zones, therefore $\lambda_N = \lambda_S$. The cost to load is $\lambda_N * L_N + \lambda_S * L_S$. Now assume that the project is not present, which would reduce the total transfer limit on Path 15, and now under the same situation there is congestion in the south to north direction. As noted before, under congestion the price in the south will remain constant or be reduced and the price in the north will remain the same or be increased. Let $\Delta\lambda_S$ be the amount of price reduction in the south and let $\Delta\lambda_N$ be the amount of price increase in the north. The new cost to load is then $(\lambda_N + \Delta\lambda_N) * L_N + (\lambda_S - \Delta\lambda_S) * L_S$. Note that $\Delta\lambda_S$ is a positive value, which is the reason for the negative sign in the cost to load equation. If the cost to load under the uncongested scenario (with upgrade) is subtracted from the cost to load under the congested scenario, the difference is $\Delta\lambda_N * L_N - \Delta\lambda_s * L_s$. Savings from the upgrade would be when $\Delta\lambda_N * L_N - \Delta\lambda_s * L_s > 0$ holds, i.e., when the cost to load under congestion is greater than the cost to load under no congestion. Rearranging this equation, for a saving to occur for the upgrade, the change in prices must be such that $\Delta\lambda_s/\Delta\lambda_N < L_N/L_s$. Assuming the load does not adjust, the change in the prices is what determines the cost or savings of the upgrade with respect to cost to load.

If this inequality condition is applied to the above numerical examples, then the results are as follows:

Part (2): $\Delta\lambda_s$ = \$5/MWh, $\Delta\lambda_N$ = \$10/MWh, $L_N$ = 10,000 MWh, $L_s$ = 12,000 MWh. The inequality 5/10 < 10/12 holds, and the result is a savings by increasing the capacity of the Path 15.

Part (2): $\Delta\lambda_s$ = \$5/MWh, $\Delta\lambda_N$ = \$2/MWh, $L_N$ = 10,000 MWh, $L_s$ = 12,000 MWh. The inequality 5/2 < 10/12 does not hold, and the result is a cost by increasing the capacity of the Path 15.